www.oeko.de

Öko-Institut

Assessment of VCS methodology VM0052 on Accelerated Retirement of Coal-Fired Power Plants using a Just Transition and its associated modules VMD0060 and VMD0061

Study conceived and funded by Carbon Market Watch

Berlin, 15 December 2025

Study by Oeko-Institut Consult GmbH

Authors

Felix Fallasch
Dr. Lambert Schneider
Hauke Hermann

Oeko-Institut Consult GmbH

Oeko-Institut Consult GmbH
info@oeko-consult.de
oeko-consult.de

Office Freiburg
Merzhauser Straße 173
79100 Freiburg
Phone +49 761 45295-0

Office Berlin
Borkumstraße 2
13189 Berlin
Phone +49 30 405085-0

Office Darmstadt
Rheinstraße 95
64295 Darmstadt
Phone +49 6151 8191-0

Table of Contents

Summary

Transitioning the world away from coal is the most important step for meeting the long-term temperature goals of the Paris Agreements. Reaching these goals requires the early retirement of many coal-fired power plants (CFPPs), especially in Southeast Asia. Exploring different policy options that can support this transition is therefore crucial. This can include well-established approaches, such as regulations or emissions trading systems, as well as innovative approaches such as using carbon credits to incentivise accelerated retirements. The effectiveness of the latter largely depends on the ability to ensure high environmental integrity of such credits. Robust quantification methodologies that ensure the additionality of the mitigation activities, conservativeness in quantifying emission reductions and the prevention of double counting are key in this regard. Given that retiring even a single CFPP would likely result in the issuance of a large number of credits, high integrity is paramount not only for these projects but also the credibility of carbon crediting markets.

In 2025, the Verified Carbon Standard (VCS) adopted the methodology VM0052 and its modules VMD0060 and VMD0061, creating the first methodological framework for quantifying the emission impact of projects phasing out CFPPs.

The methodology allows issuing carbon credits for the emission reductions resulting from an early retirement of existing CFPPs if project proponents replace parts of its generation capacity with paired renewable power.

In this study we assessed the robustness of this new methodology and its modules, by benchmarking them against different quality assessment frameworks and best practices in carbon crediting. We further used the case of the *South Luzon Thermal Energy Corporation* CFPP in the Philippines – which potentially will be a pilot project under VM0052 – to illustrate our findings with real case circumstances.

Overall, we find that the methodology has some promising elements but in other elements would need more rigor to ensure environmental integrity. Issues pertain to both the demonstration of additionality and the quantification of emission reductions. These are our main findings:

- **Very low pairing requirements for renewable energy can lead to high leakage emissions.** The methodology requires project proponents to replace 10% of the CFPP's nameplate capacity with paired renewable power plants at the start of the first crediting period, and 40% at its end. Depending on the type of the paired renewable power plants and their operation time, this translates into a range of 9-35% of electricity generation that must be replaced at the end of the first crediting period. This means that potentially large shares of electricity must be acquired from other grid-connected sources to replace the CFPPs. Depending on the share of fossil-based power plants in the grid, this can lead to high leakage emissions.
- **The methodology includes comprehensive requirements to account for leakage emissions of which some can be considered conservative while others entail overestimation risks.** Due to the low pairing requirements of the methodology, a robust quantification of leakage emissions from replacing electricity generated by the retired CFPP through other plants in the grid is critical. The methodology uses the combined margin emission factor to determine the grid emission factor. Its approach for calculating the simple operating margin is conservative, while the inclusion of plants with a relatively high intermittency in the calculation of the build margin results in overestimation risks.

- **The lack of requirements for a country-wide coal moratorium if CFPPs are owned by independent power producers (IPPs) exacerbates leakage risks and may create moral hazard risks.** The methodology establishes that a country-wide moratorium on the construction of new CFPPs or the increase of the capacity of existing CFPPs must be in place. However, this condition only applies when retiring state-owned CFPPs but not to CFPPs owned by an IPP. In this latter case, only the IPP itself must commit not to build new CFPPs or increase capacities of its existing CFPPs. These provisions introduce high leakage risks as they do not prevent situations where another IPP builds a new CFPP or increases capacities of its existing CFPPs to replace the electricity of the CFPP retired under this methodology. The materiality of this risk can be illustrated with the case of the SLTEC plant, which is discussed as a pilot project under VM0052: In the same city where the plant is located, another IPP currently plans to resume previously shelved plans for the construction of a new CFPP which has a three times larger capacity than the SLTEC plant. This is possible as the Philippine coal moratorium allows to still construct CFPPs which have already been in the planning stage at the time the moratorium was adopted. If retirements take place while new coal capacity is still coming online, this considerably increases leakage risks.
- **More ambitious pairing requirements would not render the methodology impractical.** The Philippine-based energy company ACEN announced that they plan to replace the 270 MW SLTEC CFPP with a 1.4 GW solar facility with an integrated storage capacity of 1.6 GWh. This suggests that replacing all coal-fired electricity generation with paired renewables is feasible in some cases. While the SLTEC plant is a small CFPP and replacing larger CFPPs might be more challenging, establishing more ambitious pairing requirements seems already technically feasible today. It is also critical for reducing the potentially very large and uncertain leakage emissions.
- **Demonstrating pairing based on plans of the system operator is not robust.** The methodology allows for five different pathways to achieve the pairing requirements. Three of these include direct contractual or regulatory agreements that bind the construction of the renewable power plants to the retirement of the CFPP. The fourth pathway involves demonstrating that renewable energy comes online earlier or at a greater capacity than projected in the approved regulatory resource plan of the system operator. Such a development could however also be driven by external factors unrelated to the coal plant's retirement. The fifth pathway involves demonstrating that the conditions for refinancing a CFPP for retirement require new renewable electricity generation capacity. For this it is equally uncertain to establish a clear causality. We therefore do not consider these pathways to be robust and recommend removing them from the methodology.
- **The methodology should explicitly require project proponents to source replacement energy.** The applicability conditions include a requirement for project proponents to establish a renewable energy pairing plan, including a list of renewable power generation plants that are paired to the accelerated CFPP retirement. The methodology should include a similar requirement for the replacement electricity which project proponents plan to acquire from other sources than paired renewable energy. The project proponents should be required to include the names and locations of specific plants from which electricity will be acquired through PPAs and the share and type of electricity that project proponents plan to acquire through other forms than PPAs.
- **The methodology considers a comprehensive set of different baseline retirement scenarios. The approach to determine the financially attractive baseline retirement date should be strengthened through a requirement for project-level accounting for**

uncertainty. The methodology compares the net present value of revenues required for the continued operation of the CFPP with an accelerated retirement scenario to identify the earliest date under which a retirement of a CFPP is financially attractive. This approach is generally appropriate but relies on several assumptions about key parameters such as the average cost of electricity generation in the grid. Making these assumptions on an ex-ante basis is associated with significant uncertainty. The current approach to account for uncertainty by deducting one year from the identified baseline retirement date might not appropriately account for the significant uncertainty. A more robust approach would be a sensitivity analysis that varies key parameters within plausible ranges. Furthermore, the financially attractive baseline retirement date should be included in the list of retirement scenarios that must be reassessed at crediting period renewal.

- **The requirement to use two reference CFPPs as a control group to dynamically adjust assumptions on the CFPPs baseline utilization factor would mitigate overestimation risks. The approach to selecting these reference CFPPs should be strengthened further.** The methodology requires to evaluate the appropriateness of historical data to project the baseline utilization factor with a control group of two reference CFPPs that represent similar coal operations in the country. Utilization of baseline CFPPs must be monitored annually and adjustments to the baseline must presumably be made if reference CFPPs are utilized less in the crediting period. This would allow for accounting of shifting roles of CFPPs in grids that transition towards higher reliance on renewable energy. These requirements are however only implicitly referenced through the monitoring plan and should be made explicit in the section on calculating baseline emissions. Further, the selection criteria for the reference CFPPs should be strengthened, inter alia by requiring project proponents to consider all CFPPs that meet the selection criteria instead of just two. This would reduce adverse selection risk in grids with large CFPP fleets.

- **The provisions for avoiding double claiming due to overlap with mandatory mitigation schemes are robust but double issuance risks exist due to potential overlaps with renewable energy projects.** The VCS rules for avoiding overlap with mandatory mitigation schemes, such as emissions trading systems (ETS), are robust and effective as project proponents cannot seek credit for the same GHG emission reductions under the VCS Program and an ETS or binding emission limit. However, the VCS does not have sufficient requirements to avoid double issuance. For example, there is no requirement for project proponents to enter into legal agreements with plant operators of paired renewable energy to ensure that they will not claim any carbon credits for these sources. Double issuance risks further are material for any replacement electricity acquired from grid-connected sources that receive carbon credits for their construction. Solving this issue might be technically challenging as it would require project proponents to reach agreements with many different operators and conduct close monitoring of adherence to these agreements.

- **The just transition requirements are comprehensive and include elements for inclusive and transparent stakeholder engagement processes.** This includes stakeholder mapping requirements, vulnerability assessments and requirements for independent third-party evaluation of key documentation such as financial transactions. Furthermore, project proponents must establish arrangements for finding consensus including through mediation.

- **There is a risk that project proponents overly rely on third parties for the implementation of the just transition plan.** Involving third parties in the implementation of the just transition plan is useful as they often have a specific understanding of regional conditions, local labor markets and social dynamics which can be critical when designing a just transition that meets the specific needs of workers and communities. Given that they receive the revenues from carbon credits, project proponents should however have the primary responsibility for leading, funding and implementing the measures of the just transition plan. This should be made clearer in the methodology which currently does not include limits to utilizing third party support.

- **The terms on the minimum funding to be provided by project proponents for implementing the just transition plan should be improved.** The methodology requires that at least 2% of the revenues from carbon credits will be allocated to the implementation of the just transition plan. At the same time, it contains an applicability condition which requires that the just transition plan must be fully funded through sources other than revenues from carbon credits. These potentially contradictory provisions again raise questions about the extent to which project proponents can rely on third parties to fund the implementation of the just transition plan. Revenues from carbon credits have high uncertainties. The provision that the plan must be fully funded through sources other than revenues from carbon credits can function as a safeguard against potential issues with monetizing carbon credits. It should however be made clear that it will be the responsibility of project proponents to close any gaps by making a higher share of carbon credit revenues available for the just transition plan.

The main source of uncertainty and potentially overestimation of emission reductions is the methodology's approach to addressing leakage emissions. VM0052 acknowledges that the project activity may be associated with potentially large leakage emissions which result from using replacement electricity that may be generated by fossil-fuel power plants in the grid. Allowing project proponents to use such electricity instead of paired renewable energy is an explicit choice of the methodology to accommodate the challenges associated with replacing a CFPP with renewable energy only. On the one hand it is a positive feature of the methodology that it accounts for leakage emissions, on the other hand the methodology's chosen approach does not necessarily adheres to the common principle in carbon crediting to avoid leakage emissions as much as possible before accounting for those that remain. This creates risks because the robustness of this approach hinges on the ability to conservatively account for such large leakage emissions. While the methodology's leakage accounting provisions are comprehensive, inclusion of plants with a relatively high intermittency in the calculation of the build margin results in overestimation risks. Allowing the application of the methodology in countries where new CFPPs continue to be build further increase leakage risks.

Related to this, the choice of the methodology to allow project proponents to use replacement electricity generated by non-paired, grid-connected sources results in double-issuance risks if some of these sources receive carbon credits as well. Combined, these issues can lead to a material risk that applying the methodology results in the issuance of some carbon credits that are not backed by real emission reductions.

We therefore recommend that the methodology be further strengthened before it is used by pilot projects. A key improvement would be a mandatory requirement for countries to adopt a moratorium on the construction on new CFPPs. Furthermore, increasing the pairing requirements to replace 100% of the electricity with renewable energy systems with integrated storage capacities would solve different methodological challenges, including the high uncertainty of leakage emissions and the risk of double issuance. Further, the methodology should remove all pairing pathways that do not establish clear contractual or regulatory agreements for new renewable energy sources. Finally, the net present value calculations for determining the financially attractive baseline retirement should include a sensitivity analysis to vary key parameters within plausible ranges.

1 Introduction

Transitioning the world away from coal is the most important step for meeting the long-term temperature goals of the Paris Agreements. Coal-fired power plants (CFPPs) are a significant contributor to greenhouse gas emissions – with the International Energy Agency (IEA) estimating that CFPPs accounted for about one fifth of global emissions in 2021 (IEA 2021). As of July 2025, there were 2,457 operating or mothballed[1] CFPPs across the globe with a capacity of 2,193 gigawatts. Of these, only 12% have a closure commitment that is in line with the temperature limits of the Paris Agreement. A further 11% have closure commitments which would need to be brought forward to become Paris compatible. For the remaining 77% CFPPs, no planned closure or phase-out commitment is in place (Global Energy Monitor 2025). At the same time, more than 95% of current global coal consumptions takes place in countries that have made net zero emission pledges (IEA 2022). These figures suggest that in many countries there remains a policy gap to drive the needed CFPP phase-out for achieving these pledges.

Asia is the dominant region in global coal-fired power generation. The share of global coal demand consumed in Asia rose to nearly 80% in 2024 (IEA 2025). CFPPs in Asia are comparatively young – with 13 years on average and less than 8 years in some Southeast Asian countries such as Viet Nam (IEA 2022). This creates different policy challenges for CFPPs phase-out than in most industrialised countries where many CFPPs are at the end of their typical 40 or 50-year lifespan. They underline the importance of just transition plans to ensure that bringing forward retirement dates will follow a just and orderly transition towards a zero-emission energy system.

Countries in Southeast Asia have begun to cooperate through multilateral fora to explore solutions for closing the CFPP phase-out policy gap. On a political level, Indonesia and Viet Nam, for example, have formed Just Energy Transition Partnerships (JETPs) with several donor countries. They are underpinned by instruments such as the Climate Investment Fund's Accelerated Coal Transition Program (CIF ACT) for which Indonesia and the Philippines have developed investment plans that will be implemented with support by the Asian Development Bank (ADB) and the International Finance Corporation (IFC).

Considering the scarcity of public finance, allowing CFPP operators to receive carbon credits in exchange for bringing forward retirement dates of their plants has become a further policy option explored by different stakeholders. Responding to these ideas, two of the major carbon crediting programs – the Verified Carbon Standard (VCS) and the Gold Standard have launched the development of methodologies for quantifying the emission impact of such approaches. Since May 2025, developers can use the VCS methodology VM0052 – *Accelerated Retirement of Coal-Fired Power Plants Using a Just Transition* for registering projects with the VCS.

Projects registering with the new VCS methodology will potentially generate large amounts of carbon credits. The first pilot project currently discussed for example is expected to generate emission reductions of up to 1.9 million tons of carbon dioxide (Mt CO_2) annually by bringing forward the closure of the *South Luzon Thermal Energy Corporation* CFPP in The Philippines by 10 years from 2040 to 2030 (Just Transition Finance Lab 2024).[2] The Rockefeller Foundation, which supported the methodology development, aims to scale the project pipeline under VM0052 to 60 projects across the Asia-Pacific region (Rockefeller Foundation 2025).

[1] "Mothballed" refers to plants that have been temporary shut-down but are kept as a reserve and can be brought back online if needed.
[2] This is an ex-ante estimate of the effect of bringing the retirement forward to 2030.

Given the potentially large volume of credits to be issued to projects using VM0052, it is pertinent that its application will lead to issuance of carbon credits with high environmental integrity. The purpose of this study is to assess the robustness of VM0052 and its associated modules VMD0060 and VMD0061, using the Core Carbon Principles (CCPs) of the Integrity Council for the Voluntary Carbon Market (ICVCM), the methodological requirements of the Paris Agreement Crediting Mechanism (PACM) and the assessment methodology of the Carbon Credit Quality Initiative (CCQI) as benchmarks. Further, the study will assess the robustness of the methodology's just transition requirements.

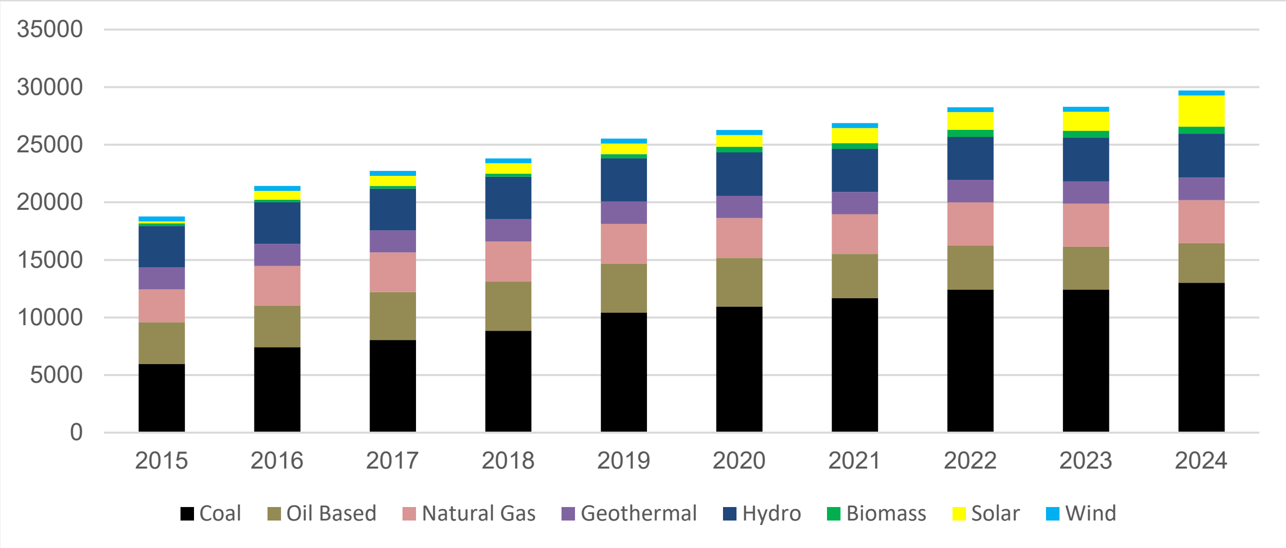
To allow for illustrating the study findings with real case circumstances and examples, the study contextualises its assessment within one country which actively explores using carbon credits for retiring CFPPs: The Philippines, which – as mentioned above – currently develops a first pilot project under VM0052. At the time of writing this study, draft project design documents were not yet available in the Verra project database. Information on the pilot project in the Philippines therefore has been sourced from grey literature and announcements by actors involved in the project's development.

1.1 Overview of relevant data and context on CFPPs in the Philippines

In 2020, the energy sector with 74,894 Gg CO_2e was responsible for about 36% of the overall GHG emissions in the Philippines (Republic of the Philippines 2025). Electricity in the Philippines is predominantly produced with fossil fuels, which had a share of 78% in total gross electricity production in 2024 (The Philippines Department of Energy 2025a). CFPPs contributed 79.36 GWh in 2024, which is equivalent to about 62% of the total power generated in that year. Renewable energies contributed 22%, with geothermal and hydro both contributing about 8.5% of total power generation. Solar (3%) and wind (1%) played a small role in electricity generation in 2024.

Since the adoption of the Paris Agreement, the Philippines increased the installed CFPP capacity from 6 GW in 2015 to 13 GW in 2024, of which 12.5 GW are grid connected. Solar power capacity increased more than 15-fold during that time, reaching a share of about 10% of overall capacities in 2024. Wind power capacity remained constant between 2015-2024 (The Philippines Department of Energy 2025a).

Figure 1 Installed Gross Power Generation Capacity by Plant Type in MW



Source: (The Philippines Department of Energy 2025a)

As the first country in Southeast Asia, the Philippines in December 2020 announced a moratorium on the construction of new CFPPs (The Philippines Department of Energy 2020). The moratorium does not affect CFPPs already planned or under construction, explaining why 2.1 GW in additional capacity was added between 2020-2024. The Philippines' Department of Energy further expects an additional 2.3 GW of coal-fired power generation capacity to come online by 2028 (Argus Media 2024). The Philippines also signed the coal exit pledge at COP21 in Glasgow, however only partially, not signing provisions relating to ceasing the issuance of new permits and ceasing construction and government support for new unabated coal-fired power generation projects (United Kingdom 2021).

1.1.1 Overview of CFPPs in the Philippines grid

The average age of the Philippines CFPP fleet is 12 years. It mainly consists of circulating fluidized bed (CFB) and pulverized sub critical coal plants (see Table 1). The former have an average age of 8.8 years (range 1-15 years) while the latter are significantly older with an average age of 19.1 years (range 5-41 years).

Table 1 Overview of grid-connected CFPPs in the Philippines

	Plants	Units	Installed Capacity	Average age	Range (min)	Range (max)
	No.	No.	MW	Years	Years	Years
Circulating Fluidized Bed (CFB)						
Coal	15	33	4,323.4	8.8	1	15
Coal Co-Generation (Supply Steam and Electricity)	1	1	52	19.0	-	-
Coal Co-generation	1	1	30	27.0	-	-
Pulverized Sub Critical Coal	8	18	5,778.1	19.1	5	41
Super Critical Coal	2	4	2,329.9	4.5	3	6
Total	**27**	**57**	**12,513.4**	**12.21**	**1**	**41**

Source: (The Philippines Department of Energy 2025d, 2025e, 2025f). Information as of 30 April 2025. Excludes the PETRON RSFFB and PETRON RSFFB PH3 facilities which are indicated as embedded CFPPs in the official statistic.

As shown in Table 2, ten of the 18 units in pulverized sub critical coal plants are 19 years or older. These units have a capacity of 3,564 MW or about 28% of the total coal capacity installed in the Philippines. A further six units using the same technology have a unit age ranging between 5-7 years. The vast majority of the CFB units on the other hand are less than 10 years of age with 4 only units installed in the last year.

Table 2 Age distribution of CFPP units in The Philippines by type (in years)

Type		1	3	4	5	6	7	8	9	10	12	14	15	19	26	27	29	41
Circulating Fluidized Bed (CFB) *Coal*	*Units*	4	0	0	0	4	2	2	11	3	0	3	4	0	0	0	0	0
	Capacity (MW)	600	0	0	0	606.5	300	300	1508.7	368.7	0	277.9	361.6	0	0	0	0	0
Circulating Fluidized Bed (CFB) *Coal Co-Generation (Supply Steam and Electricity)*	*Units*	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0
	Capacity ((MW)	0	0	0	0	0	0	0	0	0	0	0	0	52	0	0	0	0
Circulating Fluidized Bed (CFB) *Coal Co-generation*	*Units*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0
	Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30	0	0
Pulverized Sub Critical Coal	*Units*	0	0	0	2	3	1	0	0	0	2	0	0	2	2	2	2	2
	Capacity (MW)	0	0	0	689.4	453	420	0	0	0	651.6	0	0	232	1294	674.1	764	600
Super Critical Coal	*Units*	0	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0
	Capacity (MW)	0	725	725	351.8	528.1	0	0	0	0	0	0	0	0	0	0	0	0

Source: (The Philippines Department of Energy 2025d, 2025e, 2025f). Information as of 30 April 2025. Excludes the PETRON RSFFB and PETRON RSFFB PH3 facilities which are indicated as embedded CFPPs in the official statistic.

1.1.2 Overview of CFPPs in the Philippines grid

The Philippines has three main electrical grids: the Luzon grid, the Visayas grid and the Mindanao grid. Luzon is the biggest island in the Philippines on which also the capital Manila is located. The electricity grids are geographically distinct, covering the major island groups of the country but are interconnected via submarine cables and are all operated by the National Grid Corporation of the Philippines. The CFPP currently under discussion for the development of a pilot project under VM0052 is the South Luzon Thermal Energy Corp.'s (SLTEC) 270 MW power station in Calaca, Batangas. It is connected to the Luzon grid, which is the largest grid in the Philippines with about 71% of nationwide power in 2024 being generated in the Luzon grid (The Philippines Department of Energy 2025b). A total of 15 CFPPs with an overall capacity of 9,207.7 MW (see Table 3) are connected to the Luzon grid. More than half of this capacity is provided by pulverized sub critical coal plants.

Table 3 Overview of CFPPs in the Luzon grid

	Plants	Units	Installed Capacity	Average age	Range (min)	Range (max)
	No.	No.	MW	Years	Years	Years
Circulating Fluidized Bed (CFB)						
Coal	5	13	1,853.7	6.1	1	10
Coal Co-Generation (Supply Steam and Electricity)	1	1	52	19	19	19
Coal Co-generation	1	1	30	27	27	27
Pulverized Sub Critical Coal	6	12	4,942.1	23.5	5	41
Super Critical Coal	2	4	2,329.9	4.5	3	6
Total	**15**	**31**	**9,207.7**	**16.02**	**1**	**41**

Source: (The Philippines Department of Energy 2025d) Information as of 30 April 2025. Excludes the PETRON RSFFB and PETRON RSFFB PH3 facilities which are indicated as embedded CFPPs in the official statistic.

The Luzon grid hosts six out of the eight pulverized sub-critical CFPPs still operating in the Philippines. Consequently, with 16 years, the average age of the Luzon CFPP fleet is slightly higher than the average of the nationwide fleet. Average age is only slightly higher, because the Luzon grid also hosts all super critical coal plants operating in the country which have an age of six years or younger (see Table 4).

Table 4 Age distribution of CFPP units in the Luzon grid by type (in years)

Type		1	3	4	5	6	7	8	9	10	12	19	26	27	29	41
Circulating Fluidized Bed (CFB) *Coal*	*Units*	4	0	0	0	1	1	2	4	1	0	0	0	0	0	0
	Capacity	600	0	0	0	150	150	300	518.7	135	0	0	0	0	0	0
Circulating Fluidized Bed (CFB) *Coal Co-Generation (Supply Steam and Electricity)*	*Units*	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0
	Capacity	0	0	0	0	0	0	0	0	0	0	52	0	0	0	0
Circulating Fluidized Bed (CFB) *Coal Co-generation*	*Units*	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0
	Capacity	0	0	0	0	0	0	0	0	0	0	0	0	30	0	0
Pulverized Sub Critical Coal	*Units*	0	0	0	1	0	1	0	0	0	2	0	2	2	2	2
	Capacity	0	0	0	538.4	0	420	0	0	0	651.6	0	1294	674.1	764	600
Super Critical Coal	*Units*	0	1	1	1	1	0	0	0	0	0	0	0	0	0	0
	Capacity	0	725	725	351.8	528.1	0	0	0	0	0	0	0	0	0	0

Source: (The Philippines Department of Energy 2025d) Information as of 30 April 2025. Excludes the PETRON RSFFB and PETRON RSFFB PH3 facilities which are indicated as embedded CFPPs in the official statistic.

With 44.2% of total installed capacity, CFPPs provide most of the capacity in the Luzon grid. This is followed by renewable energy which had a share of 28.5% in 2024. Hydro and solar were the major renewable energy facilities in the Luzon grid in 2024. The Luzon grid is the only grid in the Philippines that has natural gas power plants. They made up 17.6% of the installed capacity in 2024. In terms of gross power generation, coal in 2024 contributed 63.2% of all power generated in the Luzon grid, followed by natural gas (20%) and renewable energy (16.1%).

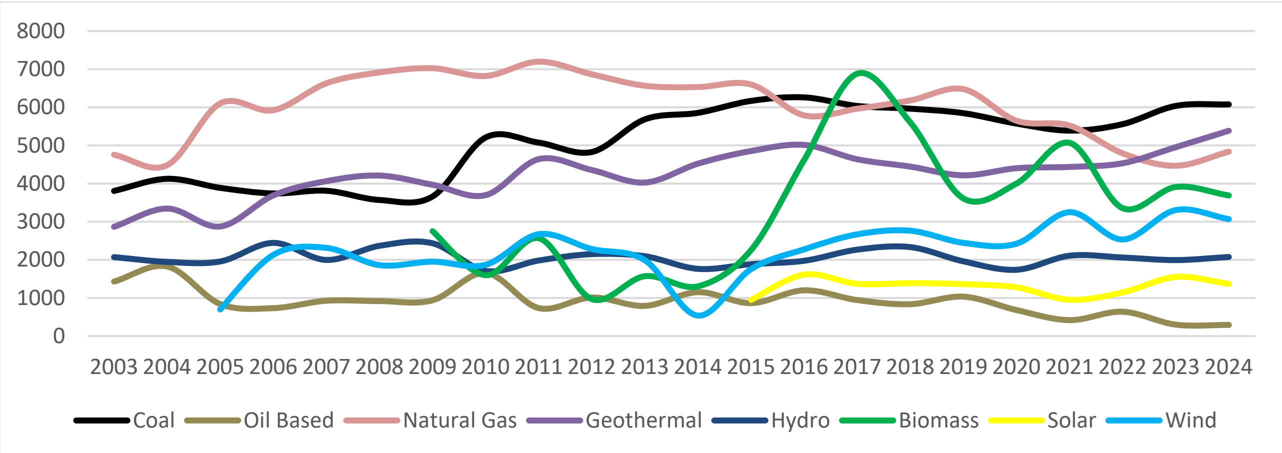
Table 5 **Overview of installed capacity and generation in the Luzon grid in 2024**

	Installed capacity (MW)	Share	Generation (MWh)	Share	Utilization (hours)
Coal	9,392	44.2%	57,069,815	63.2%	6,076
Oil Based	2,054	9.7%	602,894	0.7%	293
Natural Gas	3,731	17.6%	18,046,729	20.0%	4,836
Renewable Energy	6,055	28.5%	14,549,938	16.1%	2,402
Geothermal	*865*	*4.1%*	4,657,447	5.2%	5,384
Hydro	*2,558*	*12.0%*	5,307,787	5.9%	2,074
Biomass	*175*	*0.8%*	645,430	0.7%	3,688
Solar	*2,121*	*10.0%*	2,905,248	3.2%	1,369
Wind	*337*	*1.6%*	1,034,027	1.1%	3,068
Total	**21,232**		**90,269,376**		**25,876.08**
BESS	363		114,226		

Source: (The Philippines Department of Energy 2025b, 2025c) BESS = Battery Energy Storage System.

Utilization of CFPPs in the Luzon grid reached a peak in 2016 with 6,260 hours and then declined steadily until it reached 5,558 hours in 2022. After 2022 utilization started to increase again, reaching 6,076 hours in 2024 (see Figure 2). High utilization rates suggest that the grid continues to rely on coal for base load energy generation. As more renewable energy becomes available, utilisation may decrease in the future as CFPPs may transition to a role where they bridge renewable energy intermittency and become less important for base load contribution (see section 2.2.2.1).

Figure 2 **Utilization of different technologies in the Luzon grid (in hours)**



Source: (The Philippines Department of Energy 2025b, 2025c)

1.1.3 Overview of CFPPs in the Philippines grid

In its updated Nationally Determined Contribution (NDC), the Philippines in 2021 communicated a 2030 target of reducing GHG emissions by 75% below a cumulative business as usual pathway for the period 2020-2030 (Republic of the Philippines 2021). Except for a small portion of 2.71%, the target is conditional upon receiving international support. The Climate Action Tracker (CAT) rates the conditional target as "1.5°C compatible" with the Philippines being among very few countries that have communicated a target in line with the temperature limit (Climate Action Tracker 2023). Achieving the target will require strong reductions beyond current policies and international support.

The main framework guiding the further development of the energy system in the Philippines is the 2023-2050 Philippine Energy Plan. Under this plan, the government aims to increase renewable energy to 35% of overall power generation by 2035 and to 50% by 2040 (The Philippines Department of Energy). In addition, the government plans for the installation of 4,800MW of nuclear capacities by 2050, gradually starting with 1,200 MW becoming available in 2032.

1.1.4 Role of domestic coal mining in the Philippines

In 2023, net coal imports stood at 67.5% of total coal supply (IEA 2023). Domestic coal mining in the Philippines concentrates on open pit mining on the small island of Semirara. It is located 300 km south of the capital Manila. The coal is of inferior quality with a calorific value between 5.100 to 5.600 kcal/kg (Villegas 2024). The coal also shows a high tendency of slagging and fouling in the power plants that use this coal (Limos-Martinez und Watanabe 2006). This increases cost of power plant operation.

Coal produced on the small island of Semirara comes from different mining fields. With old fields being depleted, the main mining company – the Semirara Mining & Power Corporation aims to start production from a new mining field named Acacia Mine in 2026 (Esmael 2025a). The reserves of the Acacia Mine are 80 million metric tonnes. However, based on historic production volumes also the new Acacia mine field would be depleted after only five years (Esmael 2025b).

The Semirara Mining & Power Corporation owns the following subsidiaries which operate CFPPs in the Luzon grid:

Southwest Luzon Power Generation Corporation (SLPGC)[3]

Operates a two-unit 300 MW CFPP in Barangay San Rafael, Calaca, Batangas

SEM Calaca Power Corporation

Operates a two-unit 500 MW CFPP, also in Barangay San Rafael, Calaca, Batangas

St. Raphael Power Generation Corporation

Currently considers reviving a previously shelfed project to construct a 700 MW CFPP, also in Barangay San Rafael, Calaca, Batangas. Initially, start of construction for this CFPP was planned for 2018. Construction had been shelved in 2019 because the power supply agreement for the facility had been affected by a Supreme Court ruling mandating the conduct of competitive selection process for all capacity procurements by distribution utilities. As plans for this facility have been made before entry into force of the coal moratorium in 2020, construction would be possible under the rules of the moratorium. SMPC announced its intention to revive

[3] Not to be confused with the South Luzon Thermal Energy Corp.'s (SLTEC) that operates in the same town and plans a pilot project under VM0052 (chapter 1.1.2)

the project in 2024 (Galang 2025), depending on its ability to secure financing for the project and the National Grid Corporation finalising new transmission lines (Austria 2025).

The Semirara Mining & Power Corporation supplies all three CFPPs with coal from the Semirara mine. Ships transport the coal from the Semirara island directly to the CFPPs which all are located at the coast. Next to providing supply to its own CFPPs, Semirara Mining & Power Corporation also supplies other CFPPs with coal. This includes for example the *South Luzon Thermal Energy Corporation (SLETC) CFPP* (see section 1.2.2) which is proposed as a pilot project under VM0052 and has a long-term contract with Semirara Mining & Power Corporation for coal supply (ACEN 2021).

1.1.5 Role of LNG and natural gas

Historically natural gas fired power plants were fuelled by domestic natural gas production. 98% of natural gas consumption in the Philippines goes to the power sector. The first LNG import plant opened in 2023 to replace declining domestic production. Many more LNG import plants are currently proposed or being developed. This often goes in conjunction with planned capacity additions of modern combined cycle gas turbines close to the proposed LNG import plants (Xiao 2024).

1.2 Landscape of existing approaches to phasing out coal-fired power plants, in the Philippines, including Just Transition Partnerships

1.2.1 Accelerating Coal Transition Investment Plan

The USD 2.2 billion Climate Investment Funds (CIFs) Accelerating Coal Transition (ACT) Programme supports coal-dependent middle-income countries to accelerate energy transitions using just transition approaches. In June 2024, the CIFs allocated USD 500 million to the Philippines' Accelerating Coal Transition Investment Plan (CIFs 2024) developed together with the Asian Development Bank (ADB), the International Finance Corporation (IFC) and the World Bank. The plan includes a proposal for the early retirement of the Mindanao CFPP. The plant is a pulverized sub critical CFPP in Villanueva, Misamis Oriental, which started operation in 2006. It consists of two units with a total capacity of 232 MW. Construction of the plant followed a build-operate-transfer (BOT) contract in which a private entity finances, builds and operates an infrastructure project for a specific period before ownership and control are transferred to a public entity. Usually, the length of operating periods is chosen in a way to allow the investors to recuperate their investment. In the case of the Mindanao plant, a consortium of the German STEAG Power GmbH and Philippines' companies AboitizPower Corp and La Fiipina Uy Gongco Corp had signed a BOT contract with the Philippines Department of Energy which granted them a concession for the operation of the plant until 15 November 2031 (Global Energy Monitor). On this date plant ownership is scheduled to be transferred to the Philippines' *Power Sector Assets and Liabilities Management Corporation (PSALM)*. Between 2022 and 2024, STEAG sold all its shares to AboitizPower Corp, which now owns 85% of the project with the remaining 15% being controlled by La Fiipina Uy Gongco Corp (Global Energy Monitor).

Upon its transfer to PSALM, the Mindanao CFPP will have a remaining lifetime of about 15-20 years (assuming an overall plant lifetime of 40-45 years). Under the framework of the CIF ACT Investment Plan, the ADB is currently exploring options with PSALM for an early retirement of the plant, including an option to buy out the BOT concession (CIFs 2024). The latter would allow a retirement before 2031, with 2026 or 2028 apparently being discussed as possible retirement dates. A more recent media report however suggests that the Philippines Department of Energy is currently reconsidering feasibility of a retirement before 2031, as a longer operation of the Mindanao CFPP might be required to offset the loss of power supply during the rehabilitation of the 1,000MW Agus Pulangi hydropower plant. Its rehabilitation is scheduled to start in 2026 and projected to likely lasting several years (Argus Media 2025).

1.2.2 Early retirement of SLTEC power plant

The Mindanao CFPP would not be the first CFPP being retired early in the Philippines. In 2022, as part of a private-sector asset ownership restructuring, the new owners of the *South Luzon Thermal Energy Corporation (SLETC) CFPP* agreed to reduce the plant's operating lifetime by 25 years[4] by bringing forward its retirement date to 2040 (ACEN 2022a). The plant is a 270 MW circulating fluidized bed CFPP, which began operation in 2015 (The Philippines Department of Energy 2025d). It was constructed by the South Luzon Thermal Energy Corporation (SLTEC) – a joint venture of Philippine PHINMA Energy Corporation (80%) and Axia Power Holding (20%) a subsidiary of the Japanese business conglomerate Marubeni Corporation (Marubeni Corporation 2016). In 2019, the ACEN Corporation, a subsidiary of the Philippine industry conglomerate Ayala Corporation acquired PHINMA Energy and with it PHINMAs shares in SLETC and its CFPP plant (Rivera 2019). In 2021, ACEN acquired the stakes of the Axia Power Holding making it the single owner of SLTEC and its CFPP plant (ACEN 2019). Also in 2021, ACEN corporation had made a corporate pledge to achieve net zero GHG emissions by 2050 (ACEN 2022b). This involves a transition of the company's generation portfolio to 100% renewable energy by 2025 (ACEN 2022b). ACEN currently owns around 7,000 MW of capacities in renewable energy in the Philippines, Australia, Vietnam, India, Indonesia, Laos and the United States (ACEN 2025).

After the acquisition of PHINMA Energy, ACEN signed a Power Purchasing Agreement (PPA) with SLTEC in 2019. This PPA requires ACEN to offtake all power produced by the SLTEC plant until 2040 (Bhat et al. 2024). ACEN subsequently signed a Power Supply Agreement with Meralco, the largest private sector electric distribution utility company in the Philippines, which requires Meralco to offtake the power from ACEN until 2029 (TransitionZero).

Due to its '100% renewable energy by 2025' pledge, ACEN looked for ways to sell its stakes in SLTEC soon after the acquisition of PHINMA. For this, ACEN created the ETM Philippines Holdings, Inc, a special purpose vehicle, which was capitalized with USD 247 in debt from two local banks – Rizal Commercial Banking Corporation (RCBC) and the Bank of the Philippines Islands (BPI) as well as USD 67 million in equity provided by two institutional investors – Insular Life Insurance (USD 9 million), the Philippines Government Service Insurances System (GSIS – USD 40 million) (Bhat et al. 2024). ETM Philippines Holdings then bought ACEN's shares in SLTEC through several transactions between July and November 2022, becoming the single owner of SLTEC and its CFPP (Bhat et al. 2024). ACEN stated that they will use the proceeds of the deal to fund its pipeline of renewable energy projects. ACEN will continue to manage the facility and provide operation and maintenance services on a contractual basis (Bhat et al. 2024). It will also retain the PPA with SLTEC and the PSA with Meralco. This provides certainty to investors about the expected revenues for the plant. Apparently, the terms of the PPA and PSA will enable ETM Philippines Holding to repay the debt, and equity investors to recoup their investment by 2040, allowing ACEN to bring forward the retirement date of the SLTEC plant as part of the deal.

In 2024, ACEN signed a memorandum of understanding with investment platform GenZero, and asset manager Keppel Ltd. – both subsidiaries of the Temasek Holding owned by the Government

[4] Assuming a technical lifetime of 50 years.

of Singapore – to explore whether transition credits could be used to bring the closure of the SLTEC plant forward by another 10 years to 2030 (Keppel 2024). This MOU was later joined by the Mitsubishi Corporation and its subsidiary Diamond Generating Asia in May 2025 (GenZero 2025). The Government of Singapore's interest in this cooperation is the creation of carbon credits for a potential collaboration with the Philippines under Article 6 of the Paris Agreement. It publicly announced its intention to buy transition credits under Article 6 at COP28, given that these meet the Government's quality standards for Article 6 credits (Yep 2024). The Mitsubishi Corporation interest is the generation of carbon credits to potentially offset the emissions of its own CFPPs under the Japanese Emission Trading Scheme (GenZero 2025).

Even before signing the MOU in 2024, ACEN had started in 2023 to engage with the Rockefeller Foundation's Coal to Clean Credit Initiative (CCCI) (The Rockefeller Foundation 2023) and the Monetary Authority of Singapore's Transition Credits Coalition (TRACTION) which were developing a methodology to quantify avoided emissions from accelerated coal phase out (Monetary Authority of Singapore 2023). This methodology was launched as VM0052 by the Verra Verified Carbon Standard (VCS) in May 2025. Work is currently underway to develop a project under VM0052 for bringing forward the closure day of the SLTEC plant from 2040 to 2030. At the time of writing this study, project design documents were not yet available in the VCS project database.

The SLTEC plant is situated in Barangay San Rafael in the city of Calaca in the Batangas region. Due to its location directly at the coast of the Balayan bay it has Ocean access and coal supply is carried out by ship from the Semirara coal mine. Two further active CFPPs operate in Calaca, both owned by Semirara Mining & Power Corporation (see section 1.1.4). In December 2024, Semirara announced that they intend to resume plans to construct a third CFPP in Calaca, with a capacity of 700 MW, almost three times the capacity of the SLTEC plant. Construction is legally possible, as the coal moratorium allows to proceed with construction of CFPPs which have been already in planning stage before its entry into force.

2 Key features of VM0052

VM0052 is the worldwide first methodology to quantify the emission impact from retiring a CFPP. It was developed by the Coal to Clean Credit Initiative, led by the Rockefeller Foundation, supported by South Pole and in collaboration with Verra. It was adopted by Verra on 6 May 2025. It must be applied in combination with modules VMD0060 *"Combined Baseline and Additionality Assessment for Accelerated Retirement of Coal-fired Power Plants"* and VMD0061 *"Just Transition Requirements for Accelerated Retirement of Coal-fired Power Plants"*. In addition, it uses tools and methodologies developed under the VCS and CDM for emission factors and determining project and leakage emissions. In the following we briefly introduce key features and applicability conditions of the methodology which are important for the assessment of its integrity in the following chapters.

2.1 Eligible CFPP owners

The methodology distinguishes between two types of CFPP owners:

Regulated Utility: An integrated utility company that is the system operator, owns the power system transmission and distribution (including all associated infrastructure), and may generate or purchase wholesale electricity from independent power producers to sell to customers. A regulated utility is overseen by a public regulator with rate-making authority, mandated to provide consumers with access to reliable electricity at a reasonable cost.

Independent Power Producer (IPP): A legal entity or instrumentality that owns facilities for the generation of electricity and sells electricity to an electric utility under a power purchase agreement. In the methodology, an IPP is understood to include all members of an IPP consortium, including their parent or holding companies, and when an IPP is, or when an IPP consortium has among its members, a state-owned company such as in a Public Private Partnership, the host country.

2.2 Possible entities to lead a CFPP retirement

The methodology distinguishes between three scenarios in which different entities lead the retirement of the CFPP.

1. CFPP owned by a regulated utility, which leads the retirement
2. CFPP owned by an IPP with a long-term PPA in place

    a) Retirement lead by the IPP, which terminates the PPA and is responsible for the cost associated with early termination, retiring the CFPP, and acquiring alternative sources of generation

    b) Retirement lead by an off-taker, defined by the methodology as a utility or electricity system operator or a distribution company or power trader, which terminates the PPA with the IPP ahead of the contracted end-date and is responsible for the costs associated with early termination, retiring the CFPP, and acquiring alternative sources of generation.

Depending on the entity leading the retirement the methodology different perspectives must be considered to determine additionality and the baseline retirement date of the CFPP.

2.3 Applicability conditions

The methodology is applicable to project activities that reduce GHG emissions through the accelerated retirement of grid-connected CFPPs paired with renewable electricity. It further contains several applicability conditions which relate to the CFPP retirement, paired renewable energy and just transition (see Table 6). In the following we will briefly highlight key conditions which are relevant for the environmental integrity assessment in the following chapters of the report.

2.3.1 Long-term PPA

To be eligible under the methodology, CFPPs must have a long-term PPA in place which is fully executed before 31 December 2023. The methodology defines long-term as at least 20 years.

2.3.2 Positive annual net income

CFPPs must have a positive net income at project validation and at the accelerated retirement date. This requirement can be considered as a safeguard to not allow crediting for a retirement of CFPPs whose continued operation would result in negative income in the baseline scenario.

2.3.3 Renewable energy pairing thresholds and pathways

The methodology requires that project proponents set up a plan for pairing the retired CFPP fully or partially with new renewable electricity generation that exports electricity to the grid. At the project start date the plan must cover at least 10% of the retired CFPP generation capacity on an annual basis. At the end of the initial crediting period, it must cover at least 40% of the retired CFPP generation capacity.

In addition – not part of the applicability conditions but the definition section – the methodology defines five eligible pairing pathways:

Contractual pairing: A new or revised coal-fired power plant (CFPP) power purchase agreement (PPA) covers new renewable electricity generation capacity.

Financial pairing: The conditions for refinancing a CFPP for retirement require new renewable electricity generation capacity.

On-site pairing: New renewable electricity generation capacity is developed at the CFPP site and uses existing grid connection or balance of plant components.

Regulatory pairing: A regulator approves new renewable electricity generation capacity as an explicit replacement for retired CFPP generation capacity.

Counterfactual plans pairing: New renewable electricity generation comes online earlier or at a greater capacity than projected in the current approved regulatory resource plan of the system operators.

The pairing thresholds and pathways are important for determining the robustness of the leakage provisions of the methodology as well as the additionality demonstration.

Table 6 Applicability conditions of VM0052

CFPP retirement	Paired renewable energy	Just transition

• CFPP construction began prior to 31 December 2021.
• The CFPP is connected to the grid.
• Where in a regulated electricity market, the CFPP is owned by either a regulated utility or an independent power producer (IPP).
• The CFPP has a single long-term (at least 20 years) power purchase agreement (PPA) fully executed prior to 31 December 2023:
  ○ in a regulated electricity market, with a system operator or a regulated utility off-taker.
  ○ in a deregulated electricity market, with an eligible counterparty with obligations as a load-serving entity, such as a distribution company, power trader, government agency, or power retailer.
• At validation and at the accelerated retirement date, the CFPP has positive annual net income after tax over the three most recent years and positive fair value, determined using a methodology that meets International Financial Reporting Standards for accounting (e.g., IFRS 13 Fair Value Measurement).
• At validation, where the CFPP is owned by a state-owned utility company, both the utility and the host country have a publicly available commitment to not build new CFPPs and to not increase existing CFPP capacity in their jurisdiction.
• At validation, where the CFPP is owned by an IPP, the IPP has a publicly available commitment to not build new CFPPs, and to not increase existing CFPP capacity under their control.
• The system operator, utility, distribution company, or other government entity (as applicable) has issued a letter that confirms the accelerated retirement will not have a material negative effect on consumer prices, access to electricity, grid stability, and energy supply security, based on a reliability assessment and rate impact analysis.
• At validation, the host country's most recent Nationally Determined Contribution (NDC) includes one or more of the following commitments:
  ○ Power sector-wide decarbonization targets, either as absolute targets or intensity-based, or
  ○ Increased share of renewable energy in total electricity mix, either as an absolute increase in renewable energy capacity or percentage of renewable energy in the grid.
• At validation, the host country must have either:
  ○ Submitted a Long-Term Low Greenhouse Gas Emission Development Strategy (LT-LEDS)[5] to the UNFCCC, or
  ○ Published a power sector, energy transition, or economy wide decarbonization strategy or policy that supports the transition towards a less carbon intensive economy.
• The CFPP cannot be deactivated or repurposed to continue to combust fossil fuels, including co-firing biomass with coal or gas.
• The CFPP cannot be a mine-mouth power plant.
• The CFPP cannot be a captive power plant.
	• The project proponent has a plan, available at validation, for pairing the retired CFPP generation capacity fully or partially with new renewable electricity generation that:
	  a) exports electricity to the grid.
	  b) covers at least 10% of the retired CFPP generation capacity on an annual basis at the project start date.
	  c) covers at least 40% of the retired CFPP generation capacity by the end of the initial crediting period.
	• The renewable electricity pairing plan includes a list of renewable electricity plants that are paired to accelerated CFPP retirement including:
	  a) name, type, capacity, and location of each renewable electricity power plant, and
	  b) planned commercial operations start date.
	• The paired renewable electricity is generated by one or a combination of the following sources:
	  a) Solar power plant with or without battery energy storage systems (BESS)
	  b) On-shore and/or offshore wind power plant with or without BESS
	  c) Hydropower plant (run-of-river or individual plant net output capacity limited to 15 MW)
	  d) Geothermal power plant
	  e) Tidal/wave power plant
	  f) Landfill gas power plant
	  g) Biogas power plant, including biogas from wastewater treatment
	  h) Waste-to-energy (WtE) power plant, including waste incineration
	  i) Biomass-fired power plant that complies with requirements and procedures established for biomass in the most recent version of CDM ACM0006
		• A just transition plan developed in accordance with VMD0061 is available at the time of validation of the project description.
		• The just transition plan is fully funded through sources other than the revenues generated from the sale of Verified Carbon Units (VCUs).

Source: VM0052, version 1.0, pages 8-11.

2.3.4 Coal moratorium

For the eligibility of CFPPs owned by a regulated utility, the methodology requires that both the utility and the host country have a publicly available commitment to not build new CFPPs or increasing the capacity of existing ones in their jurisdiction. For CFPPs owned by IPPs, only the IPPs retiring the CFPP must have made a respective commitment, not the host country. Other IPPs are therefore not bound by a moratorium. These provisions are relevant for considering the robustness of the leakage provisions of the methodology.

2.3.5 Regulatory approval

The methodology requires that the entity leading the retirement has a written confirmation by regulatory authorities that the retirement will not have a material negative effect on consumer prices, access to electricity, grid stability, and energy supply security. These provisions are relevant for the assessment of the robustness of the additionality and leakage provisions.

2.3.6 Just transition plan fully funded by other sources than the sale of carbon credits

While VMD0061 requires that at least 2% of the revenues from carbon credits must be used for activities in the just transition plan, the methodology's applicability conditions further require that it is fully funded through other sources than the sale of carbon credits. These provisions are relevant for the assessment of the just transition requirements of the methodology.

3 Assessment of VM0052 against key environmental integrity criteria

In the following sections we will assess VM0052 against the key environmental integrity criteria additionality, robust quantification of emission reductions and avoiding double counting. As these criteria are well established in the discussion on the quality of carbon credits, we do not outline the rationale using these criteria. We recommend consulting the ICVCM Core Carbon Principles and its Assessment Framework as well as the Assessment Methodology of the Carbon Credit Quality Initiative (CCQI) for this purpose. Instead, we directly discuss the main issues that in our view impact quality for the specific project type of accelerated retirement of CFPPs.

3.1 Additionality

The methodology uses a project-based approach to demonstrate additionality. Projects must demonstrate that they meet the conditions outlined in VCS Module VMD0060 "*Combined Baseline and Additionality Assessment for Accelerated Retirement of Coal-Fired Power Plants*". The approach requires project proponents to demonstrate additionality, using the following aspects: regulatory surplus, investment comparison analysis and common practice. The VCS Standard further puts a restriction on the maximum time that can lapse between the start date of the mitigation activity and validation by a validation and verification body (VBB). With these elements, the methodology includes provisions for all criteria included in the quality assessment frameworks of the ICVCM, the CCQI and uses similar elements as the PACM additionality standard.

3.1.1 Regulatory surplus

All project proponents must demonstrate that the proposed retirement date for the CFPP is earlier than any retirement dates imposed at the jurisdictional or asset level by existing regulations, plans, strategies, or commitments at the national or subnational level (see section 6.1 of VMD0060). The provisions further stipulate that proponents must consider any of the following:

A coal phaseout date specified in the country's most recent version of its NDC

A coal phaseout date stipulated in the grid's most recent integrated resource or electricity sector plan

A coal phaseout date set in national or subnational legislation, law or executive mandate

A coal phase out date stipulated in a jurisdictional level phaseout plan either applying to all CFPPs in the jurisdiction or to the specific CFPP.

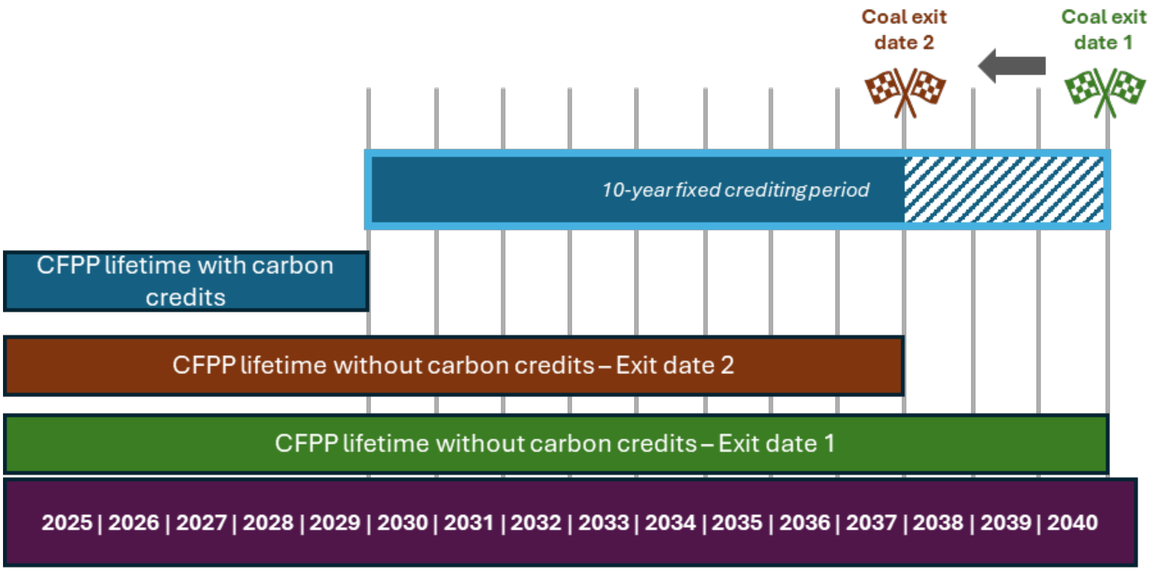
These provisions appear to be robust for ensuring that project proponents must bring forward CFPP retirement dates before those prescribed by legislation or regulatory mandates.

VM0052 further stipulates that the regulatory CFPP phaseout date must be reassessed and updated at each crediting period renewal (see Appendix 1, numeral 3). Where the reassessment returns an earlier retirement date, the duration of the renewed crediting period must be updated and will terminate at the new baseline retirement date. These provisions result in some, likely non-material, non-additionality risks as illustrated by the following example.

Under the current VCS Standard, version 4.7, proponents can choose either between a fixed crediting period of ten years or a seven-year crediting period, which is twice renewable for a total of 21 years (see section 3.9.1 of the VCS Standard v.4.7).

Consider now the hypothetical case of a country which has set a nationwide coal phaseout date of 2040 (coal exit date 1). In this country, project proponents propose to bring forward the retirement date of an individual CFPP from 2040 to 2030 with the support of carbon credits. They choose a ten-year fixed crediting period from 2030 to 2040 with a project start date in 2030. If the county in 2034 however decides to bring forward the nationwide coal phaseout date by three years to 2037 (coal exit date 2), the CFPP retirement date under the baseline would change from 2040 to 2037. This would mean, that the project really brought forward the retirement date only by seven years instead of the ten for which it registered with the VCS. However, due to the current VCS rules for baseline updating, this change in policy would not affect the project, which would continue to receive credits for a full period of ten years, including the years 2038-2040.

Figure 3 Impact of policy change in coal phaseout on regulatory surplus



Source: Own representation.

The effect of this would be that credits which the project receives in the years 2038 to 2040 would not be additional. Due to the potentially large volume of annual credits that will be issued to this project type, the result could be that significant volumes of non-additional credits will be made available to the market due to the shortcoming of the provisions.

Version 5 of the VCS Standard, which is currently under development, however, proposes changes to the length of the crediting period and requirements for updating of the baseline. The draft document proposes that the duration of the crediting period for all non-AFOLU projects (except geological carbon storage) will be limited to a maximum length of five years and can be renewed a maximum of 4 times. The option for a 10-year fixed crediting period would not be available anymore under version 5 of the VCS Standard. Further, regulatory surplus checks will be formally required at each crediting period renewal i.e. at least every five years.

Under the proposed new rules of version 5.0 of the VCS Standard, the case described above would not occur. If the country in 2034 decides to bring forward the coal-exit date from 2040 to 2037, this decision would take effect before the required reassessment of regulatory surplus after year 5 of the project (i.e. in 2035). The reassessment would therefore determine that regulatory surplus is not met for the years 2038-2040 and hence no second crediting period of full five years would be granted. Hypothetically, an issue could occur if the country would decide after the start of the second crediting period (i.e. 2036) to bring the exit date forward to 2037. Considering the complexity of a nation-wide coal exit, deciding such a change only one year before it takes effect however appears to be highly unlikely.

We still recommend considering an addition to the methodology, which would stipulate that eligibility of crediting will cease at the date at which a nationwide or jurisdictional coal exit becomes effective. This would align it more closely with best practice examples in carbon crediting. Under the Climate Action Reserve's U.S. Landfill Protocol version 6.0, for example, projects will become ineligible for crediting once landfills become subject to regulation mandating the installation of a landfill gas control system.

> *If an eligible project begins operation at a landfill that later becomes subject to a regulation, ordinance, or permitting condition that calls for the installation of a landfill gas control system, GHG reductions may be reported to the Reserve up until the date that the installation of a landfill gas control system is legally required to be operational.*
>
> Climate Action Reserve, U.S. Landfill Protocol, version 6.0, Section 3.4.3 "The Legal Requirement Test"

Similarly, the ACR carbon crediting programme defines that a project will no longer be eligible for crediting if a regulatory requirement comes into force during the crediting period effectively mandating the project activity. Under ACR rules, projects will become ineligible from the date the regulatory requirement takes effect.[5]

While the rules for assessing regulatory surplus are defined in the VCS Standard and not at methodology level, version 5.0 of the VCS Standard explicitly allows methodology developers to incorporate additional requirements for reassessing the baseline where they are justified to be equally or more robust than the default requirements.

An argument often brought forward to justify no reassessment of regulatory surplus during the crediting period – even if new legal mandates are introduced that require the project's mitigation activity – is that this approach provides project proponents with investment certainty.[6] However, policy uncertainty around coal-exit dates would be the same under the baseline and project scenario. Hence, the possibility of credit period termination would not result in any unduly investment uncertainty for project owners when compared with the baseline scenario. Another argument brought forward against ceasing eligibility of crediting is that this could create perverse incentives for governments not to adopt policies that accelerate a nationwide coal-phase out, as then individual CFPPs might lose the revenues from carbon credits. Here again the situation would however not be different from the baseline, where CFPP owners would lose revenues from the continued operation of CFPPs if a nationwide coal-exit date is introduced or brought forward.

3.1.2 Investment comparison analysis

VMD0060 requires project proponents to apply an investment analysis to demonstrate that revenues from carbon credits are required to make the project activity financially attractive. It uses the concept of "net present value of required revenues" for this purpose.

The basic idea behind this is to look at the amount of revenues that must be collected to cover the costs in two different scenarios:

- Scenario 1: Continued operation of the CFPP

[5] See section 4.A.1 Regulatory Surplus Test, The ACR Standard, Version 8.0, July 2023. Note that the Standard includes an option for methodologies to define exceptions from this rule.

[6] If no reassessment takes place, they have more certainty about the carbon credit revenues that can be expected from the project activity

- Scenario 2: Accelerated retirement of the CFPP and replacement of its electricity with paired renewable electricity and grid electricity

The future revenues are then discounted to their present value. The year in which the revenues required under scenario 2 are equal to or lower than in scenario 1 determine the date in which it makes sense from a financial point of view to pursue scenario 2. Hence, the methodology determines that any retirements before this financially attractive retirement date are additional as they would not be financially attractive without additional incentives.

The methodology includes detailed instructions for calculating the NPV of required revenues under both scenarios in its section on determining the baseline retirement date. For this reason, the robustness of these requirements and its consequences on the likelihood of additionality of activities are discussed in the respective section 2.2.2.1 below.

3.1.3 Common practice

Project proponents must perform an analysis to what extent the accelerated retirement of CFPPs has already diffused in the relevant sector and geographic region. The geographic region must be determined using section 5.1 of VCS Tool *VT0009 – Combined Baseline and additionality assessment*. Under this tool, the default applicable geographic region is the entire host country. A limitation to a specific geographic region is only possible if project proponents can demonstrate that different investment or implementation conditions apply.

For the common practice analysis, project proponents must identify the number of CFPPs that have been retired early in the relevant geographic region over the last 10 years prior to the commitment date. The relevant geographic region within the host country must be established by considering limiting factors such as differences in regional policies, regulations, or market mechanisms, variation in electricity market conditions, power sector structure, ownership models or contractual arrangements, differences in grid infrastructure, transmission access, or renewable integration capacity as well as differences in coal supply logistics or fuel costs. This step should ensure that the common practice analysis would exclude areas where e.g., the grid may be managed in different ways. Within this geographic region, project proponents must assess how many CFPPs have been retired over the past 10 years prior to the commitment date and how many of those have "essential distinctions" from the project activity.

VT0009 defines essential distinctions as an open list of aspects which can include the access to resources, prices, market, economic or socioeconomic conditions, infrastructure development, labour force and expertise as well as climatic, topographic or geological differences. If more than three out of the identified CFPPs do not have essential distinctions from the project activity and their share of all retired CFPPs is greater than 20% the project activity is considered a common practice, and hence not additional.

The robustness of these provisions can be analysed by applying them to a hypothetical case of a CFPP in the Luzon grid in the Philippines. Here, the relevant geographical area of the host country would be the area served by the Luzon grid. The grid has a total of 15 CFPPs. Consider a hypothetical case in which 5 CFPPs have been retired in the past ten years. If project proponents would be able to demonstrate that two out of these plants have "essential distinctions" from the project activity, then CFPP retirement would not be considered a common practice, and the project would be additional. Considering that about a third of the CFPPs are already retired in this hypothetical scenario, this assumption might not be very robust. The key issue is that "essential distinctions" is only loosely defined. In practice every CFPP faces different economic circumstances which will allow project proponents to make respective claims under the current rules of the tool. Abuse of the term "essential distinctions" to circumvent common practice thresholds has been a problem under the CDM. This is why the PACM Methodological Expert Panel recommended to not allow making claims of essential distinction in the PACM common practice tool. Instead, the tool broadly defines the categories of plants. We recommend the VCS to require project proponents to apply the PACM common practice tool to demonstrate additionality under VM0052 once it becomes available.

Further, the backward-looking nature of the common practice analysis might not be well suited for this project type. Due to the relatively young CFPP fleet age in countries most likely hosting projects applying VM0052, the number of CFPPs that have been retired early in the last 10 years will likely be zero in most of these countries. A more relevant question to ask would be how many of the CFPPs currently operating in the country have adopted an early retirement date in the past ten years. Although bringing retirement forward, retirement dates for most CFPPs will likely be in the future and not in the past and an assessment looking at the past ten years would therefore not capture such commitments. To illustrate this again with a hypothetical case, imagine a project proponent proposing a new project under VM0052 in 2025 in the Luzon grid. In this hypothetical scenario, 8 out of the 15 CFPPs in the Luzon grid have made public commitments to bring forward their retirements from the period between 2040-2050 (assuming, that each CFPP has an individual exit date during that period) by ten years to the period 2030-2040. The project proponent, applying the common practice assessment by looking at the number of CFPPs retired between 2015 and 2025 will conclude that zero CFPPs have been retired in that period. Hence, the project will be considered additional. However, the fact that 8 CFPPs have announced to bring forward their retirement date strongly suggests that this might have become common practice in the Luzon grid. For improving the common practice analysis, we therefore suggest making the following amendments:

Original provision:

~~N_{all} is the total number of CFPPs that have been retired over the last 10 years prior to the commitment date (excluding activities under the VCS Program and other GHG programs per VT0009).~~

Suggested amended provision:

N_{all} is the total number of CFPPs for which operators have made commitments to bring forward the retirement date in the last 10 years prior to the commitment date (excluding activities under the VCS Program and other GHG programs per VT0009)

Original provision:

~~N_{diff} is the number of CFPPs that have been retired over the last 10 years prior to the commitment date with essential distinctions from the project activity.~~

Suggested amended provision:

N_{diff} is the total number of CFPPs with essential distinctions for which operators have made commitments to bring forward the retirement date in the last 10 years prior to the commitment date

3.1.4 Maximum period between the start date of the mitigation activity and validation by a VVB

Under quality assessment frameworks, prior consideration of carbon credits is an important aspect for restricting eligibility to mitigation activities that have a high likelihood of additionality. To meet the requirements of the IC-VCM core carbon principles, carbon crediting programs for example must either require project proponents to provide evidence that they have considered the revenues from carbon credits when deciding to proceed with the mitigation activity or restrict the amount of time which can lapse between the start date of the mitigation activity and validation/submission for registration.

The VCS implements the latter approach by requiring non-AFOLU projects to complete validation within two years of the project start date. A grace period is granted to projects applying a new VCS methodology. They can complete validation within four years of the project start date during the first two years after the new methodology has been adopted.

While these restrictions may work reasonably well for some project types that do not have income other than carbon credit revenues, they may not be well suited for the project type of accelerating the retirement of CFPPs. The reason for this is the likely timeline for most projects applying for registration under this methodology. Bringing forward the retirement date of a CFPP in most cases will likely involve bringing forward a date somewhat far in the future to another date which is closer to the present but still in the future (e.g. the retirement date for SLTEC plant in the Luzon grid was brought forward from 2050 to 2040). Further, it will involve building new renewable energy capacities that need to be available once the CFPP will go off the grid. This means that project proponents will need some lead time between the decision to retire a CFPP and the actual retirement to turn a pipeline of renewable energy projects into actual capacities to fill capacity gaps associated with the CFPP retirement. The project start date is however defined by the VCS Standard as the date "on which the project began generating GHG emissions".[7] Appendix 1 to VM0052 further specifies that the start date corresponds to the date on which the CFPP completely ceases electricity production, i.e. the accelerated retirement date of the CFPP. This means that project start dates for projects under VM0052 will presumably typically be somewhat far in the future from the date when project proponents make the decision to proceed with the project (i.e. deciding to bring forward the retirement of the CFPP). The restriction regarding the maximum time lapsable between start date and validation therefore will not be a good filter for identifying non-additional projects. Whether this undermines additionality of projects can be best discussed using the following two questions:

Could project proponents register an already retired CFPP under VM0052?

In theory, the VCS start date provisions mean that project proponents could receive carbon credits for an already retired CFPP, if they manage to complete project validation, including demonstration of additionality, of the project within two years after the retirement date. Given that early retirement of a CFPP is a complex process, involving close coordination with utilities and regulatory authorities, such a case seems highly unlikely if not impossible under the current VM0052 rules. Further, the methodology includes an eligibility requirement that CFPPs at validation and the accelerated retirement date must have a positive annual text income after tax over the three most recent years and a positive fair value. This condition effectively excludes the registration of any retired CFPPs.

Could project proponents register a CFPP under VM0052 for which (undisclosed) retirement plans already exist?

Project proponents may pursue early retirement of a CFPP for reasons other than revenues from carbon credits. A reason why carbon crediting programmes require demonstration of prior consideration is to safeguard against situations where project proponents may not disclose the real reasons why they are implementing a project activity and simply claim it is for the carbon credits. In the case of an early retirement of a CFPP it seems not plausible that CFPP owners can withhold

[7] See section 3.8 of VCS Standard v.4.7, page 26.

disclosure of their retirement intention for the reasons outlined above. They will need to coordinate such action well in advance with regulatory authorities and the utilities that offtake the power produced by the CFPP.

In conclusion, the VCS provisions for prior consideration likely are not effective for the project type. This is however highly unlikely to undermine the additionality of proposed projects, considering their specific characteristics as outlined above.

3.2 Quantification

3.2.1 Selection of emission sources for calculation of emission reductions

The methodology VM0052 describes in section 5 the GHG emission sources that must be included in the boundary of projects implementing VM0052 as well as sources that are optional to include, specifying conditions under which they must or may be included or excluded.

The scope of the project boundary is comprehensive and includes all relevant emission sources for the baseline and project activity. The methodology does not require the inclusion of upstream emissions from fossil fuel production, processing and transportation. This is conservative in the baseline, as exclusion will lead to underestimation of emission reductions. It might however lead to uncertainty, underestimation or overestimation in the project scenario.

The methodology relies on CDM methodologies to quantify emissions from renewable energy technologies under the project scenario and for leakage emissions. The robustness of these approaches is therefore determined by the robustness of the CDM methodologies. We will discuss main issues with some of the methodologies in the sections 3.2.3 and 3.2.4 below. Table 7 provides a summary of how VM0052 includes the relevant sources in project boundaries and the relevance of the approach for the assessment.

Table 7 Emission sources included in project boundary under VM0052

Emission Sources	Included? How?	Relevant for this assessment?
CFPP electricity generation (Baseline)	CO_2 included as a major source	Major emission source in the baseline scenario.
	For CH_4 and N_2O it is deemed to be conservative to exclude emissions.	Excluding these sources in the baseline is appropriate and conservative.
Electricity production by renewable sources (Project)	CO_2 must be considered for landfill gas, geothermal, hydro, biomass-thermal wastewater, and waste-to-energy plants. Must not be considered for solar power, onshore and offshore wind, tidal/wave power plants, biogas power plants, including biogas from wastewater treatment	The distinction between different technology types is appropriate.
	CH_4 must be considered depending on the renewable energy electricity technology, using respective CDM methodologies: ACM0001 (landfill gas), ACM0002 (geothermal and hydro) ACM0006 (biomass-thermal), ACM0014	The listed technologies involve CH_4 emissions it is therefore reasonable to include them. Solar, wind and tidal/wave do not involve CH_4 emissions. Excluding them is therefore conservative.

	(wastewater), ACM0022 (waste-to-energy)	
	N_2O is excluded based on de minimis	
Electricity sourced from the grid (Leakage)	CO_2 included as a major source	Major leakage source in the project scenario.
	CH_4 included depending on the renewable energy electricity technology using respective CDM methodologies: ACM0001 (landfill gas), ACM0002 (geothermal and hydro) ACM0006 (biomass-thermal), ACM0014 (wastewater), ACM0022 (waste-to-energy)	Some technologies such as landfill gas and hydropower can involve significant CH_4 emissions.
	N_2O excluded based on de minimis	
Paired renewable energy sources (Leakage)	CO_2 included depending on the renewable energy electricity technology using respective CDM methodologies: ACM0001 (landfill gas), ACM0002 (geothermal and hydro) ACM0006 (biomass-thermal), ACM0014 (wastewater), ACM0022 (waste-to-energy)	The selection of renewable energy technologies for which to consider leakage emissions appears to be appropriate.
	CH_4 included depending on the renewable energy electricity technology using respective CDM methodologies: ACM0001 (landfill gas), ACM0002 (geothermal and hydro) ACM0006 (biomass-thermal), ACM0014 (wastewater), ACM0022 (waste-to-energy)	Including ACM0002 is important due to potential methane emissions from hydro power reservoirs.
	N_2O excluded based on de minimis	

Source: Section 5, VM0052, version 1.0

Overall, the emission boundary includes all relevant emission sources and the approach to excluding certain sources on a de minimis basis appears to be plausible.

3.2.2 Determination of baseline emissions

There are two elements which have the most impact on the potential volume of emission reductions from projects registering with VMD0052: The baseline retirement date, which determines the length of the potential crediting period(s) and the approach to estimating baseline emissions, including assumptions about net electricity generated in the baseline, which are based on assumptions about capacity utilization and emission factors.

3.2.2.1 Determination of baseline retirement date

Project proponents must use the provisions in VMD0060 *“Combined baseline and additionality assessment for accelerated retirement of coal-fired power plants”* to determine the baseline retirement date. These require project proponents to identify the earliest date of the following five scenarios:

1. Regulatory CFPP phaseout date: retirement date imposed at the jurisdictional or asset level by existing regulations, plans, strategies, or commitments at the national or subnational level. This includes coal phase out dates specified in the most recent version of an NDC, in national or subnational legislation, law, or executive mandate; jurisdictional level phaseout plans or a phase out date stipulated in the grid's most recent integrated resource or electricity sector plan.
2. End of technical lifetime: determined using *CDM TOOL10 Tool to Determine the Remaining Technical Life of Equipment.*
3. End of existing long-term power purchase agreement (PPA): PPAs or their extensions executed after 31 December 2023 are not eligible and the original date of the agreement must be used.
4. Committed coal transition mechanism (CTM): announced retirement date of a CFPP under a CTM, demonstrating financial closure of a transaction or signing of an electricity contract for a defined early retirement.
5. Financially attractive retirement: the earliest date at which retiring a CFPP and replacing the coal-generated electricity with renewable electricity results in a financial gain compared to continued operation.

The five scenarios appear comprehensive and appropriate for determining the baseline retirement date as they cover all plausible causes for the retirement of a CFPP.

The requirement to consider the end of an existing long-term PPA (with "long-term" in the methodology's definition section being defined as PPAs which have a term of at least 20 years) as one of the five possible baseline retirement dates can be conservative for comparatively young CFPPs (10 years or younger). PPAs for these plants may not cover their full technical lifetime (e.g. where a power producer negotiated a 20-year PPA at the start of a CFPP's operation).

Among the five scenarios, the identification of the earliest financially attractive retirement date is the most complex.

For identifying the financially attractive retirement year, the methodology uses the concept of "net present value of required revenues".

The basic idea behind this is to look at the amount of revenues that must be collected for covering the costs of two different scenarios:

- Scenario 1: Continued operation of the CFPP
- Scenario 2: Accelerated retirement of the CFPP and replacement of its electricity with paired renewable electricity and grid electricity

The future revenues are then discounted to their present value. The year in which the revenues required under scenario 2 become equal to or lower than in scenario 1 determines the date in which it makes sense from a financial attractiveness point of view to pursue scenario 2. Hence, the methodology defines this as the financially attractive baseline retirement date.

The required revenues are determined by different cost categories, which the methodology details, including eligible approaches for calculating these costs. In cases, where the CFPP is owned by an IPP, the methodology requires project proponents to consider different cost categories, both from the perspective of the IPP and from the perspective of the off-taker. In these cases, whichever perspective returns the earlier retirement date must be chosen as the financially attractive retirement date for the CFPP.

The methodology requires to calculate required revenues separately for all costs related to the CFPP and to the acquisition of alternative generation sources for electricity.

Costs related to the CFPP from the perspective of the CFPP owner include those for its continued operation (such as variable and fixed operating and maintenance costs, fuel costs as well as capital expenditure and principal payment for asset level debt) as well as its retirement (contract termination costs). Costs related to the CFPP from the perspective of the off-taker include cost for the electricity and other CFPP services provided by the IPP to the off-taker under the PPA and the cost of carbon, where these are passed-on to the off-taker, as well as contract termination costs.

The approach to calculating the costs for the acquisition of alternative energy sources is the same under both perspectives. It is based on unit cost of generation multiplied by the amount of electricity that must be generated and supplied to replace the CFPP's expected generation. The methodology requires that project proponents estimate the unit cost as the lower value of the average cost of generation in the grid and the cost of replacement generation in the project scenario.

The average cost of generation in the grid must be determined as the average of cost on a per unit basis, considering the generation that is supplied by each unit to the grid and the cost for this unit to generate that amount of energy.

The unit cost of replacement energy in the project scenario looks at the costs for a) the construction of paired renewable energy sources and b) the cost for energy that must be acquired from other sources from the gird. For the latter it uses the average cost of generation in the grid as described in the previous paragraph. For calculating the cost for the construction of paired renewable energy, project proponents must use the levelized cost of energy approach.

The methodology accounts for uncertainty by requiring project proponents to subtract one year from the baseline retirement year received through the comparison of the NPV of required revenues under the two scenarios. This requirement is based on a Monte Carlo simulation which methodology developers have performed to estimate uncertainty of the baseline retirement date. The assumptions, input parameters and results of the simulation are not available in the methodology document.

Overall, comparing the NPV of required revenues is an appropriate approach to compare the financial attractiveness of the two scenarios and for the identification of the baseline retirement date. The following issues merit a closer look and potential improvements to the methodology.

Typo in the equation comparing the two scenarios

The methodology requires project proponents to perform the comparison between the two scenarios for each year until the year in which equation (1) is true is identified. Equation (1) is denoted as follows:

$$NPVRRCS,CO \leq NPVRRGS,AR + NPVRRCS,AR$$

This would however mean, that the financially attractive retirement date would be the first year when the required revenues for the continued operation scenario are equal to or lower than the accelerated retirement scenario. This seems to be a typo as it should be the other way round.

Constant CFPP generation

The methodology requires that CFPP electricity generated and supplied to the grid must be assumed to be constant over the financial assessment period. Fixing generation at a constant level facilitates standardisation of the NPV analysis across the two scenarios as it avoids that project proponents subjectively chose different values for each of the two scenarios. The assumption of constant CFPP generation is however likely to be unrealistic given that load factors of CFPPs are currently falling in many countries worldwide. E.g. in the US a combination of cheap natural gas and capacity additions of renewable energies have significantly lowered capacity factors of the existing coal fleet. There is a general trend in many countries that CFPPs are no longer operated as base load power plants but rather provide residual load due to higher shares of intermittent electricity generation from renewables. In this case, the overall capacity factor is much lower than it has been before. Thus, an increasing share of renewables over time may imply that coal power plants will be operated differently in the future than they are today. In particular, they could run fewer hours per year. Lower generation also impacts variable operation and maintenance cost, which are higher if the plant cycles between different loads.

There could be other means to avoid subjective selection of values. For example, the methodology could include a requirement that project proponents always must apply the same capacity factor across the two scenarios in any given year of the assessment period, while allowing for decreasing values over time. Alternatively, the methodology could prescribe a single decreasing default trajectory which project proponents must use under both scenarios. The slope of the downward trend could be determined by assessing how capacity factors of CFPPs globally have evolved over their lifetime. Such an approach would enhance conservativeness of the calculations in the sense that it sets the baseline below business-as-usual (i.e. constant CFPP generation) – a principle which will apply to all new projects under the PACM.

Constant replacement generation cost

The replacement electricity cost is assumed to remain constant over the entire assessment period, which could be unrealistic given changing market conditions and changes in renewable energy costs. A more dynamic model that accounts for expected fluctuations in energy prices (particularly for renewables) could better reflect the true cost trajectory. On the other hand, procurement of renewable energy usually involves long-term PPAs that fix the price of electricity over the contract term. This could justify an assumption of constant cost for paired renewable energies. However, the methodology allows for gradual pairing shares, which increase over the crediting period. This suggests that not all paired renewable energy is constructed or paired at the same time. It is plausible that renewable energy constructed or paired at the end of the crediting period will be cheaper than at its start. The methodology should require project proponents to account for this effect.

Further, for replacement energy from the grid, generation cost also may decrease over time in case of decreasing natural gas prices and increasing cost-efficiency in renewable energy generation. Assuming a decreasing trend in replacement cost would therefore enhance the conservativeness of the approach and ensure that the baseline will be below business-as-usual. Overestimating replacement costs could lead to overestimating the costs of the early retirement scenario, resulting in later financially attractive retirements date, which in turn would result in overestimating emission reductions.

Uncertainty around carbon costs

In projecting future carbon costs, the methodology requires project proponents using the most ambitious available scenario for future carbon prices in the jurisdiction of the CFPP, relying on schedules published by regulators or government agencies. Where the assessment period extends beyond the published schedule or range of prices, project proponents must use a linear trendline to project carbon costs. This could lead to underestimation of carbon prices in case governments implement more aggressive climate policies or to overestimation where governments abandon carbon pricing instruments. Linear extrapolation therefore introduces uncertainty about the true long-term costs of continued operation of the CFPP.

Inconsistent approaches to calculate the emission factor of the CFPP (in g CO_2 /kWh$_{el}$)

The methodology uses different approaches in different places for calculating the emission factor of the CFPP. When calculating the emission factor for determining the cost of carbon for the CFPP, project proponents must use “the three-year average annual emission factor”. It is not further specified whether this refers to historic emission factors using the last three years of operation or any other reference periods. For calculating baseline emissions, the baseline emission factor must be calculated using the “historical quantity of electricity generated and supplied” suggesting that more than a 3-year reference period must be considered (see detailed discussion on the baseline emission factor in section 2.2.2.2 below). We recommend that the methodology uses a consistent approach to calculating the emission factor of the CFPP in all sections. Further, the emission factor of the plant increases if it operates at levels close to minimum stable loads. As the methodology assumes that CFPP generation will remain constant, this effect is not considered when calculating carbon cost.

Exemption to reassess the financially attractive retirement date at crediting period renewal

The methodology requires to reassess the baseline retirement date only for the regulatory phase out date and the committed coal transition mechanism scenario. The financially attractive baseline date must not be reassessed at crediting period renewal. Considering that the financially attractive baseline retirement date relies on many assumptions with high uncertainties it would be more robust and conservative to also reassess the financially attractive baseline retirement date at crediting period renewal.

Requirement for entity leading the retirement to acquire replacement energy

When calculating the net present value of required revenues for replacement energy, project proponents must calculate the cost for the electricity that must be generated and supplied to replace the CFPP’s expected generation. This suggests that the methodology assumes that CFPP owners or off-takers are responsible for and will acquire replacement energy commensurate to the electricity that would have been generated by the retired CFPP. This requirement should be more explicitly stated in the methodology, for example in its applicability conditions. The methodology already requires project proponents to set up a pairing plan for renewable energy. It would be useful if a similar requirement would be introduced for the replacement energy sourced from other sources connected to the gird. For example, project proponents could be required to detail the portfolio of replacement energy they plan to establish for the retired CFPP. This plan should include information on any replacement plants (e.g., combined cycle gas turbine or natural gas internal combustion engines) that will be constructed, and the share of energy that will be acquired from the market.

Whether or not CFPP owners or off-takers indeed acquire replacement energy commensurate to the CFPP’s expected electricity generation should also be an item in the monitoring report. If a monitoring report finds that no or less energy was acquired, this should be considered at verification of the monitoring period.

Standardized uncertainty deductions

Overall, there are many parameters with uncertainty in the approach for determining the financially attractive retirement date. Further, the financially attractive baseline retirement date is calculated ex-ante and due to the exception for reassessment at crediting period renewal, valid for up to 21 years (or potentially only 15 years under version 5.0 of the VCS Standard). Possible conditions that could develop in the near future to the detriment of CFPPs including falling costs for PV and batteries, falling natural gas prices, and possibly rising costs, e.g., for the conversion of power plants that currently run on domestic coal will therefore not be adequately reflected if not appropriately considered when establishing the baseline. The methodology's approach to account for this via a standardized uncertainty deduction could be improved by requiring project proponents to perform a sensitivity analysis to show that the conclusion regarding the financially attractive retirement date is robust to reasonable variation in the critical assumptions. Such a sensitivity analysis on a project-by-project basis is for example required under the PACM. Therefore, the methodology should require project proponents to perform an uncertainty assessment for the calculations to vary key parameters within plausible ranges. After performing the sensitivity analysis, they should choose the earliest resulting retirement date based on the variation of the parameters.

3.2.2.2 Approach to the estimation of baseline emissions

Baseline emissions are the GHG emissions from the operation of the CFPP between the accelerated retirement date and the baseline retirement date. Under VM0052, they must be calculated for each year of the crediting period and are the product of assumed net electricity generated by the CFPP and supplied to the grid and the estimated emission factor for the CFPP in the respective year.

Assumed net electricity generated

Net electricity generated and supplied in the baseline must be calculated by multiplying the net installed generation capacity with a historical utilization factor. For the capacity utilization factor, project proponents must use the <u>minimum</u> of the following parameters each divided by the installed capacity multiplied by the hours in the respective period:

- Net electricity delivered to the grid in the **3- year** period preceding **validation.**
- Net electricity delivered to the grid in the **5-year** period preceding **validation**.
- Net electricity delivered to the grid in the **3-year** period preceding **the accelerated retirement date.**
- Net electricity delivered to the grid in the **5-year** period preceding **the accelerated retirement date**.

In addition, project proponents must consider the average capacity utilization factor of at least two reference CFPPs. If this value is smaller than the historical utilization factor of the CFPP to be retired, this value must be used as the capacity utilization factor in the baseline.

The methodology in section 9.2 contains requirements that reference CFPPs must meet the following criteria to be eligible as follows:

They must be unabated CFPPs combusting at least 90% coal on a thermal input basis

They cannot be combined heat and power plants

There cannot be contracted power offtake outside the system operator

They must have equal or greater nameplate capacity than the CFPP being retired

They must have equal or greater long-run marginal cost than the CFPP being retired. If cost data are not available, they can be selected if they meet the following criteria:

Similar or lower efficiency technology than the CFPP being retired

Use of similar or lower grade of coal than the CFPP being retired

If there are no CFPPs that meet these criteria then project proponents must assume that the capacity utilization factor of the reference CFPPs declines linearly to 30% at the end of the technical lifetime of the CFPP.

There are several observations to highlight:

First, using historical data as a proxy for making predictions about the future are always associated with uncertainty. This has been an issue leading to severe overestimation of emission reductions in many REDD+ projects. The approach chosen by VM0052 appears to be however more robust than those used in REDD+ methodologies for several reasons. Unlike in some REDD+ methodologies such as VCS VM0007, project proponents do not have flexibility to choose the length of the historical reference period. Instead, they must use the lowest historical utilization factor from at least at four different reference periods. This approach is conservative as it does not allow project proponents to pick the reference period which would generate the most credits and can be considered as an effective approach to avoid gaming of the methodology.

Second, the requirement that the 3- and 5-year period preceding validation must be considered for calculating the historic utilization factor ensures that project proponents consider up-to-date values that are representative of the current situation of the CFPP and not those that are way back in the past. However, it should be noted that a period three to five years ago is not always representative. Figure 2 in section 1.1.2 shows that the utilization rate of CFPPs in the Luzon grid for example was significantly lower 10 to 20 years ago.

Third, although the approach is more conservative than the approaches chosen by some REDD+ methodologies, uncertainty remains whether the historical values are a good predictor of capacity utilization in the future. Current climate policies in the Philippines for example include a target to increase the share of renewable energy in overall power generation from 16% in 2024 to 35% by 2035 and 50% by 2040. Using historical utilization factors would not account for the effect of such policies on future baseline utilization factors considering different scenarios for power demand.

Fourth, the requirement to also consider the average capacity utilization factor of at least two reference CFPPs could mitigate some the concerns above, in particular about the effect of climate policies. The reference CFPPs could function as a control group for the appropriateness of the historical values to predict future utilization rates. The requirement to assume a linear decline to 30% at the end of the technical lifetime of the CFPP where no reference CFPPs are identified acts as a strong incentive for project proponents to comply with this requirement.

The eligibility requirements for references CFPPs aim at ensuring that reference CFPPs are representative of the CFPP being retired. The requirement that reference CFPPs must have equal or greater nameplate capacity than the CFPP being retired might not to be conservative. Usually, larger CFPPs tend to be newer and therefore more efficient and therefore will have a higher utilization than smaller CFPPs. It would therefore be more conservative to require that reference CFPP must have an equal or smaller nameplate capacity than the CFPP being retired. Further, there should be an explicit requirement in the criteria in section 9.2 that reference CFPPs must be connected to the same grid as the CFPP being retired. This is implicitly mentioned in section 8.5 where the use of reference CFPP is mentioned as a reason why overall uncertainty is estimated to be less than 10%. Here it says that the two reference CFPPs dynamically represent comparable coal operations in the country. However, it would be useful to explicitly state this as a criterium and tie eligibility to the reference CFPPs connection to the same grid as countries may have several grids, sometimes operating independently from each other. The Philippines for example, have three grids (which are interconnected) and in the case of the SLTEC plant it would be useful to select reference CFPPs located in the Luzon grid and not for example in the Mindanao grid.

Finally, the approach to using the two reference CFPPs as a dynamic control group is not well presented in the methodology. The respective section simply says that the average capacity factor of two reference CFPPs must be calculated. Section 9.2 on data and parameters monitored specifies that the value must be monitored on an annual basis. It is however not immediately clear that the baseline must be adjusted annually based on the values observed at the reference CFPPs. Other methodologies such as VM0044, which also uses control groups describe this approach more explicitly.

Robustness of the methodology could also be increased by tying the number of required reference CFPPs to the number of overall CFPPs in the respective grid. This would safeguard against adverse selection in grids with large numbers of CFPPs. In a grid with 50 CFPPs the risk of adverse selection might be high if only 2 reference CFPPs must be considered compared to a grid with only 15 or less CFPPs. Alternatively, the requirement could be changed in a way that all CFPPs that meet the eligibility criteria must be considered for calculating the average capacity utilization factor of the reference CFPPs. If less than two meet these criteria the default linear decline would need to be used.

Emission factor

To calculate the baseline emission factor, project proponents must consider the quantity of coal fired in the CFPP, the weighted average net calorific value of coal used in the CFPP, the CO_2 emission factor of coal used in the CFPP, and the historical quantity of electricity generated and supplied to the grid by the CFPP. The reference period for the quantity of coal fired in the CFPP and the historical quantity of electricity generated and supplied to the grid by the CFPP is the five-year period either preceding validation or the accelerated retirement date, whichever occurs earlier. Quantity of coal must be demonstrated with coal-purchase invoices for the period.

Using historical values as a predictor of the baseline emission factor is associated with uncertainties where the CFPP relies not on a single coal field for coal supply. There can be considerable differences in fuel quality and fuel composition among different coal fields. This includes the calorific value and carbon content of the coal. As a general rule, the lower the quality of the fuel, the higher the emission factor. If countries predominantly rely on imported coal, a change in trade partners may lead to a change of the type of coal that is used in the CFPP and hence its emission factor. Such potential changes are currently not reflected in the approach to calculate the baseline emission factor. This may lead to over- or underestimation of emission reductions depending on the coal quality and introduces uncertainty to the calculations. An effective approach to address this uncertainty could be to use the specific emission factor for the plant only in cases where it is bound to a particular local coal source. For other plants it would be more conservative to use the lower bound of the uncertainty interval of the CO_2 emission factor for the type of coal that can be used in the plant from the 2006 IPCC guidelines. This would ensure that the assumptions for the emission factor are conservative in most instances.

Upstream emissions from coal mining and transportation

The approach to calculating baseline emissions does not account for upstream emissions from coal mining and transportation. This is a conservative assumption leading to underestimation of baseline emissions.

3.2.3 Determination of project emissions

VM0052 defines project emissions as the emissions associated with operating paired renewable electricity power plants. Project proponents must quantify these emissions using relevant CDM methodologies for the respective type of renewable energy used as follows:

- Landfill gas: ACM0001 – Flaring or Use of Landfill Gas
- Geothermal and hydropower: ACM0002 – Grid-connected Electricity Generation from Renewable Sources
- Biomass-fired power plants: ACM0006 – Electricity and Heat Generation from Biomass
- Wastewater treatment: ACM0014 – Treatment of Wastewater
- Waste-to-energy power plants: ACM0022 – Alternative Waste Treatment Processes

This approach is generally robust as there are no major known issues with the quantification of project emissions in these methodologies. An exception might be the treatment of methane emissions from reservoir hydropower plants in CDM methodology ACM0002. There is considerable uncertainty around emissions from ebullition of flooded areas for hydro dams as discussed in an in-depth assessment of the methodology (CCQI 2023).

3.2.4 Determination of leakage emissions

The methodology requires project proponents to quantify leakage emissions due to the project activity. There are three potential leakage effects which must be considered:

- Leakage due to replacing the electricity of the retired CFPP with electricity from the grid.
- Leakage due to replacing the electricity of the retired CFPP with paired renewable energy sources.
- Leakage due to reusing the equipment of the retired CFPP in other places (rebuilding the CFPP in other countries, using the equipment for repairs of existing ones).

A key factor for the likelihood and magnitude of leakage is how much of the electricity is replaced with new paired renewable energy. The following section 2.2.4.1 therefore first assesses the methodology’s requirements in this regard before assessing different aspects of leakage.

3.2.4.1 Paired renewable electricity requirements

The applicability conditions of VM0052 require that project proponents at project validation have put in place a plan for pairing the retired CFPP generation capacity fully or partially with renewable electricity generation. The methodology establishes the following minimum thresholds:

- To replace at least 10% of the retired CFPP generation **capacity** on an annual basis at the project start.
- To replace at least 40% of the retired CFPP generation **capacity** on an annual basis by the end of the initial crediting period.

The methodology allows project proponents to apply five pairing pathways:

1. Contractual pairing where a new or revised PPA covers new renewable energy capacity.

2. Financial pairing, where the conditions for refinancing a CFPP for retirement require new renewable energy electricity capacity.
3. On-site pairing, where new renewable electricity generation capacity is developed at the CFPP site and uses existing grid connections or balance of plant components.
4. Regulatory pairing, where a regulator approves new renewable electricity generation capacity as an explicit replacement for retired CFPP generation capacity.
5. Counterfactual plans pairing, where renewable electricity generation comes online earlier or at a greater capacity than projected in the current approved regulatory resource plan of system operators.

There are several observations to highlight here:

First, the pairing pathways have a different degree of certainty regarding the causality of the CFPP retirement decision to cause the construction of renewables. While establishing causality seems to be straightforward for pathways 1, 3, and 4 it seems to be more uncertain for pathways 2 and 5. Unlike under the other pathways there is no direct contractual or regulatory agreement that binds the construction of the renewables to the retirement of the CFPP. Renewables coming online early or at a greater capacity than projected could be driven by external factors unrelated to the coal plant's retirement such as effectiveness of subsidies, technology advancement or other market dynamics. Pathways 2 and 5 would introduce high subjectivity and ambiguity in the causality of the pairing. We therefore recommend to removing them from the methodology.

Second, the minimum thresholds allow that most of the replacement electricity comes from the grid. The robustness of the grid emission factor in accounting for leakage emissions therefore has a key role to ensure that emission reductions are not overestimated due to leakage.

Third, the fact that the methodology uses thresholds relative to the CFPP's generation capacity and not relative to the amount of electricity generated means that more than 10% / 40% of replacement energy must be sourced through other grid-connected sources. Coal often provides base load to the grid and 1 kW of solar does not fully replace 1 kW of coal. In the Luzon Grid for example, CFPPs reached annual load hours of 6,076 hours while load hours for solar photovoltaic are only about 1,369 hours (see Table 5 in section 1.1.2 above). This means that the requirements for renewable energy pairing under the methodology are very low in terms of generated electricity that must be replaced by renewables.

The impact of the minimum thresholds on creating new renewable energy capacities can be illustrated by applying them to the SLTEC CFPP in the Luzon grid, which is proposed as a pilot project under the VM0052 methodology. The plant has a capacity of 270 MW. Under the minimum thresholds, project proponents would need to pair 27 MW of renewable energy with the CFPP at the start of the first crediting period and 108 MW at its end. Assuming that the SLTEC plant has been running the 6,076 hours, which was the average utilization of CFPPs in the Luzon grid in 2024 (see section 1.1.2), this plant would have generated 1,640,520 MWh of electricity in 2024. Again, assuming utilization of different renewable energies in the Luzon grid in 2024, to fully replace this amount of electricity would require the installation of between 305 MW (geothermal) and 1.2 GW (solar) of new renewable capacities, depending on the type of technology (see Table 8). The 27 MW of paired renewables that is required by the methodology at the beginning of the crediting period would therefore only be able to replace between 2% (solar) and 9% (geothermal) of the electricity generated by the CFPP. The 108 MW required at the end of the crediting period would be able to replace between 9% (solar) and 35% (geothermal) of the electricity generated by the CFPP.

Table 8 Effect of VM0052 pairing requirements on hypothetical retirement of 270 MW CFPP capacities in the Luzon grid using 2024 utilisation rates

	Utilization in Luzon grid in 2024 (in hours)	Approximate new capacity required to replace 270 MW of CFPP capacity in Luzon grid	Share of required new capacity resulting from 10% pairing requirement	Share of required new capacity resulting from 40% pairing requirement
Wind	3,068	535 MW	5.05%	20.20%
Solar	1,370	1,198 MW	2.25%	9.02%
Hydro	2,075	791 MW	3.42%	13.66%
Geothermal	5,384	305 MW	8.86%	35.45%

Source: Own calculations based on (The Philippines Department of Energy 2025b, 2025c)

These figures are only illustrative as they are based on average, non-plant specific utilization rates at a single point in time (2024) in the Luzon grid and do not consider potential future increase in available storage capacities as well as technical innovation which might increase future utilization rates of renewable energy. The figures show that if, for example, 100% of the minimum threshold requirements would be met with installations of new solar power plants this means that less than 10% of the electricity that has been generated by the CFPP will be replaced with renewable energy at the end of the first crediting period.

Media reports suggest that ACEN plans to construct a mid-merit integrated renewables and energy storage system to replace the SLTEC CFPP. This system would feature a 1.4 GW peak solar plant with an integrated 1.6 GWh battery energy storage system. Construction for the replacement system is scheduled to start in 2027 or 2028, while constructing is estimated to last 3-4 years. (Esmael 2024). The dimensions of this system would surpass the minimum pairing requirements of VM0052 by a wide margin and would likely be sufficient to replace all the electricity generated by the retired SLTEC plant through paired renewable energy, considering the illustrative figures in Table 8.

The example of the SLTEC CFPP suggests that higher pairing requirements than those in VM0052 are feasible for project proponents, for example where they have access to battery energy storage system technologies.

Were project proponents to apply the very low minimum pairing requirements, there could be a real risk that accelerated CFPP retirement projects under VM0052 will lead to situations where there is less capacity available in the grid due to the project. This would be inconsistent with the fundamental principle of carbon crediting approaches that the availability of goods or service should generally be the same in the baseline and project scenario (see for example criterion 8.5 of the ICVCM CCPs and partially also the provisions of the PACM leakage standard[8]). The methodology in its applicability conditions however requires that project proponents provide a written approval by regulators that the accelerated retirement will not have material negative effects on consumer prices, access to electricity, grid stability and energy supply security based on a reliability assessment and rate impact analysis. This can be an effective safeguard to avoid such situation. The methodology should however require that the results of the assessment are made publicly available.

Nonetheless, the fact that most of the replacement electricity will have to be acquired from other sources connected to the grid poses risks for leakage which needs to be appropriately accounted for. The followings sections therefore discuss the robustness of the methodology's provisions to

[8] A6.4-STAN-METH-005 https://unfccc.int/sites/default/files/resource/A6.4-STAN-METH-005.pdf

account for leakage emissions resulting from replacing the electricity generated by the retired CFPP through the grid. Project proponents must calculate these leakage emissions by determining the emission factor of the grid, using the combined margin, incorporating operating margin and build margin emission factors.

3.2.4.2 Operating margin emission factor

The operating margin emission factor EF_{OM} is a way to calculate how much carbon dioxide is emitted per unit of electricity by a power grid. Project proponents must consider two scenarios for calculating EF_{OM}:

- If mothballed CFPPs generating capacity connected to the grid is greater than or equal to the retired CFPP generation capacity, replacement by mothballed CFPPs will become the baseline scenario and a default emission factor for subcritical coal must be used. The same applies if the reserve margin is greater than or equal to the regulatory-determined reserve margin target plus 10%, and more than half of the capacity that makes up the reserve margin is coal.
- If no mothballed CFPP can replace the grid capacity, project proponents must calculate the simple operating margin, using the most recent version of VT0011.

Role of mothballed CFPPs

The requirement to use a default emission factor for subcritical coal in cases where mothballed CFPPs can replace the capacities of the CFPP might contribute to conservativeness as most recently built power plants are super critical and hence using a default factor for subcritical coal might overestimate grid emissions. However, the methodology does not further define eligible default factors. This introduces considerable uncertainty as there is a very large range of efficiency of existing coal power plants. In case the default emission factor is lower than the one of the mothballed CFPPs the approach could therefore also lead to an underestimation of the leakage emissions.

Further, it is unclear why mothballed CFPPs must not be considered when the mothballed CFPPs' generating capacities are smaller than the retired CFPP. It seems plausible that in this case mothballed CFPPs will replace the capacities of the retired CFPP up to their nameplate capacity while only the rest would be provided through other plants in the grid. A more robust approach would therefore be to require project proponents to assume a default emission factor for subcritical coal for the generating capacities that can be covered by mothballed CFPPs and use the simple operating margin only for the remaining capacities which cannot be replaced with mothballed CFPPs.

Simple operating margin

The simple operating margin is calculated as the generation weighted average of all plants connected to the grid. This means the more electricity a plant generates the more weight is attached to it in the average. The methodology requires that low cost/must-run (LCMR) electricity sources must be excluded in calculating the simple operating margin. It further defines that LMCRs include renewables and nuclear. At the same time all fossil fuel power plants, including CFPPs must be included. These requirements are conservative as they account for the effect that LCMR plants likely will not be affected by CFPP retirement and that without pairing, their capacities will likely be taken over by fossil fuel plants in the grid as they have less intermittency and can easier replace baseload electricity produced by the retired CFPP. The requirement to include all fossil fuel plants further improves upon existing methodologies under the CDM (e.g. ACM0002) which allowed project proponents to exclude fossil fuel plants under certain circumstances.

3.2.4.3 Build margin emission factor

Use of vintage data

The tool allows project proponents to either calculate the build margin emission factor once ex-ante at the start of the crediting period or to update it annually, including those units build up to the most recent year for which information is available at each update. Whether fixing the build margin emission factor at the start of the crediting period leads to overestimation or underestimation of emission reductions depends on the energy strategy and trends of the country. Given that most country's energy policies aim at increasing the share of renewables in most cases it is likely leading to underestimation of emission reductions. Under the fixed option leakage emissions due to the build margin emission factor remain constant while the emission factor of the grid likely decreases due to more renewable energies becoming available.

Inclusion of plants with a relatively high intermittency in the calculation of the build margin

For calculating the build margin, project proponents must identify a sample group of power units. The tool allows inclusion of all type of recently built plants into the sample groups, including those that have a relatively high intermittency, such as solar and wind power plants. In practice, these plants can however only partially substitute CFPP capacity in the grid. This means that their capacity contribution is overweighted in the calculation of the build margin as they are not a full substitute for flexible power provided by a CFPP. Replacing the electricity might therefore require the construction of other non-intermittent capacity or renewable energy combined with integrated storage capacities. As solar and wind power have much lower emissions than CFPPs, the approach to calculate the build margin may underestimate leakage emissions and hence overestimate emission reductions. The degree of overestimation is difficult to estimate as this strongly depends on the share of solar and wind power plants in recent capacity additions and the capacity value of these technologies in the respective electricity grid. A potential approach to strengthen the conservativeness of the calculation of the build margin could be to calculate separate margins for intermittent and non-intermittent replacement electricity.

3.2.4.4 Weighing between operating and built margin emission factor

The methodology suggests that the operating margin should be weighted at 40% and the build margin at 60% in the combined margin formula. These weights are relatively standard in many carbon crediting methodologies. The higher weight for the build margin aims to reflect that there is a worldwide trend to move to renewable energies assuming that future grid additions will increasingly consist of cleaner energy sources. At the same time the 40% weight on the operating margin acknowledges that existing plants will continue to play a role in grid emissions for the foreseeable future. In practice there might however be large uncertainty how much the retirement of a CFPP affects the build or operating margin.

3.2.4.5 No accounting of leakage due to increased use of diesel-generators

In countries with low grid reliability, where households, businesses and industry rely on diesel generators for supplementary or backup generation, the retirement of a CFPP could lead to an increased reliance on diesel if the grid cannot absorb the lost capacities in the short-term. Given the low pairing thresholds in VM0052, which require replacing only a fraction of the electricity with renewable energy, there is a real risk that projects could reduce overall grid capacity. This reduction could impact grid reliability, potentially leading to more power outages or general grid instability. In the Philippines, for example, diesel generators are commonly used as backup power sources for households, businesses and industries – though their use in residential settings is less common than in other countries. The risk of leakage may not be uniform and is likely to be higher in rural areas compared to urban centers. However, the methodology currently does not account for leakage emissions arising from increased diesel generator use. Whether or not the exclusion of diesel generators leads to overestimation or underestimation of emission reductions depends on whether the emission factor of the diesel generators is higher or lower than the operating and build margin. If it is lower, then the exclusion is conservative. If it is higher, this would not be the case. The methodology includes an applicability condition for project proponents to provide a written confirmation by the system operator that confirms that accelerated retirement of the CFPP will not have a material negative effect on grid stability, based on a reliability assessment and impact rate assessment. This might mitigate leakage risks associated with diesel generators.

3.2.4.6 Leakage emissions due to using electricity from paired renewable energy

Although only a fraction of the electricity generated by the retired CFPP must be replaced with renewable energy, their use can also be related with emissions which must be accounted for to avoid overestimation of the emission impact of projects. As with project emissions, VM0052 relies on CDM methodologies for quantifying leakage emissions from paired renewable energies. However, leakage emissions must only be calculated for the following subset of renewable energy sources: biomass, wastewater treatment and waste-to-energy. Leakage emissions from solar, wind, hydro, geothermal, tidal/wave and landfill gas on the other hand are considered de minimis under the methodology.

Among the renewable energy sources, leakage risks are most relevant for biomass-fired plants. The robustness of the CDM methodology to account for such emissions are therefore briefly discussed in the following.

Biomass

Replacing the electricity of a retired CFPP with biomass-fired power plants has a high leakage risk. If the retirement would lead to an increased demand for biomass compared to the baseline and if the project results in diverting biomass currently used for other purposes this might involve high leakage emissions. The respective CDM methodology – ACM0006 requires project proponents to determine leakage emissions using TOOL16.[9] This tool accounts for emissions due to shift of pre-project activities, diversion of biomass residues from other applications and due to processing and transportation of biomass residues outside of the project boundary. For example, under the tool, only biomass residues that are available in abundance or biomass from newly established plantations are eligible for claiming emission reductions. For demonstrating abundance in the CDM tool, project proponents must demonstrate that the total quantity of biomass residues annually available in the project region is at least 25% larger than the quantity of biomass residues which is utilized annually in the project regions.

While using biomass for power generation might not be desirable due to potential negative impact on sustainable development, the leakage provisions appear to be appropriate to minimize the risk of overestimating emission reductions.

9 CDM TOOL16 – Project and leakage emissions from biomass, paragraph 52 https://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-16-v5.0.pdf

3.2.4.7 Restriction of no new coal commitments to cases where the CFPP is owned by a state-owned utility company

The applicability conditions of the methodology include a requirement that the host country has a publicly available commitment to not build new CFPPs and not increase existing CFPP capacity in its jurisdiction. This condition however only applies to cases where CFPPs are owned by a state-owned utility company. In cases where the CFPP is owned by an IPP, countries do not need to have a moratorium on new coal capacity in place. The methodology only requires that the IPP itself has publicly committed to not build new CFPPs and to not increase existing CFPP capacity under their control.

These provisions introduce high leakage risks as they do not exclude cases where another IPP builds a new CFPP or increases capacities of its existing CFPPs to replace the electricity of the retired CFPP owned by a fellow IPP. That this risk is material is illustrated by the case of the SLTEC plant. This plant is situated in the city of Calaca in the Batangas province. Next to the SLTEC plant, there are two other CFPPs in the city of Calaca which are owned by a different IPP – the Semirara Mining & Power Corporation (see section 1.1.4). The Semirara Mining & Power Corporation in December 2024 announced that it plans to resume the construction of an additional 700 MW CFPP in the city of Calaca, a plan the company had initially shelved in 2019. While there is no substantial evidence that suggests that the decision of Semirara is linked to the retirement of the SLTEC plant, it illustrates the risks associated with accelerated retirement projects in countries without full moratoriums on the construction of new CFPPs. In the worst case the new capacity would fully replace the retired capacity or the new capacity would have led to an accelerated retirement of the CFPP in the baseline. The fact that ACEN plans to construct a 1.4 GW solar facility to replace the SLTEC plant suggest that in the particular case, the new Semirara plant will meet some other demand than the SLTEC plant, still accelerated retirement projects should support the start of a nation-wide coal exit and not only support retirement of specific plants while new CFPPs are built elsewhere.

3.2.4.8 Leakage due to reusing the equipment of the retired CFPP in other places

If the CFPP would be decommissioned and the equipment used to rebuild it e.g., in another country, this could create leakage emissions. The same would apply if the equipment is used for repairs in existing CFPPs extending their lifetime due to low repair cost.

The methodology addresses this by including specific requirements for monitoring the decommissioning of the CFPP. By the first monitoring period, project proponents must demonstrate that major equipment has undergone adequate disposal that prevents the rebuild of the CFPP or using equipment to extend the life of other CFPPs. The methodology defines that major equipment includes coal pulverizes and other equipment specifically designed for CFPP operations.

3.3 Double counting

3.3.1 Double issuance

Double issuance occurs through overlapping claims by different entities involved in mitigation projects. Such overlapping claims can happen if two projects claim emission reductions or removals from the same greenhouse gas emission source or sink (CCQI 2022). In the context of VM0052, this issue is particularly relevant when renewable energy plants that substitute the coal power plant might also claim carbon credits for the electricity they generate. This can be true for both, paired renewable energy or renewable energy sources in the grid that replace the electricity of the retired CFPP.

Double issuance with paired renewable energies

For paired renewable energy sources, avoiding double issuance might be more straightforward because in this case the plants that substitute the electricity from the CFPP either belong to the same organization proposing the CFPP retirement or if owned by other organizations can be clearly identified. To avoid double issuance, in the latter case project proponents could, for example, enter into legal agreements with such plant operators to ensure that they will not claim any carbon credits for these sources. The methodology states that renewable electricity paired with accelerated CFPP retirement is ineligible to claim other forms of environmental credits or certificates such as Renewable Energy Certificates (RECs) for the duration of the crediting period. The *VCS Program Definitions* defines "GHG-related Environmental Credit System" in the following way:

A system for the crediting, issuance of instruments, or acknowledging activities that could be interpreted as having GHG emission reduction or carbon dioxide removal value. Examples of a GHG-related environmental credit system include, but are not limited to, energy attribute certificates (EAC); renewable energy certificates (REC); Guarantee of Origin (GO); or renewable thermal certificates (RTC)

The definition does not include carbon credits, suggesting that this form of double issuance is not covered by these provisions. Further, the methodology does not include any practical steps how this will be implemented e.g., through legal agreements between the owner of such projects and the proponents of the CFPP retirement. Also, for some pairing plans such as the counterfactual plan pairing it might be difficult to identify the exact sources.

Double issuance with renewable energy sources in the grid

Due to the low pairing requirements, in some projects only a small fraction of the electricity might be replaced with paired new renewable energy sources while a majority will come from other sources connected to the grid. This means that it will be more difficult to identify the exact plants that replace the retired CFPP's electricity.

A search of project databases of relevant carbon crediting programmes shows that for the Philippines double claiming risks are relevant as there are currently several renewable energy projects registered or under development with crediting periods running through the coming years. As ACEN plans however to replace all of the electricity of the SLTEC plant with paired renewable energy it will construct itself, double issuance risks are very likely not material for the proposed pilot project.

Table 9 Registered and planned renewable energy projects with crediting periods post 2025 in the Philippines

Programme and project-ID	Project name	Active crediting period (CP)
CDM-0453	Northwind Bagui Bay Project	05/2019 – 04/2026
CDM-7980	Burgos Wind Project	11/2021 – 10/2028
VCS-1735	Negros Island Solar Power Inc.	03/2016 – 03/2026
GCC-S00454	Solar Power Project in Philippines	04/2024 – 03/2034

GS- GS2691	81MW Caparispisan Wind Energy Project	07/2022 – 07/2027
GS- GS7575	SolarAce1 Energy Project	06/2021 – 05/2026 Plans to renew the CP twice
GS- GS11423	160MW Balaoi & Caunayan Wind Energy Project	12/2023 – 11/2028
GS- GS12198	CAPARISPISAN II Wind Power Project	11/2024 – 10/2029 Plans to renew the CP twice

Source: Project databases of CDM, VCS, Gold Standard (GS) and Global Carbon Council (GCC). Information as of 29 September 2025.

To avoid double issuance, the methodology should however be strengthened by requiring project proponents to identify relevant carbon market projects and use available project information to determine the approximative share of electricity replacing the retired CFPP attributable to these projects. This portion should be deducted from the emission reductions claimed by the project proponents.

3.3.2 Double claiming due to overlap with mandatory domestic mitigation schemes

Another form of double counting relevant for this project type is double claiming with mandatory domestic mitigation schemes. This refers to schemes that are legally binding through respective laws and regulations and that establish a target for a defined group of installations, entities or sinks and sources, such an emission trading scheme (ETS) or a renewable energy quota. Double claiming occurs if, for example, the entities covered by an ETS and the buyers of the carbon credit claim the emission reduction. For the project type accelerated retirement of CFPPs there is a material risk of overlap with mandatory mitigation schemes, as some countries with CFPPs may have ETSs covering the electricity sector.

The VCS Standard in sections 3.24.3 and 3.24.4 however includes clear provisions that are effective to avoid double claiming of the project’s emission impacts. First project proponents cannot seek credit for the same GHG emission reductions under the VCS Program and an ETS or binding emission limit. Second, where reductions or project activities are also included in an ETS or binding emission limit, evidence must be provided that the reductions generated by the project activity have not and will not otherwise be counted, used, or credited under the program or scheme. The provisions further specify what type of evidence is eligible and which information must be provided. These provisions are generally robust for avoiding double claiming with mandatory mitigation schemes.

4 Assessment of the just transition principles contained in VMD0061

Projects using VM0052 must apply VCS module VMD0061 *“Just transition requirements for accelerated retirement of coal-fired power plants”* (VCS 2025). Its central requirement is for project proponents to develop and implement a plan which enables a just transition for stakeholders directly or indirectly affected by the accelerated retirement of a CFPP (henceforth referred to as just transition plan).

The just transition plan contains mandatory requirements regarding stakeholder engagement, mitigating loss of work, reliance on third parties and its implementation. We will discuss the main elements in the sections below.

4.1 Stakeholder engagement

In addition to the requirements of the VCS Standard, project proponents must meet specific requirements regarding stakeholder engagement.

4.1.1 Stakeholder identification

Project proponents must conduct a stakeholder identification and mapping process. The module defines a list of stakeholder categories that must be included in this process (see section 5.2.1). The list is comprehensive as it covers employees, formal or informal sector workers working at the CFPP site, contractors, businesses, local communities and groups, government ministries and departments as well as NGOs and non-profit organizations.

As part of the mapping process, project proponents must further reflect on aspects such as negotiating power and degree of influence on decision-making that different stakeholder groups have.

4.1.2 Stakeholder vulnerability assessment

A strong feature of the module is the requirement to conduct a stakeholder vulnerability assessment. It ensures that disadvantaged groups (e.g. women, elderly, people with disabilities and informal workers) are considered in the planning and implementation. Their integration is key to fairness and ensuring a transition that is equitable and does not leave any group behind.

In terms of the process that project proponents must follow for the assessment, the module refers to national, regional and local laws, policies or guidelines. Only where these are not available, vulnerability assessments must be conducted according to international guidelines, peer-reviewed literature or relevant assessment frameworks from organizations such as the World Bank. The methodology could be strengthened here by including minimum requirements that must be met regardless which approach is followed. This should for example include a requirement to involve experienced, impartial third parties with expertise in social equity. This would ensure that the assessments are comprehensive and meet local, national and international standards.

4.1.3 Consensus building

VMD0061 requires project proponents to include a process for building consensus with stakeholders into their just transition plans. A strong feature is the requirement to allow stakeholders to bring forward their interests, preferences and concerns in their local language or dialect using their preferred method of communication. The module further includes a requirement for neutral third-party mediation/arbitration where a consensus cannot be reached directly between the project proponent and stakeholders. In the latter aspect, the module could be strengthened by including a requirement that agreement on the entity performing mediation/arbitration should be reached jointly by all stakeholders and not be under the exclusive prerogative of the project proponents.

Further, it is not entirely clear whether consensus building only applies to the just transition plan or the entire project i.e. whether the project cannot go ahead if no consensus is reached between project proponent and stakeholders. The module could be strengthened by including clearer language in this regard.

4.1.4 Communication strategy

Project proponents must include a communication strategy in their just transition plan that identifies the modes and procedures for initial and ongoing communication with stakeholders identified during the stakeholder mapping. Project proponents must justify that the chosen modes of communication are adequate for each stakeholder group. Particular consideration must be given to the mode of communication related to cessation of employment, termination or modification of contracts for products and services, and other potential impacts on stakeholder livelihoods.

4.2 Mitigating loss of work

VMD0061 requires that project proponents mitigate the loss of work due to the project and provide compensation where such loss cannot be avoided. The process must prioritize finding other employment opportunities within the organizational structure or via upskilling and training. Where project proponents cannot provide direct employment opportunities, they must justify why barriers hinder this option.

For each stakeholder category identified in the stakeholder mapping process, project proponents must define how they support the transition of the workforce. The module provides a list of eligible measures. For each stakeholder category project proponents must select one or a combination of several of the measures listed in Table 10 below.

Table 10 Overview of eligible measures to mitigate loss of work in VMD0061

Measure
Severance package of at least six months' salary
Early retirement/voluntary retirement benefits, especially for employees who are nearing retirement age
Similar employment or any other similarly compensated alternative livelihood opportunity
Social security and/or unemployment benefits and payments by national, regional or local governments
Education and/or training for skill development
Support for job seeking (must be combined with other measures)
Lump sum compensation or staggered compensation package to businesses and/or contractors affected by the CFPP accelerated retirement

Support to businesses that depend on providing or receiving products (services to or from the CFPP or its employees
Other provisions relevant for the stakeholders.

Source: VMD0061 v1.0, section 5.3 paragraph 2)

There are two issues where the module could be strengthened:

Eligibility of social security and/or unemployment benefits and payments

One of the eligible measures is to utilize social security and/or employment benefits and payments provided by national, regional or local governments. Especially if this measure is applied without combining it with other measures it might lead to a situation where project proponents overly rely on public support instead of equitable benefit-sharing of the revenues from carbon credits. While unemployment benefits may be a form of last resort, project proponents should be required to offer education and/or training for skill development in cases they cannot offer employment opportunities. The module should therefore be strengthened by allowing utilization of social security benefits only in combination with other measures. This would help to avoid a situation where the entity retiring the CFPP is externalizing the cost of the transition onto the state or broader society, rather than directly addressing the needs of the affected stakeholders. Given that the CFPP owners are receiving revenues from carbon credits it seems to be fair that they bear a substantial share of the financial burden for the workers' transition.

Size of the severance package

The module specifies that severance packages must include at least six months of salary. This baseline amount will create short-term relief for workers which are affected by the CFPP retirement. The duration might be reasonable in countries with a strong local economy and a well-functioning labor market. However, in areas where the local economy is less diversified or workers have highly specialized skills specific to coal plants, the six-month period may not be sufficient for securing new employment. The methodology should therefore be strengthened by stating that the length of the severance package should consider factors such as the specific context of the workers and the local economy. This should include the length of the employee's tenure at the CFPP and the industry's ability to support a transition of the workforce.

Indirectly, the module's requirement for project proponents to justify the appropriateness and adequacy of the proposed measures to mitigate the loss of work may address these concerns. However, it would be useful to more clearly outline respective requirements in the methodology.

4.3 Reliance on third parties

The module allows that project proponents make use of and rely on third parties to fund and implement measures of the just transition plan. It specifies that this may include policies, programmes or grants (e.g. existing programs by national or state governments for skill development). Apart from a requirement to transparently identify and describe third-party elements there are no further guidelines or restrictions on its use.

Considering the importance of ensuring a just transition for all stakeholders, third-party support can be a valuable input to the just transition process for several reasons:

- Third parties like government agencies, NGOs and international development organizations often have specialized expertise, funding mechanisms, and experience in community development, retraining, or employment services. By including these external resources in the just transition plan, project proponents can ensure that workers have access to well-established programs and mechanisms which the project proponents might not be able to offer themselves.
- Third parties like local NGOs or community organizations may have a specific understanding of regional conditions, local labor markets and social dynamics which can be critical when designing a just transition that meets the specific needs of workers and communities.
- Utilizing support by third parties can help diversify funding sources for the just transition plan, which can enhance the support available for workers and other affected stakeholders.

While third-party support can thus enhance the effectiveness and reach of the just transition plan, an over-reliance on third-party support could raise ethical concerns as project proponents who benefit from the sale of carbon credits should take the primary responsibility for the impact of retiring CFPPs on workers. It might therefore be useful if the module includes provisions that clarify that while integrating third-party support is most desirable, the primary responsibility for leading, funding and implementing the measures of the just transition plan must remain with the project proponents. This would ensure that the project proponent remains accountable for the worker's welfare while external funds and programs help complement the just transition plan without becoming the primary source of support.

4.4 Implementation

The section relating to the implementation of the just transition plan contain several requirements on the financing and operations and management for the just transition plan implementation.

4.4.1 Financing

The module requires that project proponents include an estimated budget for the implementation of the just transition plan as well as a procedure for an annual review of the budget which must include a review of feedback received from stakeholders. The budget must include line items on the cost associated with stakeholder engagement, measures for mitigating the loss of work and the operation and management of the just transition plan implementation.

It further includes a requirement to describe the funding sources for its implementation. Funding must be disaggregated by loans, funds and grants received from government-owned/funded organizations and/or policies, funds and grants received from NGOs corporations and philanthropic organizations, dedicated just transition funds established by project proponents as well as loans or other forms of debt financing. The module further prescribes that project proponents must use more than 2% of the expected net revenues from sales of carbon credits for the implementation of the just transition plan.

Whether the 2% requirement is appropriate and whether it results in an equitable and just share of revenues going to affected workers depends on many factors including the size of the workforce and number of stakeholders affected, the volume of credits sold and the market price of carbon credits and the size of certification and brokerage costs. The potential range of revenues can be illustrated by two scenarios for a CFPP with 270 MW and annual emissions of about 1.9 MtCO2e (similar to the SLTEC plant) as shown in Table 11. In the first scenario, there are a few leakage emissions, and the average carbon price is assumed to be 20 USD while certification cost is 1% and advisory and brokerage cost 5% of revenues from carbon credits. Under this scenario the approximate annual funds for the just transition plan under a 2% share would be about USD 643k. Under scenario 2, all factors are held constant except for the leakage rate and the carbon price. Here, high leakage emissions are the result of an assumption that much of the electricity is replaced by a grid highly reliant on coal. Further, carbon prices are assumed to amount at only USD 10. Under this scenario the annual revenues for implementing the just transition plan would be just approximately USD 179k.

Table 11 Illustrative effect of 2% share on funds available for just transition plan under two exemplary scenarios

	Scenario 1	Scenario 2
Capacity	270 MW	270 MW
Annual emissions	1.9 MtCO2e	1.9 MtCO2e
Leakage rate	0.1	0.5
Carbon price	20 USD	10 USD
Certification cost	1%	1%
Advisory and brokerage cost	5%	5%
% of net revenues used for just transition plan	2%	2%
Approximate annual funds for just transition plan	**642,960 USD**	**178,600 USD**

Source: Own calculations.

These two scenarios are very simplified, but they show that the amount revenues from a 2% share might be very uncertain and fluctuations in carbon price or high leakage emissions might reduce available revenues. The revenues under scenario 2 would likely be insufficient for a robust just transition, especially given the need to support affected workers as well as local communities and businesses directly and indirectly affected by the closure of the CFPP.

The methodology aims to ensure that sufficient resources are available for the just transition plan by including an applicability condition that requires that the plan is fully funded through other sources than revenues generated from the sale of carbon credits. The intention behind this requirement is understandable because it tries to account for the fact that the revenues from carbon credits are uncertain. However, it again creates a risk, that project proponents mostly rely on third parties for implementing the just transition requirements. It also raises question for what the 2% of the carbon credits will be used if the plan is already funded through other resources. Another way to address the risk that revenues from 2% of the carbon credits are not sufficient to cover the implementation of the just transition plan could be to require that its implementation must be implemented fully with the revenues from carbon credits. This would ensure that responsibility for funding the measures remains with the project proponents.

Basing the minimum amount of funds on the amount of revenues from carbon credits also might create perverse incentives to overestimate emission reductions from a CFPP. Under this approach workers and other affected stakeholders have an interest that as many carbon credits as possible are issued under accelerated retirement projects because the size of their compensation directly depends on this. This might pit workers legitimate financial interest against the principle of conservativeness in estimating the emission impacts of carbon crediting projects.

It would therefore be useful to consider a more adaptive and scalable approach that bases the amount of funds project proponents must make available on the size of the workforce and number of affected stakeholders and the economic context instead of on a percentage of the revenues from carbon credits. This would be more effective in ensuring an equitable and just transition for all affected workers, particularly in cases of a large workforce and where workers face significant economic hardship.

Beside these considerations, a strong feature of the module is the requirement for project proponents to include a periodic review and audit of financial transactions associated with the different components of the just transition plan and its implementation. They include a requirement for an annual audit by an independent third party and review of present and planned financial risk mitigation options.

4.4.2 Operations and Management

Project proponents must describe the operational and management system for the implementation of the just transition plan. As part of this they must assign clear roles and responsibilities in the operation and management of activities and establish a governance mechanism for making and reviewing decisions associated with the plan and its implementation. They further must establish a financial management structure, including procurement policies as well as standard operating procedures for periodic internal review of the just transition plan and progress in its implementation.

Overall, these requirements are comprehensive and likely effective in creating a solid framework for the operationalization and management of the just transition plan. They could be further strengthened by requiring that the governance mechanism must include representatives from all stakeholder categories identified in the stakeholder mapping, including in decision making. This would ensure that the process is not top-down but involves those most impacted by the CFPP retirement.

5 Conclusions

The main source of uncertainty and potentially overestimation of emission reductions is the methodology's approach to addressing leakage emissions. VM0052 acknowledges that the project activity may be associated with potentially large leakage emissions which result from using replacement electricity that may be generated by fossil-fuel power plants in the grid. Allowing project proponents to use such electricity instead of paired renewable energy is an explicit choice of the methodology to accommodate the challenges associated with replacing a CFPP with renewable energy only. On the one hand it is a positive feature of the methodology that it accounts for leakage emissions, on the other hand the methodology's chosen approach does not necessarily adheres to the common principle in carbon crediting to avoid leakage emissions as much as possible before accounting for those that remain. This creates risks because the robustness of this approach hinges on the ability to conservatively account for such large leakage emissions. While the methodology's leakage accounting provisions are comprehensive, inclusion of plants with a relatively high intermittency in the calculation of the build margin results in overestimation risks. Allowing the application of the methodology in countries where new CFPPs continue to be build further increase leakage risks.

Related to this, the choice of the methodology to allow project proponents to use replacement electricity generated by non-paired, grid-connected sources results in double-issuance risks if some of these sources receive carbon credits as well. Combined, these issues can lead to a material risk that applying the methodology results in the issuance of some carbon credits that are not backed by real emission reductions.

We therefore recommend that the methodology be further strengthened before it is used by pilot projects. A key improvement would be a mandatory requirement for countries to adopt a moratorium on the construction on new CFPPs. Furthermore, increasing the pairing requirements to replace 100% of the electricity with renewable energy systems with integrated storage capacities would solve different methodological challenges, including the high uncertainty of leakage emissions and the risk of double issuance. Further, the methodology should remove all pairing pathways that do not establish clear contractual or regulatory agreements for new renewable energy sources. Finally, the net present value calculations for determining the financially attractive baseline retirement should include a sensitivity analysis to vary key parameters within plausible ranges.

List of References

ACEN (2019): Ayala buys Marubeni stake in South Luzon Thermal Energy Corp. Online verfügbar unter https://www.acenrenewables.com/2019/11/ayala-buys-marubeni-stake-in-south-luzon-thermal-energy-corp/.

ACEN (2021): SEC form 17. AC Energy Corporation and Subsidiaries. Online verfügbar unter https://www.acenrenewables.com/wp-content/uploads/2024/10/ACEN-SEC-Form-17-A-for-year-ended-2021.cleaned.pdf.

ACEN (2022a): ACEN completes the world's first ETM transaction for the 246 MW SLTEC coal plant. Online verfügbar unter https://www.acenrenewables.com/2022/11/acen-completes-worlds-first-energy-transition-mechanism-etm-transaction-246-mw-sltec-coal-plant/.

ACEN (2022b): ACEN's Net Zero progress. Online verfügbar unter https://www.acenrenewables.com/2022/12/acens-net-zero-progress/.

ACEN (2025): Integrated Report 2024. More is possible through meaningful impact. Online verfügbar unter https://www.acenrenewables.com/ir2024/wp-content/uploads/2025/05/2024-ACEN-Integrated-Report_0507.pdf.

Argus Media (2024): Philippines keeps adding coal-fired power capacity. Online verfügbar unter https://www.argusmedia.com/en/news-and-insights/latest-market-news/2579775-philippines-keeps-adding-coal-fired-power-capacity.

Argus Media (2025): Philippines to review shutdown of 232MW coal plant. Online verfügbar unter https://www.argusmedia.com/en/news-and-insights/latest-market-news/2658636-philippines-to-review-shutdown-of-232mw-coal-plant.

Austria, J. B. (2025): SMPC in talks with local banks for 700-MW coal plant expansion. Maila Standard. Online verfügbar unter https://manilastandard.net/?p=314594303.

Bhat, S.; Holzman, L.; Khannan, D.; Lone, D.; Lubis, I.; Matsuo, T. (2024): Transition Finance Case Studies: ACEN — Project Sale to Special Purpose Vehicle. Rocky Mountain Institute. Online verfügbar unter https://rmi.org/transition-finance-case-studies-project-sale-to-special-purpose-vehicle/.

CCQI (2022): Methodology for assessing the quality of carbon credits. Carbon Credit Quality Initiative. Online verfügbar unter file:///C:/Users/f.fallasch/Downloads/CCQI%20Methodology%20-%20Version%203.0-19.pdf.

CCQI (2023): 1.3.2 Robustness of the quantification methodologies applied to determine emission reductions or removals - Solar photovoltaic power, wind power (onshore), hdyropower (dams and run-of-river). Carbon Credit Quality Initiative. Online verfügbar unter https://carboncreditquality.org/download/Assessments/1.3.2%20CDM%20ACM0002%20%2814%20September%202023%29.pdf.

CIFs (2024): Climate Investment Fund – Accelerating Coal Transition Program. Investment Plan for the Republic of the Philippines: Revision. Online verfügbar unter https://www.cif.org/sites/cif_enc/files/2024-06/revised_act_ip_philippines_rev.0_05302024.pdf.

Climate Action Tracker (2023): Philippines. 5 June 2023. Online verfügbar unter https://climateactiontracker.org/countries/philippines/targets/.

Esmael, L. K. (2024): ACEN set to replace coal plant with $1.5-B solar facility. Business Inquirer. Online verfügbar unter https://business.inquirer.net/493438/acen-set-to-replace-coal-plant-with-1-5-b-solar-facility.

Esmael, L. K. (2025a): Semirara expects to obtain gov’t okay for new coal site. Business Inquirer. Online verfügbar unter https://business.inquirer.net/523877/semirara-expects-to-obtain-govt-okay-for-new-coal-site.

Esmael, L. K. (2025b): Semirara gets DENR clearance for P291-billion coal mine expansionSemirara gets DENR clearance for P291-billion coal mine expansion. Business Inquirer. Online verfügbar unter https://business.inquirer.net/530207/semirara-gets-clearance-for-p291-b-mine-expansion.

Galang, G. C. (2025): As coal power remains dominant, Semirara Mining renews interest in Saint Raphael project. Manila Bulletin. Online verfügbar unter https://mb.com.ph/2025/5/5/smpc-reaffirms-interest-in-saint-raphael-coal-project-analysts-weigh-in.

GenZero (2025): Mitsubishi and DGA Join ACEN, GenZero and Keppel to Drive Energy Transition with Transition Credits. Online verfügbar unter https://genzero.co/mitsubishi-and-dga-join-acen-genzero-and-keppel-to-drive-energy-transition-with-transition-credits/.

Global Energy Monitor: Mindanao Steag power station. Online verfügbar unter https://www.gem.wiki/Mindanao_Steag_power_station.

Global Energy Monitor (2025): Global Coal Plant Tracker. Online verfügbar unter https://globalenergymonitor.org/projects/global-coal-plant-tracker/coal-phaseout-tracking-retirements-and-paris-aligned-goals/.

IEA (2021): It's critical to tackle coal emissions. Commentary. Hg. v. International Energy Agency. Online verfügbar unter https://www.iea.org/commentaries/it-s-critical-to-tackle-coal-emissions.

IEA (2022): Coal in Net Zero Transitions. Strategies for rapid, secure and people-centred change. International Energy Agency. Online verfügbar unter https://iea.blob.core.windows.net/assets/4192696b-6518-4cfc-bb34-acc9312bf4b2/CoalinNetZeroTransitions.pdf.

IEA (2023): Where does Philippines get its coal? Online verfügbar unter https://www.iea.org/countries/philippines/coal.

IEA (2025): Global Energy Review 2025. International Energy Agency. Online verfügbar unter https://iea.blob.core.windows.net/assets/5b169aa1-bc88-4c96-b828-aaa50406ba80/GlobalEnergyReview2025.pdf.

Just Transition Finance Lab (2024): Case study: ACEN Renewables – using transition credits to accelerate coal closure. Grantham Research Institute on Climate Change and the Environment, London School of Economics and Political Science. Online verfügbar unter https://justtransitionfinance.org/wp-content/uploads/2024/12/ACEN-Renewables_using-transition-credits-to-accelerate-coal-closure.pdf.

Keppel (2024): ACEN, GenZero and Keppel join hands to catalyse retirement of coal-fired plants in Southeast Asia. Online verfügbar unter https://www.keppel.com/media/acen-genzero-and-keppel-join-hands-to-catalyse-retirement-of-coal-fired-plants-in-southeast-asia/.

Limos-Martinez, Stella Marris; Watanabe, Koichiro (2006): Slagging and fouling characteristics of seam 32/33, Panian coalfield, Semirara Island, Philippines. In: *Fuel* 85 (3), S. 306–314. DOI: 10.1016/j.fuel.2005.07.007.

Marubeni Corporation (2016): Marubeni to Acquire Stakes in the Philippines Puting Bato Thermal Power Station. Online verfügbar unter https://www.marubeni.com/en/news/2016/release/20161220E.pdf.

Monetary Authority of Singapore (2023): MAS Launches Coalition and Announces Pilots to Develop Transition Credits for the Early Retirement of Asia's Coal Plants. Online verfügbar unter https://www.mas.gov.sg/news/media-releases/2023/mas-launches-traction-and-announces-pilots-to-develop-transition-credits.

Republic of the Philippines (2021): Nationally Determined Contribution. Communicated to the UNFCCC on 15 April 2021. Online verfügbar unter https://unfccc.int/sites/default/files/NDC/2022-06/Philippines%20-%20NDC.pdf.

Republic of the Philippines (2025): Biennial Transparency Report - BTR1. Online verfügbar unter https://unfccc.int/sites/default/files/resource/%5BFinal%5D%20Philippine%20Biennial%20Transparency%20Report.pdf.

Rivera, D. (2019): AC Energy completes acquisition of Phinma Energy. Philstar. Online verfügbar unter https://www.philstar.com/business/2019/06/25/1929190/ac-energy-completes-acquisition-phinma-energy.

Rockefeller Foundation (2025): Rockefeller Foundation Announces Latest Steps to Accelerate Community-Focused Energy Transition Projects. Ashley Chang, media@rockfund.org. Online verfügbar unter https://www.rockefellerfoundation.org/news/rockefeller-foundation-announces-latest-steps-to-accelerate-community-focused-energy-transition-projects/.

The Philippines Department of Energy: Philippine Energy Plan. Volume 1. Online verfügbar unter https://legacy.doe.gov.ph/sites/default/files/pdf/pep/PEP%202023-2050%20Vol.%20I.pdf.

The Philippines Department of Energy (2020): Advisory on the Moratorium of Endorsements for Greenfield Coal-Fired Power Projects in Line with Improving the Sustainability of the Philippines' Electric Power Industry. The Philippines Department of Energy. Online verfügbar unter https://legacy.doe.gov.ph/sites/default/files/pdf/announcements/advisory-moratorium-endorsement-greenfield-coal-fired-power%20project.pdf.

The Philippines Department of Energy (2025a): 2024 Power Statistics. Online verfügbar unter https://legacy.doe.gov.ph/energy-statistics/philippine-power-statistics.

The Philippines Department of Energy (2025b): 2024 Power Statistics - Gross Power Generation per Grid, by Plant Type In MWh. Online verfügbar unter https://legacy.doe.gov.ph/energy-statistics/philippine-power-statistics.

The Philippines Department of Energy (2025c): 2024 Power Statistics - Installed Capacity per Grid, by Plant Type In MW. Online verfügbar unter https://legacy.doe.gov.ph/energy-statistics/philippine-power-statistics.

The Philippines Department of Energy (2025d): List of Existing Power Plants - Luzon Grid. As of 30 April 2025. Online verfügbar unter https://legacy.doe.gov.ph/sites/default/files/pdf/electric_power/01_Luzon%20Grid_2.pdf.

The Philippines Department of Energy (2025e): List of Existing Power Plants - Mindanao Grid. As of 30 April 2025. Online verfügbar unter https://legacy.doe.gov.ph/sites/default/files/pdf/electric_power/03_Mindanao%20Grid_2.pdf.

The Philippines Department of Energy (2025f): List of Existing Power Plants - Visayas Grid. As of 30 April 2025. Online verfügbar unter https://legacy.doe.gov.ph/sites/default/files/pdf/electric_power/02_Visayas%20Grid_2.pdf.

The Rockefeller Foundation (2023): The Rockefeller Foundation and GEAPP To Design the World’s First ‘Coal-To-Clean’ Credit Program in Emerging Economies. Online verfügbar unter https://www.rockefellerfoundation.org/news/the-rockefeller-foundation-and-geapp-to-explore-the-worlds-first-coal-to-clean-credit-program-in-emerging-economies/.

TransitionZero: ACEN early retirement in the Philippines. Asset: South Luzon Thermal Energy Corporation (SLTEC) (Deal Tracker Fact Sheet). Online verfügbar unter https://blog.transitionzero.org/hubfs/Analysis/TransitionZero%20Deal%20Tracker%20_%20ACEN%20Fact%20Sheet.pdf.

United Kingdom (2021): Global Coal to Clean Power Transition Statement. Online verfügbar unter https://webarchive.nationalarchives.gov.uk/ukgwa/20230313120149/https://ukcop26.org/global-coal-to-clean-power-transition-statement/.

VCS (2025): VMD0061 - Just tranistion requirements for accelerated retirement of coal-fired power plants. Verified Carbon Standard. Online verfügbar unter https://verra.org/methodologies/vmd0061-just-transition-requirements-for-accelerated-retirement-of-coal-fired-power-plants-v1-0/.

Villegas, B. M. (2024): Sustainable mining not an oxymoron: Lessons of Semirara. Online verfügbar unter https://www.bworldonline.com/opinion/2024/09/18/622127/sustainable-mining-not-an-oxymoron-lessons-of-semirara/.

Xiao, P. (2024): Overview of LNG, gas infrastructure in the Philippines. Independent Commodity Intelligence Services. Online verfügbar unter https://www.icis.com/explore/resources/news/2024/11/22/11053419/overview-of-lng-gas-infrastructure-in-the-philippines/.

Yep, E. (2024): Singapore, Philippine companies to use transition credits to retire coal plant. Reuters. Online verfügbar unter https://www.spglobal.com/commodity-insights/en/news-research/latest-news/energy-transition/081624-singapore-philippine-companies-to-use-transition-credits-to-retire-coal-plant.