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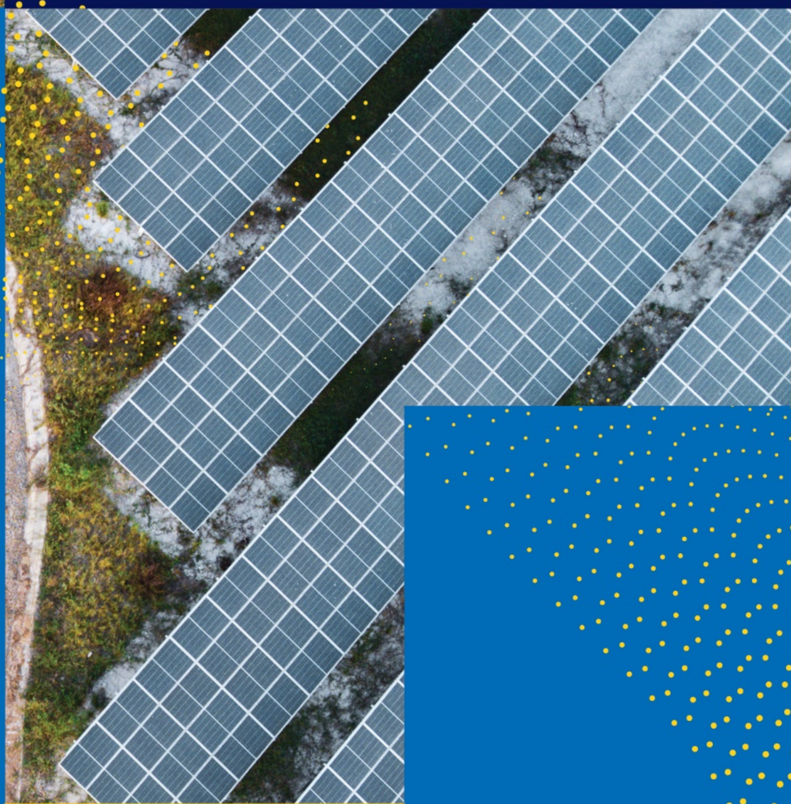

Common methodologies for transmission and wheeling tariffs.

Guidelines Report

Report Title	Guidelines Report on Common Methodologies for Transmission and Wheeling Tariffs
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Abbreviations list

AfSEM	African Single Electricity Market
AUC	African Union Commission
APM	Average Participation Method
CEPA	Continental Energy Programme in Africa
DSCR	Debt Service Coverage Ratio
ERERA	ECOWAS Regional Electricity Regulatory Authority
ES-0135	Pilot Phase Implementation of Continental Transmission Tariff Methodology for International Bilateral Transactions: Tariff Computational Model
EU	European Union
IRR	Internal Rate of Return
MW-km	Megawatt-kilometer
NPV	Net Present Value
O&M	Operation and Maintenance
OPEX	Operating Expenditure
RAB	Regulatory Asset Base
SAPP	Southern African Power Pool
SMO	System and Market Operator
TSO	Transmission System Operator
WACC	Weighted Average Cost of Capital
WACG	Weighted Average Cost of Generation
WAPP	West African Power Pool
WC	Working Capital

Executive Summary

The African Single Electricity Market requires a **transmission and wheeling tariff framework** that can support cross-border trade, protect cost recovery for transmission system operators, and give market participants confidence that network charges are transparent, non-discriminatory and grounded in measurable system use.

This Guidelines Report responds to that need by proposing a **revision of the ES-0135 continental transmission tariff methodology**. The report does not propose to discard ES-0135. Instead, it proposes to refactor it: to preserve its strongest methodological assets while adapting it to a more diverse, more regionalized and progressively more multilateral African electricity market.

The **central conclusion** of the report is that AfSEM should move away from the idea of one rigid continental tariff format and instead adopt the principle of:

one common cost-allocation engine, many possible regional tariff presentations.

This is the **main change in philosophy** behind the revised methodology.

> ES-0135 was originally designed around a point-to-point MW-km, load-flow-based approach for international bilateral transactions. That approach remains technically valuable, especially for defined wheeling transactions with clear injection and withdrawal points.
>
> However, it is not sufficiently flexible to serve as the only tariff expression for AfSEM, where regional markets may include bilateral contracts, organized trading platforms, pooled transactions, transit flows, short-term products and multiple simultaneous commercial arrangements.

The revised methodology therefore separates the problem into **two layers**.

Layer 1 is the **common AfSEM cost-allocation engine**.

> This is the focus of the present report. It defines the **common calculation logic** that should be shared across all power pools: eligible asset base, annual revenue requirement, asset usage shares, losses, technical adjustments, financial viability indicators and required cost recovery.

Layer 2 is the **regional tariff presentation layer**.

> This is **not developed in detail in this report**. It should be **addressed through follow-up activities with interested power pools**.
>
> Layer 2 is where the outputs of the common engine may be translated into the **tariff format** most appropriate for each regional context, such as APM, a two-part tariff, a hybrid model, a postage-stamp arrangement, a zonal structure or, in future, an entry-exit approach.

The practical meaning is simple:

AfSEM should harmonize the calculation discipline, not the tariff format.

The report identifies several important **methodological assets from ES-0135 that should be retained**.

The **first asset** to retain from ES-0135 is its **insistence on explicit cost recovery**.

> The original methodology gave significant weight to cost recovery, and enduring regional methodologies still begin with annual revenue determination, asset valuation, WACC, depreciation and O&M. This is fundamental. A transmission tariff methodology that cannot demonstrate how efficient network costs are recovered will not be credible to TSOs, regulators, investors, lenders, or governments.

The **second asset** is the discipline of **physical cost causation**.

> By choosing a load-flow-based MW-km methodology, continental stakeholders deliberately moved away from purely administrative tariff assignment and toward a model in which **cost follows actual system use**. That logic remains highly valuable. Even where AfSEM ultimately allows regional presentation formats other than point-to-point MW-km, the underlying discipline of tracing network usage, identifying benefiting or burdening users, and allocating losses based on measured or modelled flows should remain at the core of the revised methodology.

The **third asset** is **transparency and auditability**.

> ES-0135 was valuable precisely because it tried to **make cross-border pricing reproducible**: asset lists, benchmark values, revenue requirements, load-flow inputs, loss calculations, and computed outputs could all be inspected. For the purposes of a revised methodology, that transparency is non-negotiable. The future methodology may become more flexible in presentation, but it should not become less auditable.

A **fourth asset** is that ES-0135 created a **shared continental technical language**.

> It linked tariff policy, power-system modelling, and regulatory finance in one common framework, and it did so through **pilot implementation and training** rather than through abstract theory alone. That legacy matters: this activity does not have to invent a continental methodology from nothing. It can build on an existing computational tradition while reshaping its outputs to suit today's regional market realities.

The report's **main methodological shift** is **from a transaction-specific tariff model to a common cost-allocation engine**.

Under the original ES-0135 logic, the model asked:

> *Which assets are used by a specific bilateral transaction, and what tariff should that transaction pay?*

Under the revised AfSEM logic, the common engine asks a **broader question**:

> *What costs must be recovered, by whom, and on what measurable basis, before any regional tariff format is chosen?*

This change is necessary because the **African power pools are not identical**. They differ in system topology, data availability, institutional capacity, market maturity, settlement arrangements and tariff traditions. **A single rigid tariff presentation would either be too complex for some regions or too restrictive for others**. The revised methodology therefore preserves common economics while allowing differentiated regional implementation.

The result is **a more modular approach**. MW-km remains relevant, but it becomes one possible usage-allocation method within a broader engine. APM, two-part tariffs, hybrid models, postage-stamp arrangements and entry-exit structures may all be acceptable Layer 2 presentations, provided they are fed by the same transparent Layer 1 cost-allocation logic.

The report also makes an important boundary clear: this methodology concerns **transmission and wheeling tariffs only**. It does not cover institutional levies and fees for market operators, regulators or governance bodies. Those charges belong to a separate methodology and should remain distinct from transmission and wheeling tariffs. This separation is essential to avoid double recovery and to preserve the credibility of both tariff workstreams.

The **common engine** developed in the report has **seven core outputs**.

1. Eligible regional transmission asset base

The first step is to **define which assets are eligible for regional cost recovery**.

ES-0135 already relied on asset registers, replacement-cost valuation and load-flow results to identify assets used by a bilateral transaction. The revised methodology retains this **asset-based discipline** but changes the question. Instead of asking only which assets are used by a specific transaction, the revised engine asks **which assets are used, reserved or made available for regional transmission service**.

The eligible asset base may include cross-border interconnectors, internal high-voltage lines materially used by cross-border flows, transformers, substations, switchbays, reactive compensation equipment, and control, protection, metering and telecommunications equipment directly linked to eligible transmission service.

It should exclude generation assets, distribution assets, retail supply assets, market operator IT platforms, regulator costs, governance costs, institutional levies and fees, and general corporate assets not directly required for transmission service.

The **revised RAB logic** introduces two safeguards.

First, it deducts **non-remunerable funding**, such as grants, customer contributions or donor funding that should not earn a regulated return.

Second, it applies an **eligibility factor**, so that only the regional share of a shared asset is included in the regional asset base.

The revised approach therefore prevents regional users from **paying for unrelated domestic assets** or **earning returns on capital that was not financed by the TSO**. It also clarifies that asset eligibility and asset usage shares are separate steps: eligibility defines what enters the cost base; usage shares define who pays for that cost base.

2. Annual revenue requirement by TSO

The second step is to **determine the annual revenue requirement**.

ES-0135 already used a recognizable building-block formula based on RAB, WACC, working capital, O&M, depreciation and tax. The revised methodology retains this core logic but makes it more precise and more suitable for AfSEM.

The main change is the use of a **two-level structure**.

At **asset level**, the engine calculates the **annual revenue requirement for each eligible asset**. This preserves physical cost causation because the cost of specific assets can be traced and allocated.

At **TSO level**, the engine aggregates **eligible asset costs and adds TSO-level components** such as working capital and true-up. This preserves revenue adequacy for each network owner.

The revised formula introduces several improvements:

- use of average eligible regional RAB, to avoid distortions from commissioning, retirement or revaluation within the tariff year;
- replacement of generic O&M with efficient OPEX, preferably based on audited costs and using benchmarks only as fallback values;
- explicit pass-through costs for approved technical costs that should not be hidden in OPEX;
- explicit true-up, included once in the calculation chain, to correct under-recovery or over-recovery;
- deduction of other revenues to avoid double recovery;
- allocation of TSO-level residual costs, especially working capital, through an approved residual allocator;
- use of vanilla WACC, with tax treated separately and transparently.

The report also clarifies depreciation. Depreciation should be calculated on the **remaining eligible depreciable value**, net of accumulated depreciation and normally net of non-remunerable funding. This prevents the tariff from recovering value that has already been depreciated or funded through grants or contributions.

3. Asset usage shares

The third step is to **allocate recoverable network costs** among users, user groups, zones, transaction classes or other approved allocation objects.

This is where ES-0135's cost-causation logic is most important. The original methodology used load-flow analysis and MW-km logic to determine how a bilateral transaction used the transmission system. The revised methodology retains the principle that costs should follow network use, but no longer limits that principle to one specific expression.

The report introduces a general **usage metric**. This metric can be defined differently depending on the regional methodology, provided it is transparent, approved, auditable and consistent with the common engine.

Possible usage metrics include:

- MW-km for defined bilateral wheeling transactions;
- Average Participation Method for regional markets with recurring flows and stronger system data;
- hybrid allocation for transitional markets;
- postage-stamp allocation for early-stage or data-constrained systems;
- entry-exit or zonal allocation for more mature market designs.

This is a critical change. The revised methodology broadens the ways in which cost causation may be measured. This makes the methodology scalable and compatible with different power-pool realities.

The report also introduces an **allocation mechanism for TSO-level residual costs**. This ensures that costs admitted at TSO level, such as working capital, are not recognized in the annual revenue requirement but then left outside the user-level recovery chain.

4. Loss allocation

The fourth step is to **calculate and allocate losses**.

ES-0135 treated losses as a real cost of transmission service and calculated incremental losses through load-flow studies. The revised methodology retains this principle. Losses should remain visible, separately valued and traceable. They should not be hidden inside unrelated tariff components.

However, the revised methodology introduces a **hierarchy of loss-calculation methods**:

- The preferred method is **detailed incremental loss calculation**, comparing system losses with and without the relevant flow or user group.
- Where this is not practical, the methodology may use **corridor or zonal loss factors**, based on representative flow studies, historical losses or approved regional scenarios.
- Where data remain limited, the methodology may use a **standard transitional loss factor**, provided it is approved, published, periodically reviewed and treated as a transitional tool.

Loss quantities should be multiplied by an **approved loss price**. This may be based on weighted average generation cost, a market reference price, marginal energy cost, replacement energy cost or another transparent benchmark.

The report also recognizes that **losses may be settled financially or in kind**. If losses are settled in kind, any difference between required loss energy and delivered loss energy should be reconciled through the settlement process.

5. Reactive power and technical ancillary adjustments

The fifth step concerns **reactive power and technical ancillary adjustments**.

ES-0135 recognised that cross-border transactions may have technical impacts beyond simple active-power transport, including reactive power, voltage control and ancillary service needs. The revised methodology retains the possibility of technical adjustments but applies a conservative rule.

A **separate reactive power or ancillary adjustment** should be applied **only where the service is**:

- measurable;
- rule-based;
- attributable to a user or user group;
- not already recovered through the base network tariff.

Normal reactive support required to operate the grid within normal limits should usually be treated as part of the base transmission service.

A **separate reactive power charge** should apply only where a user causes measurable excess reactive use or operates outside approved technical limits.

The report also distinguishes **broader ancillary services**. Technical support inherent in transmission service may be recovered through the network revenue requirement. Separately procured ancillary services should be recovered through specific market or system-operation arrangements. Institutional market-operation costs must remain outside the transmission tariff and be recovered through separate levies and fees.

This distinction prevents double charging and ensures that the transmission tariff remains focused on physical network service.

6. Financial viability indicators

The sixth step is to **test whether the methodology supports financeability and revenue adequacy**.

A technically precise tariff methodology is not sufficient if it does not generate sufficient and predictable revenue for TSOs. ES-0135 already recognized this through financial viability checks such as NPV and IRR. The revised methodology retains these indicators and expands their role.

Financial viability should be **tested at three levels**:

- **asset or project level**, to assess whether a specific interconnector, corridor or reinforcement is financeable;
- **TSO level**, to verify that each network owner can recover its allowed revenue;
- **system or allocation level**, to ensure that the total recovery requirement is complete and not structurally under-recovered.

The report identifies the following indicators:

- Net Present Value;
- Internal Rate of Return;
- revenue recovery ratio;
- TSO revenue adequacy ratio;
- Debt Service Coverage Ratio where project finance is relevant;
- sensitivity testing for WACC, traded volumes, exchange rates, inflation, loss factors, loss prices, commissioning dates, demand scenarios and collection rates.

These indicators are essential because different Layer 2 tariff presentations may collect the same Layer 1 cost base with different levels of stability. For example, a highly volumetric tariff may expose TSOs to volume risk, while a fixed or capacity-based component may provide more stable recovery. The common engine should therefore test financeability before its outputs are translated into a final regional tariff format.

7. Required cost recovery

The seventh and final output is required cost recovery.

This step **consolidates all recoverable components calculated earlier in the engine and determines the amount that must be recovered from each user, user group, zone, transaction class, TSO or system**. It is the bridge between the technical-economic calculation engine and the regional tariff presentation layer.

Under ES-0135, required recovery was embedded in the tariff calculation for a specific bilateral transaction. Under the revised methodology, required recovery becomes a distinct output of the common engine.

The report defines recovery at three levels:

- **user-level required recovery**, covering allocated network costs, losses, reactive charges and other technical adjustments;
- **TSO-level required recovery**, allowing each TSO to identify its expected settlement entitlement;
- **system-level total required recovery**, defining the total amount that the regional tariff presentation must recover.

The engine also includes a revenue consistency identity, ensuring that the sum of user-level recoveries equals total required recovery. This is essential to prevent hidden under-recovery, over-recovery or allocation gaps.

True-up is treated as a reconciliation mechanism, but it must be included only once in the calculation chain. Other revenues are deducted to avoid double recovery and amounts already deducted as non-remunerable funding should not also be deducted as other revenue.

The required recovery output does not determine the final tariff. It only determines what must be recovered. The regional presentation layer later determines how it is charged.

In **conclusion**, the Guidelines propose a **pragmatic pathway for AfSEM tariff harmonization**.

It does not impose one continental tariff level. It does not prescribe one tariff format. It does not require every power pool to adopt the same tariff presentation immediately. Instead, it defines a common and auditable calculation engine that can support different regional implementation pathways.

This approach preserves the strongest features of ES-0135: explicit cost recovery, physical cost causation, transparency, auditability and a common continental technical language. At the same time, it proposes adjustments to the main limitations of the original methodology: excessive dependence on bilateral point-to-point transactions, high operational intensity, limited scalability and insufficient adaptability to regional diversity.

The **action priority** emerging from the report is therefore clear: AfSEM should use this report as the basis for **Layer 1 harmonization** and then **launch targeted Layer 2 implementation activities with interested power pools**.

Those activities should test how the common engine can be translated into practical regional tariff formats, taking account of each region's market design, settlement rules, data readiness and institutional capacity.

1 Introduction

1.1 Context

The **African Single Electricity Market (AfSEM)** requires a **predictable**, **transparent** and **credible framework** for the use of transmission networks in cross-border electricity trade.

As regional markets develop, electricity will increasingly move across several control areas, through both bilateral contracts and more organized trading arrangements.

In this context, transmission and wheeling tariffs should progressively move away from opaque, ad hoc or purely case-by-case arrangements toward transparent and predictable methodologies. They must be grounded in a **methodology that allows TSOs to recover efficient network costs**, while giving market participants confidence that **charges are fair, non-discriminatory and linked to measurable system use**.

The starting point for this work is the earlier continental methodology developed under **ES-0135**, which **operationalized a point-to-point MW-km, load-flow-based approach for international bilateral transactions**.

ES-0135 remains highly relevant because it established a continental technical language for cross-border transmission pricing. It connected asset valuation, regulatory revenue requirements, load-flow studies, loss allocation and tariff computation within a single model. However, **the market context is expected to evolve as AfSEM implementation progresses**. African power pools are at different stages of maturity, and several regions are moving beyond simple bilateral trade toward more complex regional market arrangements. A methodology designed mainly for defined bilateral transactions therefore needs to be revised so that it can **support a broader AfSEM architecture**.

This Guidelines Report proposes that ES-0135 should be revised according to a **two-layer architecture**:

- **Layer 1: a common AfSEM cost-allocation engine**, which defines the shared calculation logic for eligible assets, annual revenue requirements, asset usage shares, losses, technical adjustments, financial viability indicators and required cost recovery;
- **Layer 2: a regional tariff presentation layer**, through which the outputs of the common engine may be expressed differently depending on the power pool, for example through APM, two-part tariffs, hybrid models, postage-stamp arrangements, zonal structures or future entry-exit approaches.

<u>**The present report focuses primarily on Layer 1**</u>. It develops the common cost-allocation engine that should remain consistent across power pools.

<u>**Layer 2 is identified as the next implementation step and should be addressed through targeted follow-up activities with interested regional institutions**</u>, taking into account their market design, data availability, regulatory readiness and preferred tariff structure.

The scope of this report is limited to **transmission and wheeling tariffs**. These are charges linked to **physical use of the transmission network** and to the **recovery of transmission-related costs** such as asset remuneration, depreciation, efficient OPEX, losses and measurable technical adjustments.

The report does not cover institutional levies and fees for financing market operators, regulators or governance bodies. Those charges belong to a separate methodology and should remain distinct from transmission and wheeling tariffs in order to avoid double recovery and preserve transparency.

1.2 Structure of the Report

The report is structured as follows.

Chapter 2 – Foundational Role of ES-0135 and the Need for Revision explain why ES-0135 remains the technical starting point for the revised AfSEM methodology. It summarizes the original objective of ES-0135, its main components, and the strengths that should be retained. It then identifies the adjustments required to make the methodology more scalable, less rigidly bilateral, and more adaptable to the different stages of development of African power pools.

Chapter 3 – Revised ES-0135 Architecture introduces the two-layer structure of the revised methodology. It distinguishes between the common AfSEM cost-allocation engine, which is the focus of this report, and the regional tariff presentation layer, which should be developed through subsequent power-pool-specific work. This chapter establishes the principle of **"one core model, many presentations"**.

Chapter 4 – Common Cost-Allocation Engine develops the technical core of the revised methodology. It defines the seven outputs that the common engine should produce: eligible regional transmission asset base, annual revenue requirement by TSO, asset usage shares, loss allocation, reactive power and technical ancillary adjustments, financial viability indicators, and required cost recovery. This chapter revises the relevant ES-0135 formulas where needed and explains the logic behind each adjustment.

Chapter 5 – Conclusion summarizes the main methodological choices proposed in the report. It reiterates that the revised ES-0135 should preserve explicit cost recovery, physical cost causation, transparency and financial discipline, while moving away from a single rigid tariff presentation. It also identifies the next practical step: working with interested power pools to translate the common Layer 1 outputs into suitable Layer 2 tariff formats according to regional market conditions and institutional readiness.

Together, these chapters provide a revised methodological foundation for AfSEM transmission and wheeling tariff harmonization.

The report does not prescribe a uniform tariff level or a single regional charging format. Instead, it defines a **common and auditable calculation engine** that can support future regional implementation pathways according to the needs and readiness of each power pool.

2 Foundational Role of ES-0135 and the Need for Revision

The **original continental workstream** on harmonization of transmission and wheeling tariffs across Africa, led by the African Union Commission with support from the European Union, resulted in a **two-step exercise**:

- **First**, African stakeholders compared alternative transmission-pricing methods and selected the **point-to-point MW-km method supported by load-flow studies** as the most suitable starting point for the continent.
- **Second**, the "**tariff computational model**" workstream operationalized that choice into a practical model for international bilateral transactions, with pilot testing in African power pools before any wider roll-out.

The activity *Pilot Phase Implementation of Continental Transmission Tariff Methodology for International Bilateral Transactions: Tariff Computational Model* (ES-0135) sits squarely in that second step: it is the operationalization of the originally selected methodology.

For this report, the significance of ES-0135 is therefore twofold:

- It remains the most concrete continental attempt to convert high-level tariff principles into a practical computation of tariffs;
- Yet, it was designed for market architecture dominated by bilateral, point-to-point cross-border trades.

The chapter below explains both the continued relevance of ES-0135 and the reasons why AfSEM may need to adapt, rather than simply replicate, its approach to support a larger, more diverse, and progressively more multilateral African electricity market.

2.1 Original objective of ES-0135

The original objective of ES-0135 was to give the continent a **harmonized and technically valid way of determining transmission costs for cross-border electricity exchanges**, so that regional trade would not be undermined by opaque, inconsistent, or distortionary tariff setting.

The wider African Union program explicitly linked harmonized transmission tariffs to the creation of effective regional electricity markets, greater transparency, improved investment conditions, and the removal of barriers to cross-border trade[1].

That policy intent explains why stakeholders originally chose the **MW-km with load-flow method**. In the continental consultation process, the methodology was ranked against other approaches using criteria that included economic efficiency, cost recovery, transparency, correct price signals, simplicity of application, and impact on the transmission network[2].

> The point-to-point load-flow-based MW-km methodology was selected because it was seen, at that stage, as the best **compromise between economic logic and practical applicability** for cross-border bilateral exchanges.

The **pilot-oriented character** of ES-0135 is equally important. Continental stakeholders did not assume that adoption of the methodology would automatically produce implementation. On the contrary, the AU process explicitly recommended that the selected methodology be piloted among willing power pools, monitored closely, and refined through implementation experience before broader continental roll-out.

[1] AUC, Programme on Harmonised Continental Regulatory Framework for the Energy Sector in Africa: The Case of the Electricity Sector, 2017
[2] Ibid.

At its core, ES-0135 aimed to ensure that **a cross-border transaction would pay for the actual use it makes of the network, while ensuring that the hosting transmission operators are fairly compensated**. The 2018 continental support material described the model precisely in those terms: *TSOs should be able to allocate the cost of using transmission networks according to how much a given trade uses the network, and transmission utilities should be paid for wheeling electricity from one point to another.*

That objective remains valid today. What has changed is the institutional and market environment in which that objective must now be implemented.

2.2 Main components of the original model

Although ES-0135 was framed as a **point-to-point MW-km load-flow methodology for international bilateral transactions**, its architecture already established a **computational chain** moving from physical network data and asset registers to regulatory cost recovery and, finally, to an allocated tariff outcome.

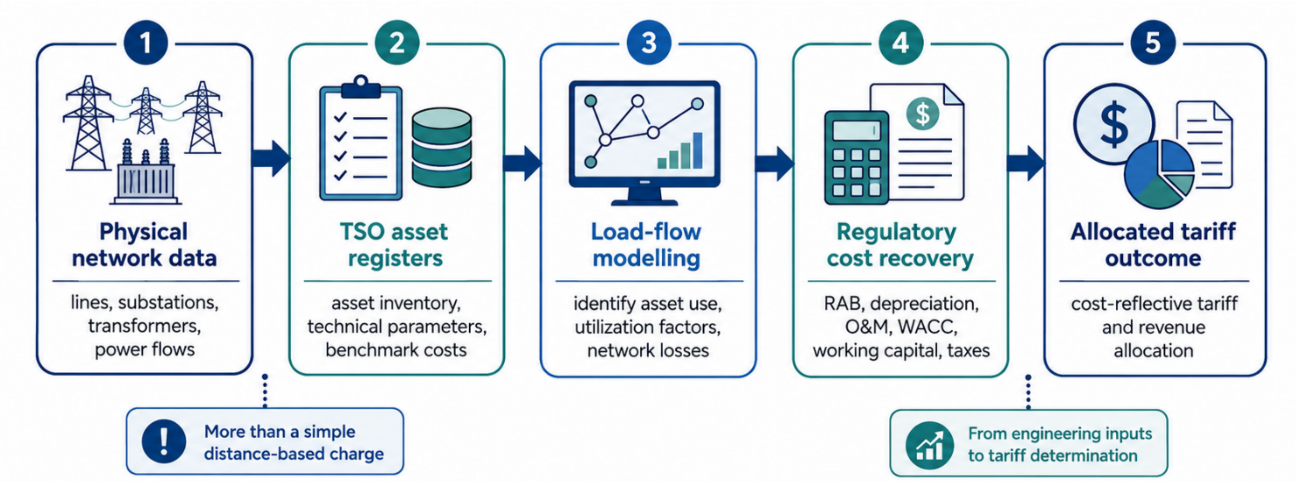

Figure 1: Computational Chain Foreseen by ES-0135 (source: CEPA AfSEM)

Comparable cost-building logic is visible in the current *2026 ERERA/WAPP Regional Transmission Tariff Methodology*[3], although that methodology replaces the earlier MW-km load-flow approach with the Average Participation Method (APM), using load-flow-derived inputs to allocate asset use, losses, costs and compensation amounts.

The formal **WAPP sequence** is to:

- determine regional transmission assets and asset values;
- calculate the annual revenue requirement for each asset;
- determine the value of electrical energy losses in the transmission network;
- prepare model-ready input files for APM;
- apply APM to determine flow contributions, loss allocation, cost allocation and compensation amounts;
- submit the results for ERERA approval, reflection in national tariffs and settlement through the SMO.

Below, the different major components of the ES-0135 are presented and analyzed together with the current WAPP methodology.

The **first major component** is therefore the **asset and benchmark-cost layer**.

[3] ERERA, RESOLUTION No. 020/ERERA/26 adopting the Regional Transmission Tariff Methodology (RTTM) applicable to the Regional Electricity Market (REM), March 2026

The underlying logic is that tariff design must not begin with ad hoc negotiated charges, but with a **defined asset base**. In ES-0135, this role was played by benchmark asset costs and the TSO asset register, which together formed the basis for establishing the **Gross Replacement Asset Value (GRAV)** and the **Net Replacement Asset Value (NRAV)**, used as the **Regulatory Asset Base (RAB)**.

The current WAPP methodology follows a comparable discipline: its regional asset database contains interconnected assets by class and Grid Operator, together with physical characteristics such as line lengths, number of circuits, line types, voltages, series capacitors, transformer ratings and commissioning dates. Replacement values are agreed by WAPP, approved by ERERA and updated periodically.

The **second major component** is the **annual revenue requirement**.

The enduring regulatory principle is that transmission pricing must first **determine what revenue the network is allowed to recover**, and only then decide how that revenue is allocated among users. ES-0135 expressed this through a **TSO annual revenue requirement formula** built around RAB, WACC, working capital, O&M, depreciation and tax.

WAPP's current methodology follows the same cost-recovery logic, beginning with asset value and annual revenue requirement, then incorporating capital costs, operation and maintenance costs and losses before allocation occurs through APM.

A **third component** is the **valuation-and-remuneration discipline embedded in the model**.

ES-0135 used replacement-cost-based asset valuation, straight-line depreciation, RAB remuneration through WACC, working capital allowance, tax treatment and explicit O&M recovery.

In WAPP's current methodology, annual asset value is calculated using the **Depreciated Replacement Standard Cost method**; ERERA may approve a common WACC for the regional system; and operation and maintenance costs are recovered through an annual margin on capital costs, typically in the range of 2% to 5%. The terminology and presentation are not identical, but the underlying regulatory discipline is comparable: **asset valuation**, **depreciation**, **remuneration of capital** and **explicit O&M recovery**. These are the conceptual equivalents of the GRAV/NRAV-RAB, depreciation, O&M and WACC blocks that made ES-0135 more than a simple transport fee.

The **fourth major component** is the **power-system engine**.

ES-0135's importance lay in its attempt to **connect transmission charges to modeled physical network** use rather than to a purely contractual or postage-stamp approximation. It used **load-flow analysis** to identify the assets participating in a wheeling transaction, calculate asset-utilization factors, apportion revenue requirements, determine incremental network losses and assess reactive power impacts.

WAPP's current methodology preserves that engineering orientation, but through APM rather than MW-km. It requires **load-flow-derived input files**, uses a **Common Grid Model**, prepares **year-ahead scenarios** representing expected system conditions, and **identifies the contribution of generators and loads to flows** on network assets.

The **fifth component** is **loss treatment**.

ES-0135 required **incremental or marginal losses** associated with specific wheeling transactions to be determined through **load-flow analysis**, so that transmission users could be charged in proportion to the losses they caused and TSOs could be compensated for additional losses incurred.

WAPP's current methodology requires the **SMO to determine annual losses on each network element using load-flow analysis**, allocate those losses according to the same APM-based proportions used for network-use allocation, and assign them a monetary value using an approved price reference.

For AfSEM, any future methodology that ignores losses or embeds them in non-transparent averages would reduce the transparency and cost-causation discipline already established in continental and regional tariff workstreams.

A **sixth component** is the **treatment of measurable technical impacts beyond simple contractual transport**.

> ES-0135 explicitly incorporated **reactive power and voltage-control considerations**, and it recognized that **ancillary services** are necessary for the reliable operation of interconnected power systems. It also recommended further work on regulation and frequency control, operating **reserves and black-start capability**.
>
> **WAPP's current methodology is narrower** in this respect: it focuses primarily on asset use, losses and inter-grid compensation, rather than fully pricing every ancillary-service or security-related impact.

Finally, the model includes an **adjustment and implementation logic**.

> ES-0135 recommended **periodic updating** of the asset register, annual updating of the system and asset databases, periodic revaluation of replacement values, updating of benchmarks and assumptions, and repeated load-flow analysis to maintain the tariff model.
>
> WAPP's current rules provide for **annual submissions** by the SMO, annual updating of the regional asset database, preparation of year-ahead Common Grid Model scenarios, ERERA approval of annual values, reflection of approved compensation in national tariffs, settlement through the SMO, and ex post review where actual flow patterns differ from ex ante allocations.

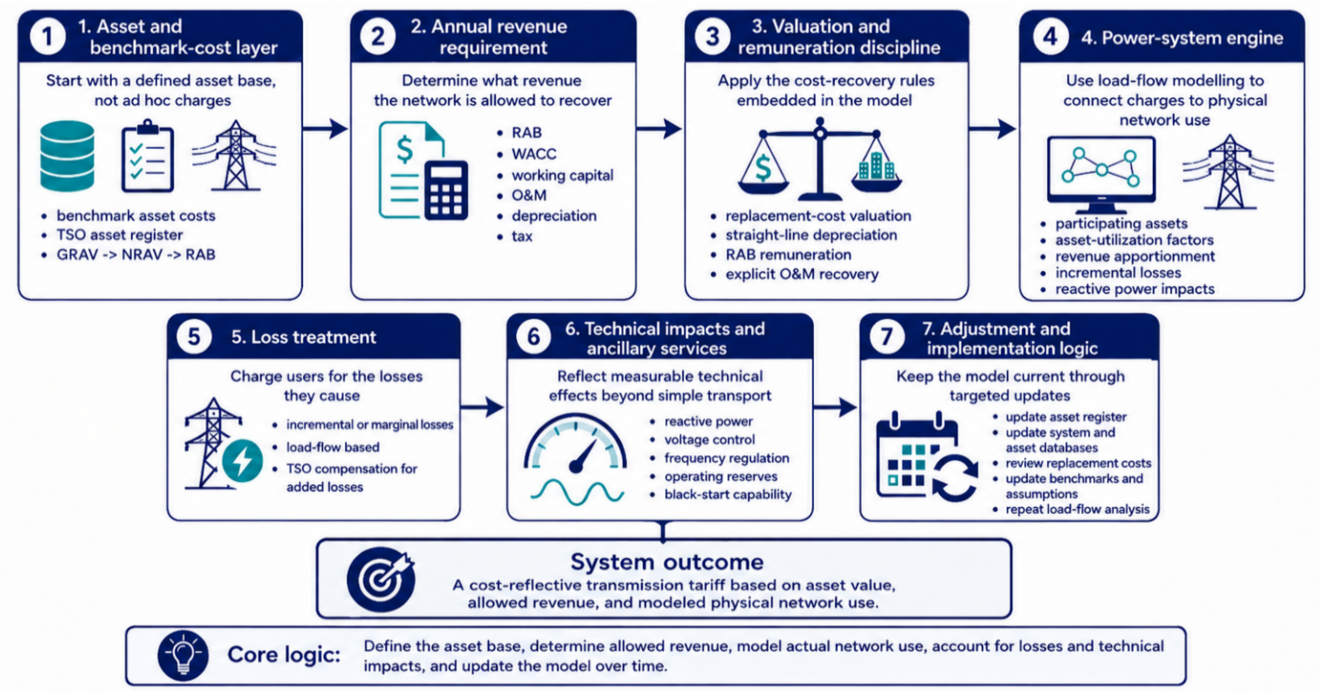

Figure 2: Main Components of the ES-0135 (source: CEPA AfSEM)

2.3 Strengths and proposed adjustments to the model

The revision of ES-0135 should not be understood as a rejection of the 2019 methodology. On the contrary, ES-0135 remains the most developed continental attempt to translate transmission tariff principles into an operational computational model for cross-border electricity trade. Its core contribution was to connect regulatory finance, asset valuation, load-flow analysis and tariff calculation within a single framework. That foundation remains valuable for AfSEM.

However, the conditions under which AfSEM will operate have evolved. The aspiration for regional markets is to increasingly move beyond isolated bilateral transactions toward **more complex trading arrangements**, including market platforms, pooled transactions, short-term products and multi-country flows. At the same time, African power pools differ significantly in institutional capacity, data readiness, market maturity and preferred tariff structures. A revised methodology must therefore distinguish between **what should be retained** as common continental discipline and **what should be adjusted** to improve scalability, usability and regional adaptability.

The following section therefore identifies, first, the main strengths of ES-0135 that should be preserved in the revised AfSEM methodology and, second, the adjustments required to transform ES-0135 from a relatively rigid transaction-specific model into a common cost-allocation logic capable of supporting different regional tariff presentations.

2.3.1 Strengths to retain

The **first strength** to retain from ES-0135 is its **insistence on explicit cost recovery**.

> The original methodology gave significant weight to cost recovery, and enduring regional methodologies still begin with annual revenue determination, asset valuation, WACC, depreciation and O&M. This is fundamental. A transmission tariff methodology that cannot demonstrate how efficient network costs are recovered will not be credible to TSOs, regulators, investors, lenders, or governments.

The **second strength** is the discipline of **physical cost causation**.

> By choosing a load-flow-based MW-km methodology, continental stakeholders deliberately moved away from purely administrative tariff assignment and toward a model in which **cost follows actual system use**. That logic remains highly valuable. Even where AfSEM ultimately allows regional presentation formats other than point-to-point MW-km, the underlying discipline of tracing network usage, identifying benefiting or burdening users, and allocating losses based on measured or modelled flows should remain at the core of the revised methodology.

The **third strength** is **transparency and auditability**.

> ES-0135 was valuable precisely because it tried to **make cross-border pricing reproducible**: asset lists, benchmark values, revenue requirements, load-flow inputs, loss calculations, and computed outputs could all be inspected. For the purposes of a revised methodology, that transparency is non-negotiable. The future methodology may become more flexible in presentation, but it should not become less auditable.

A **fourth strength** is that ES-0135 created a **shared continental technical language**.

> It linked tariff policy, power-system modelling, and regulatory finance in one common framework, and it did so through **pilot implementation and training** rather than through abstract theory alone. That legacy matters: this activity does not have to invent a continental methodology from nothing. It can build on an existing computational tradition while reshaping its outputs to suit today's regional market realities.

2.3.2 Proposed adjustments

The **first proposed adjustment** concerns the need to **adapt ES-0135's originally bilateral, transaction-specific logic to the requirements of a more multilateral electricity market**.

> The continental methodology was expressly developed for "international bilateral transactions," and that design choice **may constrain its application in a progressively more multilateral market**. Its point-to-point MW-km load-flow logic depends on identifiable transactions, known injection and withdrawal points, and the ability to associate network use with a specific bilateral trade. This makes it well suited to calculating wheeling charges for defined cross-border transactions, but less directly suited to market arrangements in which flows arise from pooled trading, anonymous platforms, loop flows, or multiple simultaneous transactions.

The **second proposed adjustment** refers to its **operational intensity**.

> A fully engineered transmission-pricing model requires a **great deal of data**: asset-by-asset network information, replacement values, commissioning dates, load-flow scenarios, cost files, and annual updates. Implicitly, the 2026 WAPP methodology recognizes this burden. It requires a regional asset database, annual updates from grid operators, replacement values periodically

approved and refreshed model-ready cost files, and yearly common-grid scenarios. ES-0135 would face similar, and in some respects greater, **implementation challenges** because it requires transaction-specific bilateral calculations in addition to asset and cost data. Where network data are incomplete, modelling practices are not standardized, or institutional capacity is uneven, applying ES-0135 at continental scale becomes operationally demanding.

The **third proposed adjustment** is to adapt ES-0135 to the evolving architecture of African electricity markets, which are **increasingly moving beyond the bilateral market structure** for which the original methodology was designed.

SAPP today operates not only bilateral contracts, but also organized short-term trading arrangements, including Forward Physical Markets, a Day-Ahead Market and an Intra-Day Market. Likewise, the Eastern Africa Power Pool is designing a regional market architecture that includes other forms of electricity market, with potential future integration or trading links with SAPP also contemplated. In such environments, the assumptions underlying a point-to-point bilateral wheeling methodology become progressively less suitable. A methodology that relies on clearly identified injection and withdrawal points, a known transaction path and transaction-specific load-flow impacts is well aligned with bilateral contracts, but **less directly aligned with pooled or platform-based trading** where multiple trades, counterparties and physical flows interact simultaneously.

The **fourth proposed adjustment** is to adapt the ES-0135 to **more naturally accommodate regional diversity**.

It should be recognized that African electricity markets are at different stages of development and therefore require phased implementation. That means **a single rigid tariff presentation is no longer appropriate**, even if **a common cost-allocation logic remains both feasible and desirable**. Harmonization must now become more modular.

3 Revised ES-0135 Architecture

The role of this chapter is to establish the conceptual architecture of the revised ES-0135 before the report turns, in the next chapter, to the common formulas and cost-allocation rules, while regional tariff presentations are identified as the next implementation step.

The central idea is that the revised methodology should be built into **two layers**:

- **A single AfSEM cost-allocation engine** that is common to all regions
- **A separate tariff presentation layer** that can vary by power pool.

This approach is consistent with two important regulatory lessons already visible in both international tariff practice and recent African regional discussions:

- First determine the allowed revenues and cost allocation logic
- Then, define the tariff structure through which those costs are presented;
- And avoid tying transmission charges too rigidly to individual commercial transactions where these risks distorting dispatch or constraining market evolution.

3.1 The common AfSEM cost-allocation engine

The **first layer** is the **common AfSEM cost-allocation engine**.

> This is the part of the methodology that must remain common across all power pools because **it defines the underlying economics of network cost recovery**.
>
> It answers the core question: *what costs must be recovered, by whom, and on what measurable basis?*
>
> In this sense, the engine is therefore not a tariff "format." It is the shared computational core that transforms network data, financial parameters, and system-use information into a **standard set of cost outputs**.
>
> This design choice follows the same logic found in regulated tariff practice more broadly, where allowed revenues are determined first and only then translated into tariff structures and user-facing charges[4].

Under the revised methodology, the common engine should calculate **seven outputs** for every relevant TSO and network user group:

- **First**, it should determine the **eligible transmission asset base**, meaning the regulated set of transmission assets that are used or made available for regional transmission service.
- **Second**, it should calculate each TSO's **annual revenue requirement**, including the admitted capital-related costs, efficient operating costs, and any approved adjustments.
- **Third**, it should determine **asset usage shares**, using the approved allocation method for identifying how cross-border usage is attributed to network elements or control areas.
- **Fourth**, it should calculate **loss allocation**, so that the cost of electrical losses is transparent and not hidden inside unrelated tariff items.
- **Fifth**, it should apply **reactive-power or ancillary adjustments** where applicable, but only where these are measurable, rule-based, and justified by the service design.
- **Sixth**, it should produce **financial viability indicators**, so that the resulting methodology can be tested against financeability and revenue adequacy.

[4] See ACER, Network Tariffs, April 2026

- **Seventh**, it should determine the **required cost recovery**, including any approved true-up or reconciliation amounts.

The important point is that all of these outputs belong to the common engine, regardless of how they are eventually presented to end-users in each region.

Accordingly, the next chapter will not yet choose a regional tariff format. It will instead define how this common engine works: which assets are eligible, how the annual revenue requirement is built, how usage shares are calculated, how losses are treated, which adjustments can be admitted, and how financial adequacy is tested.

In other words, the next chapter will define **the calculation logic that is common to all regions**.

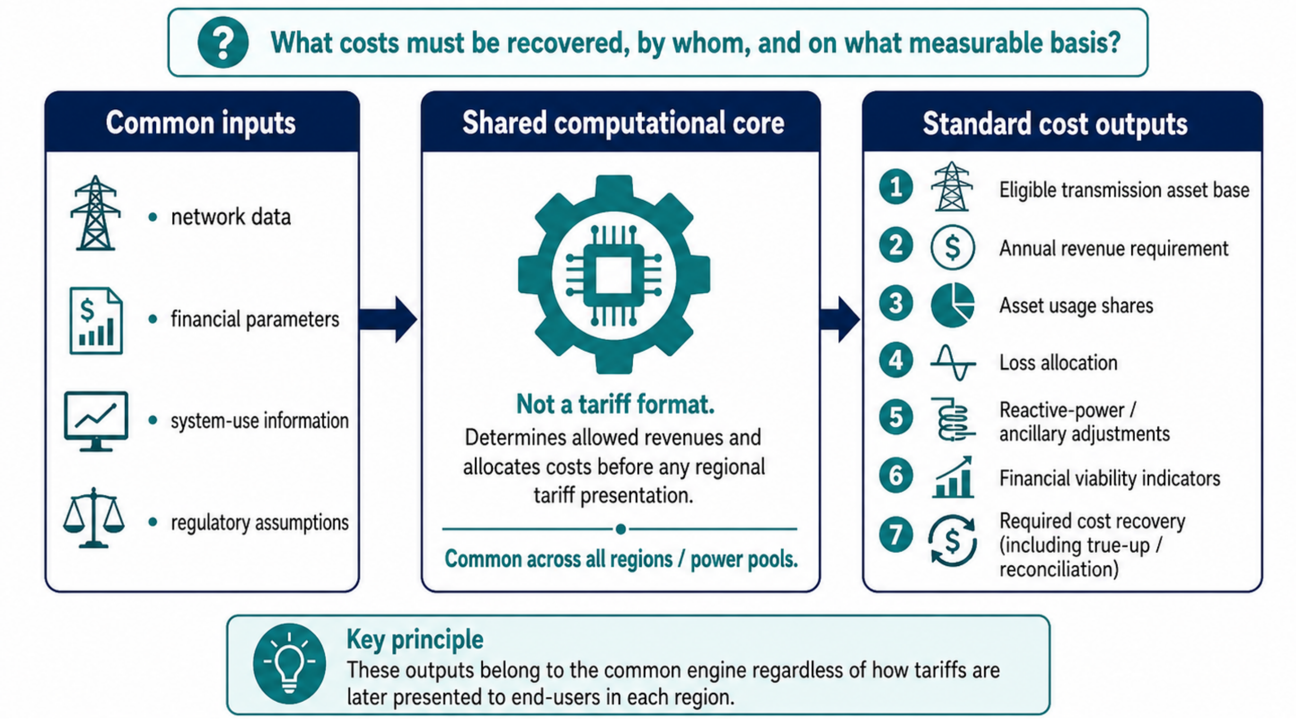

Figure 3: Layer 1: Common AfSEM Cost-Allocation Engine (source: CEPA AfSEM)

3.2 The regional tariff presentation layer

The **second layer** is the **regional tariff presentation layer**.

This is the part of the methodology that may vary across regions because it translates the common outputs of the cost-allocation engine into **tariff structures** that can be applied in practice. Once the common engine has calculated the underlying cost blocks, those **outputs may be presented in different ways** depending on market maturity, settlement arrangements, regulatory traditions, system topology, trading arrangements, and data capacity. The key discipline is that the presentation may change, but the underlying cost logic should not. This layer should therefore be understood as a presentation layer, not as a separate methodology.

Under this revised architecture, **the same cost outputs may be expressed through different tariff formats**.

- In some systems, they may be translated into an average-participation or flow-based allocation mechanism.
- In others, they may be presented as a two-part tariff, combining capacity and energy-related components.

- In markets undergoing progressive reform, they may be introduced through a hybrid model that preserves compatibility with existing bilateral arrangements while preparing for more organized trading.
- In less mature or data-constrained systems, the same outputs may initially be reflected through simpler postage-stamp or zonal arrangements.
- In more mature future market settings, the same common engine could support entry-exit or other platform-compatible charging structures.

In this way, **regional diversity is kept, while preserving continental consistency in the underlying calculation**.

This distinction is also important for market development. Regional markets increasingly include bilateral trade, day-ahead arrangements, forward products, intraday corrections, balancing actions, and more complex settlement environments. In such contexts, **the tariff methodology should not be locked into a single historical presentation format** if that format becomes incompatible with the relevant market design.

The revised ES-0135 should therefore **<u>preserve one common cost-allocation engine while allowing different regional expressions of the same outputs</u>**. That is the only way to make the methodology both harmonized and scalable.

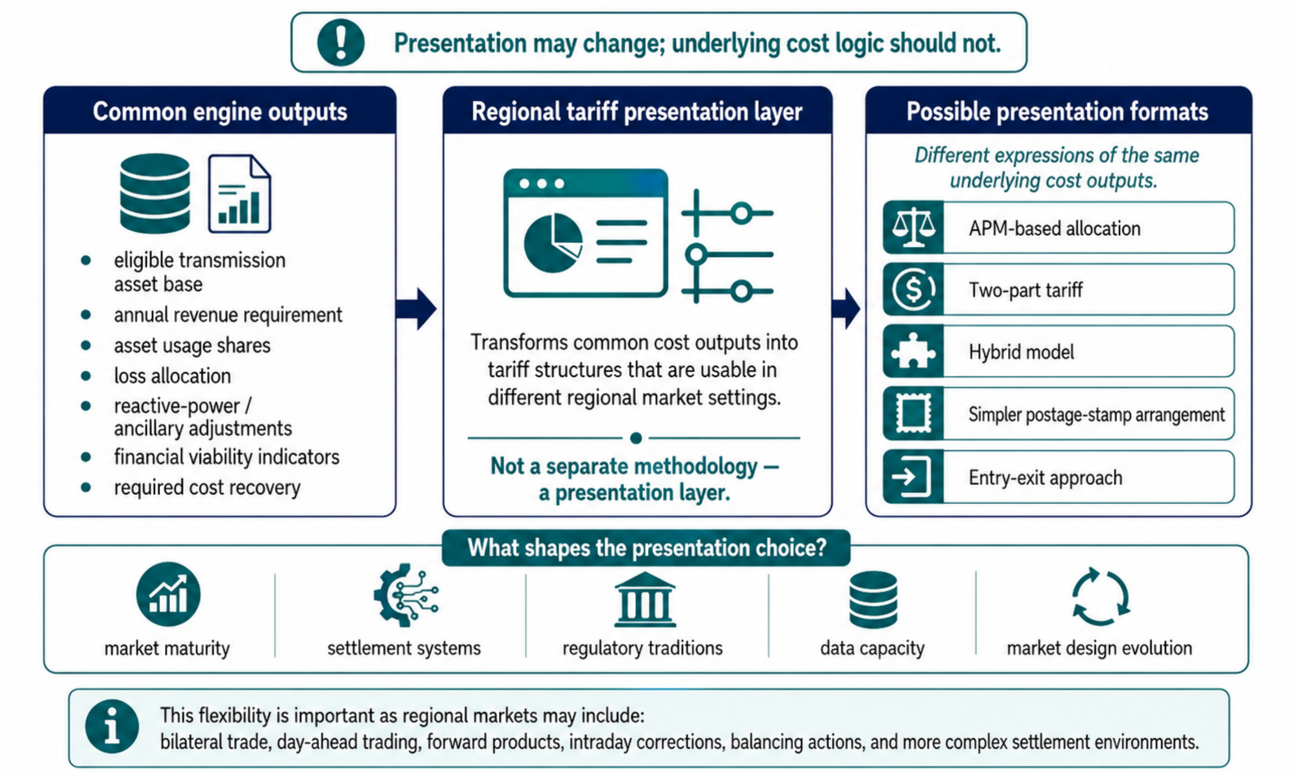

Figure 4: Layer 2: Regional Tariffs (source: CEPA AfSEM)

For the purposes of this Guidelines Report, **<u>Layer 2 is identified as the necessary next step, but it is not fully designed here</u>**.

<u>The present report concentrates on Layer 1</u>, namely the common AfSEM cost-allocation engine. **This is the part of the methodology that can be defined at continental level without prejudging the tariff format preferred by each power pool**.

The detailed design of Layer 2 should be undertaken through **<u>specific follow-up activities with interested power pools</u>**, where the outputs of the common engine can be translated into the regional format most appropriate for each context.

4 Common Cost-Allocation Engine

This chapter devises the **common AfSEM cost-allocation engine** as the revised technical core of ES-0135.

As stated before, **the objective is not to define a tariff format, but to define a common computational logic** that every power pool can use to answer the same seven questions in the same sequence:

- Which transmission assets are eligible?
- What revenue each TSO must recover
- How is asset use measured?
- How are losses valued?
- When reactive or ancillary adjustments are admissible?
- Are the resulting charges financially adequate?
- And what total cost must ultimately be recovered from users after true-up and offsets?

The revised engine should remain faithful to the strongest features of ES-0135: explicit cost recovery, physically grounded cost causation, transparency, and shared continental technical language.

At the same time, it must correct the limitations highlighted in the stocktaking exercise: excessive dependence on bilateral, point-to-point transaction tracing; very high data and modelling requirements; limited scalability in markets that are becoming more multilateral; and insufficient flexibility for regions at different stages of market maturity.

In practical terms, the revision is therefore not to abandon ES-0135, but to refactor it from a transaction-specific MW-km model into an **asset-based**, **revenue-based**, **method-neutral allocation engine**.

For clarity, the notation used below is the following:

- a denotes an asset;
- i a TSO;
- u a user or user group;
- z a zone;
- b a time block or settlement period;
- t the tariff year.

4.1 Engine architecture and core outputs

The revised engine should operate in an **asset-first sequence**.

> ES-0135 already moved in that direction by starting from asset registers, financial parameters and network studies. The revision proposed here makes that principle **explicit** and **modular**. The engine should first determine the regional share of the eligible transmission asset base; then derive asset-level and TSO-level annual revenue requirements; then calculate usage shares using the approved allocation metric; then determine loss charges and any measurable technical adjustments; and finally test revenue adequacy and bankability.
>
> Only after those outputs exist should a region decide whether to express them as APM, a two-part tariff, a hybrid model, a postage-stamp charge or, in future, an entry-exit structure.

The **seven common outputs** are summarized in the table below.

Common engine output	Purpose in the engine
Eligible regional transmission asset base	Defines which network assets are remunerated through regional transmission charges
Annual revenue requirement by TSO	Determines the efficient annual cost that must be recovered
Asset usage shares	Allocates recoverable network costs across users, zones, or transaction classes
Loss allocation	Makes electrical losses visible and separately valued
Reactive power / ancillary adjustments	Captures measurable and rule-based technical deviations where justified
Financial viability indicators	Tests whether the methodology supports financeability and revenue adequacy
Required cost recovery	Determines the net amount to be recovered after true-up, offsets and approved adjustments

Table 1: Seven Core Outputs of the Common Cost-Allocation Engine

The outputs listed in Table 1 are Layer 1 outputs. They define the common calculation discipline of the revised ES-0135 methodology. They do not, by themselves, determine the final tariff structure or invoice format.

The translation of these outputs into regional tariffs (for example through APM, two-part, hybrid, postage-stamp or entry-exit arrangements) **belongs to Layer 2 and should be developed through targeted activities with the relevant power pools**.

This report therefore focuses on ensuring that all regions can start from a common, transparent and auditable cost-allocation engine before selecting their preferred presentation format.

4.2 Eligible regional transmission asset base

The first step of the common AfSEM cost-allocation engine is to **define which transmission assets are eligible for regional cost recovery**. This step is critical because every later calculation depends on it: the Regulatory Asset Base, depreciation, WACC return, OPEX allocation, usage shares and final cost recovery all depend on the set of assets admitted into the model.

> ES-0135 already recognized the **importance of asset identification**. Its tariff model relied on a transmission asset register, replacement-cost valuation, load-flow results and utilization factors to determine which assets were used by a specific bilateral transaction. This should be retained. A transmission tariff methodology must remain **connected to the physical network**. It cannot credibly allocate costs unless it first identifies the assets providing the service.
>
> However, the revised AfSEM methodology must refine the ES-0135 approach because the common engine is no longer designed only for individual bilateral transactions. It must support regional market arrangements where assets may be used by several transactions, user groups, zones or market participants simultaneously.

The revised methodology therefore introduces a clearer distinction between:

1. **assets included in the technical network model**; and
2. **assets eligible for remuneration through the regional transmission tariff**.

This distinction is important. An asset may appear in a load-flow model because it affects system flows, but that does not automatically mean that its full cost should be recovered from regional users. The revised methodology should therefore determine eligibility explicitly before calculating the regional RAB.

4.2.1 What is retained from ES-0135

The revised methodology retains three important elements from ES-0135.

First, it **retains the principle of an asset-based tariff model**. Transmission costs should be linked to identifiable assets. This preserves the transparency and auditability of the original methodology.

Second, it **retains the use of replacement-cost asset valuation**, based on the distinction between Gross Replacement Asset Value and Net Replacement Asset Value. In ES-0135, the Regulatory Asset Base was effectively linked to the depreciated replacement value of the relevant transmission assets:

$$RAB_{a,t} = NRAV_{a,t} = GRAV_{a,t} - AccDep_{a,t}$$

Where:

- $GRAV_{a,t}$= Gross Replacement Asset Value of asset $a$in year t;
- $AccDep_{a,t}$= accumulated depreciation;
- $NRAV_{a,t}$= Net Replacement Asset Value;
- $RAB_{a,t}$= Regulatory Asset Base.

This valuation logic remains useful because it avoids relying only on historical book values, which may be inconsistent across countries and may not reflect the economic cost of replacing transmission infrastructure.

Third, it **retains the principle that the model should be based on assets that are used or useful** for the relevant transmission service.

> ES-0135 applied this mainly through transaction-specific load-flow analysis. The revised methodology keeps the same logic but generalizes it so that it can apply to broader regional transmission service, not only to a single point-to-point trade.

4.2.2 What changes compared with ES-0135

The main change is that the revised methodology moves from **transaction-specific asset participation** to **regional asset eligibility**.

Under ES-0135, the model identifies the assets used by a specific bilateral transaction and allocates costs according to that transaction's impact on those assets. This is appropriate where the question is:

> *Which assets are used by this bilateral trade?*

Under the revised AfSEM methodology, the question becomes broader:

> *Which transmission assets are used, reserved, or made available for regional transmission service, and what portion of their regulated value should be recovered through the regional transmission tariff?*

This is a different question and requires a more explicit eligibility filter.

The revised methodology should therefore classify assets into three categories as presented in the table below.

Asset Category	Treatment in the Common Engine
Dedicated regional assets	**Fully eligible**
Shared internal transmission assets	**Partially eligible**
Purely domestic assets	**Not eligible**

Table 2: Asset Category

This classification allows the common engine to preserve ES-0135's cost-causation discipline while avoiding over-recovery from regional users.

4.2.3 Assets to be included and excluded

The eligible regional transmission asset base should include **only assets that are part of the physical transmission service and are used or made available for regional electricity flows**.

The following assets may be included:

- cross-border interconnectors;
- internal high-voltage transmission lines materially used by cross-border flows;
- transformers used for regional transmission service;
- substations linked to eligible regional transmission assets;
- switchbays and switching equipment;
- reactive compensation equipment which is part of the transmission service;
- control, protection, metering, telecommunications and related equipment directly linked to eligible transmission assets.

In other words, the asset should be included only if it contributes to the provision of regional transmission service. The fact that an asset is owned by a TSO is not sufficient. The asset must either be used by regional flows, reserved for regional trade, or necessary for the reliable operation of regional transmission service.

The revised methodology should also state clearly **what must not enter the regional transmission asset base**.

The following items should generally be excluded:

- generation assets;
- distribution assets;
- retail supply assets;
- market operator IT platforms;
- regulator costs;
- governance and coordination costs;
- institutional levies and fees;
- general corporate assets not directly required for transmission service.

This exclusion is essential because the regional transmission tariff is a network-use charge. It should recover the cost of the physical transmission system, not the cost of market institutions. Market operator fees, regulatory levies and governance costs must remain separate charges under the institutional levies and fees framework. Mixing these costs into the transmission tariff would weaken transparency and create a risk of double recovery.

4.2.4 Revised eligible regional RAB formula

The revised methodology should refine the ES-0135 RAB formula as follows:

$$EligibleRegionalRAB_{a,t} = \left(GRAV_{a,t} - AccDep_{a,t} - NonRemunerableFunding_{a,t}\right) \times EligibilityFactor_{a,t}$$

Where:

- $EligibleRegionalRAB_{a,t}$= eligible regional RAB of asset $a$in year t;
- $GRAV_{a,t}$= Gross Replacement Asset Value;
- $AccDep_{a,t}$= accumulated depreciation;
- $NonRemunerableFunding_{a,t}$= grants, donor funding, customer contributions or other funding that should not earn a regulated return;
- $EligibilityFactor_{a,t}$= share of the asset admitted for regional transmission cost recovery.

This formula retains the ES-0135 replacement-cost logic but introduces **two important safeguards**.

The **first safeguard** is the deduction of **non-remunerable funding**.

> If an asset has been financed through grants, customer contributions or other funds that should not earn a regulated return, that amount should not be included in the remunerated asset base unless the applicable regulatory decision explicitly allows it. This prevents users from paying a return on capital that the TSO did not finance.
>
> The deduction of non-remunerable funding should apply not only to the return on capital but also, where appropriate, to depreciation. If a grant, customer contribution or other non-remunerable source has financed part of an asset, regional users should not normally repay that funded portion through depreciation unless a specific regulatory decision provides otherwise. The purpose is to avoid both a return on capital not financed by the TSO and recovery of capital already funded through another source.

The **second safeguard** is the **eligibility factor**.

> This prevents the whole value of a shared domestic asset from being recovered through the regional tariff when only part of the asset supports regional service.

4.2.5 Eligibility factor

The eligibility factor should express the **proportion of an asset that is eligible for regional cost recovery**.

A practical formulation is:

$$EligibilityFactor_{a,t} = \begin{cases} 1, & \text{if asset } a \text{ is a designated interconnector or regional common asset} \\ RegionalUseShare_{a,t}, & \text{if asset } a \text{ is a shared internal transmission asset} \\ 0, & \text{if asset } a \text{ is purely domestic} \end{cases}$$

Where:

$$0 \leq RegionalUseShare_{a,t} \leq 1$$

The $RegionalUseShare_{a,t}$may be determined through representative **load-flow studies**, **observed flow data**, **approved capacity reservation**, or **another transparent and approved allocation rule**.

For example:

- a cross-border interconnector would normally have an eligibility factor of 1;
- an internal 400 kV line heavily used by transit flows may have a partial eligibility factor;

- a radial line serving only domestic load would have an eligibility factor of 0.

This is one of the most important changes compared with ES-0135. The original methodology identified assets used by a specific transaction. The revised methodology identifies the **share of each asset that belongs to regional transmission service** more generally. This makes the model usable in multilateral or market-based environments.

4.2.6 Why non-remunerable funding is introduced

ES-0135 focused on replacement value and depreciation. The revised methodology should go further by explicitly deducting **non-remunerable funding**.

This is necessary because many regional transmission assets in Africa may be financed partly through **grants**, **concessional funds**, **public contributions**, **donor support** or **customer-funded connection charges**. If those amounts remain inside the RAB, users may end up paying a regulated return on funds that were not actually invested by the TSO or that were already recovered through another source.

The deduction of non-remunerable funding therefore supports three objectives:

1. avoid over-recovery;
2. protect tariff users from double payment;
3. increase confidence in the fairness of the methodology.

This change does not prevent grant-funded assets from being included in the technical model. It only **prevents non-remunerable funding from being treated as capital on which the TSO earns a return**, unless a specific regulatory decision provides otherwise.

4.2.7 Why asset eligibility must be separated from asset usage shares

It is important to distinguish between **asset eligibility** and **asset usage shares**.

Asset eligibility answers the question:

> *Is this asset, or a portion of this asset, part of the regional transmission asset base?*

Asset usage shares answer a different question:

> *Once the asset is eligible, how should its cost be allocated among users, zones, transactions or participant groups?*

These two steps should not be merged.

For example, an internal transmission line may be 40% eligible for regional cost recovery because regional flows account for 40% of its relevant use. Once that eligible portion is admitted into the regional asset base, the cost of that eligible portion may then be allocated among users using MW-km, APM, postage-stamp, hybrid or entry-exit logic.

This distinction is central to the common AfSEM engine:

$EligibleRegionalRAB$ defines the cost base
$UsageShare$ allocates that cost base among users

Keeping these steps separate preserves transparency and prevents confusion between “what costs are recoverable” and “who pays them.”

4.2.8 Summary of changes compared with ES-0135

The following table summarizes the proposed changes to the ES-0135 methodology:

Element	ES-0135 approach	Revised AfSEM approach	Reason for change
Asset identification	Assets identified mainly through transaction-specific load-flow analysis	Assets classified by regional eligibility before user allocation	Makes the model usable beyond bilateral transactions
Asset register	Transmission asset register used for tariff calculation	Regional asset database plus eligibility screening	Distinguishes technical modelling from remuneration
RAB	GRAV minus accumulated depreciation	GRAV minus accumulated depreciation minus non-remunerable funding, multiplied by eligibility factor	Avoids over-recovery and double remuneration
Regional use	Reflected through transaction-specific utilisation	Reflected first through eligibility, then through usage shares	Separates cost-base definition from cost allocation
Shared internal assets	Included if used by the transaction	Included partially where materially used or reserved for regional service	Allows fair treatment of shared domestic/regional infrastructure
Non-network costs	Not the focus of ES-0135	Explicitly excluded	Maintains separation from levies and fees
Method flexibility	Closely linked to point-to-point MW-km	Compatible with APM, two-part, hybrid, postage-stamp and entry-exit presentations	Supports one core model — many presentations

Table 3: Summary of Proposed Changes (Asset Eligibility)

4.3 Annual revenue requirement by TSO

The annual revenue requirement is the **financial core** of the common AfSEM cost-allocation engine. **It determines the amount that each TSO is allowed to recover for providing eligible regional transmission service**.

This part of ES-0135 should be retained, because the original methodology correctly recognized that transmission tariffs must be grounded in a regulated revenue requirement, including asset remuneration, depreciation, operating costs and tax.

In ES-0135, the TSO annual revenue requirement was expressed as:

$$TSOARR_t = (RAB_t \times WACC) + (WC_t \times WACC) + O\&M_t + Dep_t + Tax_t$$

Where:

- RAB is the Regulatory Asset Base;
- $WACC$ is the allowed weighted average cost of capital;
- WC is working capital;
- $O\&M$ is operation and maintenance expenditure;
- Dep is depreciation;
- Tax is corporate tax.

This formula remains **conceptually valid** and should not be discarded.

It reflects one of the main strengths of ES-0135: **explicit cost recovery** through a recognisable building-block approach.

However, the formula **needs to be refined** for AfSEM because the revised methodology is no longer intended only to calculate a tariff for a specific bilateral transaction. It must operate as a **common cost-allocation engine** that can support different regional tariff presentations.

The purpose of the revision is therefore not to change the economic principle of ES-0135, but to make the annual revenue requirement more precise, auditable, updateable and adaptable to different power pool contexts.

4.3.1 What is retained from ES-0135

The revised methodology **retains the core building blocks** of the original ES-0135 formula.

First, it **retains the principle that the TSO should earn a regulated return on the eligible asset base**.

This is essential for investment incentives and for the bankability of regional transmission infrastructure.

Second, it **retains depreciation as a separate cost component**.

This ensures that the value of transmission assets is recovered over their useful lives, rather than being recovered immediately or hidden in other charges.

Third, it **retains operating expenditure as an admissible cost**.

Transmission assets require maintenance, system operation, inspections, technical support and asset management. These costs must be recovered if the service is to remain reliable.

Fourth, it **retains tax and working capital where applicable**. These are legitimate financing and fiscal costs, provided they are treated consistently and transparently.

Therefore, the revised methodology does not reject ES-0135. It preserves its cost-recovery discipline but improves the way the revenue requirement is calculated and reconciled.

4.3.2 What changes compared with ES-0135

The main change is that the annual revenue requirement should be calculated through a **two-level structure**:

- first, an **asset-level calculation**, to preserve physical cost causation;
- and second, a **TSO-level aggregation of eligible regional asset costs**, to preserve revenue adequacy for each network owner.

This is necessary because the revised methodology must serve two objectives at the same time. It must **identify which assets are used or made available** for regional transmission service, and it must **ensure that each TSO can recover the total allowed revenue associated with those eligible assets**.

4.3.3 Revised asset-level revenue requirement

The revised methodology should first calculate the **annual revenue requirement for each eligible asset**:

$$ARR_{a,t} = (RAB_{a,t}^{avg} \times WACC_{i,t}) + Dep_{a,t} + OPEX_{a,t}^{eff} + Tax_{a,t} + PassThrough_{a,t} - OtherRevenue_{a,t}$$

Where:

- $ARR_{a,t}$= annual revenue requirement of asset a in year t;
- $RAB_{a,t}^{avg}$= average eligible regional RAB of asset a;
- $WACC_{i,t}$= allowed WACC of the TSO i owning or operating the asset;
- $Dep_{a,t}$= depreciation of asset a;
- $OPEX_{a,t}^{eff}$= efficient operating expenditure attributed to asset a;
- $Tax_{a,t}$= tax allowance, where applicable;
- $PassThrough_{a,t}$= approved technical pass-through costs;
- $OtherRevenue_{a,t}$= other revenue deducted to avoid over-recovery.

This formula keeps the same regulatory logic as ES-0135, but makes **five important adjustments**.

Firstly, it moves **from a generic RAB to average eligible regional RAB**. ES-0135 applied return on the RAB. The revised methodology should apply return on the average eligible regional RAB:

$$RAB_{a,t}^{avg} = \frac{RAB_{a,t}^{open} + RAB_{a,t}^{close}}{2}$$

This change has two purposes.

First, **it avoids distortions when an asset is commissioned, retired, revalued or partially included** during the tariff year. If the model used only opening RAB or closing RAB, it could overstate or understate the capital actually used during the period.

Second, it reinforces the distinction between the **whole asset base of a TSO** and the **eligible regional transmission asset base**. AfSEM should not remunerate all national transmission assets automatically. It should remunerate only the assets, or portions of assets, used or made available for regional transmission service.

Secondly, it moves **from O&M to efficient OPEX**

ES-0135 included O&M in the annual revenue requirement and, in practice, relied partly on benchmark percentages. That remains a useful starting point, but the revised engine should clearly prefer audited cost information where available. The primary formula should therefore be:

$$OPEX_{i,t}^{eff} = AuditedOPEX_{i,t} \times EfficiencyFactor_{i,t}$$

If only TSO-level audited OPEX is available, but asset-level allocation is needed, it should be distributed across assets using an approved allocator, such as replacement value, asset count or maintenance drivers.

Where audited data is not available, the transitional fallback should be:

$$OPEX_{a,t}^{eff} = BenchmarkOPEXRate_{c(a)} \times GRAV_{a,t}$$

where $c(a)$ is the asset class of asset a.

The revision here is methodological discipline. Benchmark OPEX rates, including the 2–5% type ranges that informed earlier regional practice, should remain available as **fallback values**, but not as the permanent endpoint of the methodology. This preserves implementability in lower-capacity regions while encouraging convergence toward actual and efficient cost data over time

Thirdly, **depreciation should be calculated on the eligible depreciable value of the asset**. To remain consistent with the deduction of non-remunerable funding from the RAB, the depreciable value should normally exclude the same non-remunerable funding amount, unless the applicable regulatory decision explicitly allows recovery of that amount through depreciation.

This results in:

$$RemainingDepreciableValue_{a,t}^{eligible} = (GRAV_{a,t} - NonRemunerableFunding_{a,t} - ResidualValue_{a,t}) \times EligibilityFactor_{a,t}$$

And:

$$Dep_{a,t} = \frac{RemainingDepreciableValue_{a,t}^{eligible}}{RemainingUsefulLife_{a,t}}$$

Where:

- $RemainingDepreciableValue_{a,t}^{eligible}$= remaining depreciable value of asset a eligible for regional recovery in year t;
- $GRAV_{a,t}$= Gross Replacement Asset Value;
- $AccDep_{a,t}$= accumulated depreciation;
- $NonRemunerableFunding_{a,t}$= grants, customer contributions, donor funding or other non-remunerable funding;
- $ResidualValue_{a,t}$= residual value, normally zero unless otherwise justified;
- $EligibilityFactor_{a,t}$= share of the asset admitted for regional transmission cost recovery;
- $RemainingUsefulLife_{a,t}$= remaining useful life of the asset.

This adjustment does not prevent grant-funded or donor-funded assets from being included in the technical network model. It only **prevents the non-remunerable portion from being recovered twice through the tariff**.

Fourthly, it explicitly **recognizes pass-through costs**

The revised formula introduces:

$$PassThrough_{a,t}$$

This term covers **approved technical costs** that are legitimate but should not be hidden inside general OPEX. Examples may include extraordinary technical studies, mandatory compliance costs, insurance costs or specific network-security expenses, where these are approved by the relevant regulatory process.

The purpose is transparency. If a cost is exceptional, unavoidable and approved, it should be visible in the formula rather than absorbed into a broad O&M estimate.

Fifthly, it considers a potential **deduction of other revenues**.

The revised formula includes:

$$OtherRevenue_{a,t}$$

This is deducted from the revenue requirement. The purpose is to **avoid double recovery**.

> If an eligible transmission asset already receives approved revenue from another source, that revenue should reduce the amount recovered through the regional transmission tariff. This is especially important where assets have benefited from grants, concessional funding, customer contributions, congestion revenues or other earmarked payments.

4.3.4 Revised TSO-level annual revenue requirement

After asset-level revenue requirements are calculated, they should be aggregated to TSO level:

$$ARR_{i,t} = \sum_{a \in i} ARR_{i,t} + (WC_{i,t} \times WACC_{i,t}) + TrueUp_{i,t}$$

Where:

- $ARR_{i,t}$= annual revenue requirement of TSO i;
- $ARR_{a,t}$= annual revenue requirement of each eligible regional asset owned or operated by TSO i;
- $WC_{i,t}$= approved working capital allowance;
- $WACC_{i,t}$= allowed WACC of TSO i;
- $TrueUp_{a,t}$= reconciliation adjustment.

The revised formula introduces:

$$TrueUp_{a,t}$$

or, where applied at TSO level:

$$TrueUp_{i,t} = AllowedNetRevenue_{i,t-1} - ActualNetRevenue_{i,t-1}$$

If a **carrying charge** is permitted, then:

$$TrueUp_{i,t}^{adj} = TrueUp_{i,t} \times \left(1 + r_t^{carry}\right)$$

Where:

- r_t^{carry} = the approved carrying-charge rate.

The point is that the revised AfSEM engine should **make reconciliation explicit**.

> If a TSO recovers less than its allowed revenue in one period, the shortfall can be recovered in a later period. If it recovers more than its allowed revenue, the excess should be returned through a downward adjustment. This prevents persistent under-recovery or over-recovery and makes the methodology more credible to TSOs and users.

Working capital is kept at TSO level because it normally relates to the financing cycle of the TSO as a service provider, not to each asset individually.

Because working capital is admitted at TSO level, the revised methodology should also define **how this TSO-level component is allocated to users**. Otherwise, the model may correctly recognize working capital in the TSO annual revenue requirement but fail to recover it through the subsequent usage-allocation step. The common engine should therefore distinguish between asset-level costs and TSO-level residual costs. Asset-level costs are allocated through asset usage shares, while TSO-level residual costs are allocated through an approved residual allocator.

$$ResidualCost_{i,t} = (WC_{i,t} \times WACC_{i,t}) + TrueUp_{i,t}^{TSO} + Tax_{i,t}^{TSO} - OtherRevenue_{i,t}^{TSO}$$

Where:

- $ResidualCost_{i,t}$= TSO-level cost not directly assigned to individual assets;
- $WC_{i,t}$= approved working capital allowance of TSO i;
- $WACC_{i,t}$= allowed WACC of TSO i;

- $TrueUp_{i,t}^{TSO}$= TSO-level reconciliation amount, where applied at TSO level;
- $Tax_{i,t}^{TSO}$= tax allowance where tax is calculated at TSO level;
- $OtherRevenue_{i,t}^{TSO}$= other revenues deducted at TSO level to avoid over-recovery.

If true-up, tax or other revenue are already allocated at asset level, they should not be included again in $ResidualCost_{i,t}$. This rule avoids double counting.

At minimum, the residual-cost block should include the **working-capital allowance**, because this is normally calculated at TSO level.

4.3.5 Treatment of Weighted Average Cost of Capital (WACC)

The revised methodology retains WACC because it is **essential for remunerating capital invested in transmission infrastructure**. However, it should avoid one rigid continental value.

The general formula is:

$$WACC_{i,t} = \frac{E_{i,t}}{V_{i,t}} K_{e,i,t} + \frac{D_{i,t}}{V_{i,t}} K_{d,i,t}$$

With:

$$V_{i,t} = E_{i,t} + D_{i,t}$$

Where:

- $E_{i,t}$= equity;
- $D_{i,t}$= debt;
- $V_{i,t}$= total capital;
- $K_{e,i,t}$= cost of equity;
- $K_{d,i,t}$= cost of debt (before-tax).

The change compared with ES-0135 is not the use of WACC itself, but the way it is specified. ES-0135 used WACC as a central parameter. The revised methodology should require the WACC to be transparently justified, periodically updated and tested through sensitivities.

Where reliable data exists, the WACC may be **TSO-specific, country-specific, corridor-specific or regional**.

Where data are weak, a **benchmark WACC range** may be used. In all cases, the approved WACC should be documented in the model and tested through sensitivity analysis because WACC is one of the most sensitive drivers of the final tariff.

4.3.6 Treatment of tax

ES-0135 included tax as a separate item in the revenue requirement. The revised methodology retains this approach. For consistency, the WACC applied in the common engine should be a **vanilla WACC**, while tax should be calculated separately and transparently. If a region decides to use a pre-tax or post-tax WACC instead, the tax line in the ARR formula should be adjusted accordingly to avoid double counting.

4.3.7 Summary of changes compared with ES-0135

The following table summarizes the proposed changes to the ES-0135 methodology:

Element	ES-0135 approach	Revised AfSEM approach	Reason for change
Revenue requirement	TSO-level building-block formula	Asset-level calculation plus TSO-level aggregation	Allows cost allocation by asset while preserving TSO revenue adequacy
RAB	RAB based on replacement value and depreciation	Average eligible regional RAB	Avoids timing distortions and excludes non-regional assets
O&M	O&M cost component	Efficient OPEX	Ensures only efficient and justified costs are recovered
Pass-through	Not separately emphasised	Explicit pass-through term	Makes exceptional approved costs visible
True-up	Adjustment logic present but not central	Explicit reconciliation term	Corrects under- or over-recovery transparently
Other revenues	Not sufficiently explicit	Deducted from ARR	Avoids double recovery
WACC	Core financial parameter	Retained as vanilla WACC, with tax treated separately and sensitivity testing required	Reflects different financing conditions
Tax	Included as cost item	Retained as a separate ARR component, provided it is consistent with the WACC definition	Avoids double counting
Working capital allocation	Included in TSO revenue requirement	Kept at TSO level and allocated through a residual-cost allocator	Ensures working capital is recovered without forcing artificial asset-level allocation
Depreciation	Straight-line depreciation on admitted asset value	Straight-line depreciation on remaining eligible depreciable value, net of accumulated depreciation and non-remunerable funding	Aligns depreciation with RAB treatment and avoids recovery of already-depreciated value or capital already funded through grants or contributions

Table 4: Summary of Proposed Changes (Annual Revenue Requirement and Financial Parameters)

4.4 Asset usage shares

Usage allocation is part of the common AfSEM cost-allocation engine that **determines who pays for the eligible transmission costs identified in the previous sections**.

Once the eligible regional asset base and annual revenue requirement have been established, the methodology must **allocate those costs** among users, user groups, zones, transactions or market participants in a way that reflects their use of, or benefit from, the transmission system.

This is where ES-0135 made one of its most important contributions.

> The original methodology did not allocate cross-border transmission costs arbitrarily. It used load-flow analysis and point-to-point MW-km logic to identify how a bilateral transaction used the transmission network. The **tariff was therefore linked to physical system use**: assets used more heavily by a transaction received a higher cost allocation, while assets not used by that transaction were not charged to it.

That principle should be retained. A revised AfSEM methodology should continue to be based on **physical cost causation**. However, the method used to express that cost causation must be broadened. ES-0135 was designed primarily for identifiable international bilateral transactions, while AfSEM must also aim at accommodating regional markets with multiple simultaneous trades, pooled market arrangements, average participation methods, hybrid approaches and future entry-exit designs.

The revised methodology therefore **keeps the cost-causation** discipline of ES-0135, but **no longer locks it into one single MW-km presentation**.

4.4.1 What is retained from ES-0135

The revised methodology retains **three key elements** from ES-0135.

First, it **retains the principle that transmission costs should follow network use**.

> Users that impose greater use on the transmission system, or benefit more from regional transmission service, should generally bear a higher share of recoverable costs.

Second, it **retains the use of technical network evidence**.

> Cost allocation should be based on load-flow studies, measured flows, representative system conditions, approved participation factors, or other transparent allocation metrics. The methodology should prioritize technical and transparent allocation metrics. Where negotiated or simplified shares are used as transitional arrangements, they should be explicitly approved, documented and time bound.

Third, it **retains the principle of asset-level traceability**.

> The model should remain capable of showing which assets create recoverable costs and how those costs are assigned to users or user groups. This is essential for transparency and auditability.

4.4.2 What changes compared with ES-0135

The main change is the move from **transaction-specific utilization factors** to a more general concept of **approved usage shares**.

Under ES-0135, the methodology asks:

> *What share of each transmission asset is used by this specific bilateral transaction?*

Under the revised AfSEM methodology, the common engine asks a broader question:

> *What approved share of each eligible asset's cost should be allocated to each user, user group, zone or transaction class, based on the allocation method applicable in that region?*

This change is necessary because different power pools may use different ways of measuring or presenting network use.

The common engine must therefore be **method-neutral** at the presentation level, while remaining disciplined at the calculation level.

4.4.3 Revised usage allocation formula

The revised methodology should introduce a general usage metric:

$$M_{u,a,t}$$

Where:

- $M_{u,a,t}$= approved measurable usage metric for user, user group, zone or transaction class u, on asset a, in year t;
- u= user, user group, zone, participant group or transaction class;
- a= eligible transmission asset;
- t= tariff period.

The usage share is then calculated as:

$$UsageShare_{u,a,t} = \frac{M_{u,a,t}}{\sum_v M_{v,a,t}}$$

Subject to:

$$\sum_u UsageShare_{u,a,t} = 1$$

Where:

- v= all users, user groups, zones or transaction classes sharing the cost of asset a;
- $UsageShare_{u,a,t}$= share of asset a's recoverable cost allocated to user u.

The allocated network cost is then:

$$AllocatedNetworkCost_{u,a,t} = UsageShare_{u,a,t} \times ARR_{a,t}$$

And at TSO level:

$$AllocatedNetworkCost_{u,i,t} = \sum_{a \in i} AllocatedNetworkCost_{u,a,t} + AllocatedResidualCost_{u,i,t}$$

Where:

- $AllocatedNetworkCost_{u,a,t}$= cost of asset $a$allocated to user u;
- $ARR_{a,t}$= annual revenue requirement of asset a;
- $AllocatedNetworkCost_{u,i,t}$= total cost allocated to user $u$for the eligible assets of TSO i;
- $AllocatedResidualCost_{u,i,t}$= share of TSO-level residual cost allocated to user u.

The Allocated Residual Cost is:

$$AllocatedResidualCost_{u,i,t} = ResidualShare_{u,i,t} \times ResidualCost_{i,t}$$

Subject to:

$$\sum_u ResidualShare_{u,i,t} = 1$$

Where:

- $ResidualShare_{u,i,t}$= approved share used to allocate TSO-level residual costs;
- $ResidualCost_{i,t}$= TSO-level residual cost calculated in Section 4.3.4.

The **residual allocator** may use the **same usage metric applied to asset-level costs, or another approved allocator** such as eligible MWh, contracted capacity, peak demand, APM share or another transparent regional metric. The selected allocator should be documented in the model. This ensures that **costs recognized at TSO level**, especially working capital, **are not left outside the user-level recovery chain**.

This formula is the core of the revised cost-causation logic. It allows AfSEM to preserve a common allocation discipline while allowing each region to define the appropriate usage metric.

The **key variable** is therefore:

$$M_{u,a,t}$$

This is where regional flexibility is introduced.

The revised methodology should not prescribe a single usage metric for all power pools. Instead, it should **define acceptable categories of usage metrics**, if each is transparent, approved, auditable and consistent with the cost-recovery logic of the common engine.

Allocation method	Definition of $M_{u,a,t}$	Typical use case
MW-km	Power flow attributable to user (u) on asset (a), multiplied by relevant distance	Defined bilateral transactions
Average Participation Method	Average participation of user (u) in the use of asset (a) across representative periods	Regional markets with recurring flows and better system data
Hybrid allocation	Weighted combination of socialised cost and usage-based cost	Transitional markets with incomplete data
Postage-stamp allocation	Same allocation metric for all eligible MWh or users in the defined charging zone	Early-stage markets or low-data environments
Entry-exit / zonal allocation	Approved allocation metric assigned to entry and exit zones	More mature markets with zonal or platform-based trading

Table 5: Examples of Usage Metric for Specific Allocation Methods

The change is necessary for **four reasons**.

First, **it makes the methodology scalable**.

A transaction-specific MW-km model can work for a small number of bilateral trades, but it becomes difficult to administer when multiple trades occur simultaneously or when transactions are cleared through organized platforms.

Second, **it allows AfSEM to accommodate regional diversity**.

Power pools are not at the same stage of market development. A single tariff presentation would either be too complex for some regions or too restrictive for others.

Third, **it preserves physical discipline without over-engineering**.

Where detailed flow studies are possible, they should be used. Where they are not yet possible, approved transitional metrics can be used, provided that the simplification is transparent.

Fourth, **it separates the calculation engine from the tariff format**.

The engine calculates recoverable costs and usage shares.

4.4.4 Summary of changes compared with ES-0135

The following table summarizes the proposed changes to the ES-0135 methodology:

Element	ES-0135 approach	Revised AfSEM approach	Reason for change
Allocation logic	Transaction-specific MW-km/load-flow allocation	General usage-share framework based on approved metric $M_{u,a,t}$	Allows multiple regional allocation methods
User definition	Specific bilateral transaction	User, user group, zone, participant class or transaction class	Supports bilateral and multilateral markets
Cost causation	Based on specific transaction impact	Based on physical use, average use, zonal use, socialized share or hybrid allocation	Preserves cost causation while improving scalability
Method flexibility	MW-km as central method	MW-km, APM, hybrid, postage-stamp or entry-exit as possible metrics	Supports one core model — many presentations

Table 6: Summary of Proposed Changes (Asset Usage Shares)

4.5 Loss allocation

Losses and technical adjustments are a distinct component of the common AfSEM cost-allocation engine. Once eligible network costs have been determined and allocated through usage shares, the methodology must also **identify and recover the technical costs caused by the physical movement of electricity across the transmission system**. These costs mainly concern transmission losses and, where applicable, reactive power or ancillary technical support.

ES-0135 already recognized that **losses should not be ignored or hidden** inside general transmission charges. Its methodology calculated the incremental losses caused by a bilateral transaction by comparing system conditions with and without the transaction and then valued those losses using an approved energy cost. This remains an important strength of the original methodology. Cross-border electricity trade imposes real electrical losses on transmission systems, and those losses must be recovered transparently if the tariff methodology is to be credible.

However, the revised AfSEM methodology should refine the ES-0135 approach in two ways. First, it should **retain the principle of explicit loss allocation** but allow different levels of calculation depending on data and modelling capacity. Second, it should **treat reactive power and ancillary technical adjustments cautiously**, admitting separate charges only where they are measurable, rule-based and not already recovered through the base network tariff.

The purpose of this section is therefore to define how the common engine should calculate losses and technical adjustments before these outputs are translated into regional tariff presentations.

4.5.1 What is retained from ES-0135

The revised methodology retains **three important elements** from ES-0135.

First, it **retains the principle that losses are a real cost of transmission service**.

> Electricity injected into the system is not fully delivered to the withdrawal point because part of it is lost as heat and other technical losses in transmission assets. These losses require additional generation and therefore create a cost that must be allocated.

Second, it **retains the principle of incremental loss calculation** as the most technically robust approach.

> Where data and network models are available, the preferred method remains to compare network losses under two cases: the base case without the relevant cross-border flow and the case with the relevant regional use included. The difference represents the losses attributable to that use.

Third, it **retains the principle that losses should be priced explicitly**.

> ES-0135 used a generation-cost reference to value incremental losses. The revised methodology should keep the same concept: loss quantities should be multiplied by an approved loss price, rather than being hidden inside unrelated tariff components.

These elements preserve the cost-causation discipline of ES-0135. Users should be able to see what portion of their charge relates to network cost recovery and what portion relates to losses.

4.5.2 What changes compared with ES-0135

The main change is that the revised methodology introduces a **hierarchy of loss-calculation methods**.

ES-0135 was designed around detailed transaction-specific calculations. This remains appropriate where the relevant transaction is clearly identifiable and reliable load-flow studies are available. However, for AfSEM, **not all power pools will be able to perform detailed incremental loss studies for every transaction, user group, zone or settlement period from the outset**.

The revised methodology should therefore use a tiered approach:

1. **detailed incremental loss calculation** where data and models allow;
2. **corridor or zonal loss factors** where transaction-specific modelling is not practical;
3. **standard transitional loss factors** where data are limited.

This is not a weakening of the methodology. It is a way to preserve transparency while avoiding an implementation burden that some regions cannot yet meet. The common engine should always calculate losses explicitly, but the level of sophistication may evolve as regional data and modelling capacity improve.

4.5.3 Preferred method: incremental loss calculation

The **preferred loss formula** is:

$$LossCharge_{u,t} = \sum_{b} \Delta\, Loss_{u,b,t} \times LossPrice_{b,t}$$

Where:

- $LossCharge_{u,t}$= loss charge allocated to user, user group, zone or transaction class $u$in year t;
- b= time block, season or settlement period;
- $\Delta Loss_{u,b,t}$= incremental losses attributable to user $u$in time block b;
- $LossPrice_{b,t}$= approved loss valuation price for time block b.

The incremental loss term may be calculated as:

$$\Delta Loss_{u,b,t} = TotalLosses^{with\ u,b,t} - TotalLosse^{without\ u,b,t}$$

Where:

- $TotalLosses^{with\ u,b,t}$ = total system losses with the relevant user, flow or regional usage pattern included;
- $TotalLosses^{without\ u,b,t}$ = total system losses without that user, flow or usage pattern.

This method is closest to ES-0135. It is technically robust because it captures the **actual impact of the relevant cross-border flow on system losses**. It is particularly suitable for defined bilateral wheeling transactions, major corridors, pilot projects or systems with strong load-flow modelling capacity.

However, this method **requires reliable network models**, **representative operating cases** and **agreed assumptions on dispatch, demand, topology and cross-border schedules**. It should therefore be the preferred method, but not the only method.

4.5.4 Fallback method: corridor or zonal loss factors

Where detailed incremental studies are not yet practical, the revised methodology should allow loss allocation through **approved corridor or zonal loss factors**.

The formula is:

$$LossCharge_{u,t} = \sum_{b} L\,F_{z(u),b,t} \times ScheduledEnergy_{u,b,t} \times LossPrice_{b,t}$$

Where:

- $LF_{z(u),b,t}$= approved loss factor for the corridor or zone associated with user u;
- $ScheduledEnergy_{u,b,t}$= scheduled energy of user $u$in time block b;
- $LossPrice_{b,t}$= approved loss valuation price.

This approach is **less precise** than incremental loss modelling, but it is **easier to implement**. It can be based on representative load-flow studies, historical measured losses, corridor studies or regional operating scenarios. It is suitable for power pools where cross-border flows are recurring but transaction-specific loss studies are too demanding.

The important requirement is that **corridor or zonal loss factors must be approved, periodically updated and separately visible in the model**. They should not become arbitrary percentages.

4.5.5 Transitional method: standard loss factor

Where even corridor or zonal loss factors are not yet available, the revised methodology may allow a **standard transitional loss factor**.

The formula is:

$$LossCharge_{u,t} = \sum_{b} L\,F_{b,t}^{std} \times ScheduledEnergy_{u,b,t} \times LossPrice_{b,t}$$

Where:

- $LF_{b,t}^{std}$= standard approved loss factor for time block b;
- $ScheduledEnergy_{u,b,t}$= scheduled energy of user u;
- $LossPrice_{b,t}$= approved loss valuation price.

This should be treated as a **transitional option only**. It may be useful for early-stage markets, low-volume corridors or regions with limited data. However, the methodology should require a **clear pathway toward corridor, zonal or incremental loss calculation as data quality improves**.

The standard loss factor should be simple, published and reviewed periodically. It should not be used to conceal inefficient network losses or to penalise users without evidence.

4.5.6 Loss price

The **loss quantity** must be **multiplied by an approved loss price**. ES-0135 used the concept of the weighted average cost of generation. The revised methodology should retain this logic, but allow the loss price to be defined according to the market context.

The general rule is:

$$LossCost = LossQuantity \times LossPrice$$

The approved $LossPrice_{b,t}$ may be based on:

- weighted average cost of generation;
- market reference price;
- marginal energy cost;
- replacement energy cost;
- another approved transparent benchmark.

The choice of loss price should be **consistent across users within the same tariff period** and should be **documented in the model**. If the region has an **organized market price**, that price may become a suitable reference. If not, a **weighted average generation cost** or **approved benchmark** may be used.

The key point is that the loss price must be transparent. Users should be able to understand both the quantity of losses allocated to them and the price used to value those losses.

4.5.7 Treatment of loss over-recovery or under-recovery

Loss charges should be reconciled where there is a **difference between forecast and actual loss recovery**.

A simple reconciliation formula may be:

$$LossTrueUp_t = AllowedLossCost_{t-1} - ActualLossRevenue_{t-1}$$

Where:

- $AllowedLossCost_{t-1}$= approved loss cost for the previous period;
- $ActualLossRevenue_{t-1}$= actual revenue collected for losses in the previous period.

If **losses are settled in kind** rather than financially, **the same principle applies**: any difference between required loss energy and delivered loss energy should be reconciled through the settlement process.

This true-up is important because losses are often forecast before the tariff period begins. Actual flows, dispatch and network conditions may differ from forecasts. The methodology should therefore avoid both permanent under-recovery and hidden over-recovery.

4.5.8 Separation between network cost allocation and loss allocation

The revised methodology should keep network cost allocation and loss allocation separate.

Network cost allocation answers the question:

How should the annual revenue requirement of eligible transmission assets be allocated among users?

Loss allocation answers a different question:

What additional energy cost is caused by electrical losses associated with regional transmission service?

These two elements **may appear together in the final tariff presentation**, but they should remain **separately calculated inside the common engine**.

This separation is important because different regional tariff formats may present losses differently. For example:

- a region may show losses as a separate line item;
- a region may apply a standard loss factor;
- a region may require loss energy to be delivered in kind;
- a region may embed losses into a usage charge.

All of these presentations may be acceptable, provided that the common engine calculates the loss component transparently.

4.5.9 Summary of changes compared with ES-0135

The following table summarizes the proposed changes to the ES-0135 methodology:

Element	ES-0135 approach	Revised AfSEM approach	Reason for change
Loss calculation	Incremental losses for specific bilateral transactions	Tiered hierarchy: incremental, corridor/zonal, standard transitional factor	Preserves technical accuracy while allowing phased implementation
Loss pricing	Weighted average generation cost logic	Approved loss price: WACG, market reference price or approved benchmark	Adapts to different market contexts
Loss visibility	Losses calculated as part of transaction tariff	Losses remain separately calculated inside the common engine	Improves transparency and prevents hidden charges
Loss reconciliation	Adjustment logic not central	Explicit loss true-up where forecast and actual recovery differ	Avoids under- or over-recovery
Implementation	Detailed transaction-specific modelling	Data hierarchy with transitional options	Makes the methodology usable across power pools with different capacities

Table 7: Summary of Proposed Changes (Loss Allocation)

4.6 Reactive power and technical ancillary adjustments

ES-0135 also considered reactive power and ancillary service impacts. The revised AfSEM methodology should retain the possibility of technical adjustments, but it should apply them conservatively.

The general principle should be: **a separate reactive power or ancillary adjustment should be applied only where the service is measurable, rule-based, attributable to a user or user group, and not already recovered through the base network tariff**.

Normal reactive power support required to operate the grid within normal limits should usually be **treated as part of the base transmission service**. It should not automatically create an additional charge.

A **separate reactive power charge** should apply **only where a user causes measurable excess reactive use or operates outside agreed technical limits**, such as approved power-factor bands.

The recommended formula is:

$$ReactiveCharge_{u,t} = ReactiveTariff_t \times ExcessReactiveUse_{u,t}$$

Where:

- $ReactiveCharge_{u,t}$= reactive power charge allocated to user u;
- $ReactiveTariff_t$= approved reactive power tariff;
- $ExcessReactiveUse_{u,t}$= measured reactive power use or deviation outside the approved operating band.

If the necessary metering, technical rules or settlement arrangements are not in place, the methodology should not impose a separate reactive charge. In that case, the relevant cost should remain within the base transmission service until the region has the technical capability to measure and allocate it properly.

4.6.1 Broader ancillary services

Ancillary services may include **voltage control**, **frequency support**, **balancing**, **operating reserves**, **black-start capability** and **other system support** services.

These services should not automatically be included in the transmission and wheeling tariff.

The revised methodology should distinguish between:

1. **technical support inherent in transmission service**, which may be recovered through the network revenue requirement;
2. **separately procured ancillary services**, which should be recovered through specific market or system-operation arrangements;
3. **institutional market-operation costs**, which must remain outside the transmission tariff and be recovered through separate levies and fees.

This distinction is necessary to **avoid double charging**. For example:

- If a balancing service is procured through a market mechanism, its cost should not also be embedded in the transmission tariff.
- If a market operator administers an ancillary services platform, the administrative cost of that platform belongs to institutional levies and fees, not to the transmission asset revenue requirement.

The common AfSEM engine should therefore include ancillary adjustments only where they relate directly to **physical transmission service** and where the **cost is measurable and attributable**.

4.6.2 Conservation and consistency rule

The common engine should apply a **consistency rule for technical adjustments (loss charge, reactive charge and other technical adjustments)**:

$$TotalTechnicalRecovery_t = \sum_u LossCharge_{u,t} + \sum_u ReactiveCharge_{u,t} + \sum_u OtherTechnicalAdjustment_{u,t}$$

The user-level required recovery then becomes:

$$RequiredRecovery_{u,t} = \sum_i AllocatedNetworkCost_{u,i,t} + LossCharge_{u,t} + ReactiveCharge_{u,t} + OtherTechnicalAdjustment_{u,t}$$

At system level:

$$TotalRequiredRecovery_t = \sum_i ARR_{i,t} + TotalTechnicalRecovery_t$$

This ensures that technical adjustments are visible and reconciled. It also prevents technical costs from being hidden inside general network cost allocation.

4.6.3 Summary of changes compared with ES-0135

The following table summarizes the proposed changes to the ES-0135 methodology:

Element	ES-0135 approach	Revised AfSEM approach	Reason for change
Reactive power	Considered as part of transaction impacts	Charged separately only where measurable, rule-based and outside approved limits	Prevents unverifiable charges
Ancillary services	Recognised in broad technical terms	Included only where directly linked to transmission service and not recovered elsewhere	Avoids double charging

Table 8: Summary of Proposed Changes (Reactive Power and Technical Ancillary Adjustments)

4.7 Financial viability indicators

Financial viability indicators are the **final control mechanism of the common AfSEM cost-allocation engine**.

> After the eligible asset base has been defined, the annual revenue requirement has been calculated, usage shares have been allocated, and losses and technical adjustments have been added, the methodology must **test whether the resulting cost recovery is financially adequate**.

This step is essential because a transmission tariff methodology can be technically precise but still fail if it does not generate sufficient and predictable revenue for TSO. ES-0135 recognized this point by including financial viability checks such as **Net Present Value (NPV)**, **Internal Rate of Return (IRR)** and **rate of return on the Regulatory Asset Base**. This should be retained.

A revised AfSEM methodology must not only allocate costs fairly; it must also demonstrate that the allocation supports financeability, revenue adequacy and investment confidence.

The purpose of this section is therefore to **define the financial viability tests** that should be produced by the common engine before the outputs are translated into regional tariff presentations.

4.7.1 What is retained from ES-0135

The revised methodology retains **three important elements** from ES-0135.

First, it **retains the principle that tariffs must be financially viable for TSOs**.

Transmission owners should be able to recover efficient costs, earn the approved return on eligible assets, and maintain the assets needed for regional service.

Second, it **retains the use of investment appraisal indicators**.

ES-0135 used indicators such as NPV and IRR to test whether the calculated tariff was compatible with investment recovery. This remains necessary, especially for new interconnectors and major regional transmission reinforcements.

Third, it **retains the idea that the methodology must support bankability**.

Cross-border transmission infrastructure often requires long-term financing. Lenders and investors will need evidence that the tariff framework can produce stable and sufficient revenue over time.

4.7.2 What changes compared with ES-0135

The main change is that **financial viability should no longer be treated only as a project or transaction-specific test**. Under ES-0135, the financial test was closely linked to specific bilateral transactions and the tariff required to make those transactions viable. Under the revised AfSEM methodology, financial viability should be tested at **three levels**:

1. **asset or project level**, to test whether a specific eligible asset or corridor is financeable;
2. **TSO level**, to test whether each TSO recovers its allowed annual revenue requirement;
3. **system or user-allocation level**, to test whether the allocation of recoverable costs is consistent, complete and not structurally under-recovering.

This broader approach is necessary because the revised methodology is designed to support different tariff presentations. A postage-stamp tariff, an APM allocation, a two-part tariff or a hybrid model may all produce the same total allowed revenue in theory, but they may differ in timing, volatility and allocation risk. The common engine must therefore test whether the selected presentation can recover the required revenue in practice.

4.7.3 Net Present Value test

For new assets, major reinforcements or pilot corridors, the methodology should apply a **Net Present Value test**.

$$NPV = \sum_{t=1}^{T} \frac{ExpectedNetCashFlow_t}{(1+r)^t} - InitialInvestment$$

The minimum condition is:

$$NPV \geq 0$$

Where:

- $ExpectedNetCashFlow_t$= expected net cash flow in year t;
- r= approved discount rate, normally aligned with the relevant WACC;
- T= appraisal period;

- $InitialInvestment$= initial investment cost.

The logic is straightforward. **If the NPV is negative, the expected tariff revenues are not sufficient to recover the investment and operating costs at the approved discount rate**. In that case, the tariff design, cost allocation, financing assumptions or complementary funding structure should be reviewed.

This test is particularly important for new cross-border assets, where revenue certainty is essential for financing.

4.7.4 Internal Rate of Return test

The methodology should also **calculate the Internal Rate of Return** of the relevant asset, corridor or project.

$$0 = \sum_{t=1}^{T} \frac{ExpectedNetCashFlow_t}{(1+IRR)^t} - InitialInvestment$$

The minimum condition is:

$$IRR \geq WACC$$

Where:

- IRR= internal rate of return;
- $WACC$= approved weighted average cost of capital.

This test checks whether the **expected return generated by the tariff is at least equal to the allowed cost of capital**:

- If the IRR is below WACC, the project may not be financeable on the assumed tariff basis;
- If the IRR is significantly above WACC, the methodology may be over-recovering or allocating excessive revenue to the asset, unless justified by a specific risk allocation decision.

The IRR test should therefore be used both **to detect under-remuneration and to identify possible over-remuneration**.

4.7.5 Revenue recovery ratio

The most important recurring test for the common engine is the **revenue recovery ratio**. This test verifies whether expected revenue under the selected tariff presentation is aligned with the total required recovery calculated by the engine.

$$RevenueRecoveryRatio_t = \frac{ExpectedRevenue_t}{TotalRequiredRecovery_t}$$

The target condition is:

$$RevenueRecoveryRatio_t \approx 1$$

Where:

- $ExpectedRevenue_t$= revenue expected to be collected in year t under the selected tariff presentation;
- $TotalRequiredRecovery_t$= total amount that must be recovered in year t, including TSO annual revenue requirements, losses, reactive charges and approved true-up amounts.

A ratio **below 1** indicates **expected under-recovery**. A ratio **above 1** indicates **expected over-recovery**.

This test is crucial because the common engine may produce the same allowed cost base, but different regional tariff presentations may recover that cost base with different degrees of reliability.

> For example, a highly volumetric tariff may under-recover if traded volumes are lower than forecast. A fixed or capacity-based tariff may provide more stable recovery but may raise concerns about affordability or entry.

The revenue recovery ratio therefore links the technical cost engine to the practical performance of the tariff presentation.

4.7.6 TSO revenue adequacy test

The methodology should also test revenue adequacy for each TSO individually.

$$TSORevenueAdequacy_{i,t} = \frac{ExpectedRevenue_{i,t}}{ARR_{i,t}}$$

The target condition is:

$$TSORevenueAdequacy_{i,t} \approx 1$$

Where:

- $ExpectedRevenue_{i,t}$= expected revenue allocated to TSO i;
- $ARR_{i,t}$= annual revenue requirement of TSO i.

This test is necessary because **system-wide recovery may appear adequate** even if some TSOs are under-recovered and others are over-recovered. That would undermine trust in the methodology, especially for transit countries whose networks are used by regional flows.

The revised methodology should therefore require **both system-level** and **TSO-level adequacy checks**. A tariff presentation should not be considered acceptable if it recovers the correct total amount but systematically fails to compensate individual TSOs in line with their allowed revenue.

4.7.7 Debt service coverage test

Where the methodology is applied to a financed project, especially a **new interconnector** or **major regional reinforcement**, the common engine should also calculate a debt service coverage ratio.

$$DSCR_t = \frac{CashFlowAvailableForDebtService_t}{DebtService_t}$$

The condition is:

$$DSCR_t \geq ApprovedThreshold$$

Where:

- $DSCR_t$= debt service coverage ratio in year t;
- $CashFlowAvailableForDebtService_t$= cash flow available to pay debt service;
- $DebtService_t$= scheduled principal and interest payments;
- $ApprovedThreshold$= minimum threshold required by the financing structure or regulatory decision.

This test should not be required for every existing asset, but it should be applied where the tariff methodology is being used to support **new investment** or where **project finance**, **concessional finance** or **blended finance** is involved.

The DSCR test helps determine whether tariff revenues are not only adequate in accounting terms, but also sufficient to meet financing obligations when they fall due.

4.7.8 Sensitivity testing

Financial viability should be tested under **sensitivities**, not only under a central case.

At minimum, the common engine should test changes in:

- WACC;
- traded volumes or scheduled energy;
- exchange rates;
- inflation or replacement-cost escalation;
- loss factors;
- loss price;
- commissioning date of new assets;
- demand or flow scenarios;
- collection rates.

The sensitivity test should identify whether the methodology remains revenue adequate under reasonable downside conditions.

For example:

$$RevenueRecoveryRatio_t^{downside} = \frac{ExpectedRevenue_t^{downside}}{TotalRequiredRecovery_t^{downside}}$$

If the downside ratio is materially below 1, the tariff presentation may require a stronger fixed component, a shorter true-up cycle, a reserve mechanism, guarantees, or other risk mitigation measures.

Sensitivity testing is especially important because one of the limitations of ES-0135 was reliance on assumptions that may become outdated. The revised methodology should therefore make parameter uncertainty visible.

4.7.9 Link with true-up and required cost recovery

Financial viability indicators must be **linked to the true-up mechanism**.

If actual revenue differs from expected revenue, the difference should be reconciled:

$$TrueUp_{i,t} = AllowedNetRevenue_{i,t-1} - ActualNetRevenue_{i,t-1}$$

The true-up prevents temporary deviations from becoming permanent under-recovery or over-recovery. However, the existence of a true-up does not remove the need for financial viability testing. A tariff that relies too heavily on future true-ups may still create cash-flow problems for TSOs, especially if they must finance operations and debt service in the current period.

Therefore, the common engine should test both:

1. whether the tariff will recover the required amount over time; and
2. whether the timing of recovery is compatible with TSO cash-flow needs and financing obligations.

4.7.10 Summary of changes compared with ES-0135

The following table summarizes the proposed changes to the ES-0135 methodology:

Element	ES-0135 approach	Revised AfSEM approach	Reason for change
Viability focus	Mainly transaction/project-level viability	Asset/project, TSO and system-level viability	Supports multiple regional tariff presentations
NPV and IRR	Included as financial viability checks	Retained and applied to pilots, corridors and major assets	Preserves bankability discipline
Revenue adequacy	Linked to tariff calculation	Explicit revenue recovery ratio	Tests whether selected tariff presentation recovers required costs
TSO-specific recovery	Less explicit	TSO revenue adequacy test	Ensures individual TSOs are not under-compensated
Debt service	Not central	DSCR test for financed projects	Supports bankability and lender confidence
Sensitivity testing	Used in ES-0135 but should be systematized	Mandatory sensitivity tests for key parameters	Addresses uncertainty and outdated assumptions
True-up	Adjustment logic present	Direct link between viability tests and reconciliation	Prevents persistent under- or over-recovery

Table 9: Summary of Proposed Changes (Financial Viability Indicators)

4.8 Required cost recovery

Required cost recovery is the final output of the common AfSEM cost-allocation engine. **It consolidates all recoverable components calculated in the previous steps and determines the total amount that must be recovered from each user, user group, zone or transaction class before the result is translated into a regional tariff presentation**.

In ES-0135, required cost recovery was embedded in the tariff calculation for a specific bilateral transaction. The methodology identified the assets used by the transaction, allocated the relevant network cost, added losses and technical components, and derived the corresponding tariff. That logic remains valuable.

However, under the revised AfSEM methodology, required cost recovery should be made a distinct and explicit output of the common engine.

This is necessary because **AfSEM must support more than one regional tariff presentation**. The same recoverable cost base may later be expressed as a per-MWh charge, an access fee, an APM allocation, a capacity charge, a zonal charge or a hybrid combination.

The required cost recovery step therefore acts as the bridge between the technical-economic calculation engine and the regional tariff presentation layer.

4.8.1 What is retained from ES-0135

The revised methodology retains **three important elements** from ES-0135.

<u>First</u>, it **retains the principle that recoverable costs must be derived from the regulated cost base**.

Required recovery should not be negotiated arbitrarily. It should follow from the eligible asset base, annual revenue requirement, usage allocation, losses and approved technical adjustments.

<u>Second</u>, it **retains the principle that the tariff must compensate the relevant TSO or TSOs**.

If regional users make use of a TSO's network, the cost recovery output should show the amount due to that TSO.

<u>Third</u>, it **retains the principle that the calculation should be transparent and reproducible**.

Users, TSOs and regulators should be able to trace the required recovery amount back to the underlying asset costs, loss costs and technical adjustments.

4.8.2 What changes compared with ES-0135

The main change is that required cost recovery becomes a **standardized output** of the common engine, rather than only the result of a transaction-specific tariff calculation.

Under ES-0135, the tariff calculation was built around a defined bilateral transaction. The model calculated the cost consequences of that transaction and produced a tariff for that case.

Under the revised AfSEM methodology, the engine should calculate **required cost recovery for any approved allocation object**, including:

- a bilateral transaction;
- a market participant;
- a user group;
- an importing or exporting zone;
- a corridor;
- a regional market segment;
- a transaction class;
- a pool-wide group of eligible users.

This broader approach allows the same engine to support multiple regional presentations while preserving a common calculation discipline.

4.8.3 User-level required recovery

The first required recovery output should be calculated at **user or user-group level**.

$$RequiredRecovery_{u,t} = \sum_{i} AllocatedNetworkCost_{u,i,t} + LossCharge_{u,t} + ReactiveCharge_{u,t} + OtherTechnicalAdjustment_{u,t}$$

Where:

- $RequiredRecovery_{u,t}$= total required recovery from user, user group, zone or transaction class $u$in year t;
- $AllocatedNetworkCost_{u,i,t}$= network cost allocated to user $u$for eligible assets of TSO i;
- $LossCharge_{u,t}$= loss cost allocated to user u;
- $ReactiveCharge_{u,t}$= reactive power charge allocated to user u, where applicable;

- $OtherTechnicalAdjustment_{u,t}$= other approved technical adjustments attributable to user u, where applicable.

In this formula, $AllocatedNetworkCost_{u,i,t}$includes both the user's allocated share of eligible asset-level costs and its allocated share of TSO-level residual costs, including the working-capital allowance where applicable.

This formula **consolidates the cost components calculated earlier** in the engine. It does not yet determine the final tariff unit.

> For example, the resulting amount may later be divided by MWh, converted into a capacity charge, split into fixed and variable components, or allocated through APM.

The important point is that the amount is calculated before the tariff presentation is chosen.

4.8.4 TSO-level required recovery

The engine should also produce a **TSO-level recovery requirement**.

$$RequiredRecovery_{i,t} = ARR_{i,t} + AllocatedLossRecovery_{i,t} + AllocatedTechnicalAdjustment_{i,t}$$

Where:

- $RequiredRecovery_{i,t}$= total amount to be recovered for TSO i;
- $ARR_{i,t}$= annual revenue requirement of TSO i;
- $AllocatedLossRecovery_{i,t}$= loss-related recovery associated with TSO i's network, where losses are settled financially;
- $AllocatedTechnicalAdjustment_{i,t}$= approved technical adjustments associated with TSO i's system;

In this formulation, $ARR_{i,t}$ **already includes any approved TSO-level true-up or reconciliation amount**. If a region chooses instead to keep true-up outside $ARR_{i,t}$, then it may be added at the required recovery stage, but not in both places.

This output is important because regional trade often involves more than one TSO. A system-wide tariff may appear adequate while individual TSOs remain under-compensated. The TSO-level recovery output ensures that each network owner can see the amount the methodology expects it to recover.

4.8.5 System-level total required recovery

The common engine should also calculate the **total system required recovery**:

$$TotalRequiredRecovery_t = \sum_i ARR_{i,t} + \sum_u LossCharge_{u,t} + \sum_u ReactiveCharge_{u,t} + \sum_u OtherTechnicalAdjustment_{u,t}$$

Where:

- $TotalRequiredRecovery_t$= total amount to be recovered from all eligible regional users in year t;
- $ARR_{i,t}$= annual revenue requirement of each TSO i;
- $LossCharge_{u,t}$= loss charge allocated to each user u;
- $ReactiveCharge_{u,t}$= reactive charge allocated to each user u, where applicable;
- $OtherTechnicalAdjustment_{u,t}$= other approved technical adjustments.

This system-level figure is the amount that the regional tariff presentation must recover in aggregate.

4.8.6 Revenue consistency identity

The common engine should include a **revenue consistency check**:

$$\sum_{u} RequiredRecovery_{u,t} = TotalRequiredRecovery_t$$

This identity confirms that **all recoverable costs have been allocated to users or user groups**.

If the identity does not hold, the model contains an allocation gap. This may indicate that:

- some asset costs have not been allocated;
- some loss or technical adjustment has been omitted;
- a socialized component has not been distributed;
- a true-up amount has not been assigned;
- there is a formula error or classification problem.

This check is **essential for transparency**. It prevents hidden under-recovery or over-recovery and ensures that the common engine produces a complete cost allocation before the tariff is presented to market participants.

4.8.7 Treatment of true-up in required cost recovery

Required cost recovery should include **approved reconciliation amounts**.

As indicated above, true-up is normally included once at TSO level, through $ARR_{i,t}$, using the following formula:

$$TrueUp_{i,t} = AllowedNetRevenue_{i,t-1} - ActualNetRevenue_{i,t-1}$$

Where:

- $AllowedNetRevenue_{i,t-1}$= allowed net revenue for TSO $i$in the previous period;
- $ActualNetRevenue_{i,t-1}$= actual net revenue collected by TSO $i$in the previous period.

If there was **under-recovery**, the **true-up is positive** and increases the required recovery in the next period. If there was **over-recovery**, the **true-up is negative** and reduces the required recovery.

The revised methodology should make this reconciliation explicit because forecast and actual outcomes will differ. Forecast volumes, losses, asset availability, exchange rates and collection rates may all vary. Without a clear true-up mechanism, the methodology may create persistent revenue gaps or excessive collections.

Where a **carrying charge** is approved, the adjusted true-up may be calculated as:

$$TrueUp_{i,t}^{adj} = TrueUp_{i,t} \times (1 + r_t^{carry})$$

Where:

- r_t^{carry}= approved carrying charge rate.

The carrying charge should be used carefully. It may be justified where the TSO has financed a revenue shortfall, but **it should not become an automatic penalty on users without regulatory approval**.

4.8.8 Treatment of other revenue and avoided double recovery

Required **cost recovery should be net of other revenues** that have already contributed to the same cost base.

At asset level, this is reflected through:

$$ARR_{a,t} = (RAB^{avg}_{a,t} \times WACC_{i,t}) + Dep_{a,t} + OPEX^{eff}_{a,t} + Tax_{a,t} + PassThrough_{a,t} + TrueUp_{a,t} - OtherRevenue_{a,t}$$

The deduction of $OtherRevenue_{a,t}$ flows through to the required recovery calculation. It is also worth mentioning that amounts deducted from the asset base as $NonRemunerableFunding_{a,t}$ should not also be deducted as $OtherRevenue_{a,t}$. Other revenue should include **only revenue streams not already reflected in the RAB, depreciation or funding adjustment**.

This is necessary to **avoid double recovery**.

> If a TSO has already received approved revenue linked to the same eligible asset or service, regional users should not be charged again for the same cost. This may include approved connection contributions, congestion-related revenues, earmarked subsidies, insurance recoveries or other revenue streams recognized by the regulator.

The common engine should therefore produce required recovery **net of recognized offsets**.

4.8.9 Relationship with regional tariff presentations

Required cost recovery is not the same as the final tariff.

It is the cost output that must later be converted into a tariff format. For example:

Required recovery output	Possible regional presentation
RequiredRecovery*$_{u,t}$*	APM charge, user-specific allocation, transaction-class charge
RequiredRecovery*$_{i,t}$*	TSO settlement entitlement
TotalRequiredRecovery*$_{t}$*	Postage-stamp revenue pool, two-part tariff revenue target
Loss recovery component	Loss factor, separate loss charge, in-kind loss settlement
True-up amount	Annual tariff adjustment, settlement reconciliation

Table 10: Required Recovery Output and Possible Regional Presentation

This distinction is fundamental. The common engine determines **what must be recovered**. The regional tariff presentation determines **how it is charged**.

For example, if the common engine determines that total required recovery is USD 100 million, a region may recover that amount through:

- a postage-stamp tariff divided by forecast MWh;
- an APM allocation across participants;
- a two-part tariff with fixed access and variable usage components;
- a hybrid model combining socialized and usage-based charges;
- an entry-exit structure.

The calculation logic remains common even if the tariff format differs.

4.8.10 Summary of changes compared with ES-0135

The following table summarizes the proposed changes to the ES-0135 methodology:

Element	ES-0135 approach	Revised AfSEM approach	Reason for change
Required recovery	Embedded in transaction-specific tariff output	Separate standard output of the common engine	Allows multiple regional tariff presentations
Recovery object	Specific bilateral transaction	User, user group, zone, transaction class, TSO or system	Supports bilateral and multilateral markets
TSO recovery	Derived from transaction allocation	Explicit TSO-level recovery output	Ensures each TSO can track expected compensation
System recovery	Not separately emphasised	Total required recovery calculated explicitly	Creates clear revenue target for tariff presentation
True-up	Adjustment logic present but not central	Explicit part of required recovery	Prevents persistent under- or over-recovery
Other revenues	Not sufficiently visible	Deducted before required recovery	Avoids double recovery
Revenue consistency	Implicit in tariff model	Explicit identity between user recovery and total recovery	Improves auditability

Table 11: Summary of Proposed Changes (Required Cost Recovery)

5 Conclusion: Key Messages and Action Priority

The revision of ES-0135 proposed in this report is based on a clear methodological conclusion: AfSEM should not abandon the 2019 continental tariff work but should transform it from a transaction-specific MW-km model into a common cost-allocation engine capable of supporting different regional tariff presentations.

The revised methodology preserves the main strengths of ES-0135 — explicit cost recovery, physical cost causation, transparency, auditability and financial discipline — while correcting the limitations identified in the stocktaking work, especially the excessive dependence on bilateral point-to-point transactions, high operational intensity, limited scalability and insufficient adaptability to regional diversity.

Four key messages emerge from this report.

The **first key message** is that **ES-0135 remains the technical foundation but should be refactored.**

ES-0135 remains the most concrete continental attempt to translate transmission tariff principles into an operational computational model. Its value lies in the fact that it connected asset valuation, regulatory revenue requirements, load-flow modelling, loss allocation and tariff computation within one framework.

However, **ES-0135 should not be replicated unchanged**. It was designed primarily for international bilateral transactions and therefore remains closely linked to point-to-point MW-km logic. That approach remains useful for defined wheeling transactions, but it is not sufficiently adaptable to serve as the only continental methodology for AfSEM.

The required revision is therefore a refactoring, not a replacement. The **underlying economics of ES-0135 should be preserved**, while the model should be made **more modular**, **scalable** and **compatible** with different regional market designs.

The **second key message** is that **AfSEM should harmonize Layer 1, not impose a single tariff format**.

The core methodological proposal of this report is the distinction between two layers.

Layer 1 is the common AfSEM cost-allocation engine. It defines the shared calculation logic for:

- eligible regional transmission asset base;
- annual revenue requirement by TSO;
- asset usage shares;
- loss allocation;
- reactive power and technical ancillary adjustments, where applicable;
- financial viability indicators;
- required cost recovery.

These outputs should be calculated in a consistent, transparent and auditable way across regions.

Layer 2 is the regional tariff presentation layer. It translates Layer 1 outputs into the tariff format used by each power pool. This may include APM, two-part tariffs, hybrid models, postage-stamp structures, zonal approaches or future entry-exit arrangements.

The conclusion is therefore that **AfSEM should harmonise the calculation discipline, not the final tariff format**. This allows continental consistency without forcing premature uniformity.

The **third key message** is that **transparency and no double recovery are essential safeguards**.

The revised methodology must maintain a **clear boundary between transmission and wheeling tariffs**, on the one hand, **and institutional levies and fees**, on the other.

Transmission and wheeling tariffs should **recover only the costs of physical transmission service**: eligible assets, depreciation, return on capital, efficient OPEX, losses and measurable technical adjustments. They should not recover market operator costs, regulator costs, governance costs or institutional levies and fees.

For this reason, the revised methodology introduces safeguards such as:

- explicit asset eligibility rules;
- deduction of non-remunerable funding from RAB;
- deduction of other revenues from the annual revenue requirement;
- separate calculation of losses and technical adjustments;
- explicit true-up and reconciliation mechanisms;
- financial viability and revenue adequacy testing.

These safeguards are necessary to **ensure that regional users do not pay twice for the same cost** and are **not charged for costs unrelated to regional transmission service**.

The **fourth key message** is that **financial viability must be tested before tariff presentation**.

A tariff methodology must be **technically fair**, but it must also be **financeable**. The revised ES-0135 should therefore require **financial viability indicators as a standard output** of the common engine.

The relevant tests include NPV, IRR, revenue recovery ratio, TSO revenue adequacy ratio, DSCR where applicable, and sensitivity testing. These tests verify whether the calculated cost recovery is sufficient to support the relevant TSO, asset, corridor or regional system.

This is especially important because **different Layer 2 presentations may recover the same Layer 1 cost base with different levels of stability**. For example, a heavy volumetric tariff may expose TSOs to volume risk, while a fixed or capacity-based component may provide more stable recovery. The common engine should therefore test financeability before the outputs are converted into a regional tariff format.

AfSEM Action Priority – Launch Layer 2 implementation work with interested power pools

The main action priority emerging from this report is to **move from the common Layer 1 methodology to region-specific Layer 2 applications**.

This report develops Layer 1: the common AfSEM cost-allocation engine. It does not fully design Layer 2 because **tariff presentation depends on power-pool-specific conditions**, including market design, settlement arrangements, data availability, regulatory mandates, existing tariff practices and institutional readiness.

AfSEM should therefore launch **voluntary follow-up activities** with interested power pools to translate the Layer 1 outputs into practical regional tariff presentations.

This work should include:

- selecting the most appropriate Layer 2 tariff format for the participating power pool;
- mapping Layer 1 outputs into that format;
- testing settlement and revenue adequacy;
- identifying data gaps and institutional requirements;
- assessing whether the selected presentation creates under-recovery, over-recovery or unwanted market distortions;
- preparing implementation lessons for wider AfSEM convergence.

Potential applications may include testing how the common engine interfaces with already established tariff mechanisms.

Box 1: AfSEM Action Priority

Therefore, it is advised that AfSEM initiates targeted Layer 2 implementation activities with interested power pools, using the common Layer 1 cost-allocation engine as the starting point and adapting its outputs into regionally appropriate tariff presentations.