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National
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PRINCIPLES OF REGULATING CLEAN ENERGY IN THE ECOWAS REGION



Working Draft

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The opinions expressed herein are those of the author and do not necessarily reflect the views of the United States Agency for International Development or the United States Government.

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Acronyms

ACG	Avoided Cost of Generation
ARE	Cape Verdean Agência de Regulação Económica
ARSE	Burkinabe Autorité de Régulation du Sous-secteur de l'Electricité
ARSE-Togo	Togolese Autorité de Réglementation du Secteur de l'Electricité
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CRSE	Senegalese Commission de Régulation du Secteur de l'Electricité
DSO	Distribution Systems Operator (also SO or TSO)
ECOWAS	Economic Community Of West African States
EREP	ECOWAS Renewable Energy Policy
EC	Ghanaian Energy Commission
ECREEE	ECOWAS Centre for Renewable Energy and Energy Efficiency
ERERA	ECOWAS Regional Electricity Regulatory Authority
EWURA	Energy and Water Utilities Regulatory Authority
GHP	Ghanaian Pesewa
GW	Gigawatt
GWh	Gigawatt Hour
FIT	Feed-in Tariff
HFO	Heavy Fuel Oil
ICB	International Competitive Bidding
IPP	Independent Power Producer
KW	Kilowatt
KWh	Kilowatt Hour
LCOE	Levelized Cost of Energy
LFO	Light Fuel Oil
LRMC	Long-Run Marginal Cost
MW	Megawatt
MWh	Megawatt Hour
NARUC	National Association of Regulatory Utility Commissioners
NGO	Non-Governmental Organization
NPV	Net Present Value
NREAP	National Renewable Energy Action Plans
NREP	National Renewable Energy Policies
OPEX	Operating Expenses
PURA	Gambian Public Utilities Regulatory Authority
PURC	Ghanaian Public Utilities Regulatory Commission
PPA	Power Purchase Agreement
PV	Photovoltaic
SE4ALL	Sustainable Energy for All
SO	System Operator (also DSO or TSO)
SPP	Small Power Producer
STC	Specific Technology Cost
TSO	Transmission System Operator (also DSO or SO)
TANESCO	Tanzania Electric Supply Company Limited
USAID	United States Agency for International Development
VAT	Value-Added Tax

WACC	Weighted Average Cost of Capital
WAGPA	West African Gas Pipeline Authority
WAPP	West African Power Pool

Executive Summary

The Economic Community of West African States (ECOWAS) Renewable Energy Policy (EREP) document adopted by the Authority of ECOWAS Heads of State and Government in July 2013 (following the October 2012 Regional Action Plan) introduced the development of renewable energy as an ECOWAS policy target.¹ EREP aims to increase the share of renewable energy in the region's overall electricity mix to 10% (2,425 MW) by 2020 and to 19% (7,606 MW) by 2030.² All ECOWAS member states are asked to introduce national policies and instruments to achieve the required targets. Regulatory agencies—at different levels according to their national mandate—are critical players in this process. The USAID/NARUC West Africa Regional Regulatory Partnership is supporting the integration of renewable energies in ECOWAS electricity systems by providing the regulatory authorities with this document, *Principles of Regulating Clean Energy in the ECOWAS Region* (*Principles*). This document is based on the lessons learned and experiences of regulators from Burkina Faso, Cape Verde, Cote d'Ivoire, Ghana, Mali, Senegal, The Gambia, and Togo. These regulators and experts examined issues in renewable energy and developed the *Principles* and the case studies contained therein, during three workshops held in Cape Verde (May 2013) and Ghana (October 2013 and April 2014).

The definition of renewable energy sources used in the *Principles* is based on the definition used in EREP, which includes solar energy, wind, hydro, geothermal, plant material, biomass and organic waste (bioenergy), wave, ocean currents, temperature differences in the oceans, and the energy of the tides.³ For the purposes of the *Principles*, however, the definition is restricted to “economically available renewable energies” such as solar, wind, hydro, and bioenergy for grid electricity supply, and the provision of access to energy services in rural areas.⁴

The *Principles* focuses on the regulatory aspects of integrating renewable energy sources into existing electricity markets. ECOWAS member states are at different stages of introducing renewable policies. Cape Verde, Ghana, Senegal, and The Gambia have approved or are in the process of approving renewable energy policies. Other countries have been focusing on anticipating market developments and building institutional infrastructures in response to the ECOWAS⁵ request for renewable energy targets. In the coming years, ECOWAS member governments will be introducing renewable energy policies in their respective countries and defining mandates for the national regulatory authorities or agencies. In this context, the inventory of fundamental assumptions, approaches, mechanisms, tools, best practices, and national experiences on key issues in the field of clean energy provided in the *Principles* should prove very useful.

Though the *Principles* is not a technical manual, it includes some formulas and regulatory mechanisms. It provides an opportunity to identify and understand the reasoning behind the main regulatory decisions and to examine the implications of those decisions in specific contexts. The *Principles* is designed to help decision-makers in the energy sector who are trying to determine the appropriate methodology to choose for setting, defining, and updating purchasing prices, connection rights and costs, and balancing rules.

ECOWAS, which encompasses a population of three hundred million people, is an economic region with significant potential to attract investment in renewable energy. The process of establishing a regional electricity market has begun, but the various electricity systems in the 15 member states have different market structures and rules. Integrating the electricity markets as well as regulatory and technical rules would be advantageous for ECOWAS member states. This level of integration will

take time to develop fully; however, any lack of harmonization at the regional level should not obstruct the integration of renewable energies into existing national electricity markets.

The electricity systems in most ECOWAS countries are vertically integrated and dominated by national utilities. Because the few IPPs that exist are confined to a handful of power purchase agreements (PPA), there are a limited number of active stakeholders in the electricity sector. Evidence from around the world indicates that renewable systems are usually developed not by existing national electricity companies, but rather by new players investing in the sector: national or international enterprises, public or private companies, local distribution utilities, large electricity consumers, cooperatives, banks, or municipalities. They do not replace existing electricity companies but exist alongside them and contribute new resources to the electricity system. Typically, some degree of liberalization in the energy generation sector is a prerequisite for the introduction of renewable-friendly legislation to allow IPPs to enter into the market. However, even without new legislation specifically focused on renewable energy existing legislation might give the regulator enough powers to facilitate renewable energy integration.

The *Principles* outlines general standards of regulation for renewable energy sources, focusing on the role of regulatory authorities. While the *Principles* focus on renewable energy specifically, many of the regulations and issues discussed would also hold true for regulation in general. However, the introduction or expansion of renewable energy into a traditionally fossil fuel-based energy sector generally requires institutional capacity building of the regulatory authority and other relevant agencies and offices. The introduction of a specific renewable energy policy spurs many changes in the electricity sector: authorities are called to set prices and incentive schemes and update them, recover costs through final consumers' tariffs, regulate grid access, and establish rights and costs for connections. It is very difficult to anticipate the full range of implications and consequences at the beginning of the process. ECOWAS member states can learn from other countries' experiences, but must also address issues specific to their local contexts.

Section I of the *Principles* describes how to establish a strong institutional environment in which roles and responsibilities are clearly defined among the three main actors: the government, the regulator, and the grid operator. The Ghana case is used to illustrate the usefulness of establishing a steering committee to guide the implementation of a renewable energy policy in the electricity market. This first section also provides examples of how the adoption of consultation practices and impact assessments can strengthen key regulatory decisions. Those instruments help to (1) facilitate the decision making process, (2) impart lessons learned from the experiences of different stakeholders, and (3) identify potential problems and mistakes that are often discovered only later in the process.

Section II of the *Principles* focuses on the economic rules of regulation, addressing specifically the issue of pricing and remunerating renewable energy sources. Introducing a feed-in mechanism is possibly the most effective option to promote renewable energy sources within ECOWAS electricity markets, which are currently characterized by limited competition in the generating and supply sectors and by the small size of national markets. Net-metering is also an effective way to promote renewable energy sources because unlike a feed-in mechanism, it only requires one meter to net the generation and usage. Usually, investors consider a regulated Feed-in Tariff (FIT) and net-metering to be less risky than other remuneration instruments, such as green

certificate systems. As the ECOWAS national regulators participating in the workshops were most interested in the feed-in mechanism, the *Principles* chose to focus on this issue – however, this is not to say that other mechanisms might not be equally suitable. For further information on additional mechanisms (such as renewable energy auctions) NARUC has published a Handbook for regulators – *Encouraging Renewable Energy Development: A Handbook for International Regulators* (available on NARUC’s website).⁶

Capital risk is the greatest barrier to the penetration of renewable energy sources. One of the roles of the regulator is balancing of investor risk with the need to protect final users from excessive and improper electricity costs. It is important to note, that when the generating costs of renewables is the same or lower than those for fossil fuel and there are no systematic offsetting risks, there is no reason to restrict access to the market, both in developed or in developing countries. Introducing a FIT that is based on the principle of avoided cost of generation—probably the easiest method to adopt—requires the regulator to run an accurate near term and long-term cost assessment of both the existing generating infrastructure and a new generating unit. The marginal generating cost of the new generating unit is closely evaluated. When regulators run the cost assessment they must pay close attention to potential hidden costs such as fossil fuel volatility and direct or indirect incentives and subsidies to fossil fuel, costs which are paid back by the national budget. However, depending on the national context and priorities, a FIT based on technology-specific costs, rather than avoided costs, might be a more effective methodology.

This section lays out the principles to consider when choosing between a FIT based on the avoided cost of generation and a specific technology cost methodology. Case studies from Ghana and The Gambia as well as examples from Tanzania, Germany, and Italy are used to illustrate mechanisms for tariff setting and updating. While there are many ways to design a feed-in mechanism, no one mechanism is optimal in absolute terms. This section provides an overview of issues to consider before choosing one methodology over the other. It is critical to choose a transparent, comprehensible mechanism that is based on a sound and clear methodology. To reduce as much as possible the risk and uncertainty for investors, a feed-in mechanism must be comprehensive, and clearly identify institutional roles and responsibilities. It is advisable to begin the process using a simple FIT design.

To prevent unnecessary delays and litigation, this section suggests that regulators can facilitate renewable energy projects by introducing a standard format for Power Purchase Agreements (PPA), adopted by all parties involved. Other options for promoting renewables may include net-metering. Net-metering regulates the exchange of electricity between final consumers and the public utility. If they are not provided through legislation, regulatory authorities may introduce net-metering options through regulation, thereby enhancing the small Photovoltaic (PV) market, for example, at no cost to the system. The impact of a renewable policy on final tariffs must be monitored by means of an impact assessment to help the regulator evaluate the different variables, particularly the costs and benefits of the system. As described later, the regulator must also evaluate the impact of cross-subsidies caused by various tariff designs and net-metering policy schemes. The capacity to control system costs offers opportunities to make more useful investments in long-term projects such as employment, security of supply, growth, and the environment at the national level.

Section III of the *Principles* covers the concept of defining connection rights and connection costs methodology, topics that will involve significant participation by regulators. The

regulator must ensure that a transparent and non-discriminatory procedure is in place to connect generation sources. Connection rights of Independent Power Producers (IPP) must be affirmed by legislation and regulators must incorporate the technical and economic specifications of renewable energy connections into the national grid code. The grid code contains technical standards for production units wishing to connect. Usually the technical requirements are defined jointly by the regulator and the system operator (SO), and are made available to the public through a regulatory order. The grid code sets the parameters for high, mid, and low voltage connections. Users who respect those parameters may access the grid without restrictions, except when the lines the IPP wants to connect to are congested and the available capacity is limited. When necessary, the regulator must establish rules to access limited connection capacity and institute a queue management procedure which can be based on a first-come, first-served principle or based on bids.

In connection rights regulation, details are very important. The timing of plant commissioning must be defined by regulation and by means of a standard connection contract. Regulators may also be called upon to verify financial backing of potential investors to avoid assigning connection rights to developers incapable of financing the construction of plants. Connection costs involve two components: shallow connection costs, in which plant developers pay only for the connection from their installation to the closest substation, and deep connection costs, which also requires developers to pay for costs associated with reinforcing the grid after the new production unit has been connected. Shallow connection costs are the easiest to establish. In vertically integrated electricity systems, the regulator must ensure that the incumbent is not discriminating against new companies trying to access the electricity market by introducing improper obstacles to new plant connections.

System balancing is another key consideration. Costs to balance some renewable technologies are highly unpredictable. Asking renewable energy producers to bear balancing costs could increase investment risk considerably. The higher risk will be reflected in higher renewable tariffs, making the renewable support scheme more expensive than in a scenario where balancing costs are socialized and other measures are in place to reinforce system stability. ECOWAS aims to increase the ratio of renewable energy to 10% of the region's overall electricity mix by 2020 and to 19% by 2030.

Section III also includes a list of regulatory and policy measures that can be used to strengthen system reliability and thereby safely dispatch a higher quota of renewable generation. With photovoltaic (PV) technologies, for example, opting to build more small plants instead of just a few larger ones would augment system stability without significantly increasing development costs. Similarly, opting to diversify the technologies of renewable generation instead of only encouraging PV technologies would augment system stability without significantly increasing development costs.

Document Purpose and Objectives

The *Principles of Regulating Clean Energy in the ECOWAS Region* was developed through the USAID-NARUC West Africa Regional Regulatory Partnership under the auspices of the USAID/West Africa Regional Mission. USAID's *Climate Change and Development Strategy 2012–2016* emphasizes the importance of establishing low carbon energy systems, increasing the incorporation of renewable energy and low-carbon fuels, and improving energy efficiency in existing energy markets.⁷ The strategy also underscores that “large-scale investments in clean energy will require an enabling environment that includes appropriate policies, laws, regulations, and institutions; and successful adaptation efforts have long been rooted in participatory, stakeholder-driven processes.”⁸

The purpose of the *Principles* is to complement and support these goals by providing ECOWAS regulators a practical guide to facilitate the integration of clean and modern energy practices into evolving traditional energy markets. The document provides regulatory agencies and policy makers an inventory of fundamental assumptions, approaches, mechanisms, tools, best practices, and country-specific lessons learned on key issues in the field of clean energy. Designed to be a resource for the entire ECOWAS region, the *Principles* incorporates best practices based on local context and takes into account energy markets, natural resources, social and environmental priorities, and other region-specific factors.

NARUC is working with the ECOWAS Regional Electricity Regulatory Authority (ERERA), the West African Gas Pipeline Authority (WAGPA), and the ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE) to examine clean energy regulation in selected ECOWAS countries and to identify the existing needs and the foreseeable challenges facing regulators in the region in the coming years. In 2012, ECOWAS organized several projects to help promote the establishment of a regional framework for the implementation of the Sustainable Energy for All (SE4ALL) initiative. Those projects focused on enhancing renewable energy and energy efficiency practices in electricity markets. During this process, in October 2012, ECOWAS Energy Ministers adopted a regional-scale action plan, a policy document that sets renewable energy targets in the region and advocates for the introduction and consolidation of renewable policies and strategies at the member states' level. Some states have already introduced, or are in the process of introducing, specific clean energy support mechanisms. Regulation will play a major role in this transformation of the energy and electricity markets in the ECOWAS countries.

An initial group of five electricity regulatory bodies from the region with experience with renewable energy policies and regulations participated in the development of the *Principles*: the Cape Verdean Agência de Regulação Económica (ARE), the Senegalese Commission de Régulation du Secteur de l'Electricité (CRSE), the Ghanaian Energy Commission (EC), the Gambian Public Utilities Regulatory Authority (PURA) and the Ghanaian Public Utilities Regulatory Commission (PURC). This document blends NARUC's experience in clean energy policy and regulation with specific case studies from the participating countries. The document was richly informed by information sharing and dialogue at three technical workshops organized by NARUC in Praia, Cape Verde, in May 2013, and Accra, Ghana, in October 2013 and April 2014.

In many countries, the development of policies and market mechanisms to promote clean energy development is a relatively new concept. Most electricity systems in ECOWAS countries are vertically integrated, that is, national companies provide electricity services at all stages of the system:

generation, transmission, distribution, metering, and sale. Although renewables may be developed within in the existing national electricity industries, the introduction of clean energy policies often coincides with the opening of vertically integrated markets to independent power producers (IPP). This process requires elaboration of a legal framework that extends beyond the integration of renewables into existing electricity markets. This enables regulation of the access of IPPs to the generation sector. Specific secondary-level legislation and regulations must be developed to make this integration possible. Each state would adopt country-specific primary legislation; subsequent secondary legislation and regulation will be specific to each context. While the resulting energy and electricity markets will vary from country to country, and regulatory agency mandates will be dissimilar, some countries have made progress adopting and implementing renewable-friendly legal frameworks and their regulatory experience may be of value for countries contemplating similar action. However, many of the main principles for integrating renewable energy will be the same. As most of the countries identified are just beginning the process of market development and integration of renewable energy, as much harmonization as possible would benefit the ECOWAS region as it becomes more attractive to investors.

To help establish an efficient electricity market, regardless of the amount of work imposed by this process, regulators must advise, support, collaborate, and share their knowledge with policy makers, market players, consumers and other stakeholders. Although this document is based on four country-specific case studies (Cape Verde, Ghana, Senegal, and The Gambia), there is no best way to develop clean energy regulations. A legal framework is based upon many different local, national, and regional ingredients, market designs, priorities, challenges, and governance structures. To establish efficient and effective clean energy markets, policy makers, institutions, and market players must share experiences and technical knowledge. We hope that other ECOWAS national regulatory bodies will use those experiences as a starting point to adopt similar measures within their own political and regulatory contexts.

Section I. Key Principles

The key principles of renewable regulation are presented in the order that they appear in this document: roles and responsibilities, remunerating renewable energy, connection and balancing rules, and consultation and impact assessment. Many of these principles apply to regulation in general and not only to regulating renewable energy. Moreover, these principles are not static. When regulations need to be modified, the principles that underpin them should be updated as well; the *Principles* is designed to be a living document.

A. Roles and Responsibilities

- **Recognize that the development of renewable energy is a national economic and energy policy objective** that can have positive impacts on national employment, local industry, security of supply, and environmental health (particularly with regard to climate change). Such recognition has been expressed at the ECOWAS level. Additionally, it opens the market to investors – even more so if harmonization of rules in the ECOWAS region allows for access to a regional market.
- **Devote sufficient financial and human resources to implement renewable energy regulation** because it is a new concept that can pose significant challenges for national authorities.
- **Clearly identify competent entities to manage the electricity sector and define connection rights.** A comprehensive legal framework must be based on some basic rules, and coordination among ministries, the regulator and the system operators is a precondition for the development of an effective renewable energy market or in liberalizing the sector in general.
- **Reduce regulatory risks as much as possible by promoting transparent and well-defined regulations.** Because capital investments comprise the largest proportion of the total costs of renewable energy production, renewables are very exposed to market and regulatory risks. A strong regulatory framework makes the market more predictable and provides market participants with the information they need to formulate their market analysis and assumptions. When market players believe risk cannot be clearly evaluated or is too high, they will not invest capital or they will demand a high capital cost or governments guarantees before they will invest. High risk is a common barrier for renewable development, which is true for all IPPs.
- **Design policies that can adapt to changing circumstances and that include price signals for markets.** Because renewables investments are paid back over a long period of time, regulatory stability is vital to customers, the utility and inspiring investors. Evidence from around the world indicates that while undertaking regular regulatory reviews can promote investor confidence and be an effective way to attract investment, retroactive policy changes can deter it.
- **Absence of new renewable energy legislation should not be seen as absolutely precluding renewable energy regulation developed and implemented by the regulator.** Some of the ECOWAS member states already have renewable energy legislation in place. However, sometimes legislative change is a difficult and lengthy process. It might be therefore a good first step for the regulator to use its existing powers (if allowed by the existing framework) to support renewable energy until new legislation can define the regulator's role more clearly.

B. Remunerating Renewable Energy

- **Most existing electricity markets must be transformed to some degree to better integrate renewables.** In some contexts the modifications can be made at no cost to final consumers. At cost parity, renewables should be valued over fossil fuel energy sources based on other attributes, such as low-carbon impact and rate stability.
- **Some renewables require economic support to develop.** Incentives should be weighed against other national priorities without delivering excessive remuneration to investors. Regulatory agencies may be asked to design and monitor the implementation of incentive schemes.
- **There are many ways to incentivize renewable development.** Incentives are economic and/or technical. Governments introducing national legal frameworks for renewables often call upon regulators to support and implement incentive policies in electricity markets. In some cases, regulatory decisions may deliver implicit incentives to renewables. Promoting national industry is a common way to help develop renewables. Specific incentive schemes favoring national industry and products can be tailored to this objective, but should not involve the introduction of trade restrictions on imports of renewables technologies, which could delay the overall growth of the renewable sector. The regulator should encourage favorable Backup or Standby Service provisions, so that national industries with the financial means for self-generation contribute to the costs of the system. This helps the national utility recover its fixed costs even when electricity is not being provided. Consequently, the national utility is better positioned to incentivize renewable development.
- **Feed-in Tariffs (FIT) or market mechanisms (e.g., green certificate systems) can be used to remunerate renewable electricity.** Considering existing and evolving legislation in ECOWAS countries, a FIT may be an appropriate mechanism to remunerate renewable electricity. There are a variety of methodologies to set up FITs, but the two used most commonly are based on the concepts of avoided cost of generation and technology-specific cost. The former remunerates renewables based on generating system cost, while the latter sets an FIT according to the cost of specific renewable technologies. Because there are advantages and disadvantages to both methodologies, legislatures and regulators should choose incentive schemes that operate most effectively within the framework of national energy priorities and objectives.

C. Technical Connections and Balancing Principles

- **To allow IPPs to enter the market, the generation sector must be open.** This is possible even in a vertically integrated electricity industry. When markets are vertically integrated, the regulator facilitates the integration of renewables into the existing markets, specifically by establishing connection rules that prevent the incumbent from initiating discriminatory practices.
- **Pricing and regulations should balance a fully cost-reflective approach as well as the need to socialize costs in order to enable utilities to reform existing infrastructure and render the overall system more suitable to dispatching future renewables.** In the process towards establishing cost reflective tariffs, regulators should bear in mind that the existing transmission network has been built largely for dispatching electricity generated by centrally located non-intermittent resources. The future electricity networks

will, on the contrary, likely see the participation of different technologies, especially renewables. The cost of upgrading the system as a whole should not be taken as the cost of connecting new plants. For this reason, defining connection rights and connection costs (shallow or deep costs) is one of the most difficult tasks for regulators, while preserving the cost reflective principle, as it is not always clear which costs are introduced by a new connection and which other costs are in fact a necessary development towards a modern system

- **The development of renewable capacity is often achieved with a combination of small and large power plants.** In selected areas of a country endowed with renewable potential, commission not only large power plants but a number of small power plants with different technologies as well. Establish this development pattern by allowing IPPs with various technologies to access the generation sector and by adopting an easily accessible grid code. Regulators should consider requiring utilities to submit an integrated resource plan. This plan includes a forecast of the load and generation capacities, allowing for the regulator to understand potential impacts of renewable energy generation in the future.
- **Regulation has to accommodate the market's need to respond to new circumstances, prices, technologies, and the renewable energy investor's desire for stability.** FITs and net-metering schemes are dynamic because they allow regulators the opportunity to respond to changing circumstances, prices, and technologies. Consequently, the regulator can deviate from a strictly cost-based principle and consider other approaches. However, it is important to reduce investment risk by establishing a clear process for responding to circumstances impacting various renewable energy schemes. Investors will accept lower capital remuneration in markets they feel confident investing in. Balancing cost is an example of this. When renewable producers are required to pay balancing costs, they tend to ask for higher remuneration on their investment given the unpredictable balancing risk. As a result, the overall system costs will be higher. However, there would be no balancing cost with a diversified renewable energy portfolio, appropriately located distributed resources, and predictable technologies.

D. Consultation and Impact Assessments

- **Decisions about renewable energy must be informed by both consultation processes and impact assessments.** The consultation process must be transparent and include all stakeholders. Regulators can undertake an impact assessment that is not as resource intensive as an assessment done by the regulator, but the outcome should identify the parameters of the impact assessment, which is an exercise that tests the proposed regulation within a given period of time in order to anticipate potential costs and benefits of a new decision. In fact, the impact assessment enters into the decision-making process itself by helping the decision-maker quantify the impacts of a proposed regulation. Today's investment in renewable energy will shape tomorrow's electricity market in numerous ways.

Section II. Selected National Renewable Policies and Harmonization in the ECOWAS Region

A. National Renewable Policies in Selected ECOWAS Countries

There are different mandates, roles, and responsibilities for each regulatory agency tasked with designing clean energy market rules and remuneration mechanisms. Primary legislation in each country establishes the policy objectives, targets, and basic legal framework for each regulator. Regional policies and directives can have a strong influence over national legislations, as is the case in the EU, for example. In other contexts, however, like the ECOWAS region, some guidance and non-mandatory clean energy targets are provided at the regional level, but member countries are free to choose the policy instruments and incentive mechanisms they determine to be appropriate. With the guidance of the regional regulator, it would be advisable, however, to establish a consensus on key points so that more regional harmonization can be achieved.

Cape Verde

In terms of the amount of clean energy capacity installed, Cape Verde is arguably the most advanced renewable market in the region. National policies in most archipelago islands strongly promote the installation of renewable energy because of the high cost of fossil fuels and the abundance of renewable resources (wind and solar). Existing power plants have been constructed under PPA agreements signed between the IPP and the national electricity company. The PPA defines the long-term purchasing price, a methodology for updating the price and the connection cost. The purchasing cost (fixed slightly below the avoided cost of generation for the national electricity company) is then incorporated into the final tariff by the Cape Verdean Agência de Regulação Económica (ARE). Connection parameters have been agreed upon by the parties. The island's System Operator (SO) manages system balancing directly with the plant operator. The role of ARE in regulating existing renewable plants has thus far been limited. The government has ambitious renewable targets,⁹ and has approved a new legal framework for clean energy in 2011. However, the secondary regulations with details to electricity remuneration, a methodology used to pay back investments, grid code, and balancing rules must still be defined. In the beginning of 2014, the mandate of ARE concerning renewable energy regulation has been reinforced to give the regulator a more relevant role in this process. The development of additional renewable capacity in Cape Verde introduces new challenges: balancing renewable energy, diversifying renewable technologies, building storage infrastructure, and integrating renewables with water treatment processes.¹⁰ These challenges could be addressed by introducing advanced tariff schemes. For example, Cape Verde is considering a residential capacity charge to help reduce the system peak and encourage net-metering. Cape Verde's legislation does provide a net-metering option for small power producers,¹¹ but because connection rules have not been defined only some pilot projects have been implemented so far.

Ghana

Ghana adopted the Renewable Energy Act (Renewable Act) in 2011. According to Article 5 of the Act, the Ghanaian Public Utilities Regulatory Commission (PURC) is responsible for setting renewable tariffs. The primary legislation does not specify which methodology or what level of tariff should be introduced, nor does it set a deadline for the approval of a renewable tariff. The regulatory agencies PURC and EC¹² have developed a FIT scheme for different renewable energy sources and implemented a consultation process for the proposed renewable tariff. In July 2013, PURC published

tariff levels for various renewable energy technologies. Some implementation rules have not yet been developed and are under discussion. PURC approved a grid code in 2009,¹³ but it does not include specific provisions for renewable plants. Ghana is considering the introduction of a market for capacity reserve and regulation of renewable energy balancing and has approved an advanced policy for promoting energy efficiency. This policy was developed in association with a consultation process and an assessment of the impact of regulation, providing a potential best practice example for other ECOWAS countries.

Senegal

Senegal is the first country in the ECOWAS region to have adopted, in 2009, a specific law to support renewable energy penetration into the electricity market. The law postpones the approval of specific support mechanism details, which will be addressed in future pieces of legislation. During the two years since the law was approved, the Ministry of Energy was designated to be the counterpart of private enterprises for renewable energy PPAs. The Senegalese Commission de Régulation du Secteur de l'Electricité (CRSE) defines connection rules based on the non-discriminatory grid access code (Article 13) as well as the purchasing price of electricity, although the purchasing rules must be defined through legislation (Article 14). The law also introduces various measures for fiscal incentives and tax exemptions that favor renewable technologies and enterprises, and establishes the right to produce electricity without restrictions from renewable energy sources for self-consumption.¹⁴ However, a comprehensive legal framework to promote renewable integration into the existing electricity market needs to be defined.

The Gambia

In December 2013, The Gambia adopted a renewable law that defines most of the elements needed to create a favorable legal environment for renewable energy. The approved pricing methodology is based on avoided cost of generation of the long-term marginal cost of a new oil power station. The legislation defines the methodology to update the tariff as well as a renewable energy capacity threshold and the overall renewable energy penetration percentage. The Gambian Public Utilities Regulatory Authority (PURA) is responsible mainly for applying the avoided cost of generation (ACG) formula within defined deadlines. The legislation already includes connection and PPA contract templates. The legal framework will be completed with the introduction of technical standards for the connection of renewable energy capacity, and specific guidelines are now under development. PURA is also currently in the processes of finalizing a FIT together with the relevant stakeholders.

B. Harmonization in the ECOWAS Region

The most efficient way to develop a renewable energy market is usually in large regional markets rather than in smaller national ones. Regional energy markets have the following technical, economic, and policy advantages:

- A regional energy market would attract more foreign investment into the entire region. Small markets do not attract foreign investors because the limited opportunities are not worth the learning cost to enter the market. Once an adequate level of harmonization is reached in a larger region, investors will find it a more favorable environment in which to operate.
- Defining economic and technical rules is a precondition for regional grid integration. More interconnections, in turn, facilitate access to larger renewable potentials unevenly distributed among countries.
- A regional energy market would provide for the introduction of a standard legal framework that would establish common guidelines for renewable energy. The framework would serve to accelerate the legislative process at the country level and facilitate information sharing along with identifying common barriers.
- A regional energy market would support smaller countries that have yet to establish a clean energy policy by providing a standard set of policies, rules, targets, and lessons learned from other countries.
- Developing renewable energy technologies over a larger area would enhance the position and importance of ECOWAS in the international market, and create more opportunities for new local enterprises in the renewables sector.
- Energy markets also benefit from a comprehensive economic integration within the ECOWAS area. The harmonization of fiscal and import rules, and the process of convergence toward a stronger monetary integration in particular, will facilitate better access to renewable and energy efficiency technologies and create a safer investment environment. A regional market can harmonize intermittency in the system by accommodating the development of various renewable energy technologies. Consequently, the system becomes more reliable and less risky for prospective investors.

ECOWAS has already taken the following steps to integrate energy and electricity markets:

- The ECOWAS Energy Protocol was approved in 2003 (A/P4/I/03) in order to establish a legal framework that promotes long-term cooperation in the energy field.¹⁵
- ERERA was established to facilitate the adoption of provisions that establish appropriate legal and institutional frameworks for the development of the electricity sector in West Africa and regulate regional cross-border trade of electricity in West Africa.¹⁶
- ECREEE was established as the center for renewable energy in the ECOWAS region.¹⁷
- The West African Power Pool (WAPP), which represents 14 of the 15 ECOWAS member countries, was established to ensure regional power system integration and the development of a regional electricity market.¹⁸
- The Authority of ECOWAS Heads of State and Government approved EREP in July 2013. EREP aims to increase the share of renewable energy in the region's overall electricity mix to 10% in 2020 and 19% in 2030.¹⁹
- An action plan was adopted within EREP that contributes to the achievement of the 2020 and 2030 regional ECOWAS targets by requiring all 15 ECOWAS countries to adopt National Renewable Energy Action Plans (NREAPs) and policies (NREPs) by the end of 2014.

The development of renewable energy in itself may also afford the opportunity to integrate and harmonize ECOWAS energy markets more quickly. Initially, however, energy policy—specifically renewable energy policy—may not mesh well with the larger process of market and policy harmonization within ECOWAS countries, although the perceived lack of harmonization should not be interpreted as a reason to delay the development of renewable energy markets in each country.

Section III. Integrating Renewable Energy into Existing Electricity Markets

A. Roles and Responsibilities

The clear identification of roles and responsibilities within a national legal framework or in a regional context is critical to the success of renewable energy legislation. Because renewable energy policies are strongly influenced by the national electricity market structure, the design of support mechanisms must accord with market fundamentals. For example, the mandate of a regulatory agency ranges from defining specific technical and economic aspects of the renewable energy market to broader involvement in developing the renewable energy policy and support mechanisms. There is no one specific model to follow; each state is forging its renewable energy strategy differently depending on local market characteristics, the level of liberalization of the energy sector, previous experience with renewable energy, and the existing policy framework. However, a comprehensive legal framework must incorporate certain basic elements and clearly identify the responsible entity, agency, ministry, etc. responsible for managing each element. Coordination among the relevant ministries, regulator, and the system operators is a precondition for an effective renewable energy market.

One of the roles of a regulator is to introduce rules and codes, such as rules for integrating new power into the existing electricity market. This is especially important because the introduction of renewable incentives often coincides with at least a partial liberalization of the generation sector and the introduction of IPPs. To support proposed changes in laws and then supporting related rules, the regulating authority might find it advantageous to establish a renewable energy office or department to strengthen renewable energy policy implementation and integrate renewable energy regulation with existing market mechanisms and technical rules.

Table I: Checklist of Roles and Responsibilities for a Comprehensive Renewable Energy Legislative Framework

Action Item	Description/Comments	Responsible Entities
Establish renewable dispatching priority	This is a basic requirement of a renewable energy supportive market. Renewable energy investors must be certain that the system will accept their electricity when the renewable source is available.	Legislation introduces the principle and the regulator implements the principle.
Identify a buyer for electricity generated by renewables	The buyer may be the local public utility, the SO, a single buyer, or a final customer, depending on the structure of the electricity market.	Legislation identifies the process for selecting final buyer and sets obligations. The regulator monitors the system.
Create a mechanism to update the purchasing price	Updating must be done because the economic value of electricity, which varies over time, must be determined. The updating mechanism may include many variables and differing priorities. The mechanism must clearly identify when and how often the tariff should be updated, and who should update it.	Legislation provides the general framework and deadlines and mandates the system regulator to update the price.
Specify whether changes are affecting old or new renewable energy generation	When rules are changed, the regulation should stipulate the date the change becomes effective and if this change applies only to newly commissioned plants or also to existing plants.	Primary legislation
Publish a standard PPA template setting the contractual standards between the seller and the buyer	Market players do not always welcome the introduction of new producers. The PPA may help prevent unnecessary delays in commissioning renewable energy plants.	The regulator may prepare a standard PPA if this is not done by the legislation , with input from all parties.

Action Item	Description/Comments	Responsible Entities
Create a mechanism to pay back renewable energy buyers under obligation	Resources for this mechanism, which must be put in place, are usually derived from the electricity tariff. The buyers under obligation are usually public utilities.	The regulator should create and manage the mechanism, introducing a renewable component on the tariff if necessary.
Ensure that the renewable energy buyer is financially stable	In countries where final electricity tariffs are not cost reflective, it is important to assure long-term financial stability of the final buyer.	Legislation defines general rules. The regulator may establish procedures to assure payment timing and regulate delays. The regulator may also establish a specific fund to manage renewable incentives.
Regulate access to the grid and support grid connection rights with a transparent grid code	The grid must be regulated from a technical and economic perspective. Technical grid connection parameters for IPPs must be available and accessible.	The regulator and the SO set the parameters. The regulator approves and publishes the grid code.
Introduce rules for paying connection costs	A general framework on a proposed grid development strategy must be made available. Costs of new grid development and reinforcement should be identified and shared among market players.	Legislation defines the principles. The regulator plays the largest role in crafting methodologies and procedures for connection costs.
Define rules to assign connection rights	This is particularly important when the grid capacity is limited.	The regulator usually defines the rules.
Introduce rules to balance fluctuations within a safety margin	Variable renewable energy plants may cause fluctuations in the electricity system. Establish a comprehensive strategy to integrate variable renewable energy needs.	Legislation usually defines the general principles and strategy. The regulator introduces market instruments that adequately improve network stability.

Action Item	Description/Comments	Responsible Entities
Introduce a second-level support mechanism (such as net-metering)	This may be necessary only for specific renewable energy systems like net-metering for small power producers (SPP). In some cases regulation introduce this mechanism directly.	Legislation introduces the option. The regulator may treat net-metering as a tariff option and regulate without a specific mandate.
Involve the SO in the definition of net-metering technical rules	The rules should include the technical connection requirement and the metering and tariff methodology	The regulator and the SO
Create a standard format for net-metering contracts	A standard format will facilitate connection of SPPs.	The regulator may produce a standard contract without a legislative mandate in order to accelerate the penetration of small renewables.
Put in place a consultation process	The process will be used to collect contributions from all players and enhance knowledge about and consensus on renewable energy.	The regulator creates an internal procedure for the consultation process.
Conduct an impact assessment of the regulations supporting renewable and energy efficiency policies	Examine both renewable energy and energy efficiency policies to assess the impact of long-term costs and the benefits of intended policies.	The regulator creates an internal procedure to assess the impact.

At the beginning of the process of developing a legislative framework, it is difficult to anticipate the full range of issues that may arise, so it may be useful to establish a *steering committee*. The committee is comprised of the four main players: a government representative, the regulator, the key stakeholders, and the SO. The steering committee would guide the introduction of new legislation, identify potential constraints, and when needed, determine the most knowledgeable identity to address any gaps and omissions in the process. While a steering committee can also be a barrier or delay, one of the key hurdles in increasing renewable energy integration is the lack of identification of roles and competences among the key players. A steering committee is an opportunity for all levels involved in renewable energy regulation to understand the problems and hopefully at the end create a favorable environment with the buy-in of all stakeholders.

For the implementation of the FIT scheme in Ghana, an *implementation committee* was established comprised of main stakeholder representatives. The committee was nominated during the tariff setting process in 2012. The committee advises PURC and other key stakeholder institutions on policy, socio-economic, technological, and environmental concerns regarding the uptake of renewable energy, and ensures rapid and efficient implementation of the FIT.

The implementation committee would be tasked to:

- Identify policy gaps that might hinder the smooth implementation of the FIT, and make appropriate recommendations to address those gaps;
- Draft a time line for the various stages, processes, and implementation of the FIT, and a budget to cover committee activities;
- Recommend, where necessary, how to incorporate concerns of interest groups, when necessary, to PURC and other key stakeholders (based on findings from stakeholder consultations organized by PURC); and
- Identify FIT implementation training needs.

In the early implementation phases of a new policy it is not easy to identify potential stakeholders and engage them immediately in a consultation process. In monopolies and vertically integrated markets, participation in most activities and decision making may be restricted to public utilities and policy makers. Other stakeholders such as consumer and environmental organizations, however, usually have interest in the design and regulation of electricity markets. Opening the market to renewables and IPPs offers the opportunity to involve new stakeholders and thereby access new technical skills, managerial competencies, and financial resources. Examples of new stakeholders are financial institutions, banks, potential national and international investors, large energy consuming companies, commercial enterprises with consistent electricity back-up units, consumer cooperatives, municipalities, professional and engineering organizations, and the like. Initially, because these new stakeholders may not have been involved in consultation processes before, it may be necessary to share significant amounts of information with them (or provide financial compensation) to encourage their participation. In the state of Massachusetts in the United States, for example, accredited stakeholders who provide relevant feedback on consultation documents published by the regulator are eligible for financial compensation for their participation. Similarly, in the state of Idaho, stakeholders are eligible for financial compensation if they meet a set of basic requirements established in the regulatory rules of procedure.

B. Remuneration of Renewable Energy

In order to develop renewable energy capacity the market must pay producers enough to cover investment costs and allow a rate of return high enough to stimulate investment. Electricity sale revenues need be equal to or higher than the levelized cost of energy (LCOE) for a given plant during its lifespan to achieve profit (see Box 1).

In some cases, remuneration at that level may be assured without having to introduce specific economic incentives, because the electricity market price is high enough to sustain renewable energy investments. In cases where economic incentives in the legislation are needed (see Box 3), a wide range of support instruments is available. Not all incentive mechanisms are compatible with all electricity market structures, however. Policy makers determine the total level of incentives by carefully evaluating different incentives. A combination of incentive mechanisms—from tax exemption to FITs—can be used instead, but it is important to ensure that the level of support does not deliver improper remuneration to investors. The regulator may be legally obligated to ensure that the tariffs cover the cost of providing services. As a rule, the regulator should not make subsidy decisions, any decisions on subsidies and funding for the subsidies should come from the government.

In electricity markets that are partially liberalized or vertically integrated, remuneration is usually based on a feed-in mechanism. When electricity is injected into the grid, each kWh is paid for by a buyer who is normally under a regulatory obligation to purchase at a price defined by regulation. In fully liberalized markets, a quota obligation system based on a green certificate mechanism may be introduced, but a green certificate system is recommended only in fully liberalized large markets, which have regional harmonization perspectives. In markets with little competition (such as markets with vertically integrated utilities with some liberalization of energy generation) the price of green certificates is not determined by the development cost of renewable energy plants but rather by a market for green certificates.

All ECOWAS member states have little or no competition in the renewable energy sector; therefore the introduction of a green certificate system could be ineffective. Regionally harmonized markets experience more competition as the national incumbent utilities of many countries compete against each other. The investor will commission the plant as long as s/he is reasonably confident that the market will remunerate the electricity at the expected LCOE. The LCOE formula is determined largely by the level of investment risk. The lower the risk, the lower the LCOE, and the lower the impact on final consumer costs. Regulating the renewable electricity sector by trying to reduce investment risks as much as possible is an important aspect. Favorable market conditions that attract investment at lower capital remuneration reduce the level of the FIT needed. As mentioned earlier, the adoption of a complete and transparent regulation can reduce risks, but they can also be reduced by choosing the most appropriate remuneration mechanism and understanding the inherent characteristics of renewable sources of energy: prevalence of capital costs over variable costs²⁰, natural resource-dependent load factors and, in some cases, generation unpredictability.

Box 1: Levelized Cost of Energy (LCOE)

The LCOE formula is widely used to calculate the electricity generating cost of different power technologies. The generating cost of a single unit of electricity (kWh) of a given power plant over a period of years is the annual total of the cost supported by the owner discounted over time divided by the total amount of the electricity produced by the power plant discounted over time.

This is the LCOE formula :²¹

$$C_{Lev} = \frac{\sum_{j=0}^n \frac{Expenses_j}{(1+i)^j}}{\sum_{j=0}^n \frac{Quantities_j}{(1+i)^j}}$$

where:

C_{Lev} = levelized cost

n = lifetime of the project

i = discount rate

For renewable power plants—which incur most of their costs during the first year, the formula may be simplified as follows:

$$LCOE = \frac{CAPEX + NPV \text{ of total OPEX for a given period}}{NPV \text{ of generated kWh for a given period}}$$

where:

- CAPEX is the capital investment cost, generally supported the first year, when the power plant is commissioned. While the regulator has limited influence over defining CAPEX, the national legislation and the relevant renewables markets may modify investment costs significantly. For example, a favorable fiscal policy for renewable energy technology imports and strong market integration between ECOWAS countries can significantly reduce CAPEX. The regulator may be more involved in the definition of renewable energy connection costs, thus influencing the total CAPEX. CAPEX can be estimated by consulting international literature sources, running national market analyses, or through consultation processes.
- OPEX (Operating Expenses) is the operational and maintenance cost, which is usually very limited (with the exception of biomass plants) for renewable energy technologies. OPEX in renewable energy may be calculated as a percentage of CAPEX. OPEX is discounted over time as the costs are paid for year by year. The regulator plays no major role in the definition of OPEX.
- NPV is the net present value. Weighted Average Capital Cost (WACC) can be used to calculate NPV. WACC is the cost of capital of a company that uses both debt and equity to finance its investments. It represents the company remuneration on investment. WACC is highly influenced by risk. The higher the risk the higher the assessed interest on debt, and the higher the investor expectations of remuneration on equity. The risk may be lowered by a regulation that limits the maximum market and regulatory risks as much as possible. The following provisions are particularly useful in lowering risk:

- Clear connection costs and connection deadlines defined by regulation
- Clear formulas to update the FIT, specifying inflation and exchange rates
- Clear dispatching rules and priority dispatching rights
- Clear rules for balancing costs and the exclusion of balancing costs for non-predictable renewable energy technologies
- Financial viability of PPA counterparts and clear timing for payment specified on PPA contracts
- Definition of curtailment compensation in case the grid does not dispatch electricity reliably

The period of time over which to calculate the LCOE is chosen by the policy maker. It may correspond to the technical lifespan of the renewable energy technology or to a shorter period in order to accelerate the payback period of the investment. The shorter the period over which the power plant is paid back, the higher the LCOE. Investors tend to prefer shorter payback periods, which reduce their investment risk and accelerate their capital remuneration. FITs are generally valid for a period of 10–20 years.

Given the characteristics of existing and the evolving legislation in the ECOWAS countries, this document focuses on FITs,²² but also covers other renewable energy mechanisms to provide a more complete picture of incentives.

FIT mechanisms are based mainly on two principles:

- The Avoided Cost of Generation (ACG) Principle
- Specific Technology Cost (STC)/Rate of Return Principle

B.1 Avoided Cost of Generation (ACG)

The principle behind the ACG is to pay renewable energy producers as much as the generation cost of the system. The ACG should not be considered as much an incentive as it is an option for IPPs to enter the market if they are satisfied with the system price. The ACG is often offered to self-producers of electricity (from fossil fuels or renewables) who are willing to sell their surplus production to the grid. The policy argument in favor of the ACG is very strong because it doesn't introduce additional costs for the consumers and therefore does not conflict with other market priorities.

The two methodologies usually used to calculate the ACG are the *long-run marginal cost of generation* and the *average cost of generation*, or wholesale price. Long-run marginal cost is the most favorable option for renewable energy producers because it is usually considerably higher than average cost. The resource characteristics used to determine the *long-run marginal cost of generation* might be dramatically different from those used for the *average cost of generation* calculation. For example, the resource used for the long-run marginal cost of generation may be newer, more technologically advanced, and environmentally friendly. Regulators are often asked to define a method for calculating the ACG along with managing and updating the mechanism once it has been introduced. In addition, they must ensure that there is a system in

place to direct the revenues earned from the electricity tariff to the renewable energy producers.

Methodologies to Calculate the ACG

Average cost of generation

Average cost of generation is usually used to deter renewable energy development because the methodology does not recognize attractive capital remuneration on investment.

Even though renewable technologies are not necessarily replacing the marginal technologies, they generate electricity not only during peak loads, but during base and mid loads as well. It is thus possible to choose a set of different technologies and fuels (reflecting national generation share and representing technologies at base, mid, and peak load) and then average the respective costs. In other cases it is possible to estimate the ACG as the wholesale price of the market, if available, or as the generation costs to the incumbent recognized by the regulator. Compared to the long-run marginal cost of generation methodology described below, both options deter renewable energy development. However, the impact can be minimized when combined with a long-run marginal cost of generation approach, for instance when the FIT is differentiated according to time of generation.

Long-run marginal cost of generation (LRMC)

Long-run marginal cost of generation is the most commonly used methodology to set ACG. LRMC is the cost that the utility would pay to introduce additional capacity into, and to run the system. LRMC estimations are based on three main components:

- Investment costs, including capital remuneration, for a reference technology
- OPEX costs, both fixed and variable
- Fuel cost of generation (variable cost)

The LRMC methodology is not suitable for markets experiencing a period of overcapacity because the introduction of new capacity will not be economically justifiable. However, this is not the case in ECOWAS countries, where the steady demand growth requires an equivalent increase in generating capacity.

To calculate the LRMC, the regulator chooses a reference expansion technology and sets reference parameters: investment cost, fuel used, lifespan, OPEX costs, fuel cost, cost of capital (usually WACC), generation efficiency of the generator, and load factor. Parameters can be identified by consulting the literature, conducting market assessments, and/or using a consultation process. Usually the regulatory authorities are responsible for running the cost assessment that determines the LRMC. If significant differences emerge from different sources, the regulator—backed by the consultation process outcomes—may decide either to give more relevance to local variables or to align the LRMC to international benchmarks.

Box 2: Calculating the ACG in The Gambia

The Gambia's ongoing process of introducing the FIT provides an example of how to calculate ACG on the LRMC. The Gambia opted to use the ACG methodology:

“On determining the setting of the renewable energy tariff for The Gambia, two different options were thoroughly explored. The first was to base it on an actual renewable technology cost-based approach. This would have allowed costs to be targeted to different technologies. This approach would require a high level of regulatory scrutiny during tariff setting intervals. The second approach to setting tariffs that was finally approved was the avoided cost methodology. This represents the avoided cost of an alternative form of generation, in our case, a potential mix of Heavy Fuel Oil (HFO) and Light Fuel Oil (LFO) mimicking the combination of both generation types available in The Gambia.”²³

The Gambia is introducing a FIT based on an ACG for which the reference technology is a 10MW oil fueled power plant that uses a mix of heavy fuel oil (HFO) and light fuel oil (LFO). The variables under evaluation by the Gambian regulator are listed in Table 2. The reference technology values are derived from international estimates when not available at the national level.

Table 2: Variables Used to Calculate the ACG in The Gambia

Technology	Unit	HFO	LFO
Capacity	MW	10	10
Net Thermal Efficiency	%	40	36
Internal Consumption	%	3	3
Calorific Value	Mkcal/sm ³	7837.5	8662.5
Scheduled Maintenance	Days/year	25	25
Forced Outage	%	10	10
CAPEX	USD/kW	1,400	1,100
Years Under Construction	year	2	2
Investment Throughout Years	%	45-55	45-55
Useful Life	year	25	25
OPEX	USD/MWh	7	7
Fuel Costs	USD/toe	624	850

The Gambian regulator, PURA, used these technical parameters, and the following financial values

- Project financing: 25 years
- Depreciation period: 20 years
- Income tax and VAT: 0%
- Debt-equity structure: 50-50
- Loan features:
 - Tenure: 6 years
 - Rate: 12%

The ACG is then calculated using three different values for the internal rate of return on the investment: 10%, 12%, and 15%.

The resulting ACG tariff was calculated using a rate of 12% is 8.4 D/kWh (22c\$/kWh).

In some places—in particular countries with oil-fueled marginal generators such as The Gambia—LRMC may be sufficient to pay back renewable energy investments, which demonstrates that the ACG methodology can be effective for renewable energy development.

LRMC recognizes an implicit incentive for renewable energy. This is generally welcomed in the early stages of the renewable energy market in countries willing to develop renewable energy capacity. An impact assessment may help the regulator make a decision. If LRMC appears to introduce excessive system costs for consumers, the best choice may be to limit the renewable energy capacity eligible for the FIT rather than reduce the feed-in level by using average cost methodology.

Box 3: Calculation of the ACG for Grid-connected and Mini-grid Renewable Energy Connected Systems in Tanzania

The Tanzanian Energy and Water Utilities Regulatory Authority (EWURA) uses two different ACG calculations on an annual basis: one for national grid-connected renewable energy power plants²⁴ and the other for renewable power plants connected to mini-grids.²⁵

For grid-connected renewable energy systems, the ACG FIT is calculated as the average between the LRMC and the generation cost of existing generating infrastructure of the national public utility, Tanzania Electric Supply Company Limited (TANESCO). The resulting value is then differentiated between the dry (August-November) and the wet season (December-July) using a premium coefficient of 1.2 for the dry season, and a reduction factor of 0.9 when electricity is generated during the wet season. For mini-grid-connected renewable energy systems, the ACG is the average of the LRMC of TANESCO and the calculated generating cost of a 1MW diesel generator. The methodology adopted in Tanzania includes many other advanced features (premium for medium voltage connection, moving average adjustment, and floor and cap price, for example) that can be introduced in a feed-in mechanism.

The calculated ACG tariff is corrected by an avoided transmission cost: *“SPPs are connected to the medium voltage network of TANESCO. Electricity produced by SPPs would be distributed through the medium and low voltage networks, thus saving high voltage transmission losses otherwise incurred by TANESCO to produce electricity at the main power plants and transfer to the medium voltage network. The avoided cost calculated will be adjusted upwards to reflect the avoided transmission losses.”*²⁶ Subsequently, in order to smooth out the annual variations, the calculated tariff is corrected by the moving average of the last three years’ calculation. The following table reproduces the methodology used in Tanzania to set the ACG:

Table 3: Methodology to Set ACG in Tanzania (Step Sequence) in Tanzania Schilling²⁷

Step 1		Step 2		Step 3		Step 4	
Calculation of ACG		Adjustment for avoided transmission cost		Adjustment with moving average of 3 years		Wet season and dry season ACG	
LRMC	133.98	Average ACG	124.08	Calculated ACG	130.53	Dry season (ACG x 1.2)	145.36
Generation cost	114.85	Correction factor	5.2%	Past two years ACG	108.80 123.06	Wet season (ACG x 0.9)	109.09
Average ACG	124.08	Adjusted ACG	130.53	Adjusted ACG	121.13		

One benefit of the ACG methodology is that it is reasonably simple to introduce a cost in line with the current costs. However, using the ACG methodology involves paying back a technology (renewable energy) whose costs are mostly fixed (capital) with the ACG of a technology whose costs are mainly variable (fuel), which may generate complications. There are two different approaches to managing this problem:

- Each renewable energy plant is linked to the ACG of the year of commissioning. The ACG is used for the entire lifespan of the plant starting when it is commissioned. In this case, a significant gap may emerge between the estimated ACG at year one and the real future generating cost, which is strongly influenced by the international price of fossil fuel. If the ACG is not updated, a future renewable energy plant might be remunerated significantly lower or higher than the future actual ACG, thus nullifying the underlying principle of ACG (keeping renewable energy costs closer to system costs).
- The ACG is estimated each year and all renewable energy plants get the same price irrespective of their year of commissioning. In this case, if the ACG is continuously updated to follow real ACG, renewable developers may perceive the capital risks to be too high, particularly during periods when variable costs are volatile.

In both scenarios, it is very likely that the regulator will be requested to continuously update the ACG, forging a compromise between those two diverging factors. In some cases the primary legislation instructs the regulator on how to do that, but in other cases the mandate may not be very clear. The ACG methodology must include rules associated with updating tariffs, identifying the institution in charge of tariffs, and determining the schedule for updating.

One of the following options is normally used to forge a compromise:

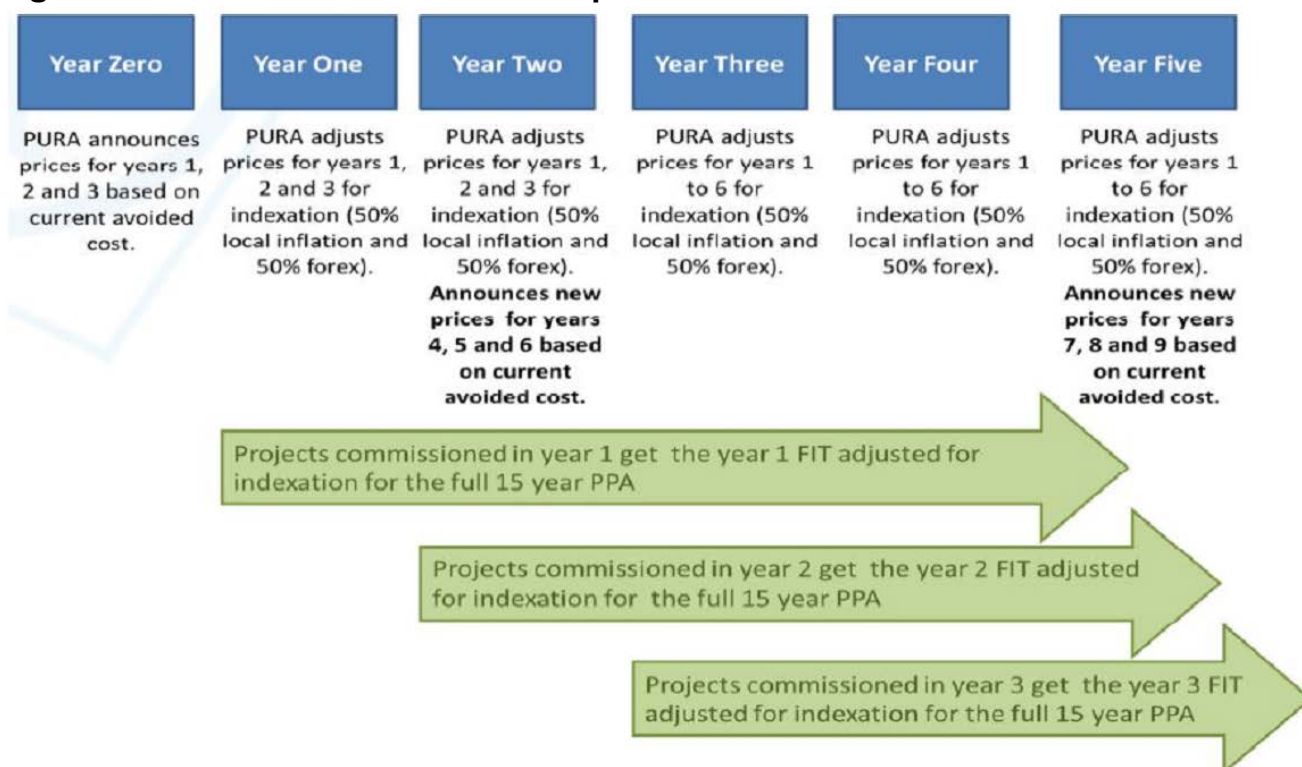
- A cap and a floor price for ACG are introduced. For example, if at year one the ACG is 100, a +/-20% bundle may be introduced in order to reflect some of the fossil fuel price variation into renewable energy purchasing prices to protect investments and prevent

over-remuneration. This guarantees the project developer of a price no higher than 120 and no lower than 80, even if the price incorporates an updated fuel price.

- A moving average of fossil fuel costs over many years may be used for ACG calculation. ACG is calculated against the average cost of reference fuel over a period of 5-10 years. By using a moving average, the effect of variation in fossil fuel price is mitigated.
- A different ACG is calculated each year (or period of years) and applied to the new renewable energy plant generation. Each plant commissioned during each period will be remunerated over its entire lifespan at the ACG calculated for that period, but each new installation will be remunerated with the most recently calculated ACG, according to the year it is commissioned (The Gambia implemented this option).

In The Gambia, PURA is setting up a clear mechanism to regulate the ACG tariff update. The first calculated ACG (year zero) is awarded to renewable energy power plants commissioned within a three-year period. In Figure I, for example, the ACG announced in “year zero” is the remuneration base for renewable power plants entering into operation in year one, two, or three. Those power plants will receive the FIT, calculated on “year zero” base value, for the entire feed-in period (15 years). The plants commissioned in the fourth year will be remunerated with a recalculated ACG. The regulator is supposed to announce the newly calculated ACG three years in advance so that developers intending to commission their renewable plants in year four, five, or six will be informed of the ACG base level by “year two” through a public announcement by PURA. Each renewable power plant will thereafter be remunerated for a 15-year period with the ACG calculation based on the year of commissioning. The ACG is annually updated according to inflation and exchange rate fluctuation parameters (this process is explained later in the document in section B.4). The following figure explains the mechanism in practice, using The Gambia as an example:

Figure I: Calculation of ACG in the Proposed FIT Mechanism in The Gambia ²⁸



For example, a renewable energy plant starting to produce in year two will be paid for 15 years with the FIT announced in the first year (as seen in Figure I), which is updated yearly according to inflation and foreign exchange fluctuations. On the contrary, a plant that begins to produce in year four will be remunerated with the ACG announced in year two. This system balances the different needs of renewable energy investors with the design of the FIT. More specifically, it balances the need of the investors to know the remuneration of the electricity produced (the tariff is announced three years in advance and is updated according to inflation and foreign exchange rates), with the mechanism to incorporate the variation of fuel costs within the calculation of the ACG.

Advantages of the ACG methodology are:

- The regulatory evaluation and methodology are easy to implement.
- Remuneration costs are in line with existing generating costs (a strong policy argument in favor of renewable energy).
- It is useful in most ECOWAS countries where oil fuel is still the reference marginal technology.
- Methodology distortions can be corrected by introducing mitigating measures such as cap and floor, or moving average.

Disadvantages of the ACG methodology are:

- Entry-level renewable energy costs may be significantly higher than ACG and some technologies may not be willing to risk entering the market. Some technologies may be more expensive in the early development phases but highly competitive in the long run.

Though renewable energy technology may advance quickly, the high upfront fixed costs may require an initial period of incentives.

- It is difficult to keep ACG close to the real system cost over time, particularly when variable costs are difficult to forecast. This is usually addressed by introducing a compromise between cost adherence and investment.

One of the main advantages of the ACG is to keep renewable energy FITs in line with the system generating cost, the long-term potential decoupling between the updated tariff and the system cost could potentially nullify the supposed advantage. However, even if the updated tariff slightly deviates from the system generating cost, it is important for regulators to consider the long-term advantages of renewable energy to rate stability and environmental sustainability. The ACG is the most effective methodology for mini-grid contexts, where the reference price of a diesel generator is generally high enough to assure the pay back of most renewable technologies. In fact, in some cases it is even possible to reduce the calculated ACG cost to better reflect the real costs of the renewable energy system. In other words, in some off-grid contexts the renewable energy cost may be considerably lower than the ACG of a diesel generator.

In some cases—in the U.S for example—the ACG is used in combination with quota obligation mechanisms and renewable portfolio standards. Public utilities are obligated to buy a given quantity of renewable energy within their energy mix at a given minimum price by a certain year.

B.2 Specific Technology Cost and Rate of Return Mechanism

The principle of the Specific Technology Cost (STC) mechanism is to introduce a feed-in price that varies according to the estimated cost of different renewable technologies. The purchase price will differ according to whether electricity is generated from hydro, solar, wind, or biomass, leading to balanced development of renewable energy sources. Rather than focusing on the cost of a single reference technology, as is the case with ACG on the LRMC, the regulator estimates renewable energy generating costs for different technologies. In some cases the technologies are also differentiated according to size. For example, the FIT published in Ghana in July 2013 is based on a specific technology cost approach. The regulator calculated the cost for each renewable energy technology and derived a FIT accordingly. For hydropower generation, there are two different FITs depending on the size of the power plant, reflecting a higher tariff for smaller hydro given the higher cost of the technology. The tariff scheme also sets capacity development limits for wind and photovoltaic technology in light of their potential impact on grid stability. No capacity limits have been set for biomass and hydro. When limits are imposed, as is discussed later in the document, project selection criteria must be in place.

Table 4: Published Feed-in Tariff Based on STC and Maximum Allowed Capacity per Technology in Ghana, 2013²⁹

Technology	FIT in GHP	Maximum allowed capacity	Maximum allowed capacity for single developer
Wind	32.10	300 MW	50 MW
Solar	40.21	100 MW	20 MW
Biomass	31.46	No limit	
Hydro > 10 MW	22.74	No limit	
Hydro < 10 MW	26.55	No limit	

The published prices represent the maximum feed-in price the public utility should pay for renewable energy electricity. Distribution utilities are obligated to purchase renewable energy electricity at or below the approved prices and quantities. The utilities will recover their costs from consumers' tariffs as approved by the regulators. To meet their renewable energy purchase obligations, all distribution utilities must procure their requirements through international competitive bidding in line with guidelines approved by PURC in consultation with the Public Procurement Authority.

Investment costs, OPEX costs, capital cost, lifespan, and load factor for different renewable energy systems are estimated through market assessments, literature reviews, and consultation processes. The methodology is the same as that used to calculate the LCOE. When setting STC, the regulator seeks a *fair* capital remuneration for the IPP. The concept of *fair* is clearly very difficult to define, and it involves different variables, not the least of which is country-specific market risks on investment.

While it is difficult to set a *fair* price when introducing a STC FIT, it is even more difficult to monitor the coherence between the estimated price and the future real technology costs. Technology costs may change for reasons that cannot be predicted: the technology-specific learning curve, increased efficiency (and thus higher load factors), the cost of raw material on international markets, exchange rates, and so on. Most STC mechanisms must be updated periodically to reflect real technology costs and keep renewable energy remuneration in line with the expected rate of return. A schedule for periodic tariff updates (every two or three years, for example) is usually introduced in the mechanism rules. This provides market participants a precise deadline for commissioning their installation with which they must comply if they want to access *that* particular level of feed-in tariff. An alternative approach is to cap the access to feed-in tariffs through a quota (MW). Once the quota is reached the regulator will update the tariff based on the outcomes of the first period. For example, the quota and price for wind and solar might depend on an updated study evaluating the cost of integrating intermittent resources to the system.

In some cases, the STC FIT already includes a degression factor, so tariffs are reduced by a given percentage each year. The reduction is based on the regulator's expectation of the learning curve for plant developers to implement and use a given technology, and it gives plant developers the incentive to accelerate plant commissioning in order to receive a higher incentive rather than a reduced tariff. For example, the FIT in Germany incorporates different regression factors for different renewable energy technologies. The regression factor may be applied yearly, as is the case with hydro, biomass, and wind, or it can be announced for a future period, as is the case for offshore wind, and geothermal technology.³⁰ Table 5 lists initial tariffs, regression factors, and feed-in years for Germany.

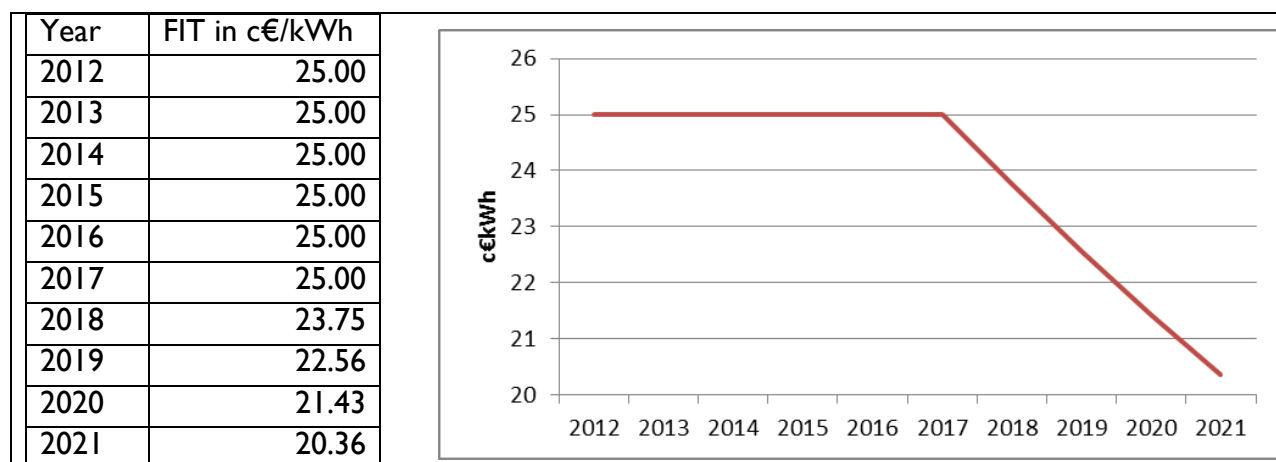
Table 5: Feed-in Tariff Regression Factors and Size Differentiation³¹ in Germany in 2012

Technology	Size	Initial tariff in c€/kWh	Degression factor	Year of feed-in
Hydro	<50 kW	12.70	1%	20
	<2 MW	8.30		
	<5 MW	6.30		
	<10 MW	5.50		
	<20 MW	5.30		
	<50 MW	4.20		
	>50MW	3.40		
Landfill Gas	<500 kW	8.60	1.5%	20
	<5 MW	5.89		
Biomass	<150 kW	14.30	2%	20
	<500 kW	12.30		
	<5 MW	11.00		
	<20 MW	6.00		
Geothermal	All	25.00	5% from 2018	20
Wind Offshore	Initial tariff	12.00	7% from 2017	12 ³²
	Basic tariff	3.50	7% from 2017	8
	Acceleration	19.00	Not	20
Wind Onshore	Initial tariff	8.93	1.5%	5 years ³³
	Basic tariff	4.87		15 years
	<50 kW	8.93		20 years

The intent of the German law is to differentiate the FIT relative to the size of the power plant, which indicates that the objective of the renewable strategy in Germany is to develop all renewable potential and not necessarily the most competitive technologies. In the case of hydro, for instance, the feed-in price for small installations is nearly four times higher than for large ones. This implies both a need to calculate a rate of return for all different technologies and plant sizes in order to set a FIT proportional to real cost of renewable plants according to their size, and to undertake a careful impact assessment in order to calculate, according to existing small hydro potential, the possible impact of feed-in costs on the final tariff. The impact on the final consumer's tariff may be negligible with regard to the limited potential of small

hydro plants or if the legislature introduces a development cap in terms of MW installed of small hydro. On the other hand, the introduction of a FIT specific to small hydro plants may favor the development of distributed generation policy targets and promote employment in small- to medium-size renewable enterprises. The following table shows the effect of introducing a regressive coefficient over FITs in order to stimulate early investments.

Figure 2: The Effect of a Delayed Regressive Coefficient FIT for a Geothermal Plant in Germany, 2012–2021³⁴



The German law anticipates introducing a yearly regressive factor geothermal power of 5% from 2018 onward. The effect of the regression on the incentive is visible in the graph. The legislation has allowed a period five years to develop the technology at a high incentive but has also declared the intention to make geothermal technology more competitive in the long-term. This example may be very useful to countries that have little or no experience with renewable energy technologies and where the introduction of a technology may be more expensive compared to international standards. In those countries, the FIT may allow a high incentive at the beginning, but after a few years, with the introduction of a regressive coefficient, the tariff will be quickly aligned to international standards. This methodology can be adopted in countries where national policies promote the development of a national renewable industry. The regression factor may be successfully adopted in emerging markets where the entry level cost of a technology may be significantly higher than the *real* technology cost. Factors such as lack of experience, scarcity of skilled and trained personnel, import procedures for plant components, and lack of connection rights and procedures may contribute to high initial technology costs. The initial incentive cost may be compensated by the development of a renewable energy national industry and the availability of technologies that may prove to be less expensive than conventional generation in the long run (see section on impact assessment).

In some cases, STC FITs can be structured with two components: the ACG and a premium proportional to different renewable energy technology costs. In liberalized markets the ACG may correspond to the electricity market price. In that context the renewable producers will sell their electricity in the market and receive a premium incentive separately. The premium is generally dispensed by an independent body that manages a renewable fund. The fund is fed by a specific tariff component introduced and continuously updated by the regulator to track the

renewable energy mix and the consequent system cost. STC FITs are very common in the EU, which is pushing for a balanced development of renewable technologies.

When an incentive is introduced, as is usual with STC, the rules and the mechanism to access it must be specified. There are three main principles of access: unconstrained access; a first-come, first-served policy; and auctioning of access rights. Because the methodologies for assigning access to tariffs and access to connection rights are largely equivalent, these principles are described in more detail later, in the section on connection rights (Section III).

The advantages of STC FITs³⁵:

- All renewable technologies can access the electricity market. Although it incurs a higher cost over the short-term, such access provides the basis for a more comprehensive renewable energy strategy that relies on a variety of technologies and solutions. It incentivizes a balanced development of renewable energy and can be combined with specific policy objectives. If STCs are not updated in response to inflation they may also increase inflation rates, reducing its impact on electricity prices.
- The tariffs may accelerate the development of renewable technologies whose entry-level costs may be higher than ACG but whose long-term potential may exceed initial costs.
- Renewable energy costs are decoupled from oil and fossil fuel cost. The electricity produced by STC plants has a stabilizing effect on final electricity costs delinked from fossil fuel cost fluctuation. If the feed-in tariff would be calculated on ACG, the ACG is typically fossil fuel generation and thus any update in the FIT based on ACG will follow fossil fuel costs. For STC FITs the cost translated into the tariff will follow the investment costs, for ACG FITs it will follow the price of fossil fuel.

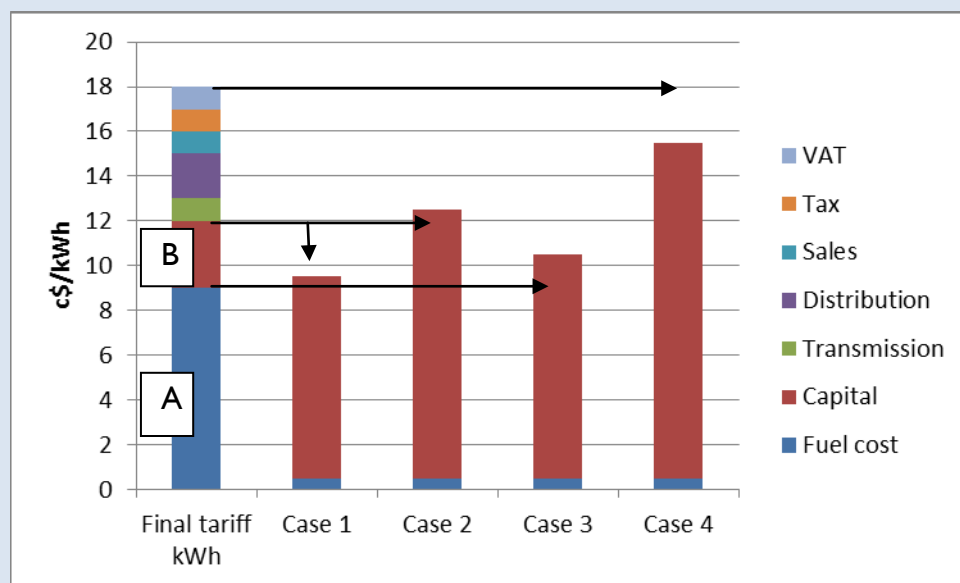
The disadvantages of STC FITs:

- Greater regulatory effort is required to calculate and update STCs, and a more complicated tariff structure may be needed to pay back the IPP.
- They usually accompany the introduction of incentives, and thus incur additional costs to the system.
- If not well designed, the methodology risks will not follow future real technology costs and the costs will become excessively expensive for the system.

There is no one best methodology option to develop a FIT. ACG and STC both have advantages and disadvantages that a legislature/regulator must be able to adapt to specific country characteristics and priorities. It may be useful to undertake impact assessments of proposed options to contrast the two systems over time. Furthermore, it might be useful to specify a minimum technical standard in order to prevent the installation of outdated renewable energy systems.

Box 4: Generating Costs and Renewable Energy

In any electricity system, final electricity cost per kWh, designated as “final tariff kWh” in the graph below, is generated from the sum of the following components: capital cost of generating infrastructure, variable costs of generation (OPEX, notably fuel cost in conventional generating plants), transmission costs, distribution costs, sale and metering service costs, taxes and duties, and Value-Added Tax (VAT). The cost of generation (capital and fuel costs) generally constitutes between 50-70% of the final electricity cost.



In the graph above, a final tariff based on fossil fuel generation (final tariff in kWh) is compared with different possible renewable cost cases.

When the cost of generation of fossil fuel [capital (B) + fuel cost (A)] is higher than the renewable energy LCOE (Case 1), introducing an ACG methodology is the most feasible option because renewable energy is competitive with fossil fuel generation.

When the renewable energy LCOE is higher than the ACG (Case 2), it is necessary to introduce some incentive: a premium must be recognized over the ACG. This is most commonly achieved with an STC FIT.

In some instances, electricity tariffs are not fully cost reflective nor are they high enough to pay back the capital cost component of generation to the public utilities. The tariff in many cases barely covers fuel costs (A). Although the ACG should be calculated using combined fuel and capital costs (A+B), the utility can only recover fuel costs (A) through the tariff, which is often the case when the legislature needs to keep tariff at low levels for political reasons. In that instance, renewables may not appear to be competitive with fossil fuel. In Case 3, renewables are still competitive with fossil fuel generation but because final tariffs are set only for fuel cost (A), renewables appear to be more expensive. Fossil fuel generating assets are, or will be, somehow paid with public assets.

In other instances, fossil fuel supply to power generation is subsidized and the public utilities do not pay the full cost of fossil fuel. In this case, fuel cost (A) appears lower than it really is. The difference between the real fuel cost and the incentive price paid by the public utility is covered by public subsidies.

The last case, Case 4, illustrates a renewable energy system installed by an end-user where the reference avoided cost is the final electricity price, which includes transmission, distribution, sales, and taxes. This cost is considerably higher than generating cost (A+B only). Retail cost is generally used to calculate net-metering options. Net-metering schemes may or may not include fiscal components (VAT and taxes on consumed kWh) on the amount of electricity exchanged between the small renewable producer and the grid. The exemption of tax components on exchanged amount is an additional incentive to distributed net-metering systems. Case 4 illustrates the generating costs of a small installation, which are generally higher than for larger installation grid-connected (Cases 1, 2, and 3), but still competitive considering the ACG at retail level.

B.3 Other Options for FIT (ACG and Specific Costs)

FITs may also be designed to incorporate tariffs based on the time of generation, which will link renewable energy remuneration to the economic value of the electricity according to when it is produced (time of day or season of the year). Time of generation tariffs may be applied to all renewable plants or solely to technologies that can be predictable, such as hydro, biomass, or biogas. It is possible to structure feed-in tariffs into base-load and peak-load prices on a daily or seasonal basis. For the ACG methodology, a reference peak-load and base-load technology can be used for the calculation. Alternatively, it is possible to introduce a premium (coefficient) to correct the reference tariff price for the electricity produced during peak hours.

Time-based tariffs can incentivize renewable production when the system is producing electricity at higher costs. This effect will promote the construction of programmable rather than non-programmable renewable energy. Two different systems may coexist: flat and time of generation tariff.

The Tanzania FIT (Box 3) provides an example of a seasonally modulated FIT. Introducing a simple coefficient gives a price signal to the power generator:

- 1.2 for dry seasons when electricity is scarcer and more expensive to generate given the water shortages in hydro plants
- 0.9 for wet seasons when hydro electricity is more abundant

Market-based systems (e.g., auctions or requests for proposals) may be instituted in order to assign access to FIT rights when the overall capacity is constrained. Total capacities (MW) for each technology as well as the opening price (i.e., the tariff to be recognized for a given period of time) are set. Potential developers bid and development rights are given to the best bidders. Ghana, for instance, has introduced a feed-in mechanism based on maximum feed-in prices the public utility may pay IPPs. The public utilities are asked to purchase renewable electricity through an international competitive bidding (ICB) process defined in specific guidelines

approved by the electricity regulator (PURC) in consultation with the Public Procurement Authority. In some cases, the competitive bidding process may further complicate and delay the commissioning of renewable energy installations. The benefit in terms of reduced incentive mechanism costs may be very limited compared to the transaction costs generated by running competitive actions.

For PV systems, rather than running competitive auctions or request for proposals, it may be more efficient to introduce a size limit for the construction of power plants (for example 2MW) and assign the available capacity on a first-come, first-served principle. PV systems are intermittent - thus the more distributed they are, the less likely are occurrences of decreased generation from all systems at the same time. While this is also the case for wind, the economics of wind power plants show that the bigger the system the lower are the cost per MW installed. The advantages of large scale PV systems in terms of cost are not as evident as in the wind sector. Larger power plants may have better chances to win the auction but will pose higher balancing problems to the national system, thus introducing hidden additional costs. For this reason the construction of large PV systems may require comprehensive technical feasibility studies to evaluate potential grid impacts of the installation that will further delay the implementation of a renewable energy favorable mechanism. The economic benefit of introducing a tendering system for PV technology, is negligible, because the marginal savings on additional kW for large systems (>2MW) are very limited. Moreover, the installation of a large number of smaller PV plants offers benefits in terms of improved system balancing and higher employment rates per kW installed, because there are more opportunities for national engineers and technicians. Especially at the beginning of market development, it is important to develop more plants in order to facilitate a national PV market and increase the national competence in the sector. It is important to underline that the development of a national industry in PV is a economical option for rural electrification, to reach un-served area and to provide backup services for large consumers. The two leading countries in PV installation - Germany (33GW) and Italy (18GW) - started with small installations, and small installation (<1MW) continue to have the highest share of PV installation and electricity production.

For other technologies, such as wind, the potential grid balancing problems are reduced according to the size of the power plant. In other words, the marginal investment cost per kW is lower for large power plants, particularly if marginal investment cost is the standard for determining compensation. In that case, the market-based mechanism may deliver higher system benefit. When an auction or request for proposal is run to assign feed-in access rights, precise arrangements must be introduced to ensure that plants are commissioned within a given period of time and that bidders are financially sustainable. For this purpose, in some cases FITs are progressively reduced if plant developers delay the installations and a financial deposit is required to participate in the auction. In Italy, for instance, legislation assigns feed-in rights on a competitive basis. The available capacity is defined by decree for each renewable energy technology (see Table 6). Once the contender has won the auction, the contender has to comply with a maximum time to complete the installation. Once the expected commissioning time has expired, the FIT is reduced by 0.5% each month for a maximum allowed delay of 24 months. Participation in the auction is contingent upon a financial deposit. If the installation is not completed within the pre-determined allowed time period, the deposit is lost.

Table 6: Deadlines for Renewable Energy Plant Commissioning to Complement FIT Rights Auction Mechanisms in Italy³⁶

Technology	Allowed capacity in 2013 MW	Expected commissioning time months	FIT reduction for any month of delay	Maximum allowed delay months
Wind Onshore	500	28	0.5%	24
Wind Offshore	650	40		
Hydro	50	40		
Geothermal	40	40		
Biomass	470	40		

The advantage of a market-based system is that it combines an administrative tariff setting process with the economic efficiency provided by a competitive allocation process. Yet often transaction and administrative costs may be higher than the expected economic efficiency improvements. Sometimes it is best to keep the feed-in system as simple as possible.

Accelerated cost recovery FIT is another option. For example, the German legislation allows the IPP to decide between a 20-year FIT and a 12-year higher tariff (see Table 7).³⁷ Introducing the accelerated option encourages early movers in the development of new technologies. A higher tariff for a shorter period of time is an additional incentive for plant developers given the lower risk and the faster break-even point of the investment.

Table 7: Acceleration FIT Model for Offshore Wind Energy in Germany³⁸

Year of Commissioning	Base remuneration [ct/kWh]	Higher initial remuneration [ct/kWh]	Initial remuneration in the acceleration model [ct/kWh]
2012	3.5	15.0	19.0
2013	3.5	15.0	19.0
2014	3.5	15.0	19.0
2015	3.5	15.0	19.0
2016	3.5	15.0	19.0
2017	3.5	15.0	19.0
2018	3.26	13.95	-
2019	3.03	12.97	-
2020	2.82	12.07	-
2021	2.62	11.22	-

Degression by 2017: 0.0 percent, from 2018: 7 percent

Duration of tariff payment: 20 years (acceleration model 12 years)

B.4 Feed-in Updates

Other parameters should also be considered when developing a FIT (either with ACG or with STC): inflation and foreign exchange rates. These two variables should be mentioned specifically in the main legal framework to enable plant developers to evaluate their long-term investment remuneration.

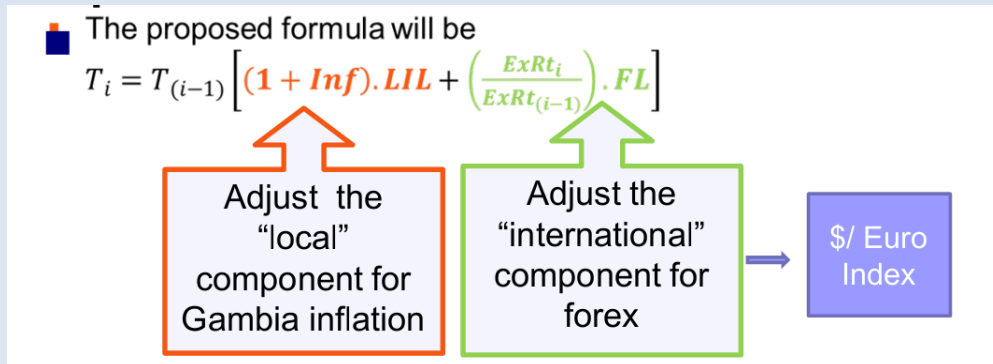
Inflation

Including inflation in the FIT formula will keep renewable energy remuneration constant to real terms over the specified period. In principle, inflation should be included in the FIT because renewable energy investments anticipate all capital at year one. In ACG, inflation correction should be applied only over the capital cost component of the reference technology. Fuel costs, if updated yearly, are an independent variable that already includes inflation. National electricity tariffs often do not follow inflation, and full inclusion of inflation for renewable energy tariffs may be perceived an excessive privilege for renewable energy developers. In some cases only a percentage quota of inflation is included. Usually it is advisable to only adjust FITs to inflation for existing plants. For new plants, the previous calculated feed-in level should not be inflation adjusted because renewable energy technology costs are often decoupled from inflation. Renewable energy technology costs may decrease significantly as inflation increases. If the FIT is also updated for future plants, investors may be incentivized to postpone plant commissioning in order to gain a benefit from rising inflation.

Foreign Exchange Rates

In some cases, because most technologies are purchased on international markets, foreign exchange variations against the Euro or U.S. Dollar are considered in tariff updates. While fully including inflation in the tariff update could compensate for the foreign exchange variations, including part or full foreign exchange fluctuations in the tariff adjustment will increase investor confidence. The formula proposed in The Gambia feed-in scheme illustrates the principle in practice (see Box 5).³⁹

Box 5: Proposed Updating Formula for ACG FIT with Inclusion of Inflation and Exchange Rate Fluctuations in The Gambia.



Where:

- T_i is the tariff for the period 'i'
- $T_{(i-1)}$ is the tariff in a previous period (i-1)
- Inf is the local inflation
- LIL is the deemed local inflation link (percentage)
- FL is the deemed foreign exchange link (percentage)
- $ExRt_i$ is the exchange rate GMD/€ for the period 'i'
- $ExRt_{(i-1)}$ is the exchange rate GMD/€ for the previous period (i-1)

Assume the initial ACG in The Gambia is GMD8.4/kWh. One year later the inflation has increased by 5% and the foreign exchange rate has changed from GMD40 to GMD45 for 1€. The Gambia mechanism recognizes 50% of inflation variation (LIL) and 50% of foreign exchange rate variation. The resulting formula is:

$$T_i = \text{GMD}8.4/\text{kWh} \times [(105\%) \times 50\% + (45/40) \times 50\%] = 8.4 \times (52.5\% + 56.3\%) = \text{GMD}9.14/\text{kWh}$$

In year two, the corresponding updated ACG to be awarded to new and renewable energy power plants commissioned in year one is GD9.14/kWh⁴⁰.

B.5 Green Certificate

An advanced option to support renewable energy is to introduce a quota obligation system together with a green certificate market. The obligation is normally placed on electric distribution companies. In some countries the obligation has been imposed on generating companies (Italy and the US) or final consumers. The obligation requires a minimum percentage of green electricity of total electricity sales each year. The percentage is progressively increased each year until the renewable energy policy development target is reached.

Setting a long-term renewable energy policy target has often proven to be subjective and difficult to determine. In some cases, the regulator is forced to reevaluate the quota obligation

because of changes in technology or unexpected economic conditions. For example, if the near term target is set too high, the electric distribution company may experience potential grid balancing problems or economic issues. Alternatively, if the near term target is set too low, the electric supplying company may be slow to incorporate renewable energy technology in its generation mix. It is the job of the regulator to carefully evaluate the quota obligation to holistically determine its overall impact on customers and the economy.

In some countries, electric distribution companies can demonstrate compliance with the obligation by redeeming the number of green certificates corresponding to their obligation quota. For example, if company A is selling 100GWh of electricity each year and the green certificate obligation is set at 5%, the company must redeem 5 green certificates (i.e., 1 certificate = 1MWh of green energy) to comply with the obligation. The following year the obligation will be 7% and the company must redeem more certificates to meet the new quota. On the production side, renewable operators generate electricity and receive an equal number of green certificates. Whereas the electricity is sold on the market at market price, the certificate may be sold bilaterally to the utilities under obligation or through a green certificate market.

Green certificate mechanisms fulfill the policy objective of achieving a determined share of renewable energy over a given period of time through a competitive mechanism where renewable energy costs are defined not by the regulator, through a complicated administrative process, but by the market. The duty of the regulator within a green certificate mechanism is limited to monitoring the market and assuring that the quota obligations are met.

The green certificate mechanism has often proven to be harder to implement than expected. In most cases, the combined electricity and green certificate remuneration risk, the market power of some operators, and the exclusive development of some competitive technologies have persuaded the legislature to correct the mechanism to the point of nullifying its alleged advantages.

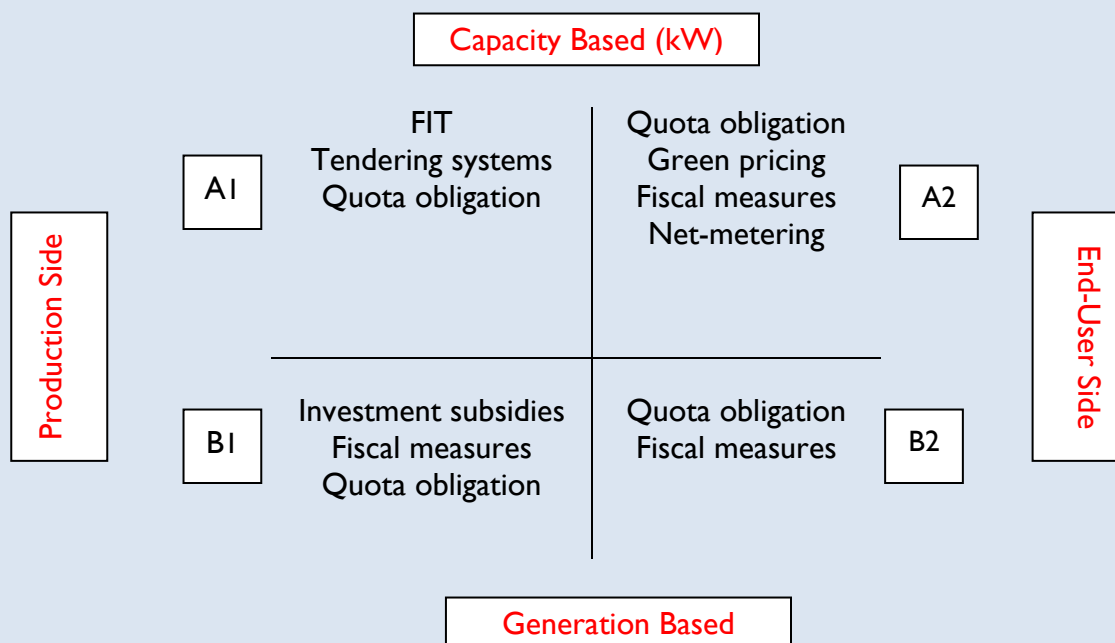
The enforcement of the mechanism also has been difficult. The introduction of non-compliance fines (buy-out option) for those operators not able to redeem a sufficient number of certificates corresponds to a price cap of the mechanism. When the fine is set too high, it is difficult to enforce payment. When it is too low, companies prefer to pay the fine rather than construct new renewable energy plants.

For those reasons, green certificate schemes seem to be successful only in large electricity markets (regional markets) with a high level of competition in both generation and supply sectors. In fact, two of the largest markets for green certificates (Italy and UK) have now reverted to FITs managed through auction rights.

Box 6: Classification of Renewable Incentive Schemes

There are many types of renewable incentive mechanisms. The schematic below illustrates one example of a classification system according to the target of the incentive. An incentive may be given on new *capacity* (kW) development or for renewable electricity *generation* (kWh), and it may be granted on the *production side* or to the *end-users*.

The choice of the incentive has different implications. In some national electricity markets, multiple incentives may coexist. Incentives, which must serve policy targets, may be given to promote the start-up of a national industry on renewables, to reduce fossil fuel dependency, to achieve environmental targets, to increase energy access, or, as it is often the case, to support some combination of policy objectives. For instance, it may be appropriate for a country eager to incentivize a national industry start-up to incentivize the installation of capacity (kW) if the priority is to increase security of supply. On the other hand, an incentive based on the generation (kWh) of electricity might prove more effective.



A1: Generation Based-Production Side Incentives

A generation based-production side incentive is the principle of remunerating each kWh generated by the power plant and fed into the grid. The policy objective of this kind of mechanism is to maximize the generation of renewable electricity. If the producer is paid for the electricity generated, the incentive to increase the system efficiency and to maintain a high plant performance is very high. As long as the technology meets international quality and security standards, the legislature and the regulator are not obligated to undertake technical and financial assessments for each plant. In a production-side incentive system, IPPs must be able to access the electricity market at the generation level.

The legislature and the regulator need to develop an open, sound and understandable mechanism for market players to access incentives. Incentives are distributed by market rules according to the kWh recorded on electricity meters at prices that are known and published by the relevant institutions (usually the regulatory authorities). As long as access to the incentives and connection right procedures is well defined, *generation based-production side incentives* can be considered a transparent and trustable mechanism to distribute public resources. *Generation based-production side incentives* represent the core of any significant renewable policy. A FIT is the typical *generation based-production side incentive*. The design of an FIT may be based on the ACG or on the STC methodology, and incentive rights may be assured through a competitive (tendering systems) or a non-competitive process. In some cases green certificate systems can also be considered *generation-based production-side incentives* when the obligation to develop a minimum percentage of new renewables is placed on conventional (fossil fuel) power plants rather than supplying companies or end-users.

With *generation based-production side incentives*, policy makers must calculate the incentive level for the remuneration of renewable electricity, which requires the adoption of specific methodologies. If a significant information asymmetry between market players and policy makers emerges when tariffs are set, the risk is an improper cost sustained by final consumers in the long-run. Open consultation processes, impact assessments, and/or international benchmarking can be used to mitigate the risk. The *generation based-production side incentive* can be used in complement with other incentive mechanisms, often with fiscal incentives (*capacity-based incentives*) and net-metering options (*generation based-end-users' incentives*), for example.

A2: Generation Based-End-User Side Incentives

This incentive is based on the kWh on the end-users side instead of the generation side. The most important *generation based-end user incentives* are obligation quotas based on green certificates and net-metering options. The principle behind green certificates is to introduce an obligation quota on public utilities (sale or distribution sector). Utilities are asked to have a minimum annual share of renewable energy in their end-users' supplied electricity mix. The obligation quota increases on an annual basis until it reaches the legislature's desired share of renewable in the national generation mix. In theory, the green certificate mechanism offers an efficient tool to develop renewables where the regulator and the legislature define the market rules and then step back to let the market determine the most efficient solutions and the least cost options to meet the obligatory targets. In practice, green certificate markets introduce additional risks for plant developers (i.e., the long-term price of green certificates) and require the implementation of certain market conditions such as high competition levels and large electricity markets. In fact, green certificate mechanisms still need a high level of intervention by policy makers to compensate market distortions and inefficiencies. *Net-metering* is a typical *generation based-end-users' incentive*. With no or limited system cost, the net-metering option provides end users the option to install a small power plant for their own uses (auto-consumption) and to use the national grid as a system of storage for their excess production. Net-metering requires the creation of technical rules and the preparation of a standard contract to be signed between end-users and local public utilities. The regulator must carefully consider class subsidization when determining the details of the net metering tariff. For example, if fixed costs are normally collected according to how much energy is used, net-metering customers may not cover the fixed cost necessary to have backup service provided by

the public utility. This is a typical area of intervention by the regulator. Green pricing tariffs based on the consumers' willingness to pay for the development of renewable energy are a *voluntary generation based-end-users' incentive*. Its effectiveness in developing renewable markets, though, remains to be seen.

B1: Capacity Based-Production Side Incentives

These incentives are usually supplied in the form of investment subsidies or fiscal measures. The regulator normally plays little part in defining *capacity based-production side incentives*; that responsibility lies with the government. Investment subsidies, for instance, are given on the commissioning of new renewable capacity as a percentage of total investment costs or as a fixed quota per kW installed. Managing the mechanism usually poses many difficulties in monitoring the system efficiency. Total investment costs may hide improper costs, and power plants may be developed with inefficient technologies and even second-hand systems. Maintenance may not be granted in the long-term as the incentive is given on initial costs only. Power plant developers might not optimize system load factors. Still, incentives on investment cost may be the most appropriate instrument to promote a national industry of renewable because incentives can be tied to specific technologies or plant components. There are different forms of fiscal incentives, which are also forms of *capacity based-production side incentives*. Import tax and VAT exemptions are forms of recurring incentive mechanisms in many countries. Fiscal measures may also encompass tax holiday regimes such as employment and income tax reductions and exemptions for companies working in the renewable energy sector. To promote energy access targets, fiscal measures in the form of tax on revenue exemptions may also be introduced to incentivize electricity supply in remote areas, as is being done in Senegal through the Investment Act.⁴¹ Tax incentives are usually a complementary feature of renewable policy. Quota obligation mechanisms as a minimum of renewable installed capacity over total energy company capacity have been used in the past, but they did not deliver the expected results. Companies have tended to install renewable power plants just to comply with the obligation, not prioritizing the plant generation efficiency and annual load factor.

B2: Capacity Based-End-User Side Incentives

These are incentives given to end-users to increase their self supply of electricity produced by renewable energy. The incentives are very often associated with photovoltaic technologies. The form of the incentive may be the imposition of a minimum quota of integration of renewable technology in buildings—usually new buildings linked to the construction permitting process. The building permit is granted if the construction project has a minimum percentage of renewable supply of electricity. VAT exemption on small renewable systems and components is also an effective instrument for the dissemination of photovoltaic technology at the household level as a back-up or basic access to energy. Net-metering options are usually used in conjunction with fiscal measures to optimize the electricity exchange with local public utilities once the system is installed.

B.6 Financial Sustainability of Renewable Energy Buyer

The financial sustainability of the renewable energy electricity buyer may be another obstacle to renewable energy development. Often, the obligation is placed on national public utilities. Not only may investors worry about the long-term capacity and willingness of the public utility to pay for the electricity generated by renewable energy sources, but it may turn out to be difficult to enforce the obligation to purchase renewable energy electricity if the final tariffs are not fully cost reflective. The concern is legitimate when tariffs do not generate enough money to pay back the full cost to the public utilities which, in turn, will not be able to pay renewable investors. In other cases, if the national public utility and the regulator dispute tariff and cost revisions, the former may delay payments to renewable energy producers until the dispute is over.

To prevent payment delays, it is possible to establish a renewable fund in which a portion of the money collected through final electricity tariffs are deposited before they are transferred to renewable energy producers. The electricity tariff or the national budget (or a combination of both) can be used to cover the renewable fund costs. International grants may be directed to the renewable fund as well.

When a renewable fund is introduced, the regulator is asked to calculate the annual forecasted costs of the renewable energy feed-in mechanism and introduce a specific renewable component into the final tariff to collect an amount of money equivalent to those costs. When tariffs are collected, the money corresponding to the renewable component is directly deposited into the fund. In this case, the PPA is agreed between the IPP and the renewable fund, which is responsible for the payments.

In many countries, the high level of non-technical losses is one of the main sources of concerns about the long-term financial sustainability of public utilities. Ghana has introduced regulation to reduce non-technical losses through the introduction of standards that must be respected by the public utilities.

C. Grid Access

The grid access rules and connection costs components of a legal framework are as important as the regulation of electricity remuneration. The location and size of renewable plants are determined by the local availability of renewable resources. Plants may be located far away from the existing grid infrastructure and/or the primary consumers of electricity. Connection costs for renewables constitute a significant part of final development costs, especially for small-scale renewable energy systems. If the SO is not used to dealing with renewable energy plants, the system has probably been designed for conventional power stations, and introduction of renewable energy may constitute a complication in the short-term. In addition, in vertically integrated electricity systems, the national company may not be willing to connect potential competitors on the generation side. This is particularly true when the vertically integrated company receives a favorable return on its own investments.

The regulator must ensure that a transparent and non-discriminatory procedure to connect the plants is put in place. At a minimum, the procedure should be based on the following components:

- Established connection rights for IPPs and clearly defined connection principles;
- A methodology to assign grid connection rights in case of constrained grid access; and
- A methodology to pay the connection costs.

C.1 Connection Rights

The non-discriminatory grid access right prescribes that the national SO must allow the connection of any IPP willing to feed its electricity into the national grid. Exceptions are if:

- The IPP is not able to meet some of the specific technical standards; or
- The distribution/transmission lines the IPP wants to connect to are congested, limiting the available capacity.

An effective way to ensure that the right to grid access is respected is to publish a grid code or adopt an internationally recognized code. The grid code contains technical interconnection standards for any production unit wishing to connect. The technical requirements are normally defined jointly between the regulator and the SO and are made available to the public through a regulatory order. A grid code sets parameters for high, medium, and low voltage connections. Anyone respecting those parameters may access the grid without restrictions. The grid code also specifies measuring and protection devices necessary for installations, as well as electronic testing time parameters and procedures for the first connection. The grid code also identifies the process steps for interconnection and may include sample interconnection documents (e.g., interconnection request forms, system impact study agreement or interconnection agreements). A standard connection request form may be appended to the grid code and a response deadline provided to the SO.

When non-discriminatory rights are in place, the SO may refuse connections only on the basis of proven transmission capacity constraints. Obsolete transport capacity, network design, and limited interconnectivity may significantly reduce the access for renewables in some parts of a country. The regulator may ask the SO to communicate available connection capacity for each area and make this information available to the market. The regulator may also ask that the SO keep records of all refused applications to be reconsidered in future grid development plans.

Renewable incentive schemes have been tested mainly in mature electricity markets where grid constraints have emerged only after a considerable penetration of renewable energy has been achieved. In emerging markets, it may be advisable to incorporate from the very beginning mechanisms that adequately remunerate renewable energy related network investments into renewable energy production.

Grid access is not an easy area to regulate. Large parts of the country may not have been connected to electric networks yet, and thus a significant percentage of the population may have no access to electricity service. In principle, future grid investments should be directed to those areas with both renewable potential and economical potential. Areas with economical potential have the financial means necessary to pay for service and consequently, lower the risk of future investment. The regulation supporting renewable energy should be balanced by taking

into consideration renewable energy potentials, economic potential, electricity access priorities, and a pragmatic approach to network developments. Specific schemes that favor the development of small renewable energy plants and net-metering options may be more effective in extending the grid to increase electricity access, especially in the short-run.

In the early stages of development when the grid is accessible, renewable energy penetration will likely not present significant problems, and unconstrained access to the grid may be granted to renewable energy developers. The SO will manage renewable energy connections and monitoring, promptly communicating to the regulator potential congestion risks. When necessary, the regulator introduces rules to access limited connection capacity and to establish queue management procedures.

Queue management is key to the orderly access to the grid. There are two main methodologies for queue management:

1. In a first-come, first-served system the renewable energy developer requests grid access from the SO, who will accept applications as long as capacity is available and will make selections that may be based on economic criteria.
2. In a tendering system, available capacity is auctioned among the renewable energy plants developers. They may be asked to offer a discount on the electricity they will sell if they are granted a connection right. Alternatively, they may be asked to pay a one-off connection fee. The revenue from the fee can be used to make new investments into the grid or be used to reduce the electricity tariff overall.

Both queue management systems include a deadline for plant commissioning. When capacity is scarce, renewable energy developers may also be asked to provide a deposit. It is important that assigned capacity be used within a reasonable period of time to avoid unnecessarily delaying renewable energy development. To avoid speculation, assigned capacity rights should not be transferred or sold. The start-up of a renewable energy market will flourish in a simple environment, and it is advisable not to introduce constrained rights unless it is absolutely necessary. Constrained rights can be introduced later, after the start-up phase.

C2 Connection Costs

The total connection cost of a new power plant is determined by two components:

1. Direct cost of connection, which is the cost of the line from the power station output meter to the closest network substation (also called shallow connection regime); and
2. Indirect cost of connection, which is the cost generated by the necessary reinforcement of the grid following the connection of new production units. These costs are also called deep connection regime.

The most commonly adopted connection cost principle, called a shallow connection regime, requires renewable energy developers to pay only for direct connection costs.

When an IPP decides to build a new line to reach the grid, the SO might agree to be the owner of that line, and the line may become a component of its future expansion strategy. For this

reason it may be useful to introduce a dual option connection cost regime. In the first option, the plant developer builds the line and bears its entire costs, but it is still necessary to:

- Make available technical connections for low, medium and high voltage specifications.
- Specify, by regulation, the maximum time allowed by the network operator for system and line inspection and testing.
- Set a maximum cost for the necessary modifications at the public utility connection point.

For deep connection costs, the SO must comply with specific time deadlines for the construction of the new line. The assigned time may vary depending on the complexity of the work that needs to be carried out, and in proportion to the total line length. The regulation should define a reference maximum time for every case. The SO is normally asked to reply to the plant developer's connection request within a given period, confirming:

- The availability of the requested capacity, and
- The SO's intention to build the new line. The reply should also specify the kind of work to be done (complex or ordinary), the expected time for connection to the grid, and a quote for the connection cost.

When the line is built by the SO, the plant developer will bear only a fraction of the total connection cost. An easy regulatory option is to introduce a lump sum payment, proportional to the length and the capacity of the requested connection.

In a vertically integrated market, the tariff reflects the cost of new connections and grid upgrades as well as the planning of the new generating infrastructure. Generation, transmission, and distribution infrastructure are parts of the same strategy. However, because the locations of the new plants introduced by IPPs may not have been anticipated by the SO, new production unit may incur additional costs to the system, which will need to be reconfigured.

Once a country prioritizes renewable energy development, it is usually understood that some of the indirect costs of connections are socialized and are absorbed into the tariff as ordinary network investments. Renewable energy developers are only asked to pay deep connection costs in very few cases.

D. Balancing the System

Renewables may be classified as dispatchable and non-dispatchable sources of energy. Non-dispatchable renewables may cause system fluctuations as they are weather dependent and cannot operate as load-following generation.

PV and wind systems display the highest fluctuation within a given period, whereas technologies using biogas, geothermal, biomass and hydro are easily predictable. Variability, however, is an inherent characteristic of some renewable energy, and fluctuation problems should not be considered a barrier to renewable energy development, especially in the early stages of renewable energy penetration in electricity markets.

Countries leading the installation of renewable energy, such as Denmark, have experienced no problem with high penetration of intermittent renewable energy sources. Denmark relies on more than 30% of wind generation, aided by many interconnections.⁴² Wind farms on the Cape Verdean islands of São Vicente and Sal provide an average of more than 30% of energy supply⁴³, but experiences a very stable wind regime. While the optimal renewable energy penetration depends on the local characteristics of each area, so far all electricity systems have been able to adapt to the new generation mix. Building many small plants also has advantages in terms of balancing the introduction. The SO - the body that allows the connections of renewable energy systems - should only stop any interconnections if it perceives a real balancing threat to the grid. Otherwise, as it often occurs, the intermittency characteristics of renewable energy are taken as an excuse not to connect renewables.

Therefore, no restrictions on renewable energy development should be introduced. Monitoring the impacts of local weather conditions may reveal that a level higher than 20% of electricity injected from renewable sources can be attained without jeopardizing grid stability. As mentioned above, in Cape Verde, the stable wind regime allows the energy system to absorb higher percentages of wind production. PV systems in Sub-Saharan countries may exhibit less fluctuation than in countries with different sun irradiation regimes. Building many small plants also has advantages in terms of balancing renewable energy: 1. The electricity system has time to adjust and 2. The impact of intermittent resources is less significant, for example if a 1MW PV plant does not generate the expected electricity it does not impact the system as significantly as a 20MW PV plant failing to generate electricity.

The following techniques can serve to strengthen the national system and enable it to cope with higher renewable penetration:

1. *Enhanced Communication*

Enhanced Communication between plant operators and the SO improves system balancing. The renewable energy owners and the SO must be incentivized to both improve their weather forecasting skills and promptly communicate any gaps.

2. *Incentive Mechanisms*

The introduction of price incentive mechanisms may motivate renewable energy generators to better utilize weather forecast data. A premium can be awarded for accurate day ahead forecasts, or a cost may be imposed upon producers to compensate unbalanced quantities. In sophisticated electricity markets, renewable energy producers are asked to pay the cost of balancing the system for the quantities they are responsible for.

3. *Electricity Storage Technologies*

The introduction of electricity storage technologies to provide back-up capacities. Pumped storage and water reservoirs are typical storage solutions: Water is pumped when there is an excess of renewable input and discharged within seconds to produce electricity when required by the system. Electrochemical storages are now being introduced in some markets that have experienced high penetration of intermittent renewables.

Storage may be considered a production or a transmission (system security) infrastructure. For production infrastructure (production), it is critical that the electricity market give

adequate price signals to remunerate storage infrastructures. For example, time of generation tariffs must be in place. A specific market for reserve capacity will also help. For transmission and security infrastructure, storage costs are recovered through the tariff.

In some contexts, intermittent sources of energy may be efficiently combined with specific energy uses that can serve as storage: water industry, water treatment plants, and water management. The water sector often benefits from discounted tariff options and incentives. The regulator may try to improve overall system management by orienting tariffs to system efficiency. It may be possible to request the water industry to offer balancing services in return for existing tariff privileges.

4. *Demand Response and Load Management*

Demand response and load management can be used to efficiently balance the system. Larger consumers may be willing to cut their load when necessitated by the system if adequately compensated. The load service may be purchased by a forfeit compensation or on a time basis. The costs of such services are normally recovered through tariffs as system costs. In advanced electricity systems, where there is a specific market for reserve, the demand loads may participate in the capacity reserve market as well as generating units and receive a balancing system price for the service they offer.

5. *Distributed Generation*

The more distributed the non-dispatchable renewable plants, the lower the risk of fluctuation. Depending on the configuration of the grid and the load center, the overall legislative framework might want to avoid the temptation to favor the commissioning of large non-dispatchable renewable energy plants and opt for the installation of a smaller-scale distributed pattern of plants in different areas of the country. Taking the context of the specific state into account, it might be better to have a number of small size plants distributed throughout the country and insist on different balancing areas rather than have a large plant in a single balancing area.

Net-metering options are an effective instrument for promoting distributed generation. It is also possible to introduce a supplementary tariff component to be added to feed-in tariffs for power plants directly connected at low or medium voltage. The component corresponds to avoided transmission costs (including losses).

6. *System Stability*

The larger the balancing area, which encompasses different production and load units, the lower the fluctuation risk. Penetration of renewables benefits from investments in network development and integration. Interconnecting larger systems, including cross-border connection, is the most efficient way to absorb local fluctuation problems. An effective instrument to incentivize network expansion is to recognize a higher remuneration on investments in new lines rather than existing capital remuneration of existing lines.

Increasing rapid response reserve capacity is another way to balance the system. Reserve capacity may be granted through administrative or market rules. Hydro basins or fossil fuel

(hot reserve) may be requested to hold a percentage of their capacity available in reserve. Alternatively, reserve capacity may be purchased in a competitive market. Finally, as overall system stability is a product of the mix and the flexibility of all generating units connected to the grid, commissioning combined-cycle gas turbine (CCGT) plants, which have the capacity to respond quickly to grid requirements, generally makes the system more flexible.

D.1 Curtailments

Curtailment of renewable energy (especially intermittent ones) may be necessary because of system requirements or may be implemented by the SO following network outages. It is a good principle to regulate curtailment procedures, especially in markets with fragile network systems. There are two main reasons why curtailment occurs:

1. Unpredictable sources of energy exceed the safety quota in the system. In a given area there may be many plants of varying size and ownership. The safety quota is the quota that the SO is able to manage within a given area.
2. Network instability or outages not caused by renewable energy generators. The protection systems of the renewable energy units will automatically shut down by the units during the time the network parameters are not re-established.

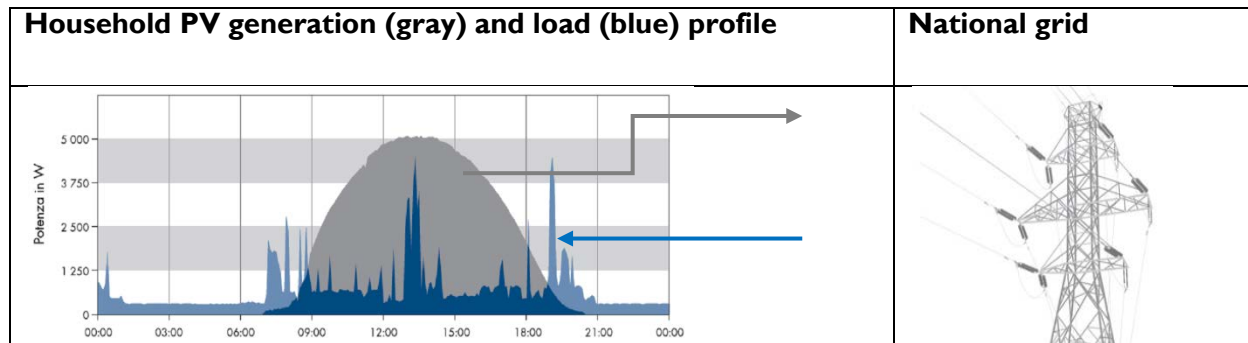
Excess capacity may be caused by many factors that renewable producers are not responsible for, these would include lack of coordination between system monitoring and plant licensing offices, mistakes in demand forecasts, unexpected load reduction, and delays in the construction of new network connections. Defining curtailment rules reduces investment risk. Criteria for curtailment have to be communicated, whether the SO proceeds by curtailing one plant at a time (a pre-determination of which plant is first curtailed should be included) or by reducing electricity inputs of all market participants (when technically feasible) by a percentage of their load. It is possible to establish a compensation for non-dispatched electricity following curtailments. The compensation to the SO or utility may be provided on all losses or only when losses occur for a significant period of time. Compensation for these economic resources may be recovered from all renewable energy producers, non-predictable renewable energy producers, or socialized into the tariff.

The second reason renewable energy producers are curtailed is because of network problems. The SO must address the problem and it may take more time than necessary. In vertically integrated markets, the SO may have little or no incentive to repair a line that an IPP is connected to, as they perceive IPPs as competitors. This situation may discourage investment by IPPs. In renewable energy plants, investment remuneration is highly influenced by the plant load factor. Some level of compensation to the SO or utility for non-dispatched electricity may be provided for, especially when outages exceed a maximum period per year. Network quality standards are usually introduced to assure the SO receives the right economic signals to repair networks in a timely manner.

E. Net-Metering

Net-metering is an important feature of renewable energy and favorable electricity markets. Net-metering is an exchange of electricity between a private producer, usually of small power plants (1-200kW), and the electric utility.

Figure 4: Net-Metering Schematic



Net-metering is an option to feed the excess of electricity produced by independent small installations into the system. It also provides independent small installations with backup service for times when their electricity demand exceeds generation. Depending on tariff design, net-metering can cause subsidization among customer groups, but generally costs the system nothing.

In some markets, financial incentives are added to the net-metering option to further support the development of small-scale renewable energy distributed generation. Net-metering alone offers a good economic incentive for small renewable energy installations (especially PV) because it values the electricity at a retail price that includes generation, transmission, distribution, metering, sale services, and taxes. Consequently, net-metering customers receive a higher remuneration than if it were simply paid the value of generation.

Net-metering usually requires the regulator to work on the following issues:

- **Technical aspects:** Net-metering plants are connected at low voltage. The SO probably has no experience with low voltage plant connections and two-direction metering. Technical connection rules must be prepared, which then can become national standards for all small renewable energy systems willing to apply for the net-metering option.
- **Economic aspects:** The net exchange of electricity between the public utility and the power producer is regulated through the electricity bill. The regulator defines the rules for this exchange. The treatment of excess energy and the method for collecting fixed costs in the tariff significantly impact the outcome of a net-metering program. If fixed costs are collected according to how much energy is used, some net-metering customers may not cover the fixed cost of having the public utility provide backup service. Consequently, the generation, distribution, and transmission fixed costs are socialized. The alternative is to have the tariff's fixed charge be high enough to cover the fixed costs required to serve small renewable energy systems when they are not

generating. However, a high fixed charge is difficult to afford for some customers, particularly after the upfront investment in the small renewable energy system.

- **Licensing:** A specific licensing procedure is normally not required for net-metering installations, given their limited size. Technical certification of products respecting grid quality and security standards, though, does need to be introduced.

In fact, because net-metering does not typically introduce a financial incentive for independent producers nor is it normally perceived as a violation of production concession rules, it may be directly introduced by regulators without the need for specific legislation. It is, in fact, a tariff option. Net-metering is not a *sale* of electricity but rather a *borrowing*. The owner of a small power plant does not receive any monetary income through the injection of the electricity produced in excess by the power plant, but is compensated solely with a corresponding amount of kWh.

F. System Monitoring, Registration and Certification

The regulator may find it necessary to keep track of the development of renewable infrastructure. Normally, renewable energy plants have a specific tariff system. The system may generate additional costs for the electricity market. The regulatory authority must have a comprehensive overview of the renewable energy plants installed and their respective tariff systems. A registry of all renewable energy installations over a given size (such as 1 kW) that are connected to the grid may be established. The registry should set up a simple registration procedure to avoid placing additional burdens on renewable energy developers.

It may be useful to certify electricity production. The certification may be used to monitor the system at the national level, to verify the renewable energy legislation progress in establishing regional targets, and to sell green rights on potential international green certificate or CO₂ markets. A certification process requires a precise definition of renewable energy technologies. The process would benefit from the harmonization of certification procedures at the ECOWAS level.

G. Contract Format

IPPs need to have a contract with the entity that will pay for the electricity the IPP generates. Regulators may be asked to comment on a standard contract format. Many plant developers have reported the absence of standard contracts as a potential barrier to renewable energy commissioning, because their counterpart, having the obligation to purchase renewable electricity, often tries to delay signing the contract by raising an infinite number of complications while the contract is being drafted. A standard contract makes the mechanism more transparent and easier to manage. The publication of a reference contract makes the application of the law clear and unequivocal for investors.

According to most FIT legislation, the developer will need a signed contract to be eligible for FITs. Often a signed contract is a precondition to access financing. A properly negotiated PPA is a critical part of a renewable energy project. It defines the price at which generated power is sold as well as various other obligations between parties. Negotiating an appropriate PPA is among the most complicated aspects of developing a clean power project, so the publication of

a standard PPA is very useful. Additionally, PPA review guidelines and procedures should be developed by the regulator – ERERA as the ECOWAS regional regulator could assist in this process as well. Information about PPAs as well as standard PPA templates can be found online.⁴⁴ The contractual legal basis differs by country. As a general rule, a complete PPA is normally structured to include:

- Definition and identification of the parties
- Recall of the legal basis the PPA is built upon (whereas)
- List of the IPP licensing requirements (land, water rights, environmental impact assessment)
- Description and identification of the power plant
- Definitions of terms and rules of interpretation
- Effective date of commencement and duration of the PPA
- Definition of the point of delivery (GIS coordinates)
- Procedures for metering produced electricity that is eligible for FIT
 - Technical requirement of metering
 - Responsibility for metering
 - Inspection to metering devices
- Payment of electricity
 - Price per kWh [legal basis]
 - Updating of tariff [legal basis]
 - Timing and format of billing
 - Timing of payments
 - Management of delayed payments
 - Adjustment and balance of payments
 - Rules for curtailments
- Obligation of the parties
 - Communication between partners
 - Connection, quality and safety standard as required by the grid code
 - Rules for inspection and counterpart access to power plant
 - Minimum standard for operation maintenance and communication of maintenance periods
 - Communication of modification of plant configuration

H. Impact Assessment and Consultation Process

The development of renewable policy and regulation is a relatively new process in all electricity markets not only because even more advanced markets, such as Germany, have introduced renewable targets only about two decades ago, but because renewable technologies continue to evolve very quickly. When a sector is growing—or booming, in the case of renewables—new players continuously enter the picture. Those players are not necessarily linked with the traditional electricity sector; because they may come from other industrial activities, universities, or financial institutions, for instance. Thus, they are usually not considered to be the *traditional counterparts* of electricity regulators.

It is difficult for regulators to follow the evolution of technologies and markets. Authorities are called upon mainly to regulate the bulk of existing electricity systems. This alone is a difficult

and complex task. Because renewable targets are being introduced at ECOWAS level and renewable technologies are challenging fossil fuel generation on a cost basis, more and more regulators must dedicate time and financial resources to understanding and regulating the renewable market.

When regulating the renewable market, regulators have to accept that stakeholders of renewable markets may not be limited uniquely to national electricity companies. New stakeholders must be taken into consideration when new regulatory decisions are proposed. If regulation does not reflect an understanding of the newcomers' points of view, it is very likely that the newcomers will not understand the resulting regulation.

In the renewable market, supplementing regulatory orders with consultation processes is a very useful tool for integrating the knowledge and the experiences both of the newcomers and the existing players into the decision-making process. A consultation process for renewable energy or regulations in general usually consists of the following four steps:

1. A preliminary notice is sent to an identified set of stakeholders soliciting their availability for a preliminary consultation.
2. A preliminary consultation is carried out with identified stakeholders, who are asked to express their views on a new decision the regulator intends to take. This feedback helps the regulator understand the general mood of market players regarding a proposed regulatory order.
3. A consultation document is published by the regulator. The document is a draft order that explains the assumptions and the principles behind the proposed decisions. Stakeholders taking part in the consultation process are asked to provide written comments on the regulator's decision that justify their point of view. In some cases the stakeholders may be asked to choose from among a number of potential options. The consultation document is usually published on the website of the regulatory authority. Stakeholders are requested to provide feedback to the regulator by a specific deadline.
4. Stakeholders may be interviewed to obtain more detailed explanations of their points of view. They may be reimbursed for the cost of participation.
5. The regulator collates all of the feedback, finalizes the order, and approves and publishes it. Documents furnished by participants during the consultation process are usually made available to the public. Participants may be asked whether or not they want their written contributions to be made public.

Because EREP anticipates national market developments, it is very important to encourage stakeholders at the national level to participate in the consultation process, or national interests may be not taken into due consideration. In addition to existing electricity companies and system operators, national stakeholders such as large consumers and their organizations, other industrial, manufacturing and agricultural companies or cooperatives, investors, financial institutions and banks, other national companies with a potential interest in the electricity sector (water or waste companies, for instance), universities, environmental organizations, and other relevant non-governmental organizations (NGO) should be invited to participate.

Another instrument that can be adopted to regulate renewable energy is the regulatory impact assessment. After reviewing the findings of the impact assessment, the regulator may decide to modify the decision before final approval.

The impact assessment should be a joint consultation process wherein the assumptions upon which the cost and benefit analysis are based are made public and may be challenged by participants during the consultation. The adoption of a consultation process and/or impact assessment facilitates the decision-making process, enables the regulator to learn from different stakeholders, and prepares the regulator to identify potential problems and mistakes that may otherwise become apparent only later.

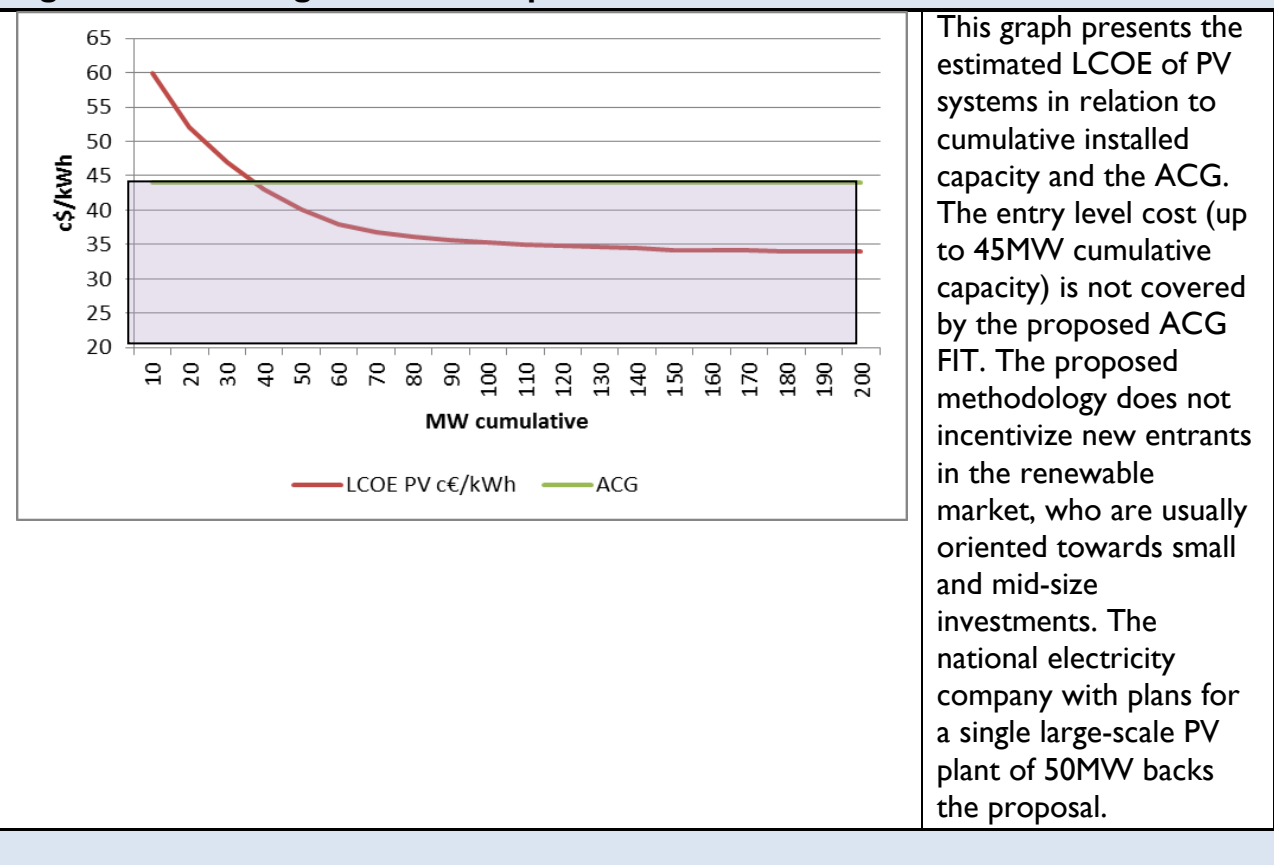
Box 7: A Hypothetical Example of a Consultation Process and Impact Assessment for a Feed-in Tariff Mechanism

The government asks the regulator to introduce a FIT for renewable technologies. The regulator wants to keep system costs as low as possible and suggests remunerating renewable electricity using the ACG principle. A specific technology cap is introduced to avoid jeopardizing system stability. The maximum allowed PV capacity is set at 50MW. During preliminary consultations (step 1 of the consultation process) the traditional stakeholders have supported the regulator's view.

A draft order is prepared and a consultation process is initiated (step 2); an impact assessment is attached to the consultation document. It is assumed that the ACG is high enough to sustain investments in renewable energy. The impact assessment reveals that the construction of renewable plants will not increase system costs in the near future.

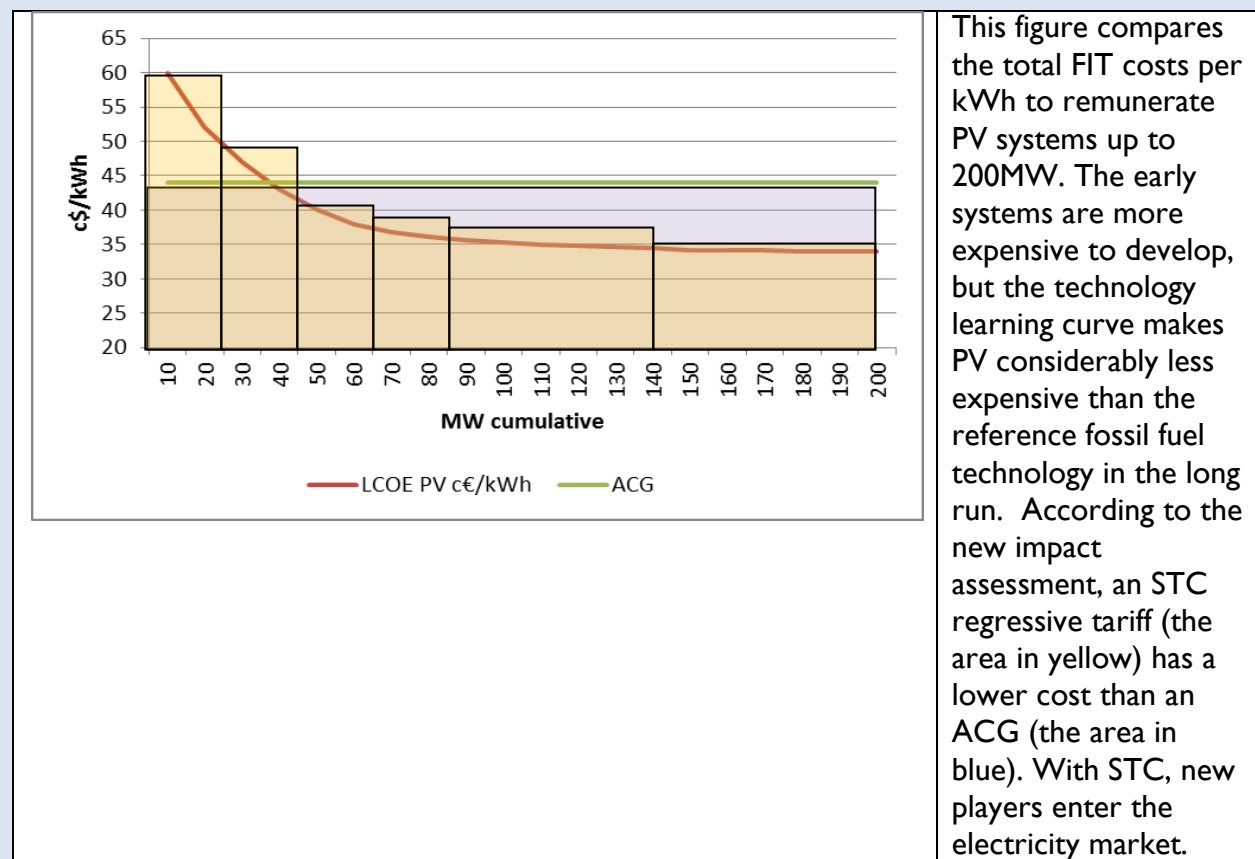
The national electricity company supports the proposed regulation. The company has, in fact, already found a potential international partner to build a large-scale PV plant (50MW) in a remote area of the country. The calculated ACG is higher than the estimated LCOE of the proposed PV plant (see Figure 5).

Figure 5: ACG Long-term Cost Impact Assessment



The association of large national electricity consumers and a consortium of small-scale enterprises respond to the consultation document, suggesting a different regulatory approach (step 3). They claim that the national cost of developing PV systems is considerably higher than international costs, given the lack of experience at the national level and the uncertain nature of the tax regime. While a tax exemption has been established by legislation, the custom offices have not fully implemented the exemption, especially with regard to small quantities. They also claim that connection rules are not clearly defined yet, and they perceive the risk of a plant commissioning delay. A delay will make capital costs unsustainable. They ask the regulator to adopt a STC methodology particularly suited to PV technologies. They prefer to have a feed-in tariff 20% higher than the calculated ACG for the first two years in order to overcome the described difficulties. They also ask that an annual cap of 10MW be introduced and that the FIT be reduced from the third year onward, reaching, at year five, a FIT lower than the ACG as well as an overall installed capacity of 50MW (see Figure 6). They also suggest introducing a limit of 2MW per PV plant in order to reduce unbalancing risks to the system. They claim that the proposed mechanism will be more effective for national growth, employment, and development of a distributed generation renewable industry.

Figure 6: STC and ACG Long-term Cost Impact Assessment



The regulator interviews the association of large national electricity consumers and the consortium of small-scale enterprises. A new impact assessment is conducted which reveals that the benefit of the proposed regulation outweighs the costs (step 4). The impact assessment calculates the additional costs on the final tariff to be paid by the consumers. The additional cost is estimated to be lower than the balancing risk introduced by the option initially proposed by the regulator. The benefit in terms of national development and employment is recognized by the government.

The final order incorporates the requests of the association of large national electricity consumers and the consortium of small-scale enterprises. Through this process new stakeholders have entered the electricity market.

Concluding Comments

The regulators in the ECOWAS region and the regional regulatory organizations supporting them will be tasked with integrating renewable energy into their existing electricity markets over the next few decades. As they begin this endeavor, we hope that these *Principles* will help regulators and policy makers understand what kinds of regulations and incentives for renewable energy are available, and how different choices might play out in their national markets.

Renewable energy is not only a new area of regulation but a continuously evolving field that embraces many new technologies. The ECOWAS region itself will continue to evolve and change. As such, the *Principles* is intended to be a living document that will continue to be updated and amended as regulations evolve and the regulatory landscape changes. USAID and NARUC are therefore especially grateful to ERERA for having agreed to institutionalize and continue to update the *Principles*.

Glossary of Terms

Direct Cost of Connection

The cost of the line from the power station output meter to the closest network substation (also called shallow connection regime).

Indirect Cost of Connection

The cost generated by the necessary reinforcement of the grid following the connection of new production units (also called deep connection regime).

Feed-in Tariff (FIT)

A policy mechanism designed to accelerate investment in renewable energy technologies by offering long-term contracts to renewable energy producers. The pre-determined price paid to renewable developers usually changes throughout the term of the contract, and unlike net-metering, the price is something other than the retail rate.

Green Certificate Mechanism

A tradable commodity proving that certain electricity is generated using renewable energy sources.

Impact Assessment

A study that tests the proposed regulation within a given period of time in order to anticipate potential costs and benefits of a new decision. In fact, the impact assessment enters into the decision-making process itself.

Mini Grid

A mini-grid is an electricity distribution area connecting generating units to few final consumers. The area is isolated from the national grid.

Net-metering

A policy mechanism designed to accelerate investment in small renewable energy technologies. Net-metering is the net exchange of electricity between a consumer who owns a small generation unit and the grid. The quantity not simultaneously absorbed by load (in-puts) is sent to the grid. In return, an equivalent amount of kWh backup service from the grid is credited. When production is not enough to supply loads, the kWh credit is utilized for the quantity consumed from the grid (with-draws).

Non-Technical Losses

Non-technical losses are caused by actions external to the power system and consist primarily of

electricity theft, non-payment by customers, and errors in accounting and record-keeping.⁴⁵

Power Purchase Agreement (PPA)

A long-term fixed contract between an electricity producer and a purchasing entity (usually a local utility) for the purchase of electricity generated by a power plant.

Standby or Backup Service

A tariff specifically designed for customers with on site generation, who might occasionally need back-up service because their system is down for maintenance or repairs. Regardless of whether back-up is requested, customers typically pay a pre-determined monthly fee for service. Sometimes the back-up must be pre-scheduled so the utility can plan on providing service.

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- ² Ibid.
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- ⁴ Ibid.
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- ⁸ Ibid.
- ⁹ Cape Verde has introduced a target of 50% renewable by 2020 and is currently discussing a national strategy for a 100% renewable target to be introduced in the future.
- ¹⁰ Out of the 10 Cape Verdean islands, only 1 has fresh water. All other islands desalinize their water resources, requiring a great amount of energy in the process. Cape Verde has begun to use renewable energy specifically to provide energy for desalinization plants.
- ¹¹ Renewable Energy Policy Network for the 21st Century. (2014). *Renewables Integrative Map Country Profile: Cape Verde*. Retrieved May 14, 201, from <http://www.map.ren21.net/pdf/profilepdf.aspx?idcountry=78>.
- ¹² The two regulatory agencies in Ghana have two different roles: PURC focuses on economic regulations and the EC on technical regulations.
- ¹³ Ghana Energy Commission (EC). (2009). *National Electricity Grid Code: Republic of Ghana*. Ghana, Accra: EC. Retrieved from <http://www.purc.com.gh/purc/sites/default/files/GridCode.pdf>.
- ¹⁴ Self-consumption, or self-production, is the amount of electricity consumed by a private entity at the same site where it is produced. A self-producer may be a factory relying on a private generator, or a household with a PV system installed. In some cases, when allowed, self-producers may feed the electricity in excess of their self-consumption into the national grid.
- ¹⁵ Economic Community Of West African States (ECOWAS). *ECOWAS Energy Protocol A/P4/I/03*. Retrieved from http://www.comm.ecowas.int/sec/en/protocoles/WA_EC_Protocol_English-_DEFINITIF.pdf
- ¹⁶ For more information on the ECOWAS Regional Electricity Regulatory Authority (ERERA), please see <http://www.erera.arrec.org>.
- ¹⁷ For more information on the ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE), please see <http://www.ecreee.org>.
- ¹⁸ For more information on the West African Power Pool (WAPP), please see <http://www.ecowapp.org>.

¹⁹ Economic Community Of West African States (ECOWAS). *ECOWAS Renewable Energy Policy (ERP)*. 2012. Retrieved from <http://www.ecowrex.org/document/ecowas-regional-policy-renewable-energy-0>.

²⁰ It is important to note that not only renewable sources of energy have higher capital costs than variable costs, but natural gas simple cycle peaker plants for example encounter the same issue.

²¹ Moomaw, W., P. Burgherr, G. Heath, M. Lenzen, J. Nyboer, A. Verbruggen (2011). Annex II: Methodology. In O. Edenhofer, R. Pichs-Madruga, Y. Sokona, K. Seyboth, P. Matschoss, S. Kadner, T. Zwickel, P. Eickemeier, G. Hansen, S. Schlömer, C. von Stechow (Eds.), *IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation*. Cambridge, United Kingdom and New York, NY, USA: Cambridge University Press.

²² While there are a number of incentive schemes for renewable energy, NARUC's ECOWAS partners have expressed specific interest in examining FIT more closely. Thus, NARUC's focus on FIT in this document is based on partner interests and does not represent a policy stance or recommendation to ECOWAS countries.

²³ PURA. (2013, October). Presentation at the USAID-NARUC Workshop: Integrating Renewables into the Electricity Market: From Policy to Practice, 16-17 October 2013, Accra, Ghana.

²⁴ The full methodology for grid connected renewable energy systems can be downloaded from EWURA's website: EWURA (Tanzanian Energy and Water Utilities Regulatory Authority). (2008). *Standardized Tariff Methodology for the Sale of Electricity to the Main Grid in Tanzania under Standardized Small Power Purchase Agreements*. Retrieved from <http://www.ewura.go.tz/pdf/SPPT/Tanzania%20STM%20for%20Main%20Grid%20under%20SPPA%20-2009.pdf>.

²⁵ Ibid.

²⁶ Ibid.

²⁷ Values in Tanzanian Shillings (approx. 1,700 TZS per 1 USD, July 2014).

²⁸ PURA. (2013, October). Presentation at the USAID-NARUC Workshop: Integrating Renewables into the Electricity Market: From Policy to Practice, 16-17 October 2013, Accra, Ghana.

²⁹ PURC. (2013, October). Presentation at the USAID-NARUC Workshop: Integrating Renewables into the Electricity Market: From Policy to Practice, 16-17 October 2013, Accra, Ghana.

³⁰ Gesetz zur Neuregelung des Rechtsrahmens für die Förderung der Stromerzeugung aus erneuerbaren Energien (Act on the Amendment of the Legal Framework for the Promotion of Electricity Generation from Renewable Energies) of 2012. Retrieved from <http://www.buzer.de/gesetz/9842/>

³¹ Ibid.

³² The initial period of 12 years at a higher FIT may be prolonged according to specific plant characteristics. For instance, it can be extended by five months for each full nautical mile beyond 12 nautical miles that the installation is located off-shore and by 1.7 months for each full meter of water depth over 20 meters. That additional premium may be used to meet other policy priorities, such as environmental ones or, in the case of an ECOWAS country, energy access strategies. FITs may be for instance prolonged if renewable energy plants are built in areas currently not reached by electricity services.

³³ The initial tariff level normally granted for five years may be prolonged according to the annual load factor compared to the standard load factor. In case production has been lower than expected the initial tariff period is prolonged accordingly. A similar approach may be used to regulate curtailment of renewable power plants in case of grid instability (see section on curtailment).

³⁴ Gesetz zur Neuregelung des Rechtsrahmens für die Förderung der Stromerzeugung aus erneuerbaren Energien (Act on the Amendment of the Legal Framework for the Promotion of Electricity Generation from Renewable Energies) of 2012. Retrieved from <http://www.buzer.de/gesetz/9842/>

³⁵ For more information, see Klein, A., Merkel, I E., Pfluger, B., Held, A., Ragwitz, M., Resch, G., and Busch, S. (2010). *Evaluation of Different Feed-In Tariff Design Options – Best Practice Paper for the International Feed-in Cooperation*. Fraunhofer ISI. EEG.

³⁶ Decreto Ministeriale - Incentivi per energia da fonti rinnovabili elettriche non fotovoltaiche (Decree on Incentive Tariffs for Renewable Energy (not including photovoltaic technologies). (2012, July). Retrieved from http://www.sviluppoeconomico.gov.it/images/stories/normativa/DM_6_luglio_2012_sf.pdf.

³⁷ Gesetz zur Neuregelung des Rechtsrahmens für die Förderung der Stromerzeugung aus erneuerbaren Energien (Act on the Amendment of the Legal Framework for the Promotion of Electricity Generation from Renewable Energies) of 2012. Retrieved from <http://www.buzer.de/gesetz/9842/>.

³⁸ Foundation Offshore Wind Energy. *EEG-Remuneration*. Retrieved on July 9, 2014 from <http://www.offshore-windenergie.net/en/politics/eeg-remuneration>.

³⁹ PURA. (2013, October). Presentation at the USAID-NARUC Workshop: Integrating Renewables into the Electricity Market: From Policy to Practice, 16-17 October 2013, Accra, Ghana.

⁴⁰ The values do not correspond to real values. The calculation is done for demonstration purposes only.

⁴¹ Sénégalais Code des Investissements (Senegalese Investment Code). Loi No. 2004-06 (Law No 2004-06). (2004 February). Retrieved from <http://www.gouv.sn/Code-des-investissements.html>.

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⁴⁴ Templates can be found at:

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⁴⁵ Definition from the World Bank in Antmann, P. (2009, July). *Reducing Technical and Non-Technical Losses in the Power Sector*. Background Paper for the World Bank Group Energy Sector Strategy. Retrieved from http://siteresources.worldbank.org/EXTESC/Resources/Background_paper_Reducing_losses_in_the_power_sector.pdf.

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