2019-2020 ELECTRICITY AND WATER MAJOR TARIFF REVIEW DECISION

JULY 2019

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PREAMBLE

The purpose of this Tariff Decision Paper is to fulfill the statutory mandate of the Public Utilities Regulatory Commission (PURC) as set out in the Public Utilities Regulatory Commission Act, 1997 (Act 538) relating to approval of tariffs for utility services – natural gas, electricity and water. Additionally, it is to enhance transparency in the utility tariff setting process in Ghana in line with international best practice. This Decision Paper provides the rationale for the 2019-2020 natural gas, electricity and water tariffs. It is issued for the benefit of the Utility Companies, Investors, Government of Ghana, Consumers and the Public.

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The Commission warrants the accuracy of information contained in this paper as at the date of the tariff decision. The decision remains in force until duly revoked by the Commission.

Executive Summary

The Public Utilities Regulatory Commission (PURC) on June 21, 2019 announced its Decision on tariffs which are applicable to Ghana's natural gas supply industry value chain, electricity supply industry value chain as well as water supply industry value chain – Generation/Production, Transmission, Distribution and Supply managed and operated by the Natural Gas Transmission Company (Ghana National Gas Company Limited), Generation Companies (Volta River Authority (VRA), Independent Power Producers (IPPs)), the Transmission Utility (Ghana Grid Company Limited) and the Distribution Companies (Power Distribution Services Ghana Limited (PDS), Northern Electricity Distribution Company Limited (NEDCo), Enclave Power Company Limited (EPC)) and Ghana Water Company Limited (GWCL) for the period 2019-2020. These tariffs set out rates chargeable for the supply of electricity by distribution utilities to end-use consumers in Ghana. This was done within the mandate of PURC under the Public Utilities Regulatory Commission Act, 1997 (Act 538) with regards to rate setting, particularly, Sections 3(b), 18 and 19.

As a regulatory requirement, the approved rates were arrived at after careful examination of tariff filings made by Utility Companies noted above. The tariffs/rates examination process was conducted taking into consideration PURC's Rate Setting Guidelines, principles and several utility operational considerations as well as exogenous factors including macro-economic and socio-economic factors which have direct bearing on natural gas, electricity and water production, supply and consumption. It also took into consideration submissions made by major stakeholders.

As part of its tariff filings, GRIDCo requested an Annual Revenue Requirement (ARR) of GHS 907.86 Million in respect of services for the transmission of 17,762 GWh electrical energy for 2019-2020.

PDS requested GHS 2,107 Million as its ARR with projected electricity sales of 8,755 GWh for 2019-2020.

NEDCo and EPC requested GHS 390.13 Million and GHS 27.81 Million with projected electricity sales of 1,103 GWh and 189 GWh respectively for 2019-2020.

The Commission upon analyses and consideration of factors mentioned above, approved ARR of GHS 650.43 Million, GHS 1,403.81 Million, GHS 316.83 Million and GHS 26.53 Million for GRIDCo, PDS, NEDCo and EPC respectively. This resulted in an average Transmission Service Charge of GHp7.4512/kWh and Distribution Service Charge of GHp 30.9266/kWh for the distribution utilities. A pass through composite generation cost of GHp45.2493/kWh was approved as cost of generating electricity for the regulated electricity market. In terms of fuel for power generation, the Commission approved US$ 6.08/MMBtu as the Weighted Average Delivered Gas Price and Heavy Fuel Oil (HFO) price of US$ 390/Metric Tonne which prices were used in computation of Fuel Recovery Charges for power plants nominated to operate on Natural Gas and HFO for the Major Tariff Review Period.

In the determination of the total income or revenue requirement for the regulated electricity supply value chain, that is, Generation-Transmission-Distribution, the Commission also provided 2% of the Distribution Utilities' ARR to cover non-collectible revenue. The overall effect of the Commission's decision with respect to approved rates for regulated electricity market is an increase of 11.17% across board for all category of customers.

With respect to water, GWCL requested through the Company's filings, a total revenue requirement of GHS 3,987.13 Million to cover costs of water production and purchases, transmission as well as distribution of water. The Commission approved total revenue requirement amounts to GHS 1,222.90 Million for the 2019-2020 tariff period. To recover fully this revenue requirement, the Commission approved an 8.01% increase in water rates across board for all categories of customers.

The Commission will like to use this opportunity to enjoin Utility Service Providers, Consumers and other key Stakeholders to honour their obligations in terms of quality of service delivery vis-à-vis electricity and water bills payment obligations.

Abbreviations and Acronyms

Act	Public Utilities Regulatory Commission Act, 1997 (Act 538)
ARR	Annual Revenue Requirement
EC	Energy Commission
ECG	Electricity Company of Ghana
EPC	Enclave Power Company
ESI	Electricity Supply Industry
GDP	Gross Domestic Product
GHc	Ghana Cedi
GNPC	Ghana National Petroleum Corporation
GoG	Government of Ghana
GRIDCo	Ghana Grid Company
GW	Gigawatt
GWCL	Ghana Water Company Limited
GWh	Gigawatt-hour
IPP	Independent Power Producer
KTPP	Kpone Thermal Power Plant
kW	Kilowatt
kWh	Kilowatt-hour
MDAs	Ministries, Departments and Agencies
MoEn	Ministry of Energy
NEDCo	Northern Electricity Distribution Company
O&M	Operation and maintenance
PDS	Power Distribution Services Ghana Limited
PURC	Public Utilities Regulatory Commission
RAB	Regulatory Asset Base
RoR	Rate of Return
TARR	Total Annual Revenue Requirement
TI	Tariff Income
TICO	Takoradi International Company
TT1PP	Tema Thermal 1 Power Plant
US$	United States of America Dollar
VALCO	Volta Aluminum Company
VRA	Volta River Authority

1.0 INTRODUCTION

The Public Utilities Regulatory Commission (PURC) is mandated by Sections 3(a) and (b) of the Public Utilities Regulatory Commission Act, 1997 (Act 538) to perform the following functions:

(i) to provide guidelines on rates chargeable for provision of utility services
(ii) to examine and approve rates chargeable for provision of utility services

In accordance with Section 19 of the Act, the PURC on 21st June 2019, published new utility tariffs, setting out rates chargeable for the supply of natural gas, electricity and water by Regulated Utilities to consumers in Ghana. The rates are contained in Appendix 3. The new rates approved by the Commission came into effect on 1st July 2019 and will remain in force until reviewed by the Commission. The Commission shall undertake rate revisions under its Automatic Adjustment Formula (AAF) mechanism to ensure that targeted revenue requirements for the Regulated Utilities are achieved. The rates are meant to recover the Annual Revenue Requirements (ARR) approved for the utility companies as well as to satisfy specific policy considerations.

The decision is the culmination of a major tariff review process which enabled the Commission to hear from regulated utility companies, consumers and other stakeholders. The process included:

- Filings by the regulated utility companies, namely: Volta River Authority (VRA), Ghana National Gas Company Limited (GNGC), Ghana Grid Company (GRIDCo), Power Distribution Services Ghana Limited (PDS), Electricity Company of Ghana (ECG), Northern Electricity Distribution Company (NEDCo), Enclave Power Company (EPC) and Ghana Water Company Limited (GWCL).
- Submissions and written papers by other key stakeholders including Ghana National Petroleum Corporation (GNPC) and the general public
- Public consultations which provided the platform for the utility companies to make representations to the general public.

2.0 PURC Tariff Decision and Principles

2.1 Tariff Decision

Tariff decisions based on prudent and efficient costs is key to the financial viability of public utilities and foster economic growth by sending signals to the market. Enhancement of operations of the country's electric utilities is a priority and the relevance of the regulatory environment must be assessed from that perspective. In arriving at prudent costs of the utility companies, the Commission took into account international best practice benchmarks as well as the utility companies' own performances in previous years.

2.2 PURC Tariff Principles

In addition to the prudent/efficient costs criterion/principle outlined in 2.0 above, the PURC Act further requires that the principle listed in Table 2 below should be taken into consideration in developing tariff guidelines and approving rates for electricity consumption.

Table 2 Summary of Relevant Sections in Act 538 on Determination of Tariffs

Relevant Section of Act 538	**Objective**
16 (3) (a)	Consumer interest
16(3) (b); 3(c)	Investor / Utility interest
16(3)(c)	Assuring reasonable cost of production of the service
16(3)(d)	Assurance of the financial viability of the public utility
20(1)	Uniformity of prices throughout the country
20(1)(a)	Population distribution
20(1)(b)	Best use of natural resources
20(1)(c)	Economic development of the country
20(2)	Different rates for different consumer classes

The Commission's interpretation of these provisions are summarised below:

- **Consumer Interest**: Ensuring value for money in terms of price, quality and reliability; maintaining an optimum balance between affordability and availability of service; fair apportionment of total cost of supply to various classes of consumers; provision of a minimum level of service (lifeline supply) at an affordable price to a specified category of residential customers; ensuring long term availability of service.

- **Investor/ Utility Interest**: Ensuring the utility or investor's ability to recover operational expenses and earn a reasonable return.

- **Reasonable Cost of Production**: Examination of the cost of production of a service by a public utility or others so as to exclude unreasonable or inefficient costs from the revenue requirement of the utility company.

- **Financial Viability:** Ensuring that the utility companies maintain positive cash flows at all times to achieve reasonable financial indices.

- **Uniformity of Prices and Population Distribution**: Allowance for a tariff structure which incorporates uniform rates for all customers within a particular consumer category regardless of geographic location.

- **Economic Development of the Country**: Providing for "Special Rates" for priority consumers whose activities may enhance or significantly affect economic development.

3.0 REGULATORY AND POLICY CONSIDERATIONS UNDERLYING 2019-2020 MAJOR TARIFF DECISION

3.1 Regulatory Considerations

Two key regulatory considerations underpin the Commission's 2019-2020 major tariff review. These are our regulatory philosophy and regulatory control period.

3.1.1 Regulatory Philosophy

The regulatory philosophy underpinning the 2019-2020 tariff determination is three-fold:

1. Allowance of efficient and prudent cost of supply of utility services to end-users
2. Recovery of reasonable and efficient costs including return on assets
3. Provision of economic signals to investors while recognising the needs of low income consumers.

Guided by this philosophy, PURC's hybrid tariff methodology combines cost-plus revenue requirement principles and performance-based incentive mechanisms to encourage Regulated Utilities to work towards achieving the Commission's regulatory performance benchmarks. This methodology will enable Regulated Utilities realise approved revenue requirements hence improve quality of service delivery to consumers.

3.1.2 Regulatory Control Period

A key policy decision which underpins the current tariff decision is the adoption of a Two-Year Multi Tariff Regulatory Control Period. In line with requirements of the Commission's Rate Setting Guidelines Volumes 1, 2 and 3, data was submitted by Utility Service Providers covering a Five-year Multi Tariff Regulatory Control Period. However, the Commission adopted a Two-Year Multi Tariff Control Period based on its legal mandate and taking into consideration Section 2.5 and 2.6 of RSG 2, which Sections stipulates a number of studies including Aggregate Technical, Commercial and Collection Loss Studies after one year of PDS's operations with a view to reviewing and adjusting tariffs using results thereof decided to apply its Two-year Multi Tariff Framework. This position is to enable PURC monitor developments within this Two-year Multi Tariff Period so as to obtain a clear insight to complete Regulatory Year 3- Year 5 in line with RSG.

3.2 Policy Considerations

In terms of policy, five key policies underlie PURC's 2019-2020 Major Tariff Review. These are harmonisation of Natural Gas Pricing for Electricity Generation, elimination of Maximum Demand Charge, Capital Works in Progress, System Losses and Non-Collectible Revenue.

3.2.1 Harmonisation of Natural Gas Pricing for Electricity Generation

Natural gas has become the preferred fuel for electricity generation in Ghana and will continue to be a critical factor in achieving competitive production of electricity in the country. However, natural gas prices have varied considerably given that there are different sources of gas supply including imports from Nigeria and domestic gas sources. In order to streamline the pricing of natural gas in Ghana, PURC in consultation with key stakeholders decided to harmonise natural gas prices into a single weighted average price. The objective is to provide a single price platform for monitoring plant efficiency and also prevent passage of inefficient fuel costs in power generation to end users.

3.2.2 Elimination of Maximum Demand Charge

As a major policy shift aimed at enhancing the competitiveness of Ghanaian industries, the Commission revised the electricity tariff structure by eliminating maximum demand charges in the

Special Load Tariff (SLT) category based on its pre-impact analysis. However, the Commission intends to undertake an ex-post impact analysis of this policy shift to determine its effects on SLT customers and Utility Service Providers.

3.2.3 Capital Works In Progress

The Commission per its policy excludes capital works in progress from its rate base. Capital works in progress or capital expenses including capitalised interest in respect of a project are only recognised upon commissioning of the project.

3.2.4 System Losses

A key policy issue with respect to electricity system loss determination as per Volume 2 of the Commission's Rate Setting Guidelines is that provisional baseline Aggregate Technical and Commercial loss ratio should be based on actual average Aggregate Technical and Commercial loss ratio from the twelve months preceding the ECG/PDS transfer date. Difficulty with establishment of this figure meant that the Commission had to apply the provisional figure within the tariff proposal. In subsequent years, this loss ratio will be established through an independent study to establish an independent baseline loss ratio. This policy applies to distribution and supply but not to determination of transmission losses. With regards to water distribution and supply, the Commission's benchmark policy on Non-revenue water remains the same.

3.2.5 Non-Collectible Revenue (NCR)

As provided in the Commission's Electricity Rate Setting Guidelines Volume 2, provisional baseline Collection loss ratio should be based on actual loss ratio at the time of determination of the tariff. However, based on payment framework established between the Ministry of Finance and ECG, the Commission maintained its non-collectible revenue benchmark of 2% for electricity distribution and supply. The same benchmark was applied for water delivery.

4.0 Filings in Respect of Major Tariff Review

The requirements for filing of tariffs by public utilities are stated in sections 21 and 22 of the Act. Each public utility is required to file its tariff proposals with the Commission showing rates to be charged by it in accordance with the PURC tariff filing forms. In furtherance of this, the Commission notified the Regulated Utilities and other stakeholders of the commencement of the tariff filing process and requested them to file tariff proposals for the period 2019-2023.

4.1 Tariff Procedure

The following procedure per Volume one (1) of the Commission's Rate Setting Guidelines was adopted.

i. Request for Papers

The Commission commenced the 2019-2020 tariff review process in October 2018 by inviting submissions on natural gas, electricity and water tariffs from interested persons. The list of entities that submitted papers in response to the Commission's invitation is provided in Appendix 2.

ii. Utility Proposals

The following Regulated Utilities filed tariff proposals with the Commission requesting adjustment of rates chargeable for their services:

1. Ghana National Gas Company Limited
2. Volta River Authority
3. Ghana Grid Company Limited
4. Power Distribution Services Ghana Limited
5. Electricity Company of Ghana
6. Enclave Power company Limited
7. Northern Electricity Distribution Company
8. Ghana Water Company Limited

iii. Submissions by Other Stakeholders

In response to the PURC's request, the following Stakeholders also made submissions to the Commission.

1. Ghana National Petroleum Corporation
2. Ministry of Finance
3. Ministry of Energy
4. Trades Union Congress (TUC) of Ghana
5. Steel Manufacturers Association of Ghana
6. Association of Ghana Industries
7. Electoral Commission of Ghana

iv. Preliminary Review

In accordance with PURC's Rate Setting Guidelines Volume 1, the Commission undertook a preliminary review of the proposals. The objective of the preliminary review was to ensure compliance with tariff filing and data requirements.

v. Filing of Supplementary Utility Data

Due to insufficient or inadequate data, some utility companies were required to submit revised and additional data to the Commission to complete their tariff proposals. The date for submissions of these additional data ended January 19, 2019.

vi. Tariff Hearings

As required under Section 18 (4) of the Act, the Commission held a series of Technical Committee hearings with each regulated utility company. This was followed by regional stakeholder consultations commencing November 9, 2018. Additionally, a joint consultative meeting with regulated utility companies and stakeholders was held on November 28, 2018. The event was televised live on JoyFm and extensively covered by journalists both from several electronic and print media houses. The Commission further directed all regulated utility companies to publish summaries of their proposals to enable interested parties examine the bases of their requests. The publications were made on the websites of the utilities and the newspapers.

vii. Examination of Tariff Proposals

As provided in Section 16 of the Act, the Commission is obliged to take account of consumer interest, investor interest, the cost of production of the service, and assurance of the financial integrity of the public utility in its Rate Setting Guidelines. These considerations form the basis of tariff examination and approval by the Commission. All representations made by regulated utility companies and other stakeholders were therefore taken into account by the Commission in arriving at a decision.

With respect to water, the Commission considered GWCL's compliance with its order number PURC/GWCL012018 with respect to the Befesa desalination plant and related matters.

4.2 Summary of Tariff Submissions by Regulated Utility Companies

As noted earlier, Regulated Utilities made submissions to the Commission for consideration and approval of their service provision levels and associated costs as well as revenue requirements. A summary of these are presented in the following section.

4.2.1 Volta River Authority (VRA)

The VRA did not submit a formal proposal as per PURC's Tariff Filling Templates. The Company however, submitted a letter dated November 08, 2018 in respect of allocation of electricity generated from both Akosombo and Kpong Hydro Electricity Dams as well as Thermal power plants generation and associated tariffs. A summary of VRA submission is presented in Table 4-1 and Table 4-2.

Table 4-1 Summary of Proposed Allocation of Electricity Generation from Akosombo and Kpong Hydroelectric Dams

VRA Customers	**2019 VRA's Proposed Allocation**	
	GWh	**%**
Electricity Distribution Utilities	2387	47%
Volta Aluminum Company	1314	26%
Export Customers	531	10%
Manufacturing/Industrial Customers	340	7%
Ghana Water Company Ltd		
Bulk Customers	296	6%
Losses	203	4%
Total	5071	100%

Source: VRA's Tariff Proposal, 2018

Table 4-2 Summary of VRA's Generation Source and Tariffs per Plant

Generation Plant	Generation (GWh)	Tariff (US Cents/kWh)
Takoradi 1	1,930	10.5294
AMERI	1,007	12.1198
Tema 1	348	12.3007
KTPP	375	11.2143
Hydro	2,648	2.9148
VRA BULK GENERATION CHARGE FOR DISCOs (GHp/kWh)		39.1003

Source: VRA's Tariff Proposal, 2018

4.2.2 Ghana Grid Company Limited (GRIDCo)

GRIDCo as part of its proposal submitted both an Electricity Supply Plan and a revenue requirement request for 2019-2023. Details of the Electricity Supply Plan for 2019 are presented in Table 4-3 whiles details of revenue requirement are presented in Table 4-4.

Table 4-3 Summary of GRIDCo's Proposed Electricity Supply Plan

Power Plant	Projected Consumption (GWh)
Akosombo	4,258.5
Kpong GS	811.5
TAPCo	1,492.5
TICO	1,933.6
TT1PP	211.4
KTPP	158.2
TT2PP	-
VRA Solar	3.0
Imports from Cote d'Ivoire	-
Total VRA Available Generation	**8,868.6**
Bui GS	650.0
SAPP 161	715.4
SAPP 330	1,940.4
CENIT	-
AMERI	1,007.2
Karpower Barge	2,775.2
AKSA	1,227.0
CENPower	-
Amandi	-
BXC Solar	27.0
Meinergy	27.0
Total Supply (GWh)	**17,237.8**

Source: GRIDCo's Electricity Supply Plan, 2019

Presented in Table 4-3 is a summary of GRIDCo's proposed Electricity Supply Plan for 2019-2020. Table 4-3 indicates that GRIDCo would transmit a total energy volume of GWh 17,237.8 GWh to both regulated and de-regulated electricity markets. The associated transmission losses as per the Supply Plan amounts to 4.2% for 2019 and 4.0% for 2020.

Table 4-4 Summary of GRIDCo's Proposed Operational Expense and Related Data

Item	Measure	Year/Amount				
		2019	2020	2021	2022	2023
Electricity Available for Dispatch	GWh	17,274	18,249	18,918	20,969	21,708
Total Electricity Sales	GWh	16,365	17,539	18,314	20,283	20,945
Transmission losses	%	5.26%	3.89%	3.19%	3.27%	3.52%
Operation & Maintenance Costs	MGHS	72.41	75.86	77.28	78.63	79.38
Administrative & General Costs	MGHS	35.22	37.55	38.78	40.86	42.51
Human Resource Costs	MGHS	210.97	217.30	223.82	246.20	256.05
Depreciation	MGHS	158.38	174.45	195.58	216.26	235.57
Interest on Foreign Loans	MGHS	54.39	68.38	64.34	65.23	68.52
Return on Equity	MGHS	215.15	222.28	258.26	322.50	372.05
Finance Costs	MGHS	54.97	68.94	64.86	69.22	75.28
Total Revenue Requirement	MGHS	**801.50**	**864.75**	**922.92**	**1,038.91**	**1,129.35**
RoRNFA	%	6	6	6	6	6
Regulatory Asset Base	MGHS	5,936	6,543	7,501	7,632	7,887
Return on ANFA	MGHS	265	320	362	414	466
Average Exchange Rate	GHS/US$	5.11	5.41	5.68	6.06	6.35

Source: GRIDCo's Tariff Proposal, 2018

Revenue wise, GRIDCo proposed a total revenue requirement ranging from GHS 801.50 Million in 2019 to GHS 1,129.35 Million in 2023. This request according to GRIDCo is in respect of transmission services the company would provide for the period noted.

The Company noted that its request for upward review of operational costs by PURC are underpinned by impact of Cedi depreciation on their operations, the need to upgrade transmission network capacity, replacement of aged and obsolete assets to meet growth in demand as well as improve quality and reliability of supply.

4.2.3 Electricity Company of Ghana Limited (ECG)

Within the framework of the Concession Agreement entered into between the Government of Ghana represented by the Ministry of Finance, Ministry of Energy and ECG on one hand, and Millennium Development Authority (MiDA) on the other hand, ECG as an asset owner submitted two tariff proposals in line with PURC's Rate Setting Guidelines Volume 3. The first of the two proposals which captures Power Plants under a Portfolio Power Purchase Agreements (PPAs) is presented in Table 4-5 while the second and final of the proposals which covers Annual Revenue Requirement of ECG, based on the Company's proposed financial and economic data is presented in Table 4-6.

Table 4-5 Summary of ECG's Proposed Portfolio Power Purchase Agreements

Name of Plant	Plant Allocation By Utility	Capacity (MW)	Contracted Energy (GWh) 2019	2020	2021	Average	Generation Mix %
VRA Power Plants:							
Legacy Hydro Allocation to PDS	ECG/PDS	498	2,237	2,237	2,237	2,387	14.6%
TAPCo	ECG/PDS	330	887	887	887	1,314	8.0%
AMERI	ECG/PDS	230	2,015	2,014.8	2,015	2,015	12.3%
IPP Power Plants:							
Bui Power	ECG/PDS	230	721.0	721.0	721	721	4.4%
Safisana Biogas	ECG/PDS	0.1	0.2	0.2	0.66	0.33	0.0%
Meinergy Solar	ECG/PDS	16	6.6	6.6	26.9	13.4	0.1%
BXC Solar	ECG/PDS	16	19.1	19	26.9	21.7	0.1%
Sunon Asogli 2	ECG/PDS	360	2,100	2,100	2,100	2,100	12.8%
Karpowership	ECG/PDS	450	3,513	3,513	3,513	3,513	21.4%
AKSA	ECG/PDS	330	2,155	1,567	1,683	1,802	11.0%
Sunon Asogli 1	ECG/PDS	180	1,077	1,077	1,077	1,077	6.6%
Early Power Project	ECG/PDS	200		1,226	1,612	1,419	8.7%
Total Supply		**2,840**	**14,730**	**15,369**	**15,899**	**16,383**	100.0%
Demand Forecast			**13,843**	**14,482**	**15,012**	**14,446**	

Source: ECG's Tariff Proposal, 2019

Presented in Table 4-5 is a summary of Portfolio PPAs indicating Capacity and Energy assigned by ECG to PDS for the period 2019-2021. As per Table 4-5, assigned capacity amounts to 2,840 MW with an associated energy ranging from 14, 730 GWh in 2019 to 15,899 GWh in 2021.

Table 4-6 Summary of ECG's Proposed Operational Expense and Related Data

Item Description	Measure	2019	2020	2021
Lease Payments				
Return on Assets (10%)	MGHS	1,591.31	1,627.90	1,546.51
Return of Assets (Depreciation)	MGHS	629.25	673.29	639.63
Opex for RECG	MGHS	82.04	92.15	99.55
Sub-Total	MGHS	**2,302.60**	**2,393.35**	**2,285.69**
Expenditure for ECG				
Interest on Existing Loans	MGHS	226.18	245.38	299.76
Forex Losses (for 2018 only)	MGHS	231.93		
Sub-Total	MGHS	**458.11**	**245.38**	**299.76**
Total Revenue Requirements for ECG	MGHS	**2,760.71**	**2,638.73**	**2,585.45**
Other Parameters				
Projected Annual Energy	GWh	13,843	14,482	15,012
Implied Lease Payment	GHp/kWh	**19.94**	**18.22**	**17.22**
Cost of Idle Capacities	MGHS	810.07	1,234.63	1,358.09

Source: ECG's Tariff Proposal, 2018

In terms of revenue requirement ECG proposed a total revenue requirement ranging from GHS 2,760.71 Million in 2019 to GHS 2,585.45 Million in 2021. This request includes lease payments of GHS 2, 302.60 Million in 2019 to GHS 2,285.69 in 2021 and Expenditure for ECG totaling GHS 458.11 Million in 2019 as well as GHS 299.76 Million in 2021.

ECG requests for approval of proposed operational costs by PURC which are underpinned by the monitoring and evaluation role the Company intends to perform as asset owner as well as recovery of value of the Company's leased assets through lease payments.

4.2.4 Power Distribution Services Ghana Limited (PDS)

On August 05, 2014, the Republic of Ghana ("Ghana"), acting through its government ("the Government") and the United States of America, acting through the Millennium Challenge

Corporation, a United States government corporation ("MCC") entered into the Millennium Challenge Compact II, a programme designed to advance economic growth and poverty reduction in Ghana, through provision of grant of up to Four Hundred and Ninety Eighty Million, Two Hundred Thousand United States Dollars (US$498,200,000) to among others enable concession arrangement for the management of operation of and investment in the electricity distribution business of Electricity Company of Ghana limited. To this end a concession Lease and Assigned Agreement was signed between Electricity Company of Ghana (Acting on behalf of Ghana) and the preferred bidder – Power Distribution Services Ghana Limited (PDS) Limited – for the management of operation of and investment in the electricity distribution business of Electricity Company of Ghana.

Having taken over management of the operations of the Distribution Network and Supply business and in line with PURC's Electricity Rate Setting Guidelines Volume 1 and 2, PDS submitted operating and capital expenses for a Five-year Regulatory Control Period commencing Transfer Date for the determination of Distribution Annual Revenue Requirements. The Company also submitted its Annual Aggregate Technical, Commercial and Collection Loss Ratio Reduction Targets which shall be marched against a Provisional Baseline Actual Loss Ratio. Details of PDS's technical as well as financial proposals are presented in Table 4-7, Table 4-8 and Table 4-9.

Table 4-7 Summary of PDS's Proposed Loss Ratios Reduction Targets

Agreement Year	Percentage Point Reduction in Aggregate Technical & Commercial Loss Ratio below Base Aggregate Technical & Commercial Loss Ratio	Percentage Point Improvement in Collection Loss Ratio below Base Collection Loss Ratio
Year 1	0.00%	-3.80%
Year 2	-1.20%	-5.80%
Year 3	-2.40%	-7.80%
Year 4	-3.60%	-9.80%
Year 5	-4.80%	-11.80%

Source: PDS's Tariff Proposal, 2018

A summary of PDS's proposed Loss reduction targets presented in Table 4-7 indicates an Annual Average reduction of 1.2% in Aggregate Technical and Commercial Loss Ratio and a 2% Annual Average reduction in Collection Loss Ratio yielding an 11.8% percentage point improvement after five years of the Company's operation of the Distribution Network.

Table 4-8 Summary of PDS's Proposed Operational Expense and Related Data

Item	Measure	Year/Amount				
		2019	2020	2021	2022	2023
Power Purchases	GWh	11,197	11,570	11,977	12,376	12,784
Power Sales	GWh	8,622	9,048	9,509	9,975	10,457
Operation & Maintenance Expenses	MGHS	607.75	688.12	767.86	842.33	920.92
Administrative & General Expenses	MGHS	230.04	256.15	280.67	303.17	327.22
Human Resource Expenses	MGHS	-	-	-	-	-
Customer Service Expenses	MGHS	405.18	458.76	511.93	561.57	613.97
Mandated Expenses	MGHS	209.76	233.29	265.97	296.43	323.88
Depreciation	MGHS					
Interest on Working Capital	MGHS					
Return on Equity	%	18	18	18	18	18
Debt Margin	%	6.8	6.8	6.8	6.8	6.8
Total Revenue Requirement	GHS	**1,453**	**1,661**	**1,851**	**2,028**	**2,211**

Source: PDS's Tariff Proposal, 2018

As shown in Table 4-8, PDS proposed a total revenue requirement ranging from GHS 1,453 Million in 2019 to GHS 2,211 Million in 2023 excluding Human Resource Expense.

Table 4-9 Summary of PDS's Proposed Capital Expense Outlay

ID	Item	Quantity	Unit	Year/Amount				
				2019	2020	2021	2022	2023
1	MV Projects							
	Increase Capacity New MV Transformer	6	MUSD	17.08	8.54	8.54	8.54	8.54
	New Feeder in Existing Substations	18	MUSD	5.74	4.31	5.74	4.31	5.74
	Feeder Extension	8	MUSD	1.39	1.39	2.78	2.78	2.78
	Lateral Extension (Reduce Losses - Longer MV feeders)	13	MUSD	5.05	2.52	2.52	2.52	3.79
	Replacement of OH MV Small Wire	10	MUSD	1.69	1.69	1.69	1.69	1.69
2	[1]Distribution Schemes and Low Voltage Main Panel (LVMP)		MUSD					
3	Substation Bus Capacitor Banks	9	MUSD	0.48	0.24	0.24	0.48	0.72
4	Feeder Capacitors	36	MUSD	0.51	0.13	0.26	0.26	0.38
5	SCADA (Substation)	29	MUSD	1.05	1.40	1.75	0.52	0.35
6	Type of Substation (Cost)	9	MUSD	12.38	24.76	24.76	24.76	24.76
7	Meters	1,483,150	MUSD	35.56	43.97	53.28	55.48	49.64
8	Test Equipment & Specialised Tools Related to Live Line Work		MUSD	1.51	0.75	1.51	0.75	1.51
9	[1]Service Cables		MUSD					
10	Distribution Automation (Reclosers)	41	MUSD	0.29	0.43	1.72	1.72	1.72
11	Motor Vehicles & Vans:							
	Fault Detection Vehicles (Cable Test Vans)		MUSD					
	Other Operational Vehicles (Pickiup)	225	MUSD	0.36	0.36	0.36	0.36	0.36
	Information Vans		MUSD					
12	IT & Communication							
	Analytical EMS Systems	1	MUSD	2.53	2.86	3.03	3.71	3.88
	Billing and MDM Software Depolyment	1	MUSD	4.13	3.83	0.43	0.00	0.00
13	Subtransmission System Spares	1	MUSD	0.00	2.25	0.00	0.00	0.00
	Distribution System Spares	1	MUSD		0.41			
14	Land and Building		MUSD					
15	Transfer Date Moveable Property Purchase Price	1	MUSD	69.60				
	Sub- Total		**MUSD**	**159.34**	**99.83**	**108.60**	**107.88**	**105.85**

Source: PDS's Tariff Proposal, 2018

Presented in Table 4-9 is a summary of PDS's proposed Capital Expense Outlay for the Five-Year Regulatory Control Period of 2019-2023. According to PDS, the Company intends to undertake Capital investments ranging from USD 159.34 Million in 2019 to USD 105.85 Million in 2023 translating into an annual average capital investment of USD 116.30 Million

4.2.5 Northern Electricity Distribution Company (NEDCo)

The Northern Electricity Distribution Company Limited projected energy sales totaling 983 GWh in 2019. This is projected to increase to 1,118 GWh in 2020 and then to 1,342 GWh in 2023. This and other data are presented in Table 4-10.

Table 4-10 Summary of NEDCo's Proposed Operational Expense and Related Data

Item	Measure	Year/Amount				
		2019	2020	2021	2022	2023
Power Sales	GWh	983	1,118	1,185	1,266	1,342
Operation & Maintenance Expenses	MGHS	19.80	21.78	23.96	26.36	28.99
Administrative & General Expenses	MGHS	47.30	52.02	57.23	62.95	69.25
Human Resource Expenses	MGHS	139.21	146.17	160.78	168.82	177.27
Depreciation	MGHS	123.15	186.04	199.51	217.16	228.49
Return on ANFA	MGHS	22.39	22.39	21.82	22.27	23.14
Total Revenue Requirement	MGHS	**351.84**	**428.41**	**463.29**	**497.56**	**527.13**
Average Net Fixed Assets	MGHS	1,119.51	1,119.56	1,090.81	1,113.63	1,156.89
Return on ANFA	%	8	8	8	8	8
Average Exchange Rates	GHS/US$	5.15	5.7	5.98	6.28	6.6

Source: NEDCo's Tariff Proposal, 2018

A summary of the data presented in Table 4-8 shows that, revenue wise, NEDCo requests recovery through its proposed tariff, total operational cost hence revenue requirement amounting to GHS

351.84 Million in 2019. This request according to the Company is expected to increase to GHS 428.41 in 2020 and GHS 527.13 Million in 2023.

The Company cited increasing depreciation of Ghana Cedi against the US Dollar, increased operational cost, the need to expand, upgrade and replace aged and obsolete distribution network which are relevant to meeting growth in demand as well as improve quality and reliability of supply coupled with Government of Ghana's on-going nation-wide electrification programmes under SHEP and GEDAP as the basis for the proposed increase in its revenue requirement.

4.2.6 Enclave Power Company Limited (EPC)

EPC's proposal projected energy sales totaling 185.32 GWh in 2019. This is projected to increase to 238.38 GWh in 2020 and then to 343.91 GWh in 2023 to its customers within the regulated market but located in Free Zone areas. Table 4-11 shows a summary of EPC's submissions for tariff approval.

Table 4-11 Summary of EPC's Proposed Operational Expense and Related Data

Item	Measure	Year/Amount (MGHS)				
		2019	2020	2021	2022	2023
Power Sales	GWh	185.32	238.38	284.22	312.64	343.91
Distribution Losses	MGHS	2.75	3.54	4.22	4.64	5.11
Operation & Maintenance Expense:	MGHS	0.78	0.86	1.44	1.04	1.14
Administrative & General Expenses	MGHS	2.24	2.52	2.79	3.14	3.53
Human Resource Expenses	MGHS	4.40	5.05	5.80	6.65	7.64
Depreciation	MGHS	4.09	4.87	5.34	5.58	6.27
Interest on Foreign Loans	MGHS	1.53	0.91	0.63	0.40	0.15
Interest on Local Loans	MGHS					
Return on Equity	MGHS	25.18	32.18	42.49	53.97	67.16
Interest on Working Capital	MGHS	0.71	0.72	0.50	0.50	0.50
Total Revenue Requirement	MGHS	**41.67**	**50.64**	**63.21**	**75.93**	**91.50**

Source: EPC's Tariff Proposal, 2018

Details of data presented in Table 4-11 indicate that EPC requests recovery of revenue requirement amounting to GHS 41.67 Million in 2019. This request the Company noted is expected to increase to GHS 50.64 in 2020 and GHS 91.50 Million in 2023.

EPC also cited the need for additional capital investments in network infrastructure to meet growing demand from customers within the free zones but within the regulated market.

4.2.7 Ghana Water Company Limited (GWCL)

The Ghana Water Company Limited submitted tariff review proposals to PURC in respect of their operations in the areas of water production, transmission and distribution. With regards to water production, GWCL projected total production volume of 321,749,593m^3 with associated sales volume amounting to 195,880,268m^3. Summary of the Company's proposal is presented in Table 4-12, Table 4-13 and Table 4-14.

Table 4-12 Summary of Proposed Water Tariff by Customer Category

Category	Proposed Tariff	Expected Sales	Expected Revenue
	GHp/m3	m3	GHS
Metered Domestic			
0-5	670.0562	5,969,116	39,996,431
5 and above	1,976.3658	87,349,553	1,726,346,673
Commercial	3,117.3302	28,023,180	873,575,055
Industrial	4,958.2149	6,426,760	318,652,559
Public Distribution/Gov't Depts	2,994.1676	26,279,908	786,864,491
Premises without connection (Public Standpipe)	655.4713	5,854,856	38,376,901
Special Commercial (Bottled Water producers)	13,983.1350	388,450	54,317,546
Sachet water producers	8,889.6864	3,665,470	325,848,756
Ocean Going Vessels	45,518.1294	23,894	10,876,024
Total		**163,981,187**	**4,174,854,437**

Source: GWCL's Tariff Proposal, 2018/2019

GWCL proposed upward adjustment in water tariffs (GHp/m^3) by customer category as presented in Table 4-12.

Table 4-13 Summary of GWCL's Proposed Operating Expenses and Related Data

Item	Measure	Year/Amount (MGHS)				
		2019	2020	2021	2022	2023
Total Production	m3	294,546,113	315,729,938	329,131,749	341,835,330	356,608,847
Total Sales	m3	159,143,265	173,651,466	181,022,462	188,009,432	196,134,866
Operation & Maintenance Expenses	MGHS	1,185.02	1,362.78	1,565.64	1,798.74	2,068.55
Administrative & General Expenses	MGHS	854.95	1,686.71	1,893.16	2,124.99	2,443.74
Human Resource Expenses	MGHS	240.19	268.58	302.29	353.89	406.97
Depreciation	MGHS	793.35	598.14	626.89	658.88	694.73
Interest on Foreign Loans	MGHS	21.22	99.24	96.08	91.92	86.21
Interest on Local Loans	MGHS	-	-	-	-	-
Return on Equity	MGHS	702.54	646.49	590.45	534.41	478.36
Total Expenses	MGHS	**3,797.27**	**4,661.93**	**5,074.51**	**5,562.83**	**6,178.57**

Source: GWCL's Tariff Proposal, 2018/2019

According to GWCL, cash operating expenses were derived from actual expenses for 2018 and projections made for 2019-2023. Additionally, the Company notes that financial projections and associated statements have been prepared to support 2019-2023 figures.

In addition, the charges to be paid Independent Water Producers (IWPs) Befesa, which are passed through costs to GWCL, have been computed and included. An allowance to cater for effects of depreciation of the Ghana Cedi against the US Dollar has also been included to allow payment to Befesa in USD.

In view of the above to recover fully GWCL operations, the Company proposed total revenue ranging from GHS 3,797.27 Million in 2019 to GHS 6,178.57 Million in 2023 as presented in Table 4-13.

Table 4-14 Summary of GWCL's Proposed Service Charge for 2019-2023

Categories	Rate/Month	Inactive Customers	Active Customers	Amount/Month
	GHS	#	#	GHS
Domestic	5	104,977	434,462	2,172,310
Commercial	10	34,768	59,267	592,670
Industrial	10	281	271	2,710
Public Distribution/Gov't Depts	10	5,072	5,812	58,120
Premises without connection (Public Standpipe)	0	3,467	7,043	-
Special Commercial (Bottled Water producers)	10	11	8	80
Sachet water producers	10	563	812	8,120
Total		**149,139**	**507,675**	**2,834,010**

Source: GWCL's Tariff Proposal, 2018/2019

In Table 4-14, GWCL proposed introduction of Service Charge for all billed customers. GWCL indicated that this charge will cater for infrastructure maintenance, meter maintenance, other commercial services and other fixed costs. According to GWCL, the reason underlying its request for increase in tariff is mainly due to Ghana Cedi to Us Dollar exchange rate depreciation, a paradigm shift in economic policies of Government, the need for adequate funds to offset required investments.

5.0 TARIFF SETTING METHODOLOGY

5.1 Introduction

The Building Blocks of PURC Tariff Methodology is the process of setting a price cap on tariffs which over a regulatory period, may result in a service provider's forecast revenue equating reasonably forecast operating costs and reasonable return on capital. The Building Blocks consist of three parts namely, Determination of Service Levels, Determination of Revenue Requirements and Translation of Revenue Requirement into Price Control.

5.2 Determination of Service Levels

As a first step in PURC's tariff setting process, service levels/standards/outcomes are determined which standards Regulated Utilities are under obligation to deliver over the tariff period. These outcomes, reflect regulatory benchmarks and legislative obligations which Regulated Utilities must meet in accordance with licensing and other regulatory benchmarks.

5.3 Determination of Revenue Requirements

By definition, Annual Revenue Requirement (ARR) is the build-up of the costs associated with various operational activities undertaken by public utilities to fulfill their mandates. In line with this, the Commission ensured that all the public utilities provided the necessary financial and technical data in order to arrive at a fair decision.

Following determination of outcomes which must be delivered, revenue requirements is determined which must be sufficient to enable regulated utilities deliver outcomes efficiently. The building blocks approach which underpins revenue requirement determination involves building up Regulated Utilities revenue from key components which reflect operating and maintenance costs as well as financing requirements. Also Utility's financing costs, both return on and of capital, are built up with reference to rolled forward value of regulatory asset bases and capital expenditure.

5.3.1 Generation Revenue Requirement

By definition, Generation Tariff is the cost recovery price of electric power purchased by Distribution Companies (Discos) and Bulk Customers from Generation Companies. The determination of Generation Revenue Requirement which is to be recovered from the regulated electricity market is based on volume of energy to be supplied within the tariff control period and the Composite Bulk Generation Tariff which is a weighted average of both energy and price per plant deployed to serve a given load at a given time or within the regulatory control period. In line with the above, the formula for computing the Composite Bulk Generation Charge is stated as follows.

$CBGC_t = GM1*P1_t + GM2*P2_t + GM3*P3_t + \ldots + GMn*Pn_t$

Where:

$CBGC_t$	*Composite Bulk Generation Tariff*
GMx	*Proportion of each Power Plant's Electrical Generation in Total Generation Mix*
Pn_t	*Generation Tariff for Respective Power Plants*

5.3.2 Transmission and Distribution Revenue Requirements (Added Value)

Transmission and Distribution Revenue Requirements are necessary for efficient operation and maintenance of services provided by both grids to rate payers. In that regard, prudent and efficient costs associated with provision of transmission and distribution services to end-users of electricity must be recovered through rates payable by consumers. It must however be noted that, costs associated with these grid services are separate from the electrical energy itself. Therefore, the costs associated with transmission and distribution grid services must be determined using the value-added approach as the cost of electrical energy is considered a pass-through cost item. In terms of methodology, the Commission applied the value-added approach in determining the charges for the transmission and distribution grid services. The Commission approves tariffs for the transmission utility (GRIDCo) and the distribution utilities (PDS, NEDCo and EPC) as well as rates for end-users/consumers served by the distribution utilities. The Commission's tariff setting methodology for transmission and distribution utilities is based on the concept of regulatory ARR.

5.4 Translation of Revenue Requirement into Price Control

The third and final component of the PURC's tariffs building blocks involves translation of revenue requirements into price control or maximum allowable rates payable by consumers. The translation process involves allocation of costs to various customer categories on the basis of their cost of service, while taking into consideration socio-economic factors as they impact identified consumer groups.

5.5 Annual Revenue Requirement (ARR) for Transmission Utility

The ARR for the transmission utility is composed of two major cost centers:

(i) transmission added value (TAV) which is related to the utility's direct operating expenses; and,

(ii) cost of power that is lost in the process of transmitting electricity from the power plant gate to the Bulk Supply Points (BSPs) of the distribution utilities or bulk customers point of connection.

The all-inclusive transmission grid service cost is expressed as follows:

$$TransCost = TAV + TransLosses$$

Where:

TransCost	is the all-inclusive transmission grid service costs
TAV	is the direct operating costs of the utility
TransLosses	is the cost of power losses in transmission grid services

The TAV is designated as the (ARR) of the transmission utility, i.e. exclusive of the cost of losses. The ARR of the transmission utility is estimated as follows:

ARR = Opex + Depreciation + Cost of Working Capital + Return on Regulatory Asset Base

Where:

Opex	is the operating expenses including staff cost, administrative costs, and operating and maintenance costs
Depreciation	is straight-line depreciation of the assets for the year
Regulatory Fixed Asset Base	is Net Book Value minus Capital Works in Progress (CWIP)
Cost of Working Capital	is financial costs (interest payment) of working capital

The average cost of the transmission grid services resulting from the ARR, excluding the transmission losses, is referred to as TSC-1 to be paid to the transmission utility.

The average cost of transmission losses is referred to as TSC-2 to be paid to the relevant generator.

In summary, the average costs of transmission grid services (TSC) is expressed as follows:

$$TSC = TSC\text{-}1 + TSC\text{-}2$$

While costs associated with TSC-1 are the direct costs of the transmission utility's operations and shall be paid to the utility, the costs associated with TSC-2 shall be paid to the relevant generator, by the distribution utility or bulk customer either directly to the generator or through the transmission utility which in turn pays it to the relevant generator. The cost of transmission losses is therefore not to be retained by the transmission utility as part of its ARR.

5.6 Annual Revenue Requirement for Distribution Utilities

The ARR for Distribution Utilities is estimated as follows:

ARR = Opex + Depreciation + Working Capital + Return on Regulatory Asset Base

Where:

Opex	is the operating expenses including staff cost, administrative costs, and operating and maintenance costs
Depreciation	is straight-line depreciation of the assets for the year
Regulatory Fixed Asset Base	is Net Book Value minus Capital Works in Progress (CWIP)
Cost of Working Capital	is financial costs (interest payment) of working capital

5.7 Total Annual Revenue Requirement (TARR)

In addition to the distribution utilities' ARR, they incur other costs – power purchases, transmission grid services - which shall be recovered from end-use consumers. The combination of all these costs are computed as distribution utilities' Total Annual Revenue Requirement (TARR) to be passed on into rates. The TARR is therefore estimated as follows:

TARR = Power Purchases + TransCost + ARR

Where:

Power Purchases	are costs of electricity purchases from generators including losses in transmission and distribution grid systems.
TransCost	is cost of transmission grid services excluding transmission losses (paid to GRIDCo).
ARR	is Annual Revenue Requirement of the distribution company as defined above

5.8 Tariff Income (TI)

Tariff Income (TI) is the actual revenue that is generated from the rates that are applied to various customer consumption bands. The rates set to recover the TARR of the distribution company include the following:

1. Cost of electricity purchased,
2. Cost of transmission services and the revenue requirement of the distribution company, and
3. Percentage adjustments of the ARR to cater for non-collectible revenue (NCR).

The TI is estimated as follows:

$$TI = TARR + NCR$$

Where:

TARR	is Total Annual Revenue Requirement as defined above
NCR	is additional costs provided to adjust the TARR for non-collectible revenue that may arise due to technical or commercial challenges facing the utility in the collection of its revenue

6.0 COMPOSITE BULK GENERATION REVENUE DETERMINATION

The Generation Revenue Requirement for 2019-2020 period was determined based on GRIDCo's electricity supply plan and also tariffs for each of the power plants contained in the supply plan. The Electricity Supply Plan for each year is prepared by a Committee made up of Energy Commission, VRA, GRIDCo, and ECG as a consensus document. The supply plan matches supply and demand of electrical energy for both regulated and de-regulated electricity markets for a given period.

For the regulated market, the results from determination of Bulk Generation Tariff is composed of allocated hydro and thermal electrical energy from VRA as well as bilateral power plants contracted by DISCos within the supply plan, details of which are presented in Table 6-1.

Based on the above, the Commission determines a Composite Bulk Generation Tariff (CBGT) hence total generation revenue requirement using the following formula.

$BGC_t = GM1*P1_t + GM2*P2_t + GM3*P3_t + \dots + GMn*Pn_t$

Where:

BGC_t	*Composite Bulk Generation Tariff*
GMx	*Proportion of each Power Plant's Electrical Generation in Total Generation Mix*
Pn_t	*Generation Tariff for Respective Power Plants*

Table 6-1 Summary of 2019-2020 Supply Plan Electrical Energy and Tariffs

Power Plant	Electricity Generation (GWh)	Tariff (GHp/kWh)
VRA Plants		
VRA-Hydro:		
Akosombo	2,646	10.2050
Kpong	504	20.9211
Sub-Total VRA Hydro	3,151	
VRA-Thermal:		
TAPCo	1,717	38.9067
TT1PP	133	43.4189
AMERI	1,007	61.6176
KTPP	145	43.2785
Sub-Total VRA Thermal	3,002	
VRA-Renewable:		
Navrongo Solar	3	92.1443
Sub-Total VRA Renewable	**3**	
Total VRA Electrical Energy/Composite VRA Bulk Generation Tariff	**6,156**	**29.0370**
IPPs:		
Sunon Asogli Phase I	715	54.6422
Sunon Asogli Phase II	1,940	53.2444
Karpowership	2,775	59.9988
AKSA	1,190	70.1569
Bui Power Authority	650	51.7120
BXC Solar	27	101.6929
Meienergy Solar	27	91.5212
Safisana Plant	0.7	88.3750
Sub-Total IPPs	**7,325**	
Total Electrical Energy/ Composite Bulk Generation Charge	**13,481**	**45.2493**

Source: PURC's Tariff Analysis, 2019

7.0 ANALYSES OF COSTS AND TARIFF DECISION IN RESPECT OF TRANSMISSION GRID SERVICES

This section presents the outcome of the analyses of the cost and Tariffs for Transmission Grid services

7.1 Determination of the Transmission Utility's Annual Revenue Requirement

In determining the TSC, the Commission was guided by the fact that transmission of power is a monopoly business and therefore requires the requisite regulatory supervision to ensure that its costs are prudent and efficient.

For this 2019-2020 tariff decision the ARR is expressed as follows

ARR = Operating Expenses + Depreciation + Return on the Rate Base

It is important to note that the costs of energy losses are not included in the ARR. This is so because the costs of system losses (transmission) are fully borne by the distribution utility companies in proportion to their usage of the grid systems and are paid directly to the generating companies.

Based on the above, the following costs centres are considered in the determination of the TSC -1 which is intended to cover GRIDCo's direct operational expenses excluding energy losses.

TSC-1 = ARR/TET

Where:

TSC-1	is Average transmission costs excluding cost of losses
ARR	is Annual Revenue Requirement of the transmission utility (GRIDCo)
TET	is Total Electricity Transmission by GRIDCo for 2019-2020

The various components of the PURC approved costs of GRIDCo's transmission grid services (TSC 1) are discussed below:

7.1.1 GRIDCo's Operating Expenses

The Commission approved an amount of GHS 650.43 Million to cover the operating expenses of GRIDCo. The total operational expenses of operations of GRIDCo consists of two components:

1. Direct operational expenses comprising staff costs, operation and maintenance costs, and general administrative expenses; and
2. Depreciation and return on the Regulatory Asset Base (RAB).

Table 7-1 shows the breakdown of GRIDCo's operational expenses approved by the Commission.

Table 7-1 Summary of PURC Approved Costs vs. Proposed Costs for GRIDCo

Cost Type	Existing (MGHS)	Proposed Costs (MGHS)	Approved Costs (MGHS)
Approved Operating Cost:			
Administrative & General Expenses	69.81	36.38	36.63
Operation & Maintenance Expenses	40.00	74.14	75.31
Human Resource Expenses	156.91	214.13	219.41
Sub-Total	**266.72**	**324.65**	**331.35**
Capital Recovery Cost (CRC):			
Depreciation	74.71	166.41	133.60
Return on Regulated Asset Base	52.33	416.80	185.48
Sub-Total	**127.04**	**583.21**	**319.08**
Total Electricity Network Business Revenue Requirement	**393.76**	**907.86**	**650.43**

Source: PURC's Tariff Analysis, 2019

7.1.2 Administrative and General Expenses

GRIDCo proposed an average amount of GHS36.38 Million to cover various administrative and general expenses for 2019-2020 representing a 47.9% reduction over 2018 approved existing costs. Based on the Company's proposal, the Commission approved an inflation-adjusted administrative and general expenses amounting to an average of GHS36.63 Million for the 2019-2020 tariff period.

7.1.3 Operation and Maintenance Expenses

With respect to operation and maintenance expenses, the Commission approved an amount of GHS75.31 Million as against GHS 74.14 Million proposed by GRIDCo. The approved costs represents an inflation-adjusted rate of 8% for the 2019-2020 Tariff Period.

7.1.4 Human Resource Expenses

Human Resource Expenses covers salaries of staff, staff allowances and other statutory payments in respect of GRIDCo's staff. The Commission approved an average amount of GHS219.41 Million to cover human resource expenses for the Company for the 2019-2020 tariff period. It must be stated that, in taking this decision, the Commission has thus approved NEDCo's human resource expenses in its entirety

7.1.5 Depreciation

The Commission approved an average depreciation amount of GHS133.60 Million as against GRIDCo's proposal of GHS166.41 Million for the 2019-2020 period. The approved amount represents 80.3% of amount proposed by GRIDCo.

7.1.6 Return on Net Fixed Assets

GRIDCo proposed an amount of GHS 416.80 Million as Return on Net Fixed Assets for the 2019-2020 tariff period. The Commission noted that Government of Ghana had assumed responsibility for USD142 Million of debt financed assets of the Company by converting same into equity holding in the Company. The Commission therefore disallowed GHS231.32 Million and approved an average amount of GHS 185.48 Million representing 44.5% of proposed.

8.0 ANALYSES OF COSTS AND TARIFF DECISION IN RESPECT OF ELECTRICITY DISTRIBUTION SERVICES

In this section, analyses of costs and tariff decision in respect of Electricity Distribution services for ECG, PDS, NEDCo and EPC are presented. The analyses recognise the split between ECG as an asset owner and PDS as a distribution network system operator as a result of the Concession arrangement entered into between the Government of Ghana and PDS. In that regard, the analyses were carried out within the framework of PURC's Rate Setting Guidelines Volume 1, 2 and 3.

8.1 Determination of PDS's Annual Revenue Requirement

The PDS's ARR determination for the 2019-2020 tariff period is expressed as follows:

$$ARR(Dist)_t = OpEx(Dist)_t + RtnRAB(Dist)_t + DepRAB(Dist)_t + LP_t + WCA(Dist)_t + CorpTax(\mathrm{Dist})_t$$

Where

$ARR(Dist)_t$	*is Projected Annual Revenue Requirement (Distribution)*
$OpEx(Dist)_t$	*is Projected Operation and Maintenance Expenses (Distribution)*
$RtnRAB(Dist)_t$	*is Projected Return on Regulated Asset Base (Distribution)*
$DepRAB(Dist)_t$	*is Projected Depreciation (Distribution)*
LP_t	*is Projected Lease Payments*
$WCA(Dist)_t$	*is Projected Interest on Working Capital*
$CorpTax\ (Dist)_t$	*is Projected Corporate Tax*

PDS proposal covered the Company's operational costs itemised as administrative and general expenses, operation and maintenance expenses, human resource expenses and mandated costs totaling GHS 2,107.37 Million. In addition, a lease payment of GHS 2,260.88 Million was proposed by ECG bringing the total proposed ARR for both PDS and ECG to GHS 4,372.40 Million.

However, the Commission approved an ARR of GHS 1403.81 Million including an annual average lease payment of GHS 223.60 Million, mandated costs of GHS 44.84 Million, interest on working capital of GHS 4.15 Million and Transfer Date moveable property amounting to GHS 97.97 Million per annum for the 2019-2020 tariff period. The costs approved for PDS was guided by the fact that the Company intends to submit a request for tariff review after their first year of operation based on actual established costs. These costs details which form the cost build-up of PDS's ARR are presented in Table 8-1.

Table 8-1 Summary of PURC Approved Costs vs. Proposed Costs of PDS

Cost Type	Existing (MGHS)	Proposed Costs (MGHS)	Approved Costs (MGHS)
Approved Operating Cost:			
Administrative & General Expenses	152.74	243.09	171.56
Operation & Maintenance Expenses	296.48	1,337.39	379.64
Human Resource Expenses	468.76	526.89	526.89
Interest on Working Capital			4.15
Capital Expenditure (Moveable Property)			97.97
Sub-Total	**917.98**	**2,107.37**	**1,180.21**
Capital Recovery Cost (CRC):			
Depreciation	498.86	651.27	188.46
Return on Regulated Asset Base	93.01	1,609.61	35.14
Sub-Total	**591.87**	**2,260.88**	**223.60**
Total Electricity Network Business Revenue Requirement	**1,509.85**	**4,368.25**	**1,403.81**

Source: PURC's Tariff Analysis, 2019

In terms of Distribution Added Value (DAV) per kWh, the cost details presented in Table 8-1 resulted in a DSC of 16.0346 GHp/kWh. It should be noted that this excludes the 2% provision for non-collectible revenue (NCR) as well as distribution system losses averaging 22.6% per annum over the 2019-2020 tariff period. Details of the various operational cost centers are discussed below.

8.1.1 Administrative and General Expenses

PDS proposed an amount of GHS 243.09 million to cover various administrative and general expenses for the 2019-2020 period. This was to cover all administrative expenses in PDS's operational regions and the headquarters. However, the Commission approved a total amount of GHS 171.56 Million by adjusting 2018 approved administrative and general expenses of PDS by 2019-2020 projected annual average inflation rate of 8%. The approved administrative and general expenses were passed through the 2019-2020 tariff.

8.1.2 Operation and Maintenance Expenses

As presented in Table 8-1, PDS proposed a total annual average amount of GHS1,337.39 Million to cover their operation and maintenance expenses. Of this amount, GHS 431.97 Million was proposed in respect of Customer Service expenses and GHS221.53 Million to cover Mandated Costs. The Commission in its analysis using 2018 Operation and Maintenance expenses as a base and applying the projected average annual inflation rate of 8% established that a total amount of GHS 379.64 Million was sufficient which included Mandated Costs of GHS44.84 Million to meet the total operation and maintenance expenses of PDS for the 2019-2020 Tariff Period.

In taking this decision, however, the Commission was mindful of ensuring that reasonable and justifiable Operation and Maintenance expenses associated with PDS's operational areas was fully passed through. The Operation and Maintenance expenses which were disallowed were largely those associated with PDS's financial expenses and agency fee. The Commission disallowed an average amount of GHS 174.95 Million Financial expenses and agency fee on the grounds that the financial expenses have already been accounted for in the Weighted Average Cost of Capital while the agency fee was disallowed on the grounds that it is not mandatory within the terms of Bulk Supply Agreement (BSA).

8.1.3 Human Resource Expenses

As provided for in the Rate Setting Guidelines volume 2, PURC is expected to give consideration to Government's Employment Protection Policy for the ECG Concession in the Major Tariff Review. The Commission therefore approved all the human resource expenses of GHS 526.89 Million proposed by ECG for PDS.

It is worth noting that the Commission's decision with respect to the various costs approved for PDS took into consideration the position of PDS to the effect that their proposed costs were all professional guesstimates. According to PDS, the true operational costs commensurate with the size and state of the distribution infrastructure will be established after a year's operation of the distribution network. The Company noted that based on establishment of these actual costs, a new proposal will be submitted to the Commission for consideration and approval.

8.1.4 Cost of Distribution Losses

The cost of power losses in the distribution network is accounted for and applied as appropriate. The benchmark regulated total average distribution system losses for 2019-2020 tariff period are estimated at an average of 22.6% of PDS's total electricity purchases excluding transmission losses. The distribution system losses which varies from PURC's previous benchmark of 21% have been approved in accordance with Section 2.5 of Volume 2 of PURC's Rate Setting Guidelines. The total cost of the distribution losses of 2,556GWh is estimated at GHS 1,303.78 Million, representing an average cost of 14.8920 GHp/kWh. The average cost of total distribution systems losses is prefixed as DSC-2.

It should however be noted that the cost of distribution losses is not applicable in cases where the total power purchases of the distribution utility includes the cost of total system losses (both technical and commercial losses). This decision considers two billing and payment options.

First, where a Bulk Customer embedded in the distribution network, procures electricity directly from an electricity generator and pays the total cost of the electricity purchased including Transmission Service Charge attributable to the transmission network business (TSC-1) and that attributable to transmission losses (TSC-2), the Bulk Customer shall pay Distribution Service Charge attributable to distribution network business (DSC-1) only to the Electricity Distribution Company.

Second, where a Bulk Customer embedded in the distribution network procures electricity through an Electricity Distribution Company, the Bulk Customer shall pay the cost of the electricity delivered at the customer's premises in addition to TSC-1, TSC-2 and DSC-1 in addition to DSC-2 which together constitute the Distribution Wheeling Charge (DWC) to the electricity distribution utility.

8.1.5 Non-collectible Revenue (NCR)

The Commission approved 2% allowance as provision for non-collectible revenue by PDS. The Commission took this decision taking into consideration the position of the Ministry of Finance as noted in Section 3.2.5.

8.2 PDS's Total Annual Revenue Requirement (TARR)

The Commission determined PDS's TARR taking into consideration the following cost items:

(i) Cost of power purchases from electricity generators including all losses in the process of high voltage transmission as well as the electricity that is not billed owing to technical and commercial losses within the utility company's distribution network (*VRA and IPPs*),
(ii) Direct cost of transmission grid services (*GRIDCo costs*),
(iii) Costs of the PDS's own operations (*PDS's ARR*), and
(iv) Provision for non-collectible revenue.

8.2.1 PDS's Cost of Power Purchases for 2019-2020

As noted in PDS's and ECG's proposals, PDS was to procure power from VRA and a number of Independent Power Producers (IPPs) allocated to the Company by ECG for the 2019-2020 Major Tariff Review Period. A total of 4,470 GWh including 2,801 GWh from Akosombo and Kpong was allocated to PDS by the Electricity Market Oversight Panel (EMOP). The balance of 1,669 GWh was to be supplied by VRA Thermal Power Plants. According to PDS's proposal, total projected electrical energy requirements of the Company for the 2019-2020 Major Tariff Review Period amounted to 11, 795 GWh. Therefore, the balance of 7,325 GWh was projected to be procured from a number of IPPs noted in Table 8-2. The Commission accepted both positions that is the VRA allocated energy and ECG's allocated electrical energy to PDS to make the 11,795 GWh.

In light of above, the Commission approved a total amount of GHS 5,524.53 Million to cover the total cost of electrical energy to be purchased by PDS in 2019-2020. The cost build-up of PDS's electrical energy purchases for 2019-2020 tariff period is presented in Table 8-2.

8.2.1.1 PDS's Composite Bulk Generation Tariff

Based on the total electrical energy allocated to PDS by VRA and IPP Power Plants vis-à-vis tariff by Power Plant presented in Table 8-2, the Commission approved Composite Bulk Generation Tariff (CBGT) of GHp27.1142/kWh payable by PDS for power purchases from VRA and GHp46.8379/kWh payable for power purchases by PDS from ECG in respect of IPPs allocated to the Company. Therefore, the Gazetted Tariff of GHp45.2493/kWh represents the Composite Bulk Generation Tariff for the three DISCos- PDS, NEDCo and EPC.

Table 8-2 Summary of PURC Approved Power Purchase Costs for PDS

Power Plant	Projected Electrical Energy (GWh)	Tariff (GHp/kWh)
VRA Plants		
VRA-Hydro:		
Akosombo	2,353	10.205
Kpong	448	20.9211
Sub-Total VRA Hydro	**2,801**	
VRA-Thermal:		
TAPCo	662	38.9067
AMERI	1,007	61.6176
Sub-Total VRA Thermal	**1,669**	
Total VRA Electrical Energy/ VRA Composite Bulk Generation Tariff	**4,470**	**27.1142**
ECG IPPs:		
Sunon Asogli Phase I	715	54.6422
Sunon Asogli Phase II	1,940	53.2444
Karpowership	2,775	59.9988
AKSA	1,190	70.1569
Bui Power Authority	650	51.712
BXC Solar	27	101.6929
Meienergy Solar	27	91.5212
Safisana Plant	0.7	88.3750
Sub-Total IPPs	**7,325**	
Total Electrical Energy/ VRA+ECG IPPs Composite Bulk Generation Charge	**11,795**	**46.8379**

Source: PURC's Tariff Analysis, 2019

8.2.2 PDS's Transmission Grid Services Cost

In addition to the cost of power purchases, PDS is required to pay for the transmission grid services provided by GRIDCo. The transmission service charge (TSC) has two components as follows:

(i) TSC-1 to recover the cost of transmission grid operations added value; and
(ii) TSC-2 to recover the cost of power lost in transmission.

For 2019-2020 tariff period, total electrical energy to be transmitted on behalf of PDS is projected at 11,795 GWh which includes transmission losses of 484 GWh. Given that PDS's total purchases of 11,795 GWh includes transmission losses, PDS is required to pay the Transmission Service Charge (TSC-1) only, to GRIDCo.

It is important to note that the cost build-up, accounts for all the associated system losses resulting from the transmission and distribution of electricity to final consumers. The breakdown of total electricity purchases, transmission and distribution losses as well as sales are presented in Table 8-3.

Table 8-3 Summary of PURC Approved Transmission and Distribution System Losses for PDS

Description	GWh
Power Purchases	11,795
Transmission System Losses	484
Distribution System Losses	2,556
Final End-User Consumption (Sales)	8,755

Source: PURC's Tariff Analysis, 2019

8.2.3 PDS Total Annual Revenue Requirement

The Commission having considered the various cost items proposed by PDS and representations made by various stakeholders has established a Total Annual Revenue Requirement (TARR) for the Company amounting to GHS 7,306.10 Million as presented in Table 8-4.

Table 8-4 Summary of PDS's Total Annual Revenue Requirement

Item/Cost Center	PURC Approved (Million GHS)
Power Purchases (Incl. Trans. & Distr. System Losses)	5,524.53
Transmission Service Cost (Excl.Transmission Losses)	431.76
Total Power Purchases & Transmisson Grid Service Costs	**5,956.29**
Administrative & General Expenses	171.56
Operation & Maintenance Expenses	379.64
Human Resource Expenses	526.89
Interest on Working Capital	4.15
Capital Expenditure (Moveable Property)	97.97
Sub-Total	1,180.21
Lease Payment:	
Depreciation	188.46
Return on Regulated Asset Base	35.14
Sub-Total	223.6
PDS Annual Revenue Requirement (ARR)	**1,403.81**
Total Annual Revenue Requirement (TARR)	**7,360.10**

Source: PURC's Tariff Analysis, 2019

The Commission wishes to state that based on its approved costs shown in Table 8-4, PDS is obliged to bill and collect from its customers, the tariffs approved and gazetted by the Commission to meet all its obligations including power purchases, transmission services, and distribution operating expenses.

8.3 Determination of ECG's Costs and Revenue Requirement

ECG's costs and revenue requirements were determined by the Commission taking into consideration costs proposed by the Company to cover its operational activities including human resource costs. The Commission also considered various lease payment scenarios proposed by the Ministry of Finance in respect of PDS use of the distribution network assets leased to the Company under the Lease and Assignment Agreement (LAA) signed between ECG and PDS.

Analysis of the various costs proposed by ECG were carried out using Volumes 1 and 3 of the PURC Rate Setting Guidelines. In light of the Company's proposal, the Commission engaged key stakeholders including the Ministry of Finance to determine the appropriate level of lease payments sufficient to pay both principal and interest costs in respect of loans contracted by the Company, administrative and general expenses as well as staff and related costs.

The Commission through various stakeholder consultations and analysis established and approved an annual average amount of GHS 223.60 Million for the 2019-2020 Major Tariff Review Period. This decision was guided also by impact of lease payments on electricity tariffs for consumers.

8.4 Determination of NEDCo's Revenue Requirement

NEDCo's ARR determination for the 2019-2020 tariff period is expressed as follows:

ARR = Operating Expenses + Depreciation + Corporate Tax + (Rate of Return × Rate Base)

NEDCo's proposal covered the Company's operational costs detailed as administrative and general expenses, operation and maintenance expenses, human resource expenses, depreciation and return on regulated asset base totaling an annual average amount of GHS 390.13 Million for the 2019-2020 Major Tariff Review Period.

However, the Commission approved an annual average ARR of GHS 316.83 Million including Capital Recovery Cost of GHS 87.25 Million and Total Operating Expenses of GHS 229.58 Million. The approved revenue requirement was determined by taking into consideration the actual historical operational cost trend of NEDCo. These costs details which form the cost build-up of NEDCo's ARR for the 2019-2020 tariff period are presented in Table 8-5.

Table 8-5 Summary of PURC Approved Costs Vs. Proposed Costs by NEDCo

Cost Type	Existing (MGHS)	Proposed Costs (MGHS)	Approved Costs (MGHS)
Approved Operating Cost:			
Administrative & General Expenses	14.27	20.79	16.02
Operation & Maintenance Expenses	61.24	49.66	68.78
Human Resource Expenses	128.18	142.69	144.78
Sub-Total	**203.69**	**213.14**	**229.58**
Capital Recovery Cost (CRC):			
Depreciation	62.23	154.59	69.90
Return on Regulated Asset Base	15.45	22.39	17.35
Sub-Total	**77.68**	**176.99**	**87.25**
Total Electricity Network Business Revenue Requirement	**281.37**	**390.13**	**316.83**

Source: PURC's Tariff Analysis, 2019

NEDCo's ARR results in an average distribution added value (DAV) charge of 28.7244 GHp/kWh. It must be noted that this excludes the NCR and system losses. Details of the various operational cost centers are discussed below.

8.4.1 Administrative and General Expenses

NEDCo proposed an average of GHS20.79 Million to cover various administrative expenses for 2019-2020. However, the Commission approved a total amount of GHS 16.02 Million by adjusting 2018 approved administrative and general expenses of NEDCo by 2019-2020 projected annual average inflation rate of 8%. The approved administrative and general expenses which represents 77% of proposed costs were passed through the 2019-2020 tariff.

8.4.2 Operation and Maintenance Expenses

With respect to operation and maintenance expenses, the Commission approved an annual average amount of GHS68.78 Million as against GHS49.66 Million proposed by NEDCo for the 2019-2020 Major Tariff Review. This represents an inflation-adjusted rate of 8% on the 2018 approved Operation and Maintenance Expenses for the 2019-2020 Tariff Period. This decision was informed by the state of NEDCo's operational area in meeting quality of service delivery to its customers.

8.4.3 Human Resource Expenses

The Commission approved an average amount of GHS144.78 Million to cover human resource expenses for the Company for the 2019-2020 tariff period. It must be stated that, in taking this decision, the Commission has thus approved NEDCo's human resource expenses in its entirety.

8.4.4 Depreciation Expense

With regards to depreciation expense, the Commission approved an annual average amount of GHS69.90 Million to be recovered directly from the tariffs representing 45.2% of what was proposed by NEDCo for the 2019-2020 tariff period.

8.4.5 Return on Net Fixed Assets (RNFA)

A Return on Revalued Net Fixed Assets (RNFA) of GHS17.35 Million was approved by the Commission for the 2019-2020 Major Tariff Review Period representing 77.5% percent of RNFA proposed by NEDCo.

8.4.6 Cost of Distribution Losses

The benchmark regulated total distribution system losses for 2019-2020 Major Tariff Review Period are estimated at 22.6% of NEDCo's total electricity purchases of 1,486GWh. The total cost of the distribution losses is estimated at GHS 164.26 Million, translating to an average cost of 14.9117GHp/kWh. Similar to the case of PDS, the average cost of total distribution systems losses is prefixed as DSC-2 and is not applicable in the cases where the total purchases of the distribution utility include cost of total system losses.

8.4.7 Non-collectible Revenue (NCR)

The Commission approved a 2% allowance to cover provision for non-collectible revenue by NEDCo.

8.5 NEDCo's Total Annual Revenue Requirement (TARR)

In determination of NEDCo's TARR the following costs are considered:

(i) Cost of power purchases from electricity generators including all losses in the process of high voltage transmission as well as the electricity that is not billed owing to technical and commercial losses within the utility company's network,

(ii) Direct cost of operating the high voltage transmission system of the power to the consumers,

(iii) Costs of the utility companies' own operations (ARR), and

(iv) Specific costs that are allowed by the Commission to cover for sundry such as non-collectible revenue, etc.

The Commission approved a total annual revenue requirement of GHS877.35 Million for NEDCo to cover all its costs including power purchases from VRA.

8.5.1 NEDCo's Cost of Power Purchases for 2019-2020

NEDCo procures all its power requirements from VRA. For the 2019-2020 Tariff Period, NEDCo has projected to purchase about 1,486 GWh of electricity to meet the needs of its customers as well as provide for all losses in the transmission and distribution of the electricity.

The Commission approved an annual average amount of GHS506.12 million to cover the total cost of electricity to be purchased by NEDCo for 2019-2020 tariff period. Table 7-6 shows the cost build-up of NEDCo's electricity purchases for 2019-2020 tariff period. The sources and projected amount of electricity supply are based on the 2019-2020 Electricity Supply Plan. The supply profile also considers the allocation of electricity from the Akosombo and Kpong hydro power plants approved by the Electricity Market Oversight Panel (EMOP) for the 2019-2020 hydro cycle.

8.5.1.1 NEDCo's Composite Bulk Generation Charge

The CBGC represents the weighted average cost of electricity to be procured by NEDCo from by VRA including the electricity from the Akosombo and Kpong hydro power plants. On the basis of the approved total cost of electricity purchases of GHS506.12 Million, the CBGC for NEDCo, for 2019-2020 is estimated at of GHp34.0592/kWh. Therefore, the Gazetted Tariff of GHp45.2493/kWh represents the Composite Bulk Generation Tariff for the three DISCos- PDS, NEDCo and EPC. Details of projected power purchases for NEDCo and tariffs by power plant are presented in Table 7-6.

Table 8-6 Summary of PURC Approved Power Purchase Costs for NEDCo

Power Plant	Projected Electrical Energy (GWh)	Tariff (GHp/kWh)
VRA Plants		
VRA-Hydro:		
Akosombo	248	10.2050
Kpong	47	20.9211
Sub-Total VRA Hydro	295	
VRA-Thermal:		
TAPCo	1,055	38.9067
TT1PP	133	43.4189
Sub-Total VRA Thermal	**1,188**	
VRA-Renewable:		
Navrongo Solar	3	92.1443
Sub-Total VRA Renewable	3	
Total VRA Electrical Energy/ VRA Composite Bulk Generation Tariff	**1,486**	**34.0592**

Source: PURC's Tariff Analysis, 2019

8.5.2 NEDCo's Transmission Grid Services Cost

In addition to the cost of power purchases, NEDCo is required to pay for the transmission grid services provided by GRIDCo. The transmission service charge (TSC) has two components as follows:

(i) TSC-1 to recover the cost of transmission grid operations added value; and
(ii) TSC-2 to recover the cost of power lost in transmission.

The total power to be transmitted on behalf of NEDCo for the 2019-2020 tariff period is projected at 1,486 GWh which includes transmission losses of 61 GWh. Given that NEDCo's total purchases of 1,486 GWh includes the cost of transmission losses, NEDCo is required to pay only the added value component (TSC-1) of the Transmission Service Charge.

Table 8-7 Summary of PURC Approved Transmission and Distribution System Losses for NEDCo

Description	**GWh**
Power Purchases	1,486
Transmission System Losses	61
Distribution System Losses	322
Final End-User Consumption (Sales)	1,103

Source: PURC's Tariff Analysis, 2019

The Commission will like to state that per its decision, the cost build-up accounts for all the associated system losses resulting from the transmission and distribution of electricity to final consumers. Table 8-7 shows the breakdown of total electricity purchases by NEDCo for the 2019-2020 tariff period.

8.5.3 NEDCo's Total Annual Revenue Requirement

Similar to PDS, the Commission considered the various cost items proposed by NEDCo. The Commission is of the view that, based on various costs proposed and representations made by various stakeholders with respect to NEDCo's proposed costs vis-à-vis performance targets, a Total Annual Revenue Requirement (TARR) for the Company amounting to GHS877.35 Million was sufficient to cover the operational costs of NEDCo for the 2019-2020 tariff period. Details of these costs including cost of power purchases are presented in Table 8-8.

Table 8-8 Summary of NEDCo's Total Annual Revenue Requirement

Item/Cost Center	**PURC Approved (Million GHS)**
Power Purchases (Incl. Trans. & Distr. System Losses)	506.12
Transmission Service Cost (Excl.Transmission Losses)	54.40
Total Power Purchases & Transmisson Grid Service Costs	**560.52**
Administrative & General Expenses	16.02
Operation & Maintenance Expenses	68.78
Human Resource Expenses	144.78
Depreciation	69.9
Return on Regulated Asset Base	17.35
NEDCo Annual Revenue Requirement (ARR)	**316.83**
Total Annual Revenue Requirement (TARR)	**877.35**

Source: PURC's Tariff Analysis, 2019

The Commission wishes to state that based on its approved costs shown in Table 8-8, NEDCo is entreated to bill and collect from its customers, the tariffs approved and gazetted by the Commission to meet all its obligations including power purchases, transmission services, and distribution operating expenses.

9.0 ANALYSIS OF COSTS AND TARIFFS FOR WATER PRODUCTION, TRANSMISSION AND DISTRIBUTION SERVICES

This section provides outcome of the PURC's analyses of costs and tariffs proposed by GWCL as well as the Commission's decision on tariffs for GWCL.

9.1 Determination of Annual Revenue Requirement

In carrying out its analyses of various costs and performance targets proposed by GWCL for the 2019-2020 Major Tariff Review period, the Commission was guided by the fact that potable water service delivery within urban Ghana is to a very large extent a monopoly business hence the need for the requisite regulatory supervision to ensure that incurred costs in service delivery are prudent and efficient and performance targets met.

For this 2019-2020 tariff decision the ARR is expressed as follows

ARR = Operating Expenses + Depreciation + Return on the Rate Base

Based on the above, the following costs centres are considered in the determination of the water tariffs which is intended to cover GWCL's direct total operations expenses excluding water purchase cost.

WT = ARR/TET

Where:

WT	is Average water costs including cost of water purchased
ARR	is Annual Revenue Requirement of GWCL
TET	is projected Water Sales by GWCL for 2019-2020

The various components of the PURC approved costs of GWCL's are discussed below.

9.1.1 GWCL's Operating Expenses

The Commission has approved an annual average amount of GHS 1,222.92 Million to cover operating expenses of GWCL for the 2019-2020 tariff period. Table 9-1 shows the breakdown of GWCL's operational expenses approved by the Commission.

Table 9-1 Summary of GWCL Proposed Vs PURC Approved Costs and Related Data

Description	Measure	Existing	GWCL Proposed Costs	PURC Approved Costs
Total Water Production	MM3	308	343.53	343.65
Total Water Sales	MM3	169	195.88	195.88
GWCL Production Cost Excluding Electricity	MGHS	232.87	1,142.39	224.53
BEFESA Capacity Cost Excluding Electricity	MGHS	75.52	85.49	86.09
BEFESA Variable Water Cost Excluding Electricity	MGHS	9.06	4.36	10.77
Transmission Cost Excluding Electricity	MGHS	33.96	429.61	34.06
Distribution Cost Excluding Electricity	MGHS	256.93	462.40	257.83
Total Electricity Consumption-GWCL	MGHS	230.14	224.78	267.19
Total Electricity Consumption-BEFESA	MGHS		39.05	52.44
Total Operating Cost	MGHS	**838.48**	**2,388.08**	**932.91**
Depreciation	MGHS	50.05	695.75	230.81
Return on Revalued Net Fixed Assets	MGHS	113.43	903.30	59.19
Capacity Cost	MGHS	**163.48**	1,599.04	**290.01**
Total Cost	MGHS	**1,001.96**	**3,987.13**	**1,222.92**

Source: PURC's Tariff Analysis, 2019

The PURC's review and analysis resulted in a balancing effect of total revenue requirement amounting to GHS 1,222.92 Million which represents 31% of what was proposed by GWCL.

9.2 Major Cost Centers

The Commission identified four main major cost centers which underpinned its decision on GWCL tariffs for 2019-2020 Major Tariff Review Period. These cost centers are discussed in the following section.

9.2.1 Water Purchases from Befesa Desalination Plant

GWCL by a Water Purchase Agreement is to procure on daily basis 60,000 m^3 of water from Befesa's Desalination Plant located at Teshie-Nungua. To enable GWCL pay for the full cost of its water purchases from Befesa, the Commission incorporated the full annual Capacity payments of USD17.1 Million and a Variable Operation and Maintenance Cost of USD2.13 Million into the total revenue requirement of GWCL for 2019-2020 tariff period.

9.2.2 Total Cost of Electricity Consumption

The cost of electricity consumption constitutes approximately 35% of the total operational cost of GWCL. In determining electricity cost for GWCL for the 2019-2020 tariff period, the Commission took into consideration approved electricity tariffs effective July 01, 2019 for the 2019-2020 Major Tariff Review. This resulted in an increase in GWCL's total electricity cost of GHS319.63 Million including Befesa's electricity cost of GHS 52.44Million.

9.2.3 Return on GWCL Assets

The Commission granted GHS59.19 Million as return for GWCL's regulated asset base representing 1.11% of GWCL Revalued Net Fixed Asset. This is to enable GWCL meet its loan obligations.

9.2.4 Depreciation

The Commission approved an amount of GHS230.81 Million to cover depreciation expense to be recovered directly from GWCL tariffs. In that regard, the Commission considers depreciation as a cash-flow item that is available to GWCL in excess of its operational expenses to enable it to undertake critical capital expenditure.

9.2.5 Non-collectible Revenue (NCR)

The Commission allowed an amount of GHS 25.31 Million, representing 2% of GWCL's ARR as provision for non-collectible revenue.

10.0 CONCLUSIONS AND RECOMMENDATION

In this decision paper, tariff proposals submitted by Utility Service Providers in the natural gas, electricity and water supply industries - Ghana National Gas Company Limited, Volta River Authority (VRA), Ghana Grid Company Limited, Power Distribution Services Ghana Limited (PDS), Northern Electricity Distribution Company Limited (NEDCo), Enclave Power Company Limited (EPC) and Ghana Water Company Limited (GWCL) to PURC, for consideration and approval of rates to be charged have been examined, analysed and results thereof approved by the Commission.

With respect to Natural Gas and Heavy Fuel Oil (HFO) as fuel for generation of electrical energy for the 2019-2020 tariff period, the Commission approved a US$ 6.08/MMBtu as the Weighted Average Delivered Price of Gas and US$ 390/Metric Tonne for HFO.

In terms of power purchases, the Commission approved a Composite Bulk Generation Tariff of GHp 45.2493/kWh taking into consideration total electrical energy volume of 13,481 GWh to be supplied to the regulated electricity market by both VRA and selected Independent Power Producers (IPPs) power plants under bilateral contract agreements with ECG for the 2019-2020 Major Tariff Review Period.

Also presented in this tariff decision are Transmission Service Charge-1 and Transmission Service Charge-2 (TSC-1 and TSC-2) as well as Distribution Service Charge-1, Distribution Service Charge-2 and Distribution Wheeling Charge (DSC-1, DSC-2 and DWC) as approved by the Commission for the 2019-2020 tariff period.

The overall effect in terms of total revenue requirements hence rates payable by electricity consumers over the 2019-2020 Major Tariff Review Period is an increase of 11.17% over the 2018 Gazetted tariffs across board for all categories of consumers effective July 01, 2019.

With regards to water, two key decisions have been taken by the Commission as presented in this report. These are restoration of GWCL's July 15, 2018 approved water tariffs (10.08%), and an increase of 8.01% over the July 15, 2018 water tariffs. This increase is across board for all water consumers and tended to recover the effects of projected inflation and exchange rate depreciation on the operations of GWCL over the tariff period.

As a recommendation, and in line with regulatory target, Utility Service Providers costs should endeavor to operate within approved regulatory costs so as enhance their liquidity and profitability.

Also, Utility Companies should work assiduously to improve their operational efficiency and bring their technical, commercial and collection losses within approved targets.

Specifically, the following recommendations are put forward for the benefit of Utility Service Providers, Government and Consumers.

A. Utility Service Providers

1. Utility companies must ensure their expenditures are within the annual revenue requirements approved by the PURC
2. PDS and NEDCo should take steps to aggressively reduce system losses
3. Increase efforts at revenue collection/mobilisation in order to enhance liquidity at all times
4. Rationalise staff recruitment and expenditure
5. Prioritise capital investments

6. Take steps to improve quality of service delivery in respect of minimizing interruptions and duration when they occur

B. Government

1. Government should put in place a sustainable arrangement to ensure it honours its financial obligations to the utility companies particularly in respect of the electricity bills of MDAs and other associated government entities
2. Rationalise fuel procurement and pricing for power generation.
3. Ensure full implementation of government's decisions regarding the rationalisation of power purchase agreements (PPAs).

C. Consumers

1. Ensure prompt payment of bills
2. Report illegal connections and theft of power

APPENDIX 1 - KEY ASSUMPTIONS

Summary of Assumptions Used in Tariff Determination

Item	Measure	Value
Fuel Price:		
Natural Gas	US$/MMBtu	6.08
HFO (Including In-Plant Handling, Treatment & Related Fees)	US$/Metric Tonne	390
Macro-Economic Variable:		
Exchange Rate	GHS/US$	5.05
Inflation Rate	%	8
Hydro Allocation:		
Akosombo GS	GWh	2,647
Kpong GS	GWh	504
Total	GWh	3,151
System Losses:		
Average Transmission System Losses	%	4.1
Average Distribution System Losses	%	22.6
Collection Loss Ratio	%	2

APPENDIX 2 - REQUEST FOR SUBMISSION

PUBLIC UTILITIES REGULATORY COMMISSION

Public Input for the 2019 Major Tariff Review

In accordance with the Public Utilities Regulatory Commission Act, 1997 (Act 538), the PURC has initiated processes for the examination and approval of electricity and water tariffs for 2019-2020. During the review the Commission will examine proposals to be submitted by utility companies. Interested organisations, groups and the general public are hereby invited to submit any inquiries or representations in respect of review of tariffs to the addresses below by December 2018:

1. Public Utilities Regulatory Commission
   No. 53 Liberation Road 2nd. Floor, Olympic Committee Building
   Ridge, Accra

2. Public Utilities Regulatory Commission
   P. O. Box CT3095 Cantonments, Accra.
   E-mail: info@purc.com.gh Tel: +233 302 244181-3 +233 504434200

List of Entities which Submitted Written Inputs for 2019-2020 Tariff Review

1. Trade Union Congress (TUC)
2. Association of Ghana Industries (AGI)
3. Africa Centre for Energy Policy (ACEP)
4. Ghana Institute of Management and Public Administration (GIMPA)
5. Electoral Commission (EC)
6. Private Enterprise Federation (PEF)
7. Ghana Journalists Association (GJA)
8. Vice Chancellors Ghana (VCG)
9. Central University (CU)
10. Ministry of Energy (MoE)

Major Joint Consultative Meeting with Utility Companies and Stakeholders

Alisa Hotel, Accra

January 14, 2019

List of Institutions which attended the program:

1. Central University College
2. Association of Ghana Industries (AGI)
3. Trade Union Congress (TUC)
4. Telecom chamber
5. Central University College
6. Association of Ghana Industries (AGI)
7. Integrated Social Development Centre (ISODEC)
8. Africa Centre for Energy Policy (ACEP)
9. Media General
10. Energy Commission
11. Imani Ghana
12. Private Enterprise Federation (PEF)
13. Trade Union Congress (TUC)
14. Consumer Protection Agency (CPA)
15. Ghana Journalist Agency (GJA)
16. Freelance
17. Select Committee on Mines & Energy
18. Ghana Grid Company (GRIDCo)
19. Northern Electricity Distribution Company (NEDCO)
20. Power Distribution Services Ghana Limited (PDS)
21. Electricity Company of Ghana (ECG)
22. Ghana Water Company Limited (GWCL)
23. Enclave Power Company Limited
24. Volta River Authority (VRA)

APPENDIX 3 - RATES

ELECTRICITY RATES EFFECTIVE JULY 01, 2019

Tariff Category	Effective 1 July 2019
First Schedule	
BGC VRA - (GHp/kWh)	29.0370
Composite BGC (VRA and IPPs) - (GHp/kWh)	45.2493
Second Schedule	
TSC 1 - (GHp/kWh)	5.5172
TSC 2 - (GHp/kWh)	1.9340
Third Schedule	
DSC 1 - (GHp/kWh)	16.0346
DSC 2 - (GHp/kWh)	14.8920
DWC - (GHp/kWh)	30.9266
Fourth Schedule	
Residential	
0-50 (GHp/kWh)	30.7780
51-300 (GHp/kWh)	61.7488
301 – 600 (GHp/kWh)	80.1380
601+ (GHp/kWh)	89.0422
Service Charge:	
Lifeline Consumers (GHp/month)	213.0000
Other Residential Consumers (GHp/month)	703.8906
Non-Residential	
0-100 (GHp/kWh)	75.3210
101-300 (GHp/kWh)	75.3210
301 – 600 (GHp/kWh)	80.1496
601+ (GHp/kWh)	126.4657
Service Charge (GHp/month)	1173.1511
SLT-LV	
Energy Charge (GHp/kWh)	98.8591
Service Charge (GHp/Month)	4692.6045
SLT-MV	
Energy Charge (GHp/kWh)	75.0589
Service Charge (GHp/Month)	6569.6464
SLT-HV	
Energy Charge (GHp/kWh)	78.7776
Service Charge (GHp/Month)	6569.6464
SLT-HV MINES	
Energy Charge (GHp/kWh)	249.1721
Service Charge (GHp/Month)	6569.6464

WATER RATES EFFECTIVE JULY 01, 2019

Category of Service	Approved Rates in GHp / 1000 Litres (Effective 1 July 2019)
Metered Domestic:	
0-5 (Exclusive)	322.05
5 and above	548.04
Commercial	902.99
Industrial	1087.68
Public Institutions /Government Departments	703.05
Premises without connection (Public stand pipes) per 1000 litres	361.42
Special Commercial	5485.74
Sachet Water Producers	1210.81
GHAPOHA (Internal Usage)	902.99
GHAPOHA (Ocean Going Vessels)	12313.42

Note

Special Commercial refers to bulk customers who use GWCL treated water as the main raw material for bottling water for resale.