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On transmission cost allocation in the West African Power Pool (WAPP): The case of the OMVG transmission project

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I. THE CONTEXT

Regional integration or power resources can have a strong positive impact on the overall electrification process, in sub-Saharan Africa in particular. Superficially, regional trading of power seems to be a low hanging fruit, since establishing an advanced power trading platform with sound rules and institutions does not require substantial expenses. It requires, though, the alignment of the involved governments and parliaments regarding giving up some sovereignty to the regional institutions – regional regulatory authority and regional operator – and the common acceptance of sound trading rules and sharing transmission utilization and cost. Development of these regulations requires specialized knowledge and their implications – although beneficial from the viewpoint of overall efficiency and facilitation of investment in generation and transmission – might enter in conflict with entrenched privileges of stakeholders in some of the countries.

This working paper presents in broad terms the current issues at play in the deployment and consolidation of power pools in sub-Saharan Africa, focusing on the West Africa Power Pool (WAPP). Lack of political action reinforcing the regional institutions and to impulse further integration, on the one side, and the need for improvement in the rules of trade and of allocation of transmission costs, on the other side, are identified as the major roadblocks impeding a stronger and more efficient cross-border trade of electricity. The paper critically examines the present rules of transmission cost allocation in the WAPP and proposes detailed guidelines to improve the present situation, in a process that should evolve towards the vision of a “single system paradigm”.

1.1. Regional trade and power pools

Regional integration of power systems can be an effective way to create economies of scale for mobilizing private-sector investments, leverage synergies related to demand and supply and advance economic integration. When properly designed and implemented, regional power pools can lower the cost of electricity supply and improve the quality of delivered electricity services, thereby driving socio-economic development. Power pools provide these benefits when they include regional-scale generation plants and adequate cross-border transmission infrastructure. These prerequisites can only be met under sound power pool rules and governance.

Regional power pools are particularly relevant in the specific context of sub-Saharan Africa, both because the size of the national power system in at least 20 countries in this region is presently below the efficient level of output for a single power plant and because some countries have sufficient renewable resources (e.g., hydro, geothermal, or solar) to not only meet domestic demand but to also export excess power. Four power pools have been established in SSA – West, East, Central and South – with the most advanced, the Southern Africa Power Pool, launched in 1995. This paper will focus of the West Africa Power Pool (WAPP), although most of the discussion applies to the four of them.

Regrettably, the potential of these power pools remains largely untapped due to technical and political barriers. A strong alignment of interest is needed among participating countries and external partners, including private entities and financing institutions that are willing to invest in regional infrastructures under the right conditions. National-level political commitment is needed to give executive responsibilities and resources to regional institutions, identify barriers and vested interests that impede progress, and build the capacity to regulate and operate regional systems.

The main obstacles to achieving the benefits of well-designed power pools have been identified[1]: ineffective regional governance and flaws in the rules for regional trading and network cost allocation. Both discourage investments in transmission infrastructure and regional-scale generation plants, especially when combined with a lack of trust among states, a lack of willingness to liberalize markets, concerns over the preservation of national autonomy and sovereignty and a preference for bilateral contracts over regional agreements.

[1] Global Commission to End Energy Poverty (GCEEP), “Inception Report”, September 2019. https://www.endenergypoverty.org/reports

Regional governance

Securing the low-cost power needed to drive industrialization and economic growth is a priority for the governments of all SSA countries. While many countries struggle with insufficient or unreliable power, others are beginning to worry about excess capacity. It is becoming increasingly clear to them that a challenge on this scale requires a regional as well as a national approach, and that trading power is of essence. Complex coordination both within and between countries is required in investment, regulations, and system operations and this will only be possible with political leadership.

Despite potential benefits, regional integration is frequently hampered by the absence of strong regional institutions and enabling regulations. Existing power pools generally lack executive powers and capacity in two key regional institutions: the system operator and the regulator. This undermines regional transmission planning and operation and results in poor regulatory harmonization.

The rules of regional trade and transmission cost allocation

The guiding principle in the design of a power pool is the single market paradigm – that is, the principle that a power pool must be as close as possible in its operation and planning decisions, transmission regulation and governance to a single country. In practice, loss-of-sovereignty concerns and implementation issues limit the reach of this principle.

When existing power pool rules fall short of this ideal, the efficiency and security of supply deteriorate. For instance, in the SSA power pools, current physical bilateral contracts distort the economic dispatch of generation and demand. The 2020-2023 WAPP Master Plan says[2]: "Indeed, up to now, contracts for the exchange of electricity between States are subject to bilateral agreements with a fixed rate for a long period and are monitored by a meter on the interconnection line. These contracts that proved their value in a radial market could be ineffective or sub-optimal in a large interconnected network in which all generation, options should be able to compete."

Sound transmission regulation is critical to successful power pools. The absence of sound, commonly agreed procedures to allocate transmission costs will deter potential investors as it increases the risk of not receiving sufficient economic compensation. Inadequate charges for cross-border transactions that use regional interconnections will stifle trade until sound transmission pricing rules are implemented. Power-pool-wide congestion management rules are needed to establish priorities in the efficient

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2 http://www.ecowapp.org/en/documentation?keys=&field_type_doc_tid=All&field_date_news_value[value]&field_date_news_value_1[value]&page=1

use of scarce network capacity. This paper focuses on the rules for allocation of transmission costs in SSA power pools and the WAPP in particular.

1.2. Regional trade of electricity in West Africa

1.2.1. The institutional context.

The Economic Community of West African States (ECOWAS).[3]

Since its creation on 28 May 1975, the Economic Community of West African States (ECOWAS)[4] has been promoting economic cooperation and regional integration as a tool for an accelerated development of the West African economy. Regional integration remains the most viable and appropriate tool for achieving and accelerating sustainable development of the West African countries.

The ECOWAS community, which has a total population of approximately 385 million people, covers a surface area of 5,105 million km comprising 15 states in West Africa, which differ significantly in terms of size, population, climate and availability of natural resources. An average of 60% of the total population of the ECOWAS community live in rural areas. The major energy resources for electricity production in West Africa are hydropower, oil and natural gas.

Demand for electricity in Sub-Saharan Africa is expected to increase fourfold between 2010 and 2040, representing an average growth of 4.5% per year. In West Africa, it is expected that demand for industrial and commercial electricity will grow faster than average, by 5.3% per year. Electricity access in West Africa, as of 2018, is at 52%; however, in many West African countries, it is much lower.

The demand gap for West Africa in 2040 is estimated to be 101 GW. Constraints to electricity provision include inadequate generation and transmission infrastructure, limited interconnection for cross-border electricity trade, suboptimal electricity sector performance, electricity tariffs not recovering costs, low capacity diesel generators, and a lack of funding.

In recognition of the demand gap, the constraints to electricity provision, and the unequal distribution of power sources and transmission capabilities between countries, ECOWAS established the West African Power Pool (WAPP) in 1999, to foster a regionally integrated power market and facilitate the balanced development of diverse energy resources for the region's collective economic benefit. The WAPP

[3] https://www.ecowas.int/

[4] Member States of ECOWAS: Benin, Burkina Faso, Cabo Verde, Côte d'Ivoire, The Gambia, Ghana, Guinea, Guinea Bissau, Liberia, Mali, Niger, Nigeria, Senegal, Sierra Leona, and Togo.

Master Plan was first created in 1999, revised in 2004 and 2012, and was most recently updated in 2018 to account for changes in the sector.

The ECOWAS Energy Protocol, adopted in 2003, establishes a legal framework in order to promote long-term cooperation in the energy field, based on complementarities and mutual benefits, with a view to achieving increased investment in the energy sector, and increased energy trade in the West Africa region. With respect to the electric power sector, the protocol provides for open and non-discriminatory access to power generation sources and transmission facilities and establishes an enforcement mechanism supported by the ECOWAS Commission.

The West African Power Pool (WAPP)

WAPP is a specialized institution of ECOWAS, covering 14 out of the 15 member states of the ECOWAS community. It was created in 1999 when the ECOWAS Heads of State and Governments came together with a vision to “integrate the national power systems into a unified regional electricity market with the ultimate goal of providing regular and reliable energy at a competitive cost in the medium- to long-term to citizens of the ECOWAS region”.

The aim of WAPP is to facilitate the balanced development of diverse energy sources of ECOWAS member states for their collective economic benefit, through long-term energy sector cooperation, unimpeded energy transit and increasing cross border electricity trade. Furthermore, the program aims to promote foreign direct investment in the sector.

WAPP members comprise public and private power generation, transmission and distribution entities involved in the operations of the power network system in West Africa.

Presently the WAPP has an Information and Coordination Center (ICC), which, according to the WAPP 2020-2023 Business Plan, will be operationalized to become a regional System and Market Operator (SMO) within the period. This upgraded institution shall ensure, among other goals, transparency and market neutrality due to the sharing of data and information, the maintenance of an up-to-date model of the interconnected regional power system, the enforcement of common operating rules, the harmonization of protection schemes, and the calculation of Net Transfer Capacity among the involved countries.

The ECOWAS Regional Regulatory Authority (ERERA).

The ECOWAS Regional Electricity Regulatory Authority (ERERA) is the regional regulator for cross-border electricity interconnections in West Africa. The members of ECOWAS have adopted an Energy Protocol designed to put in place the appropriate legal and institutional environment for the development of the electricity sector of West Africa. Within the framework of the Energy Protocol ERERA was established in 2008, as a specialized institution of ECOWAS. ERERA's general mission is to regulate cross-border electricity exchanges between ECOWAS Member States, while overseeing the implementation of the necessary conditions to ensure rationalization and reliability and contributing to setting up a regulatory and economic environment suitable for the development of the regional market.

The Directive C/DIR/1/06/13 of 21 June 2013, on the Organization of the Regional Electricity Market requires ERERA to publish in accordance with its procedures and after consultation with stakeholders, transmission tariffs setting methodology for the regional electricity market. The Transmission Tariff methodology for the West African Power Pool (WAPP) shall be used by the Regional System and Market Operator (SMO) to develop a clear, transparent and predictable model for the calculation of transmission prices. The Regional Market Rules for the West African Power Pool were approved in June 2018 and establish that the approval by ERERA of the Regional Transmission Pricing Methodology shall be one of the required conditions for the commencement of Phase 1 of the regional electricity market.

In 2015, ERERA approved a methodology for cost allocation of cross-border transmission: the "Adoption of the Tariff Methodology for Regional Transmission Cost and tariff", Resolution No. 006/ERERA/15. ERERA's method establishes: i) the procedure to estimate which assets belong to the regional network; ii) the regulated costs of these assets that must be considered in the tariffs of a given year; iii) how to determine the level of utilization by each bilateral transaction of the regional assets, making use of load flows for the peak generation scenario in the considered year; and iv) how much to charge to each bilateral transaction. More on the content and the actual implementation of this regulation later.

Regional trade in the WAPP.

Energy surpluses in some countries, and large deficits and high costs in others, make the region an appropriate candidate for regional trade, especially given its substantial renewable energy potential. The World Bank *"estimates that the economic benefits of a fully integrated power market are of the order of US$5-8 billion per year for West Africa, with the potential to reduce the cost of electricity services by half in many countries in West Africa"*[5]. Additionally, analysis conducted by the Tony Blair Institute, USAID and Power Africa estimates $30 billion in savings through mutually beneficial power trade and the potential for large-scale regional solar development[6]. There are significant benefits to optimizing the energy resources across the region, given the varying endowments and load profiles in each country.

Despite the wide consensus on benefits to regional electricity trade in the region, the level of cross-border trade is low currently. In 2018, the total electricity exported in the

[5] The World Bank. 2019. "Burkina Faso Electricity Access Project." Project Information Document.

[6] Tony Blair Institute for Global Change. 2019. "West Africa Power Trade Outlook." Power Africa Senior Advisors Group Program.

region was 5718 GWh, representing 8.5% of its total electricity production[7]. Furthermore, of the existing interconnection transmission lines, in 2017 only 42% of the line capacity was used. The number drops to 30% if we exclude electricity from Nigeria, whose distribution companies are facing liquidity issues thereby making exports more attractive to power producers[8]. That the current cross-border transmission capacity is not being fully utilized suggests the presence of non-infrastructure related barriers to trade in the region. Indeed, the Tony Blair Institute report suggests that the barriers to trade "*are largely political, including non-cost reflective country to country trade agreements, non-payment, and development of costly domestic generation plants when cheaper imports are available*."[9].

The recently concluded West Africa Masterplan 2020-2023 sets out a vision for integrating the power systems of the region which will both reduce the cost of energy and increase its reliability.[10]

According to this Masterplan, one of the challenges of the mid-term, long-term horizon is to develop a strong interconnected network to ensure synergy between hydroelectric resources, gas and solar. For example, hydroelectricity is predominantly used during the evening peak as well as during the night, when solar energy is unavailable, even if the hydraulic producible is maintained at a technical minimum during the day, especially for irrigation issues.

Thus, when analyzing the system from the point of view of marginal costs, it can be observed that the massive investments in renewable energy over the medium term as well as the development of the interconnected network will draw downwards the marginal costs of the whole region. These costs will vary from 80.6 USD/MWh in 2022 to 49 USD/MWh in 2029. In addition to this reduction of marginal costs in the region, it can also be noted that the latter vary strongly depending on the time of day considered.

If we analyze the situation during the day (12 am), we observe the marginal costs as shown in the figure below. These are naturally weaker in the North of the region (where the bulk of electricity is produced by solar photovoltaic technology) as well as in Guinea and Sierra Leone where many hydropower plants are now active.

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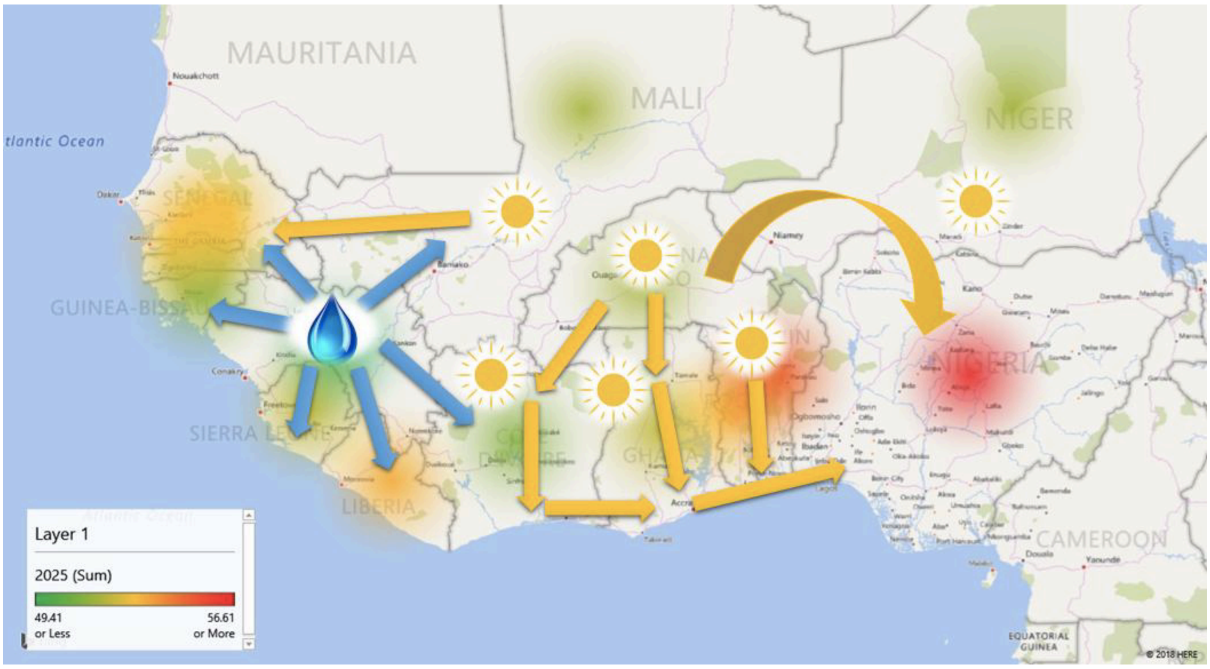
[7] World Bank Group. 2019. "ECOWAS- Battery Energy Storage Systems and Synchronization." Project Information Document.

[8] Tony Blair Institute for Global Change. 2019. "West Africa Power Trade Outlook." Power Africa Senior Advisors Group Program.

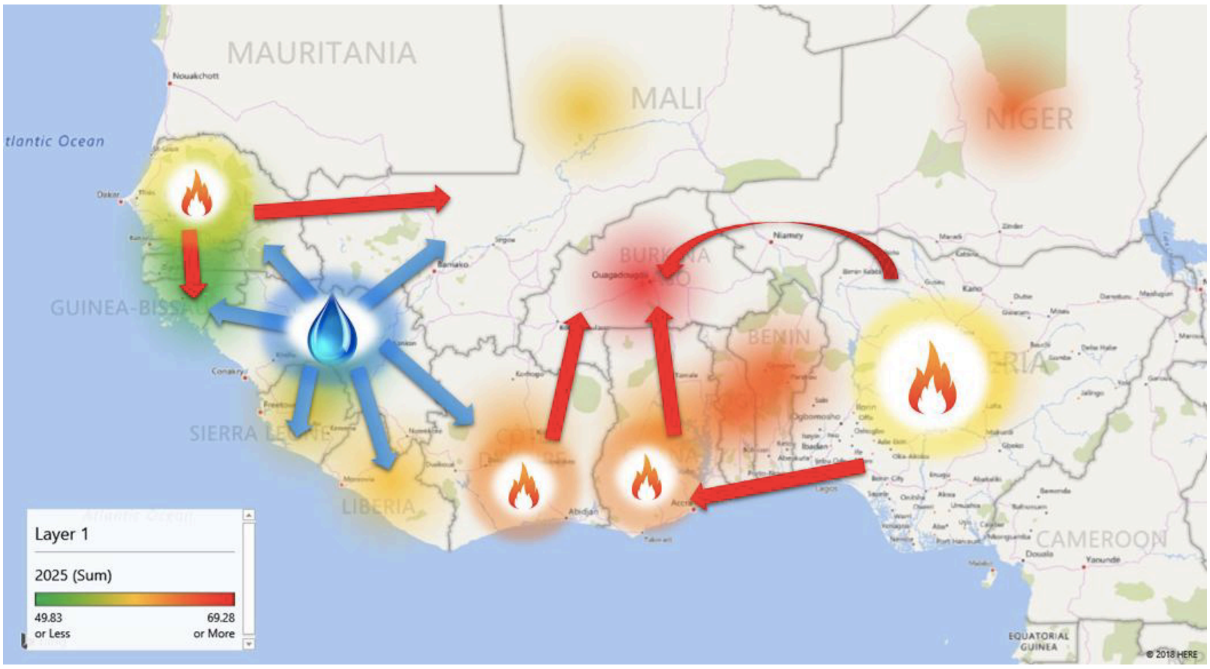
[9] Ibid.

[10] https://www.ecowas.int/



During the evening peak at 9pm, the situation is different. The countries of the North, such as Mali, Burkina Faso and Niger, must now import electricity, given the unavailability of solar energy. They are therefore facing the highest marginal costs at that moment. These imports come mainly from the countries using gas resources that run their combined-cycle power plants at full power (mainly Nigeria, Ghana, Côte d'Ivoire and Senegal). In the figure below, we can see that the flows observed at 12am are reversed in the evening.

These massive flows justify the development and/or strengthening of major transmission axes throughout the subregion.



Large privately led sub-regional transmission projects

With support from interested parties – both electricity intensive businesses and developers of generation plants – and institutions providing technical assistance on transmission planning, some major sub-regional transmission and generation projects have been proposed and have presently reached diverse levels of implementation. Prominent among them are: i) the Côte d'Ivoire – Liberia - Sierra Leone - Guinea (CLSG) Interconnector Project, which is very close to completion, and ii) the Organisation pour la Mise en Valeur du fleuve Gambie (OMVG), still in the process of negotiation among the parties, closing financing, and starting procurement.[11]

Special Purpose Vehicles (SPVs) have been established by the (typically) state-owned power utilities to be contractually and legally responsible for the implementation of these projects, in accordance with international treaties to ensure construction, ownership, exploitation and development of power transport infrastructure.

A critical issue in the successful completion of a transmission project is the allocation of its costs among the parties involved, i.e. the beneficiaries of the project. Simplicity in the allocation rules is always welcome, but it might have undesirable consequences. Parties that estimate that their benefit will not be larger than the cost allocated to them, will not be interested in the project and will try to impede its realization. There are numerous experiences of construction of transmission interconnectors, and this knowledge can be brought to the discussion of transmission cost allocation within the WAPP. It follows a brief introduction to the OMVG project, and the detailed discussion of the regulation for the allocation of transmission costs for the OMVG project in the context of the WAPP.

1.3. The OMVG

The development objective of the Organisation pour la Mise en Valeur du fleuve Gambie (the Gambia River Basin Development Organization) (OMVG) Interconnection Project for Africa is to enable electricity trade between the Gambia, Guinea, Guinea-Bissau, and Senegal. The project consists of two components.

The first component is the extension of the WAPP transmission network with two sub-components: (i) construction of 1,677 km of 225 kV transmission network capable of handling 800 MW; and (ii) construction of fifteen 225-30 kV substations and dispatching centers on the interconnection (located in the corresponding substation).

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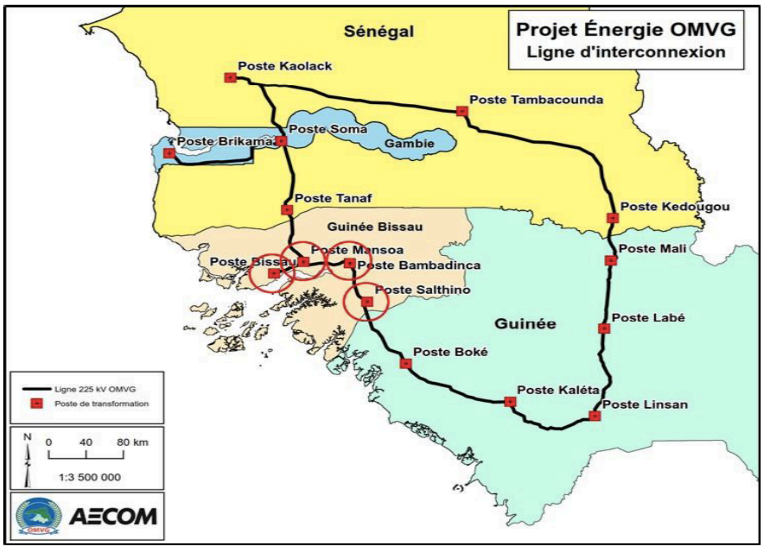
[11] CLSG: https://www.gihub.org/resources/showcase-projects/côte-d-ivoire-liberia-sierra-leone-guinea-clsg-interconnector-project/

OMVG: https://projects.worldbank.org/en/projects-operations/project-detail/P146830?lang=en

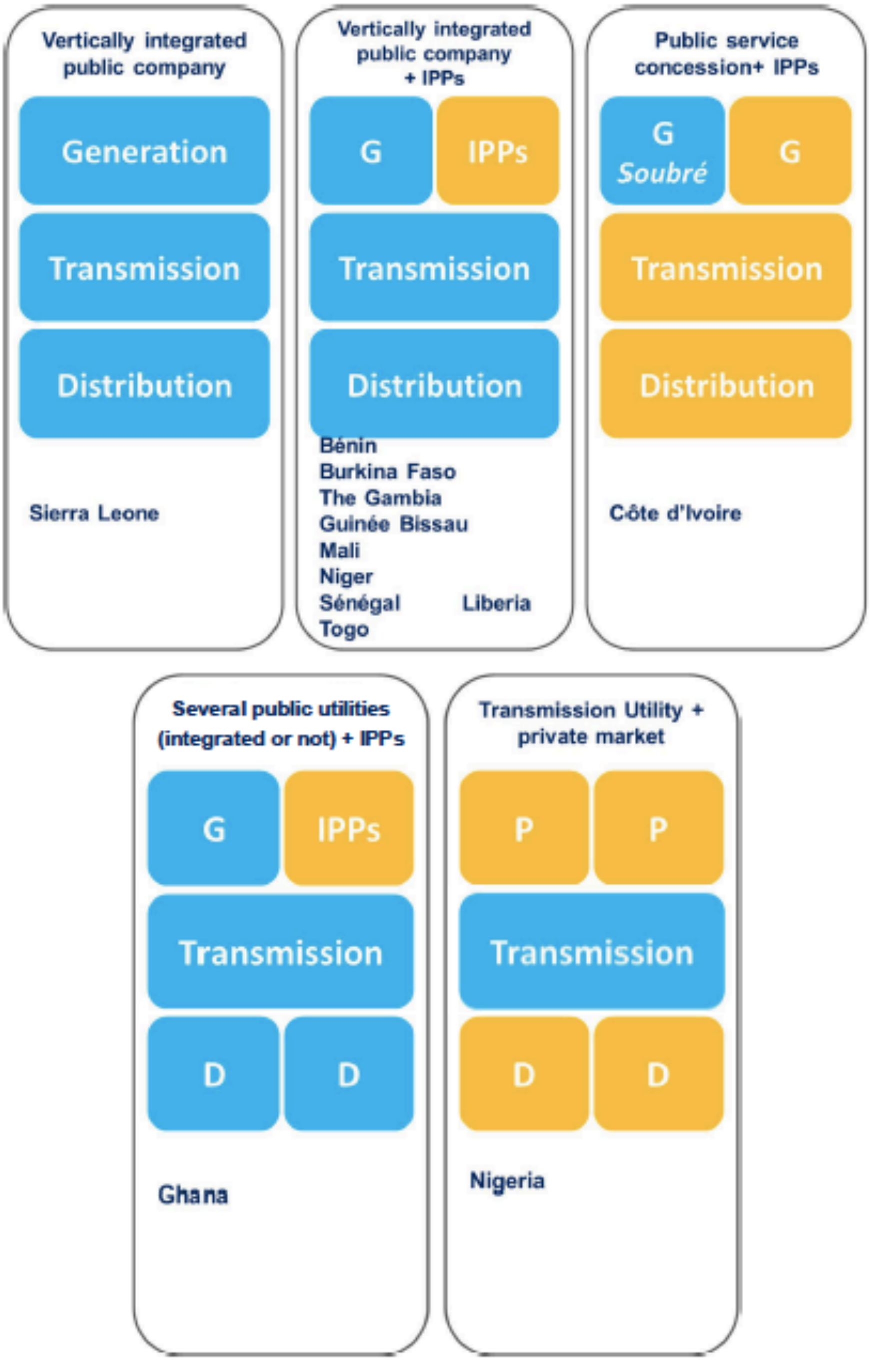
The second component – technical assistance to OMVG – has two sub-components: (i) implementation support will finance costs of the project management unit (PMU), project supervision costs including the owner's engineer, costs associated with implementing the environmental and social management plan (ESMP) and resettlement action plans (RAPs), internal audits, technical assistance (TA) related to the fiber optic cables, as well as further study of how to strengthen or mainstream collaboration between OMVG and Organisation pour la Mise en Valeur du fleuve Senegal (Senegal River Basin Development Organization) (OMVS); and (ii) operations and maintenance (O and M) support to OMVG transmission company will finance part of the O and M fees during the first five years of operation (expected FY2018-2022), on a sliding scale.

During the preparation of the project, the four governments agreed to provide counterpart funds of approximately USUSD 16 million to finance interest during construction and compensation costs of the RAPs for the interconnection line (Senegal USD 7 million, Guinea USD 3 million, Guinea-Bissau USD 5 million, and The Gambia USD 1 million). The breakdown for Guinea-Bissau included USD 4 million for interest and USD 1 million for compensation of Persons Affected by the Project (PAPs).

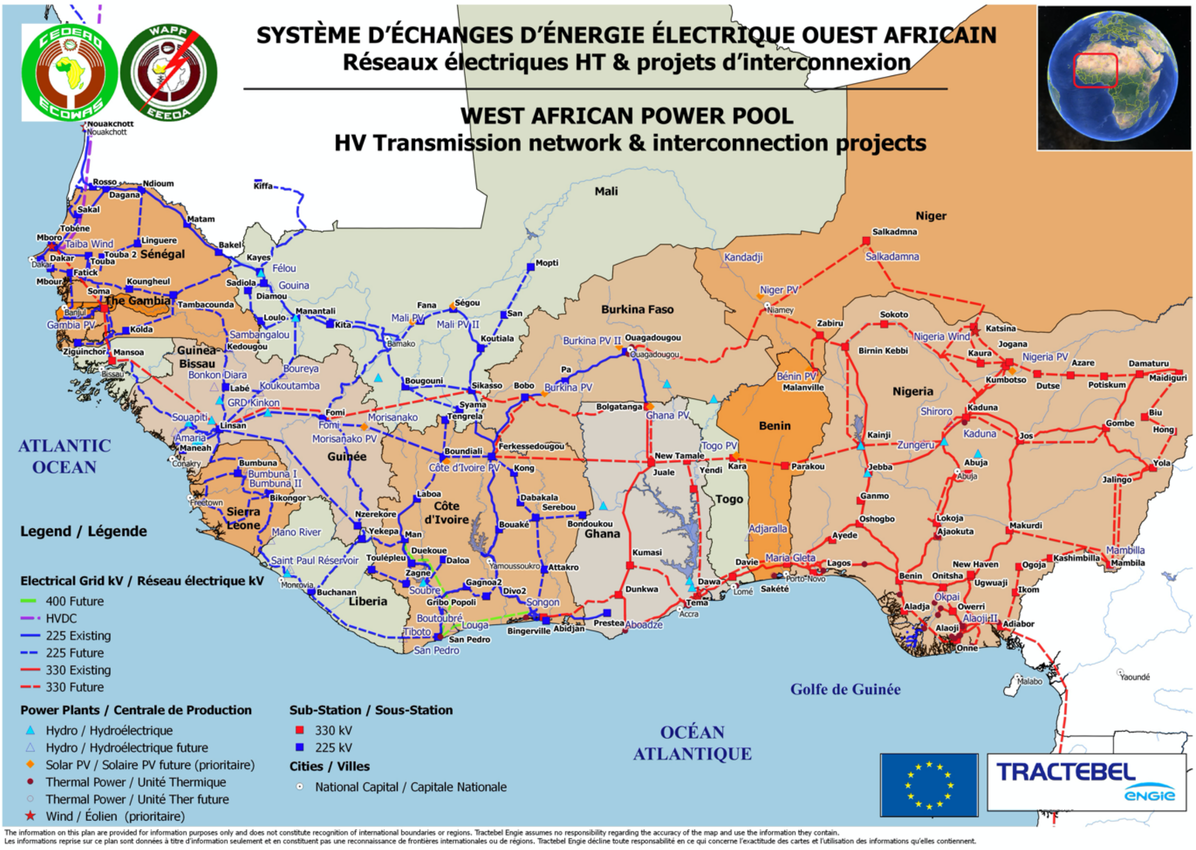
Regarding the allocation of the costs of the OMVG transmission project, it has been agreed with ERERA that the costs of OMVG will be allocated to countries (or their system operators), which will act on behalf of the agents – producers or consumers – located in their respective territories. Therefore, these system operators will take the function of single buyers and single sellers, in what respects international trade using the OMVG transmission system. OMVG initially proposed a cost allocation method, but presently other alternatives have been proposed and it is necessary to come to some conclusion.



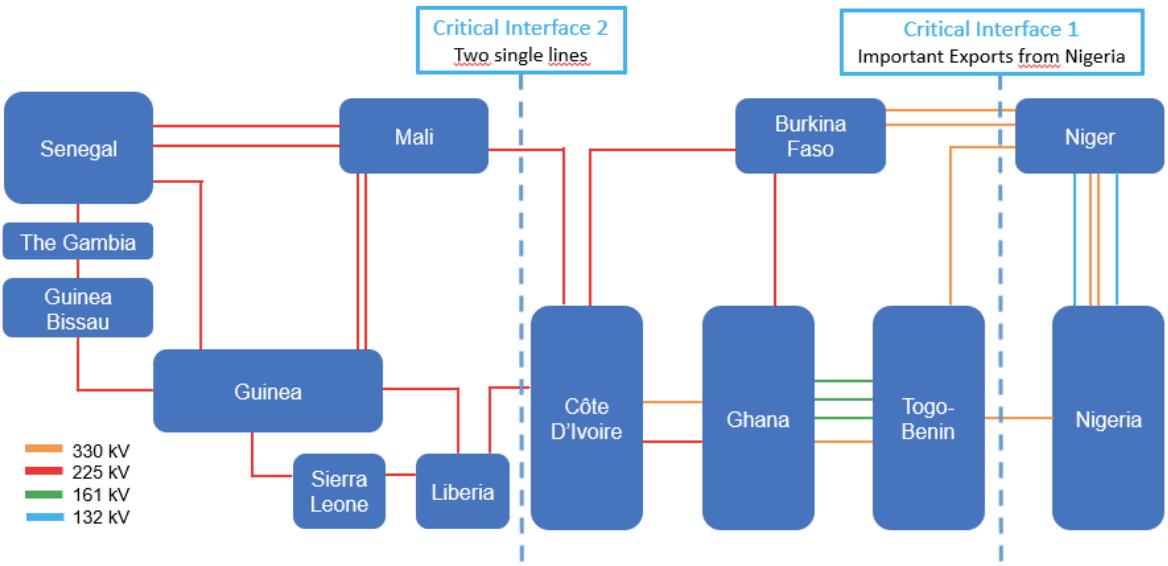
Top: Countries in WAPP. Middle: CSLG project. Bottom: OMVG project.



Blue category means companies are public. Yellow category means that companies are private. The presence of IPPs in the production component means that the organization of the sector allows IPPs to intervene (without necessarily being the case).



Map of the WAPP transmission network. Source: Master Plan 2020-2023.



Critical interfaces. Source: Master Plan 2020-2023*

(*) From 2020, the 14 countries of the subregion will be interconnected. Two sections appear to be critical from the viewpoint of the stable and coordinated operation of the entire WAPP system: The connection of Niger-Nigeria with the rest of WAPP and the connection between Western ECOWAS Member States (Senegal, Mali, Guinea, Guinea-Bissau, The Gambia, Sierra Leone and Liberia) with the rest of WAPP.

II. GUIDELINES ON TRANSMISSION COST ALLOCATION FOR WAPP

In the distribution segment of power systems in developing countries, the challenge is to figure out novel regulatory and business model approaches, because there are no truly valid experiences that can be imitated to accelerate electrification in countries struggling to achieve universal electricity access. On the contrary, there are suitable examples of multinational power trade that are working quite successfully around the world and that could be adapted to the sub-Saharan African context, where they are mostly needed. The difficulty resides in making the existing knowledge available to the concerned parties, adopted and implemented.

What guidelines could be proposed to design the transmission cost allocation method for the OMVG project and other large transmission projects in the region? Let's start with high level design considerations, to be followed by more specific recommendations.

2.1. High level guidelines.

Successful design and implementation of large transmission projects require abiding by the following general cost allocation rules:

- The allocation of the costs of the transmission segment of a power sector must respect the specific context, i.e., whether the allocation is done at national or regional (multinational level), the maturity of the regulation of power trade in the considered territory, the geographical layout and level of meshness of the network, or the expected need for locational signals for new generators or loads, among other factors. However, there are a few essential principles that, even if not strictly followed in some specific context, must inspire the design of the regulation to be implemented as much as possible. These well-established principles of transmission pricing are: [12]
    - Transmission costs should be allocated to the beneficiaries of the transmission assets.
    - Transmission charges should not depend on the commercial transactions among the power system agents.
    - Transmission charges should be announced a priori and for a long period of time, so that economic risk for the agents is reduced and any locational signals are effective.

[12] See Pérez-Arriaga, I.J. editor, "Regulation of the Power Sector", Springer, 2013, https://www.springer.com/gp/book/9781447150336 and the MIT report "The Future of the Electric Grid", https://energy.mit.edu/wp-content/uploads/2011/12/MITEI-The-Future-of-the-Electric-Grid.pdf

- Transmission cost allocation is about how the costs of the project will be assigned to the different participating agents that use or benefit from the transmission project. Two items must be clearly differentiated:
    - *Financing the total costs of the project.* The project costs have to be financed by the project promoters via some kind of SPV for the specific project. The actual costs are incurred when the investments are made and continue with additional minor investments, plus the operation, maintenance and administrative costs. These actual costs have to be financed with grants, debt and equity of different types, resulting in payments made by the SPV to the financing entities, in quantities and times previously specified in the financing agreements. The trajectory in time of the financial costs is typically very irregular, since most of the investment costs happen during the installation of the transmission network assets, i.e. during the first few years of the economic life of the project.
    - *Payment the cost of the project by its users / beneficiaries.* The users / beneficiaries of the project have to make payments – the "use-of-transmission charges" – to the SPV, so that the SPV can meet their obligations with the financial entities and incur in all the other costs of the project. The charges to the users / beneficiaries of the project will be determined by some cost allocation method. The countries may act as intermediaries in this process, with their regulators establishing the transmission component of the regulated tariffs to the users / beneficiaries that will allow to recover the transmission costs.
- Transmission costs only include the costs of investment and the cost of operating and maintaining the equipment. None of these costs depend on the level of utilization of the transmission facilities. O&M costs can be roughly estimated as percentages of the investment costs, with different percentage values for each type of facilities. Losses and congestions happen in the transmission facilities, but they are not transmission costs; losses and congestions result in higher electricity production costs.
- When regulatory authorities determine the total amount of transmission charges (the so called "revenue requirement") for a given year, they do it using accounting methods so that the annual amount (the annuity) does not change much from one year to the next, and therefore the trajectory of the transmission charges follows a smooth and predictable path over time. They also make sure that, over the economic (or regulatory) lifetime of the assets the present value of the annuities equals the present value of the actual incurred costs (perhaps including some efficiency or performance incentives), obviously including a reasonable remuneration of the invested capital and the debt service. This is a fundamental regulatory principle that must be respected always: the cost

allocation method and the design of the transmission charges to be levied to the users / beneficiaries of the transmission activity must cover the recognized cost of this activity – the "transmission revenue requirement". The regulation must be designed so that unnecessary risks are not introduced in the mechanism of recovery of the revenue requirement by the transmission charges.

How to compute these transmission charges is the problem being addressed here: To whom should the charges be levied? Countries, utilities, individual producers and load serving entities, individual customers? How much should be allocated to each one? How the amount should be paid? In full, with a lump sum, or annually, so that the charges pay for the total costs of the project every year? How do these charges end up being included in the tariffs of the end customers?

- Another necessary clarification is the differentiation between "regional" and "national" transmission assets. The latter have negligible relevance in cross border trade, while the former are needed to establish physical transfers of electric power among countries. Obviously, there is no clear separation between both categories and some threshold must be establish in the regulation, based on engineering estimates and actual power flow patterns. Transmission lines that cross country borders are obvious candidates for regional transmission assets. Note, however, that many transmission lines that are purely internal to a country can have much relevance in regional power trade, for instance allowing wheeling of power through this line between two other countries.
- It is also important to distinguish between existing and new (planned) transmission assets. The importance of the cost allocation procedure stems from the potential opposition that a technically and economically sound transmission project may find by a country or important agent that considers it will have to pay more than the benefit obtained from the project, under some proposed cost allocation method. The consequences of this potential opposition are only important for new investments, obviously.
- How should the regulation apply to new large transmission projects like OMVG? We have two major options.

    A. Under this first option, a large transmission project like the OMVG would not be exempt from the general treatment for all transmission investments of regional type. This approach will certainly simplify regulation, as it will avoid dealing all the time with particular cases that will arise continuously as the transmission network and the physical flows will become increasingly complex.

    B. Under the second option, large transmission projects – like OMVG, which is promoted by a coalition of large power sector players – would be exempted from the general rules, allowing the promoters and the future users to decide who pays for the use of their facilities, how much and for how long. This approach may facilitate the creation of consortia of promoters and the deployment of transmission investments, while multinational agreements on the market rules and cost allocation methods may take a long time to be agreed and implemented into practical regulation. However, this second approach will probably lead to chaos in the mid and long-term as the regional grid develops and these large projects become just one more component of a densely meshed transmission system.

As we shall see later, these two options may not be incompatible, if we accept to give up in other aspects, such as in the locational component of the transmission charges, and we accept the essential transmission cost allocation rule that "transmission charges should not depend on commercial transactions".

- It is desirable that transmission charges have some locational component, i.e. all other things being equal, those agents whose activity as producers or consumers makes necessary to add new transmission facilities must pay more than those that do not cause any stress or need for new reinforcements of the network. This is particularly important for large generators (or large concentrations of medium size or even small generators), because they typically have more siting freedom; locational signals may guide new investors in generation to choose sites that avoid costly transmission investments. But it has to be decided first who are the agents to be charged the cost of transmission.
- Who are the agents to whom the costs of transmission must be allocated? First, one has to make an initial major design decision between two options:
    A. The methodology of cost allocation of regional investments will be applied only at country level, leaving to each country how to include the total regional charge allocated to it in the use-of-transmission-network-charge component of the regulated tariffs within the country; or
    B. There is the intention of introducing transmission charges with locational differentiation at nodal level in the regional network, i.e., different charges for agents connected at different nodes of the regional transmission network.

According to the first principle of transmission pricing, transmission charges must be levied to the beneficiaries of a transmission project, which in a general case are both consumers and producers. Therefore, a priori radical decisions such as "only consumers shall pay for transmission" or "all transmission charges must be levied to producers" are not justified.

- Legal security dictates that the cost allocation rules must not be modified if possible, and only for a very good reason and with sufficient warning. However, the numerical results of application of these rules will typically change, for instance when a new agent enters the system.
- The regulatory authorities of each country must be responsible for setting the transmission component of the charges that apply to each system agent within this country. When computing these charges, the regulatory authorities must take into account the decision made on how to allocate the costs of the regional transmission network.
    - Consider first the case where regional cost allocation is made at country level. Then the regulator will establish the transmission costs to be

included in the regulated charges as follows: start with the costs of the transmission network within the country, then subtract the charges that might have been allocated to other countries for the use of the regional transmission network of the country, and add the charges allocated to this country because of its use of the regional network in other countries.

  - Now consider the case where the costs of the regional transmission network have been allocated already to the generators and demands connected – either directly or indirectly – to each transmission network node. Our recommendation is to socialize – i.e., make uniform – the charges to consumers within the country, except perhaps for the largest consumers, since a transmission locational signal is not going to make any difference. On the other hand, the locational transmission charges for generators should be maintained.

- Congestion (i.e., lines reaching their maximum load carrying capacity under existing conditions and maintaining specified security levels) happens frequently in transmission networks. Depending of the transaction rules at bulk power system level, many power systems collect "congestion rents" under these circumstances. The "collecting entity" is usually the System Operator, either at national or regional level. Given that the transmission revenue requirement is determined based on actual costs, and that congestions do not modify the cost of transmission, the best use of the congestion rents is to decrease the transmission revenue requirement to be charged to the network users / beneficiaries. Under no circumstance the congestion rents should augment the remuneration of transmission or of the system operators.
- Transmission investments are lumpy, and they last many years (i.e., 40 or more; actually, they are refurbished, but never removed). When they enter in service their load carrying capacity typically exceeds what is presently needed, i.e., there is a lot of idle capacity during the initial years. It does not seem cost-reflective to charge the total cost of a transmission investment to its users / beneficiaries when they are using / benefiting only from a fraction of the transmission capacity. Different approaches have been proposed to allocate these "residual costs".[13] In the context of transmission cost allocation, any simple method of socialization of the cost to demand can be considered acceptable.
- Finally, it must be avoided to introduce risk in the remuneration of transmission unnecessarily. This requires that the rules to determine and allocate the transmission costs are clearly stated and that they do not create uncertainty themselves.

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[13] Pérez-Arriaga, J.I. et al. The MIT "The Utility of the Future" study, 2016. https://energy.mit.edu/wp-content/uploads/2016/12/Utility-of-the-Future-Executive-Summary.pdf

- For instance, if the investment in a transmission project has been made in a year T and the costs incurred with the technologies and catalog of components available in year T, the calculation in year T+N of the revenue requirement for that project should not be made based on the new technologies and costs of year T+N, since this creates an unmanageable risk for the transmission investor, resulting in a higher cost of capital and higher chargers for the users / beneficiaries.
- Another example is the deviation in the forecast of demand when determining the transmission tariffs. If the transmission component of the tariff or any transmission charges are defined in volumetric terms (USD per kWh consumed, for instance), the error in the estimation of the annual demand will result in a surplus or deficit in the collection of the transmission revenue requirement. This has to be accepted, as errors in the estimation of future demand cannot be avoided. However, this should not result in any uncertainty in the revenues of the transmission company, as the actual difference – positive or negative – can be easily included in the determination of the revenue requirement of transmission for the following year.

2.2. Implementation recommendations.

Some more specific recommendations for the specific context of the WAPP and the OMVG project follow next.

We start by the definition of the agents that will be subject to the transmission charges of the regional network. In bullet (vii) above the two basic choices were described. According to option A, the allocation of the cost of a new regional transmission project must be done under a uniform set of rules set by ERERA and implemented by WAPP, which would apply to any regional transmission asset in the entire region (WAPP). On the other hand, option B would allow large projects like OMVG to have their own cost allocation rules. It happens that is possible to design a cost allocation approach that eliminates the need to choose between these two alternatives. These are the main features of this approach, which we recommend for WAPP and the OMVG:

i) Establish that the charges of the regional transmission network will be applied at country level. Therefore, any locational component of the charges will only happen in a "diluted" form, i.e., at country level, and not at nodal level.[14] This may not be the most direct interpretation of ERERA's current transmission cost allocation rules, but we shall discuss this later.

[14] This is the method adopted in the Internal Electricity Market of the European Union. The Mercado Eléctrico Regional (Regional Electricity Market) in Central America uses the nodal charge approach.

ii) For a new important transmission project, like OMVG, let the involved countries decide how much is the corresponding revenue requirement and how to allocate this cost among them.[15] The rules that these countries agree should make sure that the total annual cost of transmission of the project is fully recovered each year with the established system of charges. ERERA will supervise that this is the case and also that the agreed revenue requirement is reasonable.

iii) If the countries do not manage to reach an agreement on how to allocate among them the costs of the transmission project after a prespecified time period, the decision will be made by the regional regulator ERERA using whatever transmission cost allocation rules they have established and that have been approved for WAPP to implement. A comment on the present set of rules approved by ERERA will be given later.

iv) The allocation of the cost of the *existing* regional network will be done with the method approved by ERERA and implemented by WAPP, but in the end, the method must result in an allocation of the cost of this regional network to the countries, not to the nodes. Note that, while applying this procedure, the assets of the large projects that have been allowed to have their own allocation method must be assumed to have zero cost, i.e., are ignored for all economic purposes (this is made to avoid double counting).

v) Once the allocation of the costs of the entire regional network for the considered year has been completed, each country can proceed to determine its internal transmission charges as described in the first sub-bullet of bullet (xi) above.

Note that we have made the general method and the methods adopted by any exempted large projects allocate their respective costs at country level. This makes both methods compatible, since the costs obtained by each method can be just added. This solves the problem of the future chaos that could ensue should uncoordinated regulated and free allocation methods coexist, without any coordination among them.[16]

There is another advantage of charging countries, which must be represented by some institution: the national System Operator (SO) would be the preferred option, if there

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[15] Some engineering method based on analysis of flow patterns must be used to determine which are the countries involved. Alternatively, the promoting countries may restrict the decisions on cost allocation to themselves. Then, any future charges to other countries should be based on the general rules of WAPP.

[16] An important observation: It would be also conceptually possible – although difficult in practice – to agree that the uniform centralized method and any method developed by an exempt transmission project must both allocate the costs at nodal level, in nodes of the regional network. Then the charges obtained by any method could also be added at each node. The danger here is the use of flawed designs of cost allocation methods (for instance those based on commercial transactions), whose errors may cause distorted charges that may jeopardize efficient trade. No problem if sound methods are used.

is one, or the national public utility, or utilities. Project promoters want to make sure that the charges are levied on the utilities, since this seems to provide more guarantee of cost recovery than passing the recovery of transmission costs to national tariffs, where there is collection risk because on non-payments or illegal connections.

The approach of choosing countries as the subjects of regional network charges has another, more subtle, good property: it somehow fixes the errors that might have been committed by flawed designs of the uniform regulated method of cost allocation of the regional network. This is discussed in the following section. Now we continue with more implementation recommendations.

vi) In the implementation of this process, it is recommended that countries are represented by their (independent) system operators, when they exist. Otherwise by their national electricity companies. The actual implementation concerning the regional transmission network will be responsibility of WAPP, under the supervision of ERERA.

vii) The choice of format of the transmission charge, i.e., whether it is charged as a lump sum once per year, or included in the regulated tariff – just added to its volumetric component ($/kWh) – or proportional to the nominal capacity of the generation plants ($/kW) or to the contracted capacity of a consumer, is important, since it will have an impact on the behavior of the agents. For instance, a volumetric charge ($/kWh) for a generator is proportional to its annual energy production and it must be considered by the generator as an additional variable production cost, therefore with impact in its merit order in an optimal economic dispatch. It is advisable that transmission charges to generators be applied as an annual sum whose value cannot be directly related to actual production volume.

2.3. Recommendations for the cost allocation method of the regional network.

Once the regional transmission network has been identified, a uniform method – i.e., one that applies all over the region, for cross-border lines and for regional lines internal to a single country – is needed to allocate the costs of all these assets to the countries. Note that we have accepted that some large projects, like the OMVG, can have their own cost allocation methods, which must allocate the costs to the countries, and not to network nodes or individual generators or loads. Now we shall focus on the design of the uniform regional method, which, if well designed, could also serve as a model for the cost allocation method of any exempt large transmission project.

Evaluation of current ERERA's method

ERERA has produced the "Adoption of the Tariff Methodology for Regional Transmission Cost and tariff", Resolution No. 006/ERERA/15, 2015, approved by its Regulatory Council on August 2015. This methodology still has to be tried on existing bilateral contracts, the procedures for its detailed implementation still have to be developed. The document is not in the list of regulatory documents in the website of the WAPP and therefore it cannot be considered at this moment as the current method in place. There is none. This also explains why the individual large transmission projects are developing and implementing their own cost allocation methods. We have found serious shortcomings and gaps in the methodology proposed by ERERA.

ERERA describes its Regional Transmission Tariff Methodology in the Resolution as "a point to point MW-Km load flow based Tariff methodology that is calculated for each and every regional bilateral trade within ECOWAS", in direct violation of our second basic principle (well established in the Internal Electricity Market of the EU, the Central American Electricity Market or the US power pools, as well as in numerous country regulations) that "transmission charges should be independent on commercial transactions".

The Regional Transmission Network is defined by ERERA as the ensemble of all interconnected assets whose service voltage is greater than 132 kV (or as agreed by ERERA) in the ECOWAS region, where interconnected assets are defined as all the assets that are regionally interconnected (between two or more countries). Contrary to this definition, in well-established power pools, lines that are internal to a country but that have significance in power trade are also considered as part of the regional network. Otherwise the regional network would be awkwardly connected, with a physically impossible layout, making it difficult to use it for any meaningful engineering analysis.

ERERA's Resolution also states that "a number of cost components can be recovered through transmission prices, including capital costs of network and equipment; operation and maintenance costs; losses; and congestion." The same document indicates later that "the two cost components to be recovered are: capital costs of network elements; and operation and maintenance costs." Note that, if the purpose of the transmission tariff is to recover the acknowledged cost of the transmission activity (i.e., its regulated revenue requirement), one must realize that losses and congestions *happen* in the transmission facilities but are not transmission costs. The investment, operation and maintenance costs of transmission facilities do not depend on whether the lines are congested or not, or whether the wires are hot or cold because of losses or another factor. Losses and congestion rents must not have an impact on the revenue requirement of transmission or the revenues of the System and Market Operator. This has to be clearly reflected in the final documents implementing this ERERA's Resolution.

In the determination of the annual revenue requirement for the regional transmission network, ERERA establishes that "for each element in the regional transmission asset database, a replacement value shall be agreed upon by the WAPP Engineering and Operating Committee. The replacement values are updated every 5 years (or as agreed by ERERA).” Given that the transmission facilities were built during some year T at the cost of that year T, remunerating the transmission company using the replacement values of these assets in some future year creates an unnecessary financial risk for the transmission investor, which, no doubt, will be reflected in its cost of capital and subsequently in the transmission tariffs.

ERERA establishes that the utilization that each bilateral transaction makes of the regional assets, will be determined by making use of load flows for the estimated peak generation scenario in the considered year. The detailed method is described in the ERERA’s Resolution, but it amounts to examining, for each bilateral cross-border transaction, its impact on the flow in each regional transmission asset. Although not mentioned in the Resolution – which does not contemplate exemptions – note that the assets belonging to any of the exempted transmission projects must be considered to have a zero cost for this year, but they must be included in the power flow analysis so that the flows make physical sense. Once the contribution of each agent involved in a bilateral transaction to the flow in each regional transmission asset is known, it is straightforward to allocate the annual cost of each asset to each agent. It remains the issue of how to allocate the fraction of each regional network asset that is not used by the bilateral transactions. The Regulation mentions the difficulty, but it is not clear how to solve it, although it states that the total transmission revenue requirement must be recovered by the tariffs.

In any case, as indicated before, this procedure is in flagrant contradiction with one of the firmest principles of transmission pricing, which is to ignore commercial transactions when determining transmission charges. The obvious undesirable consequence of ERERA’s approach is to overcharge the commercial transactions – therefore disincentivizing regional trade – when the benefit of the interconnections is more widely shared (remember: the cost of transmission must be allocated to its beneficiaries). Therefore, ERERA’s method is contrary to what is being tried to achieve, which is to facilitate regional trade.

Finally, the Resolution states that “the sum of the individual asset costs for each bilateral charge is paid by the purchaser of the regional bilateral trade.” Note that charging only to consumers is against the “beneficiaries pay” principle, since generators also benefit from the trade.[17] This flawed rule will increase the possibility of having adversaries to transmission projects that make perfect economic and technical sense.

In summary, the accumulation of charges in only those parties that engage in bilateral commercial transactions, and moreover, only on the consumer side of the transaction,

[17] This flaw cannot be fixed by aggregating the charges at country level, since countries with an excess of importing over exporting commercial transactions will carry the burden of the cost of the regional transmission network.

will certainly discourage cross-border trade and will make likely that some entities will oppose the construction of the line, since they will be worse off with it. In reality, trade among countries benefits also other agents beyond those who engage in bilateral cross-border transactions and a correct allocation of the transmission costs distributes these costs more widely than ERERA's method does. With rules that accumulate the costs in a small subset of users, only projects with a cost much lower than their total actual benefit will be acceptable to the majority or even all customers.

2.4. What to do instead? Our proposal for the cost allocation method of the regional transmission network.

This section is in full agreement with the previous "Implementation recommendations" section and its purpose is just to add to these recommendations by presenting a specific proposal on the method to allocate the costs of the regional transmission network to each one of the countries. The proposed approach does not violate any of the fundamental principle of transmission pricing that were enunciated before.

Implementation of this method requires the preparation of a suitable set of representative scenarios of the flow patterns in the regional transmission network. A network representation is needed, either the full one – i.e. with all lines and nodes, either regional or not – or just the regional network, with all the generators and loads being collapsed and aggregated in the regional network nodes. This representation must be provided by the regional System Operator, with the technical and economic characteristics of each transmission facility, and the estimated injections and withdrawals of power at each node for a number of representative scenarios for the year for which the cost allocation is being performed. ERERA proposes using just one scenario – the one with maximum energy production, but ideally, a larger number representing the diverse expected system conditions should be used.

The only engineering method that seems to make sense in this context – remember that any bilateral transactions must be ignored here – is one tracking the actual flows in each network component upstream and downstream to find its origin and end.[18] This method is called "average participations", and it has been frequently used in transmission costs allocation procedures.

For each generator and each load in each scenario, this method will determine how much it has used of the capacity of each facility of the regional transmission network, both in its own country and in the other ones. A simple mathematical procedure can be used to bring the data obtained from all the transmission facilities and all the scenarios into a list of numbers per country, indicating how much it has to pay of each

[18] We know that this does not correspond to the physical reality of how the electric energy actually moves from one point to another, but it seems the best that we can do.

individual facility. Alternatively, the method can provide a table of numbers, with the number in its cell indicating how much country j must pay to country k for the use of all the transmission facilities located in country's k territory.

If some large transmission projects have been exempted, it will be easy to add the results obtained with their individual cost allocation methods to the ones obtained by the method proposed here, making sure that numbers at always aggregated at country level.

Once the cost of the regional transmission network has been allocated to each country, the regulatory authorities know the total transmission revenue requirement for their respective countries for the year under consideration. Then the regulators can proceed to apply their internally adopted method to include the transmission component in charges to producers and tariffs to end consumers.

If a large transmission project, like the OMVG, is exempted from using the general cost allocation procedure, it is recommended that: i) considers the adoption of the approach described here, or at least its basic principle, in the hope that ERERA might reconsider its flawed current methodology, so that convergence to a single method might be easier; ii) avoids entering in conflict with the three fundamental principles of transmission pricing, as much as possible; remember that, even if the three principles might not be strictly applied (and perhaps in some contexts they should not) they should be always used a guide or be consulted in case of doubt.

Locational signals.

We examine now if it is possible to include some locational component in the transmission charges that result from the approach recommended here. This can be accomplished in two stages: with the regional network charges and with the national charges that remunerate the purely national (i.e., not regional) component of the transmission network of each country.

The regional transmission charges computed with the method just described will charge more to predominantly exporting countries located far from predominantly importing countries, and also to predominantly importing countries located far from predominantly exporting countries, than to countries that do not import or export much. Therefore, the national regulators should charge the regional component mostly to generators in those far and predominantly exporting countries and mostly to demand in those far and predominantly importing countries.

Similar principles apply at national level. A national regulator, with support from the national system operator, can apply a cost allocation method based on "tracking" the actual flows corresponding to representative scenarios of actual or simulated generation and demand. Now, in areas of the country where generation prevails over demand generators should be charged more. Conversely, in areas that import power it is demand that must be charged more. The regulator has to balance the additional complexity of these methods versus the estimated usefulness of sending locational signals. New generators – in particular solar and wind farms –are the best candidates to receive these signals, because they generally have more freedom than new demand to pick a site to deploy the plant. Locational signals are most effective for potential new generators looking for a site or for old generators doubting whether to retire or not. And, as our third fundamental principle tells us, the effectiveness of the signal stems from being known a priori and for a long enough period of time, for instance the next 10 years.

III. EVALUATION OF SOME METHODS PROPOSED FOR THE ALLOCATION OF THE COSTS OF THE OMVG PROJECT

We start by reviewing the basic available information about the OMVG agreements.

3.1. The OMVG agreements.

The OMVG power trade agreements (PPA)

The OMVG deal consists of the sale of power from Guinea to Senegal, Guinea Bissau and The Gambia. The three buyers booked for the next 10 or 15 years <to be verified> a maximum of annual generation of 803,000 MWh (Senegal), 204,000 MWh (The Gambia), and 167,000 MWh (Guinea-Bissau).

As it can be seen in the map, the OMVG line is actually a ring, with a large power plant connected to it (Smabngalou), in addition to Guinea or others. There are now a few connection points to the OMVG line in each country.

The buyers and sellers in this international trade are exclusively the National Energy Companies (NECs). There are or could be IPPs connected to the OMVG grid, or to the transmission grid connected to it, but at this moment all these generators are obliged to sell to the relevant NEC (Single Buyer) which then uses the OMVG grid. These current arrangements might change in the future.

The sale volumes are not fixed, but at the beginning of every production period, Guinea will make available all the power it can (up to the volumes indicated above) and the buyers will confirm which share of it they are able to accept within a determined and relatively short timeframe. Once it’s agreed, these volumes becomes fixed, with penalties that will apply to both parties if they are not respected. Each production period will last 12 months for the transactions with Gambia and Guinea-Bissau and 3 months for the transaction with Senegal.

The energy price (i.e., the PPA tariff) is equal to the purchase price for EDG (Guinea’s national energy company) from SOGES and SOGEKA (the two SVPs managing the hydro power plants of Kaleta and Souapiti in Guinea), which is $0.1071/kWh in 2021, with an escalation factor of 1.44%/year. EDG will not apply any commercial margin to these transactions. The price does not include technical losses.

The three contracts (one PPA for each transaction) have been signed in November / December 2019.

The OMVG Transmission Service Agreements (TSA)

Now that the three PPAs are signed, the finalisation of the Transmission Service Agreement for the right of utilisation of the OMVG line comes next. A draft contract has already been presented and some early feedback from the four NECs has been received. Negotiations are ongoing.

3.2. Comments on some proposed cost allocation approaches

#0. The original proposal

This is a proposal for the "internal" OMVG tariff methodology. The original approach proposed by OMVG and included in the draft TSA contract was based on "cash accounting[19]", which is the standard approach of Public Institutions, whereas "accrual accounting" is the methodology for private businesses.

According to its own proposal, every year OMVG would calculate its cash needs, based on forecasted OPEX, its debt service and any additional fees to be paid to regional institutions and possibly national governments[20]. This revenue requirement is then turned into a tariff based on the expected consumption during the year and it is charged to the four national energy companies (NECs) which purchase power on the OMVG line. OMVG does not have to consider amortization, inventories receivables and payables, like any public administration. Note that, by computing the transmission tariff on the basis of the demand in the cross-border contracts and not on the total demand of the countries, the method violates the second basic principle, i.e. transmission charges should not depend on commercial transactions. This is a serious flaw of the method.

Within this simple mechanism, NECs should make their payments at the end of each month, according to actual usage levels. Producers (at the beginning only Guinea) would not pay the transmission tariff (unless they are also purchasers; for example, if Guinea withdraws electricity on the OMVG to supply its cities connected by the OMVG

[19] Under the cash method, income is not counted until cash is received, and expenses are not counted until actually paid. Under the accrual basis, revenues and expenses are recognized when payment is made or received.

[20] Technically, they also foresee the possibility of a profit margin, but it is unclear what this profit should be used for, as OMVG is an international organization and not a private entity. Only "debt service" is mentioned, but the OMVG project must have some equity, and that equity will have a rate of return associated to it, either regulated (this is what should be) or agreed with the countries that will benefit from / use the line.

line). This rule violates the first basic principle, since both producers and consumers benefit from the OMVG project.

This methodology has other drawbacks, such as it does not handle volume risk and it does not consider the possibility that OMVG becomes a private entity subject to "accrual accounting". The first one is particularly important, as OMVG does not have any other source of revenues and is obliged to always cover its costs. This could be easily fixed with "after the fact" adjustments, as indicated in the recommendations. It is a straightforward fix that can eliminate this unnecessary regulatory risk.

The proposed methodology is unlikely to enable trade, as – particularly during the first years when little energy is expected to be exchanged - the unit cost of transmission will be very high (it will be a fixed cost divided by a small volume of commercial imported demand), hence reducing the advantage of selling hydropower from Guinea to the other countries.

As indicated in the recommendations, this classical problem of the initial low loading of a new large transmission project like the OMVG line can be dealt with in the following way: i) apply whatever allocation method only to the fraction of line actually used in a given year, plus some security margin; ii) socialize the rest in some simple way (nothing is simple here; perhaps in proportion to the total annual electricity consumption of each country; or its GDP).

The proposed method establishes that losses would be charged to purchasers up to a standard level. Any power loss beyond that level would become a financial burden for OMVG[21], which, however, does not have any source of additional revenues to cover these possible extra fees.[22]

An example has been provided, but some issues of interpretation of the data remain to be clarified. For instance, the example indicates that amount of revenues that have to be recovered each year through transmission tariffs will depend on the real volumes of energy imported, "due to the impact of variable costs". This is not understood, since actual transmission costs do not depend on physical flows.

The example indicates that when the volumes traded are 1,174 GWh/year, the annual costs to cover are about $ 40 million. Then it proceeds to make additional calculations

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[21] Within the current design, power losses should be a pass-through item.

[22] More information is needed to make a judgment on this part of the design of the cost allocation method. It is necessary to know the OMVG project was specified in terms of technical losses and if there was any incentive or penalty associated to the technical loss level. It is also relevant to know if it OMVG is expected to install capacitors, inductors or voltage regulators, or transformer taps or whatever other technical system to control voltage and losses and if the associated cost is included in the regulated revenue requirement or not. In general, it can be said that applying retroactive rules to transmission, with penalties or incentives not included in the initial contractual conditions, creates uncertainty in the revenues and it is not a sound regulatory practice.

that do not seem to have any justification. With the current PPA, NECS have indicated nominal trading volumes for 1,174 GWh / year. If actual trade is:

- 1,300 GWh/year, the unit transmission tariff is $ 3.4 cents/kWh or $34/MWh, which is a very high transmission tariff; it results in $44.20 million of revenue.
- 150 GWh / year, the unit transmission tariff is $27.4 cents/kWh; results in $41.10 million.
- 500 GWh/year, the unit transmission tariff is $ 8.4 cents/kWh.
- 2,500 GWh/ year, the unit transmission tariff is $ 1.9 cents/kWh.

The example (very poorly explained) apparently tries to show (as commented before), that if the entire annual cost of the project is charged to the actual power traded, the transmission charges will be: a) very variable with the volume of trade (or the income to OMVG will be very uncertain, unnecessarily); ii) too high, as the line is not fully utilized yet and the costs are only charged to commercial transactions. It is difficult to believe that agents that are able to agree on a complex project like this know so little about transmission regulation or have not bothered to ask or to find out what the best practices around the world are. Internet exists!

The example continues showing the impact of the proposed rules, with the anticipated unreasonable consequences:

As for the distribution of payment among countries, let's assume each country will withdraw the nominal amount indicated in the PPA with Guinea (for 1,174 GWh in total), plus Guinea will withdraw additional 126 GWh for its own domestic consumption, the four countries will contribute as follows:

Country	Volumes (GWh/year)	Tariff (c$/kWh)	Annual Payment (M $)	% of total payment
Senelec (Senegal)	803	3.36	27.0	62%
NAWEC (Gambia)	204	3.36	6.9	16%
EAGB (Guinea-Bissau)	167	3.36	5.6	13%
EDG (Guinea)	126	3.36	4.2	10%
TOTAL	**1300**		**43.7**	**100%**

As a result, with this methodology and these volumes, almost 2/3 of the OMVG line would be paid by Senegalese consumers alone. On the other hand, Guinea, which benefits by having new export outlets, would only pay for 10% of the total costs of the infrastructure.

As a final comment, again, there is no reason why generators must not pay the cost of transmission. Both demand and production should pay. The simplistic logic that "in the end consumers pay" is wrong. Besides, without charges to generators it is not possible to send locational signals to investors, which should consider the implications on transmission network reinforcements when they are considering siting a new plant.

In order to overcome the drawbacks of this original proposal, TBI agreed with the OMVG Secretariat to formulate alternative scenarios for the transmission methodology. Some of these are briefly discussed next.

#1. Tariff based on nominal contractual values

It is proposed to calculate the annual revenue cap for OMVG according to a standard methodology in line with the regional regulation and that includes the cost of capital on the Revenue Asset Base (net of grants received), depreciation, and OPEX.

The larger part of the annual revenues (those covering cost of capital and depreciation) is then recovered by OMVG on the basis of the nominal MW (or MWh) indicated by NECs in the PPAs signed, while OPEX are recovered on actual volumes. But, again, there is no reason to introduce uncertainty in the remuneration of transmission assets, whose annual cost we know quite accurately, and the regulation job is just to allocate it.

Moreover, this part of the method seems to be arbitrary. As indicated in the recommendations, there is no justification for the different treatment of CAPEX and OPEX, since there is no causality link between capacity and CAPEX and energy and OPEX. This rule might be related to the old methodologies of cost allocation of anything (generation, distribution, all the infrastructures) that associated fixed costs to capacity charges and variable costs to energy consumption. However, we see today that this has no economic basis; for instance, in wholesale energy markets the total generation cost (except for capacity payments when they exist, but they are not that important) is recovered by energy charges. It is noted, however, that even though the CAPEX/OPEX split is arbitrary, it is not harmful, as more or less both methods amount to the same allocation ratios.

It is important to note that also the exporters could use the OMVG line to supply their own customers connected to the line. These uses should be charged as well, so at the beginning of each year, exporters should submit their estimations for the usage of the OMVG line for domestic consumption in order to adjust the nominal values for fixing the tariff[23]. NECS will then be obliged to pay the volumes / capacity booked regardless of its actual usage, as a Take or Pay basis. However, if the usage turns out to be higher than what was booked, a compensation mechanism, such as a rebate for the other NECs, should apply.

[23] At the beginning, when the only source of production is Guinea, it's just EDG that needs to communicate this, as the three importers will use part of the power supplied by EDG to fulfil their national consumption.

All these further adjustments are fine, as they get closer to the approach that has been proposed for common cost allocation at WAPP level. What is more important is that the method ends up with a final charge for each country.

The mortal sin in this method, as in the preceding one, is to charge only to the capacity and energy being transacted, and not the total energies, thus discouraging trade by setting unreasonably high tariffs.

Another drawback is that this methodology still allows NECs not to book any capacity (or volumes) if they don’t want to at the beginning of each year. If little volume/capacity is booked, the unit tariff could be too high and discourage those willing to use the network and recreate the vicious circle leading to no use of the grid at all. If that happens, OMVG once again would need to recover its fixed costs through a fallback solution that could be a fixed payment from the NECs or the four governments.

In addition, exporters (at the beginning Guinea only, but in the future potentially also others) which benefit from the existence of the line are not charged. However, this could be a legitimate choice and it is adopted in other markets around the world.

In the numerical example that has been proposed, the per unit tariff and the breakdown of payments among countries remain the same as in the original proposal, but once they are set, they become fixed, regardless of actual usage. This statement needs clarification, as now the tariffs are computed in a different way, with per kW and per kWh components.

#2. Tariff with CAPEX paid as a fixed sum

In this method the annual revenue cap for OMVG is calculated according to a standard methodology in line with the regional regulation and that includes the cost of capital on the Revenue Asset Base (net of grants received), depreciation, and OPEX, as in the preceding approach.

The fixed costs (cost of capital and depreciation) are then charged as a fixed annual payment to the four countries based on some agreed allocation criterion. This fixed payment can be charged either to the NEC or the Government. Variable costs are charged to the NECS based on actual volumes. Same comment as in the previous method concerning the arbitrariness of the differentiation in the treatment of fixed and variable costs.

Obviously, most of the final result depends on the chosen allocation criteria for the fixed costs. One option would be to share the costs based on the financial liability of each country with the donors. These amounts are still under negotiations due to the need to cover project’s extra costs, however, assuming for simplicity the same original breakdown and annual fixed costs to be recovered equal to $ 43.7 million[24], here is how much each NEC (country) should pay, regardless of the real usage of the network:

Country	Share of Debt (%)	Annual Payment (M $)[25]
Senelec (Senegal)	38%	16.6
NAWEC (Gambia)	11%	4.8
EAGB (Guinea-Bissau)	16%	7.0
EDG (Guinea)	35%	15.3
TOTAL	**100%**	**43.7**

The main advantage of this methodology is the total absence of volume risk for the OMVG, which is correct, but it could be fixed easily in the other methods by an adjustment in the next tariff period. The proponents of the method consider that a drawback is the missing link with the actual usage of the network (except for the minor part covering the variable costs), but, given that the method of allocation of OPEX is fatally flawed, as indicated in the comments to the previous method, this is not an additional problem, really. The breakdown of the annual repayment among the four NECS is quite different from the previous method, as it was to be expected, given that the cost allocation methods diverge much.

The great advantage of this method is actually the result of a fortunate accumulation of design decisions without a sound economic justification. The method proposes that most of the transmission costs must be allocated to the countries, using some metric, but apparently not to the network users, or perhaps with some flat charge to all network users. This leaves a small part to be (wrongly) allocated to the commercial transactions, even from other countries in WAPP beyond the initial four. As this part is small, the resulting charge cannot do much harm discouraging cross-border trade. In the numerical example, the official OMVG transmission tariffs are in the range of $0.2 – 0.4 cents/kWh.

#3. Tariff included in the national regulation (no OMVG tariff)

Another, radically different option is to integrate each segment of the OMVG network into the four national grids and make NECs responsible for the management (and repayment) of it through their national transmission tariffs. The allocation to each country is therefore straightforward, although a country with a long distance of the

[24] For simplicity of comparison with Scenario 1.

[25] For simplicity we didn’t consider Variable Costs, as they should be < $ 1 m/year, according to OMVG.

OMVG line but not much benefit from trade might be unhappy with the allocation and block the deal.

It remains to determine how to charge the cost of the regional network assets internally in each country. One option would be to treat these assets as any other asset within the country's territory. But this is not what the method seems to propose. The method seems to propose (wrongly again, violating the second basic principle) that the assets belonging to the regional network must be allocated only to the agents involved in cross-border trade, using whatever method ERERA has finally established. This approach would entail the termination of the OMVG as TSO for this purpose, and the acceptance of the WAPP regulation for the allocation of transmission costs of the regional network – a method that has not been implemented yet. Thus, it is obviously of essence that ERERA's method be sound. As it was shown in section 2, this is not currently the case, by far.

In the numerical example the annual repayment will be split among the four NECs according to the economic value of the transmission assets in their territories, just like in the previous scenario. These companies will recover the costs (and the variable costs as well) through their national transmission charge (or electricity tariff in case of no unbundling) paid by their own final users.

The table below shows the summary of the forecasted annual payments according to the different methods and for the regional trade situation existing now; something that could change in the future.

Country	**Volumes withdrawn (GWh/year)**	**Annual Payment Scenario 0 & 1 (M $)**	**Annual Payment Scenario 2 & 3 (M $)**	**Delta (M $)**
Senelec (Senegal)	803	27	16.6	*-10.4*
NAWEC (Gambia)	204	6.9	4.8	*-2.1*
EAGB (Guinea-Bissau)	167	5.6	7.0	*1.4*
EDG (Guinea)	126	4.2	15.3	*11.1*
TOTAL	**1300**	**43.7**	**43.7**	

The annual payments are the same in Scenarios 0 / 1 and 2 / 3, however, the risk profiles and the cost allocation methods are different. Methods 0 / 1 would naturally penalise the larger importer, while the one based on the split of the fixed costs (asset-based, cases 2 / 3) would significantly increase the contribution of the exporter.

The methodology that would facilitate trading the most is the last one (case 3), with the termination of the OMVG as TSO and the integration of the segments of grid into the national transmission networks of the four countries. This option would minimise costs, simplify the management of the national and regional grids and facilitate international trading.

IV. FINAL COMMENTS

One must remember that a sound regulation of transmission cost allocation should: i) facilitate investment in transmission by reducing as much as possible any economic justification for the stakeholders to oppose a beneficial transmission project and by reducing any unnecessary risks in the agreed remuneration of the projects; ii) promote investment in generation by reducing the risk of future uncertain transmission charges; and iii) facilitate efficient trade by avoiding to charge enormous – and totally unjustified – fees to those who dare to establish bilateral contracts with agents in other countries.

All this can be accomplished by designing cost allocation rules that stay as close as possible to the three fundamental principles that have been stated at the beginning of section 2 and are repeated here:

- Transmission costs should be allocated to the beneficiaries of the transmission assets.
- Transmission charges should not depend on the commercial transactions among the power system agents.
- Transmission charges should be announced a priori and for a long period of time, so that economic risk for the agents is reduced and any locational signals are effective.

Finally, if possible, the regulation must avoid a multiplicity of methods for transmission cost allocation at regional level while, at the same time, not creating difficulties to the progress of necessary transmission projects because of not having the transmission regulation ready. This technical note has proposed a method to make compatible these two objectives.