REGIONAL AUTHORITY
ECOWAS ELECTRICITY REGULATOR

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RESOLUTION No. 021/ERERA/26
Approving the Regional Electricity Transmission Tariff Application Procedure (RETTAP)

The Regulatory Council,

MINDFUL of the Revised Treaty of the Economic Community of West African States (ECOWAS) of 24 July 1993;

MINDFUL of ECOWAS Energy Protocol A/P4/1/03 of 31 January 2003;

MINDFUL of Supplementary Act A/SA.2/01/08 of 18 January 2008 establishing the ECOWAS Regional Electricity Regulatory Authority (ERERA);

MINDFUL of Regulation C/REG.27/12/07 of 15 December 2007 as amended, concerning the Composition, Organisation, Powers and Operation of ERERA, in particular Article 18.5 thereof;

MINDFUL of Directive C/DIR.1/06/13 of 21 June 2013 on the Organisation of the Regional Electricity Market (REM);

MINDFUL of Resolution No. 018/ERERA/25 of 13 September 2025 approving the Regional Electricity Market Codes of West Africa (REMC-WA);

MINDFUL of Resolution No. 020/ERERA/26 of March 19, 2026 adopting the Regional Transmission Tariff Methodology (RTTM) applicable to the Regional Electricity Market (REM);

WHEREAS the Regional Transmission Tariff Methodology (RTTM) defines the principles for calculating transmission tariffs applicable to the REM;

CONSIDERING that the effective implementation of the RTTM requires the adoption of an operational procedure specifying the methods of application, calculation, invoicing, collection and payment of transmission tariffs;

CONSIDERING that the Procedure for the Application of the Regional Electricity Transmission Tariff (PARETT) is an essential instrument for ensuring the transparency, traceability and predictability of transactions in the Regional Electricity Market;

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CONSIDERING the report of the twenty-fourth joint meeting of the ERERA Consultative Committees of Regulators and Operators of October 22, 2025, recommending the approval of the Procedure for the Regional Electricity Transmission Tariff Application Procedure (RETTAP) by the ERERA Regulatory Council;

CONSIDERING the conclusions of the ninety-third meeting of the ERERA Regulatory Council held from March 17 to 19, 2026, which examined and validated the draft Procedure for the Application of the Regional Electricity Transmission Tariff (PARETT);

RESOLVED

Article 1
The Regional Electricity Transmission Tariff Application Procedure (RETTAP), hereby attached, is approved.

Article 2
The Regional Electricity Transmission Tariff Application Procedure (RETTAP) specifies the operational procedures for implementing the Regional Transmission Tariff Methodology (RTTM), particularly with regard to:

(a) the mechanism for recovering electricity transmission costs;
(b) the determination and allocation of electricity transmission losses;
(c) the collection and distribution of revenues among electricity transmission grid operators.

Article 3
The Regional Electricity Transmission Tariff Application Procedure (RETTAP) is implemented by the Regional System and Market Operator, under the supervision of ERERA, in accordance with the provisions of the Regional Electricity Market Codes.

Article 4
This Resolution is published in the Official Bulletin of ERERA and on its website.

Article 5
This Resolution shall enter into force from the date of its signature.

Done in Accra, Ghana , on March 19 , 2026

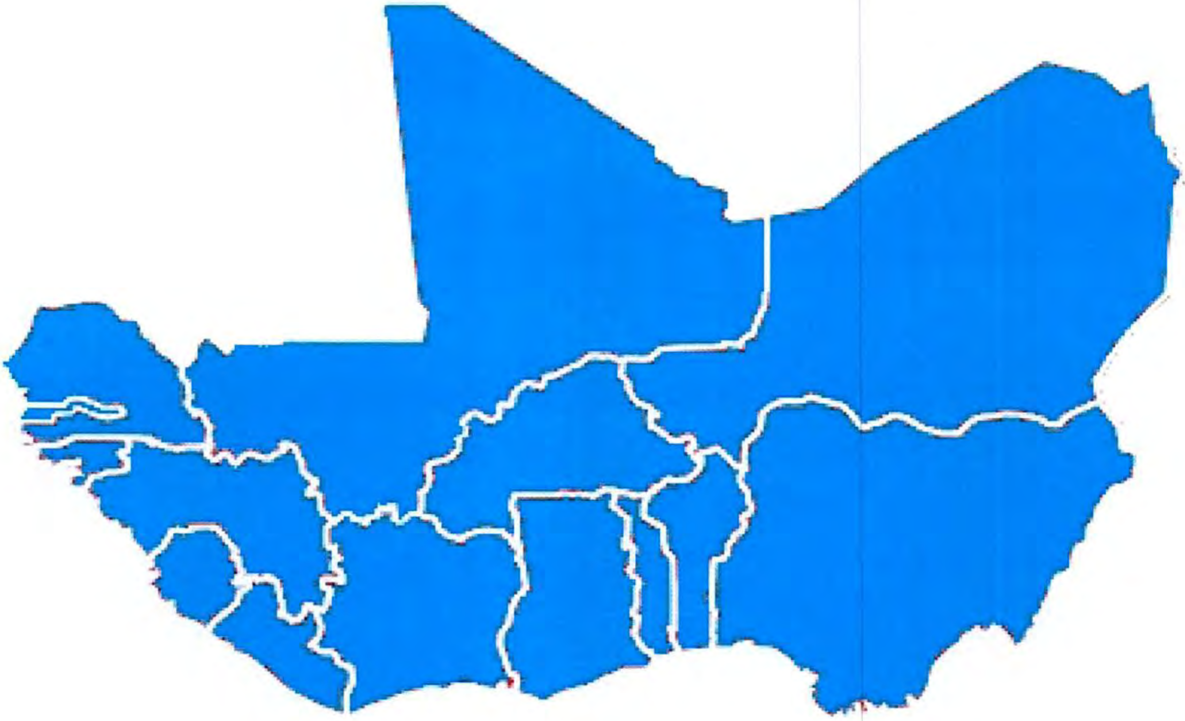
Charles NDIAYE

Council Member

Kocou Laurent Rodrigue Tossou

Chairman

REGIONAL ELECTRICITY MARKET OPERATIONAL PROCEDURE



REGIONAL ELECTRICITY TRANSMISSION TARIFF APPLICATION PROCEDURE - RETTAP

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ACRONYM

APM	Average Participation Method
CGM	Common Grid Model
CGM BP	Common Grid Model Business Process
EOC	Engineering and Operating Committee of WAPP
ERERA	ECOWAS Regional Electricity Regulatory Authority
GO	Grid Operator
OMVG	Organisation pour la Mise en Valeur du Fleuve Gambie
PIPES	Planning, Investment Programming, and Environmental Safeguards
PST	Phase Shifting Transformer
RCP	Regional Compensation Party
REM	Regional Electricity Market
RETTAP	Regional Electricity Transmission Tariff Application Procedure
RTTM	Regional Transmission Tariff Methodology
SMO	System and Market Operator
SOGEM	Société de Gestion de l'Énergie de Manantali
TRANSCO CLSG	Transmission Company Côte d'Ivoire-Liberia-Sierra Leone-Guinea
WACC	Weighted Average Cost of Capital
WAPP	West African Power Pool

1 INTRODUCTION

1.1 Purpose and Service Description

The purpose of this procedure is to describe the activities that will be performed by the SMO and ERERA to define, settle, and update the Regional Transmission Pricing of the Regional Transmission System of the WAPP in application of the Regional Transmission Tariff Methodology (RTTM).

The methodology for calculating the Transmission Pricing is outlined in the RTTM.

The time frames for the Transmission Pricing calculation are:

- **Year-ahead (Y-1)**: This is the year (Y-1) when the SMO calculates the annual net compensation for each RCP, applicable to the upcoming year (Y), as determined by the APM. The result of these calculations is referred to as the "Y RCP Compensation".
- **Year (Y)**: This is the year for which Y RCP Compensation applies, covering the use of the Transmission System and associated losses. The CGM and associated Snapshots specifically refer to this year, Year (Y).
- **Year-next (Y+1)**: This is the year when the SMO finalizes the settlement for the Y RCP Compensation, based on the actual flows observed in Year (Y). The result is referred to as the "Y RCP Reconciliation."

1.2 Scope

This procedure applies to the process of determining the Y RCP Compensation and the Y RCP Reconciliation.

Certain aspects of the process are out of scope when describing the current Procedure, including:

- The creation of the CGM is outlined in the "WAPP Y-1 Common Grid Model Business Process (WAPP Y-1 CGM BP)".
- The operational procedure that defines the steps to be followed by the SMO and RCPs, detailing the billing and settlement process of the REM, as outlined in the relevant Operational procedure.
- The process of determination, allocation, execution, and reconciliation of the payment for the REM Fees.
- The appointment of the RCP. According to RTTM, unless otherwise ERERA is notified, and communicated to the SMO, the designated RCP by each WAPP Member State is the national GO. This also includes SOGEM, TRANSCO CLSG, and OMVG when it pertains to the use of their proprietary assets.

1.3 Definitions

Any term not defined under this section shall have the meaning given to it in the RTTM or the REM Codes. The following terms shall have the meaning set forth below:

1. **Asset Database**: it contains the data for each network element of the WAPP Interconnected Transmission System (WAPPITS), including line lengths, numbers of circuits, line types, tower types, voltages, switchgear type and voltage, series capacitor rating, transformer rating and voltage, etc. The Asset Database includes reference unitary standard cost data and financial indicators for calculating asset depreciation and the Weighted Average Cost of Capital (WACC), which are used to determine the total annual revenue requirement for each asset.
2. **Common Grid Model (CGM)**: Region-wide data set agreed among GOs describing the relevant characteristics of the WAPP Power System (Generation, Demand, and Relevant Grid topology) and rules for changing these characteristics during the Net Transfer Capacity (NTC) calculation process, in a way that flows on the tie lines are consistent with the cross-border electricity exchanges.
3. **Grid Operator (GO)**: means either the Transmission System Operator (TSO) or the System Operator (SO), the latter interacting with the Transmission Operator (TO) based on the mutual competences and duties, depending on the electricity industry structure and regulation of each Member State.
4. **Market Participant**: means any Entity of the Electricity Supply Industries of any of the Member States of the WAPPITS that is registered and authorized to trade in the REM.
5. **Regional Assets**: means the assets composing the Regional Transmission Network of the WAPP, which comprises all interconnected assets whose service voltage are 132 kV and above (or as agreed by ERERA) in the region covered by the WAPPITS.
6. **Regional Compensation Party (RCP)**: in the framework of the Regional Transmission Tariff Methodology (RTTM), it refers to the entity in each Control Area that shall receive or pay the regional compensation for transmission costs resulting from cross-border electricity trade. The Grid Operator is de-facto RCP of its Control Area, unless the relevant National Competent Authority (NCA) decides otherwise and notifies the RCP to ERERA and the SMO. The SPVs acting as specialized transnational transmission operators, such as SOGEM, OMVG, and TRANSCO CLSG, are also RCPs for what concerns the compensation for the use of their proprietary assets.
7. **Regional Transmission Tariff Methodology (RTTM)**: it is the methodology adopted and approved by ERERA for determining and allocating the costs associated with the use of Regional Assets and related losses within the framework of the Regional Electricity Market (REM)
8. **Regional Electricity Transmission Tariff Application Procedure (RETTAP)**: it is the procedure for applying the RTTM.
9. **Scenario**: as per WAPP Y-1 CGM BP, it is an outlook of the future characterized by forecast data (expected load and generation) and schedule data (planned and unplanned unavailability of grid elements and generation set points).
10. **Snapshot**: it refers to a specific period of time (duration of 1 hour) that captures the relevant electrical conditions and cross-border flows at particular moments to represent a given Scenario in the Common Grid Model (CGM).
11. **WAPP Y-1 Common Grid Model Business Process (WAPP Y-1 CGM BP)**: it refers to the procedure outlining the process conducted one (1) year in advance (year

Y-1) to create the Common Grid Model (CGM) of the WAPPITS for the year (Y). This process, carried out by the System and Market Operator (SMO) using data from Grid Operators (GOs), supports operational planning and security assessments of the WAPP Power System.

2 DETAILED BUSINESS PROCESS

2.1 Main Objective

The main objective of the year ahead (Y-1) time frame for the regional transmission pricing is to calculate the ex-ante net payments that each Regional Compensation Party (RCP) will be subject to during the year (Y) of Operation. The main objective of the year after (Y+1) time frame is to settle the actual payments based on the real exchange monitored by the SMO.

The steps for the Regional Electricity Transmission Tariff Application Procedure (RETTAP) are as follows:

- The SMO and the GOs prepare the CGM as per WAPP Y-1 CGM BP.
- The SMO defines in Y-1 the allocation of the net payments by each RCP.
- ERERA approves and publishes in Y-1, the compensations based on SMO's allocation of the net payments by each RCP.
- The SMO executes the exchange of payments in Y from the net payers RCP to the SMO, and from the SMO to the net receivers RCP.
- In Y+1, the SMO prepares and executes the settlement of compensations, based on actual monitored flows observed in Y, upon ERERA's approval.

2.2 Overview of the High-Level Business Process

The determination and settlement of the regional transmission pricing on the Y-1 and Y+1 time frames consist of the following steps:

a) Tariff Inputs for CGM.
b) Update of Asset Database.
c) Allocation of the use of the Regional Transmission System and losses.
d) Determination of Y RCP Compensations.
e) Billing and settlement of Y RCP Compensations.
f) Reconciliation of Y RCP Compensations.

A high-level overview of the CGM BP is schematically presented in Figure 1.

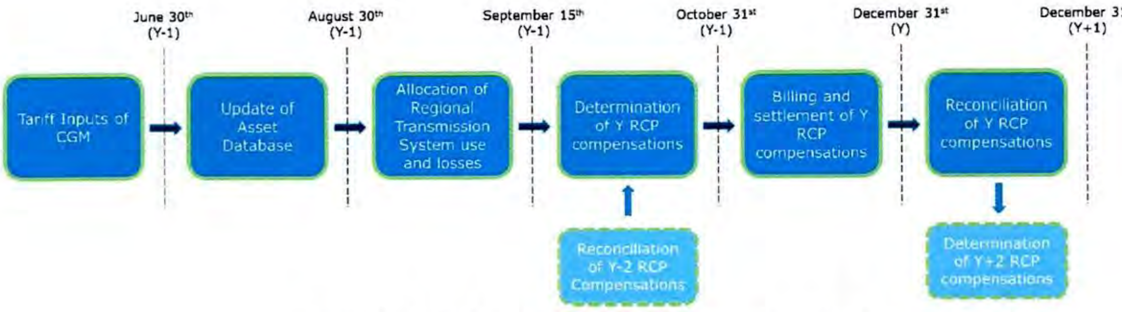

Figure 1 - High Level Business Process Overview

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2.3 Responsibilities and Obligations of Entities

Table 2-1 - Entities involved in the Business Process

Entities	Responsibilities and Obligations
ERERA	ERERA: 1. approves the Standard Cost Database 2. approves the allocation of the net payments by each RCP calculated by the SMO in Y-1 for the coming year Y (i.e., the Y RCP Compensation), 3. approves the subsequent Reconciliation (i.e., the Y RCP Reconciliation). 4. Notify NRA on the Y RCP compensation
GOs	The GOs: 1. provide the appropriate data for the update of the Asset Database to the SMO, and 2. provide a copy to the NRA.
RCP	The RCP: 1. Receives the allocation of the net payments from the SMO (i.e., the Y RCP Compensation). 2. Receives/pays the net payments from/to the SMO based on the Y RCP Compensation. 3. Receives allocation from the SMO based on the Y RCP Reconciliation. 4. Receives/pays the net payments from/to the SMO based on the Y RCP Reconciliation.
SMO	The SMO: 1. Sends notification to GOs, NRAs and ERERA on commencement of the process. 2. Requests for data from GOs. 3. Provides the Scenarios to build the CGM. 4. Updates the Asset Database. 5. Calculates the Y RCP Compensations and publish them after ERERA's approval. 6. Executes the exchange of payments from the RCP net payers to the SMO and from the SMO to the RCP net receivers. 7. Executes the Y RCP Reconciliation.
NRA	The NRA: 1. Receives notification from the SMO on commencement of the process. 2. Receives from the GO the data sent to the SMO for the update of the Asset Database. 3. Receives notification on the Y RCP Compensation from ERERA. 4. Makes provision for the Y RCP Compensation for its Control Area in the National Tariffs.

2.4 Main Input Data

The SMO provides three (3) categories of input data:

- The expected power exchanges between the GOs for year Y, based on year Y-2, Y-1, and forecasts.
- The latest standard cost data as approved by ERERA.
- A collection of Snapshots reflecting expected usage of the system for year Y, as per *Appendix 3: POC for Selecting Archetype Snapshots for the APM-IGOC.*

The creation of the CGM is outlined in the Y-1 Common Grid Model Business Process. This procedure outlines the process to inform the creation of the CGM on the appropriate market and operational information that are pivotal to the creation of the CGM for the purpose of Regional Transmission Pricing.

In the framework of the development of the CGM, the GOs provide also the data that are relevant for the update of the Asset Database, namely: the number of circuits of each line (1L, 2L, ...), the number of conductors for each phase (1C, 2C, 3C, ...), the Commissioning Year, the ownership share (in case of cross-border assets).

The Standard Cost Database shall be the source for the standard specific replacement costs of the assets of the Regional Transmission System.

The standard cost data shall be updated by the SMO in consultation with WAPP every five (5) years and as needed (e.g., the introduction of a new typology of assets) and approved by ERERA.

2.5 Business Process Description

2.5.1 Step A – Tariff Inputs for CGM

2.5.1.1 Relevant Activities

The relevant activities for the provision of the CGM to be adopted for the calculation of the RCP Compensations shall follow the list of activities set out in the WAPP Y-1 CGM BP.

This procedure includes the following activities to be considered in the framework of building the CGM for year Y:

1. In **DS.01** of Step A – Determination of Scenarios of the WAPP Y-1 CGM BP, the SMO shall propose a minimum of four (4) Scenarios to be simulated for the Regional Transmission Pricing. The market Scenarios to be determined shall reflect the expected exchanges of power between the GOs for year Y, based on year Y-2, Y-1, and forecasts. This specification translates in a new activity **TI.01** for the SMO.
2. In **US.01-04** of Step B – Model Structure Update of the WAPP Y-1 CGM BP, the GOs shall provide the data that are relevant for the update of the Asset Database, namely: the number of circuits of each line (1L, 2L, ...), the number of conductors for each phase (1C, 2C, 3C, ...), the Commissioning Year, the ownership share (in case of cross-border assets). The SMO shall perform the quality check and then integrate also these data in the CGM. This specification translates in a new activity **TI.02**, **TI.03**, **TI.04,** and **TI.05** for the SMO.

Table 2-2 - Main activities of the Tariff Inputs for CGM step

ID	Activities	Responsible Parties	Deadline	Involved Parties
TI.01	Proposal of market Scenarios *(add-on to DS.01 of WAPP Y-1 CGM BP)*	SMO	May 1st (Y-1)	SMO
TI.02	Provision of Asset Database tariff data *(add-on to US.01 of WAPP Y-1 CGM BP)*	GOs	June 10th (Y-1)	GOs, SMO, NRA
TI.03	Quality and availability check *(add-on to US.02 of WAPP Y-1 CGM BP)*	SMO	June 20th (Y-1)	SMO
TI.04	Data update *(add-on to US.03 of WAPP Y-1 CGM BP)*	GOs		GOs
TI.05	Integration into existing CGM *(add-on to US.04 of WAPP Y-1 CGM BP)*	SMO	June 30th (Y-1)	SMO

2.5.1.2 Timing

The proposal of the market Scenarios for the preparation of the whole CGM set of Scenarios shall be coherent with the **DS.01**-Proposition of Scenarios of Step A – Definition of Scenarios of the WAPP Y-1 CGM BP, which is May 1st of Y-1.

Similarly, the GOs shall follow the timing set in **US.01** of Step B – Model Structure Update of the WAPP Y-1 CGM BP – which is June 10th of Y-1 – for the provision of the data that are relevant for the update of the Asset Database. The SMO shall perform the consistency check and integrate the data into the CGM by June 30th.

By August 31st, the SMO shall provide a set of PSS/E or equivalent software for power system analysis files containing one (1) CGM for each Scenario. Each set shall include the network data (in ".sav" or ".pfd" or equivalent format) for the power flow study:

- Electrical data of the system: bus voltages, line impedances, generation and load data, etc.
- Status of switches, transformers, and other network elements.
- Results of a solved power flow case (if the case was solved before saving).
- Configuration of the power system for further studies (e.g., contingencies, fault analyses, etc.).

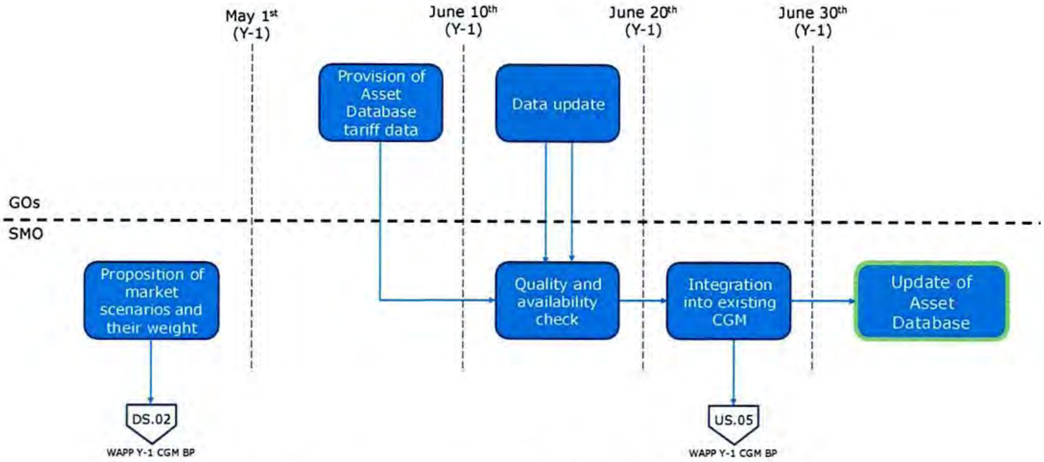

Figure 2 - Timing of the Tariff Inputs for CGM step

2.5.1.3 TI.01 - Proposition of market Scenarios and their weight

- **SMO:** before May 1st of Year Y-1, the SMO shall propose the definition of the market scenarios to be adopted as the relevant Snapshots to be developed and simulated in the WAPP Y-1 CGM BP.
- **SMO:** based on the capabilities and affordability of preparation and calculation, as well as the guidance provided by ERERA, the SMO shall select the Snapshots according to one of the following two (2) approaches:
  1) The Load Duration Curve (LDC) approach: by analyzing the LDC derived from sorting the forecasted total WAPP hourly load profile for Year Y, the SMO shall define:
     - The Snapshot, corresponding to the Peak and Off-peak hours of the 1st half of year Y.
     - The Snapshot, corresponding to the Peak and Off-peak hours of the 2nd half of year Y.
     - If possible, an intermediate hour, corresponding to the median of the load profile data.

     The weight (i.e., the total hours over the 8760 hours that each Snapshot represents) to be associated with each Snapshot in the APM calculation in *Step C – Allocation of the use of the Regional Transmission System and losses* is proposed by the SMO based on statistical considerations on the LDC and the impact on the APM results. The data used to set the Snapshots and the hypothesis on the weight shall be provided to ERERA for their review, together with the results of the Y RCP Compensations in **RC.02** of *Step D – Determination of Y RCP Compensation*.

  2) The Expected Benefits approach: if this method is selected, the SMO shall carry out one of the two proposed analyses described in *Appendix 3: POC for Selecting Archetype Snapshots for the APM-IGOC*, in order to identify the number of relevant hours (i.e., Snapshots) and their corresponding weights to propose as appropriate market Scenarios to be represented in the CGM. Unless otherwise decided by the SMO and approved by ERERA, the SMO shall adopt the first method described in *Appendix 3: POC for Selecting Archetype Snapshots for the APM-IGOC*, which is based on cross-border flows, to select the relevant Snapshot.

- **SMO**: The SMO shall then follow the steps of Step A – Definition of Scenarios of the WAPP Y-1 CGM BP to finalize the Scenarios upon which it will prepare the CGM.

2.5.1.4 TI.02 - Provision of Asset Data

- **GOs:** Before 10th June, along with the delivery of the up-to-date structural data of their power system (as per activity **US.01** of WAPP Y-1 CGM BP), the GOs must prepare and send to the SMO, with a copy to the NRA, the relevant data needed to update the Asset Database for the calculation of the Regional Transmission Pricing (using the relevant template). This data includes:
  - The Type Code for the Lines: the number of circuits of each line (1L, 2L, ...), and the number of conductors for each phase (1C, 2C, 3C, ...).
  - The Commissioning date of each asset.
  - The Ownership share (in case of cross-border assets) of the GO.

  The GOs shall make sure that:
  - All information already provided to the SMO are still valid.
  - All assets that were part of the power system during year Y-1 will still be in operation in year Y.
  - All the assets that will be commissioned during year Y are described.

  Regarding the assets that are going to be commissioned, modified, or decommissioned during the year Y, keeping the most likely hypothesis at this stage is recommended.

2.5.1.5 TI.03 - Quality and Availability Check

- **SMO:** The SMO shall verify that all GOs have provided their data and ensure that the information provided by the GOs is relevant for the process, based on the following:

- The information previously provided by the GO.
- A comparison of similar data provided by two or more different GOs.
- Any other relevant information the GO has.

Where necessary, the SMO shall send a request to the GOs for the update of the input data.

2.5.1.6 TI.04 – Data Update

- **GOs:** Upon request from the SMO, the GO shall verify if the information provided regarding the Asset Database for the calculation of the Regional Transmission Pricing is valid. Otherwise, updated information shall be provided based on the SMO comments.

2.5.1.7 TI.05 – Integration into Existing CGM

- **SMO:** Using the data provided by the GOs, the SMO integrates all the changes related to the information regarding the Asset Database for the calculation of the Regional Transmission Pricing in the existing PSS/E or an equivalent software file of reference.

The SMO implements the information regarding the Asset Database in PSS/E or equivalent software as follows:

- The number of circuits of each line (1L, 2L, ...) and the number of conductors for each phase of the line (1C, 2C, 3C, ...) by adding a term "_Type Code_" in the "Name" field.
- The Commissioning Year of each Asset by adding a term "_Commissioning Year_" in the "Name" field.
- The Ownership share (in case of cross-border assets) as follows:
  - The field "Owner" as the GO that owns all/part of the Asset;
  - The field "Fraction" as the Ownership share of each Owner.

2.5.2 Step B – Update of Asset Database

2.5.2.1 Relevant Activities

This Step B aims at updating the Asset Database in accordance with the CGM that reports the revenue requirements for all the Regional Assets to be remunerated with the Regional Transmission Pricing.

Table 2-3 - Main activities of the Update of Asset Database step

ID	Activities	Responsible Parties	Deadline	Involved Parties
UAD.01	Update of Standard Cost Database	SMO	April 15th (Y-1)	WAPP, SMO
UAD.02	Review of Standard Cost Database	ERERA	April 30th (Y-1)	ERERA
UAD.03	Data update	SMO		SMO
UAD.04	Approval of Standard Cost Database	ERERA		ERERA
UAD.05	Update of Asset Database	SMO	July 31st (Y-1)	SMO
UAD.06	Notification of Asset Database	SMO		SMO, ERERA

2.5.2.2 Timing

The timing of the different activities is represented in *Figure 3*

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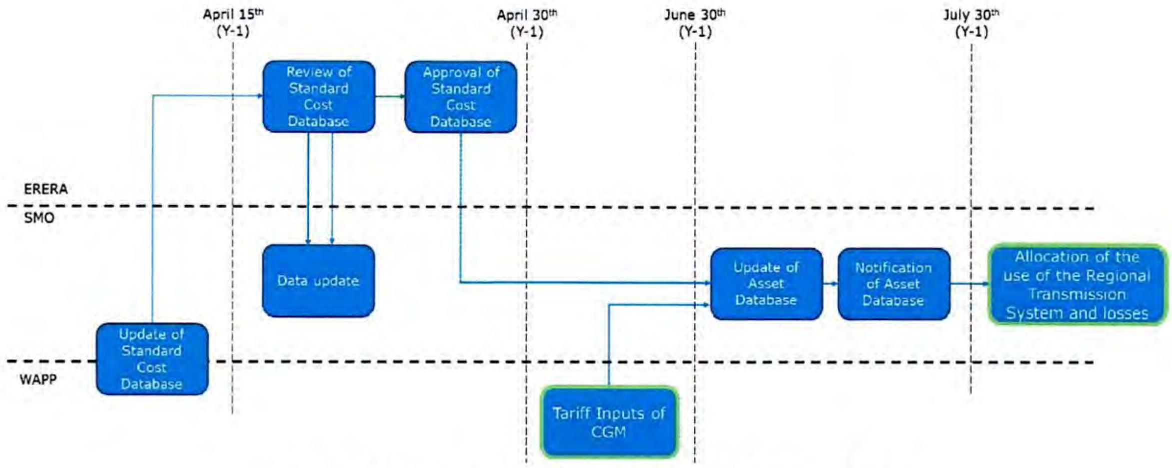


Figure 3 - Timing of the Update of Asset Database step

2.5.2.3 UAD.01 – Update of Standard Cost Database

- **SMO:** The SMO updates the Standard Cost Database every five (5) years or following the procedure for change outlined in the Market Code. The need for an update may arise if the following conditions occur:
  - The updated Asset Database integrated in the CGM (see activity **TI.05**) contains a new type of asset.
  - An unexpected change in energy asset prices.
  - Any other relevant reason that the SMO has.

The Standard Cost (capital and O&M) Database contains four (4) specific information, as further detailed in Appendix 1: Instructions for Updating the Asset Database:

1. The standard unit replacement costs of the assets of the Regional Transmission System, namely:
   - Unit cost (USD per km) of transmission lines, differentiated per number of circuit (single and double) and per number of conductors per phase for all the voltage levels in the Regional Transmission Network (≥ 132 kV). The standard unit cost for transmission line shall also include an estimation of the related civil works, acquisition of land/right of way, and other relevant equipment.
   - Unit cost (USD per MVA) of two and three-winding transformers and related bay(s) – which include breakers and switching – with the higher voltage winding at all voltage levels in the Regional Transmission Network (≥ 132 kV). The cost for three-winding transformers is computed through a fractional increment with respect to two-winding transformers. However, where a more detailed cost information is available for three-winding transformers, a cost for the tertiary winding shall be considered.
   - Unit cost (USD per MVA) of Phase Shifting Transformers (PST) for the voltage levels where there is any such equipment.
   - Unit cost (USD per MVAr), calculated as three times the product of the reactance, XC, and the square of the rated current I_{RATED}) of Series Capacitors.

- Unit cost for the typical high-voltage equipment (at voltage ≥ 132 kV) and facilities located in transformer substations, which are:
  - Reactors, including the bay (USD per unit);
  - Double Busbars with related bus couplers, differentiating the case of short- and long busbar (USD per unit);
  - Other facility related costs (USD per station), which include land acquisition, internal connections and equipment, integrated building, and civil works.

The unit standard costs are used to calculate the Total cost for Regional Assets in Step UAD.05 – Update of Asset Database.

2. The asset depreciation period, as determined by ERERA, is set for:
   - Transmission Lines to 50 years;
   - Transformers, which includes the PST to 25 years;
   - Series Cap to 35 years.

3. The allowed WACC values as approved by ERERA resolution. The ERERA resolution approving the applicable WACC values shall specify:
   - the single common WACC value to be applied, in general, to all assets included in the WAPPITS;
   - where applicable, specific WACC values to be applied to assets owned by individual Special Purpose Vehicles (SPVs) or to privately owned transmission assets.

   Where ERERA has not yet approved any WACC values, the SMO shall apply an initial uniform WACC of 11% to all WAPPITS assets. Once ERERA approves WACC values, the SMO shall thereafter apply the most recently approved values.

4. The allowed Operation and Maintenance (O&M) costs, including the cost of financing working capital, as approved by ERERA resolution. The ERERA resolution approving the applicable Operation and Maintenance (O&M) costs shall specify:
   - the single common Operation and Maintenance (O&M) cost, as a percentage of the asset value, to be applied, in general, to all assets included in the WAPPITS;
   - where applicable, specific Operation and Maintenance (O&M) costs to be applied to assets owned by individual Special Purpose Vehicles (SPVs) or to privately owned transmission assets.

   Where ERERA has not yet approved any Operation and Maintenance (O&M) costs, the SMO shall apply an initial uniform Operation and Maintenance (O&M) costs of 4% of the asset value to all WAPPITS assets. Once ERERA approves Operation and Maintenance (O&M) costs, the SMO shall thereafter apply the most recently approved values.

- **SMO:** The files used as sources of information must be labelled, saved, and filed by the SMO in a manner that they can be recovered in the future if necessary, either for studies or in case of disputes.

- **WAPP:** The SMO shall collaborate with WAPP to revise and adopt the proposal of the SMO for the updated Standard Cost Database.

- **SMO:** Upon completion, the SMO shall send to ERERA the Update of Standard Cost Database.

2.5.2.4 UAD.02 – Review of Standard Cost Database

In case the SMO updates the Standard Cost Database in **UAD.01**:

- **ERERA:** ERERA shall review the Standard Cost Database.

2.5.2.5 UAD.03 – Data update

Where the SMO updates the Standard Cost Database in **UAD.01**:

3. **SMO:** Upon request from the ERERA, the SMO shall review and update the Standard Cost Database based on ERERA comments as per **UAD.02**.

Where the SMO does not update the Standard Cost Database in **UAD.01**:

- **No action**

2.5.2.6 UAD.04 – Approval of Standard Cost Database

Where the SMO updates the Standard Cost Database in **UAD.01**:

- **ERERA:** ERERA shall approve the Standard Cost Database.

Where the SMO does not update the Standard Cost Database in **UAD.01**:

- **No action**

2.5.2.7 UAD.05 – Update of Asset Database

- **SMO:** With the publication of Model Structure Update of the WAPP Y-1 CGM BP by June 30th (see US.05 of WAPP Y-1 CGM BP) and the approval of the Standard Cost Database, the SMO prepares the full Asset Database for the calculation of the Regional Transmission Pricing in the existing excel file of reference.

  The file is composed of the Standard Cost Database and the Asset Data. The Asset Data include the Regional Assets, aggregated into the following categories:

  - TRANSMISSION LINE;
  - TRANSFORMER;
  - SERIES CAP;
  - PST.

- **SMO:** Based on the information collected and integrated in the CGM, as per Step A – Tariff Inputs for CGM, the SMO updates the following fields in the Asset Data:

  - Asset code names;
  - Length [km];
  - Reactive power rating (for series cap);
  - Marketable capacity (i.e., RATE A) [MVA];
  - High-Side Voltage [kV] and Low-Side Voltage [kV];
  - Tertiary Winding [Y/N];

  - Line type code (number of circuits and number of conductors);
  - Voltage level (HV for transformers) [kV];
  - Asset category (if TRANSMISSION LINE, TRANSFORMER, SERIES CAP, PST);
  - Name of Owner 1 and related Percentage of ownership;
  - Name of Owner 2 and related Percentage of ownership;
  - Commissioning date [year].

- **SMO:** Based on the updated asset identification and information inserted previously in the Asset Data, the SMO calculates the Total cost per asset (USD) as per the instructions included in Appendix 1: Instructions for Updating the Asset Database:
  - For each TRANSMISSION LINE, the Total cost per asset (USD) corresponds to the standard unit replacement costs (USD/km) set in the Standard Cost Database, multiplied by the length of the line.
  - For each TRANSFORMER, PST, and SERIES CAP, the Total cost per asset (USD) corresponds to the standard unit replacement costs of the asset (USD/MVA or USD/MVAr) set in the Standard Cost Database, plus an equal proportion of the additional costs related to the high-voltage equipment located in the hosting substations.

- **SMO:** After the calculation of the Total cost per asset (USD) of each asset, the SMO updates the following fields in the Asset Data:
  - Total cost per asset [USD]
  - Asset Age [Year]
  - Total and Yearly Depreciation [USD]
  - Total Value and Allowed profits on net Asset value [USD][1]
  - O&M costs [USD]
  - The Total Annual Revenue Requirement of each asset [USD]

2.5.2.8 UAD.06 – Notification of Asset Database

- **SMO**: The SMO shall provide the Asset Database to relevant stakeholders, including the GOs, WAPP, and ERERA, in accordance with REM's data confidentiality rules.

2.5.3 Step C – Allocation of the use of the Regional Transmission System and losses

2.5.3.1 Relevant Activities

This Step C aims at allocating the use of the Regional Transmission System and losses as the result of the expected operation of the WAPP Power System for year Y and the consequences of the use of the APM method.

[1] A residual value equal to 0% of the Standard Cost of the asset will be used initially until ERERA decide otherwise after appropriate study.

Table 2-4 - Main activities of the Allocation of the use of the Regional Transmission System and losses

ID	Activities	Responsible Parties	Deadline	Involved Parties
AUL.01	Preparation of APM Model Inputs	SMO	September 15^{th} (Y-1)	SMO
AUL.02	Allocation of the use of the Regional Transmission System and losses	SMO		SMO

2.5.3.2 Timing

The timing of the different activities is represented in Figure 4

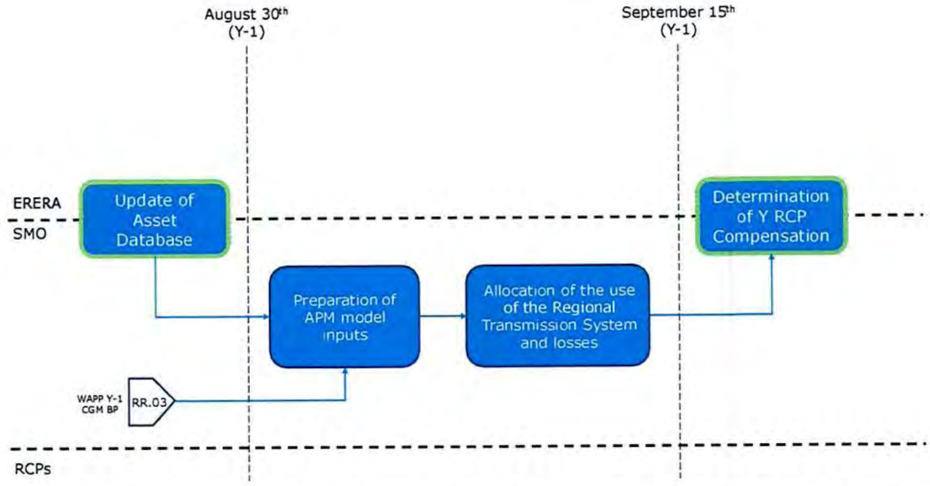


Figure 4 - Timing of the Allocation of the use of the Regional Transmission System and losses

2.5.3.3 AUL.01 – Preparation of APM Model Inputs

- **SMO:** The SMO prepares the inputs to the APM model to calculate the allocation of the use of the Regional Transmission System and losses. Inputs to the calculations, as detailed in Appendix 1: Instructions for Updating the Asset Database, are:

- One AC load flow performed for each Snapshot of the CGM generated by the SMO as per WAPP Y-1 CGM BP for each Scenario, which contains:
    - The power flow from each bus to the different Assets of the Transmission System.
    - The losses on each Asset of the Transmission System.
- The PSS-E file that describes the structure of the WAPP Network for each Snapshot of the CGM developed as per WAPP Y-1 CGM BP for each Scenario.
- The file with the Asset Database.

- The Pre-processing Control Input file that contains the variables to format the two above-mentioned files (i.e., the AC load flow and the structure of the WAPP Network) into a template suitable for the application of APM.
- The APM Control Input file that contains variables that are used by the APM to perform the applicable functionalities.

- **SMO:** The SMO shall input a power factor of 0.95 to perform the APM calculations.

- **SMO:** Unless otherwise instructed by ERERA, the SMO shall consider only regional assets by selecting the "Regional" option for the allocation of losses on the regional WAPP network.

- **SMO:** According to the RTTM, in the APM Control Input file, the SMO shall apply a Generation-Load split key equal to 10% and 90%, respectively, which represents the proportions of the total cost of the grid to be allocated to network users (generators and loads, respectively) to determine their contributions in asset usage and losses.

- **SMO:** According to the RTTM, in the APM Control Input file, the SMO sets the unit price for losses (USD/MW) to the weighted average DAM clearing price, calculated based on available data from the last twelve (12) months. In the absence of available data, the SMO shall establish an alternative value, subject to approval by ERERA.

2.5.3.4 AUL.02 – Allocation of the use of the Regional Transmission System and losses

- **SMO:** The SMO shall apply the APM Model as per RTTM for calculating the allocation of the use of the Regional Transmission System. As the APM determines the proportional use of each Asset, that same proportion is used to allocate the losses in the system.

  The calculation is performed by the SMO as per instructions annexed to this Procedure and referenced in Appendix 1: Instructions for Updating the Asset Database.

- **SMO:** Upon completion, the SMO shall file all the disaggregated and aggregated results of the application of the APM Model, which include at least:

- Disaggregated results by generator and load:
  - the overall flow contribution on each asset by generator and load
  - the losses allocation per asset by generator and load
  - the proportional cost allocation to generator and load, disaggregated by asset and total assets of the Control Area.
  - the proportional allocation of the value of the losses to generator and load, disaggregated by asset and total assets of the Control Area.
- Aggregated results by RCP:
  - Load use of the network allocation cost per RCP
  - Load losses allocation cost per RCP
  - Load overall cost per RCP

- generation use of the network allocation cost per RCP
- generation losses allocation cost per RCP
- generation overall cost per RCP
- joint overall losses cost per RCP
- joint overall use of network cost per RCP
- joint overall total cost per RCP

2.5.4 Step D – Determination of Y RCP Compensation

2.5.4.1 Relevant Activities

This Step D aims at calculating the net compensations to be paid/received by RCP at year Y as the result of the expected operation of the WAPP Power System for year Y and the consequences of the use of the Regional Transmission System and losses.

Table 2-5 - Main activities of the Calculation of RCP Compensations step

ID	Activities	Responsible Parties	Deadline	Involved Parties
RC.01	Setting the Y RCP Compensation	SMO	September 15^{th} (Y-1)	SMO
RC.02	Review of Y RCP Compensation	ERERA	October 15^{th} (Y-1)	ERERA, SMO
RC.03	Calculation update	SMO		SMO
RC.04	Approval of Y RCP Compensation	ERERA		ERERA
RC.05	Publication of Y RCP Compensation	SMO	October 31^{st} (Y-1)	SMO, ERERA, GOs

2.5.4.2 Timing

The timing of the different activities is represented in Figure 5.

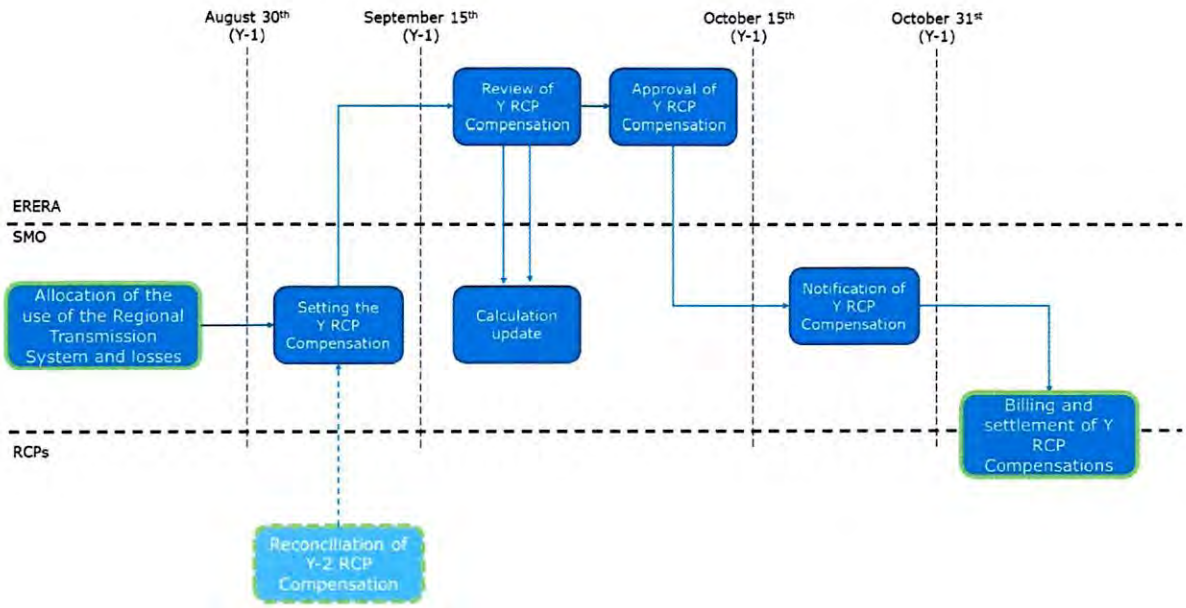


Figure 5 - Timing of the update of the Calculation of RCP Compensations step

2.5.4.3 RC.01 – Setting the Y RCP Compensation

- **SMO**: Upon completion of the Allocation of the use of the Regional Transmission System and losses and calculation, the SMO shall send to ERERA the disaggregated and aggregated results of the application of the APM Model. The aggregated "RCP joint overall total cost per RCP" results indicate the total cost (in USD) allocated to each RCP due to:
    1. Use of network cost:
        a. The use of the other RCPs' area network by the generators and loads in its area; and,
        b. The use of its area network by generators and loads of the other RCPs' areas.
    2. Losses allocation cost:
        a. The losses caused in the other RCPs' area network by the generators and loads in its area; and,
        b. The losses in its area network by generators and loads of the other RCPs' area.

  The same results report also the net positive/negative amount to be received/paid by each RCP, identifying the *net receivers* and *net payers*, respectively.

- **SMO:** The SMO shall report the results in dollar ($) format, rounded to two decimal places.
- **SMO:** The SMO shall include in the Y RCP Compensation the amount related to the Reconciliation for year (Y-2), as detailed in the Reconciliation Statement for the Y-2 RCP Compensation (see *Step F – Reconciliation of the Y RCP Compensation*).
- **SMO:** The SMO shall submit to ERERA the results of the Y RCP Compensation calculations, along with the data used to define the Snapshots and the assumptions applied in determining their respective weights.

2.5.4.4 RC.02 – Review of Y RCP Compensation

- **ERERA:** ERERA shall review the RCP Compensations and request the SMO to update the calculation.

2.5.4.5 RC.03 – Calculation update

- **SMO:** Upon request from the ERERA, the SMO shall review and update the result of the APM model and re-calculate the RCP Compensations based on ERERA's review.

2.5.4.6 RC.04 – Approval of Y RCP Compensations

- **ERERA:** ERERA shall approve the Y RCP Compensations for the use of the Regional Transmission System and losses.
- **SMO:** In the absence of current approved figures by ERERA, the SMO shall use the latest approved figures.

2.5.4.7 RC.05 – Notification of Y RCP Compensations

- **SMO**: The SMO shall notify relevant stakeholders, including the GOs, the RCPs, NRAs, and ERERA, of the Y RCP Compensations for the use of the Regional Transmission System and losses.

2.5.5 Step E – Billing and settlement of Y RCP Compensations

2.5.5.1 Relevant Activities

This Step E aims at managing the billing and settlement of the exchange of payments related to RCP Compensations from the net payers RCPs to the SMO, and from the SMO to the net receivers RCP.

The relevant activities for the billing and settlement of exchange of payments by the SMO and RCP shall follow the billing and payment procedural steps set in the relevant Operational procedure of the REM.

This procedure adds the following activities to be considered in the framework of executing the Y RCP Compensation:

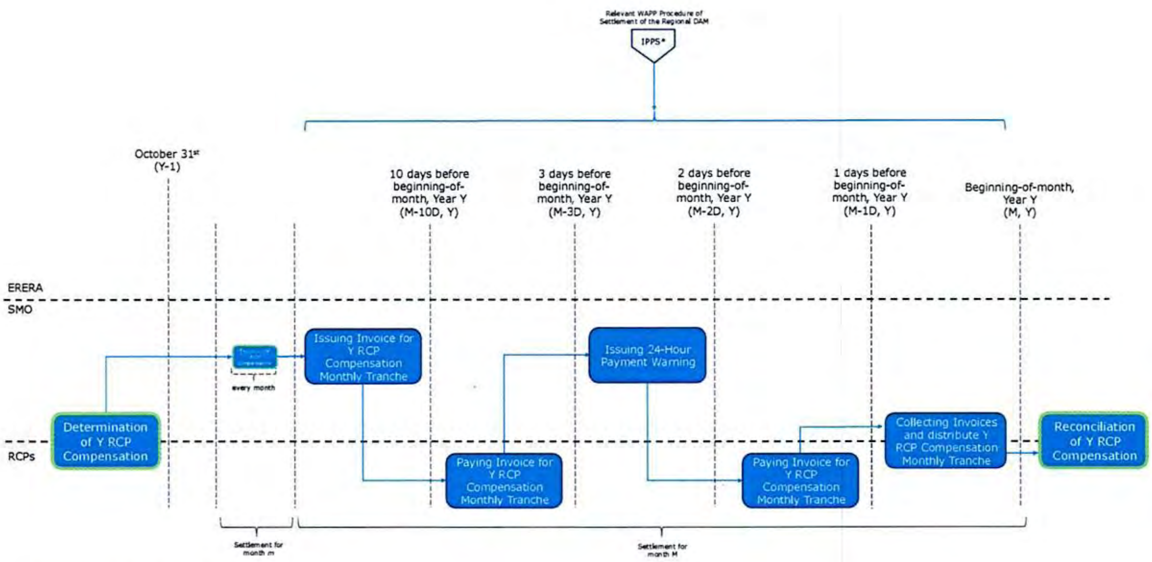
1. When applying the billing and payment procedural steps of the relevant Operational procedure of the REM in the framework of the inter-RCP Compensations and the application of this RETTAP, the parties involved in the exchange of invoices and payments are the RCP net payers and the RCP net receivers resulted from the determination of the Y RCP Compensations performed in *Step D – Determination of Y RCP Compensation*.
2. In the framework of the inter-RCP Compensations and the application of this RETTAP, the billing and payments are based on the RCP Compensations established in *Step D – Determination of Y RCP Compensation* in year Y-1, and shall be executed in twelve (12) monthly equal tranches in year Y, as defined in RTTM. This specification translates in the new activities **EC.01-EC.05** for the SMO.

Table 2-6 - Main activities of the Billing and Settlement of Y RCP Compensations

ID	Activities	Responsible Parties	Deadline*	Involved Parties
EC.01	Issuing Invoice for Y RCP Compensation Monthly Tranche	SMO	M-10D, Y	SMO, RCP
EC.02	Paying Invoice for Y RCP Compensation Monthly Tranche	RCP (net payers)	M-3D, Y	RCP, SMO
EC.03	Issuing 24-Hour Payment Warning	SMO	M-2D, Y	SMO, RCP
EC.04	Paying Invoice for Y RCP Compensation Monthly Tranche	RCP (net payers)	M-1D, Y	RCP, SMO
EC.05	Collecting Invoices and distributing Y RCP Compensation Monthly Tranche	SMO, RCP (net receivers)	M, Y	SMO, RCP
M-XD, Y = *X* days before the beginning-of-month **M**, for each month **M** of year **Y**				

2.5.5.2 Timing

The timing of the different activities is represented in Figure 6.



*IPPS=Invoicing and Payment Procedural Steps

Figure 6 - Timing of the update of the Billing and settlement of Y RCP Compensations.

2.5.5.3 EC.01 – Issuing Invoice for Y RCP Compensation Monthly Tranche

3. **SMO**: Ten (10) days before the beginning of each month, the SMO shall follow the relevant billing and payment procedural steps of the relevant Operational procedure of the REM to issue an invoice to the RCPs that resulted to be net payers from the determination performed in *Step D – Determination of Y RCP Compensation*. The invoice should be equal to one twelfth (1/12) of the total net Y RCP Compensation amount to be due by each net payer RCP as determined in *Step D – Determination of Y RCP Compensation*.

- **RCP**: the *net payer* RCP shall receive the invoice.

2.5.5.4 EC.02 – Paying Invoice for Y RCP Compensation Monthly Tranche

- **RCP**: the *net payers* RCP that receive the invoice follow the relevant billing and payment procedural steps of the relevant Operational procedure of the REM to pay the invoice within seven (7) days from the day of issue.
- **SMO**: shall receive the payment.

2.5.5.5 EC.03 – Issuing 24-Hour Payment Warning

- **SMO**: The SMO shall follow the relevant billing and payment procedural steps of the relevant Operational procedure of the REM to issue a warning to pay the invoice within 24 hours to the RCPs that have not paid the expected invoice by due deadline.

2.5.5.6 EC.04 – Paying Invoice for Y RCP Compensation Monthly Tranche

Where an RCP did not pay the invoice, as required in **EC.02**, yet:

- **RCP:** the *net payer* RCP that receives the invoice following the relevant billing and payment procedural steps of the relevant Operational procedure of the REM shall pay the invoice within 24 hours upon receipt of the payment warning.

Where the RCP has already paid the invoice, as required in **EC.02**:

- **No action**

Where the RCP has not paid the invoice after the 24 hours deadline in this **EC.04**:

- **SMO**: The SMO calls on the security guarantee in accordance with the relevant billing and payment procedural steps of the relevant Operational procedure of the REM.
- **ERERA:** ERERA shall handle any default in the payment and settlement of the Y RCP Compensation in accordance with the Rules on Sanctions[2] in the REM.

2.5.5.7 EC.05 – Collecting Invoices and distributing Y RCP Compensation Monthly Tranche

- **SMO**: Within the last day before the beginning of each month, the SMO, following the relevant billing and payment procedural steps of the relevant Operational

[2] Refers to the ECOWAS Regulation C/REG.17/06/19 of 27th June 2019 on sanctions for the Regional Electricity Market (REM)

procedure of the REM, shall collect all the due payment from the *net payers* RCP, prepare and issue the relevant monthly payment to the RCPs that resulted to be *net receivers* from the determination performed in *Step D – Determination of Y RCP Compensation*. The payment shall be equal to one twelfth (1/12) of the total net positive Y RCP Compensation amount to be received by each respective *net receiver* RCP as published in *Step D – Determination of Y RCP Compensation*.

- **RCP**: The *net receiver* RCP receives the payment.

2.5.6 Step F – Reconciliation of the Y RCP Compensation

2.5.6.1 Relevant Activities

This Step F aims at the execution of the reconciliation of the Y RCP Compensation based on the actual flows observed in Y. Reconciliation is performed based on the actual flow patterns that occurred in year Y.

Table 2-7 - Main activities of the Reconciliation for Y RCP Compensation payments

ID	Activities	Responsible Parties	Deadline	Involved Parties
RE.01	Compile the Reconciliation Statement for Y RCP Compensation	SMO	April 30th Y+1	SMO, RCP
RE.02	Publication of the Reconciliation Statement for Y RCP Compensation	SMO	May 31st Y+1	SMO, RCP, ERERA
RE.03	Billing and settlement of the Reconciliation of the Y RCP Compensation	SMO, RCP	M, Y+2	SMO, RCP

2.5.6.2 Timing

The timing of the different activities is represented in Figure 7

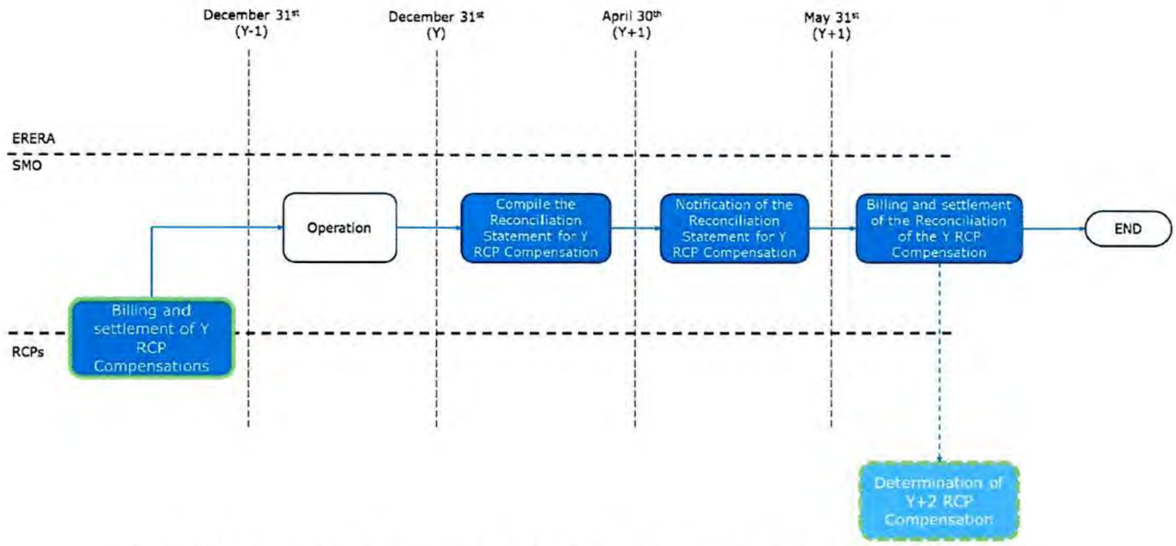


Figure 7 - Timing of the update of the Reconciliation of Y RCP Compensation step.

2.5.6.3 RE.01 – Compile the Reconciliation Statement for Y RCP Compensation

The eventual level of compensation that should be applied for year Y shall be computed ex-post using a set of Snapshots representing the actual operation of the system observed in year Y.

- **SMO**: To compute these compensations, the SMO shall collect data on the *actual* level of the clustering variables, for all hours of the year, corresponding to the *actual* operation of the system in year Y.
- **SMO**: Based on these data, the SMO shall repeat the same approach followed in ***TI.01*** - *Proposition of market Scenarios and their weight* of *Step A – Tariff Inputs for CGM* to determine the set of Snapshots to be used to recompute the annual Y RCP Compensation to be eventually reconciled.
- **SMO**: The SMO shall produce the map of flows for each revised representative Snapshot within this updated set of them, which could be the map of real physical flows measured, or the map of flows computed based on other system variables measured for these set of Snapshots (i.e., a revised set of CGM re-developed based of these new set of revised Snapshots).
- **SMO**: Based on the updated map of the flows, the SMO shall determine the updated level of annual Y RCP Compensation (hereinafter referred to as "*ex-post* Y RCP Compensation") by following the same procedure described in *Step C – Allocation of the use of the Regional Transmission System and* losses.
- **SMO**: By April 30th of Y+1, the SMO computes the deviations in compensation between the *ex-post* Y RCP Compensation and the Y RCP Compensation computed in Y-1 as the difference between these two and reports the results disaggregated by RCP in a Reconciliation Statement.

2.5.6.4 RE.02 - Notification of the Reconciliation Statement for Y RCP Compensation

- **SMO:** The SMO provides the Reconciliation Statement for Y RCP Compensation for the actual use of the Regional Transmission System and losses in year Y to ERERA.
- **ERERA:** ERERA shall review the RCP Compensations.
- **SMO:** Upon request from the ERERA, the SMO shall review and re-calculate the *ex-post* Y RCP Compensations based on ERERA's review and update the Reconciliation Statement for Y RCP Compensation.
- **ERERA:** ERERA shall approve the revised Reconciliation Statement for Y RCP Compensation.
- **SMO**: By May 31st of Y+1, the SMO shall notify relevant stakeholders, including the GOs, the RCPs, NRAs, and ERERA, of the provision of the Reconciliation Statement for Y RCP Compensation for the actual use of the Regional Transmission System and losses in year Y.

2.5.6.5 RE.03 - Billing and Settlement of the Reconciliation of the Y RCP Compensation

- **SMO**: The SMO shall include the deviations for year Y published in the latest approved Reconciliation Statement for Y RCP Compensation in a virtual deviation fund, separately computed for each RCP, accumulating both positive and negative deviations in the net compensation received by this RCP over a rolling ***P*** years (*i.e., ex-post Y RCP Compensation minus ex-ante Y RCP Compensation is cumulated in the virtual deviation fund*).
- **SMO:** The SMO shall add an amount, whether positive or negative, equal to 1/P of the accumulated balance of the virtual deviation fund to the subsequent year's RCP Compensation. In practice, this means that in year Y+1, the SMO shall add 1/P of the accumulated balance of the virtual deviation fund to the Y+2 RCP Compensation of each RCP and adjust the fund's balance accordingly.

  Unless otherwise notified by ERERA, *P* is set equal to three (3) years[3].

[3] This is to make the reconciliation though this rolling window approach as independent as possible from the latest operation decisions made by the Users within each RCP area, while also softening variations in the net compensations finally applied compared to those computed in advance and communicated to RCP areas.

APPENDIX

Appendix 1: Instructions for Updating the Asset Database

- "Development and updating of the WAPP Asset Database", 2025, by CESI.

Appendix 2: Instructions for Running APM-IGOC Model for WAPP

- "Instructions for Running APM-IGOC Model for WAPP", 2025, by CESI.

Appendix 3: POC for Selecting Archetype Snapshots for the APM-IGOC

- "Computation of Annual Inter-GO Compensations for the External Use of each GO's Network using a Reduced Number of Snapshots", 2025, by CESI.

RETTAP-Appendix 1

Instructions for Updating the Asset Database

This set of instructions complements the activities mentioned in "Step B – Update of Asset Database" of the RETTAP by providing:

1. **Stage1: Detailed Instructions for Updating the Standard Cost Database** This is to be carried out by the System and Market Operator (SMO), as outlined in activity UAD.01 – Update of Standard Cost Database.
2. **Stage2: Detailed Instructions for Updating the List of Eligible Regional Assets** This step is crucial for annually listing all the Regional Assets that are subject to the Regional Transmission Processing in the correct format from the relevant PSS®E Network Models.
3. **Stage3: Detailed Instructions for Updating the Asset Database** This step is essential for annually determining the annuities of the Regional Assets, which are used in the subsequent allocation of costs using the APM, as specified in activity UAD.05 – Update of Asset Database.

The process for updating the Asset Database relies on the following components:

1) A Python code with two (2) packages:
    a. The first one for updating the list of all Asset Data and related attributes for Transmission Lines, Transformers, Series Cap, and Phase Shifting Transformers (PST) in the latest available and updated PSSE CGM model files, one for each relevant snapshot, with the WAPP network topology.
    b. The second one for calculating the Total Cost per Asset (USD) for the relevant Categories of Assets and generating the updated Asset Database for the WAPPITS.
2) The excel file containing the Standard Cost Database (see ANNEX B: Supporting Excel for Asset Cost Database 2025).

Stage1: Detailed Instructions for Updating the Standard Cost Database

The Standard Cost Database (SCD) contains reference unitary costs useful to compute the Total Cost per Asset (USD) for the relevant Categories of Assets. It is provided in the form of an excel file composed of the following sheets:

- *SCD Computation Parameters*: it reports the main computation parameters, including WACC, O&M costs and the depreciation period per asset type.
- *SCD Transmission Lines*: it reports the unit costs [USD/km] of transmission lines, subdivided by voltage level and line type.
- *SCD Substation Elements*: it reports the units cost of the main components of substations, subdivided by voltage level.

SCD Composition

Tab1: SCD Computation Parameters

The first tab, *'SCD Computation Parameters'*, includes various financial, economic, and technical settings that can be manually updated by the SMO subject to the ECOWAS Regional Electricity Regulatory Authority (ERERA)'s approval each year. An example is shown in the following screenshot. Values in the cells with the gold-colored background can be manually edited.

Editable parameters

Table "A"- Computation Parameters / Tableau «A» - Paramètres de calcul

Row Number / Numéro de ligne	Description	u.m.	USED VALUE / VALEUR UTILISÉE	
1	Tariff calculation for year / Année de calcul tarifaire	year - année	2025	
2	Residual Value - Valeur résiduelle	%	0%	
3	Asset depreciation period - ex ERERA RESOLUTION N°006/ERERA/15 / Durée d'amortissement des actifs ex RÉSOLUTION ARREC N° 006/ARREC/15			
3.1	*TRANSMISSION LINE / LIGNE DE TRANSMISSION*	years - années	50	
3.2	*PHASE SHIFTING TRANSFORMER (PST) / TRANSFORMATEUR DEPHASEUR (PST)*	years - années	25	
3.3	*TRANSFORMER / TRANSFORMATEUR*	years - années	25	
3.4	*SERIES CAP / CONDENSATEUR SERIE*	years - années	35	
4	Parameters of companies (Weighted Average Cost of Capital - WACC), O&M Costs and price of losses Paramètres des entreprises (Coût moyen pondéré du capital - CMPC), couts d'O&M et prix des pertes		**WACC (%)**	**O&M Costs**
4.1	*TCN*		11.0%	4%
4.2	*GRIDCO*		11.0%	4%
4.3	*CEB*		11.0%	4%
4.4	*CIE*		11.0%	4%
4.5	*SONABEL*		11.0%	4%
4.6	*NIGELEC*		11.0%	4%
4.7	*LEC*		11.0%	4%
4.8	*EDSA*		11.0%	4%
4.9	*EDG*		11.0%	4%
4.10	*EAGB*		11.0%	4%
4.11	*NAWEC*		11.0%	4%
4.12	*SENELEC*		11.0%	4%
4.13	*CLSG*		11.0%	4%
4.14	*SOGEM*		11.0%	4%
4.15	*EDM-SA*		11.0%	4%
4.16	*OMVG*		11.0%	4%
4.17	*SOMELEC*		11.0%	4%
4.18	*Additional TSOs*			
4.19	*Additional TSOs*			
4.20	*Additional TSOs*			
4.21	*Additional TSOs*			
4.22	*Additional TSOs*			
4.23	*Additional TSOs*			
4.24	*Additional TSOs*			
4.25	*Additional TSOs*			
5	Voltage threshold for the regional assets / Seuil de tension pour les actifs régionaux	kV	132	

Tab2: SCD Transmission Lines

The second tab "*SCD Transmission Lines*" is a lookup table, where a unitary cost is associated to each line code represented by the voltage (V_{level}), the number of circuits ($N_{circuits}$) and the number of conductors ($N_{conductors}$),

$$V_{level}\ N_{circuits}L\ N_{conductors}C \text{ (e.g., 225 2L 1C)}$$

The unit cost of transmission lines [USD/km] provided in the Standard Cost Database considers the design, supply and construction of the lines including the costs of:

- Towers
- Conductors
- Earth wire and Optical Ground Wire
- Accessories
- Insulators + hardware
- Spare parts
- Design
- Foundation
- Erection and stringing
- Right of Ways

It does not include the cost of line bays which is included in the *"SCD Substation Elements"* tab.

The costs depend on:

- Voltage level: costs increase less than linearly with the increase of voltage.
- Number of conductors per phase: the higher the number of conductors, the higher the cost of materials.
- Number of circuits per line: double circuit lines, have double the number of conductors with respect to single circuits, but also higher costs for towers and erection.

An example is shown in the following screenshot.

TRANSMISSION LINE / LIGNES DE TRANSMISION			
VOLTAGE / NIVEAU DE TENSION			UNIT COST / COÛT UNITAIRE
kV	TYPE	CODE	kUSD/km
400	Double line, four conductors/phase	400 2L 4C	276
400	Single line, four conductors/phase	400 1L 4C	321
400	Double line, three conductors/phase	400 2L 3C	238
400	Single line, three conductors/phase	400 1L 3C	282
330	Double line, four conductor/phase	330 2L 4C	284
330	Double line, three conductor/phase	330 2L 3C	245
330	Double line, two conductors/phase	330 2L 2C	202
330	Single line, three conductor/phase	330 1L 3C	291
330	Single line, two conductors/phase	330 1L 2C	244
330	Double line, one conductor/phase	330 2L 1C	160
330	Single line, one conductor/phase	330 1L 1C	199
225	Double line, one conductor/phase	225 2L 1C	144
225	Double line, two conductors/phase	225 2L 2C	193
225	Single line, one conductor/phase	225 1L 1C	177
225	Single line, two conductors/phase	225 1L 2C	228
161	Double line, two conductors/phase	161 2L 2C	173
161	Single line, two conductors/phase	161 1L 2C	205
161	Double line, one conductor/phase	161 2L 1C	129
161	Single line, one conductor/phase	161 1L 1C	159
150	Double line, one conductor/phase	150 2L 1C	126
150	Single line, one conductor/phase	150 1L 1C	156
132	Double line, one conductor/phase	132 2L 1C	122
132	Single line, two conductors/phase	132 1L 2C	195
132	Single line, one conductor/phase	132 1L 1C	151

Tab3: SCD Substation Elements

Transmission substations are modular, and their total cost, including design, supply and construction depends on their configuration. The *"SCD Substation Elements"* tab reports the unit cost of the main elements composing the substations, including engineering services, easements, damage settlement, technical-administrative testing:

- Machinery including associated foundation works:
  - Transformers
  - Phase Shifting Transformers (PST)
  - Shunt (reactors or capacitors)
  - Series Capacitors

- Bays and equipment (circuit breakers, disconnectors, current transformers (CT), voltage transformers (VT), dischargers, transmitted wave coils) and connections HV, including conductors, terminal equipment, insulators, supports, station carpentry, grounding circuits, civil foundation works, peripheral units of the system protection, command and control, peripheral units of auxiliary and general systems, etc:
  - Transformer bay.
  - Line bay.
  - Shunt bay.
  - Busbar.
- Facility: this includes the cost of land, connections, the building, landscaping works, substation automation system, alarm system and management system.

The costs depend on the voltage level at which the components are connected.

An example is shown in the following screenshot.

	TRANSFORMER BAY (PRIMARY) / BAIE DE TRANSFORMATEUR (PRIMAIRE)	TRANSFORMER BAY (SECONDARY) / BAIE DE TRANSFORMATEUR (SECONDAIRE)	LINE BAY / BAIE DE LIGNE	SHUNT BAY / BAIE DE SHUNT	TRANSFORMER (2W) / TRANSFORMATEUR (2W)
VOLTAGE / NIVEAU DE TENSION	UNIT COST / COÛT UNITAIRE	UNIT COST / COÛT UNITAIRE	UNIT COST / COÛT UNITAIRE	UNIT COST / COÛT UNITAIRE	UNIT COST / COÛT UNITAIRE
kV	kUSD/unit	kUSD€/unit	kUSD/unit	kUSD/unit	kUSD/MVA
400	884	-	891	1068	7
330	884	-	891	1068	7
225	691	437	565	676	5
161	418	418	430	504	13
155	418	418	430	504	13
150	418	418	430	504	13
132	418	418	430	504	13
*GIS**	*70%*	*70%*	*76%*	*59%*	*0%*

* Extra cost due to GIS insulation.
† Including insulated platform.
§ Considering that the variable controlled capacity (i.e., TCSC) is around 75% of the total.

Update Process

This section sequences into a workflow the process for regularly updating the Standard Cost Database, in accordance with the 'UAD.01 – Update of Standard Cost Database' step of the RETTAP.

The procedure and references used to develop the current version of the Standard Cost Database are provided here to facilitate the development of future releases. ANNEX A: Approach followed for 2025-update details the specific references, quantities, and values adopted for the 2025 update. The SMO may consider these for supporting future updates of the database.

Step 0: References

The SMO shall identify and list the main relevant sources for updating the cost information. The section ANNEX A: Approach followed for 2025-update reports the list of references used for the 2025 update.

In general, the World Bank[1] and African Development Bank[2] platforms are continuously accessible open sources that should be monitored for updates to the Standard Cost Database.

[1] Projects & Operations | The World Bank
[2] MapAfrica

Other platforms, both freely accessible and subscription-based, such as BiddingSource[3] or Assortis[4], also exist.

Step 1: Collection of reference source costs

- For updating the "**SCD Transmission Lines**", this step consists of listing all the sources of reference and the related information that are useful for extrapolating the reference source cost (kUSD/km), according to the following format:

Description of the project	Lot	Line Code	Length [km]	Bid Year	Contractor	Total cost [USD]	Reference source cost [kUSD/km]
Guinea – Mali Interconnection Project		225 2L 1C	53.7	2021	GROUPEMENT MEC ET UPTL (509302)	8,600,523	160
...	...	...	...	...	...	...	...

NOTE: The total cost is the sum of the contracted price in USD and the local currency amount, converted to USD using the exchange rate applicable in the Bid Year.

- For updating the "**SCD Substation Elements**", this step consists of listing:
  1. All the financed projects and the related information referred to electrical substations:

Substation Names	BAMBADINCA – SALTHINO – BISSAU – MANSOA
Bid Year	2016
Contract Amount	$37,200,000
BAMBADINCA	Two 225 kV-30 kV power transformers of a capacity of 15 MVA each for the distribution
	Two 225 kV outgoing lines allowing the inclusion of the substation in the loop
	A 225 kV inductance shunt with a capacity of 20 MVAr;
	A simple set of 225 kV bars that could be doubled at a later stage
	Two incoming circuit breakers, 30 kV
	One tie breaker, 30 kV
	Two 30 kV bars
	Four outgoing circuit breakers, 30 kV
	Two outgoing fused isolating switches for the auxiliary services transformers
	Two auxiliary services transformers each rated 200 kVA
...	...
	...
	...

[3] Government Tenders
[4] https://www.assortis.com/tpl/assortis-home.asp

NOTE: The total cost is the sum of the contracted price in USD and the local currency amount, converted to USD using the exchange rate applicable in the Bid Year.

2. All the sources of reference and the related information that are useful for extrapolating the reference source cost (kUSD/...) of substation equipment, according to the following format:

Reference	Asset type	Voltage (Primary) [kV]	Rate A Capacity [MVA]	Reference Year	Total cost [USD]	Reference source cost [kUSD/...]
GO information	PST	330	250	2010	3,200,000	12.8 kUSD/MVA
GO development plan	TRAFO (2W)	225	250	2023	1,000,000	4.0 kUSD/MVA
...	...	...	...	...	...	...

This table should encompass as much as possible all the substation equipment considered in the Standard Cost Database, including Transformer bay, Line bay, Shunt bay, Transformer, Shunt, Series Capacitors, Busbar, and Facility. It should also report reference source costs to cover the widest possible range of voltage levels.

The section ANNEX A: Approach followed for 2025-update reports the figures and references used for the 2025 update.

Step 2: Cost escalation

The SMO shall escalate all the cost figures identified in *Step 1: Collection of reference source costs* from the reference year to the desired year by applying appropriate cumulative inflation multipliers and ensuring all costs are expressed in USD:

1. Obtain the annual cumulative inflation multiplier for the United States from the reference year to the desired year. Unless otherwise indicated by ERERA, use the US Producer Price Index (US PPI) for the industry classification "Electric Bulk Power Transmission and Control" as the cumulative inflation multiplier[5,6].

2. Calculate the cumulative inflation multiplier based on US PPI from the project year to the reference year Y[7] using the formula:

[5] PPI: Producer Price Index Home : U.S. Bureau of Labor Statistics

[6] Direct Link to download data for the selected Industry: https://download.bls.gov/pub/time.series/pc/pc.data.46.Utilities

[7] If data for Y are not available, use the available average data for the year Y-1

$$Cumulative\ inflation\ multiplier\ = \frac{PPI_Y}{PPI_{proj\_year}}$$

3. Apply the calculated cumulative inflation multiplier to the costs converted to USD to obtain the updated costs for year Y.

Example Calculation

Suppose we have a unit cost of $1000 in USD in 2018 and a PPI equal to 165 and 215 in 2018 and 2025, respectively, for escalating the cost to 2025:

- Cumulative Inflation multiplier = $\frac{215}{165} \approx 1.30$
- Updated Cost=$1000 \times (1.30) = 1300\ USD$

This cost escalation procedure stands upon the following assumptions:

1. **Simplification of Local Currency Components**: All costs in local currency are converted to USD in Step 1: Collection of reference source costs using the exchange rate of the project year. The cumulative inflation multiplier for the USA is then applied to the entire contract amount. This simplification is justified by the following reasons:
   - Since the escalated value for the desired year is required in USD, it is unnecessary to update the local currency components separately. Converting everything to USD from the beginning at the reference/bid year allows for a straightforward application of the US inflation rate.
   - Converting all costs to a single currency (USD) provides a uniform basis for analysis, reducing the complexity of handling multiple currencies and exchange rates.
   - US inflation indexes and economic data are more readily available and generally more stable compared to those of many African countries.
   - Given that a significant portion of the contracts is valued in USD and the contractors are primarily Chinese or Indian companies, the US inflation index serves as a reasonable indicator of cost variations in the international context.
2. Specific variations in commodity costs in the international market are not introduced, as inflation is considered a comprehensive indicator that includes such variations. This choice is justified by the following reasons:
   - Inflation generally reflects changes in the prices of a wide range of goods and services, including commodities. Therefore, using inflation as the primary indicator captures cost variations in a simpler and more direct manner.
   - Considering only inflation reduces the complexity of calculations, avoiding the need to monitor and apply specific variations for each commodity.

- Using inflation as an indicator of cost variations is a common and accepted practice in many sectors, making our calculations more understandable and verifiable.
- Inflation in the United States is an indicator of how the purchasing power of the dollar has changed over time. Even if the contractors are not American (e.g., Indian and Chinese), contracts in USD (US dollars) mean that costs are expressed in a currency subject to inflation. Therefore, the costs in USD could be adjusted using US inflation to reflect the current value of those costs in dollars.

The section ANNEX A: Approach followed for 2025-update reports the figures and references used for the 2025 escalation.

Step 3: Costs extrapolation rationale

Since not all possible combinations of transmission line and substation equipment types and voltage present in the WAPP have corresponding references in the awarded projects and/or cost references identified in *Step 1: Collection of reference source costs*, the SMO shall extrapolate the costs of the assets that do not have corresponding references identified in Step 1: Collection of reference source costs.

- For **Transmission Lines**: In case reference source costs are not available from *Step 1: Collection of reference source costs* for every voltage level of the Regional Network, and unless otherwise justified by the SMO and ERERA based on updated data and information, the SMO shall use the following rule to estimate the reference source costs based on varying voltage levels: the voltage levels 380-330 kV, 225 kV, and 161-132 kV are grouped together and assumed to have the same reference breakdown cost coefficients.

  Then, unless otherwise justified by the SMO and ERERA based on updated data and information, the SMO shall use the following line breakdown cost coefficients table to extrapolate the costs based on varying line codes (number of conductors and number of circuits):

	132 kV - 161 kV				225 kV				330 kV – 400 kV						
Component	**2L1C**	**2L2C**	**1L1C**	**1L2C**	**2L1C**	**2L2C**	**1L1C**	**1L2C**	**2L2C**	**1L1C**	**1L2C**	**1L3C**	**1L4C**	**2L3C**	**2L4C**
Towers	0.40	0.44	0.3	0.3	0.38	0.42	0.25	0.28	0.36	0.2	0.2	0.3	0.3	0.4	0.4
Conductor	0.29	0.58	0.1	0.3	0.29	0.58	0.15	0.29	0.34	0.1	0.2	0.3	0.3	0.5	0.7
Earth wire	0.01	0.01	0.0	0.0	0.01	0.01	0.01	0.01	0.01	0.0	0.0	0.0	0.0	0.0	0.0
Accessories	0.01	0.01	0.0	0.0	0.01	0.01	0.01	0.01	0.01	0.0	0.0	0.0	0.0	0.0	0.0
Insulators + hardware	0.07	0.07	0.0	0.0	0.09	0.09	0.05	0.05	0.09	0.0	0.0	0.0	0.0	0.1	0.1
Spare	0.01	0.01	0.0	0.0	0.01	0.01	0.01	0.01	0.01	0.0	0.0	0.0	0.0	0.0	0.0
Design	0.01	0.01	0.0	0.0	0.01	0.01	0.01	0.01	0.01	0.0	0.0	0.0	0.0	0.0	0.0
Foundation	0.10	0.11	0.1	0.1	0.10	0.11	0.07	0.07	0.09	0.1	0.1	0.1	0.1	0.1	0.1
Erection + Stringing	0.10	0.10	0.1	0.1	0.10	0.10	0.07	0.07	0.08	0.1	0.1	0.1	0.1	0.1	0.1
TOT	**1.00**	**1.34**	**0.62**	**0.80**	**1.00**	**1.34**	**0.61**	**0.79**	**1.00**	**0.49**	**0.61**	**0.72**	**0.82**	**1.22**	**1.41**

For each voltage level, a reference line type (highlighted in green in the table) with unitary cost is selected. For these line types, the breakdown of the total cost into different components is identified based on experience, literature, and the judgment of the SMO and ERERA, ensuring the total sums to 1. Other line types have a different breakdown, as shown in the other columns of the table.

For example, the line "2L 2C" at 132kV has twice the cost of the conductor compared to "2L 1C" but the same cost for Earthwire and Accessories. This results in a total cost for other line types that differs from 1. The ratio of the total (TOT) cost of different lines is used to estimate the costs where no literature reference is available (see Step 4: Standard Costs Database creation).

- For **Substation equipment**: Unless otherwise justified by the SMO and ERERA based on updated data and information, the SMO shall use the following simple rule to estimate the reference source costs based on varying the voltage level: the voltage levels 380-330 kV, 225 kV, and 161-132 kV are grouped together and assumed to have the same reference source costs.

Step 4: Standard Costs Database creation

The final step consists of creating the updated Standard Costs Database by merging all the results from Step 1 to 3:

- For **Transmission Lines:** the SMO can update the Standard Cost Database for Transmission lines by applying:
  1. The algebraic average for the available reference escalated costs for the known projects listed in *Step 2: Cost escalation*.
  2. the rules outlined in *Step 3: Costs extrapolation rationale* to extrapolate the costs for the unavailable reference values from the selected reference source costs after average by voltage. In case no average references source costs were available for some voltage levels at the previous step, appropriate linear interpolation by voltage and by line type shall be used to calculate a proxy for the setting the reference algebraic average for for those unavailable reference costs, and then apply the extrapolation coefficients.
  3. a mark-up to account for miscellaneous, such as the Right-of-Way (ROW) costs. In the procedure, this component is considered ex-post. In fact, in many public infrastructure projects, the acquisition of land for ROW is typically not within the contractor's scope. Instead, this responsibility lies with the Grid Operator, who ensures that the contractor has the necessary access to construct the transmission lines, to mitigate the risk of cost overruns and delays associated with land acquisition issues.
  4. **NOTE**: for 2-circuit lines, remember to divide the costs by two, since in the PSS-E model, each circuit is represented as a standalone line asset.

  The following table reports an example of calculation.

- For **Substation equipment:** the SMO can calibrate and update the Standard Cost Database for Substation equipment by:

1. *Comparing the reference sources of costs with and the bottom-up costs*: For each selected project referenced in *Step 1: Collection of reference source costs*, where the internal composition in terms of individual substation components is available, a bottom-up calculation of the total cost using the unit costs collected in *Step 1: Collection of reference source costs* should be performed and compared with the cost of financed construction of entire substation.
2. *Harmonizing the sources of references*. For each selected project, the ratio of the total cost of the financed substation project to the bottom-up reconstruction of the cost (starting from substation components) should be computed. These ratios are then averaged. If the resulting average ratio is within a 10% error margin, it indicates that the unit costs collected *Step 1: Collection of reference source costs* are accurate and can be used to update the "SCD Substation Elements" tab of the Standard Cost Database. However, if the average ratio exceeds the 10% error margin, this average ratio should be used as a multiplicative coefficient to adjust the unit costs collected in *Step 1: Collection of reference source costs*. This adjusted cost will then be used to update the "SCD Substation Elements" tab of the Standard Cost Database.

Example of creation of the Standard Cost Database for Transmission Lines:

		Reference source cost 1	Reference source cost 2	Reference source cost ...	Average between reference source costs	Selection of the reference source costs for extrapolation	Projection by extrapolation coefficient and linear interpolation by voltage	ROW (e.g., 15%) + Divide by 2 the 2-circuits lines
kV	Line Code	kUSD/km	kUSD/km	kUSD/km	kUSD/km	kUSD/km	kUSD/km	kUSD/km
400	400 2L 4C						482	241
400	400 1L 4C	275			276		281	281
400	400 2L 3C	414			416	416	416	208
400	400 1L 3C						247	247
330	330 2L 4C			495	497	497	497	249
330	330 2L 3C						429	215
330	330 2L 2C	264			266		353	177
330	330 1L 3C						254	254
330	330 1L 2C						214	214
225	225 2L 1C	185		169	178		246	123
225	225 2L 2C	400	270		330	330	330	165
225	225 1L 1C	256			263		151	151
225	225 1L 2C	277			270		195	195
161	161 2L 1C						224	112
161	161 1L 1C						138	138
150	150 2L 1C						220	110
150	150 1L 1C						136	136
132	132 2L 1C						214	107
132	132 1L 1C	131			132	132	132	132

e.g., extrapolated by extrapolation coefficient of 400 2L 4C with respect to 400 2L 3C

e.g., extrapolated by extrapolation coefficient of 150 2L 1C with respect to 150 1L 1C

e.g., linearly interpolated between 132 1L 1C and 225 1L 1C

Stage2: Detailed Instructions for Updating the List of Eligible Regional Assets

This Stage2 aims at updating the list of all Asset Data and related attributes for TRANSMISSION LINES, TRANSFORMERS, SERIES CAP, and PHASE SHIFTING TRANSFORMERS (PST) in the latest available and updated PSSE CGM model.

> **NOTE:** These four (4) categories are hereinafter referred to as Eligible Regional Assets.

This Stage2 is performed with a dedicated model function in a Python code that combines this Stage2 with the next consequent Stage3.

The code of this module takes the following inputs:

1) The format of the Asset Database, which is an empty Excel file where the new updated asset database and related properties will be overwritten in the desired format. This file also contains the pre-set formulas for computing the derived and intermediate indicators needed to calculate the Total Annual Revenue Requirement of each asset.
2) The PSS/E input Excel files, each one containing the network topology for each snapshot for the given year. These files include information about buses, loads, generators, transformers, and breakers, as well as their distribution among the RCP areas.

The code processes the PSS/E input Excel files and create a consistent single list of Eligible Regional Assets, without replications, that reports all the Eligible Regional Assets that are present in a given year.

The properties that it derives or calculates from PSSE are:

1. Asset code name
2. Length [km]
3. Reactive power (series cap) [Mvar]
4. Marketable capacity (i.e., Rate A capacity) [MVA]
5. Voltage level [kV] at departure/arrival
6. If Tertiary Winding
7. Line type code, deriving it from name of the asset
8. Asset category (if TRANSMISSION LINES, TRANSFORMERS, SERIES CAP, and PST)
9. Owner(s) of the asset and percentage(s) of ownership
10. Commissioning date, deriving it from name of the asset
11. If Air Insulated Switchgear (AIS) or Gas Insulated Switchgear (GIS) transformers, deriving it from names of the asset[8]

[8] If a Transformer is gas-insulated, its name in PSSE ends with "_GIS".

12. If a Series Cap is fixed or it is as a variable (i.e., TCSC) controlled capacity[9]

NOTE: To properly store and collect the information for items 7, 10, 11, and 12 mentioned above, ensure that the PSSE version used for updating the model is v34 or higher.

NOTE: In case information are not available/provided in relation to items 7, 10, 11, and 12 mentioned above, the list will be updated by leaving blank the related information, which in turns translate in the following assumptions when updating the total costs of the assets in *Stage3: Detailed Instructions for Updating the Asset Database*:

1) If the Line Type Code is not specified, the asset is treated as a single-circuit and single-conductor line (1L1C).
2) If the Commissioning Year is not specified, the asset is considered as already fully depreciated.
3) All Transformers and related substations are treated as air-insulated, unless "_GIS" information is available and reported in the PSSE.
4) All series capacitors are treated as fixed, unless the "_CSVAR" information is available and reported in the PSSE.

The output from Stage2 will be:

1. An intermediate version of the Asset Database, with the updated list of the List of Eligible Regional Assets and related technical and tariff information, except for the cost information, which will be computed in the subsequent Stage3.

NOTE: Since Stage2 is computed within the same Python code that handles both Stage2 and Stage3, the output from this stage is a DataFrame. This DataFrame is then passed as an input to the module of the same code that performs Stage3 (see next section *Stage3: Detailed Instructions for Updating the Asset Database*).

[9] If a Series Cap has a variable (i.e., TCSC) controlled capacity, its name in PSSE ends with "_SCVAR".

Stage3: Detailed Instructions for Updating the Asset Database

This Stage3 aims at completing the creation of the final Asset Database by calculating the Total Cost per Asset (USD) for all the Eligible Regional Assets updated in the previous Stage2, and finally computing the Annual Revenue Requirement of each asset used in the APM.

This Stage3 is performed with a dedicated model function in the same Python code that combines this Stage3 with the previous Stage2.

The code of this module takes the following inputs:

1) The same PSS/E input Excel files, each one containing the network topology for each snapshot for the given year, that was an input also for the module performing the Stage3 steps.
2) The Standard Cost Database created in Stage1.
3) The DataFrame in output from Stage2 that is the intermediate version of the Asset Database, with the updated list of the List of Eligible Regional Assets and related technical and tariff information.

Procedure and formulas are explained in the following sections.

Calculation of the Total Cost per Asset

Transmission Lines

The Total Cost of **Transmission Lines** is computed as the multiplication of lines length with the Standard Cost corresponding to the type of each line:

$$TotCost_{line} = Length[km]_{line} \cdot StdCost_{line}[kUSD/km]$$

Where:

- $Length[km]_{line}$ derived as a property from the PSSE in *Stage2: Detailed Instructions for Updating the List of Eligible Regional Assets* ; and
- $StdCost_{line}[kUSD/km]$ derived from the Standard Cost Database based on the relevant Line Type and voltage level.

Transformers, Phase Shifting Transformers (PST) and Series Capacitors

The computation of the Total Cost of the Eligible Regional Assets in a Substation, namely the **Transformers**, **Phase Shifting Transformers (PST)** and **Series Capacitors**, involves calculating the cost of all the elements of the entire substation hosting this equipment and then allocating it back to these three (3) Eligible Regional Assets. This procedure ensures that the cost of substations, including the facility, bays, and all the components, is fully allocated to the Eligible Regional Assets according to the RTTM and RETTAP.

The process is composed of the following processing steps:

1. Step 1: Identification of Substations and of their relevant components
2. Step 2: Calculation of the Substation Costs (excluding Eligible Regional Assets)
3. Step 3: Computation of the Total Cost of Eligible Assets

Step 1: Identification of Substations and of their relevant components

As first step, busbars are grouped according to the substation they belong to with the following rationale:

- Busbars connected by two-winding (2W) or three-winding (3W) transformers belong to the same Substation.
- Busbars connected by line breakers belong to the same substation.
- Busbars connected by lines with length less than 100m (i.e., 0.1km) belong to the same substation.

Once to each busbar is assigned a Substation, it is possible to count and identity, per each Substation:

- Number of line bays at each voltage level: it is the number of lines arriving or departing from the busbars of the substation.
- Number of two-winding (2W) and three-winding (3W) Transformers: they have the high and low voltage sides busbars belonging to the same Substation.
- Number of Phase Shifting Transformers (PST): they are recognized in the PSSE model as the 2W transformers with the Control Mode set as "MW symmetrical PAR".
- Number of shunts: it is the number of switched or fixed shunts connected to the busbars of the substation
- Number of Series Capacitors: they are identified as the lines arriving at each busbar respecting the following condition: *length = 0 and reactance <0*.
- Whether the Substation is a complete GIS or hybrid Substation:
  - The first case is where *all* the Transformers that fall within the same substation are gas-insulated (GIS) (as recognized in the Stage2).
  - The second case is where only *a subset* of the Transformers that fall within the same substation are gas-insulated (GIS) (as recognized in the Stage2).

Step 2: Calculation of the Substation Costs (excluding Eligible Regional Assets)

Once the configuration of each substation is known, it is possible to compute the cost of substation components (excluding Eligible Regional Assets) and the facility itself.

> **NOTE 1:** The costs of the Eligible Regional Assets (Transformers, Series Capacitors, and Phase Shifting Transformers (PST)) are excluded from this step because they are allocated directly to the assets in Step 3.
>
> **NOTE 2:** Only the high voltage side of the substation is taken into account and later allocated to the Eligible Regional Assets. This means that the cost of components connected at voltage levels below 132 kV is not considered. Only a portion of the cost

of the substation facility, proportional to the number of high voltage assets, is accounted for.

NOTE 3: If a substation is identified as a GIS substation (see previous Step 1), the cost of all components of the relevant substation is multiplied by the relative GIS increment as per the Standard Cost Database. If a substation is identified as a hybrid substation (see previous Step 1), only the bay of the related gas-insulated transformer is multiplied by the relative GIS increment as per the Standard Cost Database.

The cost of substation components (excluding Eligible Regional Assets) is calculated by summing the total cost of the shunts connected to the substation, the line bays (one for each departing and arriving line connected to the substation), and the busbars (one for each voltage level of the substation):

$$Cost\ Substation\ Components = \sum Tot\ Cost\ Shunt + \sum StdCost_{linebay} + \sum StdCost_{busbar}$$

Where:

- $Tot\ Cost\ Shunt$:
  - if the total absolute capacity (Q) of the shunt is >10 MVar, it is equal to the shunt cost [kUSD/unit] from the Standard Cost Database plus the Shunt Bay Cost [kUSD/unit] from the Standard Cost Database.
  - if the total absolute capacity (Q) of the shunt is <10 MVar, the cost is considered negligible and set to 0.

  $$Tot\ Cost\ Shunt\ (Q > 10\ MVar) = StdCost_{shunt}\left[\frac{kUSD}{unit}\right] + StdCost_{shuntbay}[kUSD/unit]$$

- $\sum StdCost_{busbar}$: The number of busbars is equal to the high voltage (≥132 kV) sections of the Substation. For example, if the substation has, in the PSSE model, 1 busbar at 225 kV and 1 at 400 kV, the total cost of busbars ($\sum StdCost_{busbar}$ in the formula) is the sum of the cost of one double[10] busbar at 225 kV [kUSD/unit] from the Standard Cost Database and one double[10] busbar at 400 kV [kUSD/unit] from the Standard Cost Database.
  If the number of bays, including Line Bays, Shunt Bays, and Transformer Bays connected to a voltage level, exceeds 10, the busbar is considered longer, and its cost increases as specified in the Standard Cost Database.

The cost of the Substation Facility is taken from the Standard Cost Database and is considered only for the share that is proportionally attributable to hosting the HV assets at V ≥ 132 kV, as follows:

$$Cost\ Substation\ Facility = \frac{StdCost_{Facility}}{\#\ Transformers + \#PST + \#\ Series\ Cap} \cdot (\#\ Transformers + \#PST + \#\ Series\ Cap)_{V \geq 132\ kV}$$

[10] **Note:** Since the SLD of the PSSE does not differentiate between double or single busbars, the assumption, based on experience, is that any high voltage busbar is physically a double busbar. The related costs are taken from the Standard Cost Database accordingly.

The portion of Cost of the Substation to be allocated to each Regional Eligible Asset in the next consequent Step is finally computed as the sum of the cost of the facility and of the components (excluding Eligible Regional Assets), divided by the number (#) of high voltage Eligible Regional Assets belonging to the substation:

$$Unit\ Cost\ Substation = \frac{Cost\ Substation\ Facilty + \ Cost\ Substation\ Components}{(\#\ Transformers + \#PST + \#\ Series\ Cap)_{V \geq 132kV}}.$$

Step 3: Computation of the Total Cost of Eligible Assets

The Total Cost of the Eligible Regional Assets, i.e., Transformers, Phase Shifting Transformers (PST), and Series Capacitors, is the sum of their specific costs, as per the Standard Cost Database, and the relevant portion of the cost of the substation to which they belong.

- For **Transformer**, the formula is:

$$\begin{aligned} TotCost_{transformer} \\ &= StdCost_{tr}\left[\frac{kUSD}{MVA}\right] \cdot Capacity_{tr}[MVA] + StdCost_{trbayPrimary}\left[\frac{kUSD}{unit}\right] \\ &+ StdCost_{trbaySecondary}\left[\frac{kUSD}{unit}\right] + Unit\ Cost\ Substation[kUSD] \end{aligned}$$

Where:

- The $StdCost_{tr}\left[\frac{kUSD}{MVA}\right]$ is taken from the Standard Cost Database at the highest voltage level of the transformer.
- For 2W transformers, the cost includes the transformer bay at the primary side and the transformer bay at the secondary side only if the voltage is higher or equal to 132 kV.
- 3W transformers have two secondary bays to account for if their voltage is higher than or equal to 132 kV.

- For **Phase Shifting Transformers (PST)**, the formula is the same as above for 2W transformers, considering the dedicated relevant unitary cost for PST in the Standard Cost Database [kUSD/MVA].

- For **Series Capacitor**, the formula is:

$$TotCost_{cap} = StdCost_{cap}\left[\frac{kUSD}{MVar}\right] \cdot Capacity_{cap}[MVar] + Unit\ Cost\ Substation[kUSD]$$

Where:

- The $StdCost_{cap}\left[\frac{kUSD}{MVA}\right]$ is taken from the Standard Cost Database.

Finalization of the Asset Database

Once the Total Cost per Asset is computed for each Eligible Regional Asset of the updated database, the Python code finalizes the preparation of the final *DataFrame* representing the Asset Database. This is done by performing simple algebraic calculations, which also involve some computation parameters from the Standard Cost Database, to calculate the following variables:

- Asset age
- Asset depreciation period
- Total Depreciation
- Net Asset value
- Yearly Depreciation
- Operation and Maintenance cost
- Allowed profits on net Asset value
- WACC (departure & arrival)
- Total Annual Revenue Requirement of each asset

The DataFrame is then exported as an Excel file, representing the updated Asset Database for year Y. This file is ready to be input into the WAPP-APM software in Step C of the RETTAP.

ANNEX A: Approach followed for 2025-update

Step 0: References

The following references were adopted for the 2025 update:

- WorldBank projects.
- African Development Bank projects.
- Terna Development Plan 2023.
- Consultant data and references (confidential information).

Step 1: Collection of reference source costs & Step 2: Cost escalation

The Excel report, annexed in *ANNEX B: Supporting Excel for Asset Cost Database 2025* includes:

1. A list of selected awarded contracts by the World Bank and African Development Bank for the construction of transmission lines in Sub-Saharan Africa, used as a cost benchmark for updating the 2025 Standard Cost Database.
2. A list of selected awarded contracts by the World Bank and African Development Bank for the construction of substations in Sub-Saharan Africa, used as a cost benchmark for updating the 2025 Standard Cost Database.
3. A list of substation equipment, disaggregated by voltage level, for which reference source costs were found based on selected references, used as a cost benchmark for updating the 2025 Standard Cost Database.

Additionally, the Excel report includes the same lists with the cost values escalated to 2025.

Step 3: Costs extrapolation rationale

For the 2025 update, the extrapolation coefficient table was introduced based on Consultant's sources of information: the reference line type (highlighted in green in the table) with unitary cost and related breakdown was available from past Consultant's projects, while for the other types, the breakdown is determined from the Consultant experience.

	132 kV - 161 kV				225 kV				330 kV – 400 kV						
Component	**2L1C**	**2L2C**	**1L1C**	**1L2C**	**2L1C**	**2L2C**	**1L1C**	**1L2C**	**2L2C**	**1L1C**	**1L2C**	**1L3C**	**1L4C**	**2L3C**	**2L4C**
Towers	0.40	0.44	0.3	0.3	0.38	0.42	0.25	0.28	0.36	0.2	0.2	0.3	0.3	0.4	0.4
Conductor	0.29	0.58	0.1	0.3	0.29	0.58	0.15	0.29	0.34	0.1	0.2	0.3	0.3	0.5	0.7
Earth wire	0.01	0.01	0.0	0.0	0.01	0.01	0.01	0.01	0.01	0.0	0.0	0.0	0.0	0.0	0.0
Accessories	0.01	0.01	0.0	0.0	0.01	0.01	0.01	0.01	0.01	0.0	0.0	0.0	0.0	0.0	0.0
Insulators + hardware	0.07	0.07	0.0	0.0	0.09	0.09	0.05	0.05	0.09	0.0	0.0	0.0	0.0	0.1	0.1
Spare	0.01	0.01	0.0	0.0	0.01	0.01	0.01	0.01	0.01	0.0	0.0	0.0	0.0	0.0	0.0
Design	0.01	0.01	0.0	0.0	0.01	0.01	0.01	0.01	0.01	0.0	0.0	0.0	0.0	0.0	0.0
Foundation	0.10	0.11	0.1	0.1	0.10	0.11	0.07	0.07	0.09	0.1	0.1	0.1	0.1	0.1	0.1

	132 kV - 161 kV				225 kV				330 kV – 400 kV						
Component	**2L1C**	**2L2C**	**1L1C**	**1L2C**	**2L1C**	**2L2C**	**1L1C**	**1L2C**	**2L2C**	**1L1C**	**1L2C**	**1L3C**	**1L4C**	**2L3C**	**2L4C**
Erection + Stringing	0.10	0.10	0.1	0.1	0.10	0.10	0.07	0.07	0.08	0.1	0.1	0.1	0.1	0.1	0.1
TOT	**1.00**	**1.34**	**0.62**	**0.80**	**1.00**	**1.34**	**0.61**	**0.79**	**1.00**	**0.49**	**0.61**	**0.72**	**0.82**	**1.22**	**1.41**

Step 4: Standard Costs Database creation

- For the Standard Cost Database related to Transmission Lines, the calculation performed for the 2025 update led to the following result:

TRANSMISSION LINE		
VOLTAGE [kV]	LINE CODE	UNIT COST [kUSD/km]
400	400 2L 4C	276
400	400 1L 4C	321
400	400 2L 3C	238
400	400 1L 3C	282
330	330 2L 4C	284
330	330 2L 3C	245
330	330 2L 2C	202
330	330 1L 3C	291
330	330 1L 2C	244
330	330 2L 1C	160
330	330 1L 1C	199
225	225 2L 1C	144
225	225 2L 2C	193
225	225 1L 1C	177
225	225 1L 2C	228
161	161 2L 2C	173
161	161 1L 2C	205
161	161 2L 1C	129
161	161 1L 1C	159
150	150 2L 1C	126
150	150 1L 1C	156
132	132 2L 1C	122
132	132 1L 2C	195
132	132 1L 1C	151

ROW value set equal to 15%.

- For the Standard Cost Database related to Substations, the comparison between the bottom-up calculation of the total cost of substations with the cost of financed construction of entire substation led to deviations lower than 10%, meaning that the unit costs collected *Step 1: Collection of reference source costs* are accurate and can be used to update the "SCD Substation Elements" tab of the Standard Cost Database.

Calculation for both Transmission Lines and Substations are in *ANNEX B: Supporting Excel for Asset Cost Database 2025.*

The final Standard Cost Database for 2025 is attached as *ANNEX C: Standard Cost Database 2025.*

ANNEX B: Supporting Excel for Asset Cost Database 2025

- "Review Asset Costs_2025_PPI.xlsx"

ANNEX C: Standard Cost Database 2025

- "WAPP - SMO_Standard Cost Database 2025.xlsx"

RETTAP-Appendix 2

Instructions for Running APM-IGOC Model for WAPP

This set of instructions complements the activities mentioned in "Step C – Allocation of the use of the Regional Transmission System and losses" of the RETTAP. It provides detailed instructions for running the software application to calculate the allocation of the use of the Regional Transmission System and losses, hereinafter referred to as the "WAPP-APM tool."

The WAPP-APM tool is a computer-based software developed in Python, consisting of the following components:

1. **Executable File**: `WAPP_APM.exe`, which is the main software composed of two modules:
   i. **Module 1 - Pre-processing Script**: This module formats the PSS/E results and Asset Database obtained in Steps A and B of the RETTAP into a suitable template for the WAPP-APM tool.
   ii. **Module 2 - APM Allocation Script**: This module applies the APM method to the WAPP-APM model-ready format obtained from Module 1.
2. **Input and Output Folders**: There are six (6) folders where the User can find and/or place the required inputs and where the software will save the outputs:
   i. Folder "*APM ready input*": This folder is where the software generates and exports from Module 1 the ready-input file in Excel. This file contains the network topology and load flow results already converted into an APM-readable format. Additionally, it includes another folder called "APM Control Inputs" that includes the ready-input Excel file containing the control information with the desired settings for running the APM. In the provided package, the input files are already included for possible 2025 simulations.
   ii. Folder "*Asset Database file*": This folder contains the WAPP Asset Database Excel file, which is generated in Step B of the RETTAP. Detailed instructions for this process can be found in *APPENDIX 2 - Instructions for Running the APM-IGOC Model for WAPP* of the RETTAP.
   iii. Folder "*PSS-E Network files*": This folder contains the PSS/E input Excel file(s) for each selected snapshot. These files include detailed information about buses, loads, generators, transformers, and breakers, as well as their distribution among the Regional Compensation Parties (RCP) areas.
   iv. Folder "*PSS-E Loadflow files*": This folder contains the PSS/E load flow results Excel file(s) for each selected snapshot. These files detail the power flow from each bus to the various network elements.

v. Folder "*General Examples*": This folder contains examples of ready APM input files for network topologies that are not related to WAPP.

APM ready input	2/17/2025 4:13 PM	File folder	
Asset Database file	2/17/2025 4:13 PM	File folder	
General Examples	2/17/2025 4:13 PM	File folder	
PSS-E Loadflow files	2/17/2025 4:13 PM	File folder	
PSS-E Network files	2/17/2025 4:13 PM	File folder	
InfraFair control inputs [General Templat...	12/20/2024 10:44 AM	Microsoft Excel W...	24 KB
WAPP_APM.exe	12/24/2024 1:03 AM	Application	141,377 KB

To allocate the use of the Regional Transmission System and account for losses in the WAPP network, the user must run both modules. This can be done either in two (2) separate stages or in a single combined launch. The following sections provide detailed instructions for implementing each module of the WAPP-APM tool.

```
Please enter the number of the configuration you would like to use:
                1- Preprocessing + APM
                2- APM only
                3- Preprocessing only
```

Stage1: Implementation of Module 1-Pre-processing Script

To start implementing Module 1 - Pre-processing Script, the User needs to launch the WAPP-APM tool by double-clicking on `WAPP_APM.exe`. When prompted with the question asking which module to launch:

1. press `3` to launch only Module 1, or
2. press `1` to launch both Module 1 and Module 2 in sequence.

Inputs

When launching Module 1, the User interface requires the User to drag and drop the requested Excel input files/folders into the executable:

```
Please add the folder that contains the PSS-E Network Data files:
Please add the folder that contains the PSS-E Loadflow Data files:
Please add the folder that contains the Asset Database files:
```

The code of this Module 1 takes the following inputs:

1. The PSS/E load flow Excel file(s): these files (e.g., "`WAPP CGM Loadflow_S1.xlsx`" provided in the software package) contain the power flow from each bus to the different network elements for each selected snapshot.

2. The PSS/E network Excel file(s): these files (e.g., "`WAPP CGM Network Data_S1.xlsx`" provided in the software package) contain all necessary topology information for each selected snapshot, including details about buses, loads, generators, transformers, and breakers, as well as their distribution among the Regional Compensation Party (RCP) areas.

> **ATTENTION:** when providing these inputs, the User needs to consider the following aspects:
>
> - Ensure compatibility with PSS-E version v.35, due to the dependability on the format and names of tabs and columns.
>
>   *NOTE: The standard compatible format of the network file is included in the original WAPP-APM tool package as "WAPP CGM Network Data_S1.xlsx".*
> - Provide one PSS/E load flow Excel file and PSS/E network Excel file for each snapshot that the User wants to apply APM on.
> - The tool will display the files corresponding to the PSS-E network data, numbered from 1 to the total number of snapshots provided.
> - The User will be prompted to assign each load flow file to a snapshot by entering the corresponding snapshot number.
>
> ```
> Please specify which of the following network configuration files correspond to the load flow file: WAPP CGM
> Loadflow_S1.xlsx
>  ['1- WAPP CGM Network Data_S1.xlsx', '2- WAPP CGM Network Data_S2.xlsx']
>  File number:
> ```
>
> - The tool will then ask the User to specify the number of hours that each snapshot represents or input 0 if all the snapshots have the same weight.
>
> ```
> Please specify which of the following network configuration files correspond to the load flow file: WAPP CGM
> Loadflow_S1.xlsx
>  ['1- WAPP CGM Network Data_S1.xlsx', '2- WAPP CGM Network Data_S2.xlsx']
>  File number:
> 1
> Please specify the number of hours  this snapshot represents. The number of hours should be an integer number with no
> decimal part. Please enter 0 if you want all the snapshot to have the same weight :
> ```

3. The Excel cost file representing the Asset Database developed in Step B – Update of Asset Database (refer to the example "`WAPP Asset Database_2025.xlsx`" provided in the software package), that contains all the assets, their RCP ownership, and their total annual revenue requirement to be allocated.

> **ATTENTION:** when providing the Asset Database, the User needs to take care of the following aspects when providing this input:
>
> - Ensure the input follows the same format as the provided Excel file "WAPP Asset Database_2025.xlsx" in the software package, due to the dependability on the format.

Processing

Once the User has dragged and dropped the requested Excel input files into the executable, the User is asked to input the power factor that should be used to convert the rated capacity in VAR to MW.

If such conversion is not necessary, the User should enter 1.

The code extracts all the relevant information from these three (3) Excel files and formats it to be compatible with the Module 2 - APM Allocation Script. The APM model requires the insertion of all the assets that convey the power between the different buses in the network. These include transmission lines, transformers (two-winding and three-winding transformers), circuit breakers, series capacitors (series CAP) and phase-shifting transformers (PST). Each of these assets is represented by the buses it connects, the flow and the losses (i.e., as a transmission line), and each is given a unique code to distinguish between them in the model. [Transmission Lines:1, Two-Winding Transformers:2, Three-Winding Transformers:3, Breakers:4, Series CAP:5, PST:6].

The three-winding transformers are represented by a virtual node that connects each of the three winding buses, i.e., as three separate lines with their respective flow and losses. This virtual node is assigned a unique value from the other physical buses. The mapping of the transformers to their virtual node is given in a separate tab within the output of Module 1.

Outputs

The code of Module 1 - Pre-processing Script produces two (2) sets of output files. If the User initially selected to launch both Module 1 and Module 2 in sequence, the outputs from Module 1 are saved in the output folder and automatically used by the tool in Module 2.

The two (2) sets of output files are:

1) This is a single Excel file that contains the network topology and load flow results of all the snapshots, already compacted and converted into a single Excel file in APM-readable format. The file, named "`WAPP_APM_ready_input_file.xlsx`" is the file the User intends to simulate for cost allocation for a target year Y in Module.

   The file is composed of different tabs. These are the following:

   1. The "Flows" tab consists of the list of all the identified assets, named by joining the buses' numbers it connects separated with "-" ([Bus A number]-[Bus B number], e.g., 12029-19005), and the following information for each asset per snapshot/scenario:
      a. The asset flow in MW/MVA.
      b. The asset losses in MW/MVA.
   2. The "Asset attribute" tab consists of the list of all the identified assets, similar to that in the "Flows" tab, and for each asset, the following attributes are given, per column:
      a. Capacity in MW/MVA.

b. Length in km.
c. Type (the aforementioned code per asset type).
d. Voltage in kV.
e. Exist/Planned, "Exist" if the asset exists or "Planned" if it is planned.
f. Cost in kUS$.
g. Regional Assets if the asset is regional, the value is 1, if not, 0.
h. TSO Owner 1, the name of the TSO owner.
i. TSO 1 Ownership, the percentage of ownership.
j. TSO Owner 2, the name of the second TSO owner, if applicable.
k. TSO 2 Ownership, the percentage of the second TSO ownership, if applicable.

3. The "Network" tab consists of the list of all the buses in the network and their following information:
   a. Generation in MW per snapshot/scenario.
   b. Demand in MW per snapshot/scenario.
   c. Country, the name of the country to which the bus belongs.
   d. Zone 1, the name of the zone to which the bus belongs.
   e. TSO 1, the name of the TSO to which the bus belongs.
   f. Zone 2, the name of the second zone to which the bus belongs, if applicable[1].
   g. TSO 2, the name of the second TSO to which the bus belongs, if applicable[1].
4. The "3WT mapping" tab contains all three winding transformers and their mapped virtual nodes. Each transformer is modelled by two or three lines, depending on how many windings are used in the simulation. Each line connects the virtual node with one of the windings.

2) In addition to the Excel file that contains the four tabs, the code produces another file that contains input variable information (named as "`WAPP-APM Control Inputs.xlsx`") for cost allocation in Module 2. These variables are described as the following[2]:

   1. Nodal Aggregation: to determine the variant of APM to be applied, 1 for aggregating demand and generation at the same node, 0 for treating them separately.
   2. Demand Cost Responsibility (%): indicates the percentage of demand responsibility for the assets' costs.
   3. Generation Cost Responsibility (%): indicates the percentage of generators' responsibility for the assets' cost.
   4. Voltage Threshold (kV): indicates the voltage threshold for the transmission assets to be considered.
   5. Number of Snapshots: indicates the number of scenarios to be considered jointly for representing the annual usage.
   6. Snapshots weight: indicates the number of hours each scenario represents, the total should be 8760 hours (one year).

[1] Note: Zone 2 and TSO 2 information of the 'Network' tab should only be applicable to the virtual node of the three-winding transformers since it represents three buses of which two could belong to different zones or TSOs. Note that file and the code use the abbreviation SO to denote TSO.

[2] For more details, refer to the scientific paper: https://www.sciencedirect.com/science/article/pii/S2352711025000366

7. Cost Allocation Option: 1 to assign the full cost of the assets, 2 to assign only the cost of the used capacity, 3 to assign full cost if the line is old and the cost of the used capacity if the line is new, 4 is to assign based on the utilization threshold, if bigger than the threshold, assign all the cost, otherwise, just the cost of the used capacity.
8. Utilization Threshold (%): indicates the percentage that determines if the cost will be assigned fully or partially. It will be used only if 'Cost Allocation' is set to 4.
9. Cost of Unused Capacity: to determine what to do with the remaining cost if it is not fully assigned. 0 to do nothing, 1 to socialize it among agents who use the asset, and 2 to socialize it among all of the agents.
10. Demand Socialized Cost Responsibility (%): indicates the percentage of demand responsibility for the assets' socialized costs.
11. Generation Socialized Cost Responsibility (%): indicates the percentage of generation responsibility for the assets' socialized costs.
12. Asset types: indicates the mapping of the asset type with its code.
13. Snapshots Results: 1 or 0 to enable or disable separate results for each snapshot, respectively.
14. Agent Results: 1 or 0 to enable or disable results per agent, respectively.
15. Country Results: 1 or 0 to enable or disable results per country, respectively.
16. SO Results: 1 or 0 to enable or disable results per SO, respectively.
17. Intermediary Results: 1 or 0 to enable or disable intermediary results in terms of flow-km contribution and utilization percentage, respectively.
18. Aggregated Results: 1 or 0 to enable or disable aggregated results per asset group, per country assets and per SO assets, respectively.
19. Losses Allocation Results: 1 or 0 to enable or disable allocating transmission losses per agent per asset.
20. Demand Losses Responsibility (%): the percentage of demand responsibility for the losses of the assets.
21. Generation Losses Responsibility (%): the percentage of generators responsibility for the losses of the assets.
22. Losses price ($/MWh): the price of energy lost. The energy unit should be the same as the flow.
23. Regional losses: 1 to allocate losses in regional assets only, 0 to allocate losses in all assets.
24. Cost of regional assets: 1 to allocate the cost of regional assets only, 0 to allocate the cost of all assets.

The code gives default values for these variables, which can be changed manually by the User before running the APM model in Module 2 as standalone, for instance, to change the method variants.

Stage2: Implementation of Module 2- APM Allocation Script

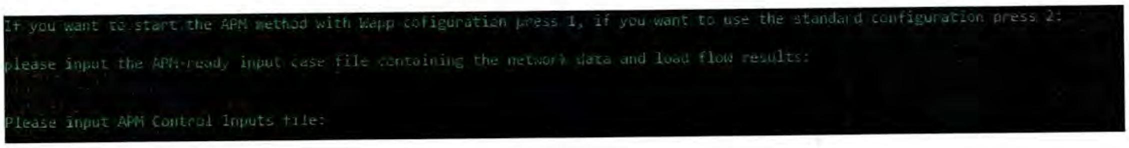
To implement Module 2 - APM Allocation Script, the User can:

1. Opt for a standalone execution by launching WAPP_APM.exe and pressing 2 when prompted with the question asking which module to launch.
2. Opt for automatic cascade execution by pressing 1 to run Module 2 automatically after Module 1 - Pre-processing Script.

Inputs

This section provides instructions for implementing the standalone method, as the automatic cascade execution following Module 1 only prompts the user with two additional questions regarding results disaggregation by snapshots and losses prices.

When launching the Module 2, the User interface mask requires the User to choose to use the WAPP configuration (output of Module 1) or the standard one, and also to drag-and-drop the requested Excel input files into the executable:



The code of this Module 2 takes the following inputs:

1) The first set includes Excel files that contain the network topology and load flow results already converted in an APM-readable format from Module 1. Each file (named as "`WAPP_APM_ready_input_file.xlsx`") corresponds to a Snapshot # that the User intends to simulate for cost allocation in Module 2.
2) The second input is the Excel file (named as "`WAPP-APM Control Inputs.xlsx`"), which contains input variable information for cost allocation. Note that the Control Input file is generated automatically from Module 1 with the following values. If a different APM application needs to be executed, these values should be changed according to the description provided in the file.

Table 1 Default values for APM input variables.

Inputs	Values	Rationale
Nodal Aggregation	0	To treat the demand and generators at the same need separately without discrimination.
Demand Cost Responsibility (%)	90	Agreed upon split key between WAPP and ERERA and set by ERERA in the RTTM.
Generation Cost Responsibility (%)	10	Agreed upon split key between WAPP and ERERA and set by ERERA in the RTTM.
Voltage Threshold (kV)	132	The voltage threshold set by WAPP and ERERA for the regional grid asset.
Number of Snapshots	#	In cascade execution mode, this parameter is automatically passed though Module 2 based on the

GB

Inputs	Values	Rationale
		PSS/E inputs file preprocessed by Module 1 and printed in the `WAPP-APM Control Inputs.xlsx` for information to the User. In standalone execution mode, Module 2 automatically compute the # of snapshots from the "`WAPP_APM_ready_input_file.xlsx`".
Snapshots Weights	#	The number of hours each snapshot represents, the total should be 8760 hours (one year).
Cost Allocation Option	2	To allocate only the cost of the used capacity of the assets within the inter-TSO/GO compensation framework since it is deemed to be more equitable and aligned with allocating the cost based on usage.
Utilization Threshold (%)	0	If the ratio between the used asset capacity and the asset rated capacity is equal or above this percentage, the asset cost will be fully allocated, otherwise, only the cost of the used capacity will be allocated. This will be used only if 'Cost Allocation Option' is set to 4
Cost of Unused Capacity	0	The cost of unused capacity is not allocated within the inter-TSO/GO compensation framework and is recovered by national tariffs.
Demand Socialized Cost Responsibility (%)	100	The percentage of demand responsibility to the socialized cost of the assets. Only used when 'Cost Allocation Option' is not set to 1 and 'Cost of Unused Capacity' is not set to 0.
Generation Socialized Cost Responsibility (%)	0	The percentage of generators responsibility to the socialized cost of the assets. Only used when 'Cost Allocation Option' is not set to 1 and 'Cost of Unused Capacity' is not set to 0.
Asset Types	Types of assets available	Mapping the asset types with its code.
Snapshots Results	0	Enabling or disabling the printing of the separate results of each snapshot.
Agent Results	0	Enabling or disabling the printing of the separate results of each agent.
Country Results	0	Enabling or disabling the printing of the separate results of each country.
SO Results	1	Enabling or disabling the printing of the separate results of each RCP.
Intermediary Results	0	Enabling or disabling the printing of the intermediary results in terms of flow-km contribution and utilization percentage.
Aggregated Results	1	Enabling or disabling the printing of the aggregated results per asset group, per country assets and per RCP assets.
Losses Allocation Results	1	Enabling or disabling the allocating transmission losses per agent per asset.
Demand Losses Responsibility (%)	90	Agreed upon split key between WAPP and ERERA and set by ERERA in the RTTM.
Generation Losses Responsibility (%)	10	Agreed upon split key between WAPP and ERERA and set by ERERA in the RTTM.

Inputs	Values	Rationale
Losses price ($/MWh)	120	Price set by ERERA.
Regional losses	1	Allocating the losses in the Regional assets only, coherently with the allocation of the costs for the use of assets.
Cost of regional assets	1	Allocating the cost of regional assets only since the costs of national assets need to be covered by national tariff.

3) A number of control parameters are directly hard-coded in Module 2, as they are not expected to be modified by users. These parameters are:

Table 2 Default values for APM input variables.

Inputs	Values	Rationale
Number of Snapshots	Calculated based on the number of flow columns in the "*WAPP_APM_ready_input_file*"	The number of hourly snapshots to be considered jointly for representing the annual usage
Asset Types	Transmission line:1, Two-winding Transformer:2 Three-winding Transformer:3 Breaker:4 Series Cap:5 PST:6	Mapping the asset type with its code
Country Results	0	1 or 0 to enable or disable results per country, respectively
SO Results	1	1 or 0 to enable or disable results per RCP, respectively
Losses Allocation Results	1	1 or 0 to enable or disable allocating transmission losses per agent per asset

Processing

After the user drags and drops the required Excel input files into the executable, the Module 2-APM Allocation Script prompts the user with two (2) additional questions regarding results disaggregation by snapshots and losses prices. Following this, the script initiates the application of the APM using the embedded matrix manipulation code[3]:

```
Starting the APM method

Based on the InfraFair tool developed by:
Instituto de Investigacion Tecnologica
Escuela Tecnica Superior de Ingenieria - ICAI
UNIVERSIDAD PONTIFICIA COMILLAS
C. de Sta. Cruz de Marcenado, 26
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The separation of Snapshots Results is disabled, to enable it press 1 otherwise press 0      (Default 0):

The price of Network losses is set to be "120" ($/MWh), if you want to change it, please add the new value otherwise press Enter:

************************************!RUNNING!************************************
```

The matrix manipulation is automatically performed in the following order:

1. Determining the contribution of inflows to outflows according to the average participation rule explained above. The fraction of inflow that is deemed to be part of outflow is computed as the ratio of the size of the latter to the total amount of power flowing through a given node. This step is represented in the following equation:

$$C(\phi_{i,x}, \phi_{o,y}) = \phi_{i,x} \frac{\phi_{o,y}}{\sum_{j=1}^{n} \phi_{o,j}} \qquad \phi_{i,x} \equiv inflow\ number\ x \qquad \phi_{o,y} \equiv outflow\ number\ y$$

2. From the previous equation, the flow in any line, ϕ, can be expressed as a linear function of the generation located at the sending bus of the line and the incoming flows to that bus. This is expressed in the following matrix equation:

$$\overline{\phi} = P^{\mathrm{out}} \cdot \overline{\phi} + PG \cdot \overline{G}$$

$p^{out} \equiv matrix\ of\ unit\ contributions\ of\ inflows\ of\ to\ outflows\ for\ every\ buses$

$PG \equiv matrix\ of\ unit\ contributions\ of\ power\ injections\ to\ the\ outflows\ for\ every\ buses$

$\bar{G} \equiv Vector\ of\ power\ injected\ at\ every\ bus$

3. The previous equation can be rearranged as follows:

$$\overline{\phi} = inv(I - P^{\mathrm{out}}) \cdot PG \cdot \overline{G} \Rightarrow \overline{\phi} = A^G \cdot \overline{G}$$

$A^G \equiv matrix\ of\ unit\ contributions\ of\ inject\ power\ at\ every\ bus\ to\ all\ line\ flows$

4. A similar formulation can be derived for the contributions of nodal power consumptions to line flows:

---

[3] Based on the InfraFair tool developed by Instituto de Investigacion Tecnologica, Escuela Tecnica Superior de Ingenieria – ICAI. UNIVERSIDAD PONTIFICIA COMILLAS. C. de Sta. Cruz de Marcenado, 26 – 28015 Madrid, Spain. Repository: https://github.com/IIT-EnergySystemModels/InfraFair. License: under the open source AGPL-3.0 license. Source: https://www.sciencedirect.com/science/article/pii/S2352711025000366

$$\overline{\phi} = inv(I - P^{\text{in}}) \cdot PD \cdot \overline{D} \Rightarrow \overline{\phi} = A^D \cdot \overline{D}$$

Where

$P^{in} \equiv$ *matrix of unit contributions of outflows of to inflows for every buses*

$PD \equiv$ *matrix of unit contributions of power withdrawals to the inflows for every buses*

$\overline{D} \equiv$ *Vector of power withdrawed at every bus*

$A^D \equiv$ *matrix of unit contributions of withdrawed power at every bus to all line flows*

5. The code then uses percentages that determine the fractions of the total cost of the grid to be recovered by generators and demands to determine their contributions in line flows, as follows:

$$\overline{\phi} = K_G \cdot A^G \cdot \overline{G} + K_D \cdot A^D \cdot \overline{D}.$$

Where

K_D = *percentage of demand responsibility*

K_G = *percentage of generator responsibility*

6. Finally, the compensation that a country must pay each country in the region (including itself), for the use that generators and loads within the country are making of the grid of these countries, is computed as follows:

$$PAY_c = LO \cdot LC \cdot (K_G \cdot A^G \cdot NO_c \cdot \overline{G} + K_D \cdot A^D \cdot NO_c \cdot \overline{D})$$

Where:

$PAY_C \equiv$ *vector of payments assigned to country C for its use of the grid ofeach country*

$LO \equiv$ *the line ownership matrix*

$LC \equiv$ *the line cost matrix*

$NO_C \equiv$ *the node ownership matrix of country C*

Outputs

The final output of the code is the contribution of each generator and demand to the cost of each of the network assets as well as the cost of losses in the assets. This is aggregated for generators and demand belonging to the same RCP area, to give the contribution per RCP area to the cost of each asset in the network. Another result is the aggregation of the assets in the latter by country or RCP to give the contribution of each generator, demand, county or RCP to the grid of other countries and RCPs.

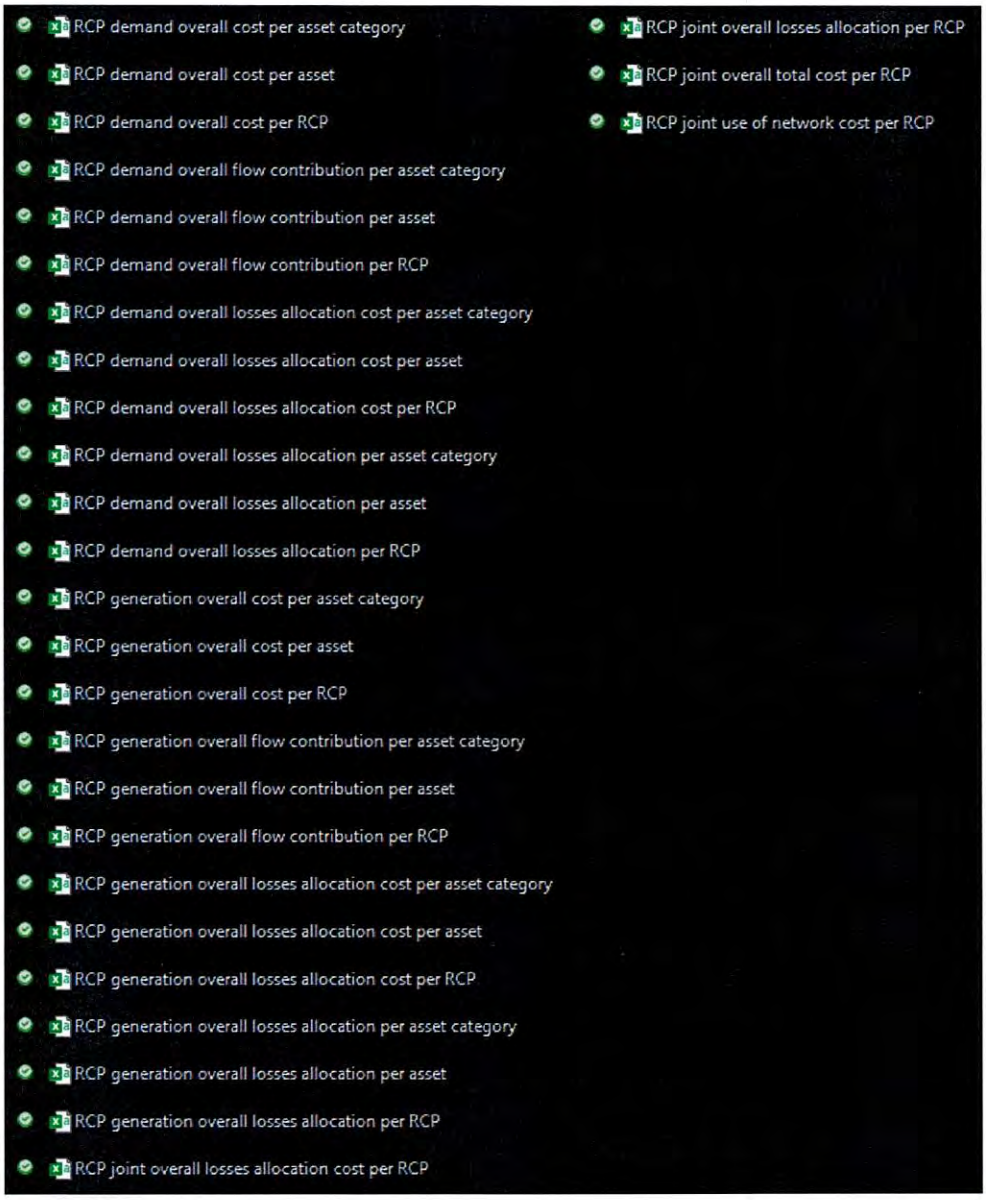
In addition to the final cost outputs, several intermediary results can be produced for each snapshot/scenario. These are the contribution of flow, flow-MW and the utilization of the assets, at the agent level or aggregated at the country or RCP level and per asset or per group of assets.

All the outputs are saved in the "Overall results" folder.

The inter-Grid Operator compensation result is found in the file called "RCP joint overall total cost per RCP" which includes the total cost (in USD) allocated to each RCP area due to:

- Use of network cost:
    a. The use of the other RCPs' area network by the generators and loads in its area; and,
    b. The use of its area network by generators and loads of the other RCPs' area.
- Losses allocation cost:
    a. The losses caused into the other RCPs' area network by the generators and loads in its area; and,
    b. The losses in its area network by generators and loads of the other RCPs' area.

The file also includes the net positive/negative amount to be received/due by each RCP, identifying the *net receivers* and *net payers* RCPs, respectively.



RCP demand overall cost per asset category
RCP demand overall cost per asset
RCP demand overall cost per RCP
RCP demand overall flow contribution per asset category
RCP demand overall flow contribution per asset
RCP demand overall flow contribution per RCP
RCP demand overall losses allocation cost per asset category
RCP demand overall losses allocation cost per asset
RCP demand overall losses allocation cost per RCP
RCP demand overall losses allocation per asset category
RCP demand overall losses allocation per asset
RCP demand overall losses allocation per RCP
RCP generation overall cost per asset category
RCP generation overall cost per asset
RCP generation overall cost per RCP
RCP generation overall flow contribution per asset category
RCP generation overall flow contribution per asset
RCP generation overall flow contribution per RCP
RCP generation overall losses allocation cost per asset category
RCP generation overall losses allocation cost per asset
RCP generation overall losses allocation cost per RCP
RCP generation overall losses allocation per asset category
RCP generation overall losses allocation per asset
RCP generation overall losses allocation per RCP
RCP joint overall losses allocation cost per RCP
RCP joint overall losses allocation per RCP
RCP joint overall total cost per RCP
RCP joint use of network cost per RCP

Document	Regional Electricity Transmission Tariff Application Procedure - Appendix 3: POC for Selecting Archetype Snapshots for the APM-IGOC	
Revision	1.0	
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RETTAP-Appendix 3

Proof of Concept (POC) for Selecting Archetype Snapshots for the APM-IGOC

Computation of Annual Inter-Grid Operator Compensations (IGOC) using a Reduced Number of Snapshots

Table of contents

1 INTRODUCTION

1.1 Why considering a reduced set of snapshots for annual IGOC computation

Within the framework of the Regional Transmission Tariff Methodology (RTTM), parties in the Regional Electricity Market (REM) have agreed to compute annual compensations for the electrical usage and losses incurred by each Grid Operator (GO) in Control areas that are the responsibility of other GOs. Obtaining a solution that accurately reflects the transmission costs that each country should be compensated for would entail taking into account 8,760 snapshots corresponding to each one of the 8,760 hours of the year. However, the application of an Inter- Grid Operator Compensation (IGOC) method to as many snapshots as hours in a year is not convenient mainly for political and practical reasons. Collecting and processing 8,760 bulky data sets is not trivial. Therefore, making use of operation results computed for a reduced set of snapshots to determine a reasonably accurate estimate of the annual compensations, charges and net inter-GO payments to be applied each year within an acceptable margin of error remains an issue of utmost importance.

1.2 Objective of this report

This report introduces a qualitative Proof-of-Concept (POC) aimed at guiding WAPP in selecting the most appropriate and relevant snapshots to properly define, simulate, and set the market snapshots necessary to implement the Inter-Grid Operator Compensation mechanism between the GOs or Regional Compensation Parties (RCPs).

2 DESCRIPTION OF THE OVERALL APPROACH PROPOSED FOR THE COMPUTATION OF ANNUAL IGOC

The snapshots to consider in the computation of annual IGOCs should be limited in number, but representative of the different types of operation situations that may unfold in the target year regarding the IGOCs that should result from these operation situations. If data was available to characterize all hourly operational situations in the system for the year, regarding the usage of the grid by generators and loads in each GO area, or the benefits they obtain from other GO area, it would be possible to classify these hourly snapshots into groups such that:

1. All snapshots within each group reflect similar patterns of cross-border network usage (or similar patterns of cross-border benefits produced by the GO grids) and, therefore, lead to similar IGOCs.
2. Snapshots in different groups reflect distinct patterns of cross-border network usage (or distinct patterns of cross-border benefits produced by the GO grids) and, therefore, lead to different IGOCs.

Then, just considering one representative snapshot of each of these groups and the weight to be given to the snapshots within each group in the IGOC computation process, one could compute a reasonably accurate estimate of the annual IGOCs to apply from the compensations computed separately for these representative snapshots as if each of these were the only ones to consider in IGOC computation. To properly classify snapshots into groups (clusters) for IGOC computation, it is necessary to identify the system variables that should be used to characterize them and determine how similar each cluster is to each other one regarding their consideration for the computation of IGOCs. Accordingly, the next section outlines two possible sets of system variables that may be used to characterize snapshots.

Once the variables to be used to characterize the hourly operation snapshots have been defined and data for these variables have been collected for each of the hourly snapshots of the target year, these hourly snapshots should be classified into groups, making use of the data collected for the characterization variables, which should, then, become the classification variables. The general classification criteria to be applied to make these groups of snapshots are discussed in chapter 3. Together with these groups of snapshots, a snapshot representing each group should be chosen. Additionally, as a byproduct of the computation of the groups of snapshots, the number of snapshots within each shall be determined as well.

Once the reduced set of snapshots to consider for IGOC computation has been determined, annual IGOCs are computed by considering each representative snapshot of a group separately, as if it were the only snapshot to consider. Computing annual compensations among GO areas considering an operation situation involves determining first the fraction of the annualized cost of each element of the regional transmission network to be considered for IGOC computation. This could be, either the fraction of this element that is used, or the total annualized cost to this element.

Finally, the IGOCs to be applied in a year are derived by aggregating values computed separately for each representative snapshot, each treated as an independent operating condition. For this, first weights are assigned to the groups of snapshots defined. These weights are to be computed according to the aggregate benefits that network users in the whole system are expected to obtain from the whole system grid in the operation situations, or snapshots, within each group of them, or, as a proxy, based on the aggregate usage that generators and loads in the whole system are expected to make of the system grid in that group of snapshots.

For clarity, this process is represented in the flow diagram in Figure 1.

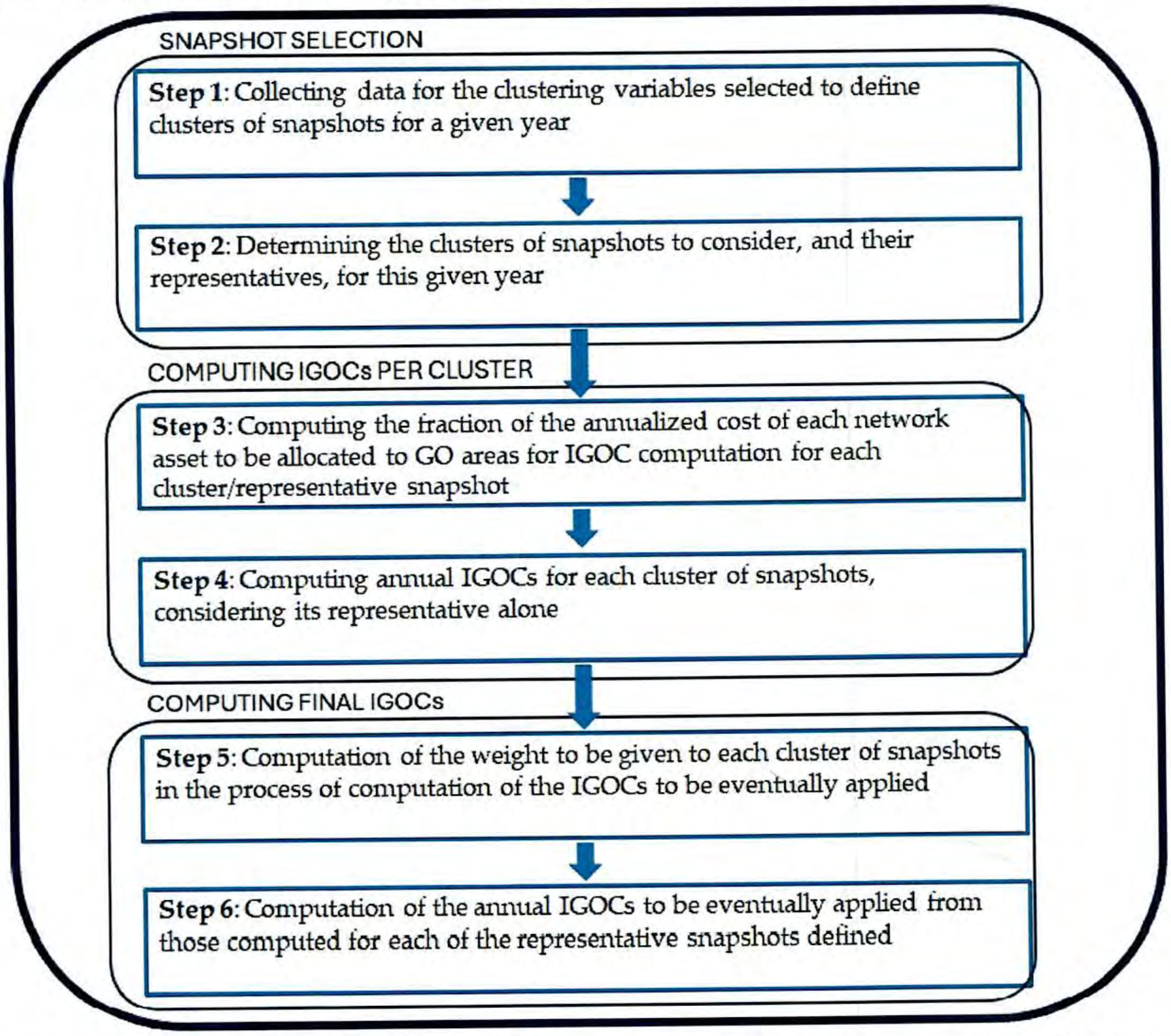

Figure 1: Selection of the snapshots to be considered in the computation of IGOCs

3 DISCUSSION OF THE SELECTION OF CLUSTERING VARIABLES

The set of system variables for grouping operation snapshots should be selected to ensure that computing IGOCs separately for each group and combining these IGOCs provides reasonably accurate estimates of the annual IGOCs, as if all hourly operation snapshots in the year were used in the IGOC computation process. The two (2) main criteria for selecting the variables to classify or cluster the operation snapshots could be:

a) The complete set of 8,760 hourly samples of these variables for the target year is easily available.

b) A high degree of correlation exists between these variables and the feature of interest for IGOC computation, namely, the benefits that each GO area obtains from the grid of each GO area, including its own, or, as a proxy, the usage each GO area makes of the grid of all GO area, including its own.

Two options, or possible sets of clustering variables, are proposed and described as follows:

3.1 *Preferable* method aimed at replicating the cost allocation results obtained by applying APM to the 8760 hours of the year

If the aim is to replicate the GO area cost allocation results that would result from applying APM considering all the hourly snapshots of the target year, it would be necessary to find a suitable "proxy" for the complete map of network flows in the system. The only reasonable proxy that ranks high according to criteria a) and b) above is the collection of import/export hourly flows for each GO area. Cross-border GO network usage only occurs when there are cross-border flows, which can be determined by tracing these flows upstream and downstream until power injections and sinks in the grids of the GOs using APM. These flows are far easier to obtain than the complete map of real network flows and, as mentioned, they seem to intuitively capture the essential conditions that influence the external utilization of a network.

Figure 2 graphically depicts the proposed method for selecting representative hours. As mentioned earlier, it is assumed that the simple pattern of hourly imports and exports for each country largely determines the matrix of contributions of each GO area to the use of the grid of others. This implies that the clusters of participation matrices should closely align with the clusters of patterns of export and import border flows. Therefore, by computing clusters of export and import border flows, it is possible to identify a reduced set of snapshots of real network flows. These snapshots can then be used to calculate representative participation matrices for network cost allocation purposes.

In the clustering process, each hourly snapshot shall be represented by a vector (sample) that should be built in either of 2 directions. If the hourly profile of flows on each of the cross-border lines between each country/GO area in the region and others is available, the sample vector for each hour shall comprise the flows, in this hour, on all the cross-border lines between each country/GO area in the region and others. Then, the sample vector should include as many elements as cross-border lines between each country/GO area in the region and others. These cross-border flows should be provided with their sign, indicating whether the energy flows in this hour from the sending to the receiving node defined for the corresponding cross-border lines or vice versa. If the hourly profile of flows on each of the cross-border lines between each country/GO area in the region and others is available, the sample vector for each hour shall comprise the net amount of exports of each country/GO area in this hour. Then, the sample vector should include as many elements as countries/GO areas. Net exports for areas should be computed with their sign, i.e. if an area is importing energy in net terms in a certain hour, their next exports in this area should be assigned a negative sign.

A sample defined in the aforementioned way should be computed for each hour in the year and hours (hourly snapshots) should be clustered according to these samples.

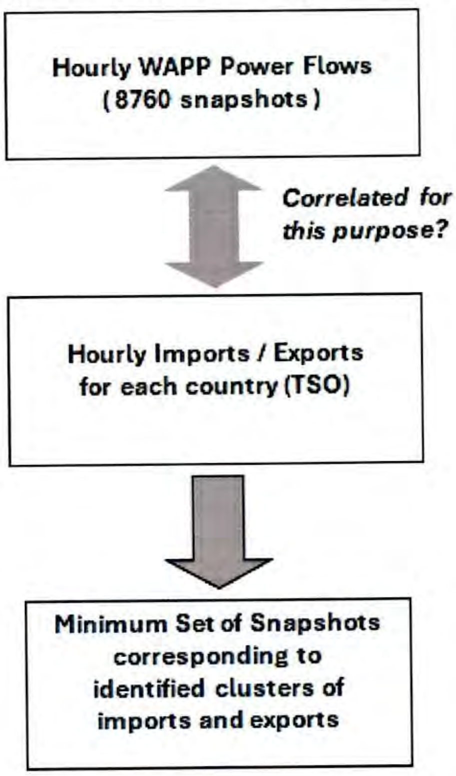

Figure 2: Selection of the snapshots to be taken into account in the computation of IGOCs

According to this approach, the set of input data to be collected for selecting the appropriate set of snapshots includes:

- The hourly profile of flows on each of the cross-border lines between each country/GO area in the region and others. These cross-border flows should be provided with their sign, indicating whether the energy flows in this hour from the sending to the receiving node defined for the corresponding cross-border lines or vice versa.

If this data is not available, an alternative input could be:

- The hourly profile of net exports (or imports) of each country/GO area.

3.2 *Alternative* method aimed at selecting the snapshots to consider according to the benefits provided by the transmission grid

Alternatively, instead of choosing snapshots to reproduce the IGOC results obtained by applying the APM method for all hours of the target year, one may select snapshots based on the benefits provided by the regional transmission grid. The objective here would be to focus on snapshots where the transmission grid significantly benefits the system by transporting cheaper energy from certain areas to others. This approach is justified by the fact that the benefits produced by the grid are the true drivers of its development and, therefore, should be the primary factor in allocating the grid's costs to countries or GO areas.

When selecting snapshots for IGOC computation, authorities should consider the benefits of different types of energy exchanges among GO areas within the regional transmission grid. These snapshots can be chosen based on the potential social benefits from two (2) types of exchanges affecting each GO area:

1. **Imports of cheaper energy**: This involves bringing in more affordable energy from other areas to partially replace local generation or non-served energy (NSE) that would otherwise be dispatched or incurred, respectively.
2. **Exports of cheaper energy**: This involves sending locally produced, cheaper energy to other areas to replace more expensive generation or avoid NSE in those areas.

Typically, each GO area will be involved in one type of energy exchange during a specific operation hour (snapshot). This means the area will either:

- Replace part of its local generation or NSE with cheaper energy from other areas, or
- Produce energy locally to replace more expensive generation or avoid NSE in other areas.

To simplify the analysis, since it is impractical to determine which types of energy resources (RES-based generation, more expensive generation, or NSE) in other areas may be affected by the potential energy exchanges each area A could be involved in, when estimating the social value created by these exchanges, we can assume that they yield the maximum possible benefits.

This corresponds to situations where the energy potentially produced in the area A to be exported effectively replaces NSE in other areas (thus avoiding it), or where the energy to be potentially imported by the area A is effectively imported and generated by RES-based generations located in other areas that have near-zero variable production costs.

Note that, among other things, this involves assuming that the grid in the region is not preventing these exchanges from taking place, nor is it affecting the magnitude of these exchanges (in reality, network congestion and losses impact exchanges among areas).

Based on this assumption, the benefits of the energy exchanges for each area can be estimated in the following two ways:

1. Social value created by the avoidance of NSE, or the replacement of local expensive generation, by importing more affordable energy produced in other areas:

$$Increase\ Social\ Benefit^{imp\ A} = Q_{NSE}^{imp\ A} \times \rho_{NSE}^{imp\ A} + Q_{dis-expensive}^{imp\ A} \times \rho_{expensive}^{imp\ A}$$

Where:

Q_{NSE}^{imp} is the amount of NSE incurred in the importing area A when demand in the area is fully served locally

$\rho_{NSE}^{imp\ A}$ is the value (cost) of NSE in importing area A

$Q_{dis-expensive}^{imp\ A}$ is the amount of expensive generation dispatched in importing area A when demand in the area is fully served locally, and

$\rho_{expensive}^{imp\ A}$ is the variable production cost of expensive generation dispatched in importing area A when demand in the area is fully served locally.

2. Social value created by supplying demand in other areas with the excess of generation in the exporting area B with respect to local demand in this area[1]:

$$\begin{aligned} & Increase\ Social\ Benefit^{exp\ B} \\ & \qquad = Q^{exp\ B}_{excess-low\text{-}cost} \times \left(\rho^{region}_{NSE} - \rho^{exp\ B}_{low\text{-}cost}\right) \\ & \qquad + Q^{exp\ B}_{excess-expensive} \times \left(\rho^{region}_{NSE} - \rho^{exp\ B}_{expensive}\right) \end{aligned}$$

Where

$Q^{exp\ B}_{excess-low\text{-}cost}$ is the excess of low-cost generation not yet dispatched in exporting area B when generation resources within this area are used just to cover local demand in the area;

ρ^{region}_{NSE} is the value (cost) of NSE assumed for the whole region;

$\rho^{exp\ B}_{low\text{-}cost}$ is the variable production cost of the excess of low-cost generation not yet dispatched in exporting area B when generation resources within this area are used just to cover local demand in the area;

$Q^{exp\ B}_{excess-expensive}$ is the excess of expensive generation no yet dispatched in exporting area B when generation resources within this area are used just to cover local demand in the area, and

$\rho^{exp\ B}_{expensive}$ is the variable production cost of the excess of expensive generation no yet dispatched in exporting area B when generation resources within this area are used just to cover local demand in the area.

The reason for making a distinction between cheap and expensive generation is that the social value created, or savings in the operation costs achieved, by exports of energy produced by cheap and expensive generation would be different, even if the problem here addressed is simplified by assuming that both type of energy exports are deemed to replace NSE in other areas, as we do here. This problem could be

[1] For simplicity reasons, we have considered here only two types of generation: (i) 'low-cost' (typically non-controllable RES-based like wind or solar), and (ii) 'expensive' (higher-variable cost generation, like thermal or hydro, for which the value of water used to produce electricity may probably be high for large reservoirs). Then, in principle, generations resources should be clustered into these two categories and representative quantities (amounts) and variable production costs should be estimated for the resources of each type. For each cluster, these could be weighted averages of the corresponding values for all the resources allocated to this cluster.

Alternatively, the summation of the products of quantities and variable production costs over all the different generation technologies existing in the system could be considered.

further simplified by assuming the same variable production cost for all the local excess of generation in an area to be potentially used to replace NSE in other areas.

Typically, within any area, when computing the potential increase in the system-wide social benefit related to the energy exchanges that each area is involved in, it is assumed that, either the local generation resources and NSE in the area are replaced by energy produced in other areas (as in case 1 above), or the local generation is used to supply demand in other areas (as in case 2). Typically, for any given area, either the amount of energy imported for local use, or the amount of energy produced locally that is exported (or both) will be zero. Therefore, the increase in the social benefit of, At least, one of the two types considered will also be zero. However, it is important to compute the social benefits of both types for each area.

Then, in the clustering process, each hourly snapshot shall be represented by a matrix (sample) comprising as many columns as areas in the region and two (2) rows. For each column (area), the social benefits of type 1 (potential social value created by the local use of energy produced in other areas) should be placed in row 1 of this sample matrix, while social benefits of type 2 (potential social value created by the use in other areas of the energy produced in this area) should be placed in row 2 of the same matrix. As aforementioned, this matrix should be computed for each hour (snapshot), and sample matrixes (hourly snapshots) should be clustered into groups of them (clusters). For each cluster, its representative should also be computed.

A sample defined in the aforementioned way should be computed for each hour in the year and hours (hourly snapshots) should be clustered according to these samples.

Therefore, the set of input data to be collected to select the appropriate set of snapshots includes:

- Hourly profiles of the amounts of NSE incurred, expensive generation dispatched, excess of low-cost generation (not dispatched), and excess of expensive generation (not dispatched) per GO area in the region resulting from demand in each area being served locally.
- Representative value (cost) of NSE in each GO area, and at regional level, as well as those of the variable production cost of low-cost and expensive generation in the area. These values may be deemed constant over the considered period of time (target year) for which clusters of hours are being determined.

3.2.1 Computing the weights to be given to each group (cluster) of snapshots in the computation of the compensations to be eventually applied

If this set (matrix) of clustering variables is used to define clusters of snapshots and their representatives, the weight assigned to the network usage/cost allocation results computed for each representative snapshot 'S' in the process of computation of the IGOCs to be eventually applied should be proportional to the total benefits produced by the overall grid (or each network element, if weights are computed separately for each element) in all the operational snapshots throughout the target year included within the cluster that snapshot 'S' represents. Next, we describe a possible method to compute these weights.

Generally, following the outlined rationale, the benefits produced by the regional grid in all snapshots within each cluster can be considered proportional to the size of energy exchanges in the representative snapshot for that cluster, the unit economic value of these exchanges, and the number of hours within the cluster.

When evaluating the economic value of exchanges, it is important to distinguish between priority exchanges, which avoid non-served energy (NSE), and other exchanges that replace expensive energy sources (fuel-oil, diesel, coal) with cost-competitive ones (i.e., renewables and other possible convenient options based on conventional technologies).

The potential amount of NSE in a snapshot (Q_{NSE}^{A}), if all demand were supplied locally, can be computed as the aggregate local deficit within the GO areas, considering the maximum power production in each area A from all generation technologies, to meet the demand in the area. The amount of NSE to be avoided through priority power exchanges in a snapshot can be computed as:

$$NSE_{\text{potential}} = \sum(Q_{NSE}^{A})$$

$$Priority\ Exchanges = \ NSE_{\text{avoided}} = min(NSE_{\text{potential}}, \sum(Q_{excess-all\ generation}^{A}))$$

Where:

- The sum of the excess of the total amount of generation over demand in each area, $Q_{excess-all\ generation}^{A}$, is to be computed over all areas, and, for each area, only values larger or equal to zero are to be considered.
- Negative values of $Q_{excess-all\ generation}^{A}$ in each area A should be made zero in the sum.

This means that the maximum amount possible of NSE that can be avoided in a snapshot cannot be larger than the minimum of the total amount of NSE in the region when demand in each area is served locally and the total excess of generation available in the areas of the region over the local demand in these areas. In other words, energy exchanges can only eliminate the NSE that exists local conditions, and only to the extent that surplus generation is available in other areas. Other than that, there is no NSE to avoid. Besides, only the amount of resources that are not needed within each area to serve the local demand can be used to avoid NSE in other areas. If a larger amount of generation within this area were devoted to serve demand in other areas, in net terms, some NSE would occur in this exporting area.

The total amount of economic exchanges in a snapshot can be computed as:

$$Economic\ Exchanges_{\text{total}} = min\{\max[Priority\ Exchanges, \sum(Q^{A}_{excess-low\ cost})], \sum(|Q^{A}_{deficit-low\ cost}|)\}$$

Where the two terms out of which the minimum (smallest one) is to be taken are:

- The maximum between the total amount of priority power exchanges in the region and the sum, over all areas, of the difference between local low-cost generation and demand when this difference is positive (when it is negative, the corresponding difference is not considered in the sum) $Q^{A}_{excess-low\ cost}$. This involves that, on the exporting side, exchanges can be justified because there is low-cost generation that is not needed to supply local load and can, thus, be exported to replace expensive generation, or because there is NSE in other areas (resulting from serving local demand only with local generation) that can be avoided through these exchanges. In other words, any kind of local generation excess within an area with respect to local demand, considering both low-cost and expensive generation, can be exported to avoid NSE in other areas. However, only low-cost generation in an area should be considered for exports if this is to replace expensive generation in other areas.
- Sum, over all areas, of the absolute value of the difference between local cost-competitive generation and demand when this difference is negative, $|Q^{A}_{deficit-low\ cost}|$ (when it is positive, the corresponding difference is not considered in the sum).

This involves that, on the importing side, it would make sense to replace any kind of local deficit of low-cost generation with respect to demand with, either low-cost generation located in other areas if what is to be replaced locally is expensive generation, or both expensive and low-cost generation located in other areas if what is to be replaced (avoided) locally is NSE.

The amount of non-priority exchanges in a snapshot can be computed as:

$$Non\text{-}Priority\ Exchanges = Economic\ Exchanges_{total} - NSE_{avoided}$$

The overall economic value of the exchanges within a snapshot can be computed by assigning a unit value to priority exchanges equal to that assigned to non-priority exchanges multiplied by the ratio of the value of NSE in the region to the variable production cost of expensive generation in the Region:

$$Unit\ Value_{\text{Non-Priority}} = \rho_{expensive}^{region} - \rho_{low-cost}^{region}$$

$$Economic\ Value_{\text{overall}} =$$

$$Priority\ Exchanges \times Unit\ Value_{\text{Non-Priority}} \times \left(\frac{\rho_{NSE}^{region}}{\rho_{expensive}^{region}}\right) + Non\text{-}Priority\ Exchanges\ \times Unit\ Value_{\text{Non-Priority}}$$

Where, logically, the non-priority exchanges should be valued at their own unit value, which do not need to be computed, as the objective is limited to computing the relative weight of each cluster of snapshots.

Finally, the total benefits produced by the regional grid in the snapshots within a cluster can be computed as:

$$Total\ Benefits_{cluster} = Economic\ Value_{\text{overall}} \times Number\ of\ Hours\ in\ Cluster$$

The weight assigned to the network usage/cost allocation results computed for the representative snapshot 'S' of each cluster is, therefore, the ratio of the $Total\ Benefits_{cluster}$ to be obtained from the regional grid, or each line, in the hourly snapshots within each cluster and the sum of the $Total\ Benefits_{cluster}$ computed for all the clusters.

3.3 Challenges, efforts, and implications of each of the two options proposed for the clustering variables to consider

From a conceptual point of view, the most efficient method to select the reduced set of snapshots for IGOC computation, among the two proposed, involves using increases in the social benefit produced by energy exchanges involving the local generation and demand in each GO area as clustering variables. These variables are closely linked to the drivers of grid development, namely the benefits produced by network reinforcements. Network assets are built to benefit network users, so, according to cost causality, the cost of these assets should be allocated to users proportionally to the benefits they receive. In contrast, cross-border flows are directly related to the cross-border usage of GO grids, which only serves as a proxy for the benefits other GO areas obtain from the grid.

However, from a practical standpoint, using the results of the dispatch of local generation in each GO area to serve local demand, as well as the variable production cost of each technology type and the value of NSE in each GO area, may prove to be challenging due to the difficulties, probably involved in collecting this information for all the areas. WAPP directly computes and collects data on cross-border flows among GO areas, while data on dispatch of local generation in each area to serve the local load, as well as the technology costs and the value of the NSE, are normally determined and provided by GO-area authorities or the GOs themselves.

Therefore, to decide which type of clustering variables to use, the conceptual advantages of considering the results of the local dispatch of generation within each GO area and the local technology costs should be weighed against the practical challenges of using these variables.

This POC suggests that WAPP should kick off the application of the APM-IGOC for at least 3-5 years using the first method based on cross-border flows to build confidence in it. Meanwhile, WAPP can consolidate the data collection process with the GOs concerning the second method based on local dispatch results and costs, and switch to it once its feasibility is demonstrated and consolidated.

4 COMPUTATION OF THE CLUSTERS

4.1 Clustering objectives

As already mentioned, once the set of clustering variables has been chosen, the clusters should be determined to achieve the following two objectives:

I. All snapshots within each cluster are as similar as possible regarding the vector of values adopted by the clustering variables.
II. Snapshots within different clusters are as different as possible regarding the values of these same clustering variables.

Therefore, the algorithm or method used to define the clusters of snapshots should aim to minimize the intra-cluster differences among the operation snapshots, in terms of the clustering variables, while maximizing the inter-cluster differences among snapshots.

4.2 Selecting the number of clusters to consider

The larger the number of clusters considered, the more similar the snapshots within each cluster can be. Consequently, a larger portion of the differences among snapshots, in terms of the clustering variables, will occur between those allocated to different clusters. Therefore, the larger the number of clusters defined, the higher the classification should rank according to the clustering objectives I and II defined above.

However, using a larger number of snapshots to compute annual IGOCs increases the amount of data to be collected and the computational burden of the IGOC computation process. Thus, the number of snapshots should be chosen to strike the right balance between the accuracy of the IGOCs computed using these clusters and the data collection effort and computational burden.

An error measurement can be defined to determine the accuracy of a cluster definition, considering the aggregate intra- and inter-cluster differences. Different possible clustering error measures are considered and provided within various clustering methods.

4.3 Type of clustering method applied

A large number of different clustering methods have been proposed in the relevant literature for computing clusters of samples (in this case, operation snapshots) based on the values exhibited by the selected clustering variables. These methods differ in several features, including:

- The need to define the number of clusters.
- The shapes of the clusters: whether they should have regular or irregular shapes.
- The ability to deal with outliers and noise.
- The size of the data set the method can handle.
- The underlying distribution of the data set assumed by the method: whether it can be considered to follow a probabilistic distribution or not.
- The computational burden.

Popular clustering methods used for similar analyses to those proposed in this POC belong to the family of *partitioning methods*. Within these, either the K-means or K-medoids methods can be employed. These well-known methods have been widely tested, have limited computational burden, and can handle large datasets. However, exploring alternative methods should be considered if these do not adequately fit the dataset at hand. The main features of the K-means and K-medoids methods are as follows:

- Both methods:
  - Require the number of clusters (k) to be specified in advance.
  - Involve an iterative process to assign data points to clusters and update centroids.
- K-means:
  - Works by minimizing within-cluster variance.
  - sensitive to outliers and assumes spherical clusters with equal variance.
- K-medoids:
  - Minimizes dissimilarity among samples assigned to the same cluster.
  - robust to outliers and does not require numerical data.

4.4 Outputs of the clustering process

A list of the main outputs of the clustering process to be considered for the computation of annual IGOCs includes:

- The definition of the clusters, i.e., the allocation of individual operation snapshots to clusters.
- The representatives of these clusters, to be considered instead of the rest of the snapshots within their respective clusters for the computation of annual IGOCs.
- The number of snapshots included in each cluster and, therefore, represented by the corresponding cluster representative.

5 HOW TO COMPUTE ANNUAL IGOCS BASED ON THE OUTPUTS OF THE CLUSTERING PROCESS

The annual IGOC to be paid by GO 'i' to GO 'j' represents the fraction of the annualized cost of the grid of GO 'j' that is deemed to be used by GO 'i'. Typically, the process of computing annual IGOCs is divided into two steps[2]:

1. **Step 1**: Compute annual IGOCs considering the representative of each cluster alone, as if this were the only snapshot to be considered.
2. **Step 2**: Compute the annual IGOCs to be eventually applied as the weighted average of those computed for individual snapshots representing the previously defined clusters.

To compute compensations among GOs, it is necessary to decide whether to consider the cost of the full capacity of each asset or just the cost of the fraction of the capacity that is being used. If the cost of the full capacity of each asset is considered in IGOC computation, in Step 1, the full annualized cost of each grid asset should be allocated to the GO areas using this asset in each representative snapshot.

If only the cost of the used fraction of each asset's capacity is considered for IGOC computation, the annualized cost of each asset for each representative snapshot should be divided into two parts: the cost corresponding to the used fraction of the capacity of asset 'l' in this representative snapshot 's', $CU_{l,s}$, and the part corresponding to the unused fraction of the capacity of asset $CNU_{l,s}$. . Typically, the overall cost of asset 'l' should be divided into these two parts proportionally to the amount of capacity used and unused for this asset in the snapshot.

Then, the annual IGOCs computed in Step 1, considering each cluster's representative snapshot 's' separately, should result from allocating to GO areas only the cost assigned to the fraction of the capacity of each asset 'l' used in the representative snapshot 's', $CU_{l,s}$.

When computing the annual IGOCs to be eventually applied in Step 2, the weights assigned to the annual IGOCs computed for individual snapshots in Step 1 should depend on the type of clustering variables considered, as detailed next:

- If cross-border flows or net exports for GO areas are used as clustering variables for defining clusters of snapshots and their representatives, the weight assigned to the network usage/cost allocation results for each representative snapshot 's' in the final annual IGOCs computation should be proportional to the total

[2] Please note that from a computational perspective, these two steps are perfomerd together in the WAPP-APM tool.

number of operation snapshots within the cluster that snapshot 's' represents throughout the target year.

- If the increase in the social benefits potentially caused by the energy exchanges that GO areas could get involved in are used as the clustering variables for defining clusters of snapshots and their representatives, the weight assigned to the network usage/cost allocation results for each representative snapshot 's' in the final annual IGOCs computation should be proportional to the total benefits produced by the overall grid (or each network element if weights are computed separately for each element) in all operation snapshots within the cluster that snapshot 's' represents throughout the target year. The benefits should be computed as per the procedure outlined in section 3.2.1.

6 RECONCILIATION OF COMPENSATIONS IN Y+1 BASED ON DEVIATIONS IN THE SYSTEM OPERATION IN YEAR Y FROM THAT CORRESPONDING TO THE SNAPSHOTS ORIGINALLY CHOSEN FOR YEAR Y

When addressing the reconciliation of compensations in Y+1 for year Y, based on deviations in the real system operation from the expected operation when selecting representative snapshots for the computation of these compensations, it is crucial that any updates to transmission charges paid by individual agents are not applied to agents whose operational decisions are sensitive to these charges. Inter-GO Compensations aim to allocate the cost of the regional transmission grid at the GO area level, which is a sunk cost independent of agents' operation decisions. Modifying the network charges paid by those individual agents whose operation decisions are elastic to the level of these charges, to allocate any deviation in the due level of IGOCs computed ex-post, would likely lead to a modification of these agents' operation decisions. This would decrease the operational efficiency of the system without affecting the network costs being allocated, since these costs are not driven by individual agent's operational decisions.

The final level of compensations to be applied for year Y shall be computed ex-post using a set of snapshots representing the actual operation of the system in year Y. In order to compute these compensations, data on the actual level of the clustering variables, for all hours of the year, corresponding to the actual operation of the system shall be collected. Based on these data, the clustering process shall be repeated to determine the set of snapshots to be used to compute the annual compensations to be eventually applied for year Y. Then, using the map of flows for each representative snapshot within this updated set, which could be the map of real physical flows measured, or the map of flows computed based on other system variables measured for these set of snapshots, an updated level of annual compensations to apply for year Y shall be determined separately applying APM considering the actual system operation for each representative snapshot, to compute the annual compensations as if this snapshot were the only one to be considered and, then, computing the weighted average of the compensations computed for all these representative snapshots.

Lastly, the deviations in compensation between the ones computed ex-post and those computed ex-ante shall be determined as the difference between these two. These deviations could be included in a deviation fund, separately computed for each GO area, accumulating both positive and negative deviations in the net compensation received by this GO area over several years. The size of the deviation fund for each country would also be updated annually, with the payment to be received or paid by this area in the corresponding year amounting to 1/n of the accumulated balance of this fund at that time. These adjustments will be applied following a rolling window approach to make them as independent as possible from the latest operation decisions made by agents within each GO area, while also softening variations in the net compensations finally applied compared to those computed in advance and communicated to GO areas.