



ETHIOPIAN ENERGY AUTHORITY

TARIFF GUIDELINE AND METHODOLOGY

For Grid power supply

DECEMBER 2018

Introduction to the tariff methodology and guideline

This tariff guideline and methodology is prepared in accordance with the energy law and the energy regulations with a view to providing clear and detail directions in the preparation of tariff Application to be submitted to the Authority. Tariff application can be submitted at every four interval supported by a comprehensive tariff study. Tariff application submission is also expected under the regulation in the preparation of interim tariff adjustment resulting from the conditions indicated in this guideline. All adjustments including the one after the elapse of the regulatory lag require preapproval applications and regular rate adjustment computations as per the energy regulation and as more elaborated in this guideline.

This methodology guide is designed to give sufficient freedom to the Utilities to introduce more innovative elements such as in the rebalancing of rates which they may suggest other alternative structures than indicated in this guideline.

In other cases while there are a number proven approaches and methodologies to address specific tariff determination such as transmission wheeling charge, the level of development of the sub sector and the industry has been taken in to account in adopting approaches and methodologies subject to the fact that this could be revised and upgraded as the need may arise. Still under circumstances where national economic situation and the domestic debt and equity market may not provide t provide sufficient statistical insight regarding the cost of capital, proxy data from regional or international experiences as may be adjusted to local circumstances are indicated to be used instead.

Chapter One

General Provisions

Article 1. Issuing Authority

This Tariff Guidelines and Methodology is issued by the Authority in accordance with Article 4(3) of the Energy Proclamation No. 810/2013, Article 32(1) and Article 32 (7) of the Energy Council of Ministers Regulation No. /2018.

Article 2. Short Title

This Guidelines may be cited as the "Tariff Guidelines and Methodology for Generation, Transmission and Distribution Sectors, No. -----/2018."

Article 3. Definitions

In this Tariff Guidelines and Methodology, unless the context requires otherwise:

1. **“Allocative Efficiency”** refers to measurement of a company’s ability to use a combination of inputs in optimal proportions, given their respective prices;
2. **“Ancillary Services”** refer to services which are provided by the transmission system operator to ensure the stability, security and quality of power transmission. These services include spinning and non-spinning reserves, voltage control, reactive power control and black start capability;
3. **“Authority”** refers to the Ethiopian Energy Authority;
4. **“Bulk Generation Tariff”** refers to the charge in the electricity retail tariff, which is paid to the distribution licensee to cover the cost of purchasing electricity from the wholesale power market. It is determined as a weighted average cost of the system generation supplies;
5. **“Bulk Supply Tariff”** means the price of electricity at the Bulk Supply Point of the power system, which recovers the total cost of generation and transmission services;
6. **“Coincident Factor”** means the ratio of coincident demand to maximum demand, and it ranges between 0 and 1;
7. **“Demand Side Management”** refers to the practices or approaches which are used to influence the amount or timing of consumer’s energy usage, to ensure efficient utilization of scarce resources;

8. **“Demand”** means amount of electricity used at a specific point in time, and measured in W, KW, MW or GW;
9. **“Dynamic Efficiency”** refers to a firm’s ability to reduce its costs by implementing new production processes. It is concerned with optimal rate of innovation and investment to improve production processes to help reduce long-run average cost;
10. **“Energy”** means the amount of electricity used over a period of time and is measured in kWh, MWh or GWh;
11. **“Kilo Volt Amperes (KVA)”** is used to mean the total apparent power that a transformer supplies to a load;
12. **“Load Factor”** means the ratio of the average load over the peak load in a specific time period. It is therefore a measure of how steady an electrical load is.
13. **“Peak Coincident Demand”** refers to the demand measured at the same time when the system demand reaches its peak;
14. **“Power Factor”** means the ratio of total apparent power (KVA) that is converted to real or useful work;
15. **“Productive Efficiency”** refers to a measure of a company’s ability to either maximise outputs from a given set of inputs, or to produce a given outputs with a minimal set of inputs;
16. **“Reactive Power”** means the portion of total apparent power which an alternating current of an electrical system requires to do useful work. However, not all reactive power requirements are necessary in every situation, and it is usually measured in vars;
17. **“Transmission Service Tariff”** refers to the charge paid to the transmission licensee to cover the cost of providing transmission network and system operator services, in an open and non-discriminatory manner;

Abbreviations

1. ATAM	Automatic Tariff Adjustment Mechanism
2. BST	Bulk Supply Tariff
3. CAPM	Capital Asset Pricing Model
4. CCV	Current Cost Valuation
5. CWIP	Capital/Construction Work-In-Progress
6. DORC	Depreciated Optimised Replacement Cost
7. DSM	Demand Side Management
8. DST	Distribution Service Tariff
9. EEA	Ethiopian Energy Authority
10. EEP	Ethiopian Electric Power
11. EEU	Ethiopian Electric Utility
12. HV	High Voltage
13. IBT	Increasing Block Tariff
14. IDC	Interest during Construction
15. IPP	Independent Power Producer
16. Km	Kilometre
17. KVA	Kilovolt Amperes
18. KW	Kilowatt
19. KWh	Kilowatt hour
20. LRIC	Long-run Incremental Cost
21. LRMC	Long-run Marginal Cost

Article 4. Objectives

The objectives of this Tariff Guidelines and Methodology are:

1. Provide the basis for **developing unbundled tariffs** for the *generation, transmission and distribution/sale segments* of Ethiopia's electricity supply industry;
2. Provide the basis for implementing **timely tariff adjustment** and hence a multi-year tariff regime in Ethiopia.
3. Establish the tariff-setting process and procedures for reviewing licensees' tariffs

Article 5.Scope

The electricity pricing Guidelines and Methodology will apply to the following grid-connected licensees:

1. Generation;
2. Transmission;
3. Distribution and Sale;

Chapter 2. Legal Basis for Tariff Setting

Article 6. Provisions in the Electricity Proclamation and Draft Energy Operations

1. Article 4 of the Energy Proclamation No. 810/2013 states inter alia that, EEA shall have the powers and duties to *review tariff proposals in relation to the national grid*, and submit same to the government for approval. Regarding off-grid tariff regulation, Article 4 of the Proclamation states that EEA *shall issue and regulate the implementation of guidelines* for the determination of off-grid systems, while Article 5 grants powers to EEA for approval of such tariffs.
2. In accordance with Article 40 sub-article 1 and 2 of the Energy proclamation and Article 29 to 32, of the Energy Regulation, which grants powers to the EEA *to issue directives to be followed by all licensees to compute the various cost components of the revenue requirement* including and other accompanying costs, and other principles for tariff submission.
3. Article 29 of the Energy Regulations outlines the following general principles which must guide EEA when reviewing and recommending grid-connected tariffs for approval, or approving off-grid tariffs:
 - 3.1 Generation, transmission, distribution and sale of electricity businesses must be conducted on commercial principles;
 - 3.2 Need to take account of factors which would encourage competition, efficiency, economical use of the resource, efficiency in performance, transparency, accommodate the needs of system integrity and attract investment to the electricity sector,

- 3.3 Safeguard customers interest and at the same time, ensure recovery of the cost of electricity, as per the relevant regulations;
 - 3.4 Adopt multi-year tariff principles;
 - 3.5 Promote co-generation and generation of electricity of electricity from renewable energy sources;
 - 3.6 Ensure that access charges for use of a transmission or distribution system shall be based upon comparable use;
 - 3.7 Costs covered by subsidies, cross-subsidies or grants shall not be reflected in the costs of business operation,
 - 3.8 Tariff adjustments, shall to the extent possible, ensure price stability and simplicity of administration;
4. Article 30, sub-Article 1, of the Energy Regulation also requires that in reviewing and recommending grid related tariff or approving off-grid tariff, the following and other appropriate factors will be considered;
- 4.1 Cost of fuel;
 - 4.2 Cost of power purchase;
 - 4.3 Rate of inflation or deflation;
 - 4.4 Foreign Currency fluctuation
5. The third party access to the transmission network according to Article 33(1), of the Energy Regulation; Based on the conditions specified in the license, access to and use of the national transmission grid shall be open for international power trade; and its use shall be, transparent and cost-reflective, and based on transmission service agreement to be approved by the regulator
6. Under Article 21 of this Tariff Guideline and Methodology principles and methodology for **Transmission Wheeling Access Charge is provided.**

Article 7. Tariff Setting and Approval

1. According to the Energy Proclamation, the tariff for grid-connected licensees is to be recommended to the government for approval based on these guidelines. In developing the tariff guidelines and methodology for both grid and off-grid, EEA is required to adopt a **consultative approach**. Article 41 of the Energy Proclamation specifically requires EEA before issuing any directive, to consult representatives of the following groups:
 - 1.1 Licensees;
 - 1.2 Users of bulk electricity service;

- 1.3 Energy efficiency implementing entities; and
- 1.4 Other stakeholders;
- 2. Licensees have the obligation as per the Energy law Article 10 sub Article 1 and the Energy Regulation Article 22 sub Article 4 to submit relevant data and information to the Authority. In submitting the data licensees will follow the “*Tariff Application Information Requirements*” guideline annexed to this “Tariff guideline and methodology”.

Chapter 3. Tariff Principles

Article 8. Regulatory Objectives

These key objectives are briefly presented discussed below:

1. Financial Viability

Financial viability implies that tariffs, including subsidies, should cover prudently incurred costs, including return on investment.

2. Productive Efficiency

The regulatory approach adopted should therefore incentivise utility operators to achieve cost minimization and ensure that no inefficient cost pass-through is transferred to customers in the tariffs.

3. Allocative Efficiency

The aim of allocative efficiency is to ensure that tariffs reflect marginal costs, especially long-run marginal or forward-looking costs. The tariff should also reflect changes which are completely beyond the control of the regulator and the licensees.

4. Dynamic Efficiency

The goal of dynamic efficiency is to ensure that licensees are incentivized to think of future consumers and invest accordingly in technological innovation. Therefore in setting the revenue requirements, it is important to also include the cost of future investments. Dynamic efficiency therefore ensures that there is a linkage between demand forecast and current and future investment levels.

5. Distributional Fairness

Distributional fairness means that the tariff structures and levels for each customer class should be consistent with end-user’s ability to pay. The Regulator can use cross-subsidies and/or obtain support through external government subsidy to help vulnerable consumers.

6. In addition to the above regulatory objectives, it is imperative that the adopted price regulation takes cognizance of the relevant policy objectives of the government, as well as those in the Energy Law or other related Proclamation.

Article 9. Pricing Principles

To apply the above regulatory principles to tariff setting, the following principles should be adopted to achieve an efficient pricing methodology:

1. Cost Reflectivity

This implies that costs should be allocated to consumers based on the cost of causation. Therefore, for efficient pricing, each consumer class should pay the appropriate share of the cost of providing the service.

2. Financial Viability

Efficient tariff should generate sufficient revenue to ensure the financial viability of the utility company by covering prudently incurred costs, so that investors can recover the full cost of providing the service, including return on investment. Financially sound utilities are more likely to invest and upgrade facilities to improve service quality to meet the needs of customers.

3. Non-discrimination

The tariff structures and levels should be non-discriminatory and, for the sake of fairness and equity, should be applicable to all customers.

4. Transparency and Ease of Application

The tariff should be developed through a transparent process, and the retail tariff structure should be simple and easy to understand and administer.

5. Correct Price signals

The tariff should provide the appropriate price signals to encourage efficiency of operations. The tariff should be performance-based and should take into account quality of service and operational efficiency of licensees. Correct signals will also lead to efficient allocation of resources.

6. Tariff and Subsidies

If the policy requires taking account of subsidies in tariff design, then for the sake of transparency, the amount of subsidy should be quantified and well-targeted.

7. Appropriate Tariff Structure

The tariffs should reflect separate cost components (i.e. fixed and variable costs) in order to send the correct price signals to consumers.

8. Cause Causality

The “*Cost Causer Pay*” rule where costs are assigned to customers that caused a cost to be incurred, should apply.

9. Elicit Demand Response

The electricity tariff should be able to signal the cost of electricity as close to real-time, as far as practicable, through Time-of-Use tariffs, Seasonal Tariffs etc.

10. Encourage Demand Side Management

An effective tariff structure should promote efficient use of energy, enhance productive efficiency and provide clear investment incentives in DSM.

11. Compatibility with Competition

The electricity rate structure should reflect competitive market outcomes as close as possible. Regulators design unbundled tariff for each segment of the electricity industry which would provide open, non-discriminatory and comparable third party access to the transmission system

12. In practice, some of the pricing principles may be in conflict however a good balance between any opposing objectives should be maintained, while taking into account, any practical issues which may affect the pricing implementation.

Article 10. Pricing Approaches

1. Types of Price Regulation

Price regulation can generally be categorized into the following main types:

- 1.1 Cost of service or Rate of Return;
- 1.2 Incentive Regulation: Price or Revenue Cap;
- 1.3 Hybrid Approach;
- 1.4 Benchmark and Yardstick Regulation;

2. Cost of Service Regulation

Cost of service regulation, also known as rate of return regulation, involves assessing the cost of various components of the total cost of providing the regulated service, and fixing an upper limit on the mark-up allowed on costs. With cost of service regulation, any shock to licensees' costs is quickly passed on to consumers through **annual tariff adjustments**. If applied in its 'purest' form, this form of regulation could serve as a dis-incentive for utility operators to be efficient, since all or most of the costs of the revenue requirements, are immediately passed-through to consumers during the annual rate review.

3. Incentive Regulation: Price Cap and Revenue Cap

Price Cap regulation consists of setting an upper limit to the **average tariff** for a service, while revenue cap involves setting an upper limit to **the revenue** that can be generated by the service. With incentive regulation, the rationale is to incentivise the utility company to cut costs, and attempt to improve productive efficiency above the regulator's benchmark. In practice, what this means is that if the utility company is able to improve its productivity levels at a faster rate than what was assumed in the tariff analysis, then the utility may be allowed to keep the higher returns for investment, to invest in and improve quality of service delivery. Conversely, if the utility's productivity improvement is below what was assumed in the tariff analysis, then the company will earn lower returns.

3.1 In applying the price or revenue cap, the regulator usually set a path for minimum cost reduction targets, using an X-factor in the generic RPI - X formula. With incentive

regulation, it is important that the utility operator's costs and international cost benchmarks are monitored by the regulator. Setting a cap which is too high could enable the operator to reap rents comparable to monopolies.

3.2 Price Caps and revenue caps are usually set every 4 - 5 years, and unlike rate of return regulation, are largely exogenous to the utility's behaviour. When applied in its 'purest' form, they can lead to quality of service deterioration, since the utilities find that one easy way of reducing cost is to cut investment in quality. It is therefore important for regulator to robustly monitor quality of service, when either price or revenue cap regulation is used.

4. Hybrid Approach

4.1 A hybrid approach is usually used in practice by modifying the 'pure' rate of return, 'pure' price cap or 'pure' revenue cap regulation. *This is done by adding some guaranteed reimbursement to price cap or revenue cap regime, or adding incentives to cost of service regulation.* In practice, 'pure' price cap or revenue cap regulation can be made a hybrid regime by incorporating an **automatic pass-through of exogenous cost to consumers**. With this approach, costs which are not under the control of the utility company are included in the pass-through mechanism. With the pass-through mechanism, any increase or decrease in costs is automatically passed on to consumers through a tariff adjustment on periodic basis.

4.2 Most regulatory jurisdictions are transiting from 'pure' rate of return or 'pure' price/revenue cap regulation to a hybrid regime, and this is usually justifiable if there are costs that the utility company cannot control, and these are combined with the introduction of incentives.

5. Benchmark and Yardstick Regulation

Benchmark and yardstick regulation approaches are usually used in conjunction with incentive regulation (i.e. price or revenue cap) and also with rate of return regulation. Benchmarking regulation involves the use of information from firms *outside the regulatory jurisdiction* to set targets for the licensees. The main advantage of benchmark regulation when used with any of the main approaches is that:

- i. It strengthens the incentive for licensees to improve on efficiency;
- ii. Encourages the licensees to pursue cost cutting measures;

Yardstick regulation on the other hand, is used for comparative analysis between or among *firms within the same regulatory system*. With this approach, the costs are determined based upon the reported costs of other firms in the same regulatory jurisdiction.

Article 11. Adopted pricing approach

1. Generally, a ‘pure’ revenue cap philosophy is adopted in some countries where there is relatively stable growth in demand while ‘pure’ price cap regulation is generally used to promote growth. The main challenge in adopting any of these approaches is the ability to accurately forecast system demand. The adoption of ‘pure’ price cap or revenue cap regulation can result in a static price regulation regime, and this can make tariff regulation very rigid and inflexible.
2. Taking cognizance of the drawbacks associated with ‘pure’ rate of return regulation in terms of incentives as a result of the annual price reviews, and since the desire in Ethiopia is to enhance access to electricity while incentivizing licensees to be efficient and improve quality of service, **EEA has adopted a hybrid price cap regulation.** This is consistent with Article 29 of the Energy Regulations which **stipulates a multiyear tariff thus licensees has to submit a full cost of service tariff study every 4 years as per Article 31 sub Article 7 of the Energy Regulation.**
3. The hybrid form of price cap regulation would still involve the use of **cost of service methodology** to determine the base tariff, but in line with draft Energy Regulations, **Tariff Adjustment Mechanism** will be incorporated in the tariff-setting process. This approach allows for this *pricing flexibility* by including pass-through **Adjustment Mechanism** to take account of costs such as: cost of power purchase, inflation etc., which are outside the control of the licensees.
4. In applying the tariff adjustment mechanism, this may involve some administrative processes. EEA **could** require the licensees to justify the need for the tariff adjustment when the uncontrollable variables deviate from the values assumed during the base period tariff-setting.
5. The hybrid price cap formula can generally be represented as follows:

$$P_t = P_{t-1} (1 + \text{CPI} - X) \pm Z$$

Where

P_{t-1} = Price in period t

P_{t-1} = Based period tariff or tariff in period t – 1

CPI = Consumer Price Index

X = Productivity Gain or X-factor

Z = cost pass-through mechanism

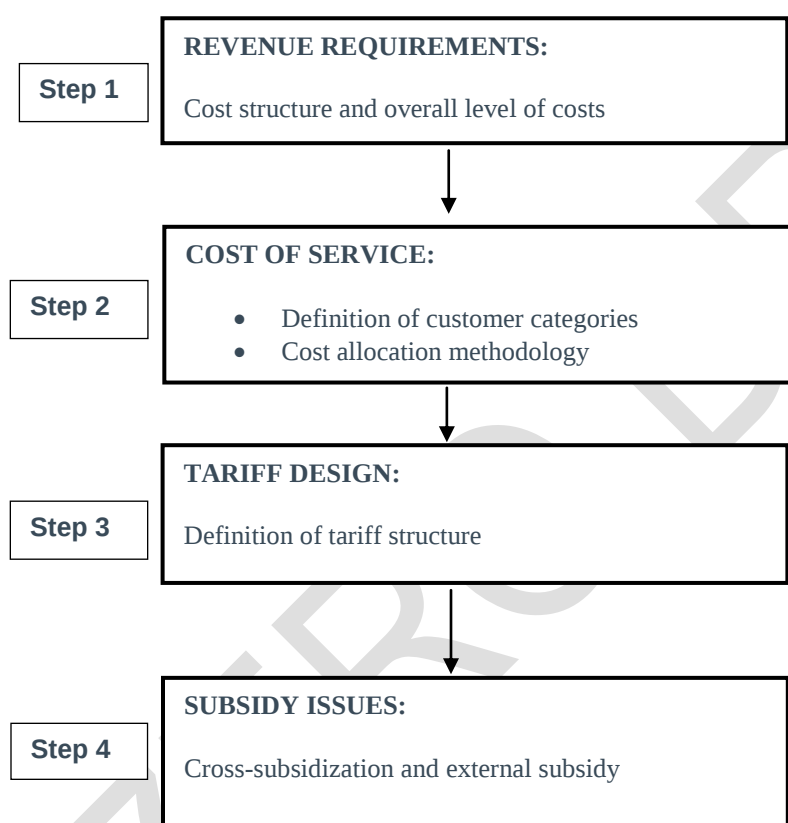
With hybrid price cap regulation, the period for determining the base period is n 4 years.

Chapter 4. Revenue Requirements

Article 12. Revenue Requirements Determination

1. Revenue requirements determination is the first step in the tariff development process as depicted in figure 4-1 below. To determine the revenue requirements, whether in cost of service or incentive regulation, the first task is to determine the cost structure and overall level of costs.

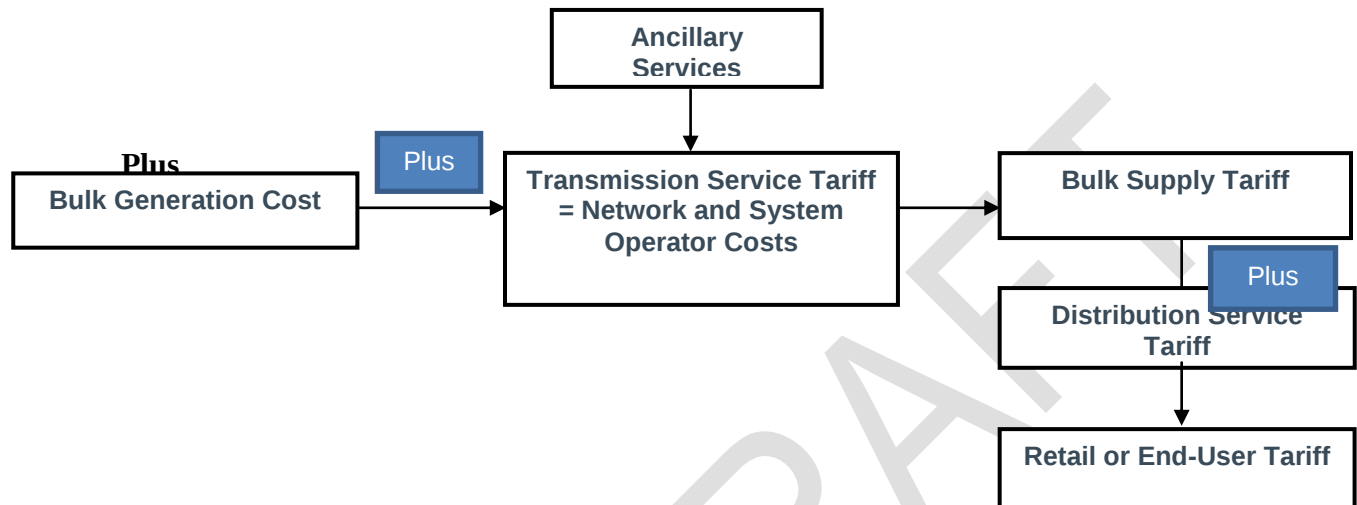
Figure 4-1. Tariff Development Process



2. Under step 1, EEA is required to determine which costs are to be recovered in the tariff, as well as the basic cost recovery principles or criteria to be applied. The ability to identify the correct cost components in step 1 is critical for ensuring the financial viability of the licensee.
3. In line with the Energy Proclamation which seeks to promote transparency and accuracy it is important that the revenue requirements and hence the tariffs, should be developed

separately (i.e. tariff unbundling) for each value segment of the service, as depicted below in figure 4-2.

Figure 4-2.Components of End-Use or Retail Tariff.



Article 13.Components of Revenue Requirements

1. It is important to identify the various cost components and ensure that all the relevant costs have been included. The key cost components which are common to the three segments (i.e. generation, transmission and distribution/sale) are discussed below in this section:

- 1.1 Regulatory Asset Base (i.e. Rate Base);
- 1.2 Working Capital Allowance;
- 1.3 Regulatory Depreciation;
- 1.4 Operating and Maintenance Expenses;
- 1.5 Cost of Capital or Financial Charges;
- 1.6 Taxes;
- 1.7 Capital Works-In-Progress;

2. Regulatory Asset Base

The Regulatory Asset Base (RAB) or the Rate Base, is the investment that the power utility has made in order to provide the regulated service. The inclusion of the RAB is therefore to recognize the investment made by the licensee in fixed assets to supply the regulated service. It is computed as the total cost of plant and equipment invested in the licensed activity, less the accumulated depreciation. To include an asset in the RAB, EEA would need to ensure that the following conditions are met:

- 2.1 The fixed assets must meet the *“Used and Useful”* rule. This implies that the asset *must be used* or is *useful* for the production of the regulated product;

2.2 A *useful or useable asset* means the asset should be in such a condition that it can be added to the generation capacity mix or should be able to supply power within 3 months;

2.3 To determine the RAB, it is important to first identify the opening asset base and *roll it forward* to obtain the closing RAB. Asset *roll-forward* refers to how the initial or opening asset base, once determined, is adjusted overtime to reflect changes in the value of the productive capability of existing asset base, including additional investment.

2.4 The Net Fixed Asset from rolling forward of opening RAB is determined as follows:

NFA

$$\text{closing}_t = [\text{RAB}_{\text{opening},t} - \Sigma D_t] + \text{AA}_t - \text{AD}_t$$

where:

$\text{NFA}_{\text{closing},t}$ = Closing Net Fixed Asset for period t;

$\text{RAB}_{\text{opening},t}$ = Opening Regulatory Asset Base for period t;

ΣD_t = Accumulated depreciation for period t.

AA_t = Asset Addition during period t;

AD_t = Asset Disposals during period t;

3. Working Capital Allowance

3.1 Working capital requirement arises where operating expenses are paid in advance of revenue receipts, which creates a cost of financing of those operating activities. Allowance for working capital are usually taken into account by regulators when computing the revenue requirements. It is allowed as part of the rate base because it consists of funds that could earn a rate of return if invested in some other venture. The working capital, in accounting terms, is the difference between Current Assets and Current Liabilities. The main items involved are:

3.1.1 Inventories (i.e. fuel, supplies, consumables etc.);

3.1.2 Accounts Receivable;

3.1.3 Salaries Payable;

3.1.4 Taxes Payment;

3.2 If the Working Capital Allowance is taken into account, the closing Regulatory Asset Base for period t, is computed as:

$$\text{RAB}_{\text{closing},t} = \text{Net Fixed Asset}_t + \text{Working Capital}_t$$

The RAB then becomes the investment upon which the licensee is allowed to earn a reasonable return which is calculated as follows:

Return on Investment = RAB × Cost of Capital

3.3 To avoid over-stating of working capital allowance, the following '*Guiding Principles*' are used to benchmark the working capital allowance:

- 3.3.1 The cost must relate only to the cost of financing operating expenditure;
- 3.3.2 The calculation must relate to only relevant revenue and expenses;
- 3.3.3 The calculation should take account of benchmark assumptions about timing of cash flows to prevent compensating licensees for **imprudent costs and inefficient activities**;

4. Adopted methodology

The working capital allowance can be derived by making **explicit assumptions or setting regulatory benchmarks** regarding the extent to which revenue is received at a lag (i.e. revenue lag) and the extent to which operating expenditure is incurred after an activity has been performed (expense Lead) to estimate the working capital. The formula is also a function of the operating expenditure (opex).

$$\text{Working Capital Allowance} = \frac{[\text{Revenue Lag (Days)} - \text{Expense Lead (Days)}] \times \text{Opex}}{365 \text{ days}}$$

5. Regulatory Depreciation

5.1 Regulatory Depreciation enables the licensees to recover the cost of initial investment over the economic life of the asset. Depreciation could be computed using either the straight-line or any of the accelerated depreciation methods. With the accelerated methods, a higher rate of depreciation is permitted in early years of an asset's useful life, and a lower rate of depreciation in the later years. As the name suggests, this method allows licensees to write off more of their assets in the earlier years and less in the later years. The main advantage of this method is the tax benefit. By writing off more assets against revenue, companies report lower income and thus pay less tax in the early years. **In general the straight-line methodology is adopted this purpose.**

5.2 Even though depreciation is a non-cash charge to earnings, it is included as an item in the revenue requirement because it provides funds for investment in new fixed assets. Depreciation, is to be recovered in the tariff over the remaining useful life of the fixed assts.

6. Operation and Maintenance (O&M Expense)

6.1 Power utilities (licensees) incur costs during the course of operating their business and maintaining plant and equipment. These O&M costs usually include the following items.

- 6.1.1 Fuel expense for generation;
- 6.1.2 Power purchases or power imports;
- 6.1.3 Staff salary;
- 6.1.4 Repairs and maintenance;
- 6.1.5 General and administrative;
- 6.1.6 Meter reading and billing;
- 6.1.7 Collection expense;

6.2 The above list is not exhaustive and the licensee may add other O&M costs for the Authority's review and approval or disapproval. In assessing the level of O&M expense, EEA will focus on estimation of efficient and prudently incurred costs. The regulator would therefore review the licensee's costs for reasonableness. The utility company would also be required to demonstrate the reasonableness of the cost. To include an O&M expense in the revenue requirement, EEA will use the following qualifying criteria.

- 6.2.1 "Reasonable and Prudent" cost test;
- 6.2.2 "Used and Useful" rule;

7. Capital Work-In-Progress (CWIP)

7.1 Capital Works-In-Progress refers to assets that are partly constructed, but yet to enter into service. The commonly used options for accounting for CWIP in the RAB are:

- 7.1.1 Recognize the expenditure **at the time it is incurred** by the licensee on an asset. This implies including CWIP in the RAB;
- 7.1.2 Recognize the expenditure at the time **the asset enters into service**. This implies that CWIP is excluded, but the financing cost incurred during construction and prior to commissioning of the asset, may be included in the RAB by the regulator;

7.2 Qualifying criteria for inclusion in the revenue requirement

Regarding Capital Works under construction, the qualifying criteria for inclusion in the revenue requirement is as follows:

- i. Project values equivalent or exceeding 10 percent of the licensee's regulated asset base requires prior approval by the Authority unless otherwise agreed in a power purchase agreement or other agreements approved of or acceded to the Authority.
- ii. Costs would be capitalized and included in the revenue requirements, *only when construction is completed and the plant or equipment is in operation and contributing to the process of providing the regulated product available.*
- iii. Interest during construction (IDC) will however be capitalised and recovered during the construction period, prior to commissioning.

8. Asset Revaluation Approaches

8.1 Given the capital intensive nature of assets in the electricity sector, the approach for recovering the cost of both historic and new investments is very crucial since it is a major determinant in the final tariff. It is therefore important that the choice of asset revaluation approach or methodology is well-established in the tariff-setting guidelines. In addition, the chosen approach should be adhered to consistently thereafter, since any attempt to make sudden changes could have significant price impacts and contribute to regulatory risk. Generally, the asset revaluation method for the RAB can be classified as follows:

- a. Economic Value or Market Based Approach;
- b. Historic Cost Valuation Approach;
- c. Replacement Cost Approach;

These approaches are discussed below:

8.1.1 Economic Value Approach

The Economic or Market based approach determines the asset's value largely from its cash generating capacity. It aims to find out the future revenue stream minus the cash operating costs that the assets will generate. The value is then adjusted to today dollars to allow for time value of money. This approach thus reflects the value of the business, as determined by investors in the financial markets. Since this method involves computation of the net present value of future cash flows, it is *usually used for companies which are listed on the stock exchange*.

8.1.2 Historic Cost Valuation Approach

The historic valuation methodology is used to determine the asset values, based on the original purchase price. The advantage of this approach is that data is easily available, and is therefore considered an objective approach. The disadvantage is that the use of this approach may under-state the asset value during time of inflation and over-states it in times of technical progress.

8.1.3 Replacement Cost Based Approach

The replacement cost methodology aims to estimate the new cost of replacing the existing asset with identical assets, but in the same condition. The replacement cost approach basically determines the value of an asset by adjusting the original cost to reflect subsequent price changes. The replacement cost methodology thus overcomes the problem of inflation and captures technical innovation and the replacement cost of assets. The purpose of indexing the RAB for inflation is to compensate investors as closely as possible, for movements in inflation, and protect them from inflation over the tariff period. The main asset replacement valuation methodologies used in the industry are as follows:

- a. **Current Cost Valuation (CCV)**

The Current Cost Valuation replacement approach takes the historic purchase price and rolls it forward by *adjusting for inflation and depreciation*, during the intervening period.

b. Depreciated Optimised Replacement Cost (DORC)

With DORC, the cost of replacing each asset individually is examined, and then *adjusted for the age of the asset according to an established depreciation schedule*. The Depreciated Optimized Replacement Cost (DORC) thus adjusts the replacement cost for technical change and past investment decisions.

c. Reference Utility Approach (RUA)

The RUA requires the regulator to construct a hypothetical company which is assumed to provide exactly the same service as an efficient utility company. The RUA is a bottom-up engineering approach and very flexible to accommodate expansions in the asset base over time. This valuation approach results from an optimization process, which does not take the age of the assets into consideration.

The approach adopted is; **current cost valuation replacement method** since it is believed that this method presents a good balance between simplicity and accuracy, while taking cognizance of data availability which simply takes the historic asset purchase price and rolls it forward to determine the new asset value by adjusting for **inflation and depreciation**.

Article 14. Cost of Capital

1. The rate of return to be applied on a licensee's RAB, shall be computed using the **Weighted Average Cost of Capital (WACC)**, and including a rate of return on investment in the licensee's revenue requirement. WACC shall be determined by the Authority in accordance with the guideline annexed to this tariff methodology (ANNEX ONE).

Chapter 5. Generation Tariff Methodology

Article 15. Industry Structure

The electricity sector consists of: Ethiopian Electric Power (EEP) responsible for electricity generation, transmission and substation construction, generation and transmission operation, bulk power purchase and sale as well as maintenance activities above 66kV. The second company is the Ethiopian Electric Utility (EEU), which is now responsible for electricity distribution and sales, operation and maintenance below 66kV.

1. The new industry structure implies that EEA has to *regulate the prices of unbundled power sector activities, to ensure that proper price signals are sent to; each business segment/ IPPs to promote investment in the generation sector*. The minimum unbundling requirement is that **EEA separates tariffs for generation, transmission and distribution/sale**. Setting unbundled tariff would require that the Authority embarks on

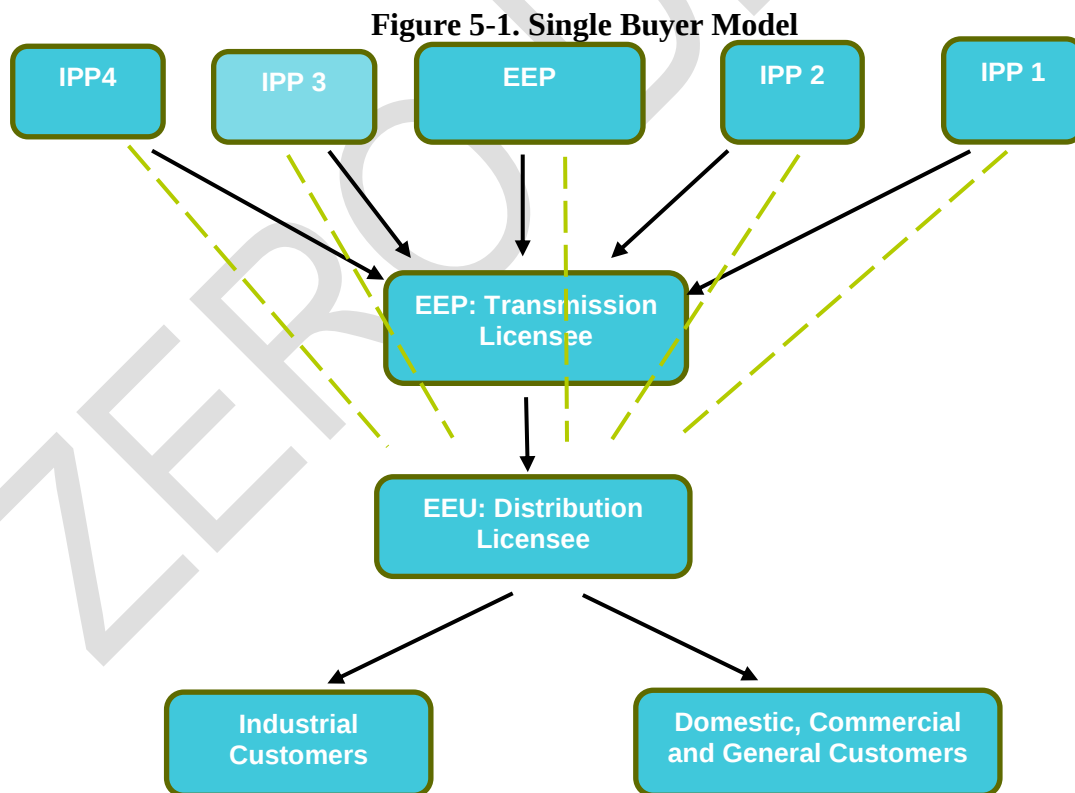
accounting separation of the utility financial information, by obtaining reliable and credible data on assets, costs and revenues for each activity.

2. Therefore to ensure effective transition to the envisaged structure it is important that the tariffs should be unbundled for each segment of the industry. Therefore in accordance with the Energy regulation _____-tariff should be unbundled for each value segment of the supply business namely; power ;Generation; Transmission and Distribution and Sales.

This tariff guidelines and methodology therefore provides the approaches and best regulatory practice for determining the electricity tariffs.

3. Regarding the industry structure model, the government Industry strategy and the investment law liberalizes power generation in the national grid, where government utilities to purchase electricity from generation licensee on the basis of competitive procurement. **The distribution and sale licensee to purchase electricity from the generation licensees** to meet customers demand. Therefore **In the short to medium a Single Buyer**, which also allows the distribution licensee to enter into long-term PPA's with generation licensees to purchase electricity, and pay the approved transmission tariff to the transmission licensee.

The Single Buyer Model is depicted in figure 5-1 below.



4. The generation tariff structure should recover both the fixed and variable costs. The variable cost can also be used by the transmission licensee which is also performs system operation duties, to make dispatch decisions based on *merit order principles*. The recommended **generation tariff structure** will be a **two-part tariff** with the following components:

4.1 **Energy Tariff:** this recovers the variable cost of the power station and non-fuel variable cost. This is expressed as **per KWh** and determined as:

$$\text{Energy Price} = \text{Fuel Cost} + \text{Non-Fuel Variable Costs}$$

4.2 **Capacity Tariff:** recovers the fixed costs, including investment costs and fixed O&M and expressed as **available Capacity (KW) and can be determined as follows:**

$$\text{Annual Capacity price} = (\text{Investment Annuity} + \text{Fixed O\&M})$$

8.3 The capacity tariff would be determined based on the *KW the generator makes available to the transmission licensee which also acts as the system operator, regardless of amount of energy it generates.*

Article 16. Generation Revenue Requirements

1. The generation tariff revenue requirements will comprise cost elements which are recorded on the licensee's financial statements. The revenue requirements can be derived using either historical or forecasted financial cost, but since investments in the electricity sector are generally lumpy, most regulators tend to *use forecast costs over which the tariffs would be in place*. The use of forward looking cost items is therefore consistent with the economic principle of *Long-run Marginal Cost*. The forecast period is set at least 4 years.
2. With the forward-looking pricing philosophy, this means that new investments are only taken into account if they meet the prudent and reasonableness tests, and they represent the efficient use of resources. New investments would therefore be submitted to EEA as per the Energy Regulation ____ Article 22 sub Article 9 and Article 25 sub Article 4 L to be considered as part of the forward-looking tariff calculation¹.
3. In the event of over-estimating forecast capital expenditure which could give the utility company additional revenue stream, EEA will deal with this problem by using **ex- post regulation**. Ex-post regulation will trigger the use of a *claw-back mechanism*, which will

¹As part of the forward looking pricing philosophy, the licensees are required to submit their future capital investment plan to EEA, for calculating the tariffs. The Authority has the obligation to ask the licensees (as per Article 22 (9) and Article 25 sub Article 4L of the energy regulation) to justify/explain the significance and level of such investments, before agreeing to roll it into the RAB. This covers new investment for expansion, upgrading or retrofitting which is expected to enhance an asset's life.

enable EEA to revise the RAB so that any benefit is passed-through to consumers as lower tariff, during the next major tariff review.

For the Generation Sector, the Revenue Requirements for the base period is given as follows:

$$RR_{Gt,i} = (RAB_{t,i} \times WACC) + TOPEX_{t,i} + DEPR_{t,i} + TAXES_t$$

Where:

$RR_{Gt,i}$ = Revenue Requirements for generation sector for period t, for power plant i;

RAB_t = Regulatory Asset Base for period t, for power plant i;

WACC = Weighted Average Cost of Capital, as established by EEA;

$DEPR_t$ = Regulated Depreciation for period for power plant i.

$TOPEX_t$ = Total Operating and Maintenance Cost for period t, for power plant i;

4. Regulated Total Operating and Maintenance Cost

The regulated TOPEX for period t is calculated as follows:

$$TOPEX_{t,i} = TPP_t + O\&M_t$$

where:

$TOPEX_{t,i}$ = Total Operating and Maintenance cost for power plant i.

TPP_t = Total Power Purchase Costs for year t,

O&M = Regulated operating and maintenance costs for year t.

The total power purchase cost is calculated as follows:

$$TPP_t = PP_t + PIM_t$$

where:

PP_t = Cost of power purchase by EEP from IPPs, based on PPAs in year t;

PIM_t = Cost of power imported in year t²;

5. Bulk Generation Pricing

5.1 In order to achieve optimal economic efficiency in competitive electricity markets, the dispatch of generating units is usually based on the Short-run Marginal Cost (SRMC), where generating units with lower variable cost are dispatched first, followed by the next

²For well-designed systems which are designed to meet n-1 or n-2 engineering criteria, there is still a probability such a system may be in serious deficit or even experience system collapse which will require power import from outside to get the domestic power system running. It is therefore appropriate for the methodology to take this into account. During periods where there is no power imports, that component decays to zero in the formula.

higher variable cost until demand is met. With this approach, the wholesale price of electricity is based on the SRMC of the system, which is the variable cost of the last unit which is dispatched, to ensure that total generation supply meets demand.

5.2 Considering the level of development of the Ethiopian electricity sector, where there is no robust competition in generation, it will not be appropriate to use SRMC to determine the system generation cost. In that regard, the **Weighted Average Generation Cost** methodology is recommended for computing the system **Bulk Generation Tariff**. This is defined as follows:

$$BGT = (W_1G_1 + W_2G_2 + W_3G_3 + \dots + W_nG_n)$$

where:

BGT = Bulk Generation Tariff

W_1, W_2, W_3, W_n = Weight of each generation technology from system plants. This is equal to the percentage contribution of each generation source from the generation mix;

G_1, G_2, G_3, G_n = Total Tariff (i.e. energy and capacity) for each generation source;

Therefore it is adopted that: a forward looking should be followed for computing tariff since it is consistent with a Long Run Marginal Cost (LRMC) principle and The **System Bulk Generation Tariff (BGT)**, which is passed through to the distribution/sale licensee and hence to consumers, should be computed using the **Weighted Average Generation cost**.

Chapter 6. Transmission Tariff Methodology

Article 17. Transmission Pricing Objectives

The key objectives of an efficient transmission pricing policy are as follows:

1. Promote Economic Efficiency;
2. Promote connections efficiency;
 - 2.1 Encourage efficient use of network;
 - 2.2 Produce economic signals for efficient investment;
 - 2.3 Encourage efficient location of new power plants;
3. Promote price transparency and non-discrimination;
4. Enable transmission company to meet its revenue requirements;
5. Promote efficient operation and maintenance of the grid ;
6. Facilitate economic interconnection of new generators;
7. Be simple, transparent, easy to regulate and practical to implement;

Article 18. Transmission Pricing Approaches & preferred methodology

This section describes the well-known transmission pricing philosophies based on international best practice, and are categorised either as **Historic and Forward Looking**.

1. Historic Cost Techniques

1.1 Postage Stamp

With the postage stamp pricing, all the transmission customers are allocated a uniform transmission price, irrespective of the load imposed or congestion created. It is based on average system costs and is associated with the following advantages:

- 1.1.1 It is easy and simple to implement;
- 1.1.2 Has the ability to recover investment in existing system;

Despite the above advantages, this pricing approach has got the following limitations. It is determined:

- 1.1.3 Independent of distance;
- 1.1.4 Independent of supply and delivery points;
- 1.1.5 Independent of the loading imposed on the transmission circuit;
- 1.1.6 Could lead to sub-optimal pricing;

1.2 Megawatt-Mile or Load Flow Method

The MW-mile method is described as a 'flow-based' type because it is based on both the magnitude (i.e. MW of power flow) and distance (i.e. Mile or Km) between the entry and exit points. The transmission prices are determined based on **LOAD FLOW** studies to determine the percentage of transaction. This pricing method has got the following advantages.

- 1.2.1 Takes account of changes in MW flows due to transactions;
- 1.2.2 It is considered to be reasonably cost reflective;
- 1.2.3 Reduces the problem of price discrimination;

The pricing method is however associated with the following disadvantages:

- 1.2.4 Fails to take account of line reliability and congestion;
- 1.2.5 It ignores changes in flows through facilities which are located along the pre-determined path;
- 1.2.6 Fails to take account of future expansion costs;
- 1.2.7 Ignores future investment costs;
- 1.2.8 Could lead to under-recovery of transmission system capital costs, if applied in its 'pure' form;

1.3 Megawatt-Mile or Distance Based Method

1.3.1 With the MW-mile or distance based method, it is assumed that the distance travelled by the energy transmitted under a specific transmission network transaction is either on a 'straight-line' basis between the points of entry and exit to the network, or *on a contract path basis agreed by the parties involved*. The

MW-km of the transaction is determined and the ratio of this to the total system MW-km, is used to compute the cost of the transaction.

1.3.2 Even though this method possesses strong cost recovery characteristics and is the relatively simple and easy for the users to understand, it fails to take account of the actual operation and costs incurred on the system.

2. Forward-Looking Techniques

2.1 Short-Run Marginal Cost (SRMC)

The SRMC measures how much it costs the transmission system to accept an additional unit of energy and deliver it to a buyer. Due to economies of scale and high capital cost, the SRMC is always below the Average Total Cost. Therefore, the use of SRMC could therefore lead to under-cost recovery.

2.2 Long-Run Marginal Cost (LRMC)

The LRMC is the cost of supplying an additional unit of energy, when the installed capacity increases optimally to meet marginal increase in demand. The LRMC is forward-looking and takes into account, both the capital and operational costs, and has the following advantages:

- 2.2.1 Gives correct price signals to users (i.e. generators and loads);
- 2.2.2 Generates investment capital for future growth;

The pricing approach is however associated with the following limitations:

- 2.2.3 Could be too high during periods of high loads;
- 2.2.4 Does not take impact of line reliability into account;
- 2.2.5 For small systems, lead to high transmission tariff;

2.3 Short-Run Incremental Cost

The Short-run Incremental Cost recovers the additional transmission which is triggered by new transactions. For the short-run incremental costs, only the **operating costs** of the existing facilities and new transactions are taken into account. It is determined by analysing the transmission operating costs with and without the particular transaction.

2.4 Long-Run Incremental Costs

The Long-run Incremental Costs are determined by taking account of both the *capital and operating costs, as well as upgrading and reinforcement costs*. It is computed by analysing the costs with and without the transmission transaction.

3. Hybrid Approach

The hybrid approach basically involves the use of any of the historic cost methods and adapting it to be forward- looking by recovering both the *historic and forward-looking capital costs*. In practice, the final tariffs can still be denominated as a **simple flat rate**, which recovers both the historic and future costs.

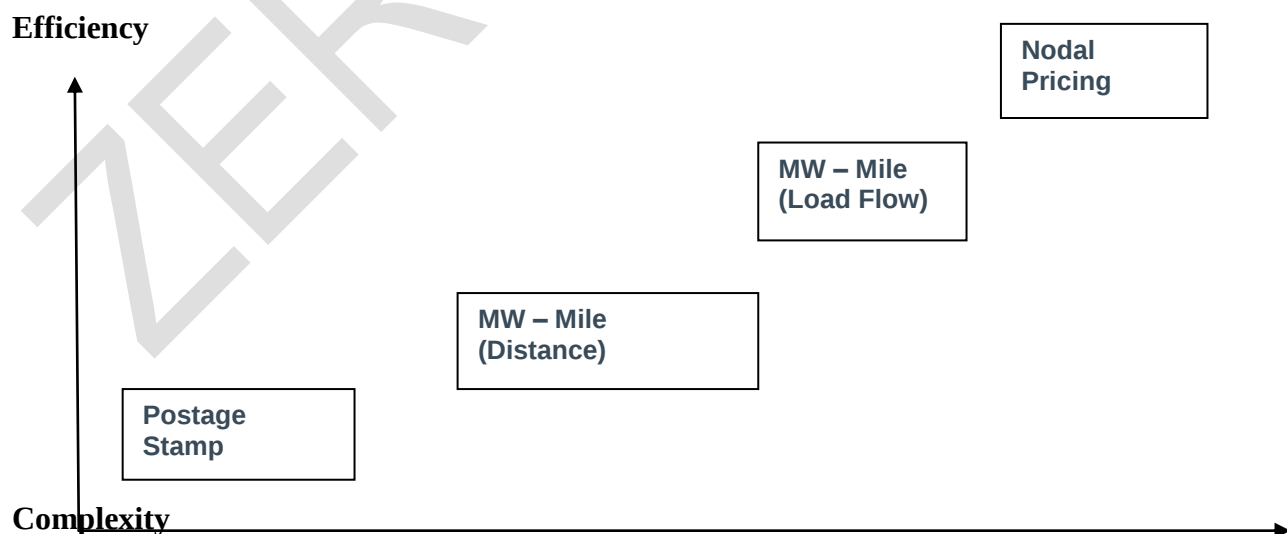
4. Nodal Pricing

4.1 Nodal pricing is considered to be an efficient transmission pricing approach. This pricing philosophy is usually justified on the grounds of locational economic signals. With nodal pricing, each origin and destination node has its own price. This pricing methodology aims to manage congestion and set transmission prices through a centralized market, based on economic dispatch.

4.2 Even though economic efficiency has been advanced as the main advantage of nodal pricing, opponents have argued that the efficiency claims are based on unrealistic or simplistic assumptions, and there are two major issues associated with it that has resulted in the system being rarely adopted in practice. First, this methodology may result in under-recovery of fixed costs, as pricing is a function of marginal costs.

4.3 To set the prices, the transmission system operator would require constant real-time information about all loads, generators and bids. This implies that prices would vary over different nodes, and also over time as supply, demand and transmission constraints change. This creates significant instability and complexity in implementation, requiring advanced information technology and communications, often resulting in countries adopting different pricing systems or simplifications of full nodal pricing. Therefore in practice, the nodal pricing can be very complex to calculate and implement, and many market participants may see the results as coming from a ‘black box’. The figure below compares the main pricing philosophies with respect to economic efficiency and degree of complexity.

Figure 6-1. Efficiency versus Complexity of Transmission Pricing Method



4.4 Recommended Pricing Approach / preferred approach and methodology

Even though the postage stamp approach has the drawback of not being economically efficient and cost reflective, it is very simple to implement and has good cost recovery characteristics. For a start the **postage stamp method** which is adapted to be forward-looking is the preferred approach however in future, depending on the level of sophistication of the electricity infrastructure other appropriate approach could be adopted in place of the postage stamp approach.

Article 19. Network Cost Recovery

1. The network or the ‘wires’ aspect of the transmission business is a monopolistic activity and must therefore be regulated, and the transmission system licensee is required to recover its cost of service for this aspect of its operations. The first step is to determine the revenue requirements for the network services, and the second step is to determine how the revenue requirement is to be recovered. The transmission system network revenue requirements are given as follows:

$$\text{TRR}_N = (\text{WACC} \times \text{RAB}) + \text{OPEX} + \text{DEPR} + \text{ALLOWABLE NETWORK LOSS}$$

where:

TRR_N = Transmission Network Revenue Requirements

WACC = Weighted Average Cost of Capital as determined by EEA;

RAB = Regulatory Asset Base;

OPEX = Operating and Maintenance Expenditure;

DEPR = Depreciation;

2. The network tariff is calculated based on forward-looking revenue requirements and estimated volumes of energy flowing over the entire system, using the postage stamp approach, where the total transmission network cost is allocated among all users, based on the peak demand (MW).

The postage stamp methodology can be represented as follows:

$$\text{Postage Stamp}_t (\text{Birr/MW}) = \frac{\text{TRR}_t}{\text{MW}_{\text{peak},t}}$$

$$\text{Postage Stamp}_t (\text{Birr/MWh}) = \frac{\text{TRR}_t}{\text{LF} \times \text{MW}_{\text{peak},t} \times 8760 \text{ hours}}$$

where:

TRR_t = Total Transmission Revenue Requirements for period t (Birr, Millions)

$\text{MW}_{\text{peak},t}$ = Transmission System Peak Demand for period t (MW)

LF = System Load Factor;

Article 20. System Operation Fee/ when system operator is a separate entity/

1. The transmission licensee also performs a second critical function of System Operation. This function is a monopolistic activity and must therefore be regulated by EEA. For the sake of tariff transparency, this cost must be accounted for separately and collected from all market participants. The System Operator costs would usually cover the following, among others:

- 1.1 Salaries;
 - 1.2 Facilities;
 - 1.3 Information System;
 - 1.4 Fixed Assets
2. Since most of these costs are fixed, cost recovery can be achieved through a *fixed monthly fee* to all market participants. The transmission company should therefore be required to submit details of cost forecast to EEA for review and approval. *In the event that the licensee fails to submit separate tariff proposals for the network and system operator functions, EEA could use a demand or capacity-based cost allocation parameter as explained in the section 7.4.2 of this document.*

Article 21. Transmission Wheeling Access Charge

1. Transmission Wheeling Concept

This section of the report examines the concept of transmission wheeling and looks at the various wheeling charge models employed internationally, with the objective of recommending a wheeling pricing framework which is practical and relevant to the Ethiopian electricity sector.

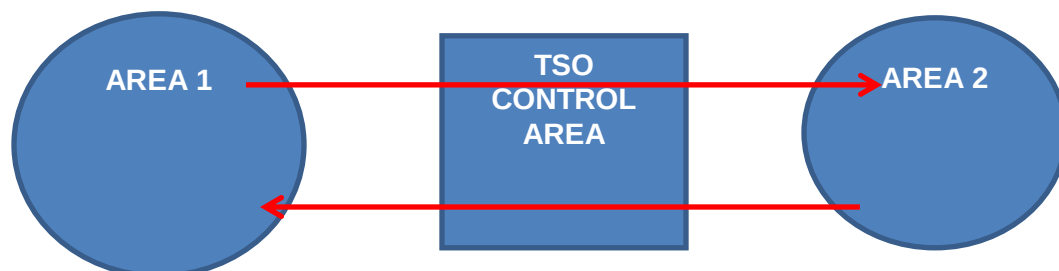
Wheeling can be described as the “rental” of a grid operator’s transmission (or distribution) infrastructure for the transportation of electricity. When a wheeling transaction takes place, the transmission licensee/system operator receives energy into its control area from one party, and transmits this energy to a third party either within or outside the control area. Wheeling charge which arises out of wheeling transaction can occur under any of the following three scenarios:

- a. Wheel –Through;
- b. Wheel – Out;
- c. Wheel – Within;

1.1 Wheel-Through

This occurs when energy is *wheeled or imported into, and across a transmission licensee/system operator control area, and finally exported out of the control area.*

Figure 6-2. Transmission Wheel-Through Concept



In the above figure, **Areas 1 and 2** are the location of the Selling or Purchasing entities

1.2 Wheel-Out

This type of wheeling transaction occurs when energy is *produced or sourced in the transmission licensee/system operator's control area and exported out of the control area.*

Figure 6-3. Transmission Wheel-Out Concept

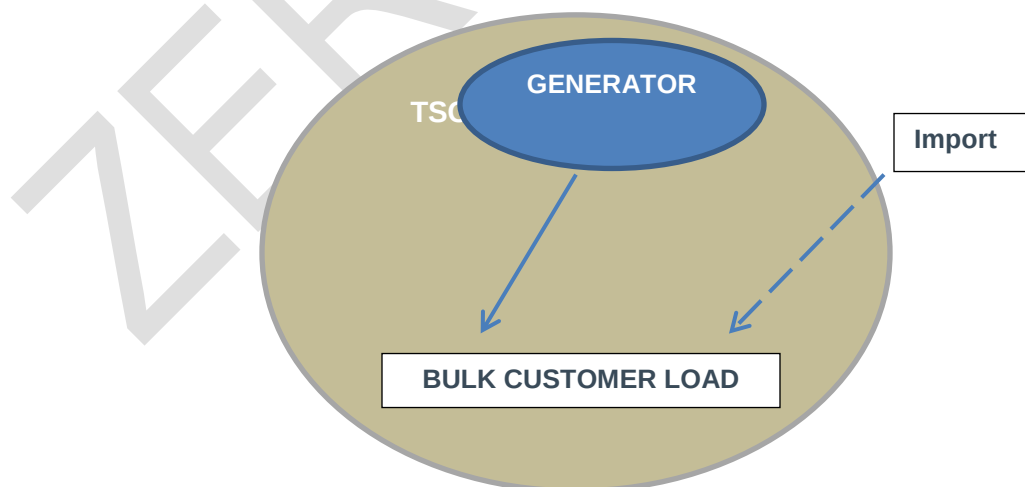


In the above figure, Area 1 is the purchasing entity's location in another control area, while Area 2 is the Selling or Generating entity's location.

1.3 Wheel-Within

This happens when the transmission system operator *schedules electricity from within its control area but uses its grid to serve a Bulk Load or Customer* e.g. Industrial load. In some instances, the locally sourced energy is complemented by imported electricity to meet a Bulk Customer load.

Figure 6-4. Transmission Wheel-Within Concept



In the above figure, the TSO schedules **import or generation** from within its controlled area, to serve a bulk load or customer.

Article 22. Transmission Wheeling Charge Pricing

1. The pricing principles stated for transmission service tariff determination also apply to wheeling charge pricing and for ease of reference, these principles are re-stated below:

- 1.1 **Non-discriminatory:** There should be no undue preference to any connected customer over the other;
- 1.2 **Full cost recovery:** Wheeling access charge should only reflect the transmission asset cost associated with the wheeling transaction;
- 1.3 Should promote efficiency;
- 1.4 Transparency and predictability;
- 1.5 Ensure equity and fairness;
- 1.6 Ease of implementation;

2. Wheeling Charge Methodologies

The transmission pricing philosophies which were discussed in the previous section are also applicable to wheeling charge. These pricing methodologies are classified either as *historic cost*, *forwardlooking* or real time in Table 6-1.

Table 6-1. Transmission Wheeling Pricing Methodologies

Pricing Philosophy	Historic Cost	Forward Looking	Real Time
Postage Stamp	√		
Contract Path	√		
MW-mile (Distance-based)	√		
MW-mile (Load Flow-based)	√		
SRMC		√	
LRMC		√	
LRIC		√	
Nodal Pricing			√

In deciding which wheeling charge pricing philosophy to adopt, the following issues must be carefully considered:

- 2.1 What should be the balance between **simplicity of approach and efficient price**?
- 2.2 Should a price signalling a historic or replacement cost approach be adopted?
- 2.3 Which method best deals with the problem of congestion management?
- 2.4 What should be the loss allocation methodology?

3. Adopted Transmission Wheeling Charge Pricing Approach

As the nodal pricing, which is considered to be the efficient pricing method, is very complex to apply, therefore, at the current state of the country's electricity market, the adoption of nodal pricing is not appropriate; therefore given the good balance which the **MW-mile (or MW-Km) approach** presents with respect to **simplicity and efficiency**, the **MW-mile methodology** is recommended for determination of transmission wheeling charges for the Ethiopian electricity sector.

Article 23. Wheeling Charge Determination

1. In order to calculate the wheeling charge, it is important to understand the various scenarios under which a wheeling transaction can occur. These locational transactions are as follows:
 - 1.1 **Scenario 1³**: Wheeling transaction which involves only the **transmission lines or the primary circuits**;
 - 1.2 **Scenario 2**: A transaction where the **both generator and the load are embedded within two distribution areas**, but the transmission lines are required to move power between the generator and the load;
 - 1.3 **Scenario 3**: Wheeling service for which **either the generator or the load** are located at the end of a distribution line, and therefore would require the **use of a transmission line**. With this scenario, either the generator or load could also be located at the end of a transmission line.
 - 1.4 **Scenario 4**: This refers to a transaction where both the generator and load are located at the end of distribution lines, and therefore **no transmission lines** are involved.

2. Wheeling Charge Cost Allocation

2.1 The fixed costs of the wheeling charge between the injection and delivery points shall have the following cost components:

- 2.1.1 Annual capital costs;
- 2.1.2 Annual operating and maintenance cost of transmission assets;
- 2.1.3 Network Losses;

2.2 In calculating the wheeling access charge, the capital costs to be considered will be those associated with the wheeling transaction. The transmission asset cost for Wheeling Access Price, is calculated using **the MW-mile (or MW-km)** method as follows:

- 2.2.1 Carry out a full load flow analysis to determine the use or the maximum MW on the respective lines, and calculate the proportion of load imposed by the wheel transaction;
- 2.2.2 Determine the power flows through the network due to a specific transaction;
- 2.2.3 Determine the total value of assets due to the maximum power flow on each line, associated with the wheeling;

³*Scenarios 1 and 3 which involve the use of the transmission lines are the likely scenarios under the East African Power Pool. As the market open up in future, the other two scenarios are likely to also emerge.*

3. In determining the capital cost of wheeling, the Authority shall consider only efficient and prudently incurred costs of the network assets along the primary and secondary circuits. The Authority will also consider the cost of system reinforcement required to provide the wheeling access and ensure system stability and reliability. To ensure full cost recovery, the wheeling charge computation will also take account of energy losses in the transmission network as a result of the wheeling transaction.

2. Treatment of Losses

1. In calculating the transmission wheeling charge, cost of losses can be expressed as follows:

Cost of losses (US\$) = [8760 (hours) × Peak Losses (MW) × Loss Load Factor] × Bulk Generation Price.

where:

Peak Losses (MW) = Maximum increase in transmission losses associated with the wheeling transaction;

The Loss Load Factor can be calculated using the generic formula which is usually used by the World Bank in and other agencies for peak loss analysis.

Loss Load Factor⁴ = $[0.7 \times (\text{Load Factor})^2 + 0.3 \times (\text{Load Factor})]$

2. Alternatively, the Loss Load Factor (LLF) can also be calculated as:

Average Power Loss ÷ Power Loss at Maximum Demand

For wheeling which involves the distribution network, the calculation of **cost of losses** and loss load factor is the same as above. The only difference is in the calculation of peak losses (MW), which is expressed as:

Peak Losses_{Distrib} = Maximum Capacity × Technical Losses (at the appropriate voltage level)

3. Although it can be argued that there may be instances where wheeling transaction can reduce system losses, in general losses on a power transaction occur during electricity transmission and distribution. Therefore if losses occur as a result of a wheeling transaction, this gap must be filled by the transmission licensee/ system operator by purchasing extra generation. It is therefore fair that the transmission licensee is compensated for replacing the electricity losses by purchasing the extra generation. In the event that the wheeling transaction contributes to reduction of system technical losses, the wheeler must be compensated through the pricing mechanism.

4. In order that the cost of losses are properly assigned in wheeling transaction, EEA and the licensee must work together to establish the current loss levels, and define the regulatory benchmark. The level of losses on the transmission lines may be calculated from the wheeling transaction based on **LOAD FLOW MODELLING**.

⁴ Typically this methodology is accepted by the World Bank and other agencies for determining the Loss Load Factor. This methodology was just for network system Technical loss World Bank funded study for Ghana (2000). Was also used in other countries such as Jamaica during Wheeling Network Analysis (2013).

5. For distribution system wheeling transaction, the cost of losses shall be based on the voltage levels. The calculation of distribution losses for a wheeling transaction should however exclude **non-technical or commercial losses**.

3. Wheeling Charge Formulation

1. The annual wheeling capital cost can be formulated as follows:

$$TCC_A = CC_A + O\&M_A$$

where:

TCC_A = Annual total capital cost;

CC_A = Portion of annual capital cost used to provide the wheeling transaction, including return on investment;

$O\&M_A$ = Fixed and operating and maintenance cost, pro-rated based on reserved capacity for wheeling;

1.1 The annual fixed $O\&M_A$ is allocated as follows:

$$O\&M_A = (\text{Operating} + \text{Maintenance Cost}) \times \frac{[MVA_{\text{Wheeling}}]}{[MVA_{\text{Available}}]}$$

where:

MVA_{Wheeling} = Actual wheeled capacity;

$MVA_{\text{Available}}$ = Available capacity for wheeling;

Alternatively, the O&M costs can be recovered by allowing a pre-determined margin on the capital costs of equipment to cover an appropriate amount of the O&M costs on an annual basis. Even though annual allowances may vary from one regulatory jurisdiction to the other, typical figures in the **range 2%-5% of the capital cost per annum are applied to cover O&M costs**. This amount needs to be sufficient to cover the costs of operating the centralised electricity wheeling control functions within the transmission operator business, as well as the maintenance requirements of the individual assets.

1.2 The allocated annual capital cost (CC_A) is calculated as follows:

$$CC_A = \text{Total Annual Wheeling Capital Cost} \times \frac{[MVA_{\text{Wheeling}}^5]}{[MVA_{\text{Available}}]}$$

⁵ $MVA = \text{Power Factor of Load} \times MW$, and therefore the use of MVA recognises customer load.

The total annuitized capital cost is calculated using the **capital recovery factor** as follows:

$$\text{The total annual wheeling capital cost} = P \times \frac{[i \times (1+i)^n]}{[(1+i)^n - 1]}$$

P = Total Investment cost, including cost of reinforcement or upgrade;

i = Discount rate (%), as determined by EEA;

n = Economic life of transmission network asset as stated in the uniform system of accounts;

2. Monthly Wheeling Tariff

The **monthly wheeling access charge (WAC_m)** shall be calculated using the wheeling capacity in MW, but finally converted into energy charge (MWh) using the load factor. The monthly wheeling charge can thus be formulated as follows:

$$\text{WAC}_m (\text{US\$}/\text{MW}) = \frac{1}{12} \times \frac{[\text{CC}_A + \text{O\&M}_A + \text{C}_{AL}]}{\text{MW}_{\text{wheeling}}} = K$$

$$\text{WAC}_m (\text{US\$}/\text{MWh}) = K / (\text{LF} \times 8760)$$

where:

C_{AL} = Annual Cost of Losses (US\$);

LF = Load Factor;

Chapter 7. Distribution System Tariff Methodology

Article 24. Distribution System Revenue Requirements

1. The distribution and sale activities include ownership, operation and maintenance of distribution assets, as well as metering, billing and consumer related costs. Distribution service costs therefore generally include:
 - 1.1 Network fixed asset and capital related costs;
 - 1.2 Operation and maintenance costs;
 - 1.3 Distribution Losses;
 - 1.4 Retail costs;
2. The retail costs cover activities such as: marketing, customer services, meter reading and billing, collections and complaint resolution. The total distribution Revenue Requirements for the distribution service charge can therefore be expressed as follows:

$$RR_{DSC} = (WACC \times RAB) + O\&M + CUST. SERVICES^6 + DEPR. + LOSSES_{DISTR} + TAXES$$

where:

RR_{DSC} = Total Revenue Requirements for Distribution System;

WACC = Weighted Average Cost of Capital;

RAB = Regulatory Asset Base;

O&M = Operations and Maintenance Costs;

DEPR. = Depreciation;

CUST.SERVICES = Customer Service Costs;

$LOSSES_{DISTR}$ = Benchmark Distribution System Loss;

Article 25. Allowable Losses

1. Technical losses are associated with electricity transported over transmission and distribution network and it is a function of each voltage level and should therefore be part of the revenue requirement for the DST.
2. The Authority through the service standard Directive shall determine **average losses** to be passed through to customers in tariff determination, which could include technical as well as portion of the non technical loss after benchmark exercise and a comprehensive system load flow analysis has been done to define a loss reduction roadmap for achieving the ultimate regulatory target.
3. Thus: a/ DST be adjusted by a loss factor to account for technical losses, and this should be based on **AVERAGE LOSSES**; b/ Loss factors in excess of the regulatory benchmark value **should not be passed-through** the tariff to consumers. Cost of excess losses should be borne by the distributor c/ For the sake of tariff transparency, the revenue requirements should separately identify the customer service costs

Article 26. End-User Tariff Derivation

1. The End-Use Tariff would consist of the following three components:

⁶ In this methodology, the customer service cost is separated from O&M for the sake of tariff transparency and lessening of information asymmetry, the licensee. This assist the regulatory review by providing a better understanding of licensee's operating cost structure.

- 1.1 Bulk Generation Tariff (BGT);
- 1.2 Transmission Service Tariff (TST), including Network and System Operator charge;
- 1.3 Distribution Service Tariff (DST);

2. The End-Use tariff can therefore be represented as follows:

$$\text{EUT} = \text{BGT} + \text{TST} + \text{DST}$$

Article 27. Customer Categorisation and Cost Allocation

1. Customer Categorisation

1.1 Tariff Structures are usually defined based on customer categories or classes. A customer class can be described as a group for which a particular tariff is developed. Customer classes are generally defined based on the voltage level of service delivery and usage characteristics such as load factor, Time-of-Use etc. Customer classification is an important step in the tariff design process because it ensures that correct price signals are sent to consumers. It also helps to quantify and rationalizes any cross-subsidization among the various customer categories.

1.2 In practice, customer classification usually involves categorizing customers into similar load profile groups, since each customer category is expected to take supply from different voltage levels. Proper customer categorization is therefore a key step in the cost allocation process since customers who take supply at a certain voltage level, would need to pay for costs associated with these voltages, while those who take electricity at a lower voltage level, must pay tariffs which reflect both high and low voltages.

1.3 In line with best regulatory practice, the following criteria are usually used for customer classification:

1.3.1 Voltage: This is the voltage level at which electricity is supplied to the consumer. It also helps in loss allocation to the various tariff classes;

1.3.2. Load Profile: Customers are grouped according to their load profile, so that base-load consumers are not mixed with peaking consumers. Classification of customers without taking account of the load profile can lead to improper price signals;

1.3.3. Meter Limitations: Customer categorization must take into account, the practicality of meters since some meters can only measure energy (kWh), while others can measure both energy (kWh) and maximum demand (KVA or KW);

1.4 Therefore customers categorization should:

- 1.4.1 be based on similar voltage levels and load profiles;
- 1.4.2 also reflect different tariff classes such as:

- a. Domestic;
- b. Commercial;
- c. Industrial (Low, Medium and High Voltage);

1.5 The (Licensee) distribution utility may use a sub-set of the above categories subject to regulatory approval. This implies that within the voltage classifications, there can be different categories or sub-categories. For customer classes which take electricity at a higher voltage, a TOU tariff can be designed for such customer groups.

1.7 The licensees may also submit to EEA: request for end-use customer categorisation during the tariff application to cover new customer classes or propose optional tariff proposal for large customers where such customers may have an opportunity to choose from various tariff options compatible to their respective operational (load) characteristics or to accommodate other emerging needs in the economy, for the Authority's review and final decision. This request should be supported by in-depth and high level studies and findings, including tariff impact analysis.

1.8 All customers regardless of their category and whose power demand is above 25 kW must have a power and reactive meter installed and are subject to demand charge applicable to their respective voltage level.

1.9 The choice of consumer categories might need to reflect the following groups, in accordance with the voltage definition in the **Energy Proclamation No. 810/2013**.

Table 7-1.Suggested Consumer Classification

Category	230V	≤400V	400V - 33KV	≥ 33 KV
Domestic: (Single phase, three phase)	√			
Commercial (Single phase, three phase)	√	√		
General and Street Lighting (Single phase, three phase)	√	√		
Industrial: (Three phase):				
Low Voltage		√		
Medium Voltage			√	
High Voltage				√

Article 28. Consumer Cost Allocation Principles

1. For best regulatory practice, cost allocation to the various consumer classes shall be based on the following:

- 1.1 Customer contribution to **peak demand** per category;
- 1.2 **Energy consumption** per class;
- 1.3 **Number of customers** per customer category;

2. The cost allocation methodology should also be linked to the cost driver for each category. In the event, that there is no obvious cost driver, costs can be allocated based on energy consumed or the number of customers. The table below provides a summary of recommended cost allocation parameter for key cost items.

Table 7-2. Cost Types and Allocation Parameters

Cost Type/Item	Cost Allocation Parameter
Bulk Supply Cost: Capacity Component	Peak-coincident demand of the customer category
Bulk Supply Cost: Energy Component	Energy consumption of customer class
Distribution losses: Capacity Losses	Peak-coincident demand of the customer class
Distribution Losses: Energy Losses	Energy consumption per customer class
Network Assets, Depreciation, Return on Assets	Peak-coincident demand of customer class
O&M costs	Energy consumption of customer category (no obvious cost driver)
Customer Service Costs	Number of customer per tariff class
Overhead Costs	Number of customers per class (no obvious cost driver)

Article 29. Cost Allocation to Tariff Elements

The best regulatory practice in tariff structure design involves allocating costs to the key tariff elements or components as follows:

1. Allocation of Demand-dependent Costs

The **demand-dependent** costs for a customer category, are allocated to a **capacity or a demand charge**, and can be denominated either in **Birr/KW or Birr/KVA**. The consumer demand is usually taken as the peak coincident demand;

2. Allocation of Energy-dependent Costs:

The **energy-dependent** costs are allocated to an **energy charge** for that category and denominated in **Birr/kWh**. In the tariff design, the definition of energy on which the consumer tariff calculated, is based on the amount consumed by that particular tariff group.

3. Allocation of Customer-dependent Cost:

The **customer-dependent** costs to a particular customer category are allocated to a fixed charge called a **customer service charge** which is denominated as **Birr/Customer**. The customer charge is usually treated as a **fixed or a standing monthly charge**.

Article 30. Cost Allocation: Peak Coincident Maximum Demand

The following equation can be used for the cost allocation for industrial class of consumers:

$$C_{i,v} = \frac{(PCD_{i,v} \times CF) \times CE_v}{\sum (PCD_{i,v} \times CF)}$$

where:

$C_{i,v}$ = Cost allocation to consumer category, i at voltage v

$PCD_{i,v}$ = Peak coincident maximum demand of customer category i, at voltage v

CF = Coincidence factor for consumer class i, at voltage v

CE = Cost element to be allocated (e.g. Asset Value) associated with voltage v

Article 31. Cost Allocation: Energy Consumption

The cost allocation can be undertaken using the following equation for all customer classes:

$$C_{i,v} = \frac{CE \times E_{i,v}}{\sum E_{i,v}}$$

where:

$C_{i,v}$ = Cost element allocated to consumer class i, at voltage v

$E_{i,v}$ = Energy consumption by customer class i, at voltage v

CE = Cost element to be allocated

Article 32. Cost Allocation: Customer Numbers

The cost allocation undertaken using the following equation:

$$C_{i,v} = CE \times \frac{NUM_{i,v}}{\sum NUM_{i,v}}$$

where:

$C_{i,v}$ Cost allocation to customer class i, at voltage, v

CE = Cost element to be allocated

$NUM_{i,v}$ = Number of customers in customer category i, at voltage v

Chapter 8. Tariff Structure

Article 33. Tariff Structure Design

1. After the cost allocation to the various customer categories, the next step is to design the tariffs by allocating the revenue requirements to cover the following three charges:
 - 1.1 Energy charge;
 - 1.2 Demand charge;
 - 1.3 Fixed monthly charge (or Service charge);
2. The energy charge recovers the variable operational costs, particularly fuel, and other non-fuel variable costs.
3. The demand charge is used to recover the fixed costs such as: fixed asset related costs including depreciation, asset value and return on investment. The fixed costs are usually associated with facilities installed to meet the peak load. Therefore, cost allocation for fixed cost recovery should be based on the **class contribution to peak demand**.
4. For the Bulk Supply Tariff (i.e. Generation and transmission tariffs), the aim is to be able to invest in sufficient capacity including reserve system margin. In that regard, **coincident peak demand** should be used as the basis for fixed cost allocation.
5. Costs associated with metering, billing and collection are usually driven by the number of customers, and known as “*customer service costs*”, and are recovered in the tariff through a **Fixed Monthly Charge**.

The recommended tariff structure is shown below in Table 8-1.

Table 8-1.Suggested Tariff structure

Tariff Category	Energy Charge	Fixed Charge	Service	Demand Charge	Remarks

	(Birr/kWh)	(Birr/Customer/Month)	(Birr/KVA/ Month)	
Domestic: Credit (Single or three phase)	√	√	* √	2-part tariff
Pre-payment (Single or three phase)	√			1-part tariff
General and Commercial: Credit (Single phase or three phase)	√	√	* √	2-part tariff
Prepayment (Single or three phase)	√			1-part tariff
Industrial (LV, MV & HV)	√	√	√	3-part tariff

- For consumers whose power demand is above 25 kW are subject to demand charge
- Licensees are however encouraged to develop and recommend alternative tariff structure consistent with the tariff principle and submit along with tariff application for review by the Authority

Article 34. Allocation of Allowed Revenue

The revenue requirements shall be allocated on the basis shown in the table below:

Table 8-2. Allocation of Allowed Revenue: LV – Domestic

Tariffs	Allocation Methodology
Energy Tariff (Birr/KWh)	$\frac{\text{Demand Cost} + \text{Energy Dependent Cost}}{\text{Total consumption of customers in customer category (KWh)}} \times 1/12$
Fixed Customer Charge	$\frac{\text{Customer Dependent Cost allocated to category}}{\text{No. of customers in the customer category}} \times 1/12$

Table 8-3. Allocation of Allowed Revenue: LV – General/Commercial

Tariff	Allocation Methodology
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Energy Tariff (Birr/KWh)	$\frac{\text{Demand Cost} + \text{Energy Dependent cost} \times 1/12}{\text{Total Consumption of Customers in Category}}$
Fixed Customer Charge	$\frac{\text{Customer Dependent Cost allocated to category} \times 1/12}{\text{No. of Customers in Category}}$

Table 8-4. Allocation of Allowed Revenue: Industrial - LV, MV and HV

Tariff	Allocation Methodology
Energy Tariff (Birr /KWh)	$\frac{\text{Energy Dependent Costs allocated to category} \times 1/12}{\text{Total Consumption of Customers in Category}}$
Demand Charge (Birr/KVA/month)	$\frac{\text{Demand dependent costs allocated to category} \times 1/12}{\text{Total Chargeable Demand for category}}$
Fixed Customer Charge (Birr/month)	$\frac{\text{Customer Dependent Costs allocated to category} \times 1/12}{\text{No. of customers in customer category}}$

Article 35. Domestic Tariff Structure

- The current end-use tariff structure for the domestic class is a **TWO-PART** type comprising the following:
 - Energy Charge (KWh);
 - Service Charge (Birr/Month)
- In the current end-use tariff structure, the energy charge is designed as **equivalent flat rate or as an Increasing Block Tariff (IBT)**, and the service charge is also structured as an IBT. *An Volume Differentiated Tariff (VDT), in which the price charged, increases with respect to each successive consumption block.*
- In the current domestic tariff structure for Ethiopia, there are seven consumption blocks as follows:
 - up to – 50 (Lifeline block): kWh;
 - up to– 100 kWh;
 - up to--200 KWh;
 - up to– 300 KWh;
 - up to– 400 KWh;
 - up to– 500 KWh;
 - Above 500 KWh.
- The use of IBT encourages conservation by penalizing customers for using energy in the upper block. A **life line tariff** has been variably introduced for the **first and second**

consumption block (0 – 50 kWh and 51 to 100kWh) as a targeted subsidy to all customers per month.

5. The current **service charge**:

A/for domestic class is dependent on energy consumed and has five blocks as follows:

- upto – 50 KWh post payment meter consumers a fixed amount per month
- Upto – 50 KWh prepayment meter consumes a fixed amount per month

B/ General tariff consumers

- post payment meter consumers a fixed amount per month
- prepayment meter consumes a fixed amount per month

C/ Industrial tariff consumers 3 phase meter

- Fixed amount per month

The service charge is used to recover the customer service costs and part of demand or fixed charges, since the domestic tariff do not include demand charge.

Article 36. Suggested Domestic Tariff Structure

For the domestic tariff structure the following recommendations are made:

1. The current **IBT structure** should be replaced by a **Volume-Differentiated Tariff (VDT)**. Unlike IBT, a VDT does not provide subsidy to customer whose consumption exceed the ‘lifeline’ tariff block;
2. Under a VDT, higher-volume customers whose consumption exceed the ‘lifeline’ threshold, are charged the next higher tariff in the next block **FOR ALL CONSUMPTION**;
3. For the sake of tariff simplicity and **in line with Article 29(h) of the dER**, the service charge should be a **fixed/flat rate, instead of five blocks, and should not be dependent on energy consumption**.
4. Since the fixed customer service charge is not dependent on energy consumed, it **should not** be directly linked to energy consumed in the tariff structure. It should therefore be denominated in **Birr/Customer/Month**;
5. The 0 – 50 KWh ‘lifeline’ tariff block should be maintained, but should be made to operate under a VDT structure. The associated tariff can be viewed as a subsidy to low uses households at the expense of higher use households. It is however important that such a subsidy is quantified and funded within the domestic customer class from the upper tariff blocks;
6. A pre-payment tariff denominated in KWh should be introduced to replace the flat rate;
7. For tariff simplicity and ease of tariff administration, a reduction in the number of tariff blocks from 7 to 5 is suggested as follows:

7.1 **1ST Block:** 0 – 50 KWh;

- 7.2 **2nd Block:** 51 – 150 KWh;
- 7.3 **3rd Block:** 151 – 300 KWh;
- 7.4 **4th Block:** 301 – 500 KWh;
- 7.5 **5th Block:** Above 500 KWh;

Article 37. General Tariff Structure

Regarding the General class of customers, the current end-use tariff structure is a **TWO-PART** tariff type comprising:

- Energy Charge (KWh)
- Demand charge (kW) for consumers with power demand above 25kW
- Service Charge (Birr/Month)

The use of service charge implies that fixed cost is recovered for single and three phase users, regardless of amount of energy consumed. Since the General customers do not use demand meters, the service charge serves as a proxy for the demand charge, and helps to recover some demand related costs as well as customer service costs (i.e. metering, billing etc.).

1. Suggested General Tariff Structure

- 1.1 For the; domestic and General Customer Category, due to the lack of demand metering, the current **TWO-PART** tariff comprising **ENERGY CHARGE (KWh)** and **SERVICE CHARGE (Birr/Customer/Month)** should be maintained;
- 1.2 For better targeting performance, the current IBT structure for the energy tariff should be converted to **VDT**;
- 1.3 For the sake of tariff simplicity, the current service charge which differentiates the tariff for single and three phase users, should be maintained and denominated as **Birr/Customer/Month**, since the service charge is used to recover customer cost and some demand related cost, and **should be independent of energy consumption**;
- 1.4 A pre-payment tariff, which is a flat rate and denominated in KWh, should replace the 'Equivalent Flat Rate'. This rate should be set at a level to recover the energy and the customer service charges and some demand related costs
- 1.5 To promote energy conservation while ensuring tariff structure simplicity, the following three-block **energy tariff structure** is suggested:

1st Block: 0 – 50 KWh;

2nd Block: 51 – 150 KWh;

3rd Block: Above 150 KWh;

Article 38. Industrial Tariff Structure

1. The current industry tariff is categorized, as: Low Voltage, High Voltage at (15KV) and High Voltage (at 132 KV), and the tariff is a **THREE-PART** type comprising the following elements:
 - a. Energy tariff : Peak and Off-peak;
 - b. Minimum Charge (KW);
 - c. Service Charge (Birr/Month);
2. The use of Time-of-Use (TOU) tariff for the energy charge is a DSM tool which is usually used in tariff design to encourage energy conservation. TOU tariff thus can therefore be used to send price signals to consumers to be aware that electricity supply costs could vary throughout the day, and enable customers to adjust their usage patterns.
3. The second tariff component is the **kW** denominated and is therefore a demand charge, which is used to recover fixed costs. The minimum charge is therefore capacity charge which covers the fixed cost incurred to meet customer MAXIMUM DEMAND. *It is a block tariff structure which specifies prices for various KW block, with the tariff decreasing for succeeding block, and is structured as follows:*
 - 3.1 High Voltage Consumer:**
 - 3.1.1 First 25 KW
 - 3.1.2 Next 400 KW
 - 3.1.3 For the balance
 - 3.2 Low Voltage Consumer:**
 - 3.2.1 First 25 KW
 - 3.2.2 Next 200 KW
 - 3.2.3 For the balance
 - 3.3 Self-Contained System – Low Voltage Consumer:**
 - 3.3.1 First 25 KW
 - 3.3.2 Next 200 KW
 - 3.3.3 For the balance
4. The third component of the industry tariff structure is the service charge. Since the industry tariff is a THREE-PART structure, the service charge will be set to specifically recover the customer related costs such as metering, billing, collection etc.

Article 39.Suggested Industrial Tariff Structure

1. The current **THREE-PART** tariff structure for the industry class should be maintained;
2. In line with the power factor payment rationalization, the demand charge (or minimum charge) should be denominated in **KVA instead of KW**. Denominating the demand charge in KVA has the added advantage of encouraging energy efficiency usage by industrial customers;
3. The current demand (or minimum charge) is a blocked tariff which gives lower prices for higher loads. To promote energy efficiency and conservation, it is suggested that the current **DECLINING BLOCK** tariff be replaced by an **IBT or INVERTED RATE** tariff;
4. The current service charge should be maintained and should be set to recover the customer service costs such as metering, billing and collection;
5. The current TOU energy tariff should be expanded for the energy tariff from **PEAK** and **OFF-PEAK** tariffs, to include a **SHOULDER PERIOD** tariff which should be set to lie between the peak and off-peak tariffs. The TOU tariff should be structured based on the daily load curve as follows:
 - 5.1 **Peak Period:** Evening Time;
 - 5.2 **Shoulder Period:** Day Time;
 - 5.3 **Off-Period:** Night Time;
6. In the event that there is *a significant shift in the daily load curve, the licensee may submit a request to EEA to modify the period or time slots, for the Authority's review and approval or disapproval, during tariff application;*
7. *The TOU tariff should however be made voluntary. Consequently, the recommended industrial tariff structure include an energy tariff for non-TOU industrial customers;*
8. The current **Active/Reactive tariffs for Domestic and General Customer categories** be replaced with **"Ancillary Services Charge"** which should be levied on generators, instead of consumers, as per the 'Guiding Principles' discussed below.

Article 40. Ancillary Services Charge

1. In addition to the fixed and variable cost components of the tariff, it is important to include payments for the supply of ancillary services. The provision for compensation for ancillary services should however be subject to available capacity and not on installed capacity. In that regard, the supply of ancillary services be ***made mandatory and included in all future PPAs with IPPs***. There should be penalties for failure to supply ancillary services by generators, and such payments can be subtracted from generators' total payments by the transmission system operator.
2. The following ancillary services are required to be supplied by generators:
 - 2.1 Operating reserves: Spinning and Non Spinning;
 - 2.2 Regulation and load frequency control;
 - 2.3 Voltage control and Reactive Power Regulation;
 - 2.4 Black start capability;
3. Provision of the above services requires the generator to be available at certain periods of time, or to operate the units in a manner to stabilise the system as directed by the Transmission Licensee/System Operator. The ancillary services payment is therefore intended to compensate the generator for the **INCREMENTAL** cost of supplying such services. Cost recovery of the ancillary services can be achieved using the following 'Guiding Principles':

3.1 Spinning Reserves

Compensate generators for loss of revenues due to regulation and pass the cost through to consumers as part of the BGT.

3.2 Non-Spinning Reserves

Cost associated with this service can be recovered as follows:

- 3.2.1 The cost for the unit to be on stand-by ready to be started on short notice;
- 3.2.2 Start-up cost and cost of energy production;

3.3 Voltage Control and Reactive Power

- 3.3.1 Each generator should be required to provide reactive power within its capacity curve without being paid any compensation;
- 3.3.2 All loads (i.e. distributors, large users) would be required to withdraw reactive power within the allowable technical limits and no penalties are imposed for such withdrawals;
- 3.3.3 All loads which withdraw reactive power outside the technical limits due to low power factors shall pay a power factor penalty, as discussed in section below;

4. Adopted approach

Reactive power payments by generators would therefore become necessary when other parties may fail to fulfil their obligations. Further Article 23(2i) of the Energy Regulations which states that *Generation Licensees shall have the obligation to provide ancillary services based on the demand of the transmission or distribution and sale licensee that* are necessary for the reliable and secure operation of the interconnected system.

Article 41. Ancillary Services Pricing Guidelines – Practical Approaches

1. Frequency Control/Regulation

The requirement for frequency control arises because of mismatches between generation and demand. The contingency the transmission system licensee must meet, is the loss of the single largest generator on the grid or the loss of the largest single load.

In Ethiopia, since the largest single generator is a hydro plant, it implies that the frequency control will be equal to the amount of excess generation capacity required to be available to compensate for this loss of generation. Thus the indicative cost of providing these services could be based on the cost of power supply from a **hydro⁷ generating plant**.

2. Spinning Reserve

Hydro plants are also best suitable for use as spinning reserves. The indicative cost of providing this ancillary service can therefore be based on the cost of power supply from the **hydro plant**.

3. Supplementary Reserve and Black Start Capability

Combustion turbines or diesel plant are best suited for providing supplemental reserves or black start capability. The indicative cost can therefore be based on the capital cost of a **diesel plant**.

4. Voltage Support/Reactive Power Supply

Since the voltage control serves primarily to support the entire bulk-power system rather than individual transactions, it is difficult to identify the voltage-control burden created by each transaction. For practical purposes, the indicative cost can be estimated based on capacity price (**denominated in \$/kW-month**) of the largest plant in the **system which is a hydro plant**.

5. Adopted approach

There should be a mandatory obligation on generators to follow System Operators instructions to provide reactive power, failure to do that would result in payment of a regulated price for ancillary services. The regulated price should be set to cover the **FIXED COST and loss of revenues** as result of sub-optimal dispatch to produce reactive power, **as elaborated under the ancillary pricing guidelines in Article 41 above**.

⁷ Hydro units are generally ideal for providing regulation because of their very fast ramp rates, usually 20 to 50 times as fast as fossil units, and also very low efficiency losses under cycling conditions.

Article 42. Power Factor Payment

1. Electricity tariff may include a power factor payment which is levied **on industrial consumers to reflect the cost or the 'stress' their reactive power usage, imposes on the power system as a result of low power factors.** Power factor can be defined as the ratio of the useful power, (expressed in KW), to total apparent power supplied, (expressed in KVA) (i.e. $PF = KW/KVA$). In an electrical, system, if the power factor is 0.60 lagging, it means only 60% of the total apparent power supplied is converted into useful work.
2. Therefore a higher Power Factor would lead to a more optimum use of electrical current by a customer. It would eventually lead to reduction of the total apparent power supplied to the customer and result in savings in power supplied to large power users, particularly industrial consumers. Industrial consumers which operate at low power factors can improve upon their values and minimize the total apparent power drawn from the power source, using any of the following methods:
 - 2.1 Reduction of lagging reactive current demand of loads;
 - 2.2 Compensate for the lagging reactive current by supplying leading reactive current using correction equipment (i.e. capacitor);
3. Since the total apparent power supplied to the load is denominated in KVA, it is better to link the power factor payment to KVA, to reflect the true power usage of the customer. *An excess of reactive current supply to correct for low power factor lowers the efficiency of the distribution and transmission network and contributes to bad voltage regulation.*
4. For a cost reflective tariff design, these costs should be reflected in the tariffs. The power factor penalty payment would apply to consumers whose power factor is below the regulatory threshold, where power factor values are considered to create excessive reactive power flow.
5. The current end-user tariff structure includes a power factor payment for high and low voltage consumers (for the interconnected and self-contained system), and is denominated in **Birr/month**. Since industrial consumers are on a three-part tariff charges, (i.e. Energy, Demand and Service Charges), the lagging power factor costs should be recovered through the **DEMAND PORTION** of the tariff.
6. In order that the large power users are incentivized to operate close to the **system benchmark value of 0.95 lagging**, a power factor penalty payment should be introduced, by using a transparent formula to compute the power factor payment. This approach is presented below.

Article 43. Power Factor Payment Formula

The Power Factor penalty payment can be calculated using the following equation:

$$\text{Power Factor Penalty Payment} = KVA \times MD_{\text{REC}} \times \frac{0.95}{PF_{\text{AVG}}} - KVA$$

$$\text{Power Factor Payment} = \text{KVA} \times \left[\frac{\text{MD}_{\text{REC}} \times 0.95}{\text{PF}_{\text{AVG}}} - 1 \right]$$

where:

KVA = Demand Charge (Birr/KVA/month), as set by EEA as part of the tariff;

MD_{REC} = Recorded Maximum Demand over the billing period (KVA)

PF_{AVG} = Consumer's average power factor during a billing period (i.e. month)

Table 8-5.Suggested Detailed Tariff Structure

Customer Category	Tariff Structure
Domestic	Energy Tariff (VDT Structure): 0 – 50 kWh 51 – 150 kWh 151 – 300 kWh 301 – 500 kWh > 500 kWh Fixed Service Charge: Birr/Customer Prepayment: Birr/kWh
General, including Street Lighting	Energy Tariff (VDT Tariff Structure): 0 – 50 kWh 51 – 150 kWh > 150 kWh Fixed Service Charge: Birr/Customer Prepayment: Birr/kWh
Commercial/Services	Energy Tariff (VDT Tariff Structure): 0 – 50 kWh 51 – 150 kWh > 150 kWh Fixed Service Charge: Birr/Customer Prepayment: Birr/kWh
Industrial: LV, MV, HV.	Energy Tariff: Birr/kWh, TOU Tariff: Peak, Off-Peak and Shoulder Period Tariffs

	Energy Tariff: Birr/kWh: Non-TOU customers Demand Charge: Birr/KVA (IBT Tariff Structure) Fixed Service Charge: Birr/Customer Power Factor Payment (as a function of KVA)
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Chapter 9. Tariff and Demand Side Management

Article 44. Significance of DSM in Tariff Design

1. Tariffs are usually designed to incentivise customers to adopt Demand Side Management (DSM) practices. DSM is basically a collection of approaches which are used to influence the amount or timing of consumers' electricity usage, and ensure efficient utilization of scarce resources associated with generation, transmission and distribution of electricity. DSM may be introduced to achieve the following objectives, among others:

- 1.1 Promote energy conservation and energy efficiency;
- 1.2 Reduce peak load;
- 1.3 Defer the construction of new power plants;
- 1.4 Encourage load shifting to time of day when power supply costs are lower;
- 1.5 Prevent overload or reliability problems for the power system;
- 1.6 Reduce negative externalities (i.e. environmental) associated with power generation, transmission and distribution;

2. In the design of tariffs, a number of tool exist for promoting DSM. These include:

- 2.1 Adoption of Time-of-Use (TOU) tariffs;
- 2.2 Use of Interruptible tariffs;
- 2.3 Voluntary demand curtailment;
- 2.4 Economic pricing for cost reflectivity;

Article 45. Time-Of-Use Tariff

1. The current end-user tariff structure includes a TOU prices for peak and off-peak use of electricity, to provide the opportunity to customers to shift electricity usage to minimize their

electricity cost. The recommendation on the TOU pricing is that it should be maintained in the tariff structure, but should be modified to cover:

- 1.1 Peak period;
 - 1.2 Off- peak period;
 - 1.3 Shoulder period.
2. Adoption of the three-period TOU price structure will allow the power supplier to achieve cost savings, and with regulatory supervision, pass-on such savings through lower tariffs to the consumers.

Article 46. Interruptible Tariff

A second DSM approach to consider is interruptible tariff, which enables a licensee to provide a customer with a lower tariff for interrupting the customer for a specified period within the day, as conditions require. The tariff reduction could come in the form of paying lower demand charges, energy tariff or both.

Article 47. Voluntary Demand Curtailment

1. The tariff design could also include an option for customers to undertake ‘Voluntary Demand Curtailment’, as a form of DSM measure. With this approach, customers who agree to participate are actually curtailing their demand during capacity shortages.
2. From the regulatory perspective, if EEA wants to adopt this DSM option, the key issue is how to set the level of compensation to customers who decide to participate in the programme. The following methods could be considered for the compensation.
 - 2.1 Use a regulated or pre-established price;
 - 2.2 Set the price based on BST;

Article 48. Economic Pricing and Cost Reflectivity

1. A critical requirement for DSM measure is to ensure that there is proper pricing for use of electricity. If the price of electricity is uneconomic and do not send the correct price signals to users, there will be little incentive for conservation by customers.
2. It is therefore recommended that a proper cost of service analysis be undertaken for each customer class, using the tariff guidelines and methodology described in this document. Where it is established that the tariffs are below the cost of service, a **TRANSITIONAL PLAN** could be established, to gradually bring the tariffs in line with the cost of service or cost reflective tariff, for each consumer class;

3. Adopted approach

DSM measures should be based on incentives for utilities and customers; TOU for industrial customers should be maintained but modified to include: Peak period, Off- Peak period and Shoulder period tariff; Other DSM tools such as interruptible tariffs and voluntary demand

curtailment could be considered Cost service study should be conducted to establish the **cost-reflective tariff for each customer class**. A transitional plan could then be

Chapter10. Tariff Review and Approval Process

Article 49. Tariff Review Process

1. The key attributes of any effective regulator include ensuring credibility and transparency of the tariff-setting process. This is necessary to ensure fairness to both consumers and utility operators. Additionally, providing rationale for tariff decisions can bolster regulatory transparency and make the regulator to be accountable for its decisions. In the light of these, the following tariff review and approval steps have being recommended to EEA and each of these steps are discussed below:
 - 1.1 Submission of Tariff Application;
 - 1.2 Preliminary Review of Application:
 - 1.2.1 Rejection of Application;
 - 1.2.2 1.2.2Acceptance of Application;
 - 1.3 Public Hearings and Post Preliminary Review;
 - 1.4 Tariff Recommendation and Approval;
 - 1.4 Tariff Publication;
 - 1.5 Press Release;

Article 50. Submission of Tariff Application

Licensees would be required to develop and submit their tariff applications in accordance with the Energy Regulation **No ???**. The tariff notification to EEA according to the draft Energy Operations Regulation should be filed at ***least 120 days from the effective date of the tariff coming into force of off-grid tariffs***. Article 32(4) of the Energy Operations Regulation requires the licensees to also publicise the proposed tariffs to the public concerned. This can be done through one of the newspapers of wide-circulation.

Article 51. Preliminary Review of Application

1. The preliminary assessment is to enable EEA to review the tariff proposals **for completeness**. EEA may reject the tariff proposals if some of data required or information are missing, after a post preliminary review. The post-preliminary review would deal with issues related to: Evidentiary hearing, technical conference, re-hearing application, discussions relating to recommendation for approval etc.If the proposals are rejected, EEA shall notify the affected licensee(s).
2. The licensee, after receiving the “***Rejection Notice***” due to incompleteness, shall then re-file its ***tariff application within thirty (30) working days***, and submit all the necessary information to EEA for re-consideration.

Article 52. Public Hearings and Post Preliminary Review

1. When EEA accepts the tariff proposals of a licensee, it shall hold ‘open’ multi-locational public hearing(s) to give opportunity to stakeholders to comment on the proposals and provide input to the tariff process. **This is line with Article 32(2) of the dEOR which requires the Authority to consider suggestions and objections from the public as part of the tariff-setting process.** At the public hearing(s), EEA may ask the licensee(s) to respond to issues raised by stakeholders on the tariff proposals.
2. Prior to holding the public hearings, EEA shall ask the licensee to publish the tariff proposals in at least one newspaper of wide circulation. This should be done at ***least 10 days before the public hearings.***

Article 53. Analysis and Recommendations

1. After the public hearings, EEA shall perform in-depth analysis of the tariff proposal, using both qualitative and quantitative analysis. The analysis will involve review of major cost elements submitted by the licensee(s). EEA may draw on the expertise or experience of stakeholders in the sector when conducting the tariff analysis.
2. The findings from the tariff analysis will be summarized in a form as shown below in Table 10-1, to enable stakeholders have a concise view of the differences between EEA’s recommendations and licensee(s) applications. Table 10-1 should form an Appendix to the tariff documentation and should also provide a summary of the rationale for EEA’s recommendations to the government.

Table 10-1.Presentation of Summary of EEA’s Tariff Recommendation.

Cost Category	Licensee Submissi on	EEA Adjustment	EEA Recommendation
Regulatory Asset Base Adjustments: a. b.			
Working Capital Adjustments:			
Cost of Capital: i. Cost of Debt ii. Return on Equity Adjustments: a. b			
Return on Investment			
O&M Adjustments: a. b.			
Depreciation Adjustments: a.			

b.			
Taxes Adjustments:			
a.			
b.			
Total Revenue Requirements			
Sales Quantities (MWh)			
Average Tariffs:			
a.			
b.			

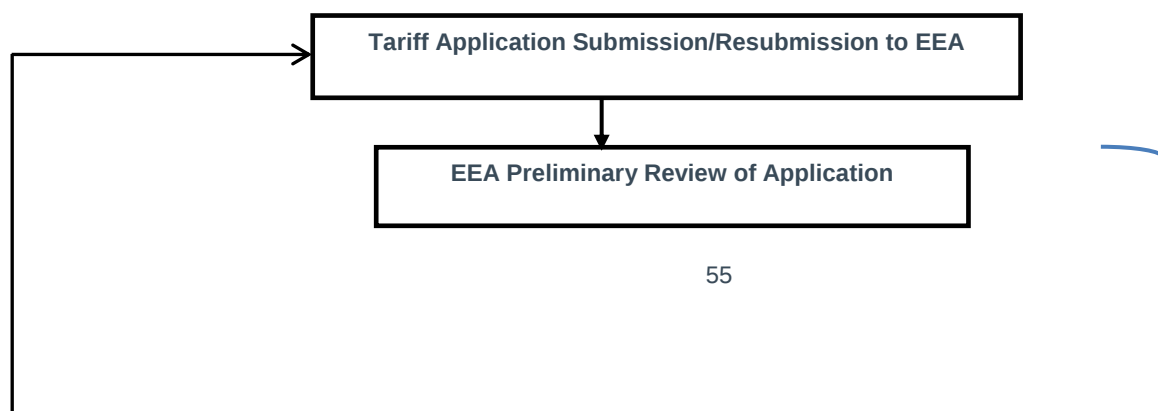
Article 54. Tariff Recommendation and Approval

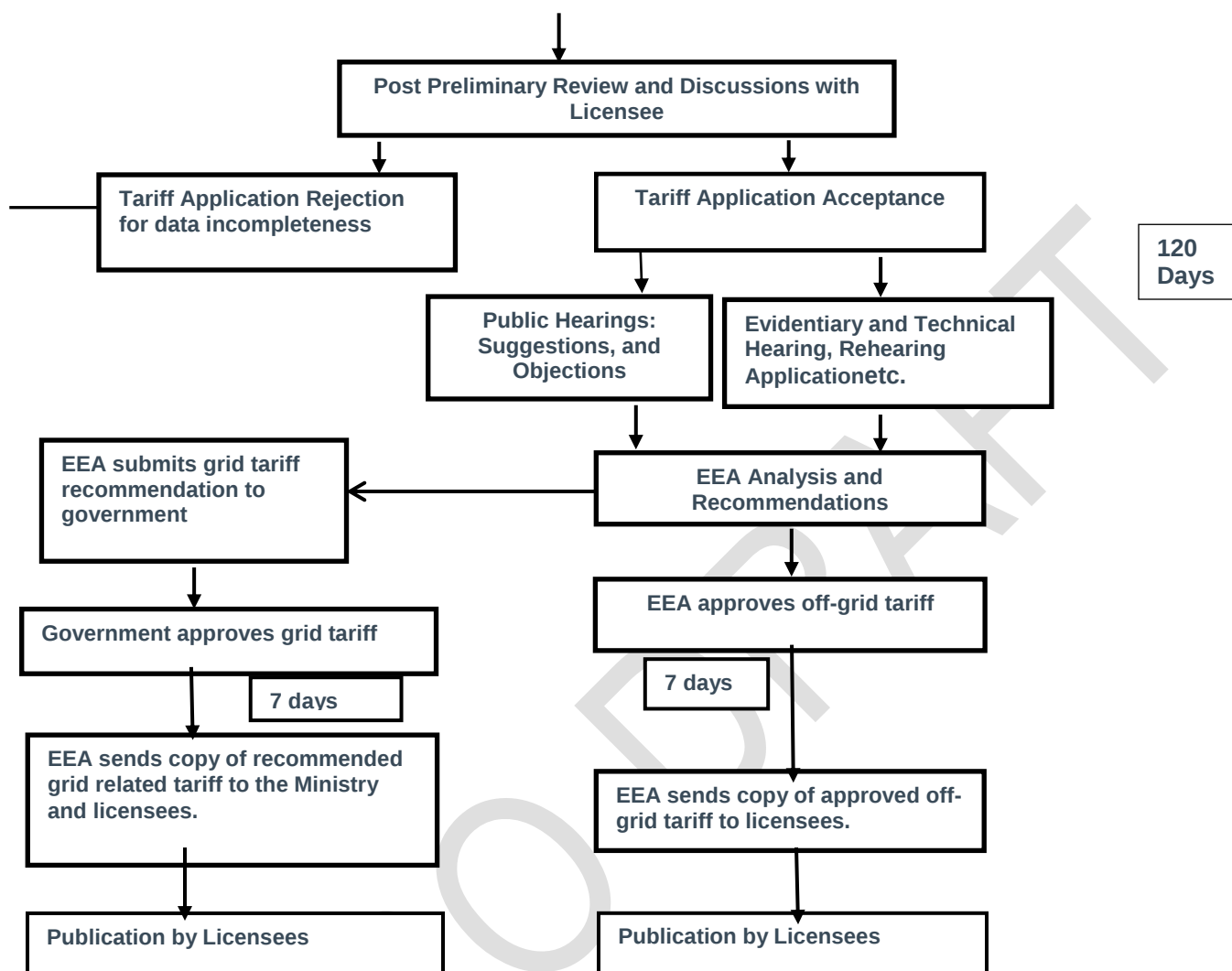
1. The Energy Proclamation No. 810/2013 specifies that for grid-related tariffs, EEA shall review and submit its recommendation to the government for approval. This would be done once EEA believes it has enough information to make the recommendations. The recommendations to the government should comprise the following:
 - 1.1 EEA's decision on the cost elements;
 - 1.2 Resulting revenue requirements;
 - 1.3 Reasons for the recommendation supported by Table 10-1, showing the differences between EEA's recommended figures and those submitted by the licensee(s);
2. For off-grid tariff, EEA shall, within **one hundred and twenty days**, after considering all suggestions and objections, approve the tariff with such modifications or such conditions, or reject the application for reasons to be recorded.

Article 55. Tariff Publication

1. The Authority is required under the Article 32(3) of the dEOR, within **seven days of recommending grid-related tariff and approving off-grid tariff**, to send a copy to the Ministry and the concerned licensees, as appropriate. Additionally, Article 32(4) of the dEOR requires the licensees to publicise the approved tariffs to the public.
2. Following the approval of the grid and off-grid tariffs by the government and EEA respectively, the Authority may also issue a '*Press Release*'. The '*Press Release*' will enable EEA to provide the rationale for the tariff adjustment, as well as other necessary information which will enable the public understand the reasons for the tariff decision. Figure 10-1 depicts the recommended flowchart for the tariff review and approval process.

Figure 10-1. Flow Chart for Tariff Review and Approval Process





Chapter 11. Tariff Adjustment Mechanism

Article 56. Basis for Tariff Automaticity

1. In reviewing and recommending grid related tariff (or approving off-grid tariff) in relation to generation, transmission, wheeling, distribution and sale of electricity, the

Energy Regulation_____ Article 30 requires *EEA to include tariff adjustments to reflect periodic changes in:*

- 1.1 Fuel cost;
 - 1.2 Cost of power purchase;
 - 1.3 Rate of inflation/deflation;
 - 1.4 Currency fluctuation;
2. In addition, in reviewing and recommending grid related tariff or approving off-grid tariff, EEA shall also be guided by the multi-year tariff principle. These imply that the tariff-setting guidelines and methodology should contain a tariff indexation mechanism which would allow for **periodic adjustment of the tariffs to reflect changes in price due to cost components which are beyond the control of EEP and EEU.**
 3. The recommended Tariff Adjustment mechanism should ensure that in future, the tariffs will always keep pace with costs during periods between major tariff reviews, which according to the Energy Regulation Article 31 sub Article 7, **will be once in every four years.** This process thus moves the tariff- setting regime into a **MULTI-YEAR** type.
 4. As per Article 31 and Sub Article 8 of the Energy Regulation licensees can file tariff adjustment request on bases of cost drivers as in sub article one of this article at any time between the four years interval with the justifications and details worked out as in this guideline. The Authority is to review verify and recommend to the government for approval of the interim adjustment.
 5. The interimTariff Adjustment mechanism is expected to achieve the following objectives:
 - 5.1 Develop a fuel adjustment mechanism to reflect fuel price volatility;
 - 5.2 Develop a formula which takes account of key macro-economic variables and other exogenous cost variables which are outside the control of the utilities such as: inflation /deflation, currency fluctuations;
 - 5.3 Recommend the mode of application of the formula, based on best industry practices;
 - 5.4 Prevent ‘tariff shocks’ which are usually associatedwith major tariff reviews by allowing licensee’s revenue to keep pace with costs;

Article 57. Significance of Tariff adjustments

1. Interim tariff adjustment or indexation mechanisms have been developed by regulators as part of tariff-setting process to off-set the disadvantages associated with **‘pure’ Rate of Return, ‘pure’ Price Cap or ‘pure’ Revenue Cap tariff regulation.** The inclusion of an adjustment mechanism thus converts the tariff process into a hybrid type and enables regulators to deal with tariff uncertainties which usually arise in utility price setting, since regulators always make assumptions on costs to be incurred by the licensees, when setting tariffs.

2. In order to address the problem of tariff uncertainties, regulators have introduced some degree of flexibility in the tariff setting process by introducing an interim tariff determination process, using a predetermined Tariff Adjustment Mechanism. The mechanism will ensure pass-through of selected exogenous cost variables by pre-specifying the formula.

Article 58. Factors to Consider for Cost Pass-through

In developing an Automatic Tariff Adjustment mechanism, the regulator must first decide which cost variables qualify as pass-through items. The decision on the qualifying variables can be made using the following qualification tests, which are based on best industry practice.

1. Materiality Test

The *materiality test* examines whether the uncertainty, if ignored, will have a **material impact** on the utility's income and costs, and affect the licensee's ability to meet regulatory targets, specific outputs and its financial covenants. If the uncertainty is considered to have a material impact on the operations of the utility, then it is treated as a cost pass-through item in the automatic tariff mechanism.

2. Separability Test

The *separability test* looks at whether the impact from the uncertainty can be separately identified. If the impact can be separately identified, then the cost could be considered as a pass-through item in the adjustment formula.

3. Controllability Test

Regarding the *controllability test*, the aim is to find out if the licensee can have a reasonable degree of control over the impact of the uncertainty. If the regulator can establish that the licensee can have a reasonable control over the impact of the uncertainty, then the cost is not considered as a pass-through item. In this case, the regulator should rather incentivize the licensee to manage the risk. If on the other hand, it is proven that the **licensee cannot control** the impact of the uncertainty, then the risk is passed-through to consumers in the adjustment formula.

4. Predictability Test

4.1. The *predictability test* examines whether the uncertainty and its impact are predictable. If the **uncertainty cannot be reasonably predicted**, then steps should be taken to mitigate the impact through the use of the Automatic Adjustment Formula.

4.2. The table below summarizes the results of the tests conducted on the exogenous cost variables to ascertain which of them pass the qualifying test as pass-through items.

Table 11-1. Test for Exogenous Cost Items for Tariff interim Adjustment

Cost Item	Materiality Test	Separability Test	Controllability Test	Predictability Test	Result
Fuel Price	Yes, has material impact	Yes, cost can be separated	No, cost cannot be controlled by licensee	Not easily predictable, if affected by fuel cost	Qualify as cost pass through
Power Purchase (Import or PPA)	Yes, has material impact	Yes, cost can be separated	No, cost cannot be controlled by licensee	Not easily predictable, if affected by fuel cost	Qualify as cost-pass through
Macro-economic Variables:					
• Inflation or Deflation	Yes, has material impact	Yes, cost can be separated	No, cost cannot be controlled by licensee	Not easily predictable	Qualify as cost pass-through
• Currency Fluctuation	Yes, has material impact	Yes, cost can be separated	No, cost cannot be controlled by licensee	Not easily predictable	Qualify as cost pass-through

Article 59. Fuel Price Adjustment Mechanism

1. The energy price components of generation which affect the system short-run marginal cost are:
 - 1.1 Variable fuel price;
 - 1.2 Non-fuel variable price;

In line with the industry practice, the variation of non-fuel variable cost is usually measured by the consumer price index or inflation. The proposed Adjustment Formula for indexing the Fuel Price in the Base Energy Price is as follows:

$$P_t = P_B \times \left[\alpha \frac{FP_{t-1}}{FP_B} + \beta \frac{Inf_{t-1}}{Inf_B} \right]$$

where:

P_t = New Energy Price for period, t

P_B = Base Energy Price (Birr/KWh)

FP_{t-1} = Fuel Price for period, t-1

FP_B = Fuel Price for base period

Inf_t = Inflation for period, t-1 as published by the Central Statistical Agency

Inf_B = Inflation for base period, as published by the Central Statistical Agency

α and β = The α is called the **fuel co-efficient** and β the **inflation coefficient**. Based on industry practice, the α or fuel coefficient varies between 0.80 - 0.90, while the inflation coefficient or the β , varies between 0.10 – 0.20.

2. A summary of **α and β values** for different fuels are shown in table 11-2.

Table 11-2. Fuel and Inflation Coefficient

Variable	Crude oil	Diesel	Natural Gas
A	0.85	0.90	0.80
B	0.15	0.10	0.20

Article 60. Hydro Price Adjustment

1. The hydro price in the Bulk Generation Tariff (BGT) can be calculated in accordance with the principles of power economics, by taking into account the **WATER VALUE** in the reservoir. The Water Value approach for pricing the hydro plants aim at calculating the opportunity cost of water stored in the reservoir for future use, which will displace the marginal system generation plant in the merit order. The Water Value is usually computed by taking the following factors into account:

- 1.1 Current level in the reservoir;
- 1.2 Hydro condition;
- 1.3 Amount of hydro energy generation;

2. At the current stage of Ethiopia's power market structure, the adoption of the water value approach to adjust the base hydro price will be difficult to implement. The recommended base hydro price adjustment formula is as follows:

$$P_{H,t} = P_{BHYD} [1 \pm \Delta CPI]$$

where:

$P_{HYD,t}$ = Hydro energy price for period t (Birr/KWh)

P_{BHYD} = Base hydro price

CPI = Consumer Price Index as reported by the Central Statistical Agency

$$\frac{\Delta \text{CPI}}{\text{CPI}_{t-1}} = \frac{\text{CPI}_t - \text{CPI}_{t-1}}{\text{CPI}_{t-1}}$$

Article 61. Bulk Generation Tariff Adjustment

The Adjustment Formula for the Bulk Generation Tariff (shall be based on the Weighted Average Generation Price) is as follows:

$$\text{BGT}_t = \{X_H P_H + X_T P_T + X_W P_W + X_G P_G + \dots + X_N P_N\}$$

where

BGT_t = Bulk Generation Tariff for period t (Birr/kWh);

X_H, X_T, X_W, X_G = Weights or percentage contribution of hydro, thermal, wind, geothermal in the generation mix (%);

P_H, P_T, P_W, P_G = Total price (energy and capacity) of hydroelectric, thermal, wind, geothermal generation etc. (Birr/KWh)

X_N = Percentage contribution from any other generation source (%);

P_N = Generation Price of any other generation source (Birr/KWh)

Article 62. Transmission Tariff Adjustment

1. In formulating the transmission price adjustment formula, it is assumed that the main variable costs associated with network operations are the technical losses. It is however worthy to note that in determining the base transmission price, EEA has already taken account of the benchmark transmission loss value. In that regard, an attempt to correct for network losses in the adjustment formula will amount to ‘double counting’.
2. The transmission adjustment formula has therefore been formulated to simply take care of inflationary effect and ensure that the price will not ‘decay’ over time. The transmission price adjustment formula is as follows:

$$\text{TST}_t = \text{TST}_B [1 \pm \Delta \text{Inf}_t]$$

where:

TST_t = Transmission Service Tariff for period t (Birr/KWh)

TST_B = Base transmission service tariff (Birr/KWh)

Inf_t = Inflation for period t, as published by the Central Statistical Agency

$$\Delta \text{Inf} = \frac{\text{Inf}_{t-1} - \text{Inf}_{t-2}}{\text{Inf}_{t-2}}$$

Article 63. Distribution Tariff Adjustment

1. The indexation for the distribution tariff adjustment takes cognizance of the fact that distribution network losses are associated with distribution operations. To ensure that only efficient costs are passed-through to consumers, the regulator in computing the base distribution tariff took into account the regulatory benchmark loss level to determine the licensees' revenue requirement.
2. In that regard, an attempt to adjust for loss levels in the distribution formula will amount to 'double-counting' and over-compensating the licensee. The recommended distribution adjustment mechanism is therefore formulated as follows:

$$\text{DST}_t = \text{DST}_B [1 \pm \Delta \text{Inf}]$$

where:

DST_t = Distribution Service Tariff for period, t (Birr/KWh)

DST_B = Base Distribution Service Tariff (Birr/KWh)

Inf_t = Inflation for period, t, as published by the Central Statistical Agency

Inf_{t-1} = Inflation for previous period

$$\Delta \text{Inf} = \frac{\text{Inf}_t - \text{Inf}_{t-1}}{\text{Inf}_{t-1}}$$

Article 64. Currency Fluctuation Correction Mechanism

1. Article 32 of the Draft Energy Operations Regulations requires that in developing the automatic tariff adjustment mechanism, the formula should also reflect periodic change in **currency fluctuation**. In line with this requirement, a foreign exchange correction factor (FRX) has been introduced. The FRX connection factor is expressed as a percentage and calculated as follows:

$$\text{FRX}_t = \frac{\text{Exchange Rate}_{t-1} - \text{Exchange Rate}_{t-2}}{\text{Exchange Rate}_{t-2}}$$

where:

FRX_t = Foreign exchange correction factor

$\text{Exchange Rate}_{t-1}$ = Average Exchange rate for previous period t, as recorded by the National Bank of Ethiopia, between the US\$ and Birr, during the previous period;

Exchange Rate_{t-2} = Exchange Rate during period t-2 between the US\$ and the Birr.

Article 65. End-User Tariff Adjustment

1. The end-user tariff adjustment for period t, shall be calculated as follows:

$$EUT_t = [BGT_t + TST_t + DST_t] \times [1 + FRX_t]$$

where:

EUT_t = Adjusted end-user tariff for period t (Birr/kWh)

BGT_t = Adjusted Bulk Generation Tariff for period t (Birr/kWh)

TST_t = Adjusted Transmission Service Tariff for period t (Birr/kWh)

FRX_t = Foreign Exchange Correction Factor

2. Adopted approach

- Ideally, the Tariff Adjustment Mechanism (TAM) should be calculated monthly and applied to customer bills. To ensure end-user price stability in line with the principles in the Energy regulation, it is adopted that the results from the TAM be tracked monthly, **but applied as frequently as deemed necessary as may be confirmed by the thresholds measure of levels as stated below** ;
- To ensure end-user price stability in line with the energy regulations, it is adopted that the TAM should be triggered when the change in the End Use Tariff (EUT) exceeds a **dead band of $\pm 4.0\%$** ;
- The final percentage charge in the end-user tariff should be applied as a **SINGLE RATE OF ADJUSTMENT** to all the customer categories. This approach will ensure *simplicity and ease of application* of the ATAM;

Chapter 12. Cross Subsidy and Subsidization

Article 66. Guiding Principles for Effective Subsidy Design

1. In designing tariffs, subsidies to customers have now become a salient feature. Subsidized service can be made by the government from general tax revenue or regulators can make use of cross-subsidization within their customer base, to fund subsidies for certain customer categories. Therefore in the electricity sector, subsidies can exist between:
 - 1.1 Governments and Licensees;
 - 1.2 Government and customers;
 - 1.3 Licensees and customers;

1.4 Customer classes (i.e. cross-subsidization);

The proponents of subsidies in tariffs argue that utility subsidies are important for the following reasons:

1.5 Make utility services affordable for poor households;

1.6 It is a form of social policy instrument for achieving income distribution;

2. The arguments have been countered by the opponents of use of subsidies as follows:

2.1 Affects the financial sustainability of the utility company;

2.2 Fails to send the correct price signals to consumers and rather create distortions in the use of electricity;

2.3 Unfunded subsidies also leave unconnected households facing the prospect of relying on often expensive and poor quality alternatives;

2.4 Subsidies are usually not well-targeted and thus do not benefit the poor;

3. The above arguments for and against the use of subsidies in tariff design show that economic efficiency is not the only criterion that may be used in electricity pricing. It is important to also take account of equity and income distribution. In practice, since an appropriate distribution of resources rarely exists in most developing countries, governments have allowed regulators to adopt subsidies as part of tariff policy.

4. Even though from theoretical economics perspective, subsidies can distort the utility pricing, from a practical and social perspective, they are needed and are therefore used by regulators as part of the tariff-setting. The key issue is for regulators and policy makers to ensure that the subsidies are **EFFECTIVE** and **WELL-TARGETED**. The following are therefore presented as the “**Guiding Principles**” for effective subsidies design in the tariffs:

5.1 Be Quantifiable

An effective must be **QUANTIFIABLE**. This is important if the regulator and government are to make informed decisions.

5.2 Transparency

The subsidy must be **TRANSPARENT**. Electricity subsidies are transparent if the cost of service for each customer class is known, so that the regulator can determine which classes are the subsidy recipients, and which classes are the subsidy providers.

5.3 Well-Targeted

An effective subsidy policy should be **WELL-TARGETED**. This implies that the subsidy must be delivered to the intended recipients. A better targeted subsidy reduces the subsidy amount required to provide a discount to the intended recipient and bring greater benefit to the poor. The current design of electricity subsidies in developing countries tend to exclude most poor households, while most of the benefits rather accrue to the non-poor.

5.4 Part of Pricing Policy

The subsidy should be in line with the pricing policy for the country. For Ethiopia, the decision on subsidy and cross-subsidy is clearly presented in the Energy Operation Regulations.

5.5 Customer Class Responsibility

In incorporating cross-subsidies in electricity tariffs, the regulator should ensure that the cross-subsidizers are not allowed to shirk that responsibility.

Article 67. Cross Subsidy Design

Cross-subsidies are incorporated as part of tariff rate structures where excess revenue earned from some customer class is used to off-set losses created by another customer class. The following types of cross-subsidies are common with the electricity sector.

1. A scenario where industrial customers pay more than their cost-reflective tariffs. (i.e. cross subsidizers), to subsidize the domestic class (i.e. subsidy recipient);
2. High volume customers within the residential class or same class, subsidize low volume or life line customers, within the same class;
3. A situation where high density or low cost areas (i.e. urban areas) subsidize low density or high cost areas (i.e. rural or peri-urban areas), through the use of uniform pricing.

Article 68. Significance of Adoption of Bulk Generation Tariff Concept

1. The adoption of Bulk Generation Tariff to compute the weighted average generation cost for the country's power system would ensure that a uniform generation tariff is passed-through the tariff-chain to end-users. This approach implicitly cross-subsidizes high cost generation technologies with low cost technologies, and ensure that a uniform tariff which balances the objectives of *social and political acceptability*, with the financial viability of the licensees, are maintained by EEA.
2. In accordance with the key principles of effective electricity subsidy design, it is important that the level of cross-subsidy, in the current Ethiopian electricity tariff structure should be properly quantified using the following guidelines:
 - 2.1 **Step 1:** Determine the cost recovery tariff for each customer class;
 - 2.2 **Step 2:** Analyze the current tariff levels per customer class with respect to the cost of service (COS) tariffs;
 - 2.3 **Step 3:** Calculate the Cost of Service Index as follows: $\text{Current tariff} \div \text{COS Tariff}$;

2.4 **Step 4:** Quantify the cross subsidies between the classes by calculating the ‘over or under recovery’ of current revenue with respect to Cost of Service revenue;

2.5 **Step 5:** Restructure the tariffs and gradually bring the tariffs per customer class to the Cost of Service level, by adjusting the Cost of Service Index to 1.0.

Article 69. Effective Date

This Tariff Guidelines and Methodology for the Generation, Transmission and Distribution sectors, shall enter into force as of the date signed by the Director General of EEA.

Done at Addis Ababa, this -December-----, 2018

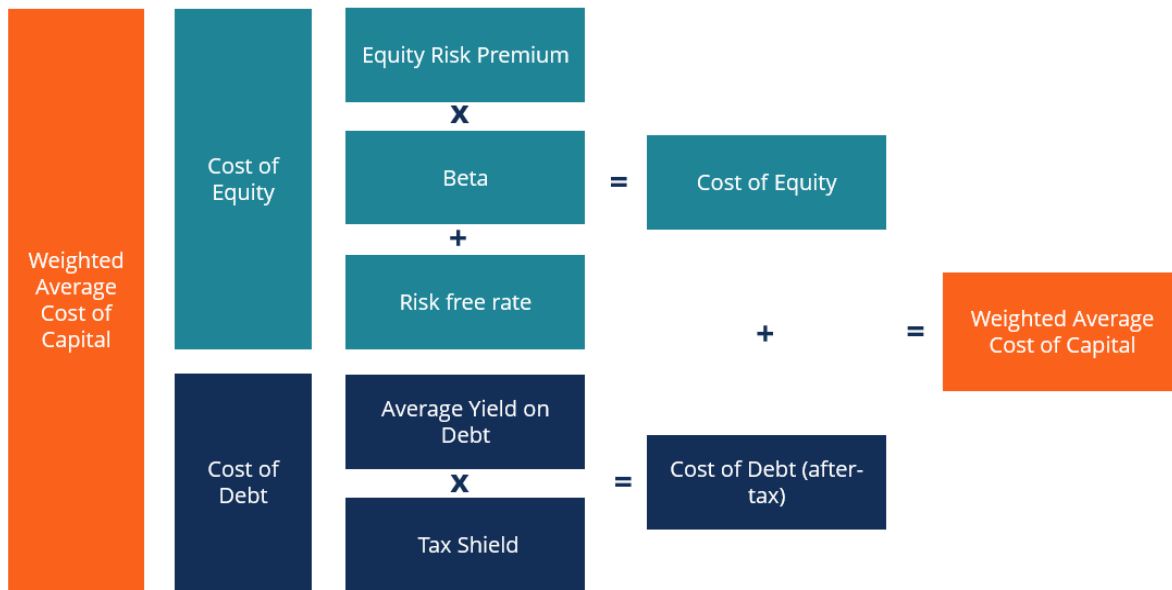
Dr. Frehiwot Wolde Hana

EEA Board Chairperson and state Minister (Energy) of Water Irrigation and Energy

ANNEX ONE

Weighted Average Cost of Capital (WACC) Computation guideline

1. Weighted Average Cost of Capital (WACC) shall be determined by the Authority in accordance with the guideline described below. WACC is the weighted average of cost of a company's debt and the cost of its equity. WACC analysis assumes that capital markets (both debt and equity) in any given industry require returns commensurate with perceived riskiness of their investments.
2. The rate of return to be applied on a licensee's RAB, shall be computed using the **Weighted Average Cost of Capital (WACC)**, and including a rate of return on investment in the licensee's revenue requirement. This is because power utilities make investments in fixed assets, in anticipation of earning a return on that investment, which must at least be equal to what the next best alternative would offer.
3. In determining the cost of capital for EEP and EEU, EEA shall take account of the use of concessionary loans by licensees from international and bilateral sources. ***Therefore in determining the tariff level, EEA shall also consider the loan covenants relating to financial indicators such as return on investment, self-financing, debt service ratio etc.***
4. In order to encourage sufficient investment in the sector, the Authority shall determine an optimum nominal WACC as follows:



Nominal POST-TAX WACC = $K_e (E/V) + K_d (1-T) (D/V)$, and

the **Nominal PRE-TAX WACC** = $K_e (E/V) + K_d (D/V)$,

where:

K_e = Cost of equity capital

K_d = Cost of debt capital

E = Market Value of equity

D = Market Value of debt

V = Total market value of firm ($E+D$)

T = Corporate or Statutory Tax Rate

4. Cost of Equity

The cost of equity, K_e , is calculated using the Capital Asset Pricing Model (CAPM)

where:

$$K_e = R_f + E(MRP) \times \beta_e$$

where:

K_e = Nominal Cost of equity

R_f = Risk free rate

$E(MRP)$ = Expected Market Risk Premium

β = Beta

4.1 Risk Free Rate (R_f)

The Authority could use a long term government Bond as a nearest value estimate for the risk free rate in the Capital Asset Pricing Model (CAPM).

4.2 Expected Market Risk Premium; $E(MRP)$ Corbeti and Methera geothermal & solar respectively

It is true that the country has not had any past experience where investors expectation to earn above the risk free rate (except few cases in the ongoing private sector involvement in the development of geothermal and solar power), international experience in the electricity sector could be considered.

4.3 Market Risk Premium (MRP)

The MRP is amount an investor expects to earn above the risk-free rate. In the absence of regulatory precedent in most of our region a value could be adopted based on industry experience adjusted to our circumstances.

4.4 Beta

Beta measures the volatility of an individual stock against the market. It therefore reflects the sensitivity of the firm's value with respect to economy-wide market movements. It is therefore a measure of systematic risk. The rationale behind CAPM is that non-systematic risks can be diversified and hence should not earn an expected return in a competitive market. This leaves the systematic risk, which is beta (β) as the only risk which is addressed in the CAPM.

4.4.1 Where a company is not listed, the industry standard is to use beta for other companies or sector averages as proxies. Since EEP and EEU are not listed, EEA would have to rely on the systematic risk of similar companies. This would however require a subjective adjustment to account for differences between the reference stocks or the proxies, and the particular stock in question. **Using unadjusted betas from overseas proxies which operate under different**

regulatory jurisdictions, economic environments and electricity markets, could cause estimation errors. The proxy betas must therefore be adjusted to ensure consistency between the capital structure and equity beta of the local licensee in Ethiopia.

4.4.2 In estimating the beta value, the trend generally is to put more weight on **regulatory precedent**. Regulatory precedent in developed countries has moved towards adopting a value no greater than 0.40 for a distribution or transmission asset beta.

4.4.3 To adopt the beta, the value of the reference stock or proxy, must however be adjusted from a **GEARED ASSET BETA** to an **UNGEARED ASSET BETA**. In other words, the **ASSET BETA** of a proxy or reference company must be re-gearred to develop an estimated equity beta for the Ethiopian licensee. This is done by using the following steps and formula:

- $B_e = \beta_{a, \text{proxy}} (1 - G_{\text{proxy}})$

where:

β_a = Unlevered asset beta of reference or proxy company

β_e = Proxy or reference company equity beta

G_{proxy} = Gearing of proxy or reference company

Then adjust the proxy equity beta as follows:

- $\beta_{e, \text{Ethiopian utility}} = \beta_e / (1 - G_{\text{Ethiopian utility}})$

where:

β_a = Unlevered asset beta of proxy or reference company

$\beta_{e, \text{Ethiopian utility}}$ = Equity beta of the local licensee

$G_{\text{Ethiopian utility}}$ = Gearing of local licensee

5. Cost of Debt

The cost of debt is computed as:

$$K_d = R_f + D_p$$

where

K_d = Cost of debt

R_f = Risk free rate

D_p = Debt premium:

The debt premium is an estimate of what the power utility has to pay extra, and is expected to compensate for the risk of a licensee's debt against government debt. It is the increment above the risk free rate to reflect the additional risk of borrowing compared with government bonds. In jurisdictions where the debt premium cannot be measured directly, the premium can be benchmarked off the yield on bond issuances of companies which possess similar credit conditions.

5.1 In the light of the above, the debt risk premium should be benchmarked off similar national or international entities.

6. Capital Structure

There is no doubt that WACC is dependent on the capital structure of a firm (i.e. debt-to-equity ratio). Even though in practice, it is difficult, to estimate the optimal capital structure of a firm, nevertheless firms do operate with some level of capital structure. While it is acknowledged that cost of debt is less than the cost of equity and so it is advantageous to use more debt than equity, it is also worthy to note that higher debt levels increases the costs of the servicing debts. Taking cognizance of the capital intensive nature of the electricity sector, **a gearing range of 60, 70 and 80% is to be used in defining WACC.**

7. Taxes

Power utilities, particularly IPPs incur taxation costs. In that regard the revenue requirements for calculating the tariff should include an allowance for taxes related to the licensed activity. As pertains in most regulatory jurisdictions in Africa, it is recommended that the statutory corporate tax rate should be used, and hence a rate of **30% for Ethiopia has been used for the WACC estimation (Source: Ethiopian Revenue and Customs Authority).**

8. Inflation Rate Assumption

In calculating the WACC, updated inflation rate by Ethiopian Central Statistical Agency will be used.

9. Adopted approaches:

A/ In determining the cost of capital in the revenue requirements, EEA shall also take account of the cost of **concessionary loans from bilateral and other international sources**, as well as the associated financial covenants

B/ Given **the uncertainty surrounding the key parameters** used in the WACC methodology, a **WACC range** is to be used defined using a gearing range of 60% to 80 % for three scenarios to assess possible dimensions before decision can be made.

C/ The recommendation is to calculate the revenue requirements using the **REAL PRE-TAX RATE OF RETURN**. The **REAL PRE-TAX** is calculated by deflating the nominal pre tax rate using the **Fisher equation**

ZERO DRAFT

Annex two

Guide line and Information on tariff application Requirements

ZERO DRAFT

Table of contents

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Abbreviations

CAPEX	Capital Expenditure
CWIP	Capita Works-In-Progress
DSM	Demand Side Management
EEA	Ethiopian Energy Authority
KVA	Kilovolt amperes
KW	Kilowatt
kWh	Kilowatt-hour
MW	Megawatt
MWh	Megawatt- hour
OPEX	Operating Expenditure
RAB	Regulatory Asset Base
WACC	Weighted Average Cost of Capital

Executive summary

The aim of defining the information requirements for submission of tariff application is to enhance the transparency and openness of the tariff-setting process and achieve the following specific objectives:

- Ensure that information is provided by licensees in an *accurate, timely, useful and consistent format*;
- Ensure *transparency* of operating and financial information from the licensees;
- Reduce the *burden on EEA* during tariff reviews;
- Reduce the degree of *information asymmetry* between EEA and the licensees;

This document presents the guidelines on the **content of tariff application** by generation, transmission, distribution and sale licensees. When making their tariff submissions, the licensees have a responsibility to ensure that they submit information clearly, and also unambiguously communicate the methods and assumptions adopted, to enable the Authority have a clear and better understanding of their positions.

This document describes the following key areas of the tariff application to be submitted:

- General requirements and rationale for tariff application;
- Financial Information:
 - General Financial Information;
 - Financial Information relevant to the tariff application;
- Technical and operational information;

In submitting the tariff application, it is recommended that the line items for financial information must show **two years of HISTORICAL FINANCIAL INFORMATION and a minimum of FOUR-YEAR forecast** period. The financial information should cover the following: The two previous financial years of *audited figures, the year* of tariff application (based on realistic or ‘best’ estimates), and *four-year* forecasts to enable the Authority implement a forward-looking tariff regime.

The document presents the minimum information requirements to be submitted by regulated utility companies in respect of the following cost components: Regulatory Asset Base, Capital Additions, Capital Works-In-Progress, Asset Disposals, Depreciation, Working Capital, Cost of Capital, Operating and Maintenance Expenses, Debtor Information, Shared Cost, Projected Sales Revenue and Demand Forecast.

Tariff applications which do not comply with the minimum information requirements could be considered incomplete by the EEA, and referred back to the licensee for re-submission, within a ***specified number of working days to be determined by EEA.***

The Appendix section of this document comprises data collection templates which have been structured to cover the three segments of the electricity industry namely: **Generation, Transmission and Distribution & Sale.**

The templates will assist the licensees to submit data in a useful format for calculating the unbundled tariffs for each segment of power sector. The Authority's ability to set tariffs for each segment of the electricity sector is expected to send the correct price signals to investors and encourage private sector investment in Ethiopia's power sector.

1. Introduction

In order to develop a robust tariff regime, a regulator must obtain credible and reliable information from the licensees. The aim of this document is to reduce the degree of information asymmetry between EEA and the licensees by establishing the information requirements to be submitted by the generation, transmission and distribution/sales licensees to EEA. The development of this document is also expected to enhance the credibility of tariff-setting in Ethiopia and improve the transparency and openness of the entire tariff-setting process. Specifically, the tariff information submission requirement is expected to achieve the following objectives:

- Ensure that information is provided by the licensees in an **accurate, timely, useful and consistent format;**
- Ensure **transparency** of operating and financial information from the licensees;
- Reduce the **burden and streamline** the type of information to be submitted to EEA during tariff reviews;
- Reduce the degree of **information asymmetry** between EEA and the licensees;

This document thus presents the guidelines on the content of tariff application by licensees. Tariff applications which do not comply with the information requirements could be considered incomplete by the EEA, and referred back to the applicant for re-submission, within a **specified number of days to be determined by EEA.**

Since regulatory economics, particularly tariff-setting is a dynamic discipline, it is recommended that the Authority carries out a periodic review of the reporting requirement, by taking account of its own information needs, as well as the reporting capabilities of the licensees.

The licensees have a responsibility to ensure that they submit information in a clear and unambiguous manner. The companies must clearly and transparently communicate the methods and assumptions adopted to enable the Authority to have a clear and better understanding of their positions. The licensees must submit the data and other information in the prescribed format, in electronic form and as a hard copy.

1.1 Legal Basis for Information Submission

The requirement to submit information in a prescribed manner to the Authority can be traced to Article 10, sub-Article 1a, of the Energy Proclamation No. 810/2013 which states *that licensees*

shall keep relevant records, and **submit plans, reports, information and supporting documents to the Authority** in accordance with regulations and directives issued. Licensees are also required under sub-Article 1b to make books and records of operation available for inspection when requested by duly authorised officials of the Authority.

Licensees are also reminded that under Article 31 of the Energy Proclamation, *any person who fails to make a report or files a false report to the Authority as required by the Proclamation or regulations or directives, **or fails to keep records in the form and manner prescribed or approved by the Authority**, shall be punished with up to two years simple punishment or with a fine of up to 15,000 Birr or with both. Article 32 of the Proclamation further states that any person who presents a false or misleading statement to the Authority in relation to any information required under the Energy Proclamation, shall be punished with a simple imprisonment up to five years or with a fine up to 25,000 Birr or with both.*

The importance of submitting accurate information and in a prescribed format to the Authority for tariff analysis, is further elaborated in Article 30, sub-Article 2 of the Energy Regulation _____ which states that *in reviewing and recommending grid related tariff or approving off-grid tariff, the Authority may require a licensee to **furnish separate details, as may be specified in the tariff directive.***

1.2 Information Submission and Confidentiality

EEA has a responsibility to create a *transparent regulatory system* to enhance the credibility and acceptance of the regulatory framework, particularly the tariff-setting process. It is therefore the responsibility of the licensees to bring EEA's attention to any information which they feel should be treated as confidential. This notwithstanding, the final decision to grant such confidentiality shall be **determined solely by EEA.**

It is also important to note that while the requirements presented in this document are designed to capture most of the key information required for tariff analysis, EEA may still request further information and clarification on any of the items from the licensees, if necessary.

2. Submission Requirements

The key elements of the tariff application to be submitted by the licensees are as follows:

- i. General requirements and the rationale for tariff application;
- ii. Financial Information:
 - General financial information;
 - Financial information relevant to the tariff application;
- iii. Technical and operational information;

2.1 General Requirements and Rationale

- Licensees must provide a summary and rationale for the tariff application;

- The licensees must disaggregate costs into various segments of the electricity industry namely: Generation, Transmission and Distribution & Sale;
- Licensees must state all assumptions made namely: Economic, Financial and Technical;
- Licensees must provide detailed explanation on all data and assumptions;
- Licensees must provide basis for splitting costs and revenue between regulated and non-regulated business, if applicable;
- All supporting data must be prepared and submitted electronically in MS Excel format;
- All supporting documentation and data must be provided both in hard and as electronic copies;
- The official tariff application must be submitted as a hard copy and also as an electronic copy in PDF and Word formats;

2.1.1 Financial Information

In submitting the tariff application, the line items for financial information must show two years of **HISTORICAL FINANCIAL INFORMATION** and a **FOUR-YEAR FORECAST** period. The financial information should cover the following:

- The two previous financial years of ***audited figures***;
- ***The year*** of tariff application based on ‘best’ estimates;
- ***Four-year*** forecasts;
- Sources of long-term finance, including concessionary loans and grants;

3. Guidelines

This section describes the guidelines for minimum information to be submitted by the licensees in respect of the key cost components to be used for determination of the revenue requirements:

3.1 Regulatory Asset Base

The information on Regulatory Asset Base (RAB) must cover the following:

- The asset value must be disaggregated according to the main segments of the electricity industry: Generation, Transmission, and Distribution & Sale;
- Asset values from licensee’s own investment must be separated from assets funded from grants, concessionary loans, government investment and customer contributions;
- The estimates of assets useful lives used in the tariff application must be in accordance with the Uniform System of Accounts;

3.2 Capital Additions and Capital Works-In-Progress

The licensee is required to provide the following information on capital additions and capital work-in-progress, as part of the tariff application:

- A summary of capital expenditures over the tariff period. The information must at least contain the following:
 - Actual capital expenditure;
 - Capital Works-In-Progress (CWIP);
 - Assets which has entered into operation (i.e. Asset Additions);
 - Asset disposals or assets abandoned;
- Licensee must provide detailed explanation and asset values of CWIP and show when they will enter into operation, to enable EEA know when such assets would be added to the RAB;
- The regulated utility companies must provide a schedule of the capital additions showing expected commencement, completion and commissioning dates;
- Licensees must also provide a 4-year forecast of planned capital expenditure programme for *each segment* of the industry;

3.3 Asset Disposal

Regarding asset disposals and impairment, the regulated utilities must provide the following information:

- List of asset disposed and/or decommissioned. This must be supported by explanation or reasons for such disposal and decommissioning;
- Revenue generated or loss incurred during the process of the assets disposal;
- Any loss/gain should be treated in accordance with the Uniform System of Accounts, where any revenue/loss is allocated to income statement over a specified time period;

3.4 Depreciation

The regulated licensees are required to provide the following information on regulatory depreciation:

- The current depreciation amount stated in the tariff application;
- Accumulated depreciation schedule for the RAB for each asset class, and for each segment of the electricity sector;
- The current depreciation methodology must be determined based on the *Tariff Guidelines and Methodology*.

3.5 Working Capital

The licensee must also provide estimate of working capital requirements, which are needed to sustain on-going operations. The working capital allowance must be estimated in accordance with the formula in the *Tariff Guidelines and Methodology*.

3.6 Cost of Capital

Since the return on investment is calculated as a product of WACC and RAB, the regulated licensees must use the benchmark WACC determined by EEA in accordance with the Tariff Guidelines and Methodology, to calculate the return on investment in the revenue requirements formula.

3.7 Operating Expenses

In submitting information on operating expenditure (opex), the licensees must take account of the following:

- That the operating expenditure must exclude all capital expenditure (capex);
- Opex information are to be disaggregated according to the following segments of the electricity industry; Generation, Transmission and Distribution & Sale;
- The cost information must clearly indicate the different cost categories;
- Licensees must provide justification on key cost drivers for each opex category;
- The licensee must provide information on staff expense and this should be broken down to reflect the following, among others:
 - i. Salaries;
 - ii. Overtime;
 - iii. Medical expenses etc.
- Any proposed percentage increase to staff salary or other staff expense must be supported with detailed justification to EEA for the forecast period for review.

3.8 Maintenance Expenses

In addition to the opex, the regulated licensees must submit information on all repairs and maintenance expenses to cover the following items:

- a. Materials;
- b. Labour;
- c. Other expenses:
 - Licensees must provide justification for any increase in repairs and maintenance expenses over the tariff period;
 - Maintenance expense must exclude **asset retrofits and refurbishments** which enhance the **economic useful lives of assets**. In line with best regulatory practice, such expenses would be capitalized and added to the RAB;

3.9 Debtor Information

The tariff applicant must supply the following details on debtors:

- Outstanding debt per customer category;

- Any provisions made for bad debts and justification for that;
- Age analysis for the debts;
- Debt write-off, if any;
- Plans to recover debts plus any associated costs;

3.10 Shared Cost

It is possible that some of *the utility company costs are centrally shared* and may not be directly linked to any particular segment of the electricity industry. This is likely to be the case if one entity operate in more than one segment of the electricity industry (i.e. generation and transmission or generation, transmission and distribution). In such an event, the licensee would be required to provide the following details:

- Any centrally administered cost must be clearly defined and identified;
- Basis for cost sharing between the segments must be explicitly spelt out. This would be reviewed by EEA, based on best practice regulatory cost allocation methodologies;
- If the costs are shared between the regulated and the non-regulated business, the basis of the percentage split or cost allocation must be provided, for review by EEA;

3.11 Projected Sales Revenue and Demand Forecasts

Regarding the sales revenue forecast, the minimum information requirements to be provided by the regulated licensee are as follows:

3.11.1 Sales Revenue

- Sales revenue per customer class;
- Net export revenues;
- Energy sales volume (MWh) for each customer category;
- Projected total energy sales for the **next four years**;

3.11.2 Energy and Demand Projections

- Projected energy demand (MWh) per customer class for **next four years**;
- System Peak demand projections (MW) for the **next four years**;

3.11.3 Energy Wheeling

- Energy wheeled, if applicable;
- Line losses (Transmission and Distribution) arising from wheeling to meet expected demand.

4. Balance Sheet and Income Statement Information

4.1 Generation Sector

For generation licensees, submission of tariff application shall include the following information related to the Balance Sheet and Income Statement. All amounts shown must include units of measure such as: KWh, KVA, KW, Birr and Birr/KWh. Cost information must be provided in clear and unambiguous manner, to enable the regulator perform detailed and in-depth analysis of all relevant cost components. The detailed information to be provided are as follows:

- **Audited Balance Sheet** for the previous **2 years** and forecasted balance sheet for the **next 4 years**, including the tariff year;
- The data for the **Balance Sheet** (actual or estimate) should include the following:
 - Gross Asset Value;
 - Accumulated depreciation;
 - Fixed Asset Value;
 - Inventories breakdown;
 - Accounts Payable;
 - Accounts Receivable;
 - Short-term Debt;
 - Other Current Liabilities;
 - Long-term Debt;
 - Equity;
- **Audited Income Statement** for the previous **2 financial years** and forecasted income statement for the following **4 years**, including the tariff year. The revenue for the forecasted income statement should be based on estimated sales (KWh) at current tariffs.
- **Supporting data** for the Income Statement (i.e. actual and forecasted) should include the following:
 - Electricity Sales;
 - Fuel cost (quantities and unit cost by fuel type);
 - Employee or Staff Costs;
 - Annual depreciation;
 - Operating and maintenance expense breakdown;
 - Short-term expense;
 - Debt service schedule;
 - Tax expense, if any;
 - DSM expense, if any;
- **Technical and Commercial Data/Parameters:**
 - Monthly Energy sales and associated revenue;
 - Annual electricity production for previous year and projected for next four years;
 - Annual electricity purchases projected for next four years;
 - Monthly system maximum peak demand
 - Projected system maximum peak demand for next four years

The generation licensee must submit detailed information on the various primary energy generation sources.

4.1.1 Thermal Power Plants

- Cost assumptions made on the fuel;
- Breakdown of operating cost and assumptions made;
- Energy output projected for next four years;
- Thermal plant utilization plan;
- Projected capacity factor for next four years;

4.1.2 Hydroelectric Power Plants

The following shall be provided by the generation licensee:

- Production plans for each plant;
- Breakdown of operating cost;
- Average unit cost per KWh for sale;

4.1.3 Renewable Energy Plants

- Breakdown of operating cost and assumptions made;
- Projected capacity factor for next four years;
- Breakdown of operating cost;
- Average unit cost per KWh for sale;

4.1.4 Purchases from Independent Power Producers

Generation licensees shall also submit information on all purchases from IPPs. The information must include the following:

- Volumes (MWh) to be purchased from IPPs each year over the tariff period and for next four years;
- Cost of power purchase from each IPP;
- Submission of signed PPA of existing contracts to EEA, if not already submitted;
- Addendum or amendments to the existing PPA, if any;

4.2 Transmission and Distribution & Sales Licensees

This section focuses on the type of data which the **network licensees** must submit when requesting for a tariff review. Licensees are to note that all schedules are to be submitted in both hard copy and electronic form. The following data and information are to be included in the tariff application, and all amounts shown should include the units of measure such as: KWh, KVA, KW, Birr, Birr/KWh, etc.

- Actual and audited Balance Sheet for the **previous 2 years**;
- Projected Balance sheet for the **next four years**;
- Supporting data for the Balance sheet should cover the following items:
 - Gross asset value;
 - Accumulated depreciation;
 - Fixed Works-In-Progress and scheduled completion dates;
 - Inventories;
 - Accounts payable;
 - Accounts receivable by customer category;
 - Short-term debt;
 - Other Current liabilities;
 - Long-term debt;
 - Equity;
- Actual and audited Income Statement for the **previous 2 years**;
- Projected income statement for the next **4 years**. Projected revenue should be based on estimated sales at current tariffs;
- Supporting data for the Income Statement should cover the following items:
 - Electricity sales per customer class (i.e. quantities and associated tariffs);
 - Bulk Supply Costs (Generation plus Transmission tariffs);
 - Staff or Employee Cost;
 - Annual Depreciation;
 - Operating and Maintenance Expense Breakdown;
 - DSM Expense, if any;
 - Short term interest expense;
 - Long-term interest expense, include debt service schedule;
 - Tax expense, if any;
- Proposed Revenue Requirements per end-use customer class;
- Proposed tariffs for each customer category;
- Technical and Commercial Data/Parameters showing the following:
 - Energy purchases;
 - Energy sales;
 - Losses: Technical and Non-technical;
 - Energy losses per voltage level;
 - Cost of Ancillary Services;
 - Major rehabilitation projects;
 - Energy sales and revenue per customer class;
 - Number of customers per tariff category;
 - Monthly electricity purchases for current year;
 - Monthly system maximum demand recorded for previous year;
 - Projected annual electricity purchase for next four years;

- Projected annual electricity sales for next four years;
- Projected system maximum demand for next four years
- Proposed Tariffs for all the end-user classes:
 - a. Domestic/Residential
 - b. General /Commercial
 - c. Industrial:
 - Low voltage;
 - Medium voltage;
 - High voltage.
- Explanation provided on the following issues:
 - efforts to improve efficiencies;
 - plans to reduce technical loss level;
 - plans to reduce non-technical losses;
 - plans to reduce accounts receivable period;
 - efforts to enhance quality of service and reduce **duration and number of outages (i.e. quality of service delivery)**;

4.3 Demand Side Management

In carrying out the tariff review, regulators usually take account of efforts by the licensees to encourage consumers to adopt energy efficiency and conservation practices. In that regard, approved DSM costs could be considered by EEA as part of licensee's revenue requirements. In order to make informed decision on DSM costs, EEA would require the licensees to provide the following information:

- DSM strategy, plans and programs covering the tariff period;
- Proposed DSM budget over the tariff period;
- Breakdown of DSM costs, with all cost items clearly identified;
- Explanation and justification for the DSM expenses, including expected benefits of the programs;

5. Revenue Requirements Information

The licensees are required to provide a summary of all the information and calculation on the total revenue requirements, in accordance with the *Tariff Guidelines and Methodology*. The total revenue to be recovered from the proposed tariff should be disaggregated according to each customer class. The total revenue requirement summary must include the following:

- a. RAB;
- b. The WACC which was used as rate of return and applied to RAB, to calculate the return on investment;

- c. Total Revenue Requirements showing the various cost components, as defined in the *Tariff Guidelines and Methodology*;

5.1 Tariff Structure Information

5.1.1 Distribution and Sale Tariff

Since the distribution licensee is also responsible for sale, the licensee must provide the following information as part of its tariff application:

- Assumptions made for each customer or tariff category, including expected volume sales, tariff increase and expected revenues from retail tariffs;
- Details of proposed tariff structure and impact of proposed structure on consumers.

5.2 Transmission Tariff

The transmission licensee is required to provide the following information:

- Assumptions made by licensee;
- Proposed transmission tariff, including System Operator fee;
- Ancillary services costs;

5.3 Appendices Section of Tariff Application

All relevant tables and templates containing the data as well as any information must be included in the appendices section of the tariff application.

Appendices: Tariff Submission Template

Appendix 1. Generation Sector

Appendix 1A. System Demand

Peak demand	Units	2013/14	2014/15	2015/16	2016/17
System Peak demand	MW				
System Average Demand	MW				

Appendix 1B. Energy Generation

Total Available Grid Energy	Units	2013/14	2014/15	2015/16	2016/17
Large Hydro	GWh				
Thermal	GWh				
Renewable: Please List	GWh				
Others:	GWh				
Sub-Total : Grid energy (excluding cross-border imports)	GWh				
Cross Border Imports	GWh				
Total available Grid energy including cross-border imports	GWh				

Appendix 1C. Generation Financial and Technical Data

Data	Unit	2013/14	2014/15	2015/16	2016/17
Energy Generation	GWh				
Installed Capacity	MW				
Sales Revenue	Birr, Mil.				
Revenue from other Sources	Birr, Mil.				
Total Revenue	Birr, Mil.				
Total Cost: Fuel	Birr, Mil.				
Total Cost: Non - Fuel	Birr, Mil.				
Operating Cost	Birr, Mil.				
Maintenance Cost	Birr, Mil.				
Operational Profit/Loss	Birr, Mil.				
Unit Electricity Cost (Average)	Birr/kWh				

Total No. of Employees	Persons				
Fixed Assets (Gross)	Birr, Mil.				

Accounts Payable	Birr, Mil.				
Accounts Receivable	Birr, Mil.				
Thermal Plant Heat Rate plant: Plant 1: Plant 2: Plant 3: Plant 4: Plant 5:	Btu/kWh				
Capital Investment (Licensee's Own Investment)	Birr, Mil.				
Government Investment	Birr, Mil.				
DSM Expenses	Birr, Mil.				

Appendix 1D. Details of Fuel Cost

	Units	2013/14	2014/15	2015/16	2016/17
Total Generation Fuel in US\$	US\$ mil.				
Exchange rate used: US\$ to Birr	Birr/US\$				
Oil price forecast	US\$/bbl				
Crude Oil	US\$/bbl				
AGO (Diesel)	US\$/bbl				
HFO	US\$/bbl				
Total Fuel Cost					

Appendix 1E. Details of Electricity Purchase Cost

Electricity Purchase Cost	Units	2013/14	2014/15	2015/16	2016/17
<u>Please Note: Costs should be presented in US\$</u>					
Cross border imports	US\$ mil.				
Other electricity purchase (i.e. IPPs)- Please List:	US\$ mil.				
Total Electricity Expense	US\$ mil.				

Appendix 2. Transmission Sector

Appendix 2A. Transmission Financial and Technical Data

Data	Unit	2013/14	2014/15	2015/16	2016/17
Electricity Purchased from Domestic Generators	GWh				
Average price of electricity purchased: Domestic	GWh				
Imported Electricity	GWh				
Average price of imported electricity	Birr/KWh				
Exported Electricity	GWh				
Average price of exported electricity	Birr/KWh				
Own/Substation Use	GWh				
Transmission Network Loss	GWh				
Transmission Network Loss	%				
Electricity Sold	MWh				
Operating Cost	Birr, Mil.				
Maintenance/Repairs Cost	Birr, Mil.				
Operational Profit/Loss	Birr, Mil.				
Number of employees	Persons				
Gross Fixed Assets	Birr, Mil.				
Accumulated Depreciation	Birr, Mil.				
Net Fixed Assets	Birr, Mil.				
Current Assets	Birr, Mil.				
Accounts Payable: a. electricity b. Others	Birr, Mil.				
Accounts Receivable: a. electricity b. Others	Birr, Mil.				
Capital investment in transmission by Licensee: (Own Investment)	Birr, Mil.				
Government investment, Investment from Grants	Birr, Mil.				

Appendix 2B. Imports and Exports

Data	Unit	2013/14	2014/15	2015/16	2016/17
Imported Electricity (Energy)	GWh				
Imported Electricity (Capacity)	MW				
Exported Electricity	GWh				
Net Imported Electricity for payment	GWh				
Payment for imported electricity:					
a. Capacity or Availability Payment	US\$ Mil				
b. Energy Payment	US\$ Mil				
Total Payment for imported electricity	US\$, Mil.				
Revenue from exported electricity:					
a. Capacity or availability tariff	US\$ Mil				
b. Energy tariff	US\$ Mil				
Total Revenue from exported electricity	US\$,Mil.				

Appendix 3. Distribution & Sale Sector

Appendix 3A. Energy Consumption

Energy Consumption metered	Units	2013/14	2014/15	2015/16	2016 / 17
Energy billed	GWh				
Energy consumed (either metered or estimated), but not billed:	GWh				
Own consumption	GWh				
Street lighting	GWh				
Total System Energy Consumption	GWh				
Exports	GWh				
Total Energy consumption	GWh				

Appendix 3B. Distribution System Losses

Distribution Network Energy Losses	Units	2013/14	2014/15	2015/16	2016/ 17
Technical network energy losses	GWh				
Non-Technical Losses	GWh				
Total Distribution System Losses	GWh				
Distribution Network Energy Losses		2013/ 14	2014/15	2015 /16	2016/ 17
Technical network energy losses	%				
Non-Technical Losses	%				
Total Distribution System Losses	%				

Appendix 3C. Consumption Data

Breakdown of Consumption & Customer Data	Units	2013/14	2014/15	2015/16	2016/17
Electricity sales by consumer category:					
Domestic	GWh				
General	GWh				
Commercial	GWh				
Industrial:	GWh				
LV					
MV					
HV					
Total Consumption	GWh				

Appendix 3D. Customer Data

Number of active customers at year end:	Units	2013/14	2014/15	2015/16	2016/17
Domestic	Number				
General	Number				
Commercial	Number				
Industrial: LV MV HV	Number				
Total active customers	Number				

Number of new connections	Units	2013/14	2014/15	2015/16	2016/17
Domestic	Number				
General	Number				
Commercial	Number				
Industrial: LV MV HV	Number				
Total new connections	Number				

Appendix 3E. Details of Electricity Revenue

<u>Assume no increase in tariffs for forecast period.</u>	Units	2013/14	2014/15	2015/16	2016/17
Energy billed	Birr Mil.				
Street Lighting	Birr Mil.				
Total System Revenue	Birr, Mil.				
Electricity Export	Birr Mil.				
Total Revenue	Birr, Mil.				

Appendix 3F.Revenue Breakdown.

Revenue Breakdown	Units	2013/14	2014/15	2015/16	2016/17
Domestic	Birr, Mil.				
General	Birr, Mil.				
Commercial	Birr, Mil.				
Industrial:	Birr, Mil.				
LV					
MV					
HV					
Exports	Birr, Mil.				
Total Revenue	Birr mil.				

Appendix 3G.Distribution Financial and Technical Data

Data	Units	2013/14	2014/ 15	2015/16	2016/17
Electricity Purchased: Grid Connections (Conventional)	GWh				
Electricity Purchased: Off - Grid	GWh				
Average Purchase Price: Grid Connection	Birr/KWh				
Electricity Purchased: Grid	Birr, Mil				
Average Purchase price: Off grid	Birr/kWh				
Electricity Purchased: Off-Grid Con	Birr, Mil				
Electricity Sold	GWh				
Average Selling Price	Birr/kWh				
Operating Cost	Birr, Mil.				
Maintenance Cost	Birr, Mil.				
Operational Profit/Loss	Birr, Mil.				
Number of employees	Persons				
Gross Fixed Assets	Birr, Mil.				
Accumulated Depreciation	Birr, Mil.				
Net Fixed Assets	Birr, Mil.				
Current Assets	Birr, Mil.				
Working Capital	Birr, Mil.				
Account Payable	Birr, Mil.				
Account Receivable:	Birr, Mil.				
Licensee Own Capital Investment	Birr, Mil.				
Government investment, Grants	Birr, Mil.				
Customer Contributions in Assets	Birr, Mil.				

Appendix 4. Gross Asset Values

Breakdown of Gross Value of Fixed Assets	Units	2013/14	2014/15	2015/16	2016/17
Generation System:					
Hydro	Birr, Mil.				
Thermal	Birr, Mil.				
Geothermal	Birr, Mil.				
Others:	Birr, Mil.				
Transmission System:					
Transmission network	Birr, Mil.				
Distribution System:					
High Voltage	Birr, Mil.				
Medium voltage	Birr, Mil.				
Low voltage	Birr, Mil.				
Total Distribution System.	Birr, Mil.				
Buildings	Birr, Mil.				
Vehicles, office furniture & fittings, computers, etc.	Birr, Mil.				
Others:	Birr, Mil.				
Total	Birr, Mil.				

Appendix 5. Capital Works-In-Progress by Sector

Generation System:	Units	2013/14	2014/15	2015/16	2016/17
Transfers to Fixed Assets:					
Work in progress at end of 2012	Birr, Mil.				
Interest during construction & capitalized exchange losses	Birr, Mil.				
Total transfers to fixed assets:	Birr, Mil.				
Closing Balance	Birr, Mil.				

Transmission System:	Units	2013/14	2014/15	2015/16	2016/17
Transfers to Fixed Assets:					
Work in progress at end of 2012	Birr, Mil.				
Interest during construction & capitalized exchange losses (prior year's)	Birr, Mil.				
Total transfers to fixed assets:	Birr, Mil.				
Closing Balance	Birr, Mil.				

Distribution/Sales Sector	Units	2013/14	2014/15	2015/16	2016/17
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Transfers to Fixed Assets:					
Work in progress at end of 2012	Birr, Mil.				
Interest during construction & capitalized exchange losses (prior year's)	Birr, Mil.				
Total transfers to fixed assets:	Birr, Mil.				
Closing Balance	Birr, Mil.				

Appendix 6. Capital Additions per Sector

Additions to Fixed Assets	Units	2013/14	2014/15	2015/16	2016/17
<u>Generation Sector:</u>					
Hydro	Birr, Mil.				
Thermal	Birr, Mil.				
Geothermal	Birr, Mil.				
Others:					
<u>Transmission:</u>					
Transmission network	Birr, Mil.				
<u>Distribution network:</u>					
High Voltage					
Medium voltage	Birr, Mil.				
Low voltage	Birr, Mil.				
Total distribution network	Birr, Mil.				
Buildings	Birr, Mil.				
Vehicles, Office Furniture, Computers, etc.	Birr, Mil.				
Others:					
Total Additions to Fixed Assets	Birr, Mil.				

Appendix 7. Accumulated Depreciation by Sector

Accumulated Depreciation	Units	2013/14	2014/15	2015/16	2016/17
Generation:					
Hydro	Birr, Mil.				
Thermal	Birr, Mil.				
Geothermal	Birr, Mil.				
Others:	Birr, Mil.				
Total Generation					
Transmission:					
Transmission network	Birr, Mil.				
Distribution network					
Medium voltage	Birr, Mil.				

Low voltage	Birr, Mil.				
Total distribution network	Birr, Mil.				
Buildings	Birr, Mil.				
Vehicles, Office Furniture, Computers, etc.	Birr, Mil.				
Total	Birr, Mil.				

Appendix 8. Asset Disposal per Sector

Annual Disposals	Units	2013/14	2014/15	2015/16	2016/17
Generation:					
Hydro	Birr, Mil.				
Thermal	Birr, Mil.				
Geothermal	Birr, Mil.				
Others:					
Total Generation					
Transmission:					
Transmission network	Birr, Mil.				
Distribution network:					
High Voltage	Birr, Mil.				
Medium voltage	Birr, Mil.				
Low voltage	Birr, Mil.				
Total distribution network	Birr, Mil.				
Buildings	Birr, Mil.				
Vehicles, Office F&F, Computers	Birr, Mil.				
Total Value of Asset Disposals	Birr, Mil.				

Appendix 9. Net Fixed Asset by Sector

Net Book Value (excluding CWIP)	Units	2013/14	2014/15	2015/16	2016/17
Generation:					
Hydro	Birr, Mil.				
Thermal	Birr, Mil.				
Geothermal	Birr, Mil.				
Others:					
Transmission:					
Transmission network	Birr, Mil.				
Distribution network					
High Voltage	Birr, Mil.				
Medium voltage	Birr, Mil.				
Low voltage	Birr, Mil.				

Total distribution network	Birr, Mil.				
Buildings	Birr, Mil.				
Vehicles, Office Furniture, Computers, etc.	Birr, Mil.				
Total Net Fixed Asset Value	Birr, Mil.				

Appendix 10. Sources of Long Term Finance

Source of Finance (Please List)	Type of Instrument: Concessionary, Grant, Commercial Loan etc.	Interest Rate (%)	2013/14	2014/15	2015/16	2016/17
1.						
2.						
3.						
4.						
5.						
6.						
7.						
8.						
9.						
10.						