

A6.4-INFO-MISC-010

Information note

Summary of the comments received from stakeholders on the draft mechanism methodology “Electricity generation from renewable sources connected to electricity system” from the call for public inputs to annex 3 of the MEP012

Version 01.0



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1. Introduction

1. This note provides a summary of the views submitted by stakeholders in response to the call for public inputs to the draft version of the mechanism methodology “Electricity generation from renewable sources connected to electricity system” prepared by the Methodological Expert Panel (MEP) at its twelfth meeting.
2. The call for public inputs was open between 17 March to 7 April 2026, and a total of eighteen submissions were received. The full list of submissions can be found in the appendix to this note.

2. Summary of views to the draft mechanism methodology “Electricity generation from renewable sources connected to electricity system”

3. The following sections summarize the views expressed in the submissions.

2.1. General

4. The sections should be kept consistent across all methodologies. The landfill methodology (A6.4-AMM-001: Flaring or use of landfill gas), the sections are swapped. [15]

2.2. Cover note

5. The draft methodology applies to greenfield renewable power plants and allows inclusion of an integrated BESS. However, in practice, the solar/wind generation equipment and the BESS equipment are often commissioned with time lag. It is suggested the methodology to may consider the installation as the renewable power plant if the BESS is commissioned within 24 months from the commissioning of the solar or wind power plant, provided it remains part of the same project activity. Also, it may be explicitly mentioned in the methodology that the energy generating and storage assets may not be colocated. [2]
6. It is reiterated the importance of ensuring that the proposed methodology remains aligned with the diversity of electricity systems and supports the effective participation of low-carbon projects in different national contexts. [18]

2.3. Introduction

7. Constructing hydropower in an existing reservoir is not sufficient; the reservoir’s volume and surface area must remain unchanged. The mechanism methodology shall be revised to apply to activities generating electricity from certain types of renewable sources connected to the electricity system, such as hydro without the construction of a new reservoir or changing the volume and surface area of an existing reservoir, wind, solar, and geothermal. [11]

2.4. Definitions

8. The requirement form paragraph 6(e) is unnecessarily strict. Even if a power plant at the same site was operated and then shut down 20 years ago, the new power plant is still not considered greenfield. Proposing to revise the definition of “Greenfield power plant” to: A

new power plant that is constructed and operated at a site where no power plant was in operation prior to the implementation of the project activity. [11]

9. The current approach to defining installed capacity as per paragraph 6(g) may lead to inconsistencies between turbine nameplate values and officially approved installed capacity by national authorities in the host country. The lack of harmonization in verification criteria may result in regulatory uncertainty and divergent interpretations across jurisdictions. This issue is particularly relevant in contexts where different authorities adopt distinct standards for capacity certification. Proposing to include the following definition: “Installed electricity generation capacity (or installed capacity) corresponds to the capacity, expressed in Watts or its multiples, for which the generating unit is designed to operate under nominal conditions. The installed generation capacity of a power plant corresponds to the sum of the installed capacities of its generating units, as indicated on the respective turbine nameplates.” [18]
10. In several CDM verification processes, there is a confusion about how to evidence the installed capacity of a power unit. In the CDM, it is recommended that the nameplate of the turbines. Sometimes, these numbers present a slight difference from installed capacity approved by National Agencies or Environmental entities responsible for approving the plant in the host country. It is suggested to complement the definition of “Installed power generation capacity (or installed capacity)” as “*The installed power generation capacity of a power unit is the capacity, expressed in Watts or one of its multiples, for which the power unit has been designed to operate at nominal conditions. The installed power generation capacity of a power plant is the sum of the installed power generation capacities of its power units as indicated in the nameplate of the turbines.*” [12]

2.5. Applicability conditions

11. The current draft methodology specifically refers to Battery Energy Storage Systems (BESS). However, other energy storage technologies, such as Pumped Storage Project (PSP) and other storage systems, can also play an important role in improving the reliability and dispatchability of renewable power plant. The MEP should consider expanding the applicability of the methodology to include other storage technologies beyond BESS, subject to appropriate monitoring, accounting, and safeguards. Note that such a provision for PSP was already a part of ACM002. [2]
12. The proposed methodology should ensure overall internal consistency and practical applicability across different electricity system configurations. In particular, methodologies applied under Article 6.4 should take into account the diversity of national contexts, including integrated hydrothermal systems, and avoid overly rigid criteria that may limit the participation of otherwise eligible low-carbon projects. Ensuring coherence, regulatory predictability, and alignment with real investment conditions is essential for the effective implementation of the mechanism. It is recommended that the methodology remains flexible and adaptable to different national and system-specific contexts, while preserving environmental integrity and avoiding unnecessary regulatory complexity. [18]
13. Comments to paragraph 8:
 - (a) Restricting the applicability of the methodology exclusively to greenfield plants may not adequately reflect the reality of electricity systems such as Brazil’s. In the Brazilian context, modernization, rehabilitation, retrofitting, and capacity expansion of existing hydropower plants contribute to increased efficiency and clean energy

generation without significant additional environmental impacts. Excluding such activities may discourage improvements in existing infrastructure and reduce the overall effectiveness of the mechanism. It is recommended to replace paragraph 8 with *“This methodology applies to Article 6.4 activities involving the installation of new power plants or the capacity increase, modernization, rehabilitation, or replacement of existing power plants generating electricity from renewable sources;”* [18]

- (b) It is proposed to change the applicability conditions under paragraph 8 in order to allow projects to deliver all electricity generated after meeting their auxiliary consumption needs, as follows: *“This mechanism methodology is applicable to Article 6.4 activities that install a greenfield power plant that generates electricity from renewable sources and feeds all electricity generated, after any auxiliary consumption, into an electricity system. The power plant may include a battery energy storage system (BESS);”* [11]
 - (c) The requirement under paragraph 8 that all electricity generated must be supplied to the electricity system is too restrictive. In real project situations, some electricity is used internally for operating the plant, including auxiliary needs and startup activities. Because of this, it is more practical and realistic to base eligibility on the electricity that is actually delivered to the electricity system. It is proposed to revise paragraph 8 such that net electricity is supplied to the electricity system, rather than requiring that all electricity generated must be exported; [14]
 - (d) The PACM should consider expanding the scope of this methodology to increase the flow of carbon finance to grid-connected renewable energy projects that require such assistance. For example, there is a growing trend to add BESS to brownfield renewable energy projects, which are currently excluded from this methodology. It is suggested to extend the applicability conditions to include combinations such as 'existing RE + greenfield BESS.' This specific project configuration is critical for markets experiencing high curtailment as it allows for the optimization of existing renewable assets through integrated storage solutions. In addition, for example in South Africa, there is a growing trend re the installation of grid-tied solar PV systems (with or without BESS) which are implemented primarily for embedded generation but also include the ability to back-feed surplus renewable energy into the grid. The provision for grid export can be very important: it can help project developers finance the PV (e.g. additional revenue stream); contributes to greening of the national energy sector (highest national GHG source) and helps make electricity supplies in the country more secure, which is extremely important for the country's development agenda; [08] [13]
 - (e) The methodology is presented as a standalone renewable electricity methodology, and only limited reference is made to BESS. This is not sufficient for projects where renewable electricity and storage are used together. Since such projects are becoming more common, clearer provisions are needed for the treatment of storage. It is recommended to revise paragraphs 8, 15, 37(c), 62(c) and footnotes 26 and 31 such that a separate section for BESS is included, and the treatment of charging source, stored electricity, energy losses, internal use, and time-shifted electricity supply is clearly stated. [14]
14. Restricting eligibility to run-of-river hydropower plants and establishing fixed criteria related to storage duration, hydraulic residence time, and land use may not adequately

reflect the role of reservoirs in electricity systems such as Brazil’s. Reservoirs play a strategic role in ensuring water and energy security, supporting system reliability, and enhancing resilience to increasing hydrological variability driven by climate change. Additionally, GHG emissions from reservoirs are highly dependent on local conditions, and indirect indicators such as residence time or land cover may not accurately capture their complexity. Internationally recognized methodologies allow for more robust, project-level assessments of emissions. It is recommended to allow the eligibility of hydropower plants (including storage), provided that:

- (a) CO₂ and CH₄ emissions associated with the reservoir are quantified using scientifically recognized methodologies;
- (b) Emission intensity does not exceed a defined threshold (e.g., 100 gCO₂e/kWh);
- (c) Mitigation and compensation measures are implemented where applicable;
- (d) Hydraulic parameters are used as indicative rather than exclusionary criteria;
- (e) Forest cover is not used as a standalone ineligibility criterion. [18]

15. Comments to paragraph 10(a):

- (a) Paragraphs 10(a)(i) – 10(a)(iii) are accepted as specified in the Draft Mechanism Methodology A6.4-MEP012-A03. [6];
- (b) For the sake clarity, it would be useful to define what is considered peatland. It is proposed introducing a footnote based on the IPCC Glossary in the 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories. See: https://www.ipcc.ch/site/assets/uploads/2019/12/19R_V0_02_Glossary.pdf. Include the following footnote: *Peatlands are wetland ecosystems where soils are dominated by peat. In peatlands net primary production exceeds organic matter decomposition as a result of waterlogged conditions, which leads to the accumulation of peat. In absence of a host country definition of peat, it shall be defined as soft, porous or compressed, sedimentary deposit of plant origin with high water content in the natural state (up to about 90 percent);* [11]
- (c) The fact that the reservoir was established at least [X] years before the start date of the Article 6.4 activity does not prove that the reservoir was built independently of the Article 6.4 activity. It is recommended to revise the language of the paragraph to *“The reservoir is independently justified (by another dominant function such as irrigation or flood control), and is planned, approved, and financed independently. It is economically viable without hydropower revenues and is designed and timed such that hydropower does not affect its design (i.e. no design changes due to hydropower) or its construction schedule (i.e. it would have been built at the same time or earlier even without hydropower).”* [11]

16. Comments to paragraph 11:

- (a) Grid-down time and instability is common across many developing country contexts. The provision of secure electricity supplies in developing country contexts is a key socio-economic development priority. It is therefore common for residential, commercial and industrial renewable power plants to include backup generators in their project boundaries, to ensure security of electricity supply,

especially to critical onsite operations, when the renewable energy supplies are interrupted, for example during load shedding or when the renewable resource is constrained, e.g. non-sunlight hours in case of solar power or no wind in the case of wind power. Limiting applicability of project to <1% use of backup generators will exclude applicability of projects, many of which are located in developing country contexts. For example, South Africa experienced extreme load shedding of the grid in 2023. Electricity power cuts were active for roughly 289 to over 300 days. This indicates that load shedding was implemented for roughly 79% to 82% of the year (289–300 days out of 365). Furthermore, many grids in developing countries, such as those in Southern Africa, are characterised by high emission intensity due to continued use of coal fired power stations. These are precisely the grids and countries that will benefit from the implementation of grid connected renewable energy power plants, many of which require carbon finances to be bankable. The possible creation of the unintended barriers to the deployment of renewable energy would be contrary to the core objective of the Paris Agreement. Furthermore, can clarity/ details on the selection of 1% as the battery threshold be provided. On what basis has this figure been established? Considering deleting 11(a) as an applicability condition. This is not necessary, as project emissions are accounted for in the case of all project emissions, such as those arising from the use of fossil fuels in backup generators. Furthermore, the current 11(b) is a reasonable applicability condition, which will ensure that backup generators are not used unless required; [8]

- (b) The threshold of 1% of total energy generation from back-up sources consuming fossil fuels under paragraph 11(a) may be restrictive for many projects, especially in the developing countries, where the operation of power grids characterized by instability. Moreover, the proposed draft Methodology accounts for project emissions from fossil fuel combustion. Therefore, we propose to either remove this applicability condition or increase the above threshold of 1% (alternatively, different thresholds depending on host country profiles can be proposed). Determination of the threshold has to be justified (if the threshold is decided to be kept in Methodology). [4]
17. The applicability conditions in paragraph 14 are intended to prevent double counting and leakage, which are appropriate and consistent with the overall architecture of the Article 6.4 mechanism. However, the current wording is overly restrictive and may unnecessarily limit the applicability of the methodology to commercially viable renewable electricity projects. Paragraph 14(a) already establishes a robust safeguard against double counting by prohibiting the use of environmental attributes (e.g. EACs/RECs) under other schemes. This objective is appropriate and sufficient to address the relevant risk. In contrast, paragraph 14(b) extends beyond this objective by prohibiting activity participants from entering into agreements to supply electricity to specific consumers. As drafted, this provision may exclude a broad range of standard market arrangements, including bilateral contracts, corporate PPAs and other contractual structures that are essential to ensure revenue certainty and financial closure for renewable energy projects. This is particularly problematic because the sale of electricity to specific consumers does not, in itself, create double counting. The relevant risk arises only where the same environmental attributes are used to support both the issuance of A6.4ERs and environmental or market-based claims by third parties. Accordingly, this risk should be addressed through restrictions on the use of environmental attributes, rather than through limitations on electricity commercialization structures. This distinction is also consistent with internationally

recognized frameworks such as the GHG Protocol, which clearly separate electricity procurement from environmental attribute accounting. In practice, large-scale renewable energy projects rarely achieve financial close without securing long-term contractual arrangements, whether through corporate PPAs in the free market or regulated procurement mechanisms such as auctions. This is particularly relevant in markets such as Brazil, where price volatility and limited long-term price predictability make ex-post electricity sales insufficient to support project bankability. Restricting such arrangements would therefore significantly reduce the pipeline of eligible projects under Article 6.4 without delivering additional environmental integrity benefits. Paragraph 14(c) introduces a similar issue by requiring that all equipment installed under the activity be newly produced. While the objective of avoiding leakage from the transfer of previously operated equipment is valid, the current wording does not distinguish between equipment that has been previously installed and operated in another facility, and equipment that has not been newly manufactured but has never been installed or used. These situations present materially different risks, and a blanket restriction is broader than necessary. For the methodology to be applicable to real-world renewable electricity markets, including wind, solar, hydro and geothermal, paragraph 14 should be revised to focus on the actual risks that need to be controlled: (i) double counting of environmental attributes; and (ii) leakage arising from the transfer of previously operated equipment. A more targeted formulation would preserve environmental integrity while avoiding the unnecessary exclusion of bankable and implementable renewable energy activities. It is proposed to revise paragraph 14 as follows: “*Furthermore, the mechanism methodology is only applicable under the following conditions:*

- (a) *The renewable electricity generated by the Article 6.4 activity, and any associated environmental attributes, shall not be claimed, credited, issued, transferred, retired, or otherwise utilized under any other certification scheme, crediting mechanism, or environmental market in a manner that would result in double counting of emission reductions;*
- (b) *The sale, delivery, or contractual supply of electricity generated by the Article 6.4 activity to specific consumers, including through bilateral agreements, power purchase agreements (PPAs), or other contractual arrangements, shall be permitted, provided that:*
 - (i) *Such agreements do not transfer, assign, or enable the use of environmental attributes associated with the electricity in a manner inconsistent with subparagraph (a); and*
 - (ii) *Any environmental or market-based claims associated with the electricity are consistent with the treatment of environmental attributes under this methodology and do not result in double counting of emission reductions. Where environmental attributes are retained by the activity participant for the purpose of generating A6.4ERs, the electricity purchaser shall not claim the associated emission reductions or equivalent zero-emission attributes, unless such claims are appropriately adjusted, disclaimed, or otherwise treated to avoid double counting;*
- (c) *Equipment installed under the Article 6.4 activity shall be:*
 - (i) *Newly produced; or*

- (ii) *Demonstrably unused, meaning that it has not previously been installed, commissioned, or operated in any other plant.*
 - (d) *Equipment that has previously been installed or operated in another plant shall only be eligible where the activity participant demonstrates, in accordance with an approved methodological approach, that its use does not result in leakage, baseline equipment transfer, or any other distortion in the estimation of emission reductions;*
 - (e) *For the avoidance of doubt, paragraph 14 shall be applied in a manner that prevents double counting of environmental attributes and leakage from equipment transfer, but shall not preclude ordinary electricity market arrangements, including bilateral contracts, power purchase agreements (PPAs), or other commercially established structures necessary for project financing and implementation.” [12]*
- 18. Some modifications are proposed in paragraph 14(a) to allow projects to be registered with another GHG/non-GHG /certification programme, provided no double issuance happens, as follows: *“The renewable electricity generated by the Article 6.4 activity is not claimed, credited, or utilized under any certification scheme or other crediting mechanism. Such claiming, crediting or utilization may occur under, but is not limited to, the issuance of energy attribute certificates (e.g., renewable energy certificates) with respect to the renewable electricity generated under the Article 6.4 activity; but it may be registered with another GHG or non-GHG certification programme, provided no double issuance of credits occurs.” [11]*
- 19. Comments to paragraph 14(b):
 - (a) While the reason for including the applicability condition under paragraph 14(b) is not stated, we understand it may be due to consumers using the PPA to claim the climate attribute of the acquired energy. However, we understand this may exclude many projects. There are developing countries, such as in Brazil, in which a large portion of participants sell electricity through bilateral agreements, which are frequently made with more than one user and for periods shorter than the operational period of the project. However, users do not necessarily claim the environmental attribute of the energy. It is recommended to consider revising the condition to allow direct supply through the system to specific customers, as long as the agreement clearly defines that the environmental attribute of the renewable energy cannot be claimed by the consumer; [16]
 - (b) Restricting or prohibiting bilateral electricity supply agreements may compromise the eligibility of a significant share of renewable energy projects. In the Brazilian context, long-term financing — including from development banks — relies on Power Purchase Agreements (PPAs) to ensure revenue predictability and enable financial close. The existence of PPAs does not eliminate additionality, as projects continue to face financial, regulatory, and implementation barriers. Moreover, contractual arrangements for energy supply should not be conflated with the accounting of environmental attributes. It is proposed to revise paragraph 14(b) to *“Activity participants may enter into electricity supply agreements through the grid with specific consumers, provided that double counting or double claiming of environmental attributes is avoided;” [18]*

- (c) The applicability condition from paragraph 14(b) excludes renewable power plants that are wheeled through the grid. Wheeling of renewable electricity is beneficial because it enables project developers to unlock geographically unconstrained demand, which in turn creates the conditions necessary to monetize carbon attributes and channel carbon finance into projects. Without wheeling, renewable projects are typically limited to selling electricity to the local grid or a single off-taker (often a utility). This restricts both pricing power and the ability to structure sophisticated environmental attribute transactions. The claiming of carbon credits and the wheeling of the renewable energy can coexist on the condition of clear articulation of the environmental attribute of renewable energy, as well as the clear and agreed ownership of the environmental attribute. This can be achieved if the project developer retains the environmental attributes and sells the “grey power” separately to the carbon credits. There must be a clear agreement and understanding that the off-taker cannot claim renewable energy use in this case. The MEP should consider allowing wheeling by changing the applicability condition of 14(b) to reflect that the claiming of carbon credits and the wheeling of the renewable energy can coexist on the condition of clear articulation of the environmental attribute of renewable energy, as well as the clear and agreed ownership of the environmental attribute. This can be achieved if the project developer retains the environmental attributes and sells the “grey power” separately to the carbon credits. There must be a clear agreement and understanding that the off-taker cannot claim renewable energy use in this case. As a suggestion, provisions from the GHG Protocol's Scope 2 Guidance could be consulted and considered, particularly the Scope 2 Quality Criteria; [8] [13] [17]
- (d) We proposed to remove paragraph 14(b) based on Malaysia (non-LDCs) RE schemes such as the Fit-In-Tariff scheme - between the project developers and the national grid operators. This is to increase participation from non-LDCs; [6]
- (e) It is indicated that electricity supplied through the electricity system to specific consumers is not intended to be covered. This suggests that projects involving captive consumption, third-party sale, wheeling arrangements, or supply to identified consumers through the electricity system may be outside the scope of the methodology. Since similar scope-related issues have required clarification previously under ACM0002, the intended scope should be stated more clearly in the draft methodology. This paragraph should be clarified to explicitly state the treatment of projects involving captive consumption, third-party sale, wheeling arrangements, supply to identified consumers through the electricity system, and power sale through energy exchanges under open access arrangements, including whether such project types fall outside the scope of this methodology; [14]
20. The term 'newly produced' under paragraph 14(c) imposes an unreasonable restriction without putting a restriction on what newly produced would mean. Hence, an alternate text is suggested to ensure the project equipment was not used elsewhere or intended to be used elsewhere in absence of the project, as follows: *“Furthermore, the mechanism methodology is only applicable under the following conditions: The equipment installed under the Article 6.4 activity has previously not being operated in any other plant.”* [11]
21. As reflected in paragraph 19, leakage from the use of pre-used equipment is avoided by requiring that equipment installed under the Article 6.4 activity is newly produced and not previously used. Because of this, clearer treatment is needed for ordinary replacement of failed parts, warranty replacements, and certified spare parts during project operation, so

that normal operation and maintenance actions are not confused with transfer of baseline equipment. It is recommended to clarify in paragraphs 14(c) and 19 that ordinary replacement of failed components, certified spare parts, and normal operation and maintenance replacements are not treated as use of pre-used equipment, provided that no baseline equipment is transferred from another plant into the credited activity. [14]

2.6. Normative references

22. It is cited that the methodology is based on elements from ACM0002 and AMS-I.D. Though it is good to have a singular methodology however the aspect of small-scale consideration is not evident thereafter in the methodology. The methodology should have consideration and provide simplification in small-scale context. [15]

2.7. Project boundary

23. The Boundary table provides for “CO₂ emissions from combustion of fossil fuels for electricity generation in solar thermal power plants and geothermal power plants”. However, in the case of some concentrated solar power (CSP) facilities, fossil fuels such as diesel are used to ensure that the project's heat transfer fluid is kept at a certain temperature. The use of this fossil fuel does not generate electricity but instead to ensure ongoing operations of the CSP plant. We propose that the wording be amended of this emission source be amended as follows: “CO₂ emissions from combustion of fossil fuels for the continued operation of solar thermal power plants and geothermal power plants.” [13]
24. Including construction emissions for the project without also including equivalent construction emissions for all grid-connected plants in the baseline would create an inconsistent system boundary and bias the comparison. Such emissions should therefore either be excluded from both baseline and project, or included consistently in both. [8] [13]
25. Upstream emissions from the construction of the activity are excluded from the project boundary. The reasoning, found in the Appendix, argues that this is conservative to exclude because the upstream emissions from renewable power plants are lower than those from the construction of fossil power plants. This reasoning is not sufficient to justify exclusion. It is recommended to include upstream emissions from the construction of the activity. [5]
26. Shadowing effects of wind power plants and CO₂ emissions from same are included. This aspect is linked to greenfield installation, common practice check and stakeholder consultation too. In case of scenario of the other effected wind power plant due to shadow effect also claiming carbon credits, therein the credit volume would get impacted (reduced) apart from discounting happening for the A6.4 activity too. The stakeholder consultation and associated issue being addressed across the involved parties would ensure the A6.4 activity progressing. Suggest removing the shadow effect aspect or introduce a screening rule to assess the material impact of this on leakage and accordingly the consideration of such by the project proponent. [15]

2.8. Demonstration of additionality

2.8.1. General

27. Section 6 represents the most operationally consequential part of this methodology. Additionality determination is the foundational credibility test for any carbon crediting mechanism; if it fails, every downstream calculation of baseline emissions, downward adjustments, and emission reductions becomes meaningless regardless of technical precision. The current architecture has serious structural problems that will systematically produce both false positives and false negatives depending on context, with SIDS and LDC projects disproportionately affected in the negative direction. Paragraph 25 states that all four analyses must be concluded positively. This conjunctive structure is not adequately justified anywhere in the document. The practical effect is that a project can pass three tests conclusively and still fail additionality because of an unresolved lock-in question where the MEP has not selected between four mutually exclusive options. Where one test is fully specified and another contains four unresolved options with bracketed thresholds throughout, the conjunctive structure produces arbitrary outcomes. A project registered before the lock-in tool is finalised faces a materially different additionality standard than one registered after. This is a rule of law problem, not merely a technical inconvenience. [10]
28. The current additionality framework applies a uniform set of tests regulatory analysis, lock-in risk assessment, investment analysis, and common practice analysis, across all activity types. While this structure is consistent with established methodologies, it does not adequately reflect the diversity of renewable electricity activities under current market conditions, nor does it align with the revised applicability and baseline provisions proposed in this submission:
- (a) Misalignment with applicability and baseline revisions: The revised applicability conditions (Section 3, Item 10(a) and 10(b)) introduce a performance-based approach, allowing hydropower activities with demonstrably low or negligible reservoir emissions; activities implemented in existing reservoirs without additional emissions; optimization, repowering, and incremental capacity additions. In parallel, the baseline framework is revised to explicitly include reservoir-related emissions where relevant. However, the current additionality framework does not reflect these distinctions and applies identical requirements to fundamentally different activity types. This may result in inconsistent treatment of renewable electricity activities that do not introduce additional emissions; increase renewable electricity generation; and are not automatically implemented in the absence of the mechanism;
 - (b) Regulatory analysis and renewable energy policies: The current regulatory analysis may exclude activities that benefit from renewable energy policies, including auctions, feed-in mechanisms, or other forms of support. In many jurisdictions, including Brazil, renewable energy expansion is supported through competitive procurement mechanisms (e.g. auctions), which may incorporate expectations of additional revenue streams, including carbon finance. In such contexts, participation in auctions should not be interpreted as evidence that a project lacks additionality. Auction outcomes often reflect regulatory constraints, risk allocation frameworks, and prevailing financing conditions rather than the full economic needs of individual projects. Moreover, carbon revenues may remain

critical to ensuring financial viability or enabling specific project configurations, such as hybridization, energy storage, or capacity expansion. Importantly, auctions are also recognized as an efficient policy instrument to promote competition among proponents, foster transparency, and achieve cost-efficient price discovery, ultimately contributing to optimized outcomes and greater value for society. Excluding all projects that benefit from such frameworks would be inconsistent with the objective of scaling mitigation under Article 6.4. At the same time, it is appropriate to exclude activities that are legally mandated or subject to binding penalties for non-compliance;

- (c) Investment analysis limitations: The current requirement for a full investment analysis does not adequately capture the characteristics of incremental investments in existing infrastructure; repowering or efficiency improvements; activities with relatively low marginal capital expenditure. In such cases, traditional financial indicators may not reflect regulatory or contractual barriers; opportunity costs; system-level constraints; or the role of carbon revenues in enabling implementation. Therefore, flexibility is required to allow alternative demonstrations of additionality. [12]

2.8.2. Regulatory analysis

29. The way the requirement in paragraph 26(b)(i) is written is a positive obligation. PPs are mandated to install renewables. It may specify: a minimum share (e.g., $\geq 30\%$ renewable capacity), a specific technology (e.g., solar required for new plants). As it does not necessarily exclude non-renewables, the legal requirement can be a hybrid system (renewable + fossil) and where such type of legal requirement exists, activities implementing renewable electricity are de facto not additional, according to this proposed art 6.4 requirement, even if they can substantiate that in the absence of the art 6.4 mechanism, they cannot be implemented. This is a too stringent and not needed requirement that can lead to loss of opportunity of GHG emission reduction. Indeed, you may have in place these positive obligations but still projects that are going well beyond the positive obligation not being implementable in the absence of the art 6.4 mechanism. Additionality is demonstrated for an art 6.4 activity in its entirety. No ER can be claimed for RE installation beyond the legal requirement of quantity of renewables. Either all the GHG ER are additional or they are not. A prohibition such as “Legal requirements explicitly prohibit the installation of non-renewable power plants” would be more suitable. Where PPs are banned from installing fossil (or other non-renewable) plants, where only renewables are allowed, activities implementing renewables are not additional. Now where the legal requirements explicitly require the installation of renewable power plants, the project can still be additional if it meets all the other additionality requirements. Emission Reduction up to the level of the legal requirement will not be granted as for that part, the project is the baseline. It is proposed to change the text of the paragraph to “The Article 6.4 activity is not implemented at a site where legal requirements explicitly require the installation of only renewable power plants”; [11]
30. Comments to paragraph 26(b)(iii):
- (a) The current provision suggests that participation in competitive bidding processes or support schemes may indicate lack of additionality. However, in markets such as Brazil, energy auctions are not subsidies but competitive procurement mechanisms that do not guarantee financial viability. Projects face high cost of capital, curtailment risks, transmission constraints, and price compression.

Therefore, using participation in auctions as a proxy for non-additionality is inappropriate and may exclude genuinely additional projects. Additionality should be assessed based on actual investment conditions and financial viability, not on the type of procurement mechanism. In the Brazilian context, participation in auctions does not imply guaranteed financial viability, nor does it constitute a subsidy scheme. Electricity is procured by multiple distribution companies under competitive conditions, and projects often retain significant exposure to market risks, including the possibility to allocate substantial shares of generation to the free market. Therefore, participation in auctions should not be considered a proxy for non-additionality. It is proposed to replace the current text of the paragraph with: *“Participation in competitive bidding processes or electricity market-based procurement mechanisms shall not, in itself, be considered as evidence that the emission reductions would occur in the absence of the Article 6.4 mechanism, and shall not automatically preclude the demonstration of additionality.”* Alternatively, if such clarification cannot be accommodated, paragraph 26(b)(iii) should be deleted; [12]

- (b) It is proposed to remove this clause based on Malaysia (non-LDCs) RE schemes such as the Fit-In-Tariff scheme - between the project developers and the national grid operators. This is to increase participation from non-LDCs; [6]
- (c) The current wording may lead to the interpretation that participation in competitive auctions or support schemes automatically implies a lack of additionality. In the Brazilian context, auctions are the primary mechanism for electricity sector expansion and do not eliminate financial, regulatory, hydrological, or implementation barriers. Therefore, participation in such mechanisms should not be considered as automatic evidence of non-additionality. It is recommended to replace the current text in paragraph 26(b)(iii) with *“Participation in competitive procurement processes or electricity contracting mechanisms based on market principles”*. Alternatively, the full deletion of paragraph 26(b)(iii) is recommended; [18]
- (d) The condition set is best addressed by evaluating the effect of any such support or penalty scheme on the financial additionality of the project, and the following change is proposed: *“If an Article 6.4 activity is participating in a support scheme or is subject to a penalty scheme that is designed to achieve a quantitative target or outcome, the additionality assessment of any such A6.4 activity shall, in demonstrating its financial additionality, take into account all such benefits and penalties, regardless of the process through which the relevant support or penalty schemes are implemented;”* [11]
- (e) It is indicated in paragraph 26(b)(iii) that participation in support schemes, penalty-linked schemes, or competitive procurement designed to achieve a quantitative target or outcome is relevant to the additionality assessment. In many jurisdictions, renewable electricity projects are developed under such policy-supported arrangements. However, participation in such arrangements does not necessarily mean that a project is financially viable without Article 6.4 revenues. In particular, some IPPs may participate in tenders but still face viability gaps due to high capital expenditure and insufficient returns under conventional electricity sale arrangements. Clearer guidance is therefore needed to ensure that such participation is not treated as determinative in itself where Article 6.4 revenue remains relevant to project viability. The paragraph should be clarified such that

participation in support schemes, penalty-linked schemes, or competitive procurement is assessed based on whether such arrangements fully remove the need for Article 6.4 incentives, rather than being treated as determinative in itself. In particular, participation in a tender or competitive procurement process should not automatically lead to the conclusion that the project is non-additional. There may be independent power producers (IPPs) that seek to develop projects in response to such tenders, but due to the high capital expenditure involved, the conventional mode of electricity sale to the respective distribution companies (DISCOMs) may not be financially viable on its own. In such cases, additional financial support through Article 6.4 incentives may still be necessary to make the project viable. Therefore, where a project activity can demonstrate, through an investment analysis, that its internal rate of return (IRR) remains below or only within the applicable benchmark without Article 6.4 revenues, such project activity should still be allowed to qualify for registration under the applicable methodology; [14]

- (f) It is cited that “The Article 6.4 activity does not participate in a support scheme or is subject to a penalty scheme that is designed to achieve a quantitative target or outcome, such as a competitive bidding processes for the installation of a certain capacity of renewable power plants.” The stated paragraph does not appear to be aligned with its origination as legal basis or regulatory requirement, and the recommendation is to remove it; [15]
 - (g) The regulatory analysis disqualifies activities that 'participate in a support scheme designed to achieve a quantitative target or outcome, such as competitive bidding processes for the installation of a certain capacity of renewable power plants.' This is overly broad. Competitive bidding processes are widely used precisely because they reduce the cost of renewable energy deployment in developing countries. Under this provision, a project that won a competitive tender — even in a country with a 5% renewable penetration — would be ineligible, regardless of whether it is financially additional. It is recommended to revise para 26(b)(iii) to distinguish between support schemes that achieve renewable targets at or above a country's NDC trajectory (which may undermine additionality) and those in countries where renewable penetration remains well below NDC targets. Projects in the latter category that participated in competitive tenders should be eligible if investment analysis demonstrates financial additionality. A specific carve-out for LDCs and SIDS — where government support schemes are often the only viable financing mechanism — should also be included. [7] [8] [13]
31. If the emission reductions of the Article 6.4 activity had also occurred as a result of legal requirements as per paragraph 27, it should not be possible to claim A6.4ERs for “emission reductions in excess of those emission reductions that would be achieved as a result of the legal requirements”. This will create significant loopholes for non-additional credits, where the activity is entirely viable without the revenue from excess emissions reductions. It is recommended to delete the text from “except” onwards. [5]
32. Paragraph 13 of the standard “Demonstration of additionality in mechanism methodologies” states that additionality is demonstrated for an article 6.4 activity in its

entirety not for GHG ER.¹ It is not possible for an art 6.4 project, some ER that are additional and others that are not. This reinforces the comment made upper on positive obligation vs prohibition. It is recommended to revise paragraph 27 to *“If one or more of the legal requirements identified in paragraph 26 fail the requirements of that paragraph, then A6.4ERs cannot be claimed.”* [13]

33. The requirement in paragraph 28 is not an additionality related requirement but rather a baseline related requirement. It is proposed to be moved to the baseline section. [11]
34. The methodology indicates that the activity participants shall assess the requirements of paragraph 26 for each monitoring period and that the crediting shall cease on the date when a new relevant legal requirement enters into force. This is too stringent considering the investment involved in constructing a greenfield power plant and could lead to situations in which after investing and implementing in the project activity, the implementor could not receive any revenue if the law changes a year or two (for example) after implementation and before the first verification. This is contrary to the principle of non-retroactivity of the laws that exists in many countries. The requirements of paragraph 26 should be assessed at the crediting period renewal. [8] [13]
35. Regulatory requirements in practice cannot be applied retrospectively. Therefore, ceasing crediting on the date when a new relevant legal requirement enters into force is inappropriate as the activity was done before such a legal requirement was in place. Activity participants shall assess the requirements of paragraph 26 for each monitoring period. When a new relevant legal requirement enters into force, during the course of monitoring, the activity will be rendered ineligible for renewal. [9]

2.8.3. Lock-in risk

36. The following comments recommend using Option 1 under paragraph 29:
 - (a) Support for Option 1. All technologies included in the methodology are consistent with global Net Zero scenarios such as IEA Net Zero Emissions by 2050 Scenario (NZE) and the IPCC 1.5° Mitigation Pathways; [16]
 - (b) There is a risk of lock-in if there is an alternative to the project activity that is more aligned with the Paris Agreement goal than the project activity itself. For grid-connected renewable electricity projects, the alternative to the project activity is the combined margin, and there is a risk of lock-in only where the combined margin is cleaner than the project activity. Thus, we recommend: “Option 1: No lock-in analysis is required for any of the activities applicable under this mechanism methodology;” [11]
 - (c) Strong support for Option 1. No lock-in analysis is required under this methodology as these risks are not relevant for grid-connected renewable energy projects; [17]
 - (d) Option 1, Para 29 should be adopted. Given the low GHG emission intensity of renewable power generation technologies, activities eligible under this

¹ Mechanism methodologies shall ensure that additionality is demonstrated for an Article 6.4 activity in its entirety (e.g. the capture of landfill gas combined with use of the landfill gas for energy generation) and that additionality is not separately demonstrated for different parts of an Article 6.4 activity (e.g. separately for the landfill gas capture and the use of the landfill gas for energy generation).

methodology are deemed to have no lock-in risk. In Kenya, geothermal fields have low emission intensities. Kenya Electricity Generating Company PLC internal data (available to the MEP if requested for accounting for over 95 of Kenya’s geothermal installed capacity have around 48CO₂e/MWh (CO₂ & CH₄ fraction of non-condensable gases) operated over 3 number of years demonstrate that emission intensity from geothermal is low and therefore does not present lock-in risk. In addition, the emissions from the activities under this methodology will be accounted and deducted from the baseline emissions; [9]

- (e) Support for Option 1 as lock-in risks are not relevant for grid-connected renewable energy projects such as solar, wind, hydro, and geothermal. These technologies are inherently aligned with long-term decarbonisation pathways and national climate commitments. They displace higher-emitting generation and support the structural transition toward low- and zero-carbon power systems. Unlike fossil fuel-based infrastructure, renewable energy technologies do not rely on continuous fuel combustion and therefore do not create or reinforce emissions-intensive systems or behaviours that would inhibit future mitigation. Lock-in risk typically arises from long-lived, carbon-intensive assets (e.g. coal or gas plants) that commit systems to ongoing emissions. Renewable technologies fundamentally avoid this risk because they operate with near-zero operational emissions and do not require carbon-intensive inputs over time. While lifecycle emissions exist (e.g. manufacturing and installation), these are minimal and do not increase during operation. As a result, the core driver of lock-in—sustained emissions—is absent. Furthermore, renewable energy investments generally enhance system flexibility, reduce reliance on fossil fuels, and enable further scaling of clean energy. Even in cases of long asset lifetimes (such as hydro or geothermal), these technologies remain fully compatible with net-zero trajectories and do not pose a technological or emissions lock-in risk. Applying a lock-in screening requirement to such activities would therefore introduce unnecessary complexity without improving environmental integrity, and may unintentionally hinder the deployment of renewable energy—an outcome that would be inconsistent with the objectives of the Paris Agreement. Finally, any residual concerns around fossil fuel lock-in should be addressed at the Host Country level, as part of sovereign energy planning and policy frameworks; [13]
 - (f) Given the low GHG emission intensity of renewable power generation technologies, activities eligible under this methodology are deemed to have no lock-in risk. Also, that a mix of RE sources would be required considering intermittent and continuous sources too and thus lock-in analysis for RE generation technologies is not appropriate. It is recommended to adopt Option 1 – No lock-in analysis is required to be conducted under this mechanism methodology; [15]
 - (g) Given the near-zero operational GHG emission intensity of renewable power generation technologies and their alignment with long-term decarbonization pathways, activities eligible under this methodology inherently avoid technological, economic, and emissions lock-in risks. These technologies do not rely on carbon-intensive inputs, do not extend the lifetime of fossil-based infrastructure, and remain fully compatible with future low-carbon energy systems. Hence, the most appropriate option for analysis of lock- in would be option 1. [7]
37. The lock-in risk assessment is primarily designed to prevent the long-term continuation of carbon-intensive technologies and may not be directly applicable to renewable electricity

activities. For technologies such as wind and solar, which are inherently low-carbon and do not create long-term emissions lock-in risks, the inclusion of such analysis may introduce unnecessary complexity and regulatory burden without delivering additional environmental integrity benefits. This position is consistent with approaches that consider lock-in risk not applicable to low-emission technologies. In particular, for renewable electricity activities, the absence of long-term emissions lock-in supports the exclusion or simplification of this assessment. Furthermore, the application of land-use based thresholds may introduce uncertainty and inconsistent interpretations across jurisdictions, particularly in the absence of clearly defined materiality criteria. Where land-use change is relevant, a more appropriate approach would be to assess emissions based on a materiality threshold, rather than applying a uniform requirement across all renewable technologies. The following changes are proposed:

- (a) *General provision: lock-in risk assessment shall not be required for wind and solar power activities, as these technologies are inherently low-carbon and do not present a risk of long-term emissions lock-in;*
- (b) *Option A (not applicable): For other renewable electricity activities, where the activity participant demonstrates that the activity:*
 - (i) *Does not introduce additional greenhouse gas emissions; or*
 - (ii) *Results in low emission intensity consistent with this methodology, the lock-in risk assessment may be considered not applicable.*
- (c) *Option B (land-use related assessment): Where the activity involves land-use change, including vegetation removal, the activity participant shall:*
 - (i) *Estimate emissions associated with land-use change using methodologies consistent with the Intergovernmental Panel on Climate Change; and*
 - (ii) *Demonstrate that such emissions are negligible or not material relative to the expected emission reductions over the crediting period.*
- (d) *Materiality may be demonstrated through comparison with total emission reductions or through the application of conservative thresholds, where available.*
[12]

38. For solar projects, the lock-in concern appears to be linked mainly to land use. However, the same level of concern may not exist where the project is implemented on barren, degraded, non-arable, or otherwise low-value land with no meaningful competing productive use. In such cases, a full land-use lock-in assessment may create unnecessary burden without improving environmental integrity. Paragraphs 29–31 shall be revised such that, for solar projects, a simplified or no land-use lock-in assessment is applied where the land can be demonstrated to be barren, degraded, non-arable, or otherwise of low competing land-use value, based on appropriate supporting evidence. [14]
39. The inclusion of technological lock-in analysis for renewable energy technologies, particularly wind and solar, may not be appropriate. These technologies are inherently low-carbon and do not present structural risks of long-term carbon lock-in. Furthermore, requiring newly produced equipment introduces unnecessary regulatory complexity without effectively addressing the actual methodological risks, which are more closely

- associated with previously used equipment. It is recommended to exclude wind and solar energy projects from technological lock-in analysis requirements. [18]
40. The proposed land-use assessment based on thresholds may not adequately reflect the limited territorial impact of small hydropower projects. In the Brazilian context, small hydropower plants typically present low land-use intensity and do not pose significant risks related to land-use lock-in. The absence of standardized thresholds within the methodology may increase transaction costs and reduce regulatory predictability. It is recommended to amend paragraph 31 by complementing paragraph 31 with “*Hydropower projects with installed capacity below 15 MW or with a power density above 4 W/m² are considered as not posing a relevant land-use lock-in risk.*” [18]
41. Need justification on the difference applicability for Option 1 and Option 3 for Solar PV & Hydro. [6]
42. Need clarification on Option 3 & Option 4 - whether an Environmental Impact Assessment (EIA) is sufficient to demonstrate the assessment of land resources. [6]
43. The lock-in risk assessment is primarily designed to prevent the long-term continuation of carbon-intensive technologies and may not be directly applicable to renewable electricity activities. For technologies such as wind and solar, which are inherently low-carbon and do not create long-term emissions lock-in risks, the inclusion of such analysis may introduce unnecessary complexity and regulatory burden without delivering additional environmental integrity benefits. This position is consistent with approaches that consider lock-in risk not applicable to low-emission technologies. In particular, for renewable electricity activities, the absence of long-term emissions lock-in supports the exclusion or simplification of this assessment. Furthermore, the application of land-use based thresholds may introduce uncertainty and inconsistent interpretations across jurisdictions, particularly in the absence of clearly defined materiality criteria. Where land-use change is relevant, a more appropriate approach would be to assess emissions based on a materiality threshold, rather than applying a uniform requirement across all renewable technologies. The following changes are proposed to the assessment of lock-in:
- (a) *General provision: Lock-in risk assessment shall not be required for wind and solar power activities, as these technologies are inherently low-carbon and do not present a risk of long-term emissions lock-in;*
 - (b) *Option A (not applicable): For other renewable electricity activities, where the activity participant demonstrates that the activity:*
 - (i) *Does not introduce additional greenhouse gas emissions; or*
 - (ii) *Results in low emission intensity consistent with this methodology;*
 - (iii) *The lock-in risk assessment may be considered not applicable.*
 - (c) *Option B (land-use related assessment): where the activity involves land-use change, including vegetation removal, the activity participant shall:*
 - (i) *Estimate emissions associated with land-use change using methodologies consistent with the Intergovernmental Panel on Climate Change; and*
 - (ii) *Demonstrate that such emissions are negligible or not material relative to the expected emission reductions over the crediting period.*

- (d) *Materiality may be demonstrated through comparison with total emission reductions or through the application of conservative thresholds, where available.*
[10]

2.8.4. Investment analysis

44. Paragraph 32 states that Activity participants shall use a valid version of the “Methodological tool: Investment analysis” (A6.4-AMT-002) to conduct the investment analysis. While the requirements of para. 30(h) and 33(h) of the A6.4-AMT-002 Tool are fundamental to demonstrating additionality under the Benchmark Analysis and Investment Comparison Analysis tracks, respectively, the Draft Methodology does not sufficiently elaborate on what constitutes “credible evidence” in the specific context of a renewable energy project under the PACM and does not provide any specific guidance on how activity participants shall satisfy the requirement under paragraphs 30(h) and 33(h) of the Tool in the context of renewable energy projects. In particular, the Draft Methodology does not (i) Define what types of evidence qualify as “credible” in the context of renewable energy projects; (ii) Specify whether the evidence must be qualitative, quantitative or both; (iii) Indicate the minimum level of detail or documentation required; (iv) Clarify whether a financing gap analysis, a decision-making narrative, a contractual or institutional record, or some combination thereof is sufficient. This situation creates significant uncertainty for Carbon Project Developers as to what documentation, analyses or information they must prepare and include in the Project Design Document and supporting documents. It is recommended to consider improving the clarity of interpretation of para. 30(h) and 33(h) by introducing additional guidance or illustrative “best practice examples” on what constitutes “Credible Evidence” based on the following illustrative examples:
- (a) **Demonstration of Funding Gap:** Activity participants prepare a base-case financial model showing that the project IRR (or NPV) without A6.4ER revenues is below the applicable financial benchmark (WACC or cost of equity). A supplementary model scenario then shows that the project IRR (or NPV) meets or exceeds the benchmark or improves by certain “specific” percentage (e.g. IRR was 10%, but became 13% - this is 30% improvement) when projected A6.4ER revenues (based on current market price estimates, volume projections consistent with the monitoring plan, and the crediting period) are included. This quantitative demonstration may, in itself, constitute a sufficient component of credible evidence where: (i) the revenue assumptions are conservative and well-justified; (ii) the sensitivity analysis confirms robustness; and (iii) A6.4ER revenues close the funding gap under all scenarios;
- (b) **Levelized Cost of Energy (LCOE) Analysis:** Where applicable, activity participants may present a levelized cost of energy (LCOE) analysis demonstrating that the project's LCOE exceeds the applicable reference price (e.g., the feed-in tariff, the power purchase agreement (PPA) price, or the prevailing wholesale electricity price) in the host country without A6.4ER revenues. The analysis then shows that A6.4ER revenues are necessary to close this cost gap, enabling the project to achieve the required return on investment;
- (c) **Investment Committee or Board Resolution:** Activity participants submit an extract of an investment committee or board resolution that explicitly conditions the final investment decision (FID) on the registration of the project as an Article 6.4 activity and the anticipated receipt of A6.4ER revenues. The resolution should identify, at minimum: (i) the expected volume of A6.4ERs over the crediting period; (ii) a

- reference to the price assumption used (e.g., a floor price or market price estimate); and (iii) an explicit statement that the investment would not proceed without these revenues;
- (d) Letter from Lender or Investor Conditioning Finance on A6.4ER Revenues: Activity participants submit a letter of intent, term sheet, or conditional offer of debt or equity financing from a bank, development finance institution (DFI), or equity investor that explicitly conditions financing (or sets a lower interest rate / required equity return) on the project's registration as an Article 6.4 activity and the assignment of A6.4ER revenues to the lender or investor. Such a letter or term sheet need not be legally binding, but it must be sufficiently specific to demonstrate that the financing terms were directly shaped by the anticipated A6.4ER revenue stream;
- (e) PPA or Offtake Agreement with Explicit Carbon Revenue Clause: Where the project developer has entered into a power purchase agreement (PPA) or offtake agreement in which the electricity price was set on the basis that A6.4ER revenues would supplement electricity revenues to achieve the required project return.
- (f) In addition to the above examples, we encourage the MEP to consider and propose further examples to provide project developers, VVBs and UNFCCC with more clarity on how to meet the requirements of para. 30(h) and 33(h) of the Investment Analysis Tool. [4] [13]
45. The distinction between alternative scenarios defined in items (ii) and (iii) is unclear, as “greenfield power plants of any type” may overlap with “new grid-connected power plants.” This may create ambiguity in the identification of alternative scenarios. Clarification or removal of item (iii) should be considered. [12]
46. The specifications in paragraph 32 are among the best-drafted provisions in the document. Two targeted issues require attention:
- (a) Paragraph 32(d) imports a competitive market assumption — that any entity could implement the project — that does not exist in SIDS electricity markets typically served by a single vertically integrated utility. This will systematically underestimate financial barriers by comparing against a hypothetical competitive developer with unrealistically low costs of capital;
- (b) Paragraph 32(e) tests only inputs exceeding 20% of total costs individually. In small SIDS projects, no single cost line may reach 20% while collectively representing the majority of financial uncertainty, leaving critical assumptions untested;
- (c) Proposed change: For SIDS/LDC projects, paragraph 32(d) should require cost of capital parameters consistent with actual market participants. Paragraph 32(e) should additionally require combined sensitivity testing of all inputs exceeding 10% of total costs moving simultaneously. [10]
47. The activity participant shall demonstrate that the Article 6.4 activity is not financially attractive or faces financial barriers in the absence of revenue from the mechanism. For activities involving modification, expansion, or optimization of existing infrastructure, the activity participant may apply (i) a simplified investment analysis; or (ii) an alternative

barrier analysis, provided that sufficient justification is presented. Such justification may include:

- (a) Incremental cost analysis;
- (b) Identification of financial, regulatory, or contractual barriers;
- (c) Demonstration of dependency on additional revenue streams. [12]

2.8.5. Common practice analysis

48. The current common practice analysis may not adequately reflect conditions in mature renewable energy markets, where certain technologies (e.g. wind, solar, hydropower) are widely deployed; but specific activity types (e.g. repowering, hybridization, incremental expansion) remain limited. In addition, a shorter and more recent reference period (e.g. 3 years) may better reflect current market conditions, particularly in rapidly evolving renewable energy markets, and should be considered as an alternative to longer reference periods. In such contexts the existence of similar activities does not necessarily imply that the proposed activity is not additional; barriers may persist despite technological maturity. Therefore, the analysis should focus on comparable activities with similar characteristics; consider regulatory, financial, and system conditions; avoid overly broad definitions that lead to false conclusions of common practice. Impact” activities can still be additional if barriers exist; and maintain environmental integrity while improving applicability. It is therefore recommended to revise the additionality provisions to introduce differentiated approaches depending on the type of activity, while maintaining consistency with internationally recognized methodological tools and ensuring robust demonstration of additionality. The use of differentiated categories for wind technologies (e.g. onshore and offshore) is supported, as it better reflects technological and market differences and improves the accuracy of common practice analysis. The following changes are proposed: the activity participant shall assess whether the proposed activity is common practice within the applicable geographical and technological context. The analysis shall:
- (a) Consider activities with similar characteristics, including scale, technology, and implementation context;
 - (b) Account for differences in regulatory, economic, and system conditions; and
 - (c) Not rely solely on the presence of similar technologies in the market. [12]
49. The current common practice approach may disadvantage countries such as Brazil, where renewable energy already represents a significant share of the electricity mix. Using broad geographical scopes (e.g., country or regional group) may incorrectly suggest that new renewable projects are not additional simply due to historical deployment levels. However, high penetration does not imply absence of barriers. In Brazil, projects still face financial constraints, curtailment, transmission limitations, and high cost of capital. Therefore, the methodology should avoid penalizing early adopters of renewable energy and should better reflect actual investment conditions and remaining barriers. Proposed change:
- (a) Clarify that common practice analysis should consider market maturity and structural barriers;

- (b) Allow for more granular geographical scopes (e.g., subnational regions or grid subsystems) and ensure that high penetration of renewables does not automatically imply lack of additionality. [12] [13]
50. Revise the common practice indicator under paragraph 33(b) to differentiate solar PV projects by the presence and duration of co-located battery energy storage, as follows: *“Indicator of common practice: (i) the installed power generation capacity, expressed in MW; and (ii) for category (b), the installed energy storage capacity, expressed in MWh.”* [1]
51. Comments to paragraph 33(c):
- (a) The current approach to common practice may disadvantage countries where renewable energy already represents a significant share of the electricity mix. High penetration of renewable energy does not imply the absence of barriers. In the Brazilian context, projects continue to face financial constraints, curtailment risks, transmission limitations, and regulatory challenges. Therefore, the methodology should avoid assuming that high renewable participation automatically implies a lack of additionality. The reference period corresponds to the three most recent years prior to whichever occurs first: (i) the start of operation of the Article 6.4 activity; or (ii) the submission of the Project Design Document (PDD) for validation; [18]
- (b) The number of years (3 or 5) to be included in the reference period under paragraph 33(c) should be consistent with the number of years used to calculate the grid emission factor with A6.4-MEP011-A02. It is recommended to fix the number of years consistently with the grid emission calculation; [8]
- (c) It is cited that “A time-bound approach shall be used (...) reference period shall be defined as the most recent [3][5] years prior to the earlier of (...)”. 5 years would be suggested; [15]
- (d) The methodology requires a time-bound common practice analysis using a reference period of the most recent 3 to 5 years under paragraph 33(c). This approach assumes that market and investment conditions remain sufficiently stable across the reference period such that historical deployment rates are meaningful indicators of current project viability. That assumption is often wrong, particularly in emerging economies. A project that was financially viable three or five years ago may not be viable today due to changes that have nothing to do with the technology itself. Host country interest rates may have risen sharply. Sovereign credit downgrades or political instability may have increased the risk premium demanded by equity investors. Trade policy changes or global supply chain disruptions may have raised equipment costs. Host country regulators may have renegotiated or reduced PPA tariff rates. Any one of these changes can fundamentally alter project economics. As a threshold matter, if a project proponent has demonstrated financial additionality under the investment analysis, the common practice analysis should not be capable of overriding that finding. A project that is demonstrably not financially viable without carbon revenue is additional regardless of how many similar projects were deployed under different market conditions in prior years. Common practice analysis serves as a cross-check, not a veto, and should be treated accordingly. If the Supervisory Body retains common practice as a standalone gate, the methodology should allow

project proponents to adjust the reference period when material changes in investment conditions have occurred. Specifically, if one or more key investment condition indicators have undergone a material change during the reference period, the proponent should be permitted to shorten the reference period to begin from the point at which the change occurred. Relevant indicators fall into three categories: Financing cost, as reflected in host country sovereign bond yields or equivalent benchmark rates, capturing changes in interest rates, country risk perception, and investor return expectations. Project cost, as reflected in host country inflation rates or changes in import duties on key equipment, capturing changes in capital and operating expenditure. Project revenue, as reflected in published PPA rates, feed-in tariffs, or auction clearing prices in the host country, capturing changes in the revenue available to project developers. This approach does not increase the reporting burden for developers whose projects pass common practice under the standard reference period. It simply provides an evidence-based mechanism for developers to demonstrate that historical deployment data is not representative of current investment conditions when that is the case. It is recommended to add the following provision to the time-bound common practice approach: *“Where the project proponent can demonstrate that a material change in investment conditions has occurred during the reference period, the proponent may propose a shortened reference period beginning from the point at which the material change occurred. Material changes in investment conditions, justified by the project proponent and assessed by the designated operational entity during validation, may include, but are not limited to:*

- (i) *Changes in host country financing costs, as reflected in sovereign bond yields or equivalent benchmark lending rates;*
- (ii) *Changes in project input costs, as reflected in host country inflation rates or import tariff rates on key project equipment;*
- (iii) *Changes in project revenue conditions, as reflected in published power purchase agreement rates, feed-in tariff schedules, or competitive auction clearing prices applicable in the host country.” [1]*

52. Comments to paragraph 33(d):

- (a) The very absence of technologies/ activities in a host country should automatically demonstrate that the technologies/ activities are not common practice. Widening the geographic scope under paragraph 33(d) has many disadvantages, principally because different countries have different political, economic, social, technological and environmental factors that may promote or constrain projects. Therefore, a comparison across countries is very unlikely to be useful and may likely serve to exclude projects/activities where they are needed the most. It is proposed to revise the paragraph as follows: *“The geographical scope for common practice analysis should be limited to the host country. Expansion beyond the host country should only be permitted where the activity participant demonstrates that: (i) there is insufficient data within the host country, and (ii) the expanded geographical area represents comparable political, economic, technological and regulatory conditions”*. If condition (ii) is not fulfilled, used information provided by international recognised sources, for example; IEA. [8] [13]

- (b) It is cited that “For Article 6.4 activities implemented in countries other than LDCs or SIDS: The applicable geographical area shall correspond to the relevant [continent][regional group under the UNFCCC]”. Continent would be suggested. [15]

53. Comments to paragraph 33(e):

- (a) The capacity scale of a renewable energy project will dictate the regulations it is subject to, its levelized cost of energy, and investment models. Therefore, it would be recommended to define a capacity range under paragraph 33(e). A possible solution would be to carry over the CDM criterion of +/- 50% of the project's capacity range; [16]
- (b) Renewable energy projects of different capacity ranges significantly differ from each other by economic (specific costs per kW installed capacity, different off-take tariffs), technical (land required, efficiency) and regulatory conditions (different grid access schemes/incentives). This result in a situation when different scale RE plants may have different barriers for implementation and different incentives for implementation. Thus, to ensure better accuracy of common practice test we propose to distinguish at least between following groups RE activities: micro: less than 1 MW; small-scale: 1 - 15 MW, large scale: more than 15 MW. It is proposed that maximum thresholds to be differentiated depending on scale of Renewable Energy A6.4 Activity, as follows: Micro (less than 1 MW), Small-Scale (1-15 MW), Large Scale (more than 15 MW); [4]
- (c) Paragraph proposes 33(e) states that “All capacity sizes of comparable activities shall be used”. However, renewable energy projects of different scales are subject to distinct economic, financial, and regulatory conditions. For example, utility-scale projects typically benefit from economies of scale, different financing structures, and access to competitive procurement mechanisms, while smaller-scale or distributed projects often face higher unit costs, different tariff structures, and additional barriers to market entry. Aggregating all capacity sizes without differentiation risks distorting the assessment of common practice, as it may mask these material differences and lead to inappropriate comparisons. This could undermine the accuracy of the analysis and potentially affect the determination of additionality. It is therefore important that comparable activities are appropriately stratified by capacity (or relevant scale categories) to ensure that the analysis reflects like-for-like conditions. This would improve the robustness and fairness of the methodology. For these reasons, it is recommended to revise the text to account for differences in project scale. [13]

54. Comments on paragraph 33(f):

- (a) While the introduction of differentiated common practice thresholds for LDCs/SIDS and non-LDC/SIDS is a constructive step toward reflecting varying market conditions, we see a more fundamental limitation in the reliance on fixed, stock-based penetration thresholds to assess common practice. In particular, at low levels of technology deployment, stock-based metrics are not a reliable proxy for common practice. In early-stage markets, small absolute changes in installed capacity or number of activities can result in disproportionately large shifts in percentage penetration, without reflecting meaningful changes in financial viability, replicability, or systemic adoption. As such, the application of low thresholds may

lead to the exclusion of activities that are not yet common in practice, especially in markets where deployment remains nascent. The 4th edition of the OECD's 2018 'Oslo Manual: Guidelines for Collecting, Reporting and Using Data on Innovation' defines diffusion as the process by which innovations are widely spread and used across markets. In policy terms, “common practice” therefore aligns with broad diffusion, not early adoption. Many highly recognised studies and references support this view point, which emphasizes “broad-based adoption” as the stage where technologies generate societal impact. For example, Everett Rogers' publication, 'Diffusion of Innovations (5th ed., 2003)' notes the concept of “critical mass”. His work shows that once adoption reaches the majority (~50–70%), an innovation becomes socially normalized. The above is relevant as it is supporting one of the Paris Agreement's core principles, which is to encourage and support the broad-based adoption of climate change mitigation technologies that have the potential to materially reduce the GHG intensity of the global economy. This is particularly important for developing countries, which have not benefited by the exploitation of fossil fuels, to the degree that more developed countries have. Accordingly, PACM should be encouraging the uptake of renewable energy technologies, particularly in developing country contexts. Accordingly, we propose to use the maximum common practice threshold values provided for in paragraph 67 of the approved common practice tool A6.4-AMT-001, Version 01.0. However, we kindly request that PACM consider the opportunity to investigate whether these thresholds can be increased in future, because in many jurisdictions, renewable energy penetration is growing due to falling technology costs and supportive policy frameworks. In particular, many smaller scale projects still face high economic and regulatory, which some larger scale projects can overcome due to economies of scale. Setting the penetration threshold at a low level risks prematurely classifying renewable energy technologies as common practice, thereby excluding a significant share of projects, particularly those classified as small scale, that continue to contribute meaningfully to emissions reductions and energy transition objectives. In other words, low common practice thresholds may inadvertently constrain the role of the mechanism in scaling up renewable energy deployment, particularly in grids that still rely heavily on fossil fuels. Limiting eligibility at relatively low penetration levels is not consistent with the Paris Agreement's objective of enabling progressive decarbonisation of electricity systems. Higher thresholds would better reflect current market dynamics and allow the mechanism to support continued expansion of renewable energy in line with long-term climate goals, while still ensuring that activities are not fully mainstream. This approach would strike a more appropriate balance between maintaining environmental integrity and enabling transformational change in the power sector. The proposed thresholds are:

- (i) 16 per cent for countries other than LDCs and SIDS and 20 per cent for LDCs and SIDS, where a stock-based approach is used; and
 - (ii) 20 per cent for countries other than LDCs and SIDS and 25 per cent for LDCs and SIDS, where a time-bound approach is used. [13]
- (b) Furthermore, we kindly request the differentiation of penetration rates based on small and large scale project activities. Providing more flexible conditions for small scale projects could reduce the barriers to implementing these project activities."

- (c) Renewable energy generation methodologies in carbon markets have historically been associated with major environmental integrity issues, namely non-additionality, as well as severe human rights impacts in the case of hydropower projects. A landmark report from 2016 recommended that renewable energy projects should no longer be eligible under the CDM, except when taking place in LDCs. As a consequence, in the last few years, many actors on the voluntary carbon market have significantly curtailed this project type. For instance, since 2020, Verra only registers small grid-connected renewable energy projects in LDCs, and excludes all large-scale projects and projects in non-LDCs. Gold Standard also only allows such projects to be set up in LDCs/SIDS/LLDCs (or low-income and low-middle-income countries with a renewable energy penetration rate less than 5% of total installed grid capacity). Notably, the ICVCM decided to reject most renewable energy methodologies from obtaining the CCP label. It is proposed to either:
- (i) Allow only small-scale activities implemented in a least developed country (LDC) or small island developing state (SIDS) as eligible for this methodology; or
 - (ii) If this is not possible, then at the very least, the common practice threshold values in paragraph 33(f) should be as follows:
 - a. 33(f)(i) 2.5 per cent for Article 6.4 activities located in non-LDCs/SIDS; and
 - b. 33(f)(ii) 10 per cent for Article 6.4 activities located in LDCs/SIDS. [5]
- (d) The common practice factor thresholds to be applied under this mechanism methodology: is it not the cost of respective renewable generation that matters for additionality instead of the penetration rate of renewables in power generation? For e.g., even if 80% of power generation came from PV the remaining 20% could still be additional as those could be remaining higher cost options, e.g., due to remaining sites that might receive less radiation. Either one would need to become much more granular on cost-classes of renewables (difficult and not recommendable) or better not to require common practice analysis at all (preferred). A penetration threshold would reward countries that have done little in promoting renewables and penalizes those that advanced the low (least) cost investments and are now struggling with higher cost options. The following thresholds are recommended:²
- (i) For non-LDCs and LDCs: 10/15% Non-LDCs;
 - (ii) and 20/25% LDCs. [15]
- (e) The common practice factor thresholds to be applied under this mechanism methodology shall be: (i) [5-10%] per cent for Article 6.4 activities located in non-LDCs/SIDS; and (ii) [10-15%] per cent for Article 6.4 activities located in LDCs/SIDS. In non-LDCs/SIDS, renewable technologies are often already widely

² However, also noting the stated comment and associated justification, common practice analysis is more appropriate in cases where additionality demonstration relies on barrier analysis, i.e., where we deal with commercially viable activities that are prohibited by financing or any other types of barriers.

deployed. A lower threshold (5-10%) ensures that only projects that are not yet common qualify as additional. In LDCs/SIDS, deployment is typically limited due to financing constraints, grid limitations, higher perceived risk. A higher threshold (10-15%) avoids excluding genuinely additional projects in underdeveloped markets. The common practice factor thresholds to be applied under this mechanism methodology shall be (i) [5-10%] per cent for Article 6.4 activities located in non-LDCs/SIDS; and (ii) [10-15%] per cent for Article 6.4 activities located in LDCs/SIDS; [7]

- (f) The common practice thresholds at paragraph 33(f) remain entirely unspecified at [x]% for both LDC/SIDS and non-LDC/SIDS contexts. This is the most operationally critical gap in the additionality framework. No project developer, DOE, or DNA can apply this methodology in its current form without this number. The geographical pooling of all LDCs and SIDS under paragraph 33(d)(i) creates a structural penalty for early movers. A SIDS that has advanced renewable deployment will show a higher comparative renewable share against the pooled LDC/SIDS reference area and be more likely to fail common practice analysis than a SIDS that has done nothing. This inverts the intended incentive structure; the projects most deserving of carbon finance support are exactly those in jurisdictions that have already demonstrated political commitment to renewable transition. The reference period of [3][5] years in paragraph 33(c) remains bracketed. For SIDS where grid-scale renewable deployment may have only one or two comparable installations in any reference window, the choice between three and five years is not a minor calibration question; it determines whether the comparable activity pool is statistically meaningful at all. It is proposed to specify numerical thresholds for paragraph 33(f) at a minimum of 30% for non-LDC/SIDS and 50% for LDC/SIDS contexts, reflecting the structurally thin comparable activity pools in smaller jurisdictions. Introduce an explicit safe harbour for first-of-kind technologies in SIDS regardless of pooled geographical threshold. Set the reference period at three years for LDC/SIDS contexts and five years for others. These are concise calibration decisions the MEP should make rather than defer. [10]

55. Comments to paragraph 33(g):

- (a) The draft methodology defines similar activities for solar PV plants as “all other solar PV power plants” and uses installed capacity in MW as the sole indicator of common practice. This approach fails to distinguish between solar PV projects and solar PV projects paired with battery energy storage systems (BESS), despite material differences in cost, risk profile, technical complexity, and grid function. According to IRENA's Renewable Power Generation Costs in 2024 report, the global weighted average total installed cost of utility-scale solar PV was USD 691/kW, rising to USD 1,093/kW in Africa. BESS costs stood at USD 192/kWh. For a 100 MW project using African cost benchmarks, adding 30 minutes of storage (for grid stability) increases project cost by roughly 9%, while 4 hours of storage (required for meaningful load shifting) increases cost by approximately 70%. These are differences have substantive impact on the financial viability of a project. Critically, the value proposition of storage varies by duration. Short-duration BESS (under 1 hour) serves primarily as a power quality and ramp-rate smoothing tool. Medium-duration BESS (2 to 4 hours) enables peak shaving and time-of-day energy shifting. Long-duration BESS (4+ hours) provides firm capacity and can displace fossil-fuelled peaking generation. Each configuration serves a different

grid function, carries a different cost structure, and faces different revenue conditions. In most emerging economy electricity markets, there is no dynamic pricing, no capacity market, and no ancillary services framework. Developers who add BESS absorb significantly higher capital costs while earning the same flat tariff per kWh. This financial barrier is exactly what common practice analysis should capture, and it becomes invisible when solar+BESS is grouped with solar-only. There is already international precedent for this distinction. Chile's 2025 Article 6 roadmap (Hoja de Ruta de Instrumentos de Precio y Mercados de Carbono, Table 7) establishes a sliding scale for energy storage projects based on storage duration, differentiating standalone BESS from hybrid configurations and scaling ITMO eligibility from 0% (under 3 hours) to 100% (7+ hours). Japan's Joint Crediting Mechanism categorizes “Solar Power Plant” and “Solar Power Plant with Battery” as separate technology types in its Annex 2 classification, using the count of projects per category per country to determine financial support levels. Both frameworks recognize that the addition of storage creates a fundamentally different project type for purposes of assessing technology diffusion and financial viability. Treating solar+BESS as equivalent to solar-only in the common practice analysis risks understating barriers to projects that deliver higher grid value, particularly in markets where storage is most needed and least commercially viable without carbon finance. It is proposed to revise the definition of similar activities to differentiate solar PV projects by the presence of co-located battery energy storage; [1]

- (b) It is proposed to exclude from the analysis of comparable activities all projects that are registered under other carbon crediting schemes, by amending paragraph 33(g)(i) with “Activity participants may exclude comparable activities registered under A6.4 and other carbon crediting schemes;” [11]
- (c) It is proposed to distinguish between binary, flash-steam, and dry-steam geothermal technologies, as their techno-economic and environmental characteristics are highly site-specific (IRENA, 2017) and therefore cannot be considered similar,³ as follows:
 - (i) For a binary geothermal power plant: all other binary geothermal plants;
 - (ii) For a dry steam geothermal power plant: all other dry steam geothermal power plants;
 - (iii) For a flash steam geothermal power plant: all other flash steam geothermal power plants. [11]

56. The following comments recommend using Option 2 under paragraph 33(g):

- (a) Different types of wind facilities (e.g. onshore vs offshore) are subject to distinct economic, financial, and regulatory conditions. Aggregating all wind facilities without differentiation risks distorting the assessment of common practice, as it may mask these material differences and lead to inappropriate comparisons. This could undermine the accuracy of the analysis and potentially affect the

³ See: IRENA (2017), Geothermal Power: Technology Brief, International Renewable Energy Agency, Abu Dhabi. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Aug/IRENA_Geothermal_Power_2017.pdf.

determination of additionality. It is therefore important that comparable activities are appropriately stratified by wind project category (e.g. onshore vs offshore) to ensure that the analysis reflects like-for-like conditions. This would improve the robustness and fairness of the methodology; [8]

- (b) Differentiating between onshore and offshore wind can lead to scenarios in which wind energy overall is already common practice, but mainly of the other variety, and therefore classified as not common practice. This could lead to an unwanted situation in which, in a country with significant offshore wind capacity, an onshore wind energy project would be deemed not to be common practice. Therefore, careful consideration of any potential loopholes that differentiation could create is needed. Consider the risk of false negatives when determining additionality through the common practice analysis using option 2. If these risks are significant, opt for option 1 in paragraph 33(g)(ii)(a); [5]
- (c) Option 2 is recommended as the techno-economic and environmental characteristics of onshore and offshore wind power plants differ substantially (Tanvir & Etminan, 2026) and therefore cannot be considered similar. See: Tanvir, M. S., & Etminan, A. (2026). Comparative analysis of offshore and onshore wind turbines: Efficiency, design, and environmental impact. *Wind Engineering*, 50(1), 200-215; [11]
- (d) Options for similar activities for wind power – recommend option 2, as the costs of off-shore wind are significantly higher so it doesn't seem a fair comparison; [15]
- (e) Option 2 is the most appropriate for identifying comparable, similar and different activities for wind power projects; [7]
- (f) Different types of wind facilities (e.g. onshore vs offshore) are subject to distinct economic, financial, and regulatory conditions. Aggregating all wind facilities without differentiation risks distorting the assessment of common practice, as it may mask these material differences and lead to inappropriate comparisons. This could undermine the accuracy of the analysis and potentially affect the determination of additionality. It is therefore important that comparable activities are appropriately stratified by wind project category (e.g. onshore vs offshore) to ensure that the analysis reflects like-for-like conditions. This would improve the robustness and fairness of the methodology. For these reasons, Option 2 is supported. [13]

2.9. Baseline emissions

2.9.1. Calculation of unadjusted baseline emissions

- 57. It is cited in paragraph 36 that “Where an Article 6.4 activity installs a greenfield hydropower plant at an existing reservoir, the activity participant shall consider all possible alternatives with regard to the existing reservoir and justify (...)”. In some paragraphs, the methodology requires projects to demonstrate certain things without being clear how this is demonstrated. It would be helpful if the methodology gave more guidance on what proof should be provided. [15]
- 58. As mentioned in paragraph 37(c), electricity generation from solar and wind power plants is required to be treated as intermittent, regardless of whether the plants are operated with

an integrated BESS. As mentioned in footnote 26 to paragraph 37(c), this treatment is only a temporary provision and further revision is envisaged. As mentioned in paragraph 38, electricity generation from the Article 6.4 activity is calculated on the basis of electricity generated by the project power plant and fed into the electricity system, but no separate treatment is provided for the stored renewable component or for later electricity supply from storage. As reflected in paragraph 62(c), the methodology does not yet provide a complete and clear treatment for renewable energy projects with storage. Because of this, the benefit of storing renewable electricity and supplying it later is not clearly recognized. This is also not fully aligned with policy approaches that give importance to the stored component of renewable energy with storage. Paragraph 37(c) shall be revised such that solar and wind projects operated with an integrated BESS are not automatically treated as intermittent in the same manner as projects without storage. Paragraph 38 shall be revised such that the stored renewable component and the later supply of electricity to the electricity system are clearly addressed in the baseline calculation. Paragraph 62(c) shall be revised consistently such that the source of charging, the later supply of electricity, and energy losses are clearly addressed for renewable energy projects with storage. [14]

59. A modification to Equations 1 and 2 is proposed by deleting $EG_{legal,y}$. In addition, we propose a correction to the definition and notation of $EG_{PJ,y}$. Specifically, the revised definition reflects that $EG_{PJ,y}$ is not the “electricity generation from the Article 6.4 activity,” but rather the amount of electricity generation that is eligible for crediting; accordingly, a change in the notation is also proposed.

$$EG_{PJ,CR,y} = EG_{plant,y} - EG_{shadowing,y} \quad \text{Equation (1)}$$

$$EG_{PJ,CR,h} = EG_{plant,h} - EG_{shadowing,h} \quad \text{Equation (2)}$$

Where:

$EG_{PJ,CR,y}$ = Electricity generation eligible for crediting from the Article 6.4 activity in year y (MWh)

$EG_{PJ,CR,h}$ = Electricity generation eligible for crediting from the Article 6.4 activity in hour h (MWh) [11]

60. Comments to paragraph 39:

- (a) The proposed methodology introduces cumulative mechanisms that may structurally reduce the volume of credits generated, particularly through the application of shadowing effects and downward adjustment of the baseline. The requirement to account for aerodynamic interference between wind farms introduces significant uncertainty and may lead to methodological and legal disputes, as it depends on complex modelling and variables beyond the control of project developers. Additionally, the mandatory downward adjustment of the baseline may lead to the systematic underestimation of avoided emissions, particularly in integrated hydrothermal systems such as Brazil’s. The combined application of these mechanisms may result in double penalization of projects and reduce their economic viability. It is recommended to limit the impact of shadowing through a predefined cap or, alternatively, replace it with a simplified and standardized methodology; [18]

- (b) As projects developed under PACM may not be necessarily generating A6.4ERs, but can also generate MCUs, when no Authorisation/CAs are provided by host countries (similar to various carbon units under VCM), we suggest that text of the para 39(a) is amended to allow Projects registered under any Carbon Standard (not only PACM). It is proposed to to revise the para 39(a) as follows: *“The shadowing effects affect other wind power plants that are registered as an Article 6.4 activity or under any other Carbon Standard;”* [4] [13]
- (c) Shadowing effect is appropriately expressed in reference to the hub height and the rotor diameter and not the express distance between turbines. In addition, power plants that do not share the same wind resource and are not on the downwind of the Article 6.4 activity are not affected by shadowing effects from the Article 6.4 activity. Shadowing effect is geographic specific, in Kenya where topography is not even, shadowing effect is rarely applicable. There are also other natural factors that are attributed to shadowing effects. The following text is proposed for paragraph 39(a): *“The distance between the wind turbines installed under the Article 6.4 activity and any other wind power plants is greater than 8 times the rotor diameter of the largest turbine of the Article 6.4 activity, given that the other wind power plants share the same wind resource and is downwind of the Article 6.4 activity;”* [9]
- (d) As per earlier comment, inclusion of shadow effect reduction should be reviewed, based on its materiality. See above suggestion on this in the project boundary section; [15]
- (e) The proposed methodology introduces the consideration of shadowing (wake) effects between wind power plants; however, it does not clearly define how key parameters—such as minimum distance thresholds or the quantification of such effects—should be determined in practice. The absence of clear and standardized criteria may lead to significant uncertainty, inconsistent application across jurisdictions, and increased transaction costs. The previous formulation appears to rely, at least in part, on fixed distance-based thresholds as a proxy for determining whether shadowing effects should be considered. While distance can serve as a useful screening parameter, its standalone application does not adequately reflect the site-specific and multi-factor nature of wake effects, which depend on turbine characteristics, plant layout, wind regimes, and local conditions. As a result, a uniform distance criterion may either overestimate or underestimate actual impacts. To address these limitations, a more robust and evidence-based approach is recommended. This approach should prioritize host country regulatory requirements where available, promote the use of recognized site-specific technical assessments—including independent third-party studies and wind power plant certifications—and allow simplified screening criteria only as a secondary or fallback option. In addition, the introduction of a clear materiality threshold would ensure that only demonstrable and relevant impacts on electricity generation are accounted for, avoiding the unnecessary inclusion of marginal or negligible effects. Overall, such an approach would enhance technical robustness and regulatory consistency, reduce the risk of arbitrary assumptions, and improve transparency and predictability for project participants, while preserving the conservative

accounting of emission reductions and supporting the practical applicability of the methodology. It is proposed to replace paragraph 39 with:

- (i) *For wind power plants, shadowing effects shall be assessed as follows:*
- a. *Wake effects occurring within the Article 6.4 activity shall not be accounted for separately, as such effects are inherently reflected in the monitored net electricity generation of the project;*
 - b. *Potential impacts on other wind power plants shall be assessed in accordance with the following hierarchy:*
 - i. *Where applicable, requirements established by the host country’s regulatory or licensing framework shall be applied, including environmental licensing conditions, grid access rules, or other relevant authorizations;*
 - ii. *In the absence of such requirements, the activity participant shall assess inter-farm wake effects using site-specific technical studies based on recognized methodologies and tools, including wind resource assessments, micrositing or wake modelling analyses, and independent third-party technical assessments or certification reports of wind power plants prepared in accordance with industry best practice;*
 - iii. *Where neither regulatory requirements nor site-specific studies are available, simplified screening criteria may be applied, including minimum spacing expressed in multiples of rotor diameter, provided that such criteria are conservatively justified and appropriate to the local wind and layout conditions.*
 - c. *Shadowing effects shall only be accounted for where a material impact on the electricity generation of other wind power plants is demonstrated.” [12]*
- (f) Paragraph 39(b) is more appropriate. The shadowing effects may affect other wind power plants that are registered as an Article 6.4 activity, depending on the density of their installation (for example); [15]
- (g) It is impossible to objectively determine one fixed distance when shadowing effect can be neglected as per paragraph 39(a). The distance depends on whether the plants are offshore or onshore, on weather conditions, wind directions, and the duration of wake-affected periods. The following text is proposed: “*As the potential for shadowing must be a product of complex modelling, it is more sound to ask project proponents to demonstrate that the activity:*
- (i) *Does not have a shadowing effect on any other downwind site; or*
 - (ii) *If it does, proper accounting of such effect, including reconciliation with the affected sites, is considered for baseline emissions downward adjustments or subtractions.” [17]*
- (h) PACM is not the only crediting programme recognised under the Paris Agreement. Other crediting mechanisms can be used to generate ITMOs under Article 6.2

and/or by the host Party to achieve its NDC. At a minimum, any shadowing effects should be accounted for and considered for reducing carbon credit units issued to the facility provoking such effect. The following text is proposed to paragraph 39(b): *"The shadowing effects affect other wind power plants that are registered as an Article 6.4 activity or under another carbon crediting programme,"* [17]

- (i) As mentioned in paragraph 39, reduction in electricity generation by other wind power plants through shadowing effects is not required to be accounted for only under limited conditions, including where the distance between wind turbines is greater than a threshold that is still left open for public input. As mentioned in the note under paragraph 39, the MEP has specifically requested stakeholder input on this distance. Because of this, the practical treatment of wind shadowing is not yet fully defined, and a high technical burden may be created for wind projects in areas where multiple wind plants are located close to each other. Paragraphs 39 and 40 shall be revised such that practical default distance thresholds and clear default evidence sources are provided for wind shadowing. Site-specific studies shall be required only where shadowing is likely to be material; [14]
- (j) The following change is proposed to paragraph 39: *"For wind power plants, any reduction in electricity generation by other wind power plants through shadowing effects ($EG_{shadowing,y}$ or $EG_{shadowing,h}$) does not need be account for if:*
 - (i) *The distance between the wind turbines installed under the Article 6.4 activity and any other wind power plants is greater than [2] kilometres;*
 - (ii) *The distance between the wind turbines installed under the Article 6.4 activity and any other wind power plants can be greater than 2 kilometres, ensuring that potential wake (shadowing) effects are negligible and do not result in measurable reductions in electricity generation."* [7] [13]
- (k) It is quite difficult to objectively determine one "fixed" minimal distance, when one can confidently state that shadowing effect can be neglected. The distance may depend on whether the Wind Plants are off-shore or on-shore, on the location (where the weather conditions are predominantly stable or unstable, wind directions), on the duration of wake-affected periods. What is suggested is that the "default distances" shall be different depending on whether the Wind Plant is on-shore or off-shore; [4]
- (l) In order to facilitate Project Participant and DOE efforts during validation, we suggest to introduce 2 options for Project Participants: (a) the default values (conservative default value of $EG_{shadowing,y}$, in % of total Energy Production by other Plant depending on the distance), (b) The value to be sourced from reports (e.g., Environmental Impact Assessment, feasibility reports) or technical studies undertaken at the project site. In cases where no such sources/reports available, or efforts/costs for preparation of such reports are significant, Project Participants should be able to opt for Option (a) - the default values. [4]

2.9.2. Determination of the downward adjustment

61. The calculation proposed to calculate the minimum downward adjusted baseline in equation (4) is arbitrary and it beneficiates the activities with larger project emissions. It is

- suggested to eliminate the minimum downward adjusted baseline and the comparison between the approaches for determining the downward adjustment. [8]
62. A uniform 10% discount factor is applied regardless of grid carbon intensity or renewable penetration. This results in disproportionately high ER reduction in already low-carbon grids. There are concerns that there is a lack of clarity and transparency regarding the determination of 10% as the minimum downward adjusted baseline. It is requested to consider investigating whether the 10% minimum downward adjustment is appropriate. Furthermore, it is proposed that the methodology replace fixed and compounding conservative adjustments with dynamic, context-specific, and capped approaches in order to maintain environmental integrity while avoiding systematic under-crediting. [7] [13]
63. There may be a concern with Equation (7), where the crediting period start date does not start on 1 January. Where the crediting period starts fairly early in the year, e.g. 16 February 2026 in the example provided below, the emission reductions in the final year will be negative. This is because the downward adjustment (DA_{y1}) from year 2 is an absolute adjustment. We propose that changing DA_{y1} to a % will overcome this issue. We propose that changing DA_{y1} to a % will overcome this issue. [13]
64. Paragraphs 41–55 shall be revised such that the downward adjustment method is simplified and clearly explained, and additional annual reduction is avoided where changes in the electricity system are already reflected in the electricity-system emission factor. Further, the application of a uniform downward adjustment, including the minimum 10 per cent reduction, should be reconsidered for renewable energy project activities such as solar and wind power projects. Downward adjustments may be more relevant for certain categories of projects, such as energy transition or energy efficiency activities, where baseline emissions or performance parameters may involve greater uncertainty or scope for manual intervention. By contrast, in renewable energy projects, electricity generation data is typically measured accurately and conservatively through well-calibrated energy meters, and project operations are monitored and controlled through authorized SCADA systems. As a result, the data obtained is robust, transparent, and subject to limited scope for material error. In such circumstances, the application of a blanket 10 per cent downward adjustment appears arbitrary unless supported by a clear scientific or methodological rationale. Therefore, the methodology should either exempt such project types from the fixed downward adjustment or provide a clear justification for the application of the 0.1 downward adjustment factor to renewable energy projects where measurement uncertainty is already minimal. [14]
65. Paragraphs 43–45 shall be revised such that a simplified or default approach is provided for determining first-year baseline uncertainty for standard grid-connected wind and solar projects. Paragraphs 47–49 shall be revised such that, where the baseline is based on standard metered electricity generation and a standard electricity-system emission factor, project-specific uncertainty modelling, including Monte Carlo simulation, is not required by default and the initial downward adjustment is not made more conservative than necessary. [14]
66. It is cited that “This documentation and the derivation of the overall uncertainty through the error propagation or Monte Carlo simulation methods shall be provided together with the PDD (e.g., in a spreadsheet).” The grid emission factor related uncertainties are already defined in the Tool and such additional requirements would pose undue burden on the project participants. It is suggested to remove this clause or provide guidance on uncertainty handling (especially for weak data systems). [15]

67. The application of the downward adjustment in the draft methodology as per paras 45, 47, 49, 50-52 in section 7.3.1 is done in a way where the percentage of the continuous downward adjustment is the same at the first year of the crediting period for each activity, regardless of the actual calendar year in which the crediting period begins. This leads to a lower continuous downward adjustment level for activities that start at later dates, which distorts the competitive situation in favour of activities that start at later dates. These receive more A6.4ERs for the same calendar year compared to the activities that started earlier. For the annual downward adjustment of 0.01, an activity starting in 2021 has a downward adjustment factor of 0.85 in 2035, whereas the factor of an activity starting in 2030 reaches 0.95. It is, therefore, proposed that the starting value of the continuous downward adjustment at the start of the crediting period of an activity is the level that the continuous downward adjustment reaches calculated from 2021. This would mean that the initial continuous downward adjustment factor for an activity starting in 2030 would be 0.91, for an activity starting in 2035 0.86, an activity starting in 2040 0.81, and so on. It is proposed that host country-specific net zero targets are to be taken into account. [3]
68. Downward adjustment increases by 1% annually. Adjustment increases independent of actual system changes causing progressive decline in credited ERs, even with constant generation. It is proposed to either remove 0.99 factor or apply it only if uncertainty exceeds a defined threshold (e.g., >10%). [7] [13]

2.9.3. Determination of conservative BAU emissions

69. Please clarify understanding. Paragraph 54 indicates that the conservative BAU baseline scenario = the baseline scenario. Therefore, do we understand correctly that the conservative baseline emissions = the unadjusted baseline emissions (i.e. $BE_{EG,y1}$)? If the above is correct, please clarify how the conservative BAU baseline emissions can be higher than the downward adjusted baseline in year 1 ($BE_{EG,adj,y1}$)? In our calculations, $BE_{EG,y}$ is always higher than $BE_{EG,adj,y}$. Accordingly, no further downward adjustment by 0.99 is needed? Furthermore, if the 0.99 discount on BAU emissions is required, we kindly request that PACM consider whether this is the compounding of conservative measures, as the baseline has already been adjusted downwards: (likely 10% in year one and then 1% compounding decrease). These measures could be considered as unnecessary layering of conservative factors, considering that there also a number of conservative factors imbedded the calculation of the Grid EF, as per the draft PACM tool. It is recommended to investigate the cumulative impacts of the various conservative downward adjustments, considering that there may be an unnecessary layer of conservative factors when the methodology is combined with various mandatory tools, such as the tool to calculate grid EF. [13]

2.10. Project emissions

70. As mentioned in paragraphs 56–64, project emissions are required to include emissions from fossil fuel consumption at the project site and from electricity consumption. This means that even small quantities of backup fuel use or imported auxiliary electricity are required to be monitored and included in project emissions. This is broader than the usual treatment under ACM0002 for standard renewable electricity projects, where such emissions were often limited or treated as negligible. Because of this, a high monitoring and documentation burden may be created even where the quantities involved are very small and do not materially affect the overall result. Paragraphs 56–64 shall be revised such that a project-emission threshold is defined, below which project emissions are

- deemed immaterial and may be treated as zero. Project emissions above that threshold shall be calculated as PE and deducted from the baseline emissions accordingly. [14]
71. Fossil fuel consumption associated with the construction or decommissioning of the Article 6.4 project power plant must be considered, and emissions from its construction must be included, for an accurate and conservative quantification of the emission reductions achieved by the activity. See also comment 1. The following change is proposed to paragraph 57: *“This emission source shall include any fossil fuel consumption occurring during the operation of the Article 6.4 project power plant. This may, for example, include emissions from the operation of backup generators or emissions arising from maintenance of the Article 6.4 project power plant (e.g. emissions from fossil fuels used in ships or helicopters to maintain offshore wind power plants). Fossil fuel consumption and emissions associated with the construction or decommissioning of the Article 6.4 project power plant shall be included.”* Calculations to include these emissions should be added to this methodology section. [5]
72. As reflected in paragraphs 57–64, project emissions are required to include electricity consumption and other relevant project-side emission sources. As reflected in paragraph 62(c), separate treatment is not yet clearly provided for storage-linked situations where electricity may be used for grid charging, renewable charging, auxiliary consumption, or later discharge. Because of this, project emissions for renewable energy projects with storage may not be quantified and verified in a fully consistent manner. Paragraphs 57–64 and paragraph 62(c) shall be revised such that a separate project-emissions treatment is provided for renewable energy projects with storage. In this treatment, grid charging, renewable charging, auxiliary consumption, later discharge, and battery losses shall be clearly distinguished and addressed. [14]
73. The emission coefficient for fossil fuels used in backup generators can be calculated via three options: chemical composition (A.1 for mass-based, A.2 for volume-based) or net calorific value (B). Option A is preferred unless data is unavailable, at which point Option B is allowed. However, for diesel generators in remote locations — the most common backup generator type for renewable plants — the practical data available to project developers is typically the volume of fuel purchased (litres of diesel), and Option A.2 requires the density of the fuel, which may not be reliably known. Option B's reliance on net calorific value is simpler but introduces additional uncertainty. It is recommended to add a default density value for diesel (as per IPCC) and default carbon content values for common backup generator fuels (diesel, LPG, natural gas) to Table 13 (Data and Parameters Not Monitored), so that activity participants in data-poor environments can apply Option A.2 without requiring fuel sampling. This reduces uncertainty relative to Option B while maintaining practicality. [7] [8] [13]
74. Fossil fuel consumption associated with the construction or decommissioning of the Article 6.4 project power plant must be considered, and emissions from its construction must be included, for an accurate and conservative quantification of the emission reductions achieved by the activity. See also comment 1. It is recommended to revise paragraph 57 as follows: *“This emission source shall include any fossil fuel consumption occurring during the operation of the Article 6.4 project power plant. This may, for example, include emissions from the operation of backup generators or emissions arising from maintenance of the Article 6.4 project power plant (e.g. emissions from fossil fuels used in ships or helicopters to maintain offshore wind power plants). Fossil fuel consumption and emissions associated with the construction or decommissioning of the Article 6.4 project*

power plant shall be included.” Calculations to include these emissions should be added to this methodology section. [5]

2.11. Leakage emissions

75. The Appendix identifies 'diversion of existing production processes or outputs' as a leakage source that is 'affected by the Article 6.4 activity' but is not quantified. This could be significant where a greenfield solar or wind project is built on previously productive agricultural land, displacing food production to other areas (potentially involving land clearing). This is a material issue for large-scale solar in countries, where solar parks can occupy thousands of hectares of farmland. It is recommended to add an applicability condition or screening question in the PDD requiring project developers to document the prior land use of the project site and assess whether displacement of agricultural production is likely to result in land-use change emissions elsewhere. For projects on degraded or barren land, a default 'no displacement leakage' determination is appropriate. For projects on productive agricultural land exceeding 100 hectares, a qualitative assessment by the DOE should be required. [7] [13]
76. Level of service increase as compared to the baseline scenario (rebound effect) as opposed to level of service used to satisfy additional demand and equal to the level of service under the baseline scenario which is done by greenfield project and is not related to rebound effect. It is proposed to revise paragraph 4(b)(vi) of the appendix as follows: *“Increase in the level of service compared to the baseline scenario as a result of the implementation of the Article 6.4 activity (rebound effect). This emission source is affected by the Article 6.4 activity if the electricity generated by the project power plant lowers electricity prices, leading to an increased use of electricity.”* [11]
77. Low operating cost (market demand response to the intervention) may lead to rebound effect, but this effect is largely compensated by the substitution effect (from fossil to electric end uses) as well as the market creation and suppression (decline of high emission products: transformative changes). Nevertheless, this emission source is not considered here for simplicity and because although low operating cost (market demand response to the intervention) may lead to rebound effect, this effect is largely compensated by the substitution effect (from fossil to electric end uses) as well as the market creation and suppression (decline of high emission products: transformative changes). This may outweigh the rebound effect. [11]

2.12. Avoidance of double-counting

78. As mentioned in paragraph 14(a), the methodology applies only where the renewable electricity from the activity is not also claimed, credited, or used under another certification scheme, crediting mechanism, or environmental attribute system. As mentioned in paragraphs 73–74, activity participants are also required to provide evidence that the emission reductions are not being claimed elsewhere in overlapping market or accounting frameworks. This means that the current draft relies mainly on full exclusion where overlap exists. Because of this, the methodology may become too restrictive even in situations where the same environmental integrity objective could still be achieved through transparent cancellation, ring-fencing, or reconciliation of the relevant claims, instead of complete prohibition. Paragraph 14(a) and paragraphs 73–74 shall be revised such that participation in environmental attribute systems is permitted where the relevant claims are transparently cancelled, ring-fenced, or otherwise reconciled in a manner that prevents

- double claiming. Clear conditions shall be provided to distinguish prohibited overlap from overlap that is adequately managed through transparent accounting treatment. [14]
79. As mentioned in paragraph 73(b), evidence is required to show that the emission reductions are not being claimed in overlapping domestic mitigation schemes or other relevant systems. This means that, during verification and issuance, activity participants may need to repeatedly submit documentary proof for the same type of overlap check. Because of this, additional documentation burden and avoidable delays may be created if no standard form of evidence, declaration, or acceptable documentary pathway is specified in the methodology. Paragraph 73(b) shall be revised such that standard templates, standard declarations, and clear acceptable evidence pathways are provided for overlap checks with domestic mitigation schemes and other relevant systems. Where the same type of overlap assessment is repeated across monitoring periods, the methodology shall also clarify when previously submitted evidence may continue to be relied upon, subject to confirmation that no relevant change has occurred. [14]
80. The MEP should clarify how the points in paragraph 73(b) may impact a project which has already received a National Authorization. We understand that once a project receives the authorization no further demonstration is required. [8]
81. In the conditional situation of paragraph 73(b)(iii), it should be mandatory for the activity participant to provide this evidence. It is proposed to revise paragraph 73(b)(ii) as follows: *“Where the Article 6.4 activity or the activities displaced in the baseline scenario fall within the scope of a mandatory domestic mitigation scheme, activity participants shall provide evidence in each monitoring report that the mitigation outcomes of the Article 6.4 activity are not counted in the mandatory mitigation scheme to reduce the obligations by the entities covered by the scheme. For example, in the case of an emissions trading system covering electricity generation, a confirmation from the operator of the emissions trading system may be sought that a number of allowances equal to the A6.4ERs being requested for issuance for the electricity generation component were cancelled before the issuance of the A6.4ERs.”* [5]
82. Since this is a general provision stemming from A6.4-STAN-AC-002, it would be helpful if this methodology included more detailed guidance on how to prevent double counting when participating in instances where the mechanism is formally recognised as a means to achieve a target set by frameworks, environmental markets, or mandatory domestic mitigation schemes. It is currently unclear how double counting will be prevented in these instances. It is recommended to elaborate on the requirements to prevent double counting in the case of participation in a framework or environmental market or domestic mitigation scheme that formally integrates the mechanism. [5]
- 2.13. Demonstration of alignment with the policies, options and implementation plans with regard to the NDC and LT-LEDS of the host Party and the long-term temperature goal of the Paris Agreement and long-term goals of the Paris Agreement**
83. Paragraph 75 requires DNA confirmation, but lacks operational clarity. As this is included in every methodology, consider providing standardized templates for host country approval and NDC alignment. [15]

2.14. Data and parameters not monitored

84. As reflected in Data / Parameter table 3, the methodology does not yet clearly specify the acceptable data sources to be used for wind shadowing effects. As also indicated in the draft, public input has been invited on the sources commonly used to report the shadowing effect. Because of this, implementation may become difficult if a clear order of acceptable evidence is not provided, especially where different types of studies or documents may be used for the same purpose. Data / Parameter table 3 shall be revised such that a clear hierarchy of acceptable evidence sources is provided for assessing wind shadowing effects. Preferred primary evidence shall include project-specific micro siting / wake-loss modelling prepared using appropriate wind flow modelling and optimization tools, together with turbine coordinates, rotor diameter, predominant wind-direction analysis, and site-assessment inputs consistent with IEC 61400-1. Acceptable secondary evidence shall include micro survey / wind-resource-assessment reports, detailed layout drawings, land-boundary / GIS maps, and inter-developer spacing records or mutual-consent documents from a government recognized R&D Institute where applicable. Where these records show that the site complies with applicable micro siting separation norms or otherwise demonstrates no material shadowing risk, default conservative assumptions shall be permitted instead of project-specific re-modelling. [14]
85. The source of the shadowing effect data: Environmental Impact Assessments or feasibility studies are typically prepared by developers and may not be independently verified for the purpose of carbon crediting. The accuracy of wake-loss modelling varies significantly between software tools and wind resource assessors. There is no requirement for the shadowing data to be derived using a specific modelling standard, or to be independently verified before submission. It is recommended to require that shadowing effect estimates for projects within [2] km of existing wind farms be derived using an industry-standard wind flow model (e.g., WindPRO, or equivalent) and be certified by an independent wind energy assessor as part of the PDD validation. Require annual monitoring of actual curtailment events attributable to shadowing (where measurable via SCADA data) and allow ex-post correction of the assumed shadowing factor if actual measured impact differs from the modelled estimate by more than 10%. [7] [13]
86. In order to facilitate Project Participant and DOE efforts during validation, we suggest to introduce 2 options for Project Participants: (a) the default values (conservative default value of $EG_{shadowing,y}$, in % of total Energy Production by other Plant depending on the distance), (b) The value to be sourced from project-specific reports (e.g., Environmental Impact Assessment, feasibility reports) or technical studies undertaken at the project site. In cases where no such sources/reports available, or efforts/costs for preparation of such reports are significant, Project Participants should be able to opt for Option (a) - the default values. [13]
87. Situations may arise in which there is a trade-off between the use of a reservoir prior to the implementation of an A6.4 activity and the implementation of that A6.4 activity itself. For example, implementing an A6.4 activity may divert water from irrigation to power generation. It is unclear in the current version of the methodology how such trade-offs are to be addressed. It is recommended to add an additional monitoring parameter to ensure that any diversion of water from an existing reservoir resulting from the implementation of the project activity does not cause adverse environmental and/or social impacts. This parameter shall be assessed once, at the beginning of the project's first crediting period. If adverse impacts are identified, appropriate mitigation measures shall be implemented,

and this shall be verified at the first monitoring. If adverse impacts are identified and mitigation measures are not implemented, the issuance of credits shall be paused until the mitigation measures have been fully implemented and verified. [11]

88. As reflected in Data / Parameter table 4 and in the equations for $EG_{PJ,y}$ and $EG_{PJ,h}$ in paragraph 38, renewable electricity generation that would occur in the baseline due to legal requirements ($EG_{legal,y}$ / $EG_{legal,h}$) is required to be deducted. This means that the methodology requires legal or regulatory requirements to be translated into generation quantities. In practice, this may be difficult to apply consistently unless a standard conversion method is provided, because legal requirements in countries such as India may be expressed in different forms, including percentage-based obligations, procurement obligations, storage obligations, tender-based supply requirements, or other regulatory instruments. Further, the existence of an RPO, Energy Storage Obligation, or similar legal requirement should not automatically mean that a project’s generation is legally required baseline generation. Such obligations may create compliance demand, but they do not by themselves demonstrate that a specific project activity would be implemented without Article 6.4 support. If the project activity can demonstrate through investment analysis that its IRR without Article 6.4 revenues remains below, or only within, the applicable benchmark, then the project cannot reasonably be assumed to occur merely because such obligation exists. Clearer guidance is therefore needed both on how legal or regulatory requirements are to be converted into annual or hourly generation quantities, and on when such quantities should appropriately be treated as $EG_{legal,y}$ / $EG_{legal,h}$. Data / Parameter table 4 shall be revised such that, for determining $EG_{legal,y}$ / $EG_{legal,h}$, a standard procedure is provided for converting legal or regulatory requirements into generation quantities. For example, in Indian projects, acceptable evidence may include central or state RPO / Energy Storage Obligation notifications, SERC regulations or orders, procurement guidelines, tender / RfS documents, LoA / PPA provisions, and any other applicable government or regulatory requirement that clearly defines the relevant obligation. The procedure shall also clarify how obligations expressed in percentage form, procurement-target form, storage-obligation form, or other regulatory formats are to be translated into annual or hourly electricity generation quantities. In addition, the methodology shall clarify that the mere existence of an RPO, Energy Storage Obligation, procurement mandate, or similar legal or regulatory requirement shall not automatically mean that the corresponding electricity generation is to be treated as $EG_{legal,y}$ / $EG_{legal,h}$. Such treatment should only apply where it can be reasonably demonstrated that the legal or regulatory requirement would, by itself, result in the implementation of the relevant project activity in the baseline without the need for Article 6.4 support. Where a project activity demonstrates through a robust investment analysis that its IRR without Article 6.4 revenues is below, or only within, the applicable benchmark, the project activity should not be presumed to occur solely due to the existence of such obligation, and the corresponding generation should not be deducted as legally required baseline generation. The methodology should therefore provide clear criteria for distinguishing between general regulatory demand signals and generation that is truly mandatory and financially viable in the baseline. [14]

2.15. Data and parameters monitored

89. In the row “Measurement methods and procedures” of the Data / Parameter table 05, it is mentioned the ASTM standard; we propose to include the wording “or equivalent”. There are other norms applicable to sampling and analysis in laboratories that could be used. Moreover, there are countries in which there is no laboratory using the ASTM standard

but using national standards and procedures. It is recommended to include the wording "ASTM or equivalent". [8]

90. As reflected in Section 14 para 79, the monitored-parameter tables do not yet clearly identify the full set of data needed for renewable energy projects with storage. This means that, for storage-linked projects, key parameters such as charging source, charged energy, discharged energy, battery losses, and time-shifted delivery may not be monitored in a consistent way unless they are explicitly listed. In India, storage is already being recognized in policy and procurement frameworks, including the National Framework for Promoting Energy Storage Systems, RPO / Energy Storage Obligation-related measures, and bidding guidelines for firm and dispatchable renewable power with storage. Because of this, clearer and more complete monitored-parameter requirements are needed so that the stored renewable component can be verified properly in practice. Further, the battery system should be recognized as a separate technology component for monitoring purposes, because it performs a distinct function by storing electricity, incurring efficiency losses, and discharging electricity at a different time for delivery to the grid. This distinction is also relevant in light of the broader Article 6.4 methodological direction, under which storage may require separate technical and accounting treatment. If BESS-specific parameters are not explicitly monitored, the storage contribution may be under-accounted or inconsistently verified. It is recommended to revise section 14 such that BESS-specific monitored parameters are added for renewable energy projects with storage. For Indian projects, these parameters should include at least the charging source, charged energy, discharged energy, round-trip efficiency, auxiliary load, and time-shifted electricity delivered to the electricity system. Acceptable project evidence may include meter data, inverter / PCS records, SCADA / EMS / BMS logs, scheduling and settlement records submitted to the relevant load dispatch center, contractual or bid documents identifying the storage-linked supply obligation, and performance documents showing round-trip efficiency or operating losses. In addition, the methodology shall clarify that the battery energy storage system is to be recognized as a distinct technology component within renewable energy projects with storage, rather than being treated merely as an auxiliary part of the generation system. Separate monitored parameters shall therefore be required to identify electricity charged into the battery, the source of that electricity, electricity discharged from the battery, storage losses, and the quantity of time-shifted electricity ultimately supplied to the electricity system. Where applicable under the relevant Article 6.4 methodological framework, renewable electricity directly supplied to the grid and renewable electricity supplied after storage should be capable of separate identification and verification if they are subject to different technical or crediting treatment. The methodology should therefore explicitly require the monitoring architecture necessary to support separate recognition of the BESS component and any stored renewable electricity delivered to the grid. [14]

Appendix 1. List of submissions

1. The following table contains the list of submissions used in this information note.

Table 1. List of submissions received

Submission #	Stakeholder	Submission date
1	Clean Commodities & Energy	19 March 2026
2	General Carbon advisory Pvt. Ltd	27 March 2026
3	Perspectives Climate Research	01 April 2026
4	First Climate	02 April 2026
5	Carbon Market Watch	03 April 2026
6	Cenergi SEA Berhad	06 April 2026
7	Value Network Ventures Pte. Ltd.	06 April 2026
8	Karbon-x	06 April 2026
9	Kenya Electricity Generating Company PLC	07 April 2026
10	UN Climate and Technology Centre Network (CTCN)	07 April 2026
11	Global Carbon Council	07 April 2026
12	ABEEólica - Brazilian Association of Wind Energy and New Technologies	07 April 2026
13	Project Developer Forum	07 April 2026
14	Independent Academic Researcher	07 April 2026
15	World Bank	07 April 2026
16	EcoSecurities	07 April 2026
17	International Emissions Trading Association (IETA)	07 April 2026
18	FMASE	07 April 2026

Document information

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01.0	21 April 2026	Compilation of inputs from stakeholders by the secretariat.

Decision Class: Operational
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Business Function: Methodology
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