I&EC research
Industrial & Engineering Chemistry Research
pubs.acs.org/IECR

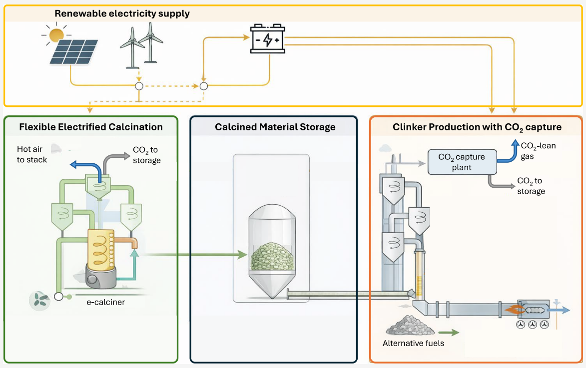
Article

Renewable Electrified Cement Production: Flexibility and Economic Competitiveness

Sebastian Andres Quevedo Parra and Matteo C. Romano*

Cite This: *Ind. Eng. Chem. Res.* 2026, 65, 10813−10839

ABSTRACT: Cement production remains among the most carbon-intensive industrial processes due to intrinsic process emissions and the conventional use of fossil fuels to supply the thermal demand in Portland clinker manufacture. While carbon capture and storage (CCS) is widely regarded as the cornerstone of decarbonization in this sector, electrification offers a complementary pathway capable of eliminating combustion-related emissions and enhancing the efficiency of CO_2 capture systems. This study presents a comprehensive techno-economic assessment of renewable-powered electrified cement configurations benchmarked against leading CCS alternatives. Using detailed process modeling and a mixed-integer linear programming framework, we evaluate fully (completely electrified thermal energy demand) and partially (electrified thermal energy demand either in the calciner or in the rotary kiln) electrified plants under varying technology integrations, cost scenarios, and renewable supply conditions, including operational flexibility enabled by intermediate calcined-material storage. The analysis spans four geographically diverse locations to capture the effects of renewable resource quality and their impact on economic performance. Full electrification eliminates fuel combustion but increases electricity demand by approximately an order of magnitude relative to a conventional cement plant, while partially electrified configurations require 4.5−7 times more electricity. When combined with alternative fuels containing 30% biogenic carbon, partially electrified configurations equipped with CCS can achieve net-negative direct emissions through the capture of biogenic CO_2. However, conventional CCS benchmark plants capture larger CO_2 volumes and, therefore, derive greater economic benefits from carbon credits. Introducing operational flexibility in configurations with an electrified calciner and an alternative fuels-fired kiln enables long-duration load shifting, reducing renewable overbuild and curtailment by 7−26%, lowering the levelized cost of renewable electricity by 37−48%, and decreasing the cost of avoided CO_2 by up to 17%, depending on location and time frame. Despite these improvements, a retrofitted Oxyfuel plant remains the most economically favorable decarbonization pathway under baseline assumptions. Sensitivity analyses indicate that electrified alternatives could become competitive in regions with abundant low cost, low-carbon electricity, and limited access to the CO_2 transport and storage infrastructure, albeit under conditions of significant capital expenditure and technology integration uncertainty.



1. INTRODUCTION

Cement manufacturing stands as one of the most carbon-intensive and hard-to-abate industrial activities, accounting for approximately 7% of global CO_2 emissions.[1,2] This is largely due to fossil-based energy consumption and the intrinsic nature of Portland clinker production, which lies at the heart of cement manufacturing. Nonetheless, the cement industry has taken bold steps toward climate mitigation, leading other heavy industries in pledging net-zero emissions targets by 2050.[3] To this end, industry is actively advancing and implementing a comprehensive range of decarbonization strategies across its value chain.

These include incremental and near-term levers that can be implemented within existing production systems, such as the increased use and development of new supplementary cementitious materials (SCMs) to reduce the clinker factor,[4] coprocessing of nonreusable and nonrecyclable waste materials as alternative fuels to displace fossil inputs and offer waste management benefits,[2,5] optimization of structural design and improvement of efficiency in concrete use to reduce material demand,[3,6] and enhancement of circularity through concrete recycling and component reuse.[6]

In parallel, the industry is pursuing structural, capital-intensive transformation pathways, including large-scale electrification of thermal processes and the deployment of carbon capture and storage (CCS), and carbon capture and utilization (CCU) technologies.[2] Unlike incremental measures, these interventions

Received: December 31, 2025
Revised: April 3, 2026
Accepted: April 17, 2026
Published: May 18, 2026

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

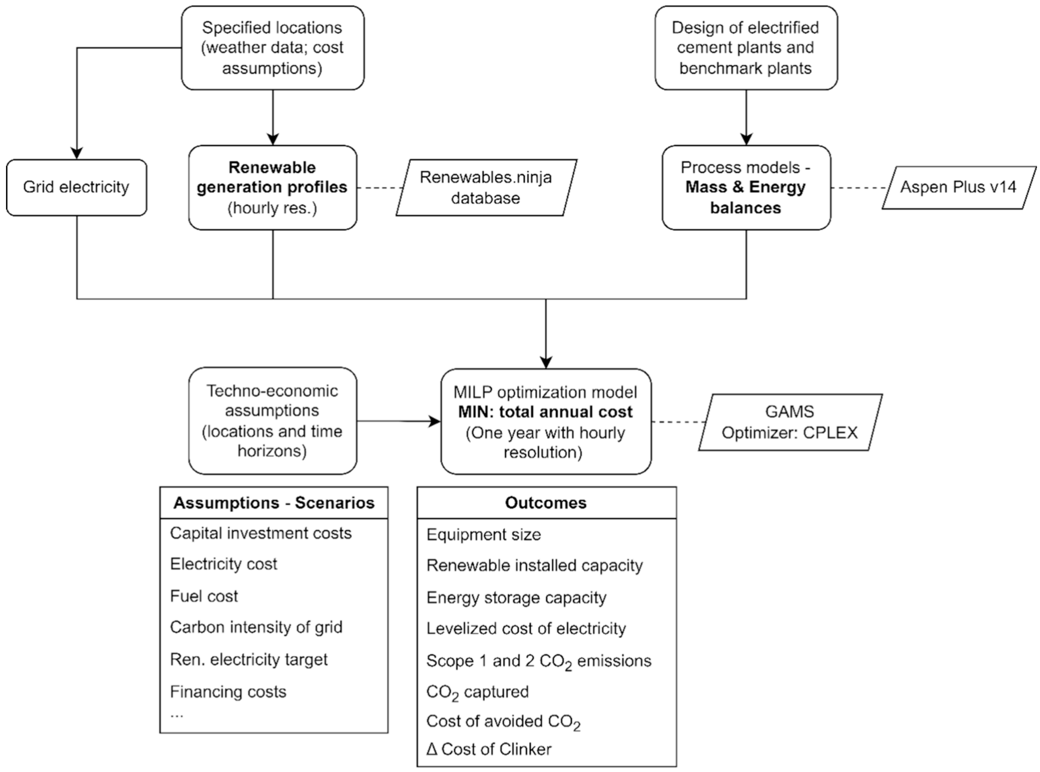


Figure 1. Methodological framework for the techno-economic evaluation.

require substantial infrastructure development, technology integration, and long lead times of investment, but they offer the potential for deep emissions reductions at the process level.

Despite the progress and potential of efficiency improvements, material substitution, and fuel switching, carbon capture remains indispensable for achieving the full decarbonization of cement production. This is primarily due to the dominance of process-related emissions in clinker manufacturing. These emissions arise from the calcination of limestone ($CaCO_3 \rightarrow CaO + CO_2$), which accounts for roughly 60−70% of total direct emissions.[3,7] Even under ambitious scenarios of fuel switching and clinker substitution, inherent chemical emissions cannot be eliminated without CO_2 capture. According to the Global Cement and Concrete Association (GCCA) estimates, CCS/CCU is projected to contribute approximately 36% of emissions reduction by 2050, making it the largest single lever for deep decarbonization.[3] Significant investments are currently being channeled into research, development, and demonstration projects to commercialize these breakthrough technologies, reflecting strong momentum toward their large-scale deployment.[2,3,8]

In this context, electrification emerges as a complementary strategy that can offer compelling synergies with CCS/CCU in cement production.[9] Electrified heating through plasma burners, resistance heaters, or other high-temperature technologies can fully eliminate fossil fuel-related emissions, leaving a concentrated CO_2 stream dominated by calcination emissions.[7,9−11] This reduces flue gas volumes and increases CO_2 concentrations,[9,10] potentially lowering capture, transport, and storage costs. Thus, electrification not only provides a direct decarbonization pathway for energy-related emissions but also acts as an enabler for more efficient and cost-effective CCS/CCU deployment for process emissions.

Recent years have seen a surge in R&D activity around electrified cement production. Plasma heating has been explored in the CemZero project,[10] including pilot tests,[12] in the EU Horizon 2020 ELECTRA project,[13] and by Holcim in partnership with SaltX Technology's Electric Arc Calciner.[14] Hydrogen combustion, primarily as a co-fuel to boost the calorific value of low-LHV alternatives, has been tested by CEMEX across European kilns since 2021[15] and in the UK Mineral Product Association's (MPA) Net-Zero Fuel project.[7] Resistance heating for precalciners has been advanced through the ELSE II project in the University of South East Norway,[16−18] through Finland VTT's Decarbonate pilot project,[19] and via detailed techno-economic research by Varnier et al. (2025).[20] Likewise, the LEILAC project's drop-in reactor design is fuel agnostic, including the potential for electrification.[21] Additional concepts include Coolbrook's RotoDynamic heater, which can be applied to both the calciner and kiln, and FLSmidth's ECoClay electrified clay calcination.[22,23] Lastly, startups such as Sublime Systems are pursuing electrochemical routes that could fully replace conventional pyro-processing techniques.[24−26]

Despite this momentum, significant knowledge gaps remain in the techno-economic understanding of how to effectively deploy electrification technologies for cement production and whether pursuing such strategies is economically and environmentally warranted. Most existing literature treats CCS as the primary decarbonization route with limited comparative analyses of electrification versus CCS under consistent modeling assumptions. For electrification to emerge as a viable large-scale strategy, it must demonstrate cost-competitiveness with CCS, either as a stand-alone option or in integrated configurations with alternative fuels or biomass, and prove to be operationally compatible with high shares of variable renewable electricity. This includes the potential for operational flexibility to provide

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

long-term and demand-side grid-balancing support and enable deeper renewable penetration.[27,28]

These knowledge gaps hinder the ability of industry stakeholders and policymakers to assess the long-term role of electrification in the decarbonization of the cement industry. To address them, this study builds on our earlier work[9] and develops a comprehensive techno-economic framework to systematically compare electrification pathways with leading CCS configurations across multiple geographical and market contexts. The analysis integrates process-level modeling, renewable energy system design, and operational flexibility considerations under both near- and long-term cost scenarios to capture the impact of technology learning and regional variability.

To this end, the study pursues the following objectives:

1. To develop detailed process models of electrified cement plants using multiple electrification technologies and to benchmark them against state-of-the-art CCS strategies, with renewable capacity optimally sized to local resource conditions under different cost scenarios.
2. To design and evaluate a partially electrified clinker manufacturing process that incorporates operational flexibility through the storage of calcined material, providing an additional degree of freedom to cope with renewable electricity intermittency.
3. To implement a Mixed-Integer Linear Programming (MILP) framework for the optimal design of renewable energy generation portfolios and energy storage systems for electrified cement plants across representative locations, considering both conservative (short-term) and optimistic (long-term) cost scenarios.
4. To assess the techno-economic conditions under which electrification pathways may deliver economic and environmental advantages relative to CCS-based strategies, and to quantify the trade-offs between these decarbonization options.

2. METHODS

This section introduces the methodology developed to evaluate the techno-economic performance of electrified cement plants under different scenarios, conceptually summarized in Figure 1. Electrified systems were designed and translated into rigorous process models built in Aspen Plus to obtain mass and energy (M&E) flows. Likewise, M&E balances of decarbonized plants based on benchmark CCS technologies were calculated using a mixture of process modeling and available information from the literature. Energy demands can be met by burning coal, alternative fuels (AF), electricity (from the local grid and on-site renewable production), or a combination of these, depending on the characteristics of the decarbonization strategy. The renewable electricity supply is modeled considering location-specific generation profiles for PV panels and onshore/offshore wind turbines, retrieved from one representative year with hourly resolution. Moreover, the portfolio and size of captive renewable installed capacity, energy storage options, and other process equipment were optimized using an MILP model developed to minimize the total annual cost of clinker production, taking into account a range of techno-economic assumptions specific to different scenarios based on location and time horizon.

The details of each step are described in the following subsections.

2.1. Design of Electrified Cases

Fully and partially electrified cement plants were designed based on direct or indirect electrification technologies tailored to the specific heat demand characteristics of the various unit operations in a conventional clinker manufacturing plant. Three cases were designed:

i) eC-p*K* (*fully electrified*): involves an electrified calciner (eC; e-calciner) via electric resistances or inductive heating, a CO_2 purification and compression unit (CPU) to capture process emissions, and plasma burners to supply the high-temperature heat in the rotary kiln (p*K*).

ii) OC-HK (*partially electrified*): consists of the oxy-fired combustion of alternative fuels in the calciner (OC), a CPU to treat emissions arising in the calciner, and combustion of green hydrogen (H_2) from a solid oxide electrolysis cell system (SOEC) in the rotary kiln (HK). This design leverages available waste heat from unused tertiary air to generate steam for the SOEC.

iii) eC-afK (*partially electrified*): combines an electrified calciner (eC) heated via resistive elements or magnetic induction, a CPU for process emissions, and the combustion of alternative fuels in the rotary kiln (afK) coupled with a solvent-based postcombustion capture (PCC) system to manage the kiln's flue gas. The design takes advantage of available waste heat from tertiary air to meet most of the heating requirements for solvent regeneration, utilizing a heat pump to supply the remaining needs.

Figure 2 shows the simplified diagrams of the three electrified cases consisting of a preheating tower, calciner, rotary kiln, and clinker cooler, with additional input/output streams and equipment representing the modified processes of the electrified systems.

Mass and energy balances were calculated by building process models in Aspen Plus. First, a baseline model was developed, simulating industrial Best Available Technique (BAT) conditions for a five-stage cyclone preheater, calciner (consuming 62% of total plant fuel, achieving 94% calcination), rotary kiln, and grate cooler. A comprehensive description of the characteristics of the reference process model is presented in the Supporting Information, Section (SI-S1).

Second, electrified designs were incorporated into the simulation of the reference process (host plant) by modifying the operating conditions to adapt to the features of each electrification technology. A thorough explanation of the operating parameters and bibliographic background supporting the main assumptions of each case is given in our previous work.[9] Detailed information on the process flowsheets is provided in SI-S2.

Each electrified cement plant design reflects the unique characteristics of the underlying electrification pathway. However, several overarching considerations apply to the techno-economic evaluation of all cases.

First, to facilitate effective CO_2 capture via the CPU and reduce operating costs, process emissions from the calciner must remain undiluted by the flue gas from the rotary kiln. To achieve this, the preheater tower is split into two parallel preheating strings (PHS), separating the gas streams and preserving the high CO_2 concentration. Second, false air ingress—a significant source of dilution and inefficiency in conventional cement kilns—should be minimized through improved sealing, enhanced maintenance, and operational practices. In this study, a 90% reduction in false air ingress relative to typical plant operation is assumed. Third, any mineralogical deficiency as a consequence of removing fuel combustion from the process and dust recirculation into the calciner can be balanced with the use of corrective materials at the kiln's inlet. A recent techno-economic study conducted by Varnier et al. (2025) studied the impact of electrifying the calciner under different configurations. They adjusted the raw meal composition required to maintain consistent clinker chemistry to a coal-based scenario, resulting in differences in the order of 0.01−0.46% wt. in raw meal constituent materials.[20] Therefore, it is assumed that small discrepancies in clinker composition from the process models of electrified plants concerning the reference process can be managed with a negligible impact on the techno-economic outcomes.

Finally, fuel sourcing assumptions align with the decarbonization objectives of the analysis. As of 2021, 53% of the cement industry's thermal energy demand in Europe was met with AF, and some kilns have already achieved a 100% AF substitution rate.[3,29] In line to explore fully decarbonized production routes, it is assumed that 100% of the

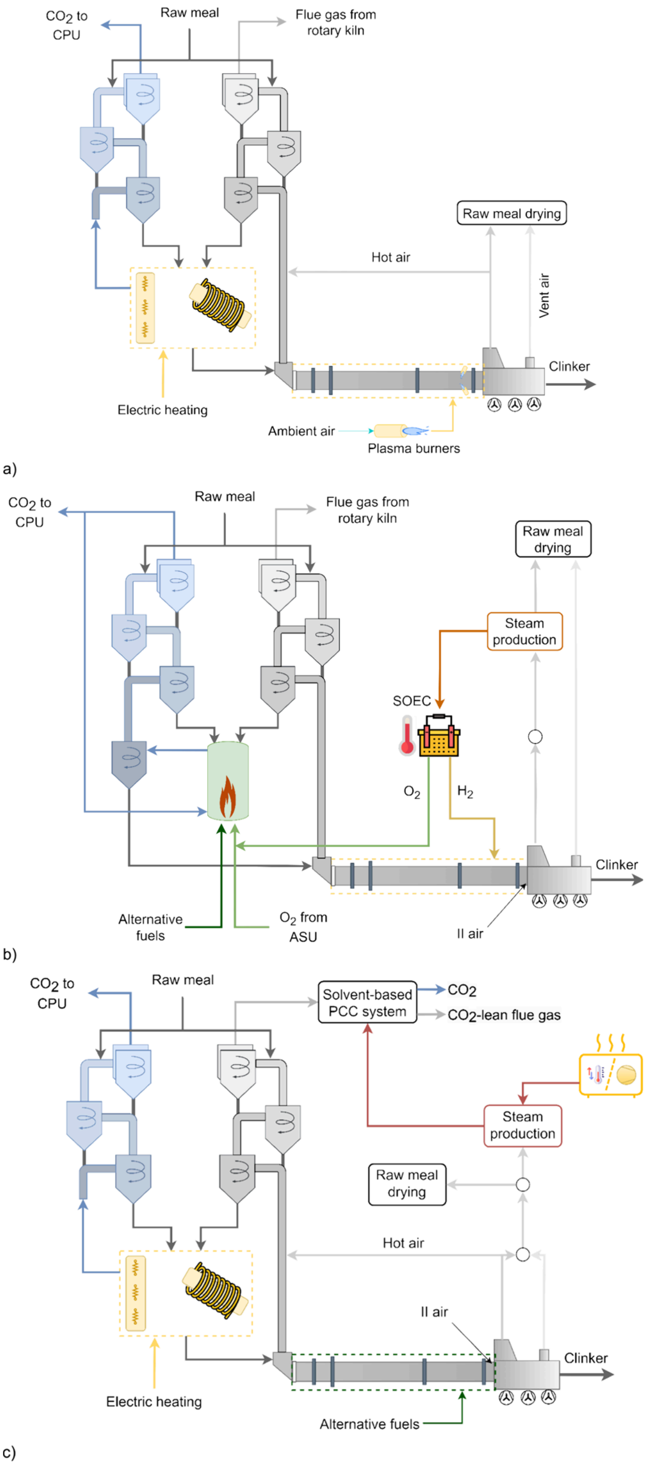


Figure 2. Simplified diagrams of the three electrified cement plants indicating main mass and energy input/output streams: (a) eC—p*K*; (b) OC—HK; (c) eC—afK.

nonelectrified thermal demand is met with AF (for electrified systems and CCS benchmark plants), containing a 30% biogenic fraction.[30] Energy flows and CO_2 emissions from coal-based operation of the reference plant and the CCS benchmark are included in the technical results for comparison.

2.2. Flexible Configuration

The flexible, partially electrified eC-afK design can be described as two separate sections (or two separate manufacturing plants), linked by an intermediate storage unit (Figure 3). The first section delves into the production of calcined material, which needs to be cooled before storage. This is performed with an intermediate grate cooler, where inlet air (stream #9) is adjusted to achieve an outlet calcined meal temperature of 100 °C. Two parallel strings are used to preheat the raw meal before the e-calciner. A fraction (#3) is preheated using the hot CO_2 generated during the calcination of the limestone, extracted with an ID fan at the top of the PHT. The other share of the raw meal (#2) is preheated by the hot air exiting the intermediate cooler (#10). In addition, high-temperature air (i.e., former tertiary air) from the clinker cooler (#18) might be diverted to the air-heated string to assist with the preheating, maintaining a solids outlet temperature below 750 °C (#6). With the assumed false air ingress improvement, hot CO_2 (#5) with a concentration >98%vol.dry is sent for compression and purification[31] and then to transport and storage (T&S), assuming pipeline transport conditions of 110 bar and 30 °C. Meanwhile, the gas outlet from the air-heated string (#4) is sent to the stack after heat recovery.

It is important to note that the modeled system does not rely on entrained calcination, meaning CO_2 recycling is avoided. Moreover, the design of the e-calciner itself is not within the scope of this study. Instead, the e-calciner can be considered as either a rotary system or a drop-in tube to prevent additional energy consumption associated with the heating of the recycled gas.[20,32,33] Alternatively, a packed bed calciner similar to the ones used in the Lime industry could be envisioned with the use of coarse material and a high-purity limestone feed. Such a configuration would require a shaft-type preheater and a downstream milling step to ensure an adequate particle size for the kiln feed. Regardless of the design, the techno-economic results presented here are valid for electrified systems that do not require CO_2 recycling, thus minimizing complexity and efficiency losses. The process model was built as a drop-in tube, assuming ΔT = 70 °C between the inlet material and exiting CO_2.

Equipment in the flexible section is assumed to operate reliably within a range of 20% (minimum operating load) and 150% (maximum operating load) of throughput under an inflexible design. These operational boundaries were selected to avoid equipment start-ups and shutdowns while limiting excessive oversizing of major unit operations.

In the techno-economic evaluation, the e-calciner, preheating string (calciner), and CO_2 compression are each presumed capable of sustaining off-design operation within the specified operational envelope. For tractability, the economic impact of efficiency losses at part load, such as reduced reaction efficiency in the e-calciner or diminished gas—solid heat transfer in the preheaters, was not included. Likewise, modifications and efficiency penalties to accommodate widespread CO_2 throughput in the CPU were not incorporated in the economic evaluation.

The section after the intermediate storage involves the clinker production, which follows a typical *preheater + rotary kiln* configuration plant, with the addition of a PCC unit designed to capture the CO_2 in the kiln's flue gas. The carbon capture plant was not modeled but treated as a black box, scaling capital investment and operating costs from refs 34,35 and assuming that the heat for solvent regeneration in the stripper column is supplied via heat pump with a constant COP of 2.

Instead of raw meal, the preheater is fed with calcined material from the storage silos (#12), passing through a series of three cyclones in counter current with the flue gas of the rotary kiln entering the last stage at 1138 °C (#15), allowing the solids to reach a temperature of 829 °C (#14). Clinker production is kept constant by feeding a continuous supply of calcined meal from the intermediate storage (#12).

Heat integration is key to reducing energy penalties of the plant. Part of the available heat from the high-temperature clinker cooler outlet air (formerly used as tertiary air to assist combustion in the precalciner) together with vent air is used to preheat the raw material in the Raw Mill (#22), while the remainder is used to produce steam for the regeneration of the solvent in the PCC system (#21). The latter is supplemented with available heat from the hot CO_2 exiting the calciner string (#5) and hot gases from the kiln string (#13). To ensure the conditions of the generated steam are sufficient to regenerate the MEA solvent, the availability of waste heat is assumed up to a temperature of 135 °C. If heat from the high-temperature clinker cooler outlet air is still

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

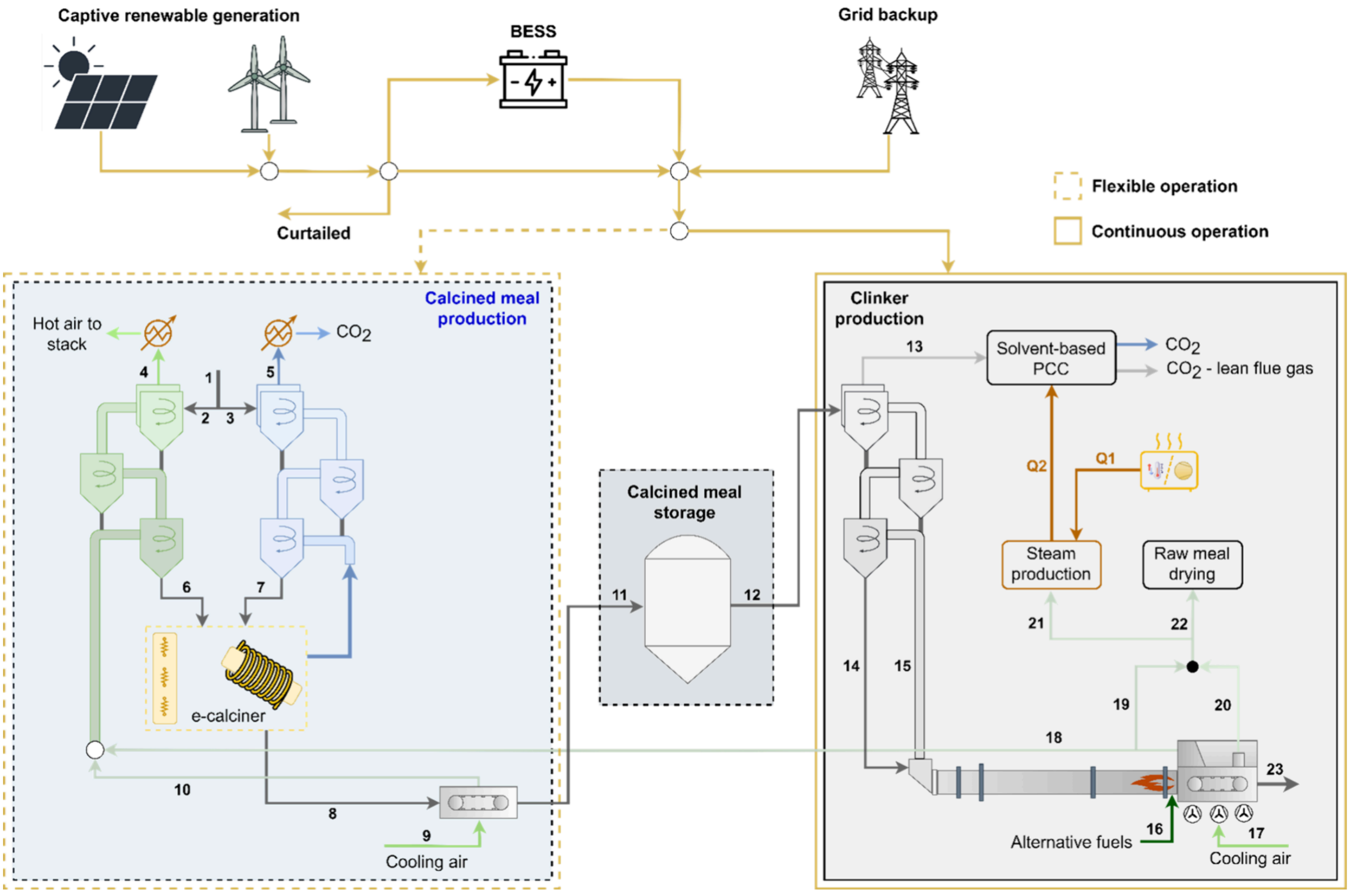


Figure 3. Flexible eC: afK plant configuration with storage of intermediate calcined material.

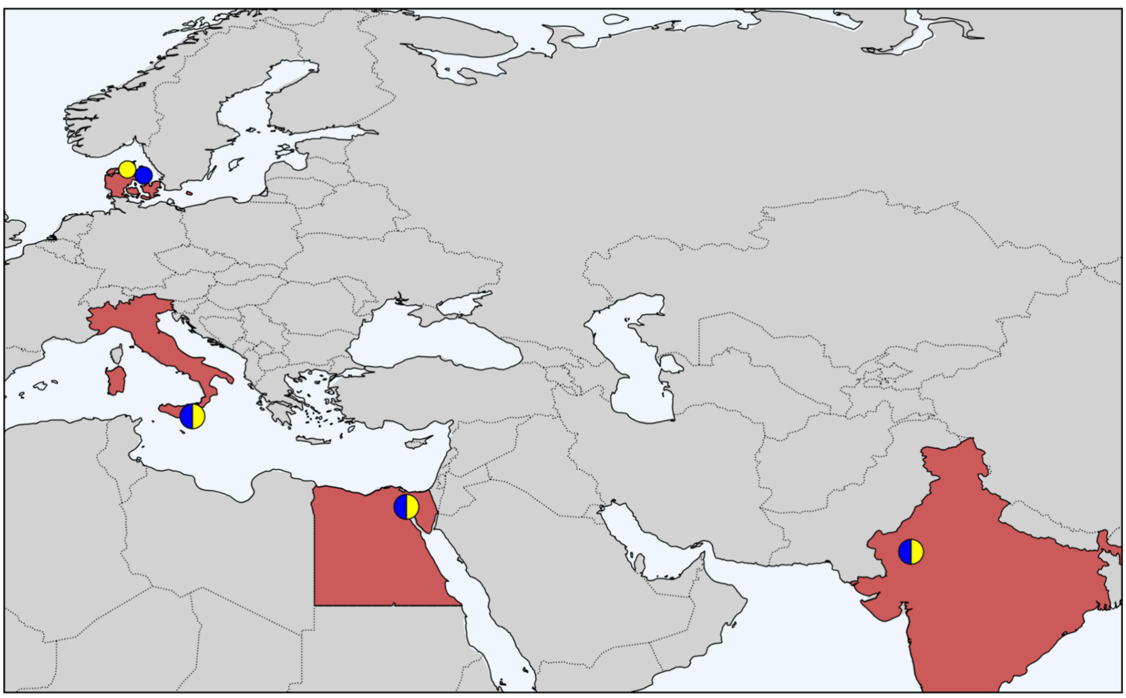


Figure 4. Map of locations chosen for the techno-economic assessment. Yellow and blue patterns indicate the positions of the PV panels and wind turbines, respectively.

available, then a portion is diverted to support the preheating of raw meal in the air-heated string (#18).

Detailed information about the operating conditions of the streams is provided in SI-S2, under three representative operating modes. These include minimum load, maximum load, and a continuous-load case. In

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

this latter operating mode, the calcined output of the flexible section precisely matches the feedstock demand of the downstream clinker production unit to meet the constant clinker demand.

2.3. Optimization Model

A Mixed-Integer Linear Programming model was developed in GAMS, employing the CPLEX solver, to capture the mass and energy interactions within the flexible, partially electrified eC−afK cement plant. The model operates with an hourly resolution over a full annual cycle, aiming to minimize the total annual cost (TAC) of clinker production by simultaneously optimizing the renewable energy generation mix (including storage systems) and the capacity of the flexible plant section. Key material and energy balances related to the calcined meal and clinker production stages were linearized to comply with the MILP structure, assuming a constant clinker output of 117.1 tons per hour. Specific techno-economic parameters were varied depending on location and time horizon to evaluate how external conditions influence the economic viability of electrified configurations. A detailed description of the optimization algorithm and model formulation is provided in SI-S3.

2.4. Locations

To assess the influence of meteorological variability on the techno-economic performance of electrified cement processes, the MILP model was applied to four geographically and climatically distinct locations. In addition to quantifying performance under diverse renewable energy profiles, the assessment includes a comparison of electrified process competitiveness against benchmark CCS configurations. This comparison is made under both short- and long-term cost assumptions, providing insights into the geographical and temporal conditions most favorable for the deployment of electrified process technologies.

The selected locations include Denmark, southern Italy (Sicily), Egypt (Suez region), and northwest India (Jodhpur; Figure 4). These sites span a broad spectrum of renewable resource availability, ranging from high wind penetration in the North Sea to strong solar irradiance in arid and subtropical regions. This geographic diversity allows for the identification of key renewable configurations and techno-economic characteristics that could support the viable adoption of electrified cement production systems across various regional contexts.

In all cases, electricity supply is modeled as a combination of on-site (captive) renewable generation, meeting most of the demand, and a grid connection to cover residual demand. Consequently, the optimal energy mix is location-specific and is determined endogenously by the MILP model. The renewable electricity input is derived from hourly generation data for photovoltaic (PV) panels and wind turbines (WT), obtained from the renewables.ninja platform.[36] Meteorological data from the selected source, including hourly solar irradiance and wind speeds, are retrieved from two databases for a representative year (2019): NASA's Modern-Era Retrospective Analysis for Research and Applications[37] and CM-SAF's SARAH data set.[38] The solar irradiance and the wind speeds are converted into power outputs using the models developed by Pfenninger and Staffell.[39,40]

Each location was evaluated under two distinct scenarios: a short-term outlook, representing current technology and cost structures, and a long-term horizon, in which capital investment costs for renewable generation, key process equipment, and grid electricity decarbonization are assumed to improve, in line with expert projections. These are described in more detail in the next subsection.

Table 1 summarizes the main assumptions used to estimate the hourly power outputs from PV panels and wind turbines. Fixed-tilt PV panels with constant azimuth and inclination were assumed across all locations, based on renewables.ninja's default alternative. For wind generation, onshore wind turbines (Vestas v90 2.0 MW, 80 m hub height) were used in Egypt, India, and Italy, while the Danish case leveraged the region's exceptional offshore wind resource. Here, the model adopts the configuration of an existing offshore wind farm located nearby, based on technical data reported by Ørsted.[41] Furthermore, capacity factors provide a good estimate of the diverse renewable resource availability from the chosen locations, which is further exacerbated by differences in daily and monthly variations not captured by this general parameter.

Table 1. Location-Specific Characteristics for Optimization of the Renewable Electricity Generation Portfolio

	Italy	Denmark	India	Egypt
year of data	2019	2019	2019	2019
Photovoltaic (PV)				
latitude	37.1935	57.0463	26.2968	29.9123
longitude	15.1781	9.9215	73.0351	32.4076
capacity factor	19.0%	12.9%	19.3%	21.8%
system loss	10%	10%	10%	10%
tracking	no	no	no	no
tilt	35°	35°	35°	35°
azimuth	180°	180°	180°	180°
Wind power				
location	onshore	offshore	onshore	onshore
latitude	37.1935	56.5834	26.2968	29.9123
longitude	15.1781	11.2439	73.0351	32.4076
capacity factor	30.3%	55.8%	21.3%	35.4%
hub height	80m	80m	80m	80m
turbine model	Vestas v90 2000	Siemens SWT 3.6 120	Vestas v90 2000	Vestas v90 2000

2.5. Key Performance Indicators

The assessment of electrified cement plants was conducted through a series of technical and economic key performance indicators (KPI) from a gate-to-gate perspective. In addition to electrified systems, two CCS benchmark plants were included, namely, a retrofitted Oxyfuel cement plant and a solvent-based postcombustion capture (PCC) plant using a heat pump with a COP of 2 to supply the regeneration heat (see description and main assumptions of CCS benchmark processes in the SI-S4).

Furthermore, the decarbonization strategies were evaluated under two time horizons, short-term and long-term, applied consistently across the four geographic locations. The short-term outlook assumes construction starting around 2030 and reflects current cost estimates for renewable generation equipment, storage mechanisms, and technologies supporting the different decarbonization routes as well as location-specific grid electricity characteristics. The long-term horizon assumes construction starting around 2050, with capital investment costs of key technologies, both for renewable electricity production and for the operation of electrified and CCS benchmark plants, updated based on best estimates from techno-economic reports to reflect more favorable conditions for the implementation of electrified systems. The reference years 2030 and 2050 are used as indicative temporal anchors to contextualize technology cost assumptions rather than as fixed deployment targets.

2.6. Environmental Performance

The environmental performance of the assessed technologies was evaluated by combining direct and indirect emissions, termed net emissions. Direct emissions arise from the decarbonation of raw materials during clinker production (i.e., process emissions) and fuel combustion. These emissions also reflect any balance of neutral CO_2, if a portion of the fuel originates from biogenic sources. Equation 1 shows the components of direct CO_2 emissions:

$$CO_2^{dir} = CO_2^{process} + CO_2^{fuel} - CO_2^{bio} - CO_2^{capt} \quad (1)$$

where $CO_2^{process}$ corresponds to process emissions, CO_2^{fuel} represents overall emissions from fuel combustion, CO_2^{bio} represents the emissions from biogenic fuel combustion, and CO_2^{capt} is the amount of captured CO_2 transported to a storage site, all expressed in kg_{CO2}/t_{clk}.

To assess the decarbonization impact of each technology, both direct and net CO_2 emissions avoidance were estimated. The direct CO_2 avoidance rate is calculated from eq 2:

$$CO_2^{av,dir} = 1 - \frac{CO_2^{dir,tech}}{CO_2^{dir,ref}} \quad (2)$$

where $CO_2^{dir,tech}$ are the direct emissions from the decarbonized plant and $CO_2^{dir,ref}$ the direct emissions of the reference process.

Net CO_2 emissions avoidance is computed analogously, incorporating both direct and indirect emissions, thereby capturing the full climate impact of fuel substitution and electricity use:

$$CO_2^{av,net} = 1 - \frac{CO_2^{dir,tech} + CO_2^{ind,tech}}{CO_2^{dir,ref} + CO_2^{ind,ref}} = 1 - \frac{CO_2^{net,tech}}{CO_2^{net,ref}} \quad (3)$$

Indirect emissions are associated with electricity sourced from the grid and the captive renewable electricity portfolio. The latter was estimated by incorporating CO_2 emissions embedded in the construction and installation of PV panels, wind turbines, and the battery energy storage system (BESS). These were calculated using figures retrieved from life cycle assessment (LCA) studies found in the literature, expressed as kg of CO_2 per kW or kWh of installed capacity, and summarized in Table 2. Meanwhile, the contribution of grid electricity was based on site- and time horizon-specific carbon intensity values. For consistency, the comparative reduction in net CO_2 emissions was conducted considering a mix of renewable energy and grid backup to supply the electricity demand in the reference process (as defined in Table 8), consistent with the location and time horizon.

Table 2. Summary of Embedded CO_2 Emissions for Renewable Energy Generation Technologies

technology	embedded indirect emissions (LCA)	lifetime	reference
PV panels	810 [kg_{CO2}/kW_p]	25 years	42
wind turbines	600 [kg_{CO2}/kW_p]	25 years	43
BESS	70 [kg_{CO2}/kWh]	13 years	44

2.6.1. Economic Performance. *2.6.1.1. Captive Renewable Generation Portfolio.* A summary of the cost assumptions used to model the electricity supply portfolio under both time scenarios is presented in Table 3. Capex of renewable electricity technologies was gathered from different sources. In the short term, investment costs for Denmark, Italy, and India were based on the 2022 edition of IRENA's Renewable Power Generation Costs report.[45] For wind turbines, the values reflect the weighted average total installed costs for onshore wind in Europe (applicable to Italy), onshore wind in India, and offshore wind in Denmark. In the case of Egypt, PV capex was derived from reported investment costs associated with the 200 MW Kom Ombo utility-scale solar PV farm.[46] For onshore wind, the most conservative capex figure was adopted from a detailed techno-economic assessment of a 50 MW wind farm in Egypt.[47]

Long-term capex assumptions for PV systems were sourced from ref 48 and were applied uniformly across all locations. While the report provides projections for 2050, the 2030 estimates were adopted to partially offset the lower starting values compared with those used in the short term scenario. For onshore wind, a reference value of 1000 €/kW from the same study was assumed for Italy. For India and Egypt—both of which exhibit lower short-term capex—the same percentage reduction as in the Italian case was applied to maintain relative consistency. Similarly, for Denmark, the projected cost reduction ratio for offshore wind turbines between 2020 and 2030 was applied to the short-term baseline.

Battery system parameters used in the MILP model were compiled from a range of recent literature sources. Capital expenditure figures reflect the most favorable estimates from,[48−51] which forecast significant cost reductions over the long term due to learning experiences in component manufacturing. Other key operational parameters incorporated in the model include the depth of discharge (DoD),[52] system lifetime,[49−51] charge and discharge efficiencies,[50] self-discharge rate,[49] energy to power ratio, fixed opex,[50] and replacement costs.[53]

The optimization of the management of variable renewable energy is completed with the storage of calcined meal and the use of grid backup. A capital cost of 130 €/t_{CM} was assumed for solid-material storage silos, applied uniformly across all locations and time horizons. This reflects a mature technology with a minimal expected cost decline. To simulate realistic decarbonization trajectories, renewable penetration constraints were imposed in the MILP formulation. In the short-term scenario, grid

Table 3. Key Assumptions Used for the Evaluation of the Renewable Electricity Supply to Decarbonized Cement Plants

	Italy		Denmark		India		Egypt	
	short-term	long-term	short-term	long-term	short-term	long-term	short-term	long-term
PV								
capex [€/kW]	780	306	780	306	590	306	824	306
opex [%capex/year]	2%	2%	2%	2%	2%	2%	2%	2%
on-shore Wind								
capex [€/kW]	1500	1000			920	620	906	607
opex [%capex/year]	2%	2%			2%	2%	2%	2%
Off-shore wind								
capex [€/kW]			2280	2000				
opex [%capex/year]			3%	3%				
BESS								
capex [€/kWh]	300	100	300	100	300	100	300	100
fixed opex [€/kWh-year]	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
replacement [% of capex]	60%	60%	60%	60%	60%	60%	60%	60%
energy/power ratio	4	4	4	4	4	4	4	4
charge/discharge efficiency	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%
depth-of-discharge, DoD	90%	90%	90%	90%	90%	90%	90%	90%
self-discharge rate [%/h]	0.054%	0.054%	0.054%	0.054%	0.054%	0.054%	0.054%	0.054%
Calcined meal storage silos								
capex [€/ton]	130	130	130	130	130	130	130	130
grid electricity price [*€/MWh*]	70	50	100	70	68	50	34	24
carbon intensity of grid [kg_{CO2}/MWh]	373	125	180	120	633	440	628	322
minimum share of electricity supplied from renewables	90%	98%	90%	98%	90%	98%	90%	98%
WACC [%]	6%	6%	6%	6%	10%	10%	10%	10%

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

electricity backup was allowed to provide up to 10% of the total annual demand, while in the long-term case, this share was reduced to 2%, reflecting improvements in renewable capacity and system reliability.

Grid electricity prices were used to capture the cost dynamics of the supplemental electricity supply. For Italy and Denmark, prices were retrieved from the Eurostat database,[54] based on data reported before the market volatility induced by the COVID-19 pandemic and the war in Ukraine. In the case of India, no official electricity price was found for the Jodhpur region. Instead, a proxy value of 68 €/MWh was used, corresponding to tariffs for large industrial users in a neighboring state.[55] For Egypt, the most recent (2024) electricity tariff was applied, using the highest industrial consumption bracket and a conversion rate of 53 EGP/EUR.[56] In the long-term scenario, a uniform 30% reduction in electricity prices was assumed across all locations.

Finally, weighted average cost of capital (WACC) values were adapted to reflect the prevailing financing conditions in each region. Lower WACC values were assigned to the developed economies (Italy and Denmark), while higher values were used for the developing countries (India and Egypt), based on data compiled by the International Energy Agency.[57] These distinctions were used to produce realistic financial assessments and to capture the effect of investment risk on the cost competitiveness of decarbonized systems. They are applied to capex estimations of all equipment involved in the economic performance evaluation (i.e., including process equipment).

2.6.1.2. Capital Expenditure of Process Equipment (Capex). The capital expenditure of new technologies was estimated following the methodology detailed in ref 35, based on a bottom-up approach to arrive at the Total Plant Cost (TPC). TPC is derived from Total Direct Costs (TDC) by adding Indirect Costs, Owner's Costs, and Project Contingency.

The estimation of the TDC begins with the compilation of Total Equipment Costs (TEC) and Installation Costs (IC). These were gathered from the literature and scaled based on adequate sizing parameters to meet the design conditions of electrified systems and the CCS benchmarks, assuming a scaling factor of 0.67 to account for economies of scale. In addition, all costs were brought to €2022 values using the average Chemical Engineering Plant Cost Index (CEPCI). As a reference, the CEPCI values used for 2014, 2018, 2020, and 2022 were 576.1, 603.1, 596.2, and 816.1, respectively. Information on TEC + IC is summarized in Table 4.

Following the determination of TEC and IC, process contingencies are applied. These contingencies account for unknown costs and uncertainties in the implementation of new technologies. They are determined based on the maturity status of the technology and adjusted to incorporate the estimated level of detail in the equipment lists.[34]

Specific process contingencies applied to the technologies assessed in the electrified and CCS benchmark plants are presented in Table 5.

Table 4. TEC and IC of Key Equipment for Assessed Technologies

equipment	TEC + IC in reference	size in reference	reference
electrified calciner	13.5 [M€$_{2014}$] + 100 €$_{2014}$/kW$_{th}$	195 MW$_{th}$	58 own assumption
plasma system	0.37 M€$_{2020}$	0.1 MW$_{el}$	59
CPU	45.8 M€$_{2018}$	124 t_{CO_2}/h	31
ASU[a]	22.0 M€$_{2014}$	18 t_{O_2}/h	58
SOEC system	1250 €$_{2020}$/kW$_{el}$		60
others OC − HK[b]	1.28 M€$_{2014}$	125 t_{clk}/h	35
solvent-based PCC system[c]	345.9 M€$_{2022}$	162.8 t_{CO_2}/h	61
heat pump	300 €$_{2020}$/kW$_{th}$		62
Retrofits Oxyfuel	33.8 M€$_{2014}$	99 t_{CO_2}/h	35

[a]A scaling factor of 0.6 was used in the ASU case, as per the reference. [b]TEC + IC of the exhaust gas recirculation system of the Oxyfuel plant in the cited reference was used as a proxy for the CO_2 recycle needed in the oxy-fired calciner. It also includes a recycle blower and sealed O_2 fan. [c]TEC + IC of the natural gas boiler removed. Estimated with a 0.9 €/US$ conversion rate.

Table 5. Process Contingency Factors for Assessed Technologies

equipment	process contingency − maturity (% of TEC + IC)	process contingency − equipment list (% of TEC + IC)	reference
electrified calciner[a]	60	12	own assumption
plasma system[a]	60	12	own assumption
CPU	20	12	31
ASU	5	0	58
SOEC system	30	12	own assumption
solvent-based PCC system[b]	14		61
heat pump	20	3	own assumption

[a]Used the highest range from CEMCAP (comparable to a Calcium Looping system under integrated configuration) to account for the high uncertainty degree in the implementation of the technology. [b]Applied only to the CANSOLV system (Absorption/Desorption columns). See table Exhibit 5−14 from ref 61.

When applicable, the values reported in the literature were directly used. For technologies where no contingency values were found, a proxy estimation based on the authors' criteria was used instead.

Beyond the direct costs (TEC + IC) and process contingencies, additional cost elements contribute to the TPC. Indirect Costs are set at a uniform rate of 14% of the TDC for all technologies. These costs encompass elements such as yard improvement, service facilities, engineering and consultancy expenses, and building and sundries. Owner's Costs and Project Contingencies are assumed to be 7 and 15% of the TDC, respectively.

The assessment also includes equipment replacement costs for two key components in electrified systems: the electrodes in plasma burners and the SOEC stacks. Electrode replacement in plasma-based gas generation has been identified as a limiting factor for the system's economic viability due to its relatively short lifespan, ranging from 500 to 1000 operating hours.[7,10,33] At an annual capacity factor of 8000 h, this would require up to eight replacements per year. For this study, it is assumed that large-scale deployment in rotary kilns will achieve extended durability, reducing replacement frequency to twice per year, with an estimated annual cost equal to 15% of the plasma system's capex.[59] For the SOEC system, opex is based on the 2024 target outlined in the Clean Hydrogen Partnership SRIA 2021−2027 report, which specifies an annual cost equivalent to 6.5% of capex, including stack replacements.[60]

Long-term cost variations of some key process technologies were incorporated into the economic assessment. These are summarized in Table 6.

For the SOEC and heat pump systems, long-term cost assumptions were taken directly from the literature. In the case of plasma burners, no capital cost reduction was assumed. However, improvements in electrode lifetime were considered based on anticipated technological advancement and operational experience in kiln environments. Specifically, the electrode replacement rate was adjusted from twice per year in the short term to once every 2 years in the longer term.

For the solvent-based PCC system, short-term investment costs were based on a recent (2023) study by the U.S. Department of Energy (DoE) and the National Energy Technology Laboratory (NETL).[61] The study updated previous estimates (e.g., Gardarsdottir et al. (2019)[35]) using Shell's CANSOLV Post-Combustion Capture process, resulting in a specific capex of 3.3 M€/(t_{CO_2}/h) for the case with a 95%

Table 6. Short-Term (ST) and Long-Term (LT) Cost Assumptions of Key Technologies[a]

	TEC+IC[b]	opex[c]	references
SOEC	ST: 1250 [$€_{2020}$/kW_{el}]	ST: 6.5% capex/year	60
	LT: 520 [$€_{2020}$/kW_{el}]	LT: 5.6% capex/year	
heat pump	ST: 300 [$€_{2020}$/kW_{th}]		62,63
	LT: 200 [$€_{2022}$/kW_{th}]		
plasma burners[d]	ST: 0.37 [$M€_{2020}$]	ST: 2.0*4% capex/year	59
	LT: 0.37 [$M€_{2020}$]	LT: 0.5*4% capex/year	own assumption
PCC system[e]	ST: 345.9 [$M€_{2022}$]		61,64
	LT: 209.1 [$M€_{2022}$]		own assumption

[a]Cost of equipment not included in this table is left unchanged between the two time horizons (see Table 4). [b]All costs were updated to $€_{2022}$ using corresponding CEPCI values. [c]Opex includes the replacement cost of key components (stack in the SOEC and electrodes in the plasma burner system). [d]TEC+IC of the reference process. For the assessment, these are scaled using a reference size of 0.1 MW_{el}. [e]TEC+IC of the reference process. For the assessment, these are scaled using a reference flow rate of 162.8 t_{CO2}/h.

capture rate—including CO_2 emissions from the natural gas boiler used for solvent regeneration—and considering indirect, owner's, and project contingencies costs equal to 36% of TDC combined (consistent with calculations in this study), as well as a conversion rate of 0.9 €/US $.

To project long-term cost reductions, a learning curve methodology was applied in line with guidelines published by the International Energy Agency Greenhouse Gas R&D Programme.[64] The description is provided in SI-S6.

2.6.1.3. LCORE and LCOE. The electricity supply cost from the optimized captive renewable generation portfolio is expressed as the Levelized Cost of Renewable Electricity (LCORE). This parameter includes annualized investment costs and operating expenses of the PV panels, wind turbines, and the battery energy storage, divided by the electricity supplied to the system, expressed in €/MWh. Curtailed electricity is not included in the denominator. The equation used to calculate the LCORE is given below:

$$\mathrm{LCORE} = ((\mathrm{Capex}_{PV} + \mathrm{Capex}_{WT} + \mathrm{Capex}_{BESS} + \mathrm{Capex}_{repl}) \times \mathrm{CRF} + \mathrm{Opex}_{ren})/E_{ren} \quad (4)$$

where Opex_{ren} represents the combined operating expenses of each technology, CRF is the Capital Recovery Factor, based on a given operational lifetime n and a discount rate i, and E_{ren} is the electricity supplied to the system from renewable sources (including the BESS), excluding curtailments.

Capex_{repl} is the estimated BESS replacement cost adjusted to today's value using the corresponding discount rate i (6% or 10% depending on the location), and a lifetime n of 13 years, considering a replacement rate of C_{repl} = 60% of initial capex:

$$\mathrm{Capex}_{repl} = \mathrm{Capex}_{BESS} \times C_{repl} \times \frac{i \times (1+i)^n}{(i+i)^n - 1} \quad (5)$$

In addition, the levelized cost of the electricity (LCOE) supply is estimated by adding the contribution of grid electricity to the overall cost (numerator) and energy supply (denominator).

2.6.1.4. Operating Expenses (Opex). Operating costs depend on the characteristics of each decarbonization technology, distinguishing between fixed and variable components. Fixed opex was derived as a function of the capex using uniform assumptions across technologies. Specifically, insurance and location taxes were set to 2% of TPC, while annual maintenance costs were taken as 2.5% of TPC. Maintenance labor is defined as 40% of the maintenance cost. Consequently, elements of a fixed opex are indirectly influenced by the process contingencies included in the capex estimation.

A summary of the assumed variable operating costs is presented in Table 7. Fuel and electricity-based heating demands (covering the e-calciner, plasma burners, SOEC, and heat pump for solvent regeneration) were derived from the mass and energy balances obtained via the Aspen process models. The corresponding opex was calculated assuming a baseline fuel price of 5 €/GJ_{LHV} and a site- and time horizon-specific levelized cost of electricity (LCOE) estimated from a mixture of on-site renewable generation and grid backup.

Table 7. Summary of Variable Opex

variable opex	units	value
alternative fuels	€/GJ_{LHV}	5
cooling water	€/m^3	0.39
process water	€/m^3	6.65
MEA-based solvent	€/t	1,450
steam from waste heat	€/MWh_{th}	8.5
carbon tax—short-term	€/t_{CO2}	100
carbon tax—long-term	€/t_{CO2}	150
T&S of captured CO_2—short-term	€/t_{CO2}	50
T&S of captured CO_2—long-term	€/t_{CO2}	25

For the CCS benchmark cases, auxiliary electricity needs for the capture plant (including CO_2 compression), ASU, electricity generation from the Oxyfuel's heat recovery organic Rankine cycle (ORC), the operation of waste heat recovery systems (including annualized capex), and other consumables were scaled from values reported in the literature (see SI-S5).

2.6.1.5. Incremental Cost of Clinker (ΔCOC). Two KPIs were used to compare the economic performance of assessed technologies: the incremental cost of clinker (ΔCOC) and the cost of avoided CO_2 (CAC). The incremental cost of clinker (ΔCOC) reflects the investment and operating expenditures needed *in addition* to the operation of the reference cement plant. It is defined as

$$\Delta\mathrm{COC} = \frac{C_{Capex}^{ann.} + C_{opex}}{\dot{m}_{clk}} \quad (6)$$

where $C_{capex}^{ann.}$ is the annualized capex of additional equipment and retrofitting investments; C_{opex} represents the plant's incremental opex, including fuel cost, electricity cost, fixed costs, and any other consumable expenditures, expressed in euros per year; and $\dot{m}_{clk}$ is the clinker production rate in t_{clk}/year.

$C_{capex}^{ann.}$ is calculated by multiplying the TPC by the Capital Recovery Factor according to eq 7:

$$C_{Capex}^{ann.} = \mathrm{TPC} \times \mathrm{CRF} = \mathrm{TPC} \times \frac{i \times (1+i)^n}{(i+i)^n - 1} \quad (7)$$

2.6.1.6. Cost of Avoided CO_2 (CAC). The CAC reflects the variation in ΔCOC between the decarbonized cement plant and the reference process divided by the difference in net specific CO_2 emissions. By incorporating both direct and indirect emissions, it provides a robust estimation of the overall reduction in CO_2 emissions as well as the total avoidance cost.

$$\mathrm{CAC} = \frac{\Delta\mathrm{COC}_{tech} - \Delta\mathrm{COC}_{ref}}{\mathrm{CO}_2^{net,tech} - \mathrm{CO}_2^{net,ref}} \quad (8)$$

3. RESULTS

3.1. Operation of the Flexible eC−afK Plant

To illustrate the operation of the flexible eC−afK plant, Figure 5 shows the hourly behavior of the plant located in Italy during 5 days in March (a) and August (b) under long-term conditions.

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

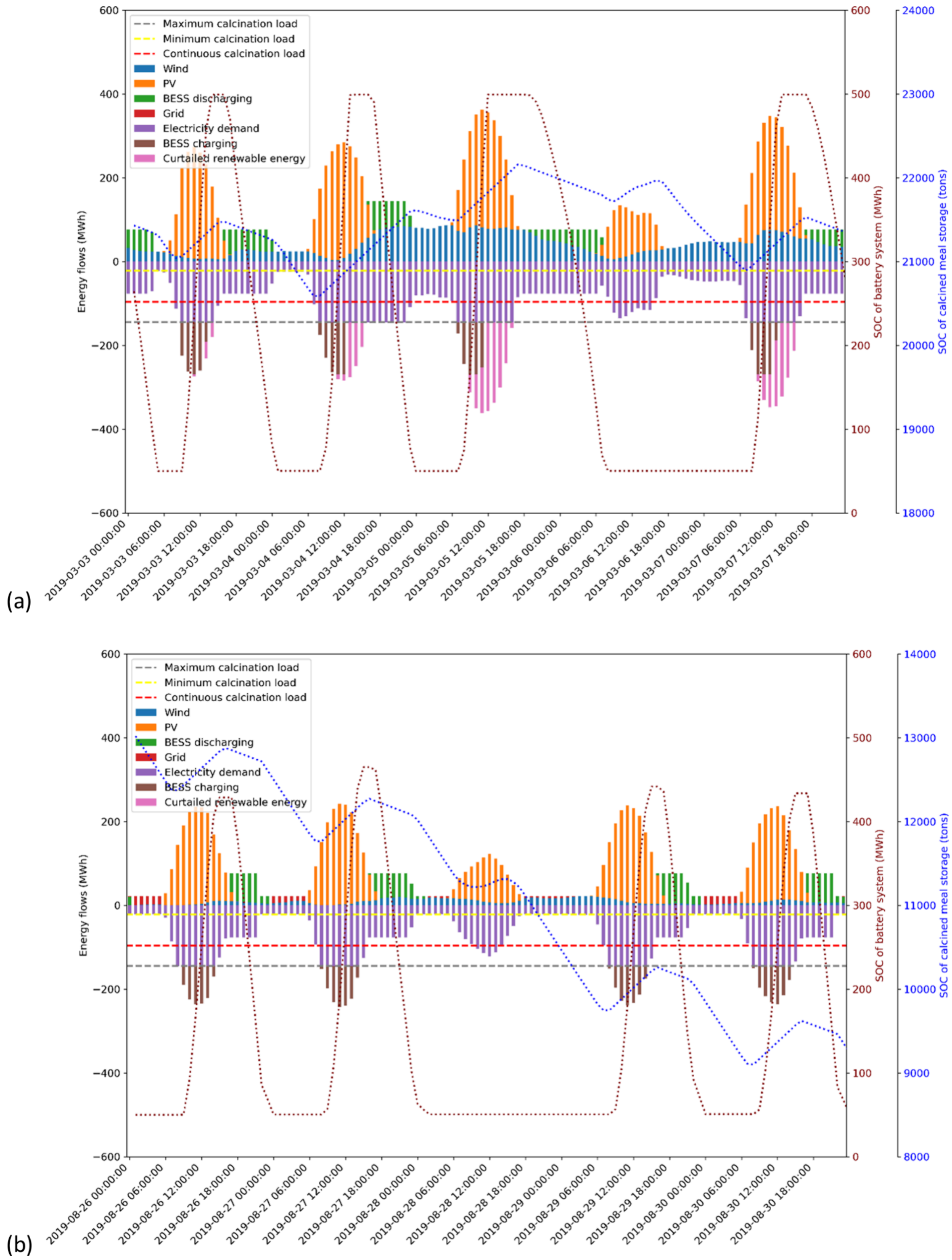


Figure 5. Operation of the flexible eC−afK plant showing hourly energy flows and the SOC of the BESS and the calcined meal storage unit for a plant located in Sicily, Italy, under the long-term scenario during 5 days in March (a) and 5 days in August (b). Horizontal dotted lines represent three different operating modes: minimum calcination load of the flexible section (yellow), continuous calcination load (red), and maximum calcination load (gray).

Bars represent energy flows, with electricity consumption (and curtailment) expressed as negative values (in MWh), while the positive values indicate the source of the electricity supply (PV, wind, or BESS). The state of charge (SOC) of the battery (in MWh) and of the calcined material (in tons) are shown as maroon and blue dotted lines, respectively. Moreover, three horizontal dotted lines indicate key operating conditions, namely, the *minimum load* (yellow), the *maximum load* (gray), and the average *continuous load* (red).

While the operation varies depending on the type of plant, location, and time scenario, the figure helps explain the logic behind the hourly decisions made in the system. During periods of high renewable availability (i.e., hours characterized by low electricity prices due to abundant renewable generation), the

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

Table 8. Summary of Energy Balance and Direct CO_2 Emissions of Decarbonized Plants Compared against the Reference Cement Process

		reference plant		PCC + HP		oxyfuel		eC − afK	eC − pK	OC − HK
		coal	AF	coal	AF	coal	AF	Inflexible		
Fuel										
demand	[MW_{th}]	104	108	104	108	111	114	45	0	97
	[GJ_{th}/t_{clk}]	3.21	3.33	3.21	3.33	3.42	3.50	1.39	0	2.97
variation[a]	Δ%			0%	0%	+6.6%	+5.3%	−58.1%	−100%	−10.6%
Electricity										
demand	[MW_{el}]	15	15	79	79	33	33	108	155	70
	[GJ_{el}/t_{clk}] (kWh/t_{clk})	0.47 (131.7)	0.47 (131.7)	2.43 (675.5)	2.42 (672.3)	1.01 (281.6)	1.01 (279.9)	3.33 (924.0)	4.75 (1319.7)	2.15 (597.5)
variation[a]	Δ%			+413%	+411%	+114%	+113%	+602%	+902%	+354%
Direct CO_2 emissions										
absolute[b]	t_{CO2}/h	100.7	89.1	5.0	−5.5	5.1	−6.0	−3.8	5.2	−5.3
specific	kg_{CO2}/t_{clk}	859.6	761.2	43.0	−47.3	43.8	−51.5	−32.6	44.8	−45.6
avoided w/r to reference plant[a]	%			95%	106%	95%	107%	104%	94%	106%
avoided per unit of electricity[c]	kg_{CO2}/kWh			1.50	1.50	5.44	5.48	1.00	0.60	1.73
captured CO_2 to T&S	t_{CO2}/h			95.6	94.7	97.3	95.9	82.9	62.5	97.7
captured CO_2 to T&S[b]	t_{CO2}/year			764,800	757,200	778,600	767,300	663,300	500,000	781,600

[a]Variations in fuel and electricity demand are calculated using the reference plant burning the same fuel type (coal or AF) as baseline. [b]Estimated by assuming a clinker production rate of 117.1 tph with a yearly capacity factor of 93.1%. [c]Direct CO_2 emissions avoided per additional unit of electricity.

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

Table 9. Summary of Energy Balance and Direct CO_2 Emissions of the Flexible eC−afK Plant under Different Operating Modes Compared against the Inflexible Configuration

		eC−afK inflexible	eC−afK flexible plant continuous load	eC−afK flexible plant minimum load	eC−afK flexible plant maximum load	eC−afK [a]max.−min. cycle
calciner throughput	%	100%	100%	20%	150%	
Fuel						
demand	[MW_{th}]	45	51	51	51	51
	[GJ_{th}/t_{clk}]	1.39	1.56	1.56	1.56	1.56
variation	Δ%		+11.6%	+11.6%	+11.6%	+11.6%
Electricity						
demand	[MW_{th}]	108	110	39	161	
	[GJ_{el}/t_{clk}] (kWh/t_{clk})	3.33 (924.0)	3.37 (936.9)	1.19 (331.9)	4.96 (1376.7)	3.52 (977.3)
variation	Δ%		+1.4%	−64.1%	49.0%	+5.7%
Direct CO_2 emissions						
absolute	t_{CO2}/h	−3.8	−3.1	−4.1	−2.5	
specific	kg_{CO2}/t_{clk}	−32.6	−26.6			−26.6
avoided w/r to reference plant	%	104%	103%			103%
avoided per unit of electricity[b]	kg_{CO2}/kWh	1.00	0.98			0.93
captured $CO_2$to T&S	t_{CO2}/h	82.9	87.0	12.9	119.8	

[a]Values computed for a full max−min load cycle, i.e., consuming all material previously stored. Based on the throughput, a cycle is composed of a maximum load and a minimum load operation sequence, where the duration of the maximum load operation is 1.6 times higher than the duration of the minimum load operation. [b]Direct CO_2 emissions avoided per additional unit of electricity.

electrified calciner operates at maximum capacity, storing excess calcined meal and electricity. Yet, the plant follows a clear merit order for storing energy. Surplus renewable electricity is first used to store calcined material, charging the BESS only when the maximum operating load is reached. Indeed, considering the additional specific electricity demand of operating at maximum capacity (+440 kWh/t_{clk}) caused by reduced efficiency, the specific storing capacity of the system (0.57 t_{CM}/t_{clk}), and a capex for the calcined meal storage silo of 130 eur/t_{CM}, leads to an equivalent energy storage cost of 0.17 €/kWh (including additional capex for oversized equipment), i.e., three orders of magnitude less than the electrochemical storage system.

When the availability of renewable resources declines (i.e., during higher electricity price periods), the system chooses to operate at 80% of the continuous operating level. This threshold is found by balancing the maximum throughput conditions of the plant without the need to activate the heat pump to support the heating demands for solvent regeneration. Below this operating point, waste heat from the process is enough to supply the regeneration heat. Therefore, the plant decides to meet 80% of the kiln's demand with the flexible section, and the remainder (27 tons of calcined material) is sourced with stored material, representing approximately 0.2 h of storage capacity. The BESS is primarily discharged to maintain this operating condition during shortages of renewable energy until it is depleted. Afterward, the plant operates in minimum load conditions by supplying the majority of the kiln's feedstock with stored material.

Figure 5b reflects a week of scarce renewable resources, using a backup grid to support the operation of the system, particularly during the night. The hourly behavior is similar to the week in March, charging the BESS after the maximum load condition is reached, and discharging both storage mediums to support the optimum level found at 80% throughput capacity. Notably, the long-term load-shifting strategy of the solid storage can be evidenced, operating at minimum load for several hours, leading to approximately 29 h of stored meal consumption during the 5-day period.

A file containing hourly energy and CO_2 emissions flows for the inflexible and flexible eC − afK configurations is shared in SI.

3.2. Energy Balance and CO_2 Emissions

Table 8 compares the energy demand (fuel and electricity) and CO_2 emissions among the electrified plants, the CCS benchmarks, and the reference cement plant. Moreover, the effect of changing from 100% coal to 100% AF as the main source of fuel is included for the reference plant and the two benchmark cases, assuming a biogenic content of 30% in the AF, which is consistent with the average estimation of biogenic fraction of carbon in RDF from a recent European LCA study.[30] The composition and energy content of the AF can be found in Quevedo Parra and Romano (2023).[9] Table 9, on the other hand, summarizes the CO_2 and energy balance of the flexible eC−afK plant compared against the inflexible operation, including different modes of operation of the flexible design.

There are noticeable trade-offs between the energy requirements and CO_2 emissions abatement potential between technologies, which should be weighted based on the conditions, site limitations, and targets of a specific cement plant. Assuming an amine-based PCC system with a CO_2 capture efficiency of 95% and using a heat pump with a COP of 2 to supply the regeneration heat, the electricity demand is expected to increase by 413% compared to the reference case burning coal. No additional fuel is required. The environmental performance can be considerably improved by switching to AF, potentially transforming the plant into a net negative emissions process with only a 4% increase in fuel consumption compared to the coal-based case. Oxyfuel technology is also expected to abate around 95% of CO_2 emissions (using coal as the main fuel), by predominantly impacting the electricity demand (114% increase) rather than fuel consumption (6.6% increase). Again, shifting from coal to AF could transform the plant into a negative

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

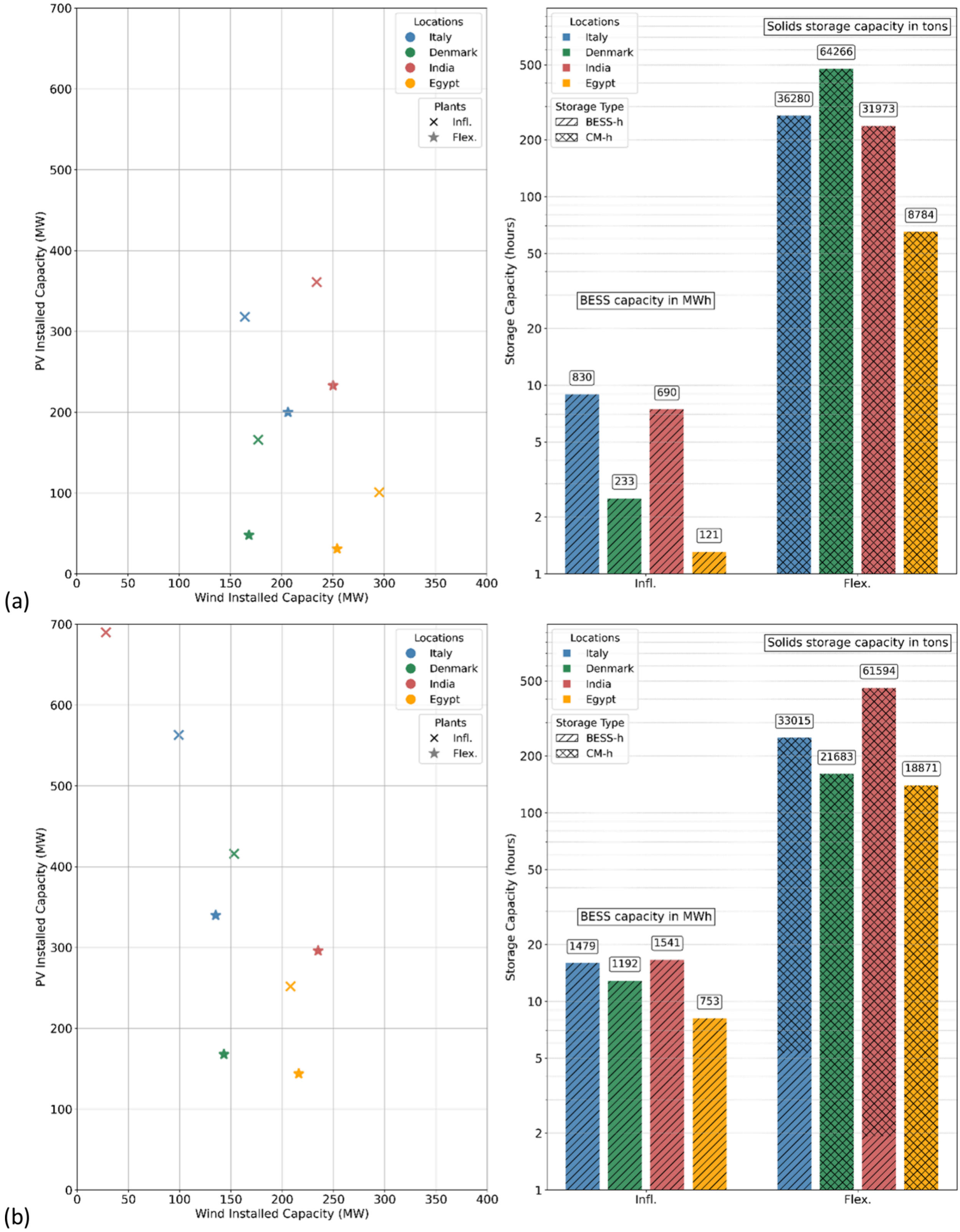


Figure 6. Renewable installed capacity mix of PV panels and Wind turbines in MW_p (left) and energy storage capacity of BESS and calcined meal in hours (right) for the inflexible and flexible eC−afK designs. Numbers shown above the bars in the right plot represent the BESS-installed capacity in MWh and the calcined meal storage installed capacity in tons. Plot (a) corresponds to results in the short term and plot (b) to results under long-term conditions.

emissions process, storing biogenic CO_2 to reach 106% of the direct CO_2 emissions avoided.

Partially electrified cases (eC−afK and OC−HK) have the potential of becoming negative emission processes by combining high capture rates, boosted by the production of a

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

highly concentrated CO_2 stream, and the combustion of AF with biogenic carbon (Table 8). The fully electrified case (eC−p*K*), however, is limited to the capture of mineral CO_2 emissions from limestone calcination by electrifying all of the process heat demand. Conversely, the eC−p*K* plant shows the greatest capacity to reduce the amount of captured CO_2 to be treated by a future CO_2 T&S infrastructure, followed by a partially electrified eC−afK plant. The two cases with oxy-fired calciners (OC−HK and Oxyfuel) have the largest flow rate of captured CO_2, with maximum values expected for the OC−HK case, capturing 56% more CO_2 than a fully electrified eC−p*K* plant.

Table 9 highlights the efficiency penalty resulting from the intermediate cooling and storage units to support operational flexibility of the flexible eC−afK plant. Load constraints for the electrified calcination section were assumed by setting a minimum of 20% throughput and a maximum of 150% throughput, with respect to the inflexible operation. Fuel consumption increases by 12% in the flexible case operated at the average continuous load compared to the inflexible plant, driven by an 89 °C reduction in the solids inlet temperature to the rotary kiln. Instead, electricity demand varies depending on the operating mode of the plant, ranging from −64.1% when the calciner throughput is at a minimum to +49% when it is operating at maximum capacity. Similarly, the amount of captured CO_2 emissions depends on how much raw meal is being calcined in the calcination section, while the CO_2 emissions arising from fuel combustion in the rotary kiln remain constant.

Notably, the energy efficiency and specific CO_2 emissions during the different operating modes do not scale linearly with the production of calcined material. This is a consequence of the system's configuration, which is constantly balancing waste available heat for raw meal drying in the preheaters and the Raw Mill based on the system's feedstock demand. This limits the heating capacity of the air-preheated string during high-throughput periods. The efficiency loss is evidenced when comparing the columns from continuous operation against a maximum−minimum load cycle, i.e., where all previously stored material is consumed for clinker production by alternating between these extreme operating modes. In practice, the operation is gradual, incorporating periods of intermediate loads. During the maximum−minimum cycle, the same amount of clinker is produced, requiring higher electricity consumption (977 vs 937 kWh/t_{clk}) compared with the continuous operation.

More extreme variations in energy requirements with respect to the reference process are expected as the fuel demand is replaced with electricity. The fully electrified eC−p*K* case reduces fuel consumption by 100% while increasing the electricity demand by 902%, i.e., a 10-fold increase compared to the operation of a reference cement plant. The partially electrified eC−afK plant, on the other hand, electrifies only the unit operation with the largest share of fuel consumption (calciner), which drives a 58.1% decrease in fuel demand compensated by a 602% increase in electricity demand, while avoiding 104% of the refence plant's direct CO_2 emissions through the capture of neutral CO_2 from the combustion of AF in the rotary kiln. The flexible configuration loses some efficiency due to the addition of intermediate cooling and preheating steps, which is why an optimal heat integration design is key. As a result, there is an additional 0.17 GJ_{th}/t_{clk} (+11.6%) of fuel and 0.04 GJ_{el}/t_{clk} (+1.4%) of electricity consumption in continuous load with respect to the inflexible operation.

Variations in the scale of captured CO_2 are relevant, in particular, for the estimation of technical designs needed for the transport supply chain and its economic impact. In this sense, removing the fuel-related CO_2 emissions of the calciner and/or rotary kiln will have a positive outcome in terms of the CO_2 flow rate to be managed. Using the AF-based PCC with HP case as a reference and then changing to a partially electrified eC−afK plant results in a 12% reduction in the yearly amount of captured CO_2 for the inflexible case or an ∼8% reduction for the flexible design. Conversely, the Oxyfuel technology increases the amount of captured CO_2 by an additional 1.3% (maintaining the same fuel characteristics). This rising trend is also noticed for the OC−HK plant, where the >100% CO_2 avoidance rate is met with a 3.2% increase in captured CO_2 due to the larger flow rate expected from CO_2 recirculation to the Oxyfuel calciner.

3.3. Renewable Electricity Generation Mix

This section describes the different patterns observed in the optimal renewable generation portfolio, including the decision to install and the size of storage alternatives, and the need to meet minimum renewable electricity supply targets in the short term (>90%) and long term (>98%). Because the inflexible plants cannot shift their load based on the availability of renewable resources, the renewable electricity generation mix remains constant, albeit scaled based on their respective energy demands. Therefore, the analysis will be focused on comparing the behavior of the inflexible and flexible eC−afK plants, understanding that the discussion on the inflexible operation can be extended to the rest of these cases (i.e., eC−p*K*, OC−HK, and the benchmark CCS plants).

A summary of the installed capacity and other parameters associated with the supply of renewable energy for all the assessed plants, locations, and time horizons can be found in SI-S7. Furthermore, a complete analysis of the inflexible and flexible electrified systems under different meteorological conditions is provided in SI-S8.

Under short-term conditions (Figure 6a), inflexible plants situated in wind-rich regions, i.e., Denmark and Egypt, derive more than 80% of their annual renewable energy supply from wind turbines (WT), thereby minimizing reliance on photovoltaic (PV) output and the installation of expensive battery storage systems to manage their intraday fluctuations (SI, Table S24). By contrast, solar-dominated regions, i.e., Italy and India, converge on portfolios that couple comparable PV and WT annual generations (PV:WT ratios of 55:45 and 58:42, respectively) and deploy larger BESS capacities to deal with PV daily intermittency. In every location, battery charging is driven by surplus PV power, with Egypt additionally exploiting afternoon wind peaks (SI-S8.2). Residual energy deficits uncovered by battery discharges are met with grid backup, which increases during low-wind months. Overall, energy imbalances lead to annual curtailment rates of 21% in Italy and 27% in India, clustered around the peak hours of PV production and extended to the rest of the day during months of higher wind availability. Meanwhile, wind-dominant locations display day-long curtailment profiles owing to more uniform wind generation patterns, reaching annual rates of 30% in Denmark and 33% in Egypt (SI-S8.5).

Introducing process flexibility shifts the optimum decisively toward WT, as the kiln can now exploit the low-cost, long-duration storage of the calcined material to bridge seasonal wind variability. Hourly storage dynamics differ by the location-specific renewable generation mix. Italy and India charge

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

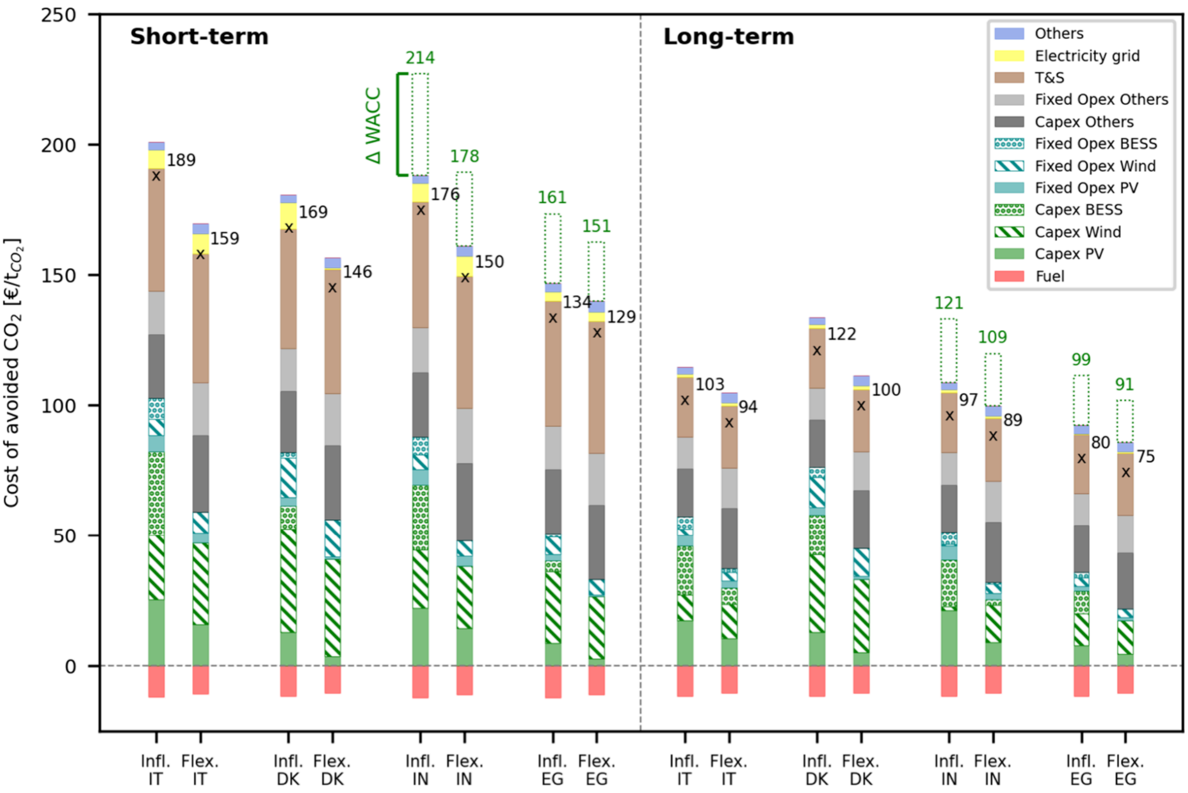


Figure 7. CAC comparison between inflexible and flexible eC−afK plants under short-term and long-term scenarios against a reference cement plant burning 100% alternative fuels with 30% biogenic content. Green boxes at the top of plants in India and Egypt show the economic impact of reducing WACC from 10 to 6% (i.e., matching the ones in Italy and Denmark). "Capex others" comprises all additional equipment beyond renewable generation capacity (e-calciner, CPU, ASU, PCC capture system, heat pump, SOEC, plasma generators, retrofitting needs for Oxyfuel operation). A breakdown of additional capex can be found in the Supporting Information.

predominantly at noon, whereas Egypt combines the midday PV output with high afternoon winds. With the grid support capped at 10% of demand, no BESSs are required. Notably, in Denmark, stable wind energy supply, cheap seasonal storage, and costlier grid electricity price reduce the grid backup needs to 0.7% (SI-S8.3).

Stored calcined material serves two roles. On the one hand, it smooths intraday renewable fluctuations through daily charge−discharge cycles. On the other hand, it can accumulate energy during prolonged surplus periods to support the system through low-wind months. This function is most pronounced in Denmark, where stable wind patterns justify the 64,266 tons of calcined meal storage (equivalent to 476 h of operation) to load-shift between high- and low-wind cycles. On the contrary, only 8754 tons of calcined meal storage (equivalent to 65 h) is needed in Egypt, also predominantly sourced by wind energy. In this case, unstable daily wind profiles characterized by morning valleys followed by sharp afternoon peaks favor daily storage dynamics (SI-S8.2). Notably, these capacities are well within the storage scales already common in the cement industry: Clinker silos at European plants can exceed 100,000 tons in capacity,[65] indicating that the proposed storage requirements are technically achievable within existing industrial practice.

By enabling long-term energy storage, flexible plants are able to substitute PV and WT overcapacity, reducing annual renewable energy generation by 9−24%, and curtailment rates by 4−14%, compared to their corresponding inflexible configuration (SI, Table S25).

Motivated by steep cost reductions in the long term, the optimal portfolios pivot toward the installation of PV and BESS while cutting WT capacity to maintain the >98% renewable electricity supply constraint (Figure 6b). The inflexible plant in Egypt, benefiting from near-seasonal uniformity of solar resource complemented with afternoon winds, needs 37−51% less BESS capacity than the other sites, and curtailment falls from 33 to 26% relative to the short-term inflexible case. Conversely, in Italy, Denmark, and India, the economic case for PV overinvest plus BESS, coupled with limited grid back-up, drives excess output during high-irradiance hours and raises curtailment by 7, 2, and 2%, respectively.

The cheap combination of PV plus BESS and cost-effective storage of calcined material drives the optimal systems in the flexible plants to a more balanced mix of PV panels and WT, incorporating a battery system depending on whether the plant is assessed in sun- or wind-dominant locations. Denmark and Egypt meet all intraday balancing requirements by storing solid material without the need for any BESS capacity. Solar-driven Italy and India, however, add 500 and 182 MWh of battery capacity, respectively, encouraged by the 67% drop in capex. While calcined material offers cheaper intraday energy storage, it is limited by the flexible plant's maximum operating conditions. BESS can provide the incremental storage capacity to deal with peak power production from PV panels in locations where it is economically attractive.

Seasonal load shifting follows site-specific resource patterns. India nearly doubles its solid storage capacity to 61,594 tons (equivalent to 456 h), driven by the larger renewable electricity supply constraint and the lack of grid backup to support the low-wind periods. In Denmark, the high short-term CM storage requirement falls to 21,683 tons (equivalent to 161 h) as a

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

consequence of the change in the renewable energy portfolio. The addition of more sun-based electricity production shifts the storage's role toward more intraday smoothing.

Finally, across all flexible cases, the combined effect of storage and portfolio rebalancing cuts renewable energy generation between 19 and 37% compared to the inflexible designs, limiting curtailment rates to 7−12%.

3.4. Comparative Economic Assessment—Flexible vs Inflexible eC−afK Plant

Operational flexibility introduces a capital expenditure trade-off: It reduces the need for renewable installed capacity but requires higher investment in oversized process equipment (e-calciner and CPU) and an additional calcined meal storage system. The larger processing units account for a 4−7% increase in total capex, while the storage system adds a comparatively minor 0.2−1.8% relative to the investment cost of the inflexible configurations. Conversely, the reduced renewable capacity results in substantial capex savings of 22−33% in the short term and between 16 and 27% in the long term, depending on the location, more than offsetting the additional investment in flexible operation. A detailed breakdown of the cost structure for all configurations across the four locations and time horizons is provided in SI-S9.

Figure 7 illustrates the benefits of adding operational flexibility to the eC−afK plant by comparing the CAC of the inflexible and flexible designs across locations and time horizons, including the breakdown of main contributors to the economic performance. In the short term, wind-dominant locations (i.e., Denmark and Egypt) emerge as the most economically viable options, as they leverage a stable daily wind energy supply, thereby avoiding the high costs associated with BESS needed to manage the intraday variability of PV systems. Despite a higher cost of capital, the inflexible plant in Egypt demonstrates superior performance due to its favorable climatic conditions, achieving the lowest levelized cost of renewable electricity (LCORE) (Table 10). Conversely, the plant in India exhibits the highest costs, primarily due to the combined effect of significant BESS requirements and higher financing costs.

Table 10. Comparison of Levelized Cost of Renewable Electricity (LCORE) between Inflexible and Flexible eC−afK Plants across Locations and Time Scenarios

	LCORE—inflexible (€/MWh)	LCORE—flexible (€/MWh)	variation (€/MWh)	variation (%)
Short-term				
Italy	109	60	49	−45%
Denmark	89	54	35	−39%
India	120	63	57	−48%
Egypt	70	44	26	−37%
Long-term				
Italy	57	36	21	−37%
Denmark	76	43	33	−43%
India	67	40	27	−40%
Egypt	48	27	21	−44%

Wind-dominant locations continue to outperform in the flexible cases, although greater economic benefits are observed in sun-dominant regions, reducing the CAC by 16 and 17% in the plants in Italy and India, respectively, compared with the inflexible alternatives. This improvement is primarily attributed to the complete elimination of BESS installation, which further drives down the LCORE. The plants in Denmark and Egypt also benefit, albeit to a lesser extent, with CAC reductions of 14 and 6%, respectively. Notably, the share of CAC attributable to renewable capacity (PV, WT, and BESS) can vary significantly across locations, comprising 51% for the inflexible plants in Italy and India, 45% for Denmark, and only 39% in Egypt. This disparity leads to any reduction in LCORE by virtue of introducing operational flexibility plus material storage, having a more substantial impact on the economic feasibility of plants in Italy and India compared to Egypt. Meanwhile, the particularly stable daily wind patterns in Denmark remove the need for grid backup beyond the model's constraint, further improving its competitiveness.

Under long-term conditions, the CAC spread between the different sites becomes more nuanced. Inflexible plants in sun-dominant locations exhibit the largest improvements (44−46% CAC reductions versus 28−38% in Denmark and Egypt), driven by steep PV and BESS cost declines. Nonetheless, the plant in India remains the least attractive alternative together with Denmark. In the latter, long-term cost projections from offshore wind turbines are considerably less significant (−12%) compared to those from PV panels (−48 to −63%) or BESS (−67%). In India, the system is hindered by the impact of higher financing costs. Remarkably, Egypt results in the best performance despite higher WACC, owing to a privileged mix of renewable resources that lead to the most competitive LCORE (Table 10).

The benefits associated with operational flexibility in sun-dominant regions are diminished (9% in Italy and 10% in India), due to the increased competitivity of PV and BESS-based daily storage compared to the WT and material-based seasonal storage. On the contrary, flexible operation leads to a significant 17% reduction in CAC in Denmark, driven by the complete elimination of large BESS capacity and a reduction in WT requirements compensated by cheaper storage of calcined material (a breakdown of the Capex is provided in SI-S9). The benefit in Egypt is comparable to that of the sun-dominant cases (8%), reflecting the smaller contribution of renewable capacity to the overall CAC.

Besides renewable electricity generation costs, CO_2 T&S infrastructure, along with other equipment costs, plays a significant role in determining economic performance. The efficiency losses associated with modifying conventional plant operations to introduce flexibility result in increased fuel consumption in the rotary kiln (see Table 9) and increased production and capture of CO_2 emissions, raising T&S costs proportionally. These costs represent 21−28% and 27−31% of the CAC for inflexible and flexible plants in the short term, respectively. In the long-term scenario, T&S costs are assumed to decrease from 50 to 25 €/t_{CO2}, improving economic performance across all locations and reducing the contribution of T&S to the overall CAC to 17−20% and 20−23% for inflexible and flexible plants, respectively.

Capital investment (with associated fixed costs) for equipment beyond renewable capacity can become the largest component of the CAC when renewable capacity is driven to a minimum (i.e., under flexible operation) in locations and economic conditions favoring renewable electricity production, for instance, flexible plants located in Egypt or flexible plants in Italy and India under a long-term cost scenario.

The relevance of higher financing costs in the overall economic performance of the different sites can be evidenced when comparing the CAC improvement highlighted in green in

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

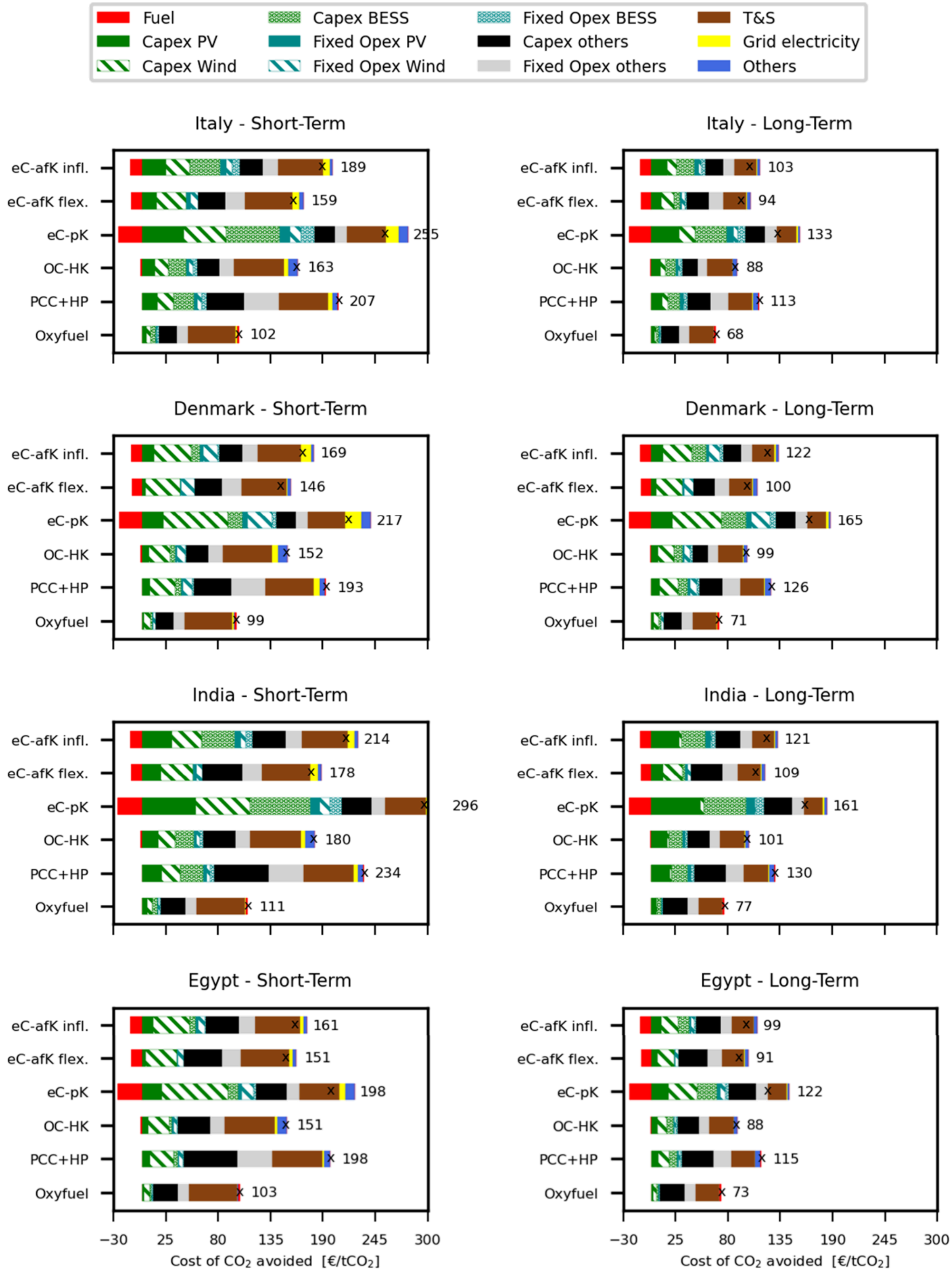


Figure 8. CAC breakdown of decarbonized cement plants across locations and time horizons.

Figure 7. Assuming 6% WACC improves CAC between 16 and 20% in India and between 15 and 19% in Egypt among plant designs and time horizons. As a consequence, they become the most competitive sites in the long term, outperforming Denmark and Italy. Importantly, this analysis shows that a 4% reduction in WACC has a greater impact on the economic performance of partially electrified plants than introducing operational flexibility (within the chosen operational boundaries), underscoring the importance of financing conditions in determining the overall cost efficiency of these systems.

3.5. Comparative Economic Assessment—All Decarbonized Options

An economic comparison between all assessed plants across locations and time horizons in terms of the cost of avoided CO_2 is provided in Figure 8. Results for the CCS benchmark correspond to the 100% AF alternatives. Capex repayment

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

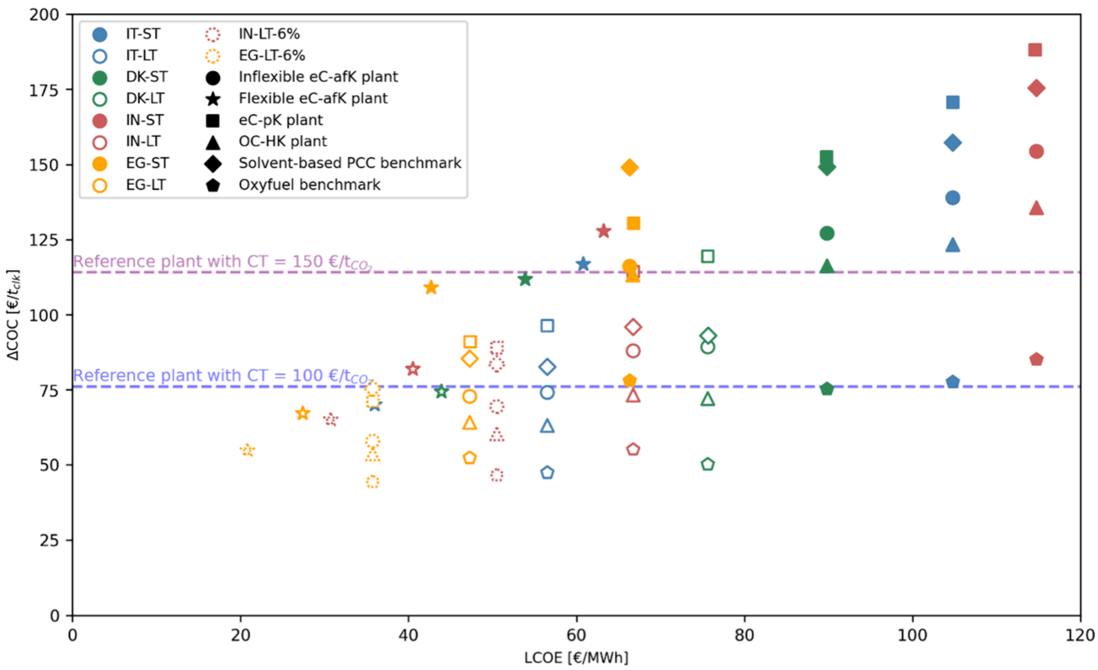


Figure 9. ΔCOC comparison of decarbonized cement plants across location and time horizon conditions. Straight dashed lines represent the ΔCOC of a reference cement plant burning AF and paying full price for its direct CO_2 emissions at two different prices for CO_2 emissions, or carbon tax (CT), 100 and 150 €/t_{CO2}. Dotted markers correspond to the values calculated for the plants in India and Egypt under the long-term scenario, considering a more favorable WACC of 6%.

(including capex for the renewable power generation plants) with related fixed operating costs stands as the most influential factor determining the cost of implementing all decarbonization technologies to cement production, representing between 55 and 79% of the CAC of electrified plants in the short term, and between 66 and 87% in the long term. For the benchmark CCS cases, capex is found to be in the range of 45−73% of the CAC in the short term, and 60−75% in the long term, with the lowest values belonging to Oxyfuel plants. Within technologies exhibiting high levels of electrification, capex associated with renewable power generation becomes predominant, ranging from 54 to 70% of the CAC for fully electrified eC−p*K* plants to 11−19% for the Oxyfuel plants, among locations and time horizons. Consequently, cost reductions for PV, BESS, and WT, have a significant impact on the performance improvement of fully and partially electrified processes in the long-term scenario. Instead, electricity sourced from the grid plays only a minor role due to the renewable energy supply restriction introduced in the model. Therefore, it becomes somewhat noticeable in the short term, when the constraint is only 90%, for a fully electrified design, and where the electricity price is higher (e.g., Denmark).

CO_2 transport and storage costs represent a substantial share of the CAC of every plant in the short term. Contrary to the capex of renewable capacity, the cost associated with CO_2 T&S decreases with the degree of electrification as the amount of fuel-related CO_2 is reduced or completely eliminated, except in the OC−HK case, where high CO_2 recycle required to sustain the operation of the Oxyfuel calciner increases the flow rate of captured CO_2 per ton of clinker to similar degrees as the benchmark CCS plants. Consequently, T&S costs range from a maximum of €52−53 per ton of avoided CO_2 in the OC−HK plants to €39−43 per ton of avoided CO_2 in the eC−p*K* plants. The ranges are a result of the different indirect emissions associated with site-specific renewable generation portfolios and grid carbon intensity. In the long term, CO_2 T&S costs are assumed to halve based on learning curves and economies of scales from shared infrastructures, leading to a minimum range of €19−20 per ton of avoided CO_2 in the eC−p*K* plants.

Reductions in fuel demand positively influence the competitiveness of the fully electrified eC−p*K* and partially electrified eC−afK cases, while the change is negligible for the OC−HK and CCS benchmark plants. The economic impact was assessed assuming a constant fuel cost of 5 €/GJ_{LHV}. However, it is worth noting that this assumption neglects the vast price range of AF sourcing among locations as well as the influence of site-specific characteristics such as price fluctuations due to market conditions and supply chain perturbations or any cost incentives to promote the utilization of AF in the industry.

To understand the role of fuel consumption and other key parameters in the economic performance, the sensitivity of the CAC to a ±50% variation in the cost of fuel, production of renewable electricity, CO_2 T&S, and other equipment are estimated for each decarbonized plant and presented in SI-S10 for each time horizon.

Fuel cost account for the least impactful parameter, trailing significantly behind expenses associated with annualized capital investments and CO_2 T&S costs, although exerting a meaningful effect on the eC−p*K* plants (between 5 and 6% in the short term and 7 and 9% in the long term).

Electrified plants are most sensitive to the renewable electricity supply cost, i.e., to the capex of the renewable generation capacity, except in the flexible plant, where oversizing of key unit operations while reducing BESS needs leads to equivalent impact from the capex of other equipment such as the e-calciner, CPU, and PCC system. Benchmark CCS plants are more sensitive to the capex of other equipment than to the renewable electricity supply. This is particularly salient in the PCC case in the short term due to higher investment cost assumption of the capture system. The impact is reduced in the long term under more favorable capex conditions. Likewise, all

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

plants are significantly influenced by CO_2 T&S costs in the short term, while the sensitivity drops significantly when considering long-term assumptions.

In the long-term scenario, capex improvements in solvent-based PCC systems are assumed, becoming the leading reason for the 35−45% CAC reduction in the absorption-driven PCC benchmark plants together with the halving of CO_2 T&S costs, and renewable electricity production in sun-based locations. Under these conditions, the calculated CAC for the PCC benchmark plants align well with values reported by Cremona et al. (2025)[66] (126−130 €/t_{CO2}), who optimized a reverse Rankine cycle high-temperature heat pump, both with and without mechanical vapor recompression, to supply regeneration heat to an MEA-based PCC system in a cement plant. Their assumptions for specific capital cost of the CO_2 capture unit and for CO_2 transport and storage (T&S) are comparable to those adopted in the long-term horizon of this study (1.7 vs 1.9 M€/(t_{CO2}/h) and 30 vs 25 €/t_{CO2}, respectively). Although their optimized system achieved lower electricity consumption (with COPs between 2.7 and 3.6), the economic advantage is offset here by the lower electricity price resulting from the optimized renewable electricity supply, as opposed to their constant cost assumption of 100 €/MWh. Similarly, the long-term CAC values in this work are consistent with those estimated from the outcomes obtained by Hughes and Cvetic (2023) when considering the same carbon intensity of electricity supply, including a cost of 25 €/t_{CO2} for the transport of captured CO_2, and an exchange rate of 0.9 €/US$.[61] Their analysis was focused on PCC systems in cement production based on Shell's CANSOLV process and a natural gas boiler for regeneration heat (capturing both the cement and boiler CO_2 emissions), assuming a natural gas price of 4.4 US$/$GJ_{th}$.

Significant capex savings are also expected for SOEC systems, benefiting the performance of the HK−OC plant. Meanwhile, Oxyfuel plants remain as the most economically attractive technology across locations and time horizons, owing to their comparatively lower energy consumption and modest capex requirements.

Besides the intrinsic uncertainty in the capital investment costs of new technologies, it is important to note that there are other factors that influence the decision-making process of implementing a specific decarbonization strategy that were not incorporated inside the scope of this economic assessment. These include but are not limited to qualitative considerations such as land availability for the captive renewable capacity and supporting equipment or transmission grid constraints in the case of renewable electricity supply through a power purchase agreement (PPA), or quantitative trade-offs like lost production from technologies that require large retrofitting efforts to the reference process (e.g., Oxyfuel and electrified plants vs end-of-pipe PCC systems).

The relationship between location-specific climate conditions and the economic performance of the different decarbonized plants is presented in Figure 9, in terms of the calculated LCOE vs ΔCOC. In addition, the ΔCOC of a reference cement plant burning AF without any decarbonization strategy, i.e., paying fully for its direct CO_2 emissions, under two scenarios is represented by straight dotted lines in blue and red, considering a price on CO_2 emissions of 100 and 150 €/t_{CO2}.

To put the magnitude of the calculated cost variations into perspective, the World Cement Association reported production costs in the range of 80−90 € per ton of cement in Europe in Q4 2024.[67] The lower range is consistent with the modeled BAT reference plant considered in this study and, therefore, serves as an appropriate benchmark for interpreting the ΔCOC results in absolute terms. Assuming that approximately 80−90% of total cement production costs are attributable to clinker manufacturing and considering an average clinker factor of 0.73, this corresponds to an estimated clinker production cost of roughly 87−99 € per ton of clinker under European conditions.

Comparable publicly available cost data for Egypt and India were not identified. While absolute production costs in these regions are generally expected to differ due to variations in energy prices, labor costs, and regulatory environments, the analysis focuses on internally consistent cost differentials (ΔCOC) to ensure robust cross-regional comparison.

In general, a lower LCOE enhances the economic competitiveness of decarbonized strategies, favoring wind-dominant locations in the short term and sun-based renewable electricity production in the long term. However, this correlation can be altered under less favorable financing conditions, as observed in the ΔCOC values of CCS benchmark plants. Because the capex of process equipment and retrofits outweighs the influence of the renewable electricity supply, the economic performance of CCS benchmark plants in developing economies is worse compared to that in developed countries, even if lower LCOEs are achieved (e.g., Egypt vs Denmark in the short term). This disparity is resolved when analyzing the ΔCOC of decarbonized cases under the same WACC, highlighting that better climate conditions (enabling a cheaper renewable electricity supply) improve competitiveness when financing interest rates are aligned.

In the short term, fully electrified eC−p*K* cases exhibit the poorest performance, primarily affected by a 10-fold increase in electricity demand. These are followed by PCC benchmark plants, largely driven by the high cost of the capture technology. Egypt is an exception, where better conditions for the production of low-carbon electricity favor the electrified alternative. Conversely, Oxyfuel plants emerge as the only option competitive against a reference case paying €100 per ton of emitted CO_2. In the long-term scenario, the comparison with respect to a reference plant is shifted significantly under stringent environmental constraints. Nearly all cases outperform a reference process subject to a CO_2 emissions cost of 150 €/t_{CO2}. Lower LCOEs, coupled with capex improvements in key technologies, narrow the gap between decarbonization strategies, while fully electrified plants (eC−p*K*) continue to show the poorest economic performance.

As expected, electrified alternatives are more sensitive to variations in the LCOE, including the solvent-based PCC benchmark using an electricity-driven heat pump system to supply the solvent regeneration heat. For instance, considering long-term conditions and removing the effect of different financing conditions (i.e., comparing locations with a uniform WACC of 6%), linear trends on the ratio of ΔCOC/ΔLCOE can be observed for all cases, which can be grouped into three categories. The eC−p*K* plant can be regarded as largely sensitive to the LCOE, with a ratio of 1.21 (€/t_{clk})/(€/MWh), i.e., increasing the cost of electricity supply by 10 €/MWh raises the COC by 12.1 €/t_{clk}. Partially electrified cases and the electrified PCC benchmark can be viewed as moderately sensitive, with an upper range of 0.87 and 0.79 (€/t_{clk})/(€/MWh) for the eC−afK flexible and eC−afK inflexible plants and a lower range between 0.47 and 0.43, for the OC−HK and PCC benchmark configurations. Lastly, the Oxyfuel case can be considered as

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

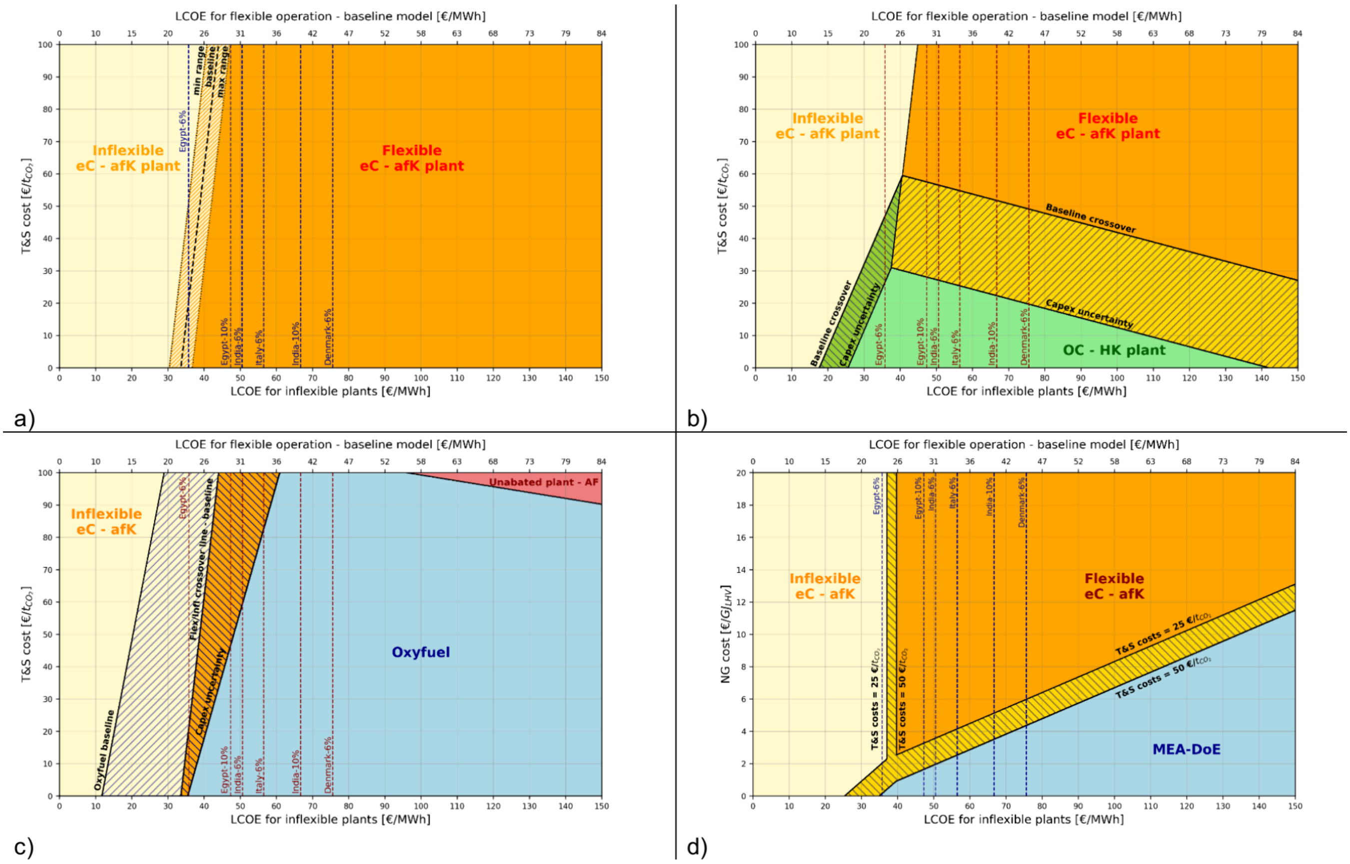


Figure 10. Competitive regions based on LCOE and CO_2 T&S costs under long-term scenario between (a) inflexible and flexible eC−afK plants; (b) partially electrified cement plants (inflexible eC−afK, flexible eC−afK, and OC−HK designs); (c) eC−afK plants (inflexible and flexible designs) and Oxyfuel benchmark plants; and (d) partially electrified eC−afK plants (inflexible and flexible designs) and the PCC system described in the DoE-NETL report with a capture rate of 95%. Hashed regions correspond to uncertainty limits based on the lower and upper range curves calculated by shifting the intercept of the baseline curve ±75%. Dashed vertical lines represent estimated LCOE across locations under long-term conditions, including Egypt and India with a WACC of 6%.

only mildly sensitive to variations in the cost of electricity supply with a ratio of 0.14 $(€/t_{clk})/(€/MWh)$.

Moreover, operational flexibility is shown to provide critical leverage for reducing LCOE by exploiting the possibility of material storage. This (cheaper) storage alternative not only helps mitigate short-term variability but also provides long-term stability by shifting the electricity load from renewable-scarce periods to seasons with greater availability of renewable resources. Consequently, LCOEs are reduced in the range of 35−45% across locations and time horizons, improving the ΔCOC compared to the inflexible eC−afK designs between 4 and 17%. The range is given by location-specific characteristics that drive the selection of the optimum renewable portfolio based on short-term and long-term cost assumptions (see Section 3.3). Thus, sun-dominant sites benefit the most in the short term, while Denmark's improvement greatly exceeds the rest in the long term (17 vs 5−8% ΔCOC declines). This allows flexible plants to become the most competitive electrified alternatives in the short-term horizon, narrowly outcompeting the OC−HK design, which benefits from ∼36% less electricity demand, compared to continuous operation of the flexible eC−afK configuration (see Tables 8 and 9), and larger capture of biogenic CO_2 emissions. Cost reductions in the management of captured CO_2, the SOEC system, and increased revenue from larger capture of biogenic emissions drive the OC−HK plants to outperform the rest of the electrified cases in the long term, achieving ΔCOC values between 2 and 12% lower than the flexible eC−afK plants.

Interestingly, while Oxyfuel technology maintains superior performance across assessed locations and time horizons, its economic advantage over the most competitive electrified alternatives diminishes as LCOE decreases. This trend suggests the existence of a crossover point where electrification becomes the most economically attractive solution. The next section explores this potential in greater detail.

3.6. Conditions for the Competitiveness of Electrified Plants

In this section, conditions favoring the introduction of electrified alternatives against the CCS benchmark technologies are studied by evaluating their competitiveness in terms of ΔCOC in a range of two key parameters, the cost of electricity supply expressed as LCOE [€/MWh], and the cost of transport and storage of the captured CO_2 [€/t_{CO2}]. Harder to electrify industrial processes will require a favorable framework to become competitive, namely, cheap renewable electricity supply; therefore, the comparative assessment was conducted using long-term scenario assumptions.

To simplify the analysis, a generalized model was developed using a least-squares regression method to approximate the LCOE of flexible eC−afK plants from the inflexible operation. The model is built by using the 12 data points derived from cases across the four locations and the two time horizons, including

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

plants in developing economies with a WACC of 6%. This methodology does not account for economic variations due to differences in meteorological profiles, grid electricity prices, or renewable energy constraints within time horizons. Nevertheless, the model demonstrates a high predictive accuracy, with an R^2 coefficient of 0.98, sufficient for identifying trends and distinguishing competitiveness between technologies on a generalized basis (more details in SI-S11).

The comparison between inflexible and flexible eC−afK plants is presented in Figure 10a. The bottom x-axis depicts the LCOE for inflexible operations, while the corresponding LCOE for the flexible process, estimated using the regression model, is shown on the top horizontal axis. The observed tilt in the crossover lines reflects efficiency losses in the flexible design, primarily due to cooling and reheating requirements of the stored calcined material, leading to an increased fuel consumption relative to inflexible plants. Consequently, the flexible design also involves higher flow rates of captured CO_2, thereby raising the impact of T&S costs. Meanwhile, the minimum and maximum curves represent an uncertainty range to take into account the inaccuracy of the regression model. In parallel, the benefits of managing the renewable electricity supply with intermediate storage of calcined material diminish as electricity costs decrease, evidenced by the gap between inflexible and flexible LCOE.

When renewable electricity becomes sufficiently inexpensive without requiring energy management strategies, the flexibility of operation can negatively impact the economic performance. To improve the economic viability of the system, the reduction in LCOE of a flexible design needs to compensate for the higher fuel demand, capex in other equipment, and CO_2 T&S costs. This means, for instance, that considering the long-term assumption of €25 per ton of transported and stored CO_2, inflexible plants are more competitive than flexible operations at baseload electricity supply costs below 37 €/MWh under the baseline model (corresponding to 24 €/MWh sourced by the flexible design). If CO_2 T&S costs increase to 100 €/t_{CO_2}, then the breakeven baseload LCOE becomes 45 €/MWh (or 28 €/MWh of flexibly sourced electricity).

The competitive region of the flexible design expands to sufficiently low electricity prices to include all long-term LCOE from the four assessed locations under baseline financing conditions. Only in the case of Egypt with 6% WACC is the inflexible plant more competitive over a large range of CO_2 T&S costs. Considering baseline conditions, the crossover T&S cost between inflexible and flexible design with respect to the Egypt—6% WACC plant is found at 20 €/t_{CO2}, while the uncertainty range expands from 0 to 51 €/t_{CO2}.

Figure 10b shows the same analysis extended to include all partially electrified cases, i.e., inflexible eC−afK, flexible eC−afK, and OC−HK plants. In addition to the comparison under baseline conditions for the long-term horizon, uncertainty margins were incorporated for the capital investment cost of the postcombustion carbon capture technology. This was accomplished by increasing the learning rate of the technology from 11 to 17%, reducing the capex of the solvent-based PCC system in the eC−afK designs by 55% compared to the baseline long-term assumption (explanation found in SI-S12). Regions where the competitiveness of electrified eC−afK plants are enhanced due to the stronger learning rate are illustrated in hatched patterns.

In this case, competitive areas between partially electrified alternatives are heavily influenced by electricity prices and CO_2 T&S costs. Inflexible and flexible eC−afK designs consume 1.5−1.6 times more electricity compared to an OC−HK plant. Combined with competitive SOEC capex and higher revenues from biogenic emissions capture, the OC−HK case can outcompete at electricity prices as low as 18 €/MWh under baseline assumptions, if no CO_2 T&S expenditures are considered. However, the breakeven threshold is highly sensitive to T&S costs, due to the additional 18% of captured CO_2 resulting from the CO_2 recycle needed for the oxy-fired calciner. As a result, a crossover value of LCOE of 41 €/MWh is found when CO_2 T&S costs reach 60 €/t_{CO2}. This region moves 10 €/MWh to the right when assuming higher learning rates for the PCC system, following the same slope until reaching a maximum T&S cost of 31 €/t_{CO2}. Above it, the competitive region is divided between inflexible and flexible eC−afK designs under the most favorable capex projections.

The impact of operational flexibility and solid storage is more consequential at higher LCOE, evidenced by the downward slope between the competitive regions of the flexible eC−afK design and the OC−HK plant. Importantly, the uncertainty range from varying the capex of the PCC system is greatly accentuated compared to the inflexible case, owing to its larger share on the overall economic performance. Therefore, the competitiveness of the flexible system can potentially be greatly improved if the cost progression of the carbon capture technology follows the highest estimation of learning rates.

The region where partially electrified eC−afK alternatives become competitive against benchmark Oxyfuel plants burning AF is highlighted in Figure 10c. Using baseline assumptions for the long-term horizon, only the inflexible design can compete, albeit at very low electricity prices, with increasing competitiveness as T&S costs rise. The crossover curve is found at baseload LCOEs of 12−29 €/MWh for CO_2 T&S costs between 0 and 100 €/t_{CO2}. Competitiveness of electrified cases is expanded when capex uncertainties are incorporated, shown in hashed patterns, even reaching LCOE regions where operational flexibility benefits the system (orange hashed area). Besides the −55% capex assumption for the PCC system in the eC−afK plants, an additional +50% of capital investment costs for Oxyfuel technology were included to take into account uncertainty in the technology's reference value (SI-S12). With capex uncertainties, breakeven baseload electricity prices can reach 35−61 €/MWh depending on CO_2 T&S costs. Under such conditions, only a plant located in Egypt with optimized captive renewable capacity could outperform Oxyfuel benchmarks across the majority of T&S costs, provided optimal financing conditions are met (i.e., WACC of 6%). Electrified plants in India (with a WACC of 6%), Egypt (with a higher WACC of 10%), or Italy (WACC of 6%) could also become competitive when T&S costs stand above 46, 59, and 82 €/t_{CO2}, respectively, and under flexible design.

The competitiveness of the partially electrified eC−afK plants was also compared against the second benchmark: the PCC plant, using amine-based solvents. In this case, electricity consumption increases by 411% relative to the reference cement plant, which accounts for 72−73% of the partially electrified design energy requirements. However, the CCS system incurs higher CO_2 T&S costs and elevated capital expenditures for the additional process equipment, eroding its competitiveness at low electricity prices. Conversely, at higher baseload LCOE values, where the solvent-based CCS plant's lower energy demand becomes advantageous, the benefits from the flexible eC−afK design are more pronounced, outperforming the amine-

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

based benchmark. Consequently, across all ranges of LCOE and CO_2 T&S costs analyzed, the partially electrified alternatives consistently outcompete the solvent-based, electrified CCS plant.

The analysis was extended to include a comparison with the PCC plant described in the 2023 DoE-NETL report on solvent-based systems for the cement industry (Figure 10d).[61] Economic performance was estimated based on the specific capital expenditure and energy consumption parameters of case CM95-B, which targets a 95% CO_2 capture rate including emissions from the natural gas boiler used to supply the solvent-regeneration heat. Equipment size and CO_2 capture volumes were scaled accordingly to ensure a consistent and equitable comparison across the cases. Likewise, fuel consumption, CO_2 emissions, and the share of biogenic emissions were homologated to the benchmark CCS plant designed in this study.

Partially electrified configurations outperform the solvent-based CCS plant in all locations over a broad range of operating conditions. The sensitivity analysis was focused on the influence of varying the LCOE and natural gas prices on the boundaries of the competitiveness region. Additionally, the impact of increasing T&S costs from 25 and 50 €/t_{CO2} is represented with hashed patterns. Under CO_2 T&S costs of 25 €/t_{CO2}, the inflexible eC−afK design exhibits superior performance at baseload electricity prices under 37 €/MWh, for natural gas prices above 2.3 €/GJ_{th}. As the LCOE increases, the amine-based CCS system gradually gains competitiveness due to its lower electricity demand, outperforming the flexible electrified option even at higher natural gas costs. With an LCOE of €150/MWh, the crossover natural gas price reaches 13 €/GJ_{LHV}. In this region, the greater capture of biogenic emissions combined with less electricity consumption offsets the increased fuel costs, shifting the advantage to the solvent-based plant. However, due to the larger volumes of CO_2 captured in the CCS configuration, the breakeven threshold is highly sensitive to changes in CO_2 T&S costs. For example, at an LCOE of €150/MWh, increasing the CO_2 T&S cost from 25 to 50 €/t_{CO2} shifts the natural gas breakeven price from 13 €/GJ_{LH} to approximately 11.4 €/GJ_{LHV}.

4. DISCUSSION AND LIMITATIONS OF THE STUDY

This section delves deeper into the implications and limitations of this study's main results, divided into three subsections. Section 4.1 discusses the potential for electrified systems in the cement industry and the main barriers to its deployment, while Section 4.2 considers the impact of capital investments and policy decisions. Finally, Section 4.3 provides an overview of the main limitations of this study.

4.1. Electrification Potential in the Cement Industry and Barriers

Electrification can offer a technically viable decarbonization strategy for the cement industry provided certain system-wide conditions are met. In particular, the competitiveness of electrified systems is conditioned by key trade-offs involving fuel and electricity costs, CO_2 T&S cost, and the potential to monetize the capture of biogenic emissions via carbon credits. Electrified cement plants become economically attractive in contexts where fuel prices are high, and low-carbon electricity is both low-cost and reliably available. Although this study employed a baseline fuel cost of 5 €/GJ_{LHV} for comparability across scenarios, actual costs can vary significantly by site. Moreover, the cement industry is uniquely positioned to coprocess nonrecyclable waste streams. This industrial symbiosis not only substitutes fossil fuels with lower-cost waste-derived alternatives but also enables the treatment of environmentally hazardous materials under controlled, high-temperature conditions, thereby offering a superior outcome compared to landfilling. In some cases, plants may receive gate fees for accepting industrial or municipal wastes, effectively transforming fuel procurement into a revenue-generating activity. Additionally, the mineral content of certain waste streams can be beneficially incorporated into the clinker matrix, further enhancing the material efficiency and circularity. Electrification strategies must therefore be evaluated not only on their energy and emissions profiles but also on the opportunity costs of forgoing these potential economic and operational synergies.

When coupled with the combustion of alternative fuels containing biogenic carbon and supported by a CO_2 capture infrastructure, partially electrified systems can achieve net-negative emissions, assuming that the accounting mechanism is regulated and low-carbon electricity is available. Full electrification, however, presents significantly greater challenges. On the one hand, direct electrification alternatives for the main burner would need to be designed and tested to treat large volumes of hot meal, producing heat at temperatures above 1400 °C, without losing heat transfer efficiency. Meanwhile, a completely electrified plant increases the electricity demand by a factor of 10 relative to a conventional manufacturing process and removes the possibility of receiving carbon credits for the storage of neutral emissions. Partially electrified plants, on the other hand, may only require a fuel switch to the main burner, though they still require a substantial increase in electricity demand, approximately 4.5 to 7 times that of the reference plant.

This increase in electricity consumption translates into a large demand for on-site renewable generation and storage infrastructure. Back-of-the-envelope calculations assuming 90 m^2/kW of wind turbines and 12 m^2/kW of PV panels suggest land requirements between 10 and 40 km^2 to meet the demand of electrified systems using a captive renewable portfolio, for a ∼1 Mton per annum clinker plant. Such requirements are an order of magnitude greater than the current land footprint of similar cement production sites, including the limestone quarry.[68] This scale of land use makes full electrification extremely difficult in practice in densely populated locations.

Power purchase agreements (PPAs) may provide a path to overcome the space constraints of on-site renewables, but they introduce a new layer of complexity. The market for low-carbon electricity is not yet mature in many jurisdictions, and increasing demand from industrial applications and other sectors in the economy (e.g., households, light-duty vehicles, data centers, etc.) will exacerbate competition for limited low-carbon power. Thus, while electrification may be viable in theory, it hinges on regional electricity prices and carbon intensities as well as the policy landscape shaping grid expansions and electricity markets.

The analysis also showed that fuel combustion leads to an increase in CO_2 T&S costs, which directly influences the economic performance in favor of electrified systems, except in a partially electrified OC−HK plant, which captures similar volumes of CO_2 as a conventional Oxyfuel configuration (OC−HK: 781,500 t_{CO_2}/year; Oxyfuel: 767,140 t_{CO2}/year). Consequently, the CO_2 T&S advantage of electrifying the heat supply is eroded.

As a result of these trade-offs, electrifying the thermal processes of cement plants is seldom competitive with the application of the most promising CCS technologies—such as Oxyfuel—and lags behind in technology readiness, thus posing greater technical challenges. Nonetheless, the outcomes of this research revealed that electrification can become the most cost-effective solution in selected scenarios, particularly in regions with limited access to CO_2 T&S infrastructure (i.e., with high CO_2 T&S costs) and in locations and scenarios with low-cost, low-carbon electricity supply. Under such conditions, electrified systems may help prevent asset stranding and maintain regional production capacity.

Finally, electrification approaches may also find niche applications beyond traditional clinker manufacturing. Promising opportunities lie in complementary processes, such as calcined clay production or in emerging electrochemical cement synthesis routes, which could benefit from electrification in ways that circumvent the need for CCS altogether.

4.2. Capital Investment, Location, and Policy Uncertainty

Capital investment has emerged as one of the most decisive factors affecting the viability of decarbonization technologies. Solvent-based PCC systems performed poorly under short-term conditions due to high capital costs and relatively high electricity demand, despite their comparatively high TRL and proven performance at scale. In contrast, Oxyfuel retrofits are assumed to be less capital-intensive, but they require a more complex technological integration and carry cost uncertainty related to modifications of core components such as burners and clinker cooler. Electrified systems, while potentially competitive in some cases, present greater technological and financial uncertainty due to their limited demonstration in industrial settings. These uncertainties are compounded by the need for novel integration strategies and an infrastructure buildout. Analyzing the optimum conditions for electrified cement plant competitiveness shows that reducing PCC systems capital expenditures by 55% and increasing Oxyfuel retrofit costs by 50% from long-term estimates could make electrified systems the preferred option in three of the 12 scenarios included in the assessment, highlighting the impact of capex uncertainty on economic performance.

The configuration and size of the energy storage mechanisms were found to depend heavily on the local renewable energy profiles. In solar-dominant regions such as Italy and India, daily irradiance fluctuations necessitate larger BESS capacities, with 830 and 690 MWh required, respectively, for inflexible eC−afK configurations in the short term. In contrast, wind-rich regions such as Denmark and Egypt showed much lower BESS requirements. Moreover, flexible configurations effectively bypass BESS in the short term by leveraging calcined meal storage, which offers a lower-cost buffer against renewable variability. However, long-term cost reductions in battery storage could significantly alter this balance. If BESS capex decreases by 67%, as assumed in the long-term scenario, battery deployment becomes cost-competitive, even for flexible designs in solar-intensive contexts.

The importance of the policy design and stability cannot be overstated. Establishing a guaranteed market for low-carbon cement, for instance, through green public procurement mechanisms, could derisk capital investments and facilitate deployment of new technology approaches. Given that roughly 40% of global cement demand originates from the public sector,[69] procurement mandates could rapidly accelerate decarbonization. In parallel, the availability and affordability of low-carbon electricity remain preconditions for electrification. Grid expansion, interconnection, and permitting processes are currently too slow to support the required scale of broad industrial electrification. Comprehensive planning and investment frameworks, including subsidies for grid upgrades and storage integration, are therefore vital.

A robust and predictable carbon price signal also plays an essential role in shifting economic incentives. The techno-economic model showed that a CO_2 emissions cost of 150 €/t_{CO2} is required for electrification pathways to become economically attractive, in combination with favorable electricity and CO_2 T&S cost scenarios. Yet, historical price volatility in the EU-ETS and the continued allocation of free allowances to the cement sector dampen the effectiveness of carbon pricing as an investment driver (though providing a key mechanism to avoid carbon leakage, with regard to free allowances). The progressive implementation of a Carbon Border Adjustment Mechanism (CBAM), in tandem with the phasing out of free allowances, is a promising strategy to address this misalignment if executed with clarity and consistency.

Lastly, integrating alternative fuels with biogenic carbon content offers a strategic advantage for the cement sector, enhanced by the cement kiln's coprocessing role. When combined with CCS, this pathway opens the door to the generation of certified carbon removal credits if the regulation is updated. In this sense, emerging EU legislation—most notably the Carbon Removals and Carbon Farming (CRCF) Regulation—aims to formalize certification and market mechanisms for this purpose. Policymakers should build on this framework by promoting the cobenefits of waste management and CO_2 removal, thereby incentivizing circular and low-carbon pathways in cement production. Such a direction would enable a sustainable and complementary strategy to CCS for the cement industry, albeit in direct competition with electrification approaches.

4.3. Limitations of the Study

Some limitations should be acknowledged in interpreting the findings of this study. First, electrical integration constraints were not explicitly considered in the modeling framework. The implementation of electrified technologies at the scale proposed would require significant upgrades to the site's electrical infrastructure. If electricity is supplied via the grid (e.g., through a PPA), additional investments in transmission infrastructure, such as grid reinforcement or transformer stations, would be necessary and could represent a non-negligible share of total project costs as well as a technical barrier. Conversely, the on-site renewable generation capacities estimated for the electrified scenarios are on the order of several hundred megawatts. Deploying such large-scale portfolios not only is capital-intensive but also poses substantial technical and regulatory challenges, particularly regarding land availability, permitting, and grid connection.

Second, certain system-level benefits of electrification were not captured. For example, excess renewable electricity production was assumed to be curtailed rather than sold back to the grid. Moreover, the operational flexibility enabled by intermediate storage (i.e., calcined meal buffering) could, in principle, allow electrified plants to participate in ancillary services markets, offering grid support functions, such as demand response. These services could introduce additional revenue streams and enhance the system value. Future studies

https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839

should incorporate grid-coupling dynamics to evaluate these interactions more comprehensively.

Third, this analysis assumes successful technical development and safe operation of electrified components, including 100% hydrogen combustion in rotary kilns, high-reliability plasma burners, and electrified calciners. It also assumes a 90% reduction in false air ingress consistently maintained throughout the year, an ambitious operational standard not yet realized in industrial settings. Achieving these targets will require substantial innovation in materials, engineering design, process control, and maintenance practices.

Fourth, although several sensitivity analyses were performed to assess techno-economic robustness, some parameters were held constant throughout locations and time horizons. Most notably, the composition and biogenic share of alternative fuels (set as 30%) were not varied. This has a significant influence on the feasibility of electrified systems, as the combustion of biogenic carbon offers a sustainable, low-cost alternative to electrification with the advantage of generating carbon credits when coupled with CCS technologies. Given the heterogeneity of waste streams, fuel markets, and regulatory environments, this assumption may overstate or understate the economic competitiveness of electrified systems in different contexts, which needs to be evaluated individually at each site for an accurate estimate.

Finally, several modeling simplifications should be noted: (i) Renewable energy profiles were based on a single representative meteorological year, which does not capture interannual variability in solar and wind availability; (ii) CO_2 T&S costs were assumed to vary only across time horizons, and not geographically. In reality, proximity to pipeline networks or geological storage sites can dramatically affect both feasibility and cost; (iii) the process model used in the MILP optimization framework was based on linearized energy and mass flow relationships. While necessary for computational tractability, this introduces a degree of error relative to the true nonlinear behavior of the integrated electrified systems.

5. CONCLUSIONS

As electricity grids progressively decarbonize and the cost of variable renewable energy (VRE) sources continues to decline, electrification is emerging as an increasingly attractive lever for deep decarbonization in energy-intensive industries. In the case of cement production, where process emissions are unavoidable and thermal energy has traditionally been fossil-based, electrification offers a pathway to substitute combustion-derived CO_2 emissions with clean energy sources.

This work provides a comprehensive techno-economic and system-level assessment of electrification strategies for the decarbonization of clinker production, benchmarked against carbon capture and sequestration (CCS) pathways and including management of VRE through operational flexibility in different locations and cost scenarios. The outcomes indicate that electrified systems can achieve high levels of CO_2 emissions avoidance by eliminating or reducing fuel-related emissions and enhancing CO_2 concentration upstream of the capture process. Nonetheless, CCS cement plants under the Oxyfuel configuration remain the most competitive option in most scenarios, benefiting from moderate capital requirements, comparatively low additional fuel and electricity demands, and high capture efficiency. However, these results carry high uncertainty regarding technical barriers and capex associated with the retrofitting efforts of complexly integrated methods such as Oxyfuel and electrification (as compared to end-of-pipe solutions like solvent-based postcombustion capture).

The advantages of CCS approaches are amplified by the potential to generate carbon removal credits when coupled with alternative fuel combustion. However, their deployment is contingent on access to a CO_2 transport and storage infrastructure, which may not be feasibly accessible to all sites, and favorable regulation update. In such cases, electrification offers a viable alternative by reducing the flow rate of CO_2 to be managed, although CCS remains necessary to avoid most of the emissions which are associated with calcium carbonate calcination.

Operational flexibility notably improves the economic performance of the flexible eC−afK configuration across locations and time horizons, compensating for the higher capital investment needs from oversized equipment with a reduction in the levelized cost of electricity supply. By decoupling calciner and kiln operations and exploiting calcined meal as energy storage medium, this configuration provides a cost-effective means to address renewable electricity variability, particularly over longer-time scales where battery energy storage systems (BESS) become prohibitively expensive. This advantage, however, is context-dependent and diminishes in solar-rich regions in the long term, where falling PV and BESS costs narrow the gap between flexible and inflexible designs.

To fully realize the potential of electrified cement plants, further research into new technologies and configurations for heat generation and transfer in cement production is needed. Reducing parasitic heat loads, such as those associated with gas recycle to ensure solids entrainment in conventional calciners, will be essential to lowering electricity demand and overall system costs. Finally, the viability of electrified systems depends on overcoming several technical hurdles, establishing favorable regulatory frameworks, and aligning the grid infrastructure with industrial demand.

■ ASSOCIATED CONTENT

Data Availability Statement

The code for the GAMS optimization model can be found at Renewable electrified cement production: flexibility and economic competitiveness with DOI 10.5281/zenodo.17578470. The version used for this study is v1. Additional data and assumptions used for this article are available in the same zenodo repository.

Supporting Information

The Supporting Information is available free of charge at https://pubs.acs.org/doi/10.1021/acs.iecr.5c05237.

Detailed description of Aspen Plus process models and MILP optimization model; complete modeling results, including tables with plant stream properties and detailed mass and energy balances; discussion and interpretation of the optimized renewable energy mixes; renewable energy generation profiles in the considered locations; BESS and calcined materials storage patterns; capital cost breakdown; sensitivity analysis on cost of avoided CO_2; linear regression model description for inflexible and flexible LCOE (PDF)

Cost summary and MILP code (ZIP)

AUTHOR INFORMATION

Corresponding Author

Matteo C. Romano − *Department of Energy, Politecnico di Milano, 20156 Milano, Italy;* orcid.org/0000-0003-0213-2245; Email: matteo.romano@polimi.it

Author

Sebastian Andres Quevedo Parra − *Department of Energy, Politecnico di Milano, 20156 Milano, Italy*

Complete contact information is available at: https://pubs.acs.org/10.1021/acs.iecr.5c05237

Author Contributions

Sebastian Quevedo Parra: conceptualization, methodology, investigation, formal analysis, software, visualization, and writing—original draft. Matteo C. Romano: conceptualization, methodology, supervision, validation, writing—review and editing, project administration, and funding acquisition.

Notes

The authors declare no competing financial interest.

ACKNOWLEDGMENTS

This study is supported by the Innovandi Global Cement and Concrete Research Network, as part of its Core Project 12: *Meta-analysis on the use of electric energy for clinker production.*

ACRONYMS

AF, alternative fuels; **ASU**, air separation unit; **BAT**, best available technique; **BESS**, battery energy storage system; **CAC**, cost of avoided CO_2; **CBAM**, carbon border adjustment mechanism; **CCS**, carbon capture and storage; **CCU**, carbon capture and utilization; **CEPCI**, chemical engineering plant cost index; **COP**, coefficient of performance; **CPU**, CO_2 compression and purification unit; **CRF**, capital recovery factor; **DoD**, depth of discharge; **eC−afK**, partially electrified plant (electrified calciner and alternative fuels in rotary kiln); **eC−p***K*, fully electrified plant (electrified calciner and plasma torches in rotary kiln); **GCCA**, Global Cement and Concrete Association; **IC**, installation costs; **KPI**, key performance indicators; **LCA**, life cycle assessment; **LCOE**, levelized cost of electricity; **LCORE**, levelized cost of renewable electricity; **MEA**, monoethanolamine; **MILP**, mixed-integer linear programming; **OC−HK**, partially electrified plant (oxy-fired calciner and hydrogen-fired rotary kiln); **ORC**, organic Rankine cycle; **PCC**, post-combustion capture; **PHS**, preheating strings; **PHT**, preheating tower; **PPA**, power purchase agreement; **PV**, solar photovoltaics; **SCM**, supplementary cementitious materials; **SOC**, state of charge; **SOEC**, solid oxide electrolysis cell; **T&S**, transport and storage; **TAC**, total annual cost; **TDC**, total direct costs; **TEC**, total equipment costs; **TPC**, total plant cost; **TRL**, technology readiness level; **VRE**, variable renewable energy; **WACC**, weighted average cost of capital; **WT**, wind turbines; **ΔCOC**, incremental cost of clinker

REFERENCES

(1) Andrew, R. M. Global CO 2 Emissions from Cement Production. *Earth System Science Data* **2018**, *10*, 195−217.

(2) Marmier, A.*Decarbonisation Options for the Cement Industry*; Publications Office of the European Union: Luxembourg, 2023. .

(3) GCCA. *Cement Industry Net Zero Progress Report 2024/25*; Global Cement and Concrete Association**2024**.

(4) Shah, I. H.; Miller, S. A.; Jiang, D.; Myers, R. J. Cement Substitution with Secondary Materials Can Reduce Annual Global CO2 Emissions by up to 1.3 Gigatons. *Nat Commun* **2022**, *13* (1), 5758.

(5) Mikulčić, H.; Klemeš, J. J.; Vujanović, M.; Urbaniec, K.; Duić, N. Reducing Greenhouse Gasses Emissions by Fostering the Deployment of Alternative Raw Materials and Energy Sources in the Cleaner Cement Manufacturing Process. *J. Clean. Prod.* **2016**, *136*, 119−132.

(6) Rissman, J.; Bataille, C.; Masanet, E.; Aden, N.; Morrow, W. R.; Zhou, N.; Elliott, N.; Dell, R.; Heeren, N.; Huckestein, B.; Cresko, J.; Miller, S. A.; Roy, J.; Fennell, P.; Cremmins, B.; Koch Blank, T.; Hone, D.; Williams, E. D.; de la Rue du Can, S.; Sisson, B.; Williams, M.; Katzenberger, J.; Burtraw, D.; Sethi, G.; Ping, H.; Danielson, D.; Lu, H.; Lorber, T.; Dinkel, J.; Helseth, J. Technologies and Policies to Decarbonize Global Industry: Review and Assessment of Mitigation Drivers through 2070. *Appl. Energy.* **2020**, No. 114848.

(7) Mineral Products Association; Cinar Ltd; VDZ gGmbH. Options for Switching UK Cement Production Sites to near Zero CO2 Emission Fuel:*Technical and Financial Feasibility*; Mineral Products Association**2019**.

(8) IEA. *CCUS Projects Database*. 2025. https://www.iea.org/data-and-statistics/data-product/ccus-projects-database (accessed 2025−05−05).

(9) Quevedo Parra, S.; Romano, M. C. Decarbonization of Cement Production by Electrification. *J. Clean. Prod.* **2023**, *425*, No. 138913.

(10) Wilhemsson, B.; Kollberg, C.; Larsson, J.; Eriksson, J.; Eriksson, M.A *Feasibility Study Evaluating Ways to Reach Sustainable Cement Production via the Use of Electricity*; 2018. https://www.cement.heidelbergmaterials.se/sites/default/files/assets/document/65/de/final_cemzero_2018_public_version_2.0.pdf.pdf (accessed 2025−12−31).

(11) Fraunhofer, I. S. I.. Direct Electrification of Industrial Process Heat An Assessment of Technologies, Potentials and Future Prospects for the EU.*Study on Behalf of Agora Industry*; **2024**. www.agora-industry.orginfo@agora-industry.org; www.deneff.orginfo@deneff.org; www.energyinnovation.orgindustry@energyinnovation.org.

(12) Castillo, J. A.*Cement Clinker Formation in Concentrated Carbon Dioxide Atmospheres Mineralogical and Reactivity Insights*; Umeå University2025.

(13) Electra, ELECTRA - Electrification of High Temperature and Flexible Technologies for Transforming Cement, *Lime and Pulp Industry.***2024**.

(14) Holcim. *Holcim invests in SaltX's plasma technology for scalable near-zero cement production.* https://www.holcim.com/media/company-news/investment-saltx-plasma-technology#:~:text=30%20June%202025-,Holcim%20invests%20in%20SaltX's%20plasma%20technology%20for%20scalable%20near%2Dzero,leading%20partner%20for%20sustainable%20construction.%E2%80%9D (accessed 2025−07−17).

(15) CEMEX. *CEMEX to introduce hydrogen technology to reduce CO_2 emissions in four cement plants in Mexico*. https://www.cemex.com/w/cemex-to-introduce-hydrogen-technology-to-reduce-co2-emissions-in-four-cement-plants-in-mexico (accessed 2024−06−25).

(16) Jacob, R. M.; Tokheim, L. A. Electrified Calciner Concept for CO2 Capture in Pyro-Processing of a Dry Process Cement Plant. *Energy* **2023**, *268*, No. 126673.

(17) Jacob, R. M.; Tokheim, L. A. CPFD Simulation of an Electrically Heated Fluidized Bed Calciner with Binary Particles. *Energy Convers. Manage.: X* **2023**, *20*, No. 100444.

(18) Jacob, R. M.; Tokheim, L. A. Novel Design of a Rotary Calciner Internally Heated with Electrical Axial Heaters: Experiments and Modelling. *Results Eng.* **2023**, *17*, No. 100992.

(19) Tsupari, A.; Korpijärvi, K.; Kauppinen, J.; Pikkarainen, T.; Leino, T.; Simell, P.; Lappalainen, M.; Winberg, I.; Katajisto, O.; Mäkikouri, S.*Decarbonate Co-Innovation Project Cost to Revenue - Public Final Report*; 2022. https://www.decarbonate.fi/wp-content/uploads/2022/06/Decarbonate_Final_report.pdf (accessed 2025−12−31).

(20) Varnier, L.; d'Amore, F.; Clausen, K.; Melitos, G.; de Groot, B.; Bezzo, F. Combined Electrification and Carbon Capture for Low-

Carbon Cement: Techno-Economic Assessment of Different Designs. *J. Cleaner Prod.* **2025**, *498*, No. 145029.
(21) LEILAC. *LEILAC ROADMAP 2050*. https://www.leilac.com/wp-content/uploads/2022/09/LEILAC-Roadmap.pdf (accessed 2024–07–02).
(22) FLSmidth. *ECOCLAY™. A partnership to decarbonize the cement industry*. https://www.flsmidth-cement.com/solutions/research-and-development/ecoclay-a-partnership-to-decarbonize-the-cement-industry (accessed 2025–01–08).
(23) Volaity, S. S.; Aylas-Paredes, B. K.; Han, T.; Huang, J.; Sridhar, S.; Sant, G.; Kumar, A.; Neithalath, N. Towards Decarbonization of Cement Industry: A Critical Review of Electrification Technologies for Sustainable Cement Production. *npj Materials Sustainability* **2025**, *3* (1), 23.
(24) Leão, A.; Collin, M.; Ghodkhande, S.; Bouissonnié, A.; Chen, X.; Malin, B.; Liu, Y.; Hovey, G.; Govindhakannan, J.; Plante, E. La; Jassby, D.; Gädt, T.; Corsini, L.; Simonetti, D.; Rosner, F.; Sant, G. ZeroCAL: Eliminating Carbon Dioxide Emissions from Limestone's Decomposition to Decarbonize Cement Production. *ACS Sustain. Chem. Eng.* **2024**, *12* (43), 15762–15787.
(25) Halfen Wexler, P.*Turning Gray into Green*. https://patriciahalfenwexler.medium.com/turning-gray-into-green-60a21c446760 (accessed 2024–08–08).
(26) Sublime Systems. *Sublime Systems/Our Process*. https://sublime-systems.com/our-process/ (accessed 2025–02–17).
(27) Foslie, S. S.; Knudsen, B. R.; Bjarghov, S.; Korpås, M. Faster Decarbonization of Heavy Industries in Low-Carbon Power Grids: Using Process Flexibility for Handling Grid Congestions. *Energy Environ. Sci.* **2024**, *17* (22), 8838–8854.
(28) Mai, T.; Denholm, P.; Brown, P.; Cole, W.; Hale, E.; Lamers, P.; Murphy, C.; Ruth, M.; Sergi, B.; Steinberg, D.; Baldwin, S. F. Getting to 100%: Six Strategies for the Challenging Last 10%. *Joule* **2022**, *21*, 1981–1994.
(29) CEMBUREAU. *CEMBUREAU KEY FACTS & FIGURES*; 2024.
(30) Cavalett, O.; Watanabe, M. D. B.; Voldsund, M.; Roussanaly, S.; Cherubini, F. Paving the Way for Sustainable Decarbonization of the European Cement Industry. *Nat Sustain* **2024**, 568.
(31) Magli, F.; Spinelli, M.; Fantini, M.; Romano, M. C.; Gatti, M. Techno-Economic Optimization and off-Design Analysis of CO2 Purification Units for Cement Plants with Oxyfuel-Based CO2 Capture. *Int. J. Greenhouse Gas Control* **2022**, *115*, No. 103591.
(32) Usterud, M. H.; Jacob, R. M.; Tokheim, L.-A. Modeling and Simulation of an Electrified Drop-Tube Calciner. *SIMS EUROSIM* **2021**, *2021*, 279.
(33) Tokheim, L.-A.; Mathisen, A.; Øi, L. E.; Jayarathna, C.; Eldrup, N.; Gautestad, T.; Capture, T.Combined Calcination and CO2 Capture in Cement Clinker Production by Use of Electrical Energy; *Trondheim CCS Conference - CO2*; 2019.
(34) Voldsund, M.; Gardarsdottir, S.; De Lena, E.; Pérez-Calvo, J. F.; Jamali, A.; Berstad, D.; Fu, C.; Romano, M.; Roussanaly, S.; Anantharaman, R.; Hoppe, H.; Sutter, D.; Mazzotti, M.; Gazzani, M.; Cinti, G.; Jordal, K. Comparison of Technologies for CO2 Capture from Cement Production—Part 1: Technical Evaluation. *Energies* **2019**, *12* (3), 559.
(35) Gardarsdottir, S. O.; De Lena, E.; Romano, M.; Roussanaly, S.; Voldsund, M.; Pérez-Calvo, J. F.; Berstad, D.; Fu, C.; Anantharaman, R.; Sutter, D.; Gazzani, M.; Mazzotti, M.; Cinti, G. Comparison of Technologies for CO 2 Capture from Cement Production—Part 2: Cost Analysis. *Energies* **2019**, *12* (3), 542.
(36) Pfenninger, S.; Staffell, I.*Renewables.ninja*. https://www.renewables.ninja/ (accessed 2023–04–04).
(37) Rienecker, M. M.; Suarez, M. J.; Gelaro, R.; Todling, R.; Bacmeister, J.; Liu, E.; Bosilovich, M. G.; Schubert, S. D.; Takacs, L.; Kim, G. K.; Bloom, S.; Chen, J.; Collins, D.; Conaty, A.; Da Silva, A.; Gu, W.; Joiner, J.; Koster, R. D.; Lucchesi, R.; Molod, A.; Owens, T.; Pawson, S.; Pegion, P.; Redder, C. R.; Reichle, R.; Robertson, F. R.; Ruddick, A. G.; Sienkiewicz, M.; Woollen, J. MERRA: NASA's Modern-Era Retrospective Analysis for Research and Applications. *J. Clim.* **2011**, *24* (14), 3624–3648.
(38) Pfeifroth, U.; Kothe, S.; Drücke, J.; Trentmann, J.; Schröder, M.; Selbach, N.; Hollmann, R.*Surface Radiation Data Set - Heliostat (SARAH) - Edition 3, Satellite Application Facility on Climate Monitoring*. Satellite Application Facility on Climate Monitoring (CM SAF)**2023**. DOI:.
(39) Staffell, I.; Pfenninger, S. Using Bias-Corrected Reanalysis to Simulate Current and Future Wind Power Output. *Energy* **2016**, *114*, 1224–1239.
(40) Pfenninger, S.; Staffell, I. Long-Term Patterns of European PV Output Using 30 Years of Validated Hourly Reanalysis and Satellite Data. *Energy* **2016**, *114*, 1251–1265.
(41) Orsted. *Offshore wind turbines in Denmark*. https://orsted.dk/vores-groenne-loesninger/havvind/vores-havvindmoelleparker (accessed 2024–06–10).
(42) Müller, A.; Friedrich, L.; Reichel, C.; Herceg, S.; Mittag, M.; Neuhaus, D. H. A Comparative Life Cycle Assessment of Silicon PV Modules: Impact of Module Design, Manufacturing Location and Inventory. *Sol. Energy Mater. Sol. Cells* **2021**, *230*, No. 111277.
(43) Bhandari, R.; Kumar, B.; Mayer, F. Life Cycle Greenhouse Gas Emission from Wind Farms in Reference to Turbine Sizes and Capacity Factors. *Journal of Cleaner Production* **2020**, *277*, No. 123385.
(44) Bonalumi, D.; Kolahchian Tabrizi, M. Re-Evaluation of the Global Warming Potential for the Production of Lithium-Ion Batteries with Nickel-Manganese-Cobalt Cathode Chemistries in China. *Energy Fuels* **2022**, *36* (22), 13753–13767.
(45) IRENA. *Renewable Power Generation Costs in 2021*; Abu Dhabi, 2022.
(46) ACWA Power. *ACWA Power achieves financial close for 200MW Kom Ombo solar project in Egypt*. https://www.acwapower.com/news/acwa-power-achieves-financial-close-for-200mw--kom-ombo-solar-project-in-egypt/# (accessed 2024–08–11).
(47) Abdelrahman, M. A.; Abdel-Hamid, R. H.; Abo Adma, M. A.; Daowd, M. Techno-Economic Analysis to Develop the First Wind Farm in the Egyptian Western Desert at Elkharga Oasis. *Clean Energy* **2022**, *6* (1), 211–990.
(48) Ram, M.; Galimova, T.; Bogdanov, D.; Fasihi, M.; Gulagi, A.; Breyer dena, C.; Micheli, M.; Crone, K.*Powerfuels in a Renewable Energy World - Global Vol.s, Costs, and Trading 2030 to 2050*. LUT University and Deutsche Energie-Agentur Gmbh (Dena); Deutsche Energie-Agentur Gmbh (dena): Lappeenranta, Berlin, 2020.
(49) Terlouw, T.; Bauer, C.; McKenna, R.; Mazzotti, M. Large-Scale Hydrogen Production via Water Electrolysis: A Techno-Economic and Environmental Assessment. *Energy Environ. Sci.* **2022**, *15* (9), 3583–3602.
(50) Cole, W.; Karmakar, A.*Cost Projections for Utility-Scale Battery Storage: 2023 Update*; **2024**. www.nrel.gov/publications.
(51) Bauer, C.; Desai, H.; Heck, T.; Sacchi, R.; Schneider, S.; Terlouw, T.; Treyer, K.; Zhang, X.; Bauer, C.*Electricity Storage and Hydrogen-Technologies, Costs and Impacts on Climate Change*; Paul Scherrer Institut.**2022**.
(52) IRENA. Electricity Storage and Renewables: Costs and Markets to 2030; *Abu Dhabi*, **2017**. /-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf (accessed 2024–05–04).
(53) Crespi, E.; Colbertaldo, P.; Guandalini, G.; Campanari, S. Design of Hybrid Power-to-Power Systems for Continuous Clean PV-Based Energy Supply. *Int. J. Hydrogen Energy* **2021**, *46* (26), 13691–13708.
(54) EUROSTAT. *Electricity Prices for Non-Household Consumers - Bi-Annual Data (from 2007 Onwards)*.2024. https://ec.europa.eu/eurostat/databrowser/view/nrg_pc_205__custom_17091203/default/table?lang=en (accessed 2023–08–11).
(55) U.P. Electricity Regulatory Commission. *Rate Schedule for FY 2022–23*; 2023.
(56) Business Today Egypt. *Egypt applies new electricity prices after 2-year delay, effecitve Jan.1*. https://www.businesstodayegypt.com/Article/1/3870/Egypt-applies-new-electricity-prices-after-2-year-delay-effective#:~:text=Households%20within%20the%200%2D50,kWh%20will%20pay%20EGP%201.40. (accessed 2024–06–01).

(57) IEA. *Cost of capital by project type in selected countries*. https://www.iea.org/data-and-statistics/charts/cost-of-capital-by-project-type-in-selected-countries-2022 (accessed 2024−10−07).

(58) De Lena, E.; Spinelli, M.; Gatti, M.; Scaccabarozzi, R.; Campanari, S.; Consonni, S.; Cinti, G.; Romano, M. C. Techno-Economic Analysis of Calcium Looping Processes for Low CO2 Emission Cement Plants. *International Journal of Greenhouse Gas Control* **2019**, *82*, 244−260.

(59) Mączka, T.; Pawlak-Kruczek, H.; Niedzwiecki, L.; Ziaja, E.; Chorążyczewski, A. Plasma Assisted Combustion as a Cost-Effective Way for Balancing of Intermittent Sources: Techno-Economic Assessment for 200 MWel Power Unit. *Energies* **2020**, *13* (19), 5056.

(60) Clean Hydrogen Partnership. Strategic Research and Innovation Agenda*Agenda*2021*2021 - 2027*2027

(61) Hughes, S.; Cvetic, P.*Analysis of Carbon Capture Retrofits for Cement Plants*; National Energy Technology Laboratory (NETL): Pittsburgh, 2023.

(62) Kosmadakis, G.; Arpagaus, C.; Neofytou, P.; Bertsch, S. Techno-Economic Analysis of High-Temperature Heat Pumps with Low-Global Warming Potential Refrigerants for Upgrading Waste Heat up to 150 °C. *Energy Conversion and Management* **2020**, *226*, No. 113488.

(63) Zühlsdorf, B.; Poulsen, J. L.; Schlosser, F.*IEA HPT Annex 58 about HTHPs-State of the Art Review*; Demonstration Cases and Development Perspectives. Copenhagen, 2022. https://heatpumpingtechnologies.org/annex58/.

(64) IEAGHG. *Towards Improved Guidelines for Cost Evaluation of Carbon Capture and Storage 2021-TR05*; 2021. www.ieaghg.org.

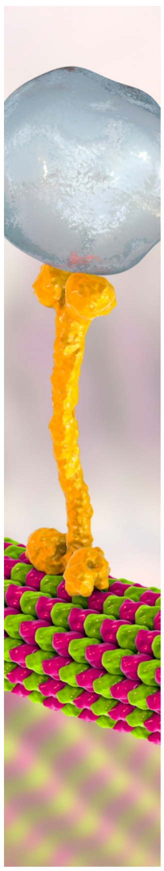
(65) AUMUND. *Clinker Storage Systems*. 2025. https://aumund.com/wp-content/uploads/2023/07/AUMUND_Clinker-Storage-Systems.pdf (accessed 2025−05−15).

(66) Cremona, R.; De Lena, E.; Conversano, A.; Spinelli, M.; Romano, M. C.; Gatti, M. Techno-Economic Assessment of High Temperature Heat Pumps Integrated in MEA-Based Post-Combustion CO2 Capture for Cement Plant. *Carbon Capture Science & Technology* **2025**, *16*, No. 100446.

(67) Riley, I.Impact of EU ETS on the Structure and Profitability of the Cement Industry. In *WCA Annual Conference*; 2024.

(68) Staunton, C.*Lagan Baseline Report (Kinnegad)*; 2015. https://epawebapp.epa.ie/licences/lic_eDMS/090151b2805874b4.pdf (accessed 2025−05−31).

(69) Climate Bonds Initiative. *Cementing the Global Net-Zero Transition Cementing the Global Net-Zero Transition*; 2023.



https://doi.org/10.1021/acs.iecr.5c05237
Ind. Eng. Chem. Res. 2026, 65, 10813−10839