TARIFF REVISION PROPOSAL

JULY 2022 TO JUNE 2025

BHUTAN POWER CORPORATION LIMITED

March 2021

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1. Background

The prevailing tariff of Bhutan Power Corporation Limited (BPC) as shown in Table 1 below was approved by the Bhutan Electricity Authority (BEA) for the period 1st October 2019 to 30th June 2022.

Table 1: Existing Approved Tariff

Tariff structures	Units	1st October 2019 to 30th June 2020	1st July 2020 to 30th June 2021	1st July 2021 to 30th June 2022
Low Voltage				
Block I (Rural) 0-100 kWh	Nu/kWh	0	0	0
Block I (High landers) 0-200 kWh	Nu/kWh	0	0	0
Block I (Others) 0-100 kWh	Nu/kWh	1.28	1.28	1.28
Block II (All) 101-500 kWh	Nu/kWh	2.68	2.68	2.68
Block III (All) > 500 kWh	Nu/kWh	3.57	3.6	3.64
LV Bulk	Nu/kWh	4.06	4.1	4.14
Medium Voltage (MV)				
Energy Charge	Nu/kWh	2.24	2.45	2.65
Demand Charge	Nu/kVA/month	325	325	325
High Voltage (HV)				
Energy Charge	Nu/kWh	1.5	1.5	1.5
Demand Charge	Nu/kVA/month	292	292	292
Wheeling Charges	Nu/kWh	0.27	0.27	0.27

The tariff is revised every 3 years, and according to the Tariff Determination Regulation (TDR) 2016 of the Bhutan Electricity Authority (BEA), a licensee for transmission and distribution is required to submit application for a revised tariff schedule at least four months prior to the expiry of the current tariff period. An extension to file the tariff on 8th March 2022 was sought from BEA vide letter No. 16/BPC/CEO/BEA/2022/37 dated 28th February 2022.

2. Rationale for Tariff Revision

Bhutan Power Corporation Limited is implementing work programs for capital investments, which are in line with the BPC's Five Year Plans (FYP). BPC envisages an investment of over Nu. 14.659 billion to build the commensurate infrastructure in providing reliable and quality services. The key drivers of investments are; infrastructure expansion and upgradation to meet the increasing demand, infrastructure replacement due to old age or technological obsolescence and infrastructure upgradation to improve reliability and reduce technical losses. Investments also have to be made to modernise the Grid by leveraging automation and digitalization.

In addition, BPC has to incur operation and maintenance expenditures considering the significant expansion of the distribution network and addition of transmission assets.

The tariff revision proposal is worked out to cover and meet the allowed costs and returns in the forthcoming tariff period.

3. Methodology

This tariff revision proposal is based on the Tariff Determination Regulation (TDR) 2016 and Domestic Electricity Tariff Policy (DETP) 2016. Bhutan Electricity Authority's (BEA) Distribution Tariff model, which is based on the cost of supply methodology, has been used to determine the end user tariff. In addition, in light of the increase in domestic power consumption due to considerable power import to meet domestic HV demand, and considering the national energy security imperatives - electricity to substitute use of fossil fuels at household levels, the need felt to moderate the prevailing power tariff of the LV category, the tariff restructuring possibilities are also covered in the proposal. Towards this end, the proposal highlights some of the restructuring requirements to address the changing power system scenario of Bhutan. Under the guidance of the BPC Board, the rationale for changes in tariff parameters are detailed in the subsequent sections.

For determining the end user tariff, the following are the major assumptions made:

1. The current power purchase price of Nu 1.50/kWh has been considered. This price will change as the generation tariff is reviewed separately. Any revision in the power purchase price will change the proposed tariffs since the Regulation allows power purchase cost to be treated as pass-through cost. The Authority may consider making changes in the power purchase price while determining the final domestic tariffs.
2. There has been no import of power from the distribution line from West Bengal State Electricity Board (WBSEB) and Assam State Electricity Board (ASEB) since 2020.
3. The import of power in each tariff period is forecasted.

4. The import of power for the HV Customer is considered by the DGPC and settled through a separate mechanism. BPC has not considered any cost for the import of power.
5. The generation from Tangsibji Hydro Energy Limited (THyE) has been considered for computation of wheeling charges from mid-2023.
6. Currently, the wheeling charge is applied only for the net exported energy. Since the energy import is quite substantial as experienced during the import of power from January 2022, the wheeling charge on the imported energy has been determined and included in the HV tariff for consideration by the BEA.
7. BPSO is to be delinked from BPC in keeping with provisions of Electricity Act, 2001. Only 50% of the operation and maintenance and capital cost are considered as per the System Operator Charges Regulation 2022.
8. Embedded Generation shall be transferred to DGPC and any related costs are excluded from tariff calculation.

4. Salient features of the tariff proposal

The salient features of the tariff proposal are presented below:

4.1 Allocation Factor

The Power Scenario of Bhutan has undergone a major shift with demand growth especially with the industrial sector outpacing the capacity addition, and we are already experiencing instances of net-import during the lean generation months and this scenario is not only projected to continue but increase over the years. The upcoming High Voltage industries are expected to propel unprecedented acceleration in the demand growth. The Medium Voltage industries are projected to be established in the Industrial Parks which are in the advanced stages of construction. Therefore, the asset allocation factors are reworked to reflect the changed utilisation of the system by these significant demand growths.

4.2 Import of Power

With strengthening of internal distribution systems, BPC has curtailed import. There has been no import from the distribution line from West Bengal State Electricity Board (WBSEB) and Assam State Electricity Board (ASEB) since 2020.

However, going forward, due to the import of power required for the HV customers during the lean lean period when the domestic generation is not adequate to meet domestic demand, the quantum of energy required is forecasted. Since the import is arranged by DGPC and settled through a separate mechanism, the import tariff rate has not been considered.

4.3 Customer Category

Presently, there are four major customer categories:

I. Wheeling
II. HV (High Voltage) customers
III. MV (Medium Voltage) customers and
IV. LV (Low Voltage) customers

The wheeling charge is applied for exported energy. In keeping with provisions of extant policies and laws, the transmission loss on the energy import has been determined to reflect the actual cost of delivery of supply and included in the HV cost f.

4.4 Separate Wheeling Tariff

While the present tariff regulations allow only one wheeling tariff which is a weighted tariff of the generating plants, separate wheeling tariffs for existing plants prior to commissioning of Mangdechu Hydroelectric Project (MHP) and after MHP have been worked out and considered. This is to reflect the actual cost and implications on wheeling charges with the addition of Generation Plants and associated transmission system. As more generation plants get added to the system, such a mechanism is key to reflect the actual wheeling costs attributable to each generating station. As such the export tariffs are generally determined at the delivery points (Bhutan-India border) that includes the cost of ATS and also to avoid any cross subsidy between old and new hydropower plants wherein the former has to pay disproportionately to its export tariff.

4.5 Demand Charge Application

In the prevailing tariff, only 90-100% of capacity-related costs for HV customers and 60-100% of the capacity-related costs for MV customers are recovered by BPC through the demand charge. BPC has consistently requested the BEA to allow recovering 100% of capacity-related costs through demand charges for both the HV and MV customers for full recovery of the investments.

Therefore, the minimum level of demand, presently being considered by BEA, requires a serious review to consider the full contracted demand for recovery of the network cost. BPC makes the full investment and not allowing the full recovery of investment through the demand charge results in under recovery of the investment. This, along with fixing the demand charges to cover the network costs, would ensure that the HV and MV customers would not seek for more demand than their actual requirement and thus curtailing the hoarding of power.

5. Weighted Average Cost of Capital (WACC)

5.1 Cost of Equity (CoE)

As per Clause 7.2 of DETP, the CoE shall be based on the average lending rate of the domestic financial institutions and BEA may allow a reasonable premium up to a maximum of 250 basis points on the average lending rates of the financial institutions depending on the domestic market situation and gearing ratio applied.

From the various loans offered by the domestic financial institutions, the Industrial/Manufacturing loan is found to be relevant to BPC. Therefore, present lending rates on Industrial/Manufacturing Loan of all the financial institutions of Bhutan are presented in Table 2 and attached as *Annexure 1*.

Table 2: Lending Rates of Financial Institutions

Sl. no.	Financial Institution	Types of Loan	Interest Rate	Term (Years)
1	Bank of Bhutan Ltd (BoBL)	Manufacturing-Hydropower/Renewable energy	9.87%	20
2	Bhutan Development Bank Ltd (BDBL)	Manufacturing/Industrial Loan	11.80%	10
3	Bhutan Insurance Ltd (BIL)	Manufacturing/Industrial Loan	12.00%	10
4	Bhutan National Bank Ltd (BNBL)	Manufacturing/Industrial Loan	11.88%	10
5	National Pension & Provident Fund (NPPF)	Member Home Loan	9.00%	30
6	Druk Punjab National Bank Ltd (DPNBL)	Manufacturing/Industrial Loan	11.50%	15
7	Royal Insurance Corporation of Bhutan Ltd (RICBL)	Industrial term loan Manufacturing Industry	12.00%	10
8	Tashi Bank Ltd (TBL)	Manufacturing and Industry	11.00%	15
Average Lending Rate			**11.13%**	

BPC would like to propose a CoE of 13.63%, a premium of 250 basis points on the average lending rates.

5.2 Cost of Debt (CoD)

The CoD has been calculated as the weighted average interest rate of the interest rates on existing as well as loans that are envisaged to be taken during the tariff period using the loan balance at the end of each year as per DETP.

BPC has existing loans for Rural Electrification Projects and the new Transmission Systems. For the Associated Transmission System (ATS) of MHPA, only Nu. 7,720.682 million pertaining to MHPA portion was capitalized and accounted in BPC's books in the earlier tariff period. The balance ATS cost of Nu. 4,979.46 million shall be taken over by BPC in 2022. The loan agreements are attached as *Annexure 2*.

Tangsibji Hydro-Electric Limited (THyE) loan for the 132 kV transmission line from Nikachu till MHPA pothead yard is considered to be taken over by BPC from 2023. The Principal loan amount and Interest during Construction (IDC) as at 30th June 2022 is included in the CoD calculation.

For the computation of the COD, the investments during the proposed tariff period have been considered to be financed through a mix of 50% debt and 50% equity to reduce the interest costs.

Thus, the total loan considered for determining the weighted interest rate for the tariff period is given in Table 3.

Table 3: Total Loan

Sl.No	Loan particulars	Interest rate	Loan Balance as of (M Nu.)			
			2021	2022	2023	2024
1	RE I	6.00%	116.26	107.95	99.65	91.34
2	RE II	6.00%	183.26	164.93	146.61	128.28
3	RE III	6.00%	255.20	236.97	218.74	200.51
4	RE IV	6.00%	916.36	869.36	822.37	775.38
5	RE V	6.00%	732.26	698.20	664.14	630.08
6	RE JICA I	0.01%	1,728.82	1,661.02	1,593.22	1,525.43
7	RE JICA II	0.01%	775.36	746.64	717.93	689.21
8	NPPF Loan	9.00%	941.10	860.55	773.12	678.48
9	ADA LOAN	0.70%	209.32	183.15	156.99	130.82
10	MHPA loan	10.00%	5,404.48	5,404.48	5,237.72	5,053.87
11	ThyE loan	9.00%		802.70	775.80	746.41
12	CHEL	10.00%		1,485.10	1,439.28	1,388.76

Sl.No	Loan particulars	Interest rate	Loan Balance as of (M Nu.)			
			2021	2022	2023	2024
13	KHEL	10.00%		1,066.87	1,033.95	997.65
14	Puna II	10.00%		371.77	360.30	347.65
15	Future loan	9%		2,065.19	1,758.13	722.23
16	Nikachu 132 KV	11.55%			597.29	581.12
Total			**11,262.40**	**16,724.88**	**16,395.22**	**14,687.23**
Annual Cost of Debt			**6.74%**	**7.74%**	**7.88%**	**7.83%**

Accordingly, the CoD is calculated for each customer category and provided in *Annexure 3.*

The allocation of loans for different customer categories are given in Table 4, Table 5, Table 6 and Table 7.

Table 4: CoD for Wheeling

Sl. No	Loan particulars	Interest rate	Loan Balance as of (M Nu)				CoD for Wheeling
			2021	2022	2023	2024	
1	MHPA Loan	10.00%	2786.59	2786.59	2,700.61	2,605.82	9.94%
2	ThyE loan	9.00%	-	802.70	775.80	746.41	
3	CHEL	10.00%	-	765.73	742.10	716.05	
4	KHEL	10.00%	-	550.08	533.11	514.40	
5	Puna II	10.00%	-	191.69	185.77	179.25	
6	Future loan	9.00%	-	206.51	175.81	72.22	
7	ADA loan	0.70%	-	-	-	-	
8	ThyE 132kV	11.55%		-	597.29	581.12	
Total			**2,786.59**	**5,303.31**	**5,710.49**	**5415.27**	
Annual cost of Debt			**10.00%**	**9.81%**	**10.00%**	**10.02%**	

Table 5: CoD for HV

Sl. No	Loan particulars	Interest rate	Loan balance as of (M Nu.)				CoD for HV
			2021	2022	2023	2024	
1	NPPF Loan	9.00%	941.10	860.54	773.11	678.48	9.70%
2	MHPA loan	10.00%	2,617.88	2,617.88	2,537.11	2,448.05	
3	Future loan	9.00%	-	1239.11	1054.78	433.33	
4	CHEL	10.00%	-	719.37	697.17	672.70	
5	KHEL	10.00%	-	516.78	500.84	483.26	
6	Puna II	10.00%	-	180.08	174.52	168.40	
Total			**3,558.98**	**6,133.77**	**5,737.63**	**4,884.22**	
Annual cost of Debt			**9.74%**	**9.66%**	**9.68%**	**9.77%**	

Table 6: CoD for MV

Sl. No	Loan particulars	Interest rate	Loan balance as of (M Nu.)				CoD for MV
			2021	**2021**	**2021**	**2021**	
1	ADA LOAN	0.70%	106.75	93.40	80.06	66.71	**3.33%**
2	Future loan	9.00%	-	206.51	175.81	72.22	
3	RE I	6.00%	29.05	26.97	24.90	22.82	
4	RE II	6.00%	45.79	41.21	36.63	32.05	
5	RE III	6.00%	63.76	59.21	54.65	50.10	
6	RE IV	6.00%	228.96	217.22	205.48	193.74	
7	RE V	6.00%	182.96	174.45	165.94	157.43	
8	RE JICA I	0.01%	431.96	415.02	398.08	381.14	
9	RE JICA II	0.01%	193.73	186.56	179.38	172.21	
Total			**1,282.95**	**1,420.55**	**1,320.92**	**1,148.42**	
Annual cost of Debt			**2.64%**	**3.55%**	**3.46%**	**2.99%**	

Table 7: CoD for LV

Sl.No	Loan particulars	Interest rate	Loan balance as of (M Nu.)				CoD for LV
			2021	**2021**	**2021**	**2021**	
1	RE I	6.00%	56.75	52.70	48.64	44.59	**3.43%**
2	RE II	6.00%	89.46	80.51	71.57	62.62	
3	RE III	6.00%	124.57	115.68	106.78	97.88	
4	RE IV	6.00%	447.32	424.38	401.44	378.50	
5	RE V	6.00%	357.45	340.83	324.20	307.58	
6	RE JICA I	0.01%	843.93	810.83	777.74	744.64	
7	RE JICA II	0.01%	378.49	364.48	350.46	336.44	
8	ADA LOAN	0.70%	102.56	89.74	76.92	64.10	
9	Future loan	9.00%	-	413.03	351.62	144.44	
Total			**2,756.71**	**2,691.65**	**2,508.87**	**2,180.32**	
Annual cost of Debt			**2.46%**	**3.67%**	**3.57%**	**3.07%**	

5.3 Gearing Ratio

As per Clause 72 of the TDR, gearing ratio is the ratio of debt to total net assets and is determined for each customer category. BPC's actual overall gearing is 42.92% for 2021. As a separate WACC is required to be calculated for each customer category, the calculated gearing for each customer category is tabulated in Table 8 and the detail is attached as *Annexure 3.*

As per Clause 7.1 of DETP, gearing ratio for computation of WACC should be higher than actuals up-to a maximum of 70:30. The average gearing ratio for export is 96.97% but a maximum of 70% has been proposed as allowed by the TDR. A ratio of 60% for the HV has been proposed, the same percentage as approved in the tariff period of 2019-2022.

The gearing ratios for MV and LV are proposed at 70%.

Table 8: Gearing ratio

Parameters	Customer Category			
	Export/Wheeling	**HV**	**MV**	**LV**
Gearing (Actual)	96.97%	32.29%	38.68%	26.52%
Gearing (Proposed)	70.00 %	60.00 %	70.00 %	70.00 %

5.4 Tax rate

The tax rate is maintained at a statutory corporate tax rate of 30% as prescribed in Section 45, Chapter 49 of the Income Tax Act of the Kingdom of Bhutan, 2001.

5.5 WACC

The WACC is calculated using the formula given below:

$$WACC = \frac{CoE(1 - Gearing)}{1 - Tax} + (CoD\ X\ Gearing)$$

The WACC for each customer is given in Table 9.

Table 9: WACC for Customer Categories

Parameters	Customer Category			
	Export/Wheeling	**HV**	**MV**	**LV**
Gearing (Actual)	96.97%	32.29%	38.68%	26.52%
Gearing (Proposed)	70.00 %	60.00 %	70.00 %	70.00 %
CoE	13.63%	13.63%	13.63%	13.63%
CoD	9.94%	9.70%	3.33%	3.43%
Tax	30.00%	30.00%	30.00%	30.00%
WACC (Actual)	**10.23%**	**16.32%**	**13.23%**	**15.22%**
WACC (Proposed)	**12.80%**	**13.61%**	**8.18%**	**8.25%**

6. Operation and Maintenance Costs (O&M)

6.1 Historical O&M cost

The historical O&M costs in the past tariff period is given in the "Input Sheet" of the Application and the same is given in Table 10. The detailed calculation of O&M cost is attached as *Annexure 4.*

Table 10: Historical O&M Cost of BPC

O&M Cost (Nu. Million)	2019	2020	2021
Generation	-	-	-
Transmission	382.42	441.24	461.56
Distribution	813.11	850.76	1,064.77
Other	591.02	829.9	419.08
Total (Nu. Million)	**1,786.54**	**2,121.90**	**1,945.41**

The O&M costs are arrived at after deducting non-allowable costs such as Corporate Social Responsibility (CSR), Licensee fee to BEA (accounted under regulatory fees), Fines and Penalties, Management fee for Holding Company. The foreign exchange fluctuations (gain/losses) are also excluded.

Further the O&M costs exclude the following O&M received from other agencies to operate and maintain infrastructure:

i) Historical O&M cost excludes the historical O&M costs of Embedded Generation as the asset will be taken over by DGPC.
ii) Historical O&M of BPSO as the O&M cost is allocated as per system operator regulation fees.
iii) O&M budget for Fiber Network Division (FND) provided by the Department of Information Technology and Telecom (DITT), Ministry of Information and Communication (MOIC) for the use of 18 fibers (75%) out of 24 fibers. The O&M cost of the remaining 6 fibers is included in BPC.
iv) O&M fund received from Punatsangchu Hydro Project Authority (PHPA)-I to maintain PHPA-I 400 kV lines.
v) O&M fund from Punatsangchu Hydro Project Authority-II to maintain PHPA-II kV lines.
vi) O&M fund from Kholongchu Hydro Electric Project (KHEP) for Corlung substation.

6.2 Inflation

As per DETP, the inflation to be used for O&M expenses shall be based on historical average inflation rates published by the National Statistics Bureau (NSB).

The inflation rates based on historical inflation rates as per National Statistical Bureau is considered as given in Table 11 and attached as *Annexure 5.* Inflation for the next three years has been based on the average of the past three years for the non-food items.

Table 11: Inflation

Year	2019	2020	2021
Inflation figures	2.24%	1.24%	5.62%
Average Inflation: 3.03%			

6.3 Benchmark O&M Costs for New Assets

The O&M for new assets under each asset category determined as per the benchmarks is as shown in the Table 12 and attached as *Annexure 6*.

Table 12: Benchmark O&M for New Asset

Benchmark O&M		**2022**	**2023**	**2024**	**2025**
Microhydel	2.50%	-	-	-	-
Diesel generation	10.00%	2.57	0.10	0.30	0.50
Transmission	1.00%	59.41	37.00	5.52	2.21
Distribution	3.00%	51.04	20.19	19.26	9.78
Other	2.00%	1.18	0.94	0.54	0
Total		**114.20**	**58.23**	**25.62**	**12.49**

6.4 O&M Efficiency Gains

The model for tariff allows the O&M costs to increase yearly by inflation less than the target set for improvements in efficiency gains. BPC has proposed an efficiency gain of 2% as required by BEA.

7. Regulatory Fees

As per the Fees and Charges of the Regulatory Fees Regulation 2006, the license fee for transmission and distribution is calculated at 0.2% of revenues from sale of electricity. Therefore, based on the annual revenue calculated for the upcoming tariff, the regulatory fee is given in Table 13.

Table 13: Annual Regulatory Fees

Year	**2022**	**2023**	**2024**
Annual Licence Fees (M Nu.)	**28.50**	**33.08**	**35.07**

The tariff application fee of Nu.16.11 million, calculated as 0.1% of the average revenue as per the regulation, has been included as part of the regulatory fee as all fees are excluded in the O&M cost.

8. System Operator Charges

The Bhutan Power System Operator (BPSO) has proposed System Operator charges as per the System Operator Charges Regulation 2022. According to the regulation, the transmission and distribution licence will be allocated 50% of the total cost of the System Operator.

BPC has included only 50% of the total charges proposed by BPSO as per the regulation. The BEA may consider making changes after finalization of the total charges of the System Operator.

Table 14: System Operator Charges

Year	2022	2023	2024
System Operator cost	198.69	327.57	126.27
50% of the cost	99.35	163.79	63.14

The system operator charges are proposed to be allocated equally between the Export and HV customer category.

9. Asset Values and Depreciation

The gross and net asset value, lifetime, accumulated, and annual depreciation for the year 2021 is given in Table 15 and is attached as *Annexure 7 & 7A*. The asset values and depreciation have been calculated using BPC's depreciation rates which is the same as that specified by the Tariff Determination Regulation 2016.

As per the letter no. DHI/BOARD/2022/15 dated 4th January, 2022, the Board approved the transfer of BPCs embedded generation assets to DGPC and directed that the transfer may be treated as the sale of assets to DGPC. Therefore, the transferable generation assets are segregated and only those assets not fully related to generations are retained and included in the net assets of BPC. The net asset of Nu. 258.738 million is considered to be transferred to DGPC. Similarly, with the delinking of BPSO, the BPSO asset value of Nu. 21.43 million is excluded from the BPC asset.

BPC received a letter from Dagachhu Hydropower Plant Corporation (DHPC) to take over the distribution system, which is estimated at Nu.27.83 million (net value) and the same is included in the BPC's net asset.

The Guideline for determination of Regulatory Asset Base 2021 specifies that for existing Licensees, the historical cost of assets based on audited accounts as of 31st December 2021 shall be considered. Hence, the Asset Base as on 2021 taking into account the above changes are considered.

Table 15: BPC Net Asset as of 2021

Asset Particulars	Gross Value	Acc. Dep	Net Value	Dep
Building and Land	4,225.63	1,120.56	3,105.06	142.95
Generation	124.94	38.50	86.45	46.22
Transmission	22,057.32	5,217.18	16,840.14	717.16
Distribution	11,700.62	4,009.67	7,718.78	374.97
Others	2,181.67	1,295.83	762.28	151.17
Total (Nu. Million)	**40,290.18**	**11,681.74**	**28,512.71**	**1,432.47**

10. Investments

The investments for the upcoming tariff period are derived from the Approved Investment Plan for the period 2021-2025. However, there are additional investments, beyond the Approved Investment Plan which was submitted to BEA, that have been included in the proposed tariff cycle.

As per the Standard Operating Procedure for Transmission System Expansion, techno-economic clearance for expansion/reinforcement after 1st July 2021 are required to be obtained from the Department of Hydropower and Power Systems (DHPS), Ministry of Economic Affairs (MoEA).

BPC submitted the Investment plans for transmission system to DHPS, MOEA and the techno-economic clearance was received via letter no. 19/DHPS/PSD/2020-2021/688 on 28th February 2022. The letter is attached as Annexure 9A.

10.1 Approved Investment Plan 2021-2025

The approved investment plan for 2021-2025 and the capitalization of the investments are used to calculate the net asset addition for each year under each asset category. The detail list is attached as *Annexure 8 & 9*. The Net Asset Addition during the year is shown in Table 16.

Table 16: Net Asset Addition

Year	2021	2022	2023	2024	2025
Buildings & land	**80.97**	**263.04**	**166.42**	**97.00**	**28.50**
Land	0.00	0.00	0.00	0.00	0.00
Buildings	80.97	240.56	149.63	97.00	28.00
Civil structures	0.00	22.48	16.79	0.00	0.50
Generation	**1.70**	**25.65**	**1.00**	**3.01**	**5.00**

Year	2021	2022	2023	2024	2025
Civil structures	0	0	0	0	0
Electro-mechanical	0	0	0	0	0
Mini & micro hydel	0	0	0	0	0
Diesel generator sets	1.7	25.65	1	3.01	5
Transmission	**325.10**	**5941.15**	**3700.41**	**551.50**	**221.11**
Civil structures	0.00	0.00	0.00	0.00	0.00
400+ kV lines	0.00	3278.46	0.00	0.00	0.00
220 kV lines	0.00	77.14	556.00	0.00	0.00
132 kV lines	3.39	41.35	597.29	0.00	0.00
66 kV lines	201.43	0.00	19.00	0.00	0.00
Substations	120.28	2544.21	2528.12	550.00	221.11
Meters	0.00	0.00	0.00	1.50	0.00
Distribution	**705.81**	**1701.37**	**672.84**	**642.04**	**325.96**
Civil structures	9.09	0.00	35.89	0.00	0.00
33 kV lines	383.58	668.83	322.28	153.76	109.19
11 kV lines	67.74	43.70	91.64	14.28	48.01
6.6 kV lines	0.00	0.00	0.00	0.00	0.00
LV lines	7.06	22.14	32.54	71.07	12.06
Substations & transformers	198.11	966.70	93.94	306.38	60.15
Meters	40.22	0.00	96.55	96.55	96.55
Vehicles	**69.15**	**169.8**	**138.99**	**37.00**	**14.40**
Heavy vehicles	24.20	32.10	7.20	3.00	1.50
Light vehicles	31.95	29.70	33.19	34.00	12.90
Tx Smartgrid Hardware	13.00	108.00	98.60	0.00	0.00
Tx Smartgrid software	0.00	0.00	0.00	0.00	0.00
Office equipment	**185.25**	**380.59**	**812.38**	**581.35**	**1682.39**
Computers & accessories	7.41	9.62	1.65	2.17	3.24
Printers	2.34	4.20	0.81	3.09	3.16
Dx Smart Grid Hardware	161.99	360.09	796.88	560.00	1670.00
Dx Smart Grid Software	0.00	0.00	0.00	0.00	0.00
Software	5.90	1.00	1.00	1.60	1.00
Telecomms	3.58	2.77	10.47	10.92	1.83
Other office equipment	0.60	0.72	0.30	2.03	0.79
Furniture & fixtures	3.41	2.19	1.28	1.54	2.36
Tools	**50.92**	**35.78**	**13.84**	**20.01**	**30.82**
Tools & plants	40.57	31.91	11.31	14.95	23.56
Firefighting equipment	0.00	2.41	2.41	2.49	2.18
Electrical equipment	10.35	1.46	0.12	2.57	5.09
Other assets	**119.8**	**58.97**	**47.05**	**27.24**	**0.05**
Total	**1,538.65**	**8,576.35**	**5,552.92**	**1,959.15**	**2,308.23**

The investments were further scrutinised and rationalised for the capitalization of assets during the upcoming tariff period in accordance with the guidelines of Regulatory Asset Base.

10.2 Additional investment

The following additional investments are also included in the investment for the tariff period.

10.2.1 Upgradation of existing 2X5 MVA, 66/33 kV transformers at Damji substation to 2 x 10 MVA, 66 /33 kV Transformers

The upgradation of the substation is being carried out to cater to additional load. The details of works and amount is given in Table 17.

Table 17: Upgradation of Damji Substation

Sl. No.	Project	BPC
1	Upgradation of existing 2X5 MVA, 66/33 kV transformers at Damji substation to 2 x 10 MVA, 66 /33 kV Transformers along with the associated works	**8,185,955.25**
2	Construction a 33 kV line from the 66 kV Damji substation to proposed site of Gyalsung Data Center	**4,555,036.20**
3	Addition 1No of 10MVA, 66/33kV Transformer	**14,057,500.00**
Total		**26,798,491.45**

10.2.2 Upgradation of existing 2X10 MVA, 220/33 kV transformers at Dagapela substation to 2X 40 MVA, 220/33 kV Transformers and upgradation of 33 kV VCB panel to 33kV GIS and associated works

The current 2x10MVA, 220/33kV transformers are not able to cater to the additional load. Hence, the substation is being upgraded to 2x40MVA, 220/33kV transformers, including the existing 33 kV VCB to 33 kV GIS along with associated works. The details of work is given in Table 18.

Table 18: Upgradation of Dagapela Substation

Sl. No.	Particulars	Amount
1	Upgradation of existing 2X10 MVA, 220/33 kV transformers at Dagapela substation to 2X 40MVA, 220/33 kV Transformers and upgradation of 33 kV VCB panel to 33kV GIS and associated works including 33 kV lines and ADSS cable.	**214,289,334.40**

10.2.3 Upgradation of existing 2X15 MVA, 132/33 kV transformers at Yurmoo substation to 2X 40MVA, 132/33 kV Transformers and upgradation of 33 kV VCB panel to 33kV GIS and associated works.

The existing 2x15MVA, 132/33kV transformers at Yurmoo substation are not able to cater to the upcoming additional load. Hence, the substation is being upgraded to 2x40MVA, 132/33kV transformers including existing 33 kV VCB to 33 kV GIS and associated works. The detail of works is given in Table 19.

Table 19: Upgradation of Yurmoo substation

Sl. No.	Particulars	Amount
1	Upgradation of existing 2X15 MVA, 132/33 kV transformers at Yurmoo substation to 2X 40MVA, 132/33 kV Transformers and upgradation of 33 kV VCB panel to 33kV GIS and associated works including 33 kV and ADSS	**161,170,186.03**

10.2.4 Construction of 3x80 MVA 220/33 kV, 2x30 MVA 220/66kV and 2 x 5 MVA 66/33kV GIS substation at Chumdo

The current 66kV Chumdo substation is only a switching substation which cannot cater to upcoming load at Jamjee. Therefore, to supply power to the upcoming load at Jamjee and growing loads of Thimphu, Haa & Paro Dzongkhags, construction of a 220/66/33kV new substation at Jamjee along with LILO of 220 kV D/C TL is being carried out. The details of work are given in Table 20. Under these works, construction of 3x80 MVA Transformer, 220/33 kV along with 33kV GIS Panels is for envisaged industrial load at Jamjee.

Table 20: Construction of 220kV GIS substation at Jamjee/Chumdo

Sl. No.	Particulars	Amount
1	Construction of 3x80 MVA 220/33 kV, 2x30 MVA 220/66kV and 2 x 5 MVA 66/33kV GIS substation along with associated works including 33 kV line and ADSS	**344,994,850.00**

10.3 Associated Transmission System (ATS) of Mangdechu Hydroelectric Project Authority (MHPA)

From the total cost of Associated Transmission System (ATS) of MHPA, only the partial cost of MHPA cost portion was capitalised and accounted in BPC's books in the earlier tariff period amounting to Nu. 7,720.682 million. The balance ATS cost of Nu. 4,979.46

million was not capitalised in the earlier tariff since the additional loan Agreement signed between GOI and RGOB (apportioned cost to JV projects) had provided a moratorium for repayment with interest in anticipating commissioning of JV projects and apportioned cost to Nikachhu and Punatsangchu Hydroelectric Project Authority (PHPA-II) although the complete ATS including jigmeling ICT has been taken over by BPC. The apportioned costs related to Chamkharchu Hydro Electric Project (CHEP), Kholongchu Hydroelectric Project Limited (KHEL) THyE and PHPA-II as provided in Table 21 will be capitalised in June 2022 since the assets i.e. ATS is being used for evacuating Mangdechhu power and Jigmeling ICT is catering industrial load, at debt-to-equity ratio of 70:30.

Table 21: MHPA ATS Costs

Sl. No.	Total Cost to completion (Nu. in Million)		IDC	Total Asset Cost (Cost +IDC)
1	**MHPA**	6,702.03	1,020.07	7,722.10
2	**CHEP**	1,841.26	280.31	2,121.57
3	**KHEL**	1,322.73	201.37	1,524.09
4	**THyEL**	696.65	106.05	802.7
5	**PHPA-II**	460.93	70.17	531.1
	Total	**11,023.60**	**1,677.97**	**12,701.57**

Further, the construction of 132kV line of THyE up to the pothead yard of MHPA has been completed and will be taken over by BPC in 2023. The total cost of the line is Nu.358.37 million. The transferable amount has been taken as a loan at the interest rate of 11.55%.

10.4 Service Cable

As per BEA's directives issued vide letter no. BEA/CEO/BPC/2021-22/148 dated 26th August 2021, Service cable to Low Voltage (LV) consumers at the time of supply release should be provided free to LV customers and recovered through consumer tariffs. BPC has estimated an amount of Nu. 95.55 million per year for the service cables for LV customers (only considered domestic households) based on expected number of customer growth and included for implementation from year 2023 onwards and kept 2022 for procurement of cables if approved in the tariff. However, as BEA is aware, LV customers also include bulk LV customers comprising large commercial enterprises and institutions. These customers require substantially higher investments as compared to an ordinary LV consumer and entails provision of higher capacity service cables as well as construction of substations. In view of the above further directive is sought for the application of provision of service cable to these LV bulk, institutions and large commercial customers.

11. Cost of working capital

11.1 Arrears

The arrears proposed are 35 days for HV, MV, and LV customers and 40 days for Wheeling. They are the same as approved by the BEA for the prevailing tariff period.

11.2 Inventory

For the forthcoming tariff period, the total inventory is Nu 568.76 million, which is the value reported as per the audited accounts of 31st December 2021.

As per Clause 75 of TDR, the allowance for the cost of working capital shall be determined as the interest on an allowance for working capital, where the allowance for working capital shall consist of an allowance for arrears and inventories. The interest is based on the prevailing lowest short term lending rate of financial institutions in Bhutan. The short-term lending rate of 9.97% of Bank of Bhutan is used to calculate the return on working capital.

12. Allocation Factor

As per the DEPT, the allocation factors for assets and associated costs like O&M costs, inventories, fees and levies shall be determined for the customer categories based on the following guidelines:

i) Where assets and associated costs are exclusively used by a particular customer category, the same shall be allocated fully to this customer category.

ii) Where assets and associated costs are for export purposes, the entire allocation shall be to the export category.

iii) Where generation, transmission and distribution assets and their associated costs are meant for joint usage by different customers, the allocation factor shall be based on capacity demand.

iv) From the above i), ii), and iii), weighted average allocation factors for all the customer categories shall be determined for allocating assets and associated costs that do not fall under the above three items.

The power utilisation scenario in Bhutan has undergone substantial changes with industry demand alone contributing over 80% of domestic load. To boost the economy, the Government is promulgating several new energy intensive HV Industries to be established in the country. BPC has already signed Capacity Reserve Charge Agreements with two Industries and expected to sign more with the Government having sanctioned power for several industries to be established at Jigmeling Industrial Estate. Similarly, several Medium Voltage Industries are projected to be established in the Industrial Parks under construction. Therefore, based on above scenarios, the asset allocation factors are re-examined and reworked to reflect the utilisation of the system by these growth centers.

12.1 Transmission Allocation Factor

Under the transmission assets, 400kV lines allocation are determined on the basis of the generation capacity and the 400kV substation capacity of Malbase and Jigmeling for use mainly by Industries. The substation capacity of Jigmeling and Malbase are allocated to HV as exports are done directly without requiring such ICT. The allocation factors for substations, 220kV, 132kV and 66kV transmission lines have been worked out by taking the contract demands of the HV & MV customer category including the future loads during tariff cycler and computing it against the peak load (for transmission substations) and line loading (for transmission lines) adjusted with future demand. For the LV category usage, load factor has been used on the peak demand to derive the allocation factor of HV Transmission systems.

Based on above, the calculated allocation factors for the transmission system are as shown in Table 22.

Table 22: Proposed allocation factors under each customer category for Transmission

Transmission	Existing				Proposed			
	Export	HV	MV	LV	Export	HV	MV	LV
Civil structures	36%	46%	6%	12%	22%	70%	5%	3%
400+ kV lines	99%	1%	0%	0%	52%	48%	0%	0%
220 kV lines	42%	58%	0%	0%	45%	55%	0%	0%
132 kV lines	18%	63%	4%	15%	0%	63%	29%	9%
66 kV lines	0%	37%	15%	48%	0%	88%	8%	4%
Substations	33%	51%	7%	9%	0%	90%	5%	5%
Meters	36%	46%	6%	12%	22%	70%	5%	3%
Transmission O&M	36%	46%	6%	12%	22%	70%	5%	3%

The allocation factors for civil structures, meters, O&M for transmission are determined from the weighted average allocation factors for all the customer categories.

12.2 Distribution Allocation Factor

The distribution assets (33kV & 11kV) are allocated to MV and LV customers. The contract demand of MV customers including the future load and the total average energy sales to LV customers converted to MW are used to determine the allocation factors for the distribution lines. Table 23 shows the allocation factor for MV and LV of the distribution assets.

Table 23: LV and MV allocation calculation

LV 2021	702	MU sales	
Calculation of MV and LV lines allocation			
Demand		**Capacity**	Allocation
MV	84.03	MW	51%
LV	80.14	converted to MW	49%
Total	**164.16**	**MW**	

For the 6.6 kV lines, the asset is fully allocated to the LV category. Similarly, the LV lines and distribution substations/transformers are allocated 100% to the LV category. The allocation factor for civil structures, meters and distribution O&M is determined from the weighted average allocation factors for MV & LV. The allocation factors for distribution assets are as shown in Table 24.

Table 24: Proposed allocation factors under each customer category for Distribution

Distribution	Existing				Proposed			
	Export	HV	MV	LV	Export	HV	MV	LV
Civil structures	0%	0%	14%	86%	0%	0%	21%	79%
33 kV lines	0%	0%	36%	64%	0%	0%	51%	49%
11 kV lines	0%	0%	36%	64%	0%	0%	51%	49%
6.6 kV lines	0%	0%	0%	100%	0%	0%	0%	100%
LV kV lines	0%	0%	0%	100%	0%	0%	0%	100%
Substations/transformers	0%	0%	0%	100%	0%	0%	0%	100%
Meters	0%	0%	14%	86%	0%	0%	21%	79%
Distribution O&M	0%	0%	14%	86%	0%	0%	21%	79%

12.3 Other assets

For the remaining assets that do not fall under transmission and distribution, the allocation factor is determined from the weighted average allocation factors for all the customer categories. The detailed calculation of proposed allocation factors is attached in *Annexure 10.*

13. Power Purchase

13.1 From Generating Companies (GENCOS)

The current power purchase price of Nu 1.50/kWh has been considered. The energy quantum and rate from DGPC plant and other generation plants will impact the power purchase price. As generation tariff is reviewed separately by the BEA, for the computation, any revision in the power purchase price will change the proposed tariffs since the Regulation allows power purchase cost to be treated as pass-through cost. As permitted by the regulation, any revision on the prevailing generation tariffs may be incorporated by the BEA. BPC, however, would like to highlight that under the current differential generation tariff of MHPA, when the domestic consumption exceeds the prescribed quantum, it adversely impacts the weighted generation tariff for BPC. Similarly, for future projects, such circumstances would arise. Therefore, this needs to be addressed by BEA.

From the ongoing Hydropower Projects, the energy generation from the THyE has been considered from mid-2023. However, THyE has contracted 80% of energy through long term PPA with India and remaining 20% through short-term market. Therefore, the energy from THyE is not considered for domestic use. The energy purchase from GENCOS is given in Table 25.

Table 25: Energy Purchase from GENCOS

Energy Purchase from GENCOS (MU)			
Tariff Period	**2022/2023**	**20203/2024**	**2024/2025**
Energy to be purchased from GENCOS excluding import	4,424.44	5,373.72	5,775.09

No generations from PHPA-I and II are considered during the current tariff period since there is no certainty as to when the Projects will be commissioned. However, BEA may have to consider determining the generation tariff for sale of power for domestic consumption separately depending on the Government directives if projects get commissioned during the tariff cycle.

13.2 From Import

With strengthening of internal distribution systems, BPC has curtailed import through the distribution line from West Bengal State Electricity Board (WBSEB) and Assam State Electricity Board (ASEB) since 2020.

However, with demand outpacing the supply especially during lean months, the import of power from India has become a necessity. The deficit is proposed to be met through import of power during the lean season. The import is to be arranged by DGPC and settled through a separate mechanism. Therefore, the import cost is not included in the tariff calculation by BPC while the quantum of energy is forecasted to indicate the domestic demand.

Based on our energy forecasts, the annual import projection for the tariff period is given in Table 26.

Table 26: Energy Import Projection

Energy Import Projection (MU)			
Tariff Period	**2022/2023**	**2023/2024**	**2024/2025**
Energy Import	672.90	1,442.40	1,638.79

13.3 Total Energy Purchase

The total energy purchase projection for the tariff period is shown in Table 27.

Table 27: Total Energy Purchase Projection

Tariff Period	2022/2023	2023/2024	2024/2025
Energy to be purchased from GENCOS excluding import	4,424.44	5,373.72	5,775.09
Energy Import	672.90	1,442.40	1,638.79
Total Energy Purchase (MU)	**5,097.33**	**6,816.12**	**7,413.89**

14. Energy Sales Forecast

Energy sales for the tariff period 2022 - 2025 has been forecasted as under:

14.1 LV Customers

Energy sales has been forecasted for different categories of LV Customers using the Annual Compounded Growth Rate (CAGR) method.

14.2 MV Customers

Energy sales for the existing MV Customers has been forecasted individually using their average Load Factor (LF) and Power Factor (PF) of 0.85.

For upcoming MV customers, projected loads of Kholongchu HEP, Gyalsung project and the Industrial parks are considered. Although the Capacity Reserve Charge (CRC) agreements are not signed, the Industries list as per lease agreement signed with the Department of Industries for land allotment are considered from 2023 onwards.

14.3 HV Customers

For existing HV Customers, individual industries load factor (LF) and power factor (PF) have been considered to forecast the energy sales.

For the upcoming HV customers, the energy sales have been forecasted based on the contract demand signed with BPC, expected load at different times, appropriate LF and PF.

The overall energy sales forecast proposed under each customer category (LV, MV & HV Customers) is presented in Table 28.

Table 28: Energy Sales Forecast

Sl. No	Customer Category	2022/2023	2023/2024	2024/2025
1	High Voltage (HV)	3950.58	5356.86	5740.47
2	Medium Voltage (MV)	107.27	232.86	304.32
3	Low Voltage (LV)	665.61	701.65	739.72
	Total	**4,723.46**	**6,291.38**	**6,784.52**

Detailed calculations and assumptions made for the energy sales forecasts for each category of customer are included in *Annexure 11 A & B*.

15. Wheeling Forecast

The wheeling forecast for the forthcoming tariff period is given in Table 29.

Table 29: Export Energy Forecast

Tariff Period	2022/2023	2023/2024	2024/2025
DGPC	3,370.07	2,363.01	2,028.23
MHP	2,708.23	2,364.16	2,364.16
DHPC	436.96	445.08	445.08
Nikachhu	30.53	444.26	481.66
PHP-I	0.00	0.00	0.00
PHP-II	0.00	0.00	0.00
Total	**6,545.78**	**5,616.52**	**5,319.13**

The calculations and assumptions made for wheeling energy are given in *Annexure 12*.

15.1 Separate Wheeling Tariff

While the current wheeling tariff is a single weighted tariff of the generating plants, separate wheeling tariffs for two categories of generation plants a) plants before MHP i.e with DGPC and DHPC plant, and b) MHP and THyE have been worked out to reflect the actual cost of wheeling for existing and new plants.

For computing separate wheeling cost, the existing generation price of MHP and DGPC plants are considered to calculate the wheeling tariffs. The computed wheeling cost for DGPC and DHPC is shown in the Table 30.

Table 30: Wheeling cost of DGPC and DHPC

Year	2022	2023	2024
Energy costs	108	80	70
Network costs	446	493	480
Working capital	10	11	11
Other revenue			
Subsidies			
Total	**564**	**584**	**561**
Wheeling Tariff	0.20 Nu/kWh		

The computed wheeling cost of MHP and THyE is shown in the Table 31.

Table 31: Wheeling cost of MHP and ThyE

Year	2022	2023	2024
Energy costs	207	212	215
Network costs	714	836	794
Working capital	10	11	11
Other revenue	-	-	-
Subsidies	-	-	-
Total	**931**	**1,059**	**1,020**
Wheeling Tariff	0.36 Nu/kWh		

The detailed calculation on the wheeling charges are added in the tariff model.

15.2 Wheeling Charges for Imported Energy

Currently, the wheeling charge is applied only for the net exported energy. Since the energy import is projected to be a regular occurrence and quite substantial, the wheeling charge on the imported energy has been determined and included in the HV cost of supply.

Table 32: Import Energy Forecast

Tariff Period	2022/2023	2023/2024	2024/2025
Energy Import	672.90	1,442.40	1,638.79
Wheeling cost	20.00	44.00	50.00
Cost/Unit	0.03	0.03	0.03

As per TDR, any net monthly import cost to meet the shortfall of domestic supply shall be allocated to HV customers. Accordingly, the wheeling cost calculated for import is proposed to be included in the HV cost.

16. Losses

BPC's proposed technical losses are as per Schedule E of the existing TDR.

17. Non-tariff Revenue

The historical non-tariff revenue for the previous tariff period is given in Table 33 and the proposed non-tariff revenue for the forthcoming tariff period for each customer category is indicated in *Annexure 13*.

Table 33: Non-tariff Revenue

Non-tariff revenue	2019	2020	2021	2022/2023	2023/2024	2024/2025
LV	131.79	156.33	152.59	146.90	146.90	146.90
MV	0.05	0.05	0.05	0.05	0.04	0.05
HV	0.01	0.01	0.01	0.01	0.02	0.02

The non-tariff revenue for the next three tariff years has been based on the consolidated historical non-tariff revenue as maintained by BPC. Since the non-tariff revenue is not maintained on a category-wise basis, the total non-tariff revenue has been apportioned based on the no. of customers in the category. The calculation of non-tariff revenue for the next tariff period is based on the average of historical (past 3 years) non-tariff revenue to the total number of customers forecasted (in %) for the next tariff period.

18. Cost of Supply

The tariff input parameters used in the distribution tariff model to calculate the cost of supply is given in Table 34.

Table 34: Major Tariff Input Parameters summary

Customer category	Export	HV	MV	LV
Gearing (Actual)	96.97%	32.29%	38.68%	26.52%
Gearing (Proposed)	70.00%	60.00%	70.00%	70.00%

Customer category	Export	HV	MV	LV
CoE	13.63%	13.63%	13.63%	13.63%
CoD	9.94%	9.70%	3.34%	3.44%
O&M	As per 2021 actual O&M (Mill Nu)			
Losses	Loss allowances as per existing regulation			
Inflation	As per past inflation published by NSB			
Asset Allocation and O&M allocation factor	As proposed			
Generation price	Nu.**1.5**/kWh			
Investments	As per the Five-Year Investment Plan 2021-2025, Additional Investments and MHPA transmission costs			

18.1 Unsubsidized Cost of Supply

The Cost of supply for each customer category is calculated in Table 35.

Table 35: Unsubsidized Cost of Supply

Customer Category	Proposed Tariff (Nu/kWh)
LV	4.98
MV	5.48
HV	2.62
Export (Wheeling) DGPC+ DHPC	0.20
Export (Wheeling) MHPA + THyE	0.36

As the allocation of the subsidy is the prerogative of the RGoB, the subsidy allocation to the targeted customers is reviewed and examined by the RGOB, only the unsubsidized cost has been calculated as detailed above.

18.2 Tariff Structure

In line with the guideline of the tariff structure in the DETP, BPC proposes the structure of LV and MV, HV and wheeling be retained.

The HV and MV tariff is proposed to maintain the variable costs as pass-through generation cost, the fixed charge as demand charge based on Nu/kVA/month as in the existing tariff.

The billing assumptions for the upcoming tariff period is given in Table 36.

Table 36: Billing assumptions

Billing data		2022/2023	2023/2024	2024/2025
LV	No. of Customer	230,228	239,360	248,493
	0-100 (rural)	103	108	114

Billing data		2022/2023	2023/2024	2024/2025
	0-200 (highlanders)	1.19	1.34	1.51
	0-100 (urban)	65	69	73
	101-500	135	142	151
	>500	273	285	299
	Total	576	606	638
	LV bulk	90	95	102
	LV total	666	702	740
MV	GWh	107	298	383
	MVA	61	156	156
HV	GWh	3,278	3,877	4,060
	MVA	780	1,012	1,012
Wheeling	GWh	6,546	5,584	5,277

i) LV Tariff Structure and Customer Categorisation

Provision of Subsidy is the prerogative of the Royal Government of Bhutan and the LV tariff trend depends on the subsidy application. There are many new customer categories that are introduced to target the subsidy benefits. It is important to have proper guidelines to categorize LV customers for correct application of subsidies.

Table 37: LV Tariff Structure

Tariff structures		2021/2022	2022/2023	2023/2024	2024/2025
LV			Depends on the subsidy		
Block I	0-100	**1.28**			
Block II	101-500	**2.68**			
Block III	500+	**3.64**			
LV Bulk	Energy	**4.14**			

BEA's letter vide no. BEA/CEO/BPC/2021-22/137 dated 24th August 2021 has asked BPC to review the LV customer categorization. BPC would like to submit a report on the current customer categorization for review by BEA. The report is enclosed as Annexure 14.

ii) HV and MV Tariff Structure

For HV, the energy charge would be the generation tariff and the losses. For MV tariff structure, to work towards reflecting energy cost as generation tariff, the energy charge is increased to 4% in the first year and kept constant whereas the demand charge is increased to 6% annually.

Table 38: Tariff Structure for MV and HV

Tariff structures		2021/2022	2022/2023	2023/2024	2024/2025
MV	Nu/kWh	**2.65**	2.76	2.76	2.76
	Nu/kVA/month	**325**	345	365	387
HV	Nu/kWh	**1.5**	1.5	1.5	1.5
	Nu/kVA/month	**292**	321	353	385

On the demand charge, BPC would like to submit the review of the current minimum level of demand (90% for HV and 60% for MV) and consider the full contracted demand so as to recover full network cost. The demand charges calculated are on the basis of recovery with the full contract demand. The impact of allowing a minimum level of demand compared to full recovery is given in Table 39.

Table 39: Impact of demand charge application

Tariff Year	1st October 2019 to 30th June 2020	1st July 2020 to 30th June 2021	1st July 2021 to 30th June 2022	Total	Remarks
HV	(42.82)	(105.59)	(110.33)	(258.74)	Feb to June 2022 considered same as January
MV	(42.99)	(73.76)	(72.35)	(189.10)	
Total	**(85.81)**	**(179.35)**	**(182.68)**	**(447.84)**	

19. Miscellaneous

BPC's proposal for miscellaneous charges revision for 2019-2022 was approved vide letter no. BEA/CEO/BPC/2021-22/148 dated 26th August 2021. As the rates are revised recently, no revision on the miscellaneous charges are proposed.

The approval included provision of service cables to LV customers and subsequent directives were given to carry out further study and submit the proposal along with the tariff application. Hence, the proposal is included as part of the tariff application and the cost of service cables is included as part of additional investment. The detailed proposal is attached as Annexure 15.

The approval was also accorded for discontinuation of collection of meter security and refund meter security. The collection of meter security is discontinued and the proposal on the refund of meter security is attached as Annexure 16.

20. Recommendations for Restructuring Tariff Determination Modality

The current tariff determination modality needs to be reviewed in light of changing energy consumption landscape. Going forward, it is expected that the industrial demand will grow exponentially and in addition we also have new power plants (including from other Alternate Renewable Energy Sources and Import of expensive power) which are coming online that will have very high generation cost. Whereas, the LV consumption trend is going to increase at much slower pace and therefore will be unfairly burdened by increasing tariff contrary to the objective of providing affordable electricity to the populace. The current regulation, we believe, will not be able to address the distortion created in the power market place by these factors. In view of the foregoing and the changing dynamics in the energy sector, BPC would like to propose the following for BEA's consideration.

i) Seasonal Tariff

The electricity generation in Bhutan is highly seasonal. All the existing hydropower plants are run-of-river (ROR) types that are dependent on the inflow of rivers which in turn is dependent on hydrology. During the winter season, the generations are at minimum. From the past record, the lean period of hydropower generation is from December to March with February being the leanest month. The highest generation is for the period from June to October.

On the contrary, the demand is maximum during the winter months and lower during summer months.

As there are seasonal variations in the availability of power and energy demand is growing year on year, it is the right time for Bhutan to work towards formulating a seasonal tariff structure to send economic and price signals to bring balance in supply and demand especially during the winter months.

It may also be an appropriate time to look at other future tariff design possibilities to align customer incentives and electricity consumption decisions keeping the required additional metering and systems capability of our infrastructure into account. The rate design could also look into the deployment pace of Electric Vehicle, Solar rooftop adoption and modernise the rate structure while also looking at the technology landscape and infrastructure development requirement of the utility.

ii) One Tariff for all Customer Categories (High, Medium and Low)

While the current framework requires tariffs to be filed for all different customer categories, BEA could consider adopting a uniform tariff for all customer categories. This would not only address the anomalies in the current tariff structure which is sensitive to subjective asset allocation factors but also ensures fair and equitable distribution of benefits to all Bhutanese. The government could still consider providing a rationalised and targeted subsidy to make the electricity affordable especially for the LV consumers.

iii) Allocation of Generation in order of Priority of Customer Category

As per Clause 7.16 of the DETP 2016, the existing plants owned by RGOB as of 2015 is to be first booked for domestic supply and the next least cost of generation of additional plants shall be selected. BSHDP 2021 clause 15.5 states the order of merit while prioritizing the supply of electricity as Essential Public Institution & Services, Individual Households, General Commercial establishment and Industries including construction power.

In 2021, The LV customers constituted about 20% of the overall sales. The energy consumption by Low voltage is projected to constitute an average of 15% of the total sales volume, which can be met from the DGPC plants. Hence, the allocation of the power plants prior to 2015 for domestic supply in the order of priority of supply relating to the customer category may also be considered.

21. Conclusion

The tariff proposal covers the revenue requirement calculations to recover all prudent costs incurred to provide efficient customer service and ensure adequate investments in transmission, distribution network infrastructure and deployment of required technology. BPC would like to submit the proposal for the forthcoming tariff period to the BEA for consideration.

BPC would like to suggest tariff restructuring and designing possibilities to cater to the changing demand supply scenario and for optimal usage of electricity within the country.