

EU Taxonomy

Complementary Climate Delegated Act

Eurogas position

The EU Taxonomy Complementary Climate Delegated Act (CCDA) was adopted to reflect the role of certain transitional activities within the EU Taxonomy, particularly those related to natural gas.

Several elements of the current CCDA criteria risk limiting investments in assets that could deliver substantial emissions reductions in the short to medium term, including in Member States relying on coal-to-gas switching as part of their decarbonisation strategies. Beyond their emissions abatement potential, such assets play a crucial role in guaranteeing Europe's security of energy supply. Even though the CCDA includes in the current technical screening criteria a compliance pathway for plants replacing existing high emitting activities using solid or liquid fossil fuel, the overly restrictive criteria¹ ends up discriminating among technologies.

Eurogas sets out below several recommendations that would improve the CCDA and address the identified shortcomings.

Key elements

- The rationale underpinning the **GHG-emission thresholds across both existing Taxonomy criteria and potential revisions** remains insufficiently aligned with technological realities and has not been supported by a comprehensive impact assessment. **The tightening of energy-related technical screening criteria risks negatively affecting a successful transition to a low-carbon economy.** The fact that the current thresholds are already a significant challenge to be met should form the basis of the reflection about any potential tightening.
- The prohibition on **installing capacity above that of the replaced unit** should be revised.
- **CO₂ and solid carbon capture use and storage should be fully recognised** in the technical screening criteria, which refers only to blending with renewable and/or low-carbon gases
- The requirement to **commit to the use of renewable or low-carbon gases after 2035** should focus primarily on technical capability and emissions performance, rather than on the guaranteed availability of specific fuels.
- The requirement that the **construction permit** must be granted by 31 December 2030 sets arbitrarily and too early the cutoff date for transitional activities.
- The **55% relative GHG-reduction** requirement should be adjusted to reflect realistic emission factors, with a threshold closer to 40%.
- The CCDA predates several important legislative developments. **It is fundamental to ensure full alignment**, especially regarding definitions, sustainability criteria and accounting methodologies for renewable and low-carbon gases to provide legal certainty, safeguard investor confidence and ensure coherent and credible decarbonisation signals across the EU framework.

¹ I.e. direct GHG emissions must be either lower than 270 g CO₂e/kWh or, alternatively, must not exceed an average of 550 kg CO₂e/kW of installed capacity over a 20-year period

I. GHG-emission thresholds and alignment with real-world performance

The CCDA sets out a range of technical screening criteria under which certain natural gas activities may qualify under the EU Taxonomy. As highlighted by Eurogas in its response to the call for evidence on the Climate and Environmental Delegated Acts, and in relation to threshold proposals put forward by the Platform on Sustainable Finance, the rationale underpinning the GHG-emission thresholds across both existing Taxonomy criteria and potential revisions remains **insufficiently aligned with technological realities and has not been supported by a comprehensive impact assessment**.

These considerations are equally relevant to the CCDA, where similar approaches to threshold-setting give rise to comparable challenges.

In this context, **the tightening of energy-related technical screening criteria risks negatively affecting a successful transition to a low-carbon economy** if it does not:

- adequately reflect technological performance,
- take account of market maturity and economic feasibility, or
- allow flexibility in the choice of decarbonisation pathways

The CCDA criteria include life-cycle greenhouse gas emissions requirements for substantial contribution of 100 g CO₂e/kWh, as well as emissions performance thresholds of 270 g CO₂e/kWh direct emissions or annual direct GHG emissions of the activity do not exceed an average of 550kg CO₂e/kW of the facility's capacity over 20 years.

In practice, achieving the 100 g CO₂e/kWh life-cycle emissions threshold is highly challenging for gas-fired installations under current technological and market conditions, as additional emissions-abatement measures, such as carbon capture use and storage (CCUS), or the use of renewable and low-carbon hydrogen are not yet widely available at the scale required across the EU. While only high-efficiency cogeneration installations typically operate around the 270 g CO₂e/kWh direct emissions level, even modern combined-cycle gas turbines (CCGT) and open-cycle gas turbines (OCGT) operate above the 270 g CO₂e/kWh direct emissions level, with further reductions beyond this range effectively out of reach unless additional emissions-abatement measures becomes available at scale. Even considering the timeline to achieve compliance with the current technical screening criterion of ≤ 550 kg CO₂e/kW over 20 years would assume an optimistic scenario in light of the current level of market maturity, infrastructure deployment and cost conditions for such fuels.

The fact that the current thresholds are already a significant challenge to be met should form the basis of the reflection about any potential tightening, including considering the continued important role of gas-fired assets for system resilience and flexibility. Indeed, gas-fired power plants continue to play an important role in the decarbonisation and flexibility of the electricity sector and will increasingly continue to do so despite the missing business case².

² ENTSO-E ERAA 2024 "ERAA modelling suggests that over 50 GW of new fossil gas flexible capacity would be beneficial given anticipated high scarcity prices, though these are expected to occur infrequently in 2035. This capacity would help ensure adequacy during peak times or low RES infeed." and "Market signals based on rare scarcity hours may not justify investment, particularly when driven by rare extreme weather events."

In light of these constraints, Eurogas does not recommend tightening the emissions performance thresholds in the near term, as there is neither technical justification for such a change nor economic rationale: any further tightening would undermine the viability of installations currently designed and financed in compliance with the existing requirements, significantly increasing investment and operating costs without delivering proportionate environmental benefits.

Eurogas considers that the CCDA should strike an appropriate balance between ambition and feasibility, by reflecting the real-world performance of gas technologies and enabling investments that can deliver meaningful emissions reductions in the near to medium term, while also safeguarding security of supply and supporting an orderly transition towards climate neutrality.

II. Activities 4.29, 4.30 and 4.31

1. Capacity Limits

The prohibition on installing capacity above that of the replaced unit should be revised. When substituting high-emission individual heating units or expanding district heating networks, higher output is often necessary. While capacity may increase at the unit level, overall emissions in the given area can fall significantly. As a more general comment, the requirement to show that the activity replaces an existing coal or lignite plant is difficult to prove for individual companies (especially if it is not the same company shutting down the coal/lignite plants) and **does not reflect how investment decisions are made in practice.** Instead, investment decisions are based on **system-level assessments, including demand and supply projections, price signals, security-of-supply considerations and expected returns.**

a. Recognition and inclusion of significant upgrades beyond coal-to-gas conversion

The GHG emissions threshold (270 g CO₂e/kWh), is currently limited to coal-to-gas conversion projects. This, paradoxically, disadvantages countries/operators that achieved an early phase-out of their coal-powered facilities and does not capture the need to answer to the evolving needs of the system. Indeed, it excludes upgrades that would allow for the replacement of less efficient gas-fired units, despite the significant GHG emissions reductions potential of such initiative. Beyond their GHG abatement potential, such upgrades may be required to meet evolving supply, demand, market or system integration needs, the latter also allowing further potential GHG emissions reduction.

Such approach needs to be revisited, and those upgraded included.

b. Recognising the role of CO₂ and solid carbon capture, use and storage technologies

The reference framework for activities 4.29, 4.30, 4.31 recognises the role of CCS to decarbonise electricity and heating generation. **However, carbon capture use and storage – even beyond the sole capture of CO₂, for example with the capture of solid carbon - is not recognised in the current technical screening criteria, which refers only to blending with renewable and/or low-carbon gases.** In line with the principle of technology neutrality, in line with the spirit and intent of the Net Zero Industry Act – recognizing CCU/CCS as net-zero technologies – **this should be corrected.**

2. Post-2035 Fuel-Switching

a. Responsibility of Operators

Instead of focusing primarily on technical capability and emissions performance, the requirement to have the operators responsible to use renewable or low-carbon gases after 2035 pushes on them the responsibility and liability when it comes to the availability of specific fuels, something outside of their control.

Indeed, such rationale is hitting two roadblocks:

- Without proper recognition of market-based instruments as defined in the rest of the EU policy framework (e.g. RED), the requirement will be bottlenecked by the physical availability of renewable and low carbon gases in the supply area of the Operator.
- It relies on the availability at scale of these gases. As previously mentioned, in light of the current level of market maturity, infrastructure deployment and cost conditions, this is likely to represent a significant challenge. *See below in part b. more elements pertaining to the current progresses in this area.*

Notwithstanding the level of support for decarbonisation efforts of the operators of gas-fired facilities, they realistically should not be held responsible for the pace of market development or infrastructure deployment for renewable and low-carbon gaseous fuels. The commercial availability of such fuels remains largely outside operators' control and depends on enabling EU- and national-level policy frameworks, investment incentives, and permitting processes - conditions that are all lagging behind.

b. Availability of Renewable and Low-Carbon Gases for conversion by 2035

Available evidence indicates that the EU and its Member States are not on a trajectory that would ensure sufficient availability of renewable or low-carbon gases by 2035. Although the EU has set ambitious targets, such as the REPowerEU objective of producing 35 bcm of biomethane by 2030, current planned investments cover only around 20% of the required capacity, highlighting a significant implementation gap and slow infrastructure deployment. Similarly, the EU's target of reaching 10 Mt of renewable hydrogen by 2030 requires almost 100 GW of installed electrolyser capacity, yet current installed capacity and project commitments fall far short of this trajectory.

The European Court of Auditors has confirmed the market impact has yet to materialise, and Member States are progressing unevenly, further undermining predictability of supply by 2035. That can be explained by limited project commitments due to regulatory fragmentation and overly restrictive criteria (e.g. RNFBODA). Indeed, EU climate policy recognises renewable gases as a key component of the 2050 decarbonisation pathway. With a coherent and stable regulatory framework, markets for biomethane and hydrogen have strong potential to scale and play a significant role in the energy system.

Given this context, the commercial availability of renewable and low-carbon gases by 2035, at scale and at competitive prices, cannot be guaranteed by operators, as market development depends on national and EU-level policies and infrastructure deployment beyond their control. Therefore, the 2035 deadline should be extended to post-2040 to better reflect a realistic timeline for the large-scale and commercially viable availability of renewable and low-carbon gaseous fuels across the Union.

3. Construction permit by 31 December 2030

The requirement that the construction permit must be granted by 31 December 2030 sets arbitrarily and too early the cutoff date for transitional activities. Permits often cannot be planned completely.

Delays arise due to procedures, legal proceedings, or grid issues. Enforcing such date would lead projects delivering significant CO₂ reductions to be excluded from being recognised as environmentally sustainable under the EU Taxonomy and negatively impact access to transition finance.

In light of current energy transition challenges, there should remain a possibility to maintain eligibility for activities beyond 2030 under recalibrated thresholds that reflect technological progress and system realities, particularly where projects demonstrably replace more carbon-intensive generation or deliver measurable emissions reductions.

4. 55% Greenhouse-Gas Reduction Requirement

The 55% relative GHG-reduction requirement should be adjusted to reflect realistic emission factors, with a threshold closer to 40%. Highly efficient coal CHPs may not allow a 55% comparative reduction even when replaced by gas units that already meet strict absolute emission thresholds. Maintaining the current rule inadvertently penalises historically efficient operators and hinders cost-effective decarbonisation.

5. Clarifying the 100 gCO₂e/kWh Methodology

The calculation of the 100 g CO₂e/kWh threshold should continue to be based on a life-cycle approach, but greater clarity is needed regarding the applicable methodologies. It should be recalled that the 100 g CO₂e/kWh threshold is already highly stringent, as noted above.

As noted by the Platform on Sustainable Finance, the inclusion of construction and decommissioning phases is not consistently required across recognised life-cycle assessment standards and can be extremely difficult to assess in practice due to limited and heterogeneous data. In this context, it should be clearly stated, for example through interpretative guidance or FAQs, that methodologies which do not require the inclusion of construction and decommissioning phases, where consistent with the Taxonomy framework, are permissible for the purpose of demonstrating compliance with the 100 g threshold.

6. Alignment with EU Legislation

We wish to highlight that the Complementary Climate Delegated Act, which entered into force on 1 January 2023, predates several important legislative developments, including RED III, the RFNBO and RCF Delegated Regulation 2023/1184, and the Low Carbon Fuel Directive 2024/1788 together with its Delegated Regulation 2025/2359. As these instruments were adopted subsequently, inconsistencies have emerged, particularly in the definitions and treatment of renewable and low-carbon gaseous fuels. This fragmented regulatory landscape creates legal uncertainty, increases compliance risks and complicates investment planning for companies seeking to align with the EU Taxonomy while meeting parallel obligations under other pieces of legislation. **It is fundamental to ensure full alignment, especially regarding definitions, sustainability criteria and accounting methodologies for renewable and low-carbon gases to provide legal certainty, safeguard investor confidence and ensure coherent and credible decarbonisation signals across the EU framework.**