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PROPOSAL OF DOMESTIC GENERATION TARIFF OF MANGDECHHU HYDROELECTRIC PROJECT AUTHORITY (MHEP)
(July 2022-June 2025)

MARCH 2022

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1. Executive Summary

This proposal is prepared for the tariff period July 2022 - June 2025 in accordance with the Tariff Determination Regulation 2016 (hereinafter referred to as TDR), Guideline for Determination of Regulatory Asset Base 2021 (hereinafter referred to as RAB) and the Domestic Electricity Tariff Policy 2016 (hereinafter referred to as Tariff Policy) reflecting the actual cost of efficient business operation of Mangdechhu. The tariff is calculated using Bhutan Electricity Authority's (BEA) Generation Tariff Model based on the parameters as specified in the TDR and the Tariff Policy.

The proposed domestic generation tariff of Nu. 3.85 per kWh for Mangdechhu has been arrived at by using a cost of equity as 13.56%, cost of debt of 10% and gearing ratio of 70% and a net average annual energy of 2,528 GWh considering the mean average generation of 3008 MU.

Table 1: Proposed cost of generation

SN	Parameters	MHEP
1	Cost of Equity	13.56%
2	Cost of Debt	10%
3	Gearing Ratio	70%
4	WACC	12.81%
5	Energy (GWh)	2,528
	Tariff (Nu. Per kWh)	**3.85**

The project was fully commissioned in the year 2019 and all units were commercially operationalized since then. The Government of India (GoI) is in the final stages of approving the final RCE (Revised Cost Estimate) of project completion cost of Rs. 51,110 million (hard cost excluding IDC), which is used in the derivation of Mangdechhu's domestic generation tariff of Nu. 3.85 per unit.

The proposed generation tariff of Nu. 3.85 per unit is an increase of 2% over the prevailing tariff of Nu. 3.77 per unit. In addition to the normal allocation of power from the DGPC power plants, from the energy allocation analysis for the tariff period, Mangdechhu power is expected to be used in the domestic market during lean river discharge months (November – December and January – May) and to be supplemented with some imports. In other months, the domestic energy requirement will be met from the DGPC power plants. From the additional average annual domestic energy requirement of 1,550 GWh during the lean river discharge months, MHEP can allocate 530 GWh of energy for the domestic load based on the mean average generation. Therefore, it is proposed that the allocation of Mangdechhu energy for domestic consumers be limited to the period November – December and January – May with the applicable domestic proposed tariff of Nu. 3.85/kWh unlike in the last tariff period where a weighted average generation tariff of DGPC and Mangdechhu of Nu. 1.50/kWh was considered.

The proposal for generation tariff of Mangdechhu is based on the recovery of the cost of generation reflecting the cost of efficient business operation. The proposed tariff has been worked out based on the provisions of the Tariff Policy to enable the recovery of permissible costs as per the regulatory framework. DGPC submits to the Bhutan Electricity Authority for consideration of the domestic generation for Mangdechhu for the period July 2022 - June 2025 tariff period.

2. Introduction

This proposal for the revision of domestic generation tariff has been prepared as per the provisions of the Tariff Determination Regulation 2016 (TDR), Guideline for Determination of Regulatory Asset Base 2021 (RAB) and the Domestic Electricity Tariff Policy of Bhutan 2016 (Tariff Policy) considering the following principles for tariff determination:

- Fairness to both service customers and service providers;
- No unjust discrimination against service providers or those who wish to use the services;
- Reflect the actual cost of efficient business operation;
- Conducive to efficiency improvement in business operation;
- Enhance efficient and adequate supply to satisfy the domestic demand; and
- Transparency in the determination and presentation of tariffs.

The domestic generation tariff for Mangdechhu HPP was approved at Nu. 3.77 per kWh for the tariff period October 1, 2019 to June 30, 2022. With the expiry of the existing tariff period as on June 30, 2022, the proposal for the revision of the generation tariff has been prepared based on net asset schedule, the investment plans and the O&M costs for the tariff period July 2022 - June 2025.

Although the project was fully commissioned in the year 2019 and all units were commercially operationalized since then, the final RCE (Revised Cost Estimate) of project completion cost is still under process of final approval with the Government of India. The Revised Cost Estimate under approval of GoI of Rs. 51,110.61 million has been considered as the project cost to completion for the derivation of the domestic tariff of Mangdechhu.

3. Parameters Used for Tariff Determination

The Generation Tariff Model provided by BEA is used to calculate the average cost of supply. The average cost of supply is determined based on the cost of supply methodology and using the principles to reflect the actual cost of efficient business operation.

The various inputs used in the generation tariff model are in keeping with the TDR and the Tariff Policy as presented below.

3.1 Tariff Period

The total cost and the total energy are discounted over the tariff period using the Weighted Average Cost of Capital (WACC). The tariff period is proposed as 3 (three) years as per the provisions of the Tariff Policy. The financial statements of Mangdechhu as of 31st Dec 2021 for both the construction and O&M components have been considered. The financial statements are attached as ***Annexure I.***

3.2 Cost Parameters

The total cost comprises of O&M cost, depreciation, return on assets, cost of working capital, generation licensee fee and BPSO charges. The cost components used as input in the tariff model are as below.

3.2.1 Cost of Equity

The Cost of Equity (CoE) of 13.56% has been proposed in line with BEA's consideration of the long-term average lending rates for all sectors provided by the domestic financial institutions including five (5) banks and three (3) non-bank institutions in the last tariff review. The present average lending rates of the domestic financial institutions of all sectors is 11.06% as given in Table 2. As per the Tariff Policy, BEA shall allow a reasonable premium up to a maximum of 250 basis points on the above rates depending on the domestic market situation and gearing ratio applied. Therefore, a premium of 250 basis point is considered and post-tax cost of equity of 13.56% is proposed.

Table 2: Average long-term lending rates of financial institutions in Bhutan

SN	Banks	Interest Rate
1	Bhutan Development Bank Limited (BDBL)	11.24%
2	Bhutan Insurance Limited (BIL)	12.40%
3	Bhutan National Bank Limited (BNBL)	10.83%
4	Bank of Bhutan Limited (BOBL)	11.66%
5	Druk Punjab National Bank (Druk PNB)	9.94%
6	National Pension & Provident Fund (NPPF)	9.50%
7	Royal Insurance Corporation of Bhutan Limited (RICBL)	12.20%
8	Tashi Bank Limited (T Bank Ltd.)	10.69%
	Average Rate	**11.06%**

Source: Interest rates information available on the respective company websites (Interest rates as of January 26, 2022 and considered term loan above 10 years as long term)

The proposed cost of equity of 13.56% is reasonable compared to approved COE in the previous tariff review. Further, considering the Central Electricity Regulatory Commission (CERC) norms in India, which provides cost of equity at the base rate of 16.50% for the storage type hydro generating stations including pumped storage hydro generating stations and run of river generating station with pondage, the proposed CoE of 13.56% is very reasonable.

3.2.2 Cost of Debt

The weighted average Cost of Debt (CoD) of 10% for Mangdechhu is proposed. This is based on the provisions of the Tariff Policy, which states that the actual cost of debt for the tariff period should be considered. The details of debt for Mangdechhu are given in Table 3.

Table 3: Debt Details

Loan Details	Loan Disburse-ments	Principle Amount (MNu.)	Interest rate (%)	Repay-ment period (years)	Loan balance 31.12.2022 (MNu.)	Loan balance 31.12.2023 (MNu.)	Loan balance 31.12.2024 (MNu.)
MHEP Loan	2020-2036	35,088.41	10.0	17	30,960.36	28,896.34	26,832.31

3.2.3 Gearing Ratio

The gearing ratio has been calculated as defined in the TDR using the Debt to Total Net Fixed Assets. In order to ensure competitive and efficient pricing through an optimal capital structure, the Tariff Policy provides that the gearing ratio for computation of WACC shall be higher than the actual gearing ratio and up to a maximum of 70:30.

During the proposed tariff period, Mangdechhu actual average gearing ratio is 70.84%. Therefore, a gearing of 70% is proposed.

3.2.4 Weighted Average Cost of Capital (WACC)

The WACC is determined using the formula set out in the TDR with cost of equity and the cost of debt as proposed above. The WACC determined for Mangdechhu is given in Table 4 below.

Table 4. WACC

SN	Parameters	MHEP
1	Cost of Equity (CoE)	13.56%
2	Cost of Debt (CoD)	10.00%
3	Corporate Tax	30.00%
4	Proposed Gearing	70.00%
5	**WACC**	**12.81%**

3.3 Return on Assets

The return on assets is determined by the Net Assets multiplied by the WACC. The asset schedule that has been used in the tariff model is as given in Table 5.

3.3.1 Fixed Assets

Although the project was fully commissioned in the year 2019 and all units were commercially operationalized since then, the approval of the cost to completion of the project has been delayed by the GoI and the project is also not yet handed over to the RGoB. The final cost to completion of project of Nu. 51,110 million as vetted by Central Electricity Authority (CEA) and under approval of Government of India (GoI) has been considered as the project cost to completion for the derivation of the domestic tariff of Mangdechhu.

The final Revised Cost Estimate (RCE) of the project or the cost to completion of the project as submitted by Mangdechhu Hydroelectric Project Authority (MHPA) to the GoI was Nu. 51,441 million, which included the cost of construction of additional residential buildings for the O&M employees. However, this appears to be not recommended by the CEA to the GoI. Therefore, the cost for construction of additional buildings has been considered separately in the MHP Investments Plan.

The fixed asset of Mangdechhu is derived based on the total gross asset and depreciation as per the Revised Cost Estimate of Nu. 51,110 million under process for approval by GoI. This is because the asset handing taking of Mangdechhu is still under process and most of the major component of Mangdechhu assets are still under work in progress (WIP) and are yet to be capitalized as of 31.12.2021. As per the audited project annual accounts 31/3/2021, an asset worth of Nu. 41,216.20 million is still under WIP (Work in Progress). The details cost of RCE value is attached in the ***Annexure II.***

The details of the project cost considered for deriving the gross asset schedule of Mangdechhu is shown in the Table 5 below:

Table 5. Final RCE Cost Break Up

Asset Description	Acquisition Cost (MNu.)
Asset Capitalized till 31st March 2021	2,784.80
CWIP including TL/ATS	41,216.73
Value of Assets as per SAP	44,001.61
Add: Pre-operating Expenses	6,573.34
Add: Balance cost to completion as per proposed final RCE	535.05
Total Projected Completion Cost (Proposed final RCE under approval)	**51,110.00**
Add: Prorated IDC for MHEP (86.66% of the IDC considered for export tariff)	12,118.70
Less: MHEP TL/ATS handed over to BPC	(6,716.98)
Less: Yurmo Substation handed over to BPC	(144.21)
Projected MHEP Cost excluding the Assets handed over to BPC	56,367.51
Add: Operational Asset (as on 31.12.2021) *	83.89
Gross Asset Capitalization (MNu.)	**56,451.41**

**Nu. 83.892 million worth of asset under the operation accounts is capitalized as of 31st December 2021*

Therefore, the assets schedule based on the above project cost for generation has been used for the determination of the fixed asset of Mangdechhu. Mangdechhu asset schedule derived as per the depreciation rates given in Schedule B of the TDR used for the tariff calculation is given below.

Table 6. Asset Schedule for Mangdechhu

Asset	Gross value (MNu.)	Acc. Dep	Net value (MNu.)	Depreciation (MNu.)
Land	11.18	-	11.18	
Buildings	1,298.06	481.25	816.80	34.11
Civil structures	666.92	166.71	500.21	22.23
Dam complex	16,409.72	-	16,409.72	546.99
Water conductor	9,530.02	-	9,530.02	317.67
Power house	28,094.56	63.74	28,030.82	1,038.28
Transmission equipment	-	-	-	-
Equipment	176.37	82.76	93.61	24.87
Office equipment	264.58	111.60	152.98	50.31
Total	**56,451.41**	**906.06**	**55,545.34**	**2,034.47**

3.3.2 Investments

The five-year investment plan as per capitalization schedule has been used for the tariff determination. The investment schedule is as below:

Table 7. Mangdechhu Investment Schedule

Asset	**2022 (MNu.)**	**2023 (MNu.)**	**2024 (MNu.)**	**2025 (MNu.)**
Land	-	-	-	-
Buildings	2.00	-	95.87	191.73
Civil structures	0.52	-	35.45	-
Dam complex	-	-	-	-
Water conductor	-	-	-	-
Power house	526.02	150.97	100.97	25
Transmission equipment	-	-	-	-
Equipment	63.55	64.82	66.12	67.44
Office equipment	19.86	20.26	20.66	21.07
Total Nu. 1,472.30 Million	**611.95**	**236.04**	**319.06**	**305.25**

3.4 O&M Allowance

The O&M cost for Mangdechhu as per the financial accounts 31/12/2021 is shown in the table below:

Table 8: O&M Expenses for 2020 and 2021

SN	**Description**	**2020**	**2021**
1	Operation and Maintenance Cost (MNu.)	305.729	540.163
Deductible Expenses			
2	CSR	-	0.858
3	Rental income	1.410	8.518
4	License Fee	7.20	7.20
5	**Total Deductions**	**8.61**	**16.58**
6	**O&M Allowable**	**297.12**	**523.586**

The historical O&M cost reflected in the accounts for year 2020-2021 for Mangdechhu is not the true representation for the basis of projection of O&M cost for the upcoming tariff period (2022-2025) for the present moment. This is mainly on the account that the project was not handed over to the O&M entity and majority of the components were under defects liability period (DLP) wherein, the contractors were liable for repair cost incurred in attending to any defects that might appear in the equipment. The present O&M deployment is on the lower side and once the DLPs are completed for all the project components, there will be an increase in the number of O&M personnel, which MHP will have to start mobilizing starting from the middle of 2022 by which time it is expected that the GoI/MHPA would hand over the project to the RGoB/DGPC.

As per TDR for large hydropower generation, the bench mark cost of 1.0 to 1.5 percent of capital cost is allowed. Based on the TDR, it is proposed to consider benchmark O&M cost of 1% of the capital cost as the allowable O&M cost for Mangdechhu in the upcoming tariff period. The allowable O&M cost works out to Nu. 564.51 million, which is reasonable when compared with the O&M cost of the DGPC power plants of equivalent capacity but within a higher spread in area coverage. Even on comparing to the benchmarks set by India's 2019 CERC norms where it allows for an allowance of 4% of original capital cost for projects with installed capacity less than 200 MW and 3.5% for projects with installed capacity more than 200 MW, the proposed O&M cost is very reasonable.

Similar to the DGPC's proposal, the O&M cost is escalated at an inflation rate of 3.40% and O&M efficiency gains of 0% is proposed.

3.4.1 Inflation

The average annual inflation rate of 3.40% based on the average inflation rate for the past three years is proposed. As per Clause 7.4 of the Tariff Policy, the inflation rate used for escalation of O&M expenses shall be based on the historical average inflation rates published by the National Statistics Bureau (NSB). The historical inflation figures are based from the Consumer Price Index bulletin of the NSB for non-food items and calculated as the arithmetic average of the year on year inflation rates.

Table 9. Year on Year historical Inflation on Non-Food Item

Year	2019	2020	2021	Average
Inflation figures	1.35%	2.02%	6.82%	**3.40%**

Source: Consumer Price Index Bulletin, National Accounts and Price Division, National Statistical Bureau.

3.5 Cost of Working Capital

The calculation of the cost of working capital uses the annual inventories and arrears.

3.5.1 Inventories

During the previous tariff period, all the project components/equipment were under the defect liability period (DLP) where the suppliers/contractors were obligated to carry out the repair of the defects appearing in the equipment supplied/components constructed by them during the period. Therefore, a very minimal inventory was maintained by the project. However, as the DLP is over, the plant will have to build up the required level of inventory of spares as per the Inventory Management Guideline to ensure smooth operation of plant for ensuring steady revenue streams. To determine the inventory value for Mangdechhu in the upcoming tariff period, the benchmark inventory level of DGPC has been considered, which is 0.314% of the replacement value. Since Mangdechhu project's assets are new and on applying 0.314% of the current capital cost, the proposed inventory value works out Nu. 177 million. This proposed amount is found reasonable when compared with DGPC power plants of equivalent capacity.

Table 10. Proposed Inventories, Arrears and Rate

Proposed Inventories, Arrears and Interest Rate	
Inventories (MNu.)	177
Arrear (Days)	50
Interest rate	9.97%

3.6 Regulatory Fees

The regulatory fees to the BEA of Nu. 7.2 million (Nu. 10,000 per MW) has been added separately in the tariff model as the annual regulatory fee for Mangdechhu project. As per the System Operator Charges Regulation 2022, the System Operator charges from the Generation, Transmission, Distribution Licenses and any other users is applicable from the upcoming tariff period. As per clause 37 of the regulation, the total cost of System Operator shall be recovered from Generation, Distribution, and any other users as System Operator charges for the service rendered by System Operator and accordingly shall be allocated as follows:

1) Generation = Half (1/2) of total cost of System Operator
2) Transmission and Distribution = Half (1/2) of total cost of System Operator

The System Operator cost allocated to generation shall be further allocated to individual Generation Licensee based on the installed capacity (MW).

Based on the above provisions from the regulation, the System Operator charge for Mangdechhu is calculated as below and considered in the tariff model.

Table 11. System Operator Proposed Charges (in MNu.)

SN	Parameters	July 2022 – June 2023	July 2023 – June 2024	July 2024 – June 2025
1	Proposed O&M Cost	57.66	56.77	55.52
2	Proposed Capital Cost	140.63	270.14	70.00
3	Regulatory Fees	0.40	0.65	**0.75**
	Total	**198.69**	**327.57**	**126.27**

Table 12. System Operator Cost Allocation to Generation and Mangdechhu HPP

SN	Parameters	July 2022 – June 2023 (MNu.)	July 2023 – June 2024 (MNu.)	July 2024 – June 2025 (MNu.)
1	Allocated to Generation (50%)	99.35	163.79	63.14
2	**Allocated to MHPA (MNu.)**	**30.80**	**50.70**	**19.50**

Tariff revision application fee of Nu. 2,500/MW, which works out to Nu. 1.80 million for MHPA is included in regulatory fees.

3.7 Energy Volumes

As per the TDR 2016, the annual energy volumes shall be determined as the mean annual energy generation of the past three years based on 98% water utilization factor to the extent of generation capacity less royalty energy adjusted for auxiliary consumption and transformation losses.

The energy volumes for computing the domestic tariff for the existing DGPC generating plants are derived from the generation forecasts based on the actual generation for the past 3 years. However, since Mangdechhu was commissioned only in the mid of 2019 and there were numerous outages with the generating units from commissioning till August of 2021, the annual generation forecast for Mangdechhu cannot be based on the historical generations for deriving its energy volumes as explained below.

All four generating units were commissioned between June and August of 2019. Unit No. 1 was declared for commercial operation on 28th June 2019 followed by Unit No. 2 & 4 on 8th July and 14th August 2019 respectively. Due to a major failure during testing and commissioning, Unit 3 was commissioned last on 15th August 2019 and put up for commercial operation on 16th August 2019. However, thereafter also, Unit 3 had number of outages due to inherent defects with the equipment.

It is common for new machines to experience such inherent teething problems initially. The generation in 2019 was 1,320.35 GWh with all Units commissioned by mid of the year. The downtime in Unit No.3 was quite substantial, which resulted to a very low generation in the first year of commissioning.

While Mangdechhu generated 3,218.39 GWh in 2020 despite Units breaking down frequently, particularly with Unit No. 3 due to four major failures, the hydrology in 2020 was very good, which boosted higher generation during the year. The generation from DGPC plants was also the highest during this same year. Therefore, it will not be correct to consider the 2020 generation as the basis for projecting the generation for the 2022 – 2025 tariff.

During the year 2021, the annual generation was 2,987.89 GWh even with Unit 3 not available for the July month and half of August month. The generation was possible due to very good hydrology during the post monsoon (October 2021), and therefore use of the 2021 generation figure for 2022 – 2025 tariff determination might not be proper.

As the actual generation of Mangdechhu during the last three years was under the exceptional circumstances, it is proposed to consider the annual mean generation of 3,008 GWh, which was used during 2019-2022 Domestic Generation Tariff determination and also used for export tariff determination, as the annual generation forecast of Mangdechhu for the years from 2022 till 2025. Energy generation forecast as given in Table 13 below is proposed for the calculation of Mangdechhu tariff. As experienced from the other hydropower plants, the mean annual generation eventually works to very close to design mean annual generation forecast. The Mangdechhu energy estimates is attached as ***Annexure III.***

3.7.1 Annual Energy Volume

Energy volume net of royalty energy of 15% and adjusted for auxiliary losses (1.12%) of 2,528 GWh has been considered in the calculation of the MHEP tariff as shown in Table 13.

Table 13. Energy Volumes for MHEP (GWh)

Year	2022	2023	2024
Mean Annual Energy	3,008	3,008	3,008
Less: Auxiliary Losses (1.12%)	34	34	34
Less: Royalty (15%)	446	446	446
Energy Used for Tariff Determination	**2,528**	**2,528**	**2,528**

4. Generation Tariff

The Mangdechhu domestic generation tariff determined using the BEA's tariff model works out to Nu. 3.85 per kWh as given below:

Table 15. Mangdechhu Tariff

SN	Parameters	Mangdechhu Hydroelectric Project (MHEP)
1	Cost of Equity (CoE)	13.56%
2	Cost of Debt (CoD)	10.00%
3	Corporate Tax	30%
4	Proposed Gearing	70%
5	WACC	12.81%
6	Energy (GWh)	2,528
	Tariff (Nu. Per kWh)	**3.85**

The generation tariff for Mangdechhu for domestic consumption has been arrived at by using the cost of equity as 13.56%, cost of debt of 10%, gearing ratio of 70%, and average annual energy of 2,528 GWh. The detail tariff output from the model is enclosed as ***Annexure IV.***

5. Allocation of Energy for Domestic Supply

The Clause 7.16 of the Tariff Policy 2016 provides that "in order to meet the domestic demand, the existing plants fully owned by the Royal Government as of 2015 shall first be booked for domestic supply to the extent that they are able to meet the demand. In the event that they are not able to fully supply the demand, the plant(s) with the lowest cost of generation shall be selected to supplement the energy". The annual generation forecast for DGPC power plants and the domestic demand during the tariff period is compared to determine the energy deficit that may have to be catered from the MHEP and through import.

5.1 Domestic load allocation from DGPC existing power plants

Based on the domestic load projections from the report on Supply and Demand Analysis (DHPS, DRE, DGPC and BPC), 2021 and the energy generation forecast of the DGPC existing hydropower plants, the domestic energy deficit in year 2022-2025 is shown in the Table 16 below:

Table 16: DGPC Generation and Domestic Load Forecast (GWh)

Month	DGPC Generation Projection (GWh)	Domestic Load Projection (GWh)				Domestic Energy Deficit (GWh)			
	2022-2025	2022	2023	2024	2025	2022	2023	2024	2025
Jan	219.02	274.82	550.87	630.26	643.11	(55.80)	(331.86)	(411.24)	(424.09)
Feb	179.67	274.25	505.32	581.51	583.92	(94.58)	(325.65)	(401.84)	(404.25)
Mar	225.46	304.66	549.16	626.35	628.55	(79.20)	(323.70)	(400.89)	(403.09)
Apr	322.08	321.93	544.91	616.26	618.49	-	(222.83)	(294.18)	(296.41)
May	580.06	340.64	556.18	623.13	625.15	-	-	(43.07)	(45.10)
Jun	814.98	351.54	548.77	610.12	612.07	-	-	-	-
Jul	1,096.44	355.71	567.30	619.75	621.63	-	-	-	-
Aug	1,140.13	358.10	581.09	624.16	631.44	-	-	-	-
Sep	1,080.25	352.67	574.30	606.31	618.65	-	-	-	-
Oct	849.61	447.69	601.28	628.74	647.09	-	-	-	-
Nov	466.64	441.45	601.27	623.75	647.57	-	(134.64)	(157.11)	(180.93)
Dec	314.92	463.06	632.22	650.49	681.05	(148.14)	(317.30)	(335.57)	(366.14)
Total	**7,289.24**	**4,286.52**	**6,812.68**	**7,440.82**	**7,558.72**	**(377.73)**	**(1,655.98)**	**(2,043.91)**	**(2,120.00)**
	Average				**6,524.69**				**(1,549.40)**

From the domestic load projection in upcoming tariff period (2022-2025), the domestic load demand is expected to increase manifold with the average annual demand of 6,525 GWh. The DGPC existing plants will not be able to meet the domestic demand during the lean period, especially during January - May and November – December months. An average annual energy demand of 6,525 GWh is forecasted for domestic load during the tariff period. After first allocating an average annual energy of 4,975 GWh from DGPC power plants for domestic consumption, an approximate average annual energy deficit of 1,550 GWh is expected in tariff period.

5.2 Allocation of MHEP Energy for Domestic Load

As per the Tariff Policy, the plant(s) with the lowest cost of generation shall be selected to supplement the energy for the unmet domestic load. Table 17 shows the allocation of MHEP energy for domestic load during the Tariff Period.

Table 17: MHEP energy allocation for domestic load (GWh)

Month	MHEP Energy Forecast (GWh)	Domestic Energy Deficit (GWh)				MHPA supply to domestic (GWh)			
	2022-2025	2022	2023	2024	2025	2022	2023	2024	2025
Jan	73	(55.80)	(331.86)	(411.24)	(424.09)	55.80	73.00	73.00	73.00
Feb	62	(94.58)	(325.65)	(401.84)	(404.25)	62.00	62.00	62.00	62.00
Mar	85	(79.20)	(323.70)	(400.89)	(403.09)	79.20	85.00	85.00	85.00
Apr	134	-	(222.83)	(294.18)	(296.41)	-	134.00	134.00	134.00
May	256	-	-	(43.07)	(45.10)	-	-	43.07	45.10
Jun	405	-	-	-	-	-	-	-	-
Jul	508	-	-	-	-	-	-	-	-
Aug	509	-	-	-	-	-	-	-	-
Sep	467	-	-	-	-	-	-	-	-
Oct	282	-	-	-	-	-	-	-	-
Nov	135	-	(134.64)	(157.11)	(180.93)	-	134.64	135.00	135.00
Dec	92	(148.14)	(317.30)	(335.57)	(366.14)	92.00	92.00	92.00	92.00
Total	**3,008**	**(377.73)**	**(1,655.98)**	**(2,043.91)**	**(2,120.00)**	**289.00**	**580.64**	**624.07**	**626.10**
	Average (GWh)				**(1,549.40)**	**Average (GWh)**			**529.95**

From the additional average annual energy requirement of 1,550 GWh for domestic during the winter months, MHEP can allocate 530 GWh of energy for the domestic load based on the mean average generation. Hence deficit of 1,020 GWh is anticipated during the winter months during the tariff period and the deficit need to be met through import. The monthly import requirement is depicted in the table below.

Table 18: Forecast of import requirement (GWh)

Month	Import Requirement (GWh)			
	2022	**2023**	**2024**	**2025**
Jan	-	258.86	338.24	351.09
Feb	32.58	263.65	339.84	342.25
Mar	-	238.70	315.89	318.09
Apr	-	88.83	160.18	162.41
May	-	-	-	-
Jun	-	-	-	-
Jul	-	-	-	-
Aug	-	-	-	-
Sep	-	-	-	-
Oct	-	-	-	-
Nov	-	-	22.11	45.93
Dec	56.14	225.30	243.57	274.14
Total	88.73	1,075.34	1,419.84	1,493.90
	Average (GWh)		**1,019.45**	

Table 19: Summary of Energy Allocation

Description	**Average Energy (2022-2025) GWh**
DGPC Generation	7,289.24
Domestic Load	6,524.69
DGPC allocation to domestic supply	4,975.28
MHPA allocation	529.95
Import Requirement	1,019.45

From the above energy allocation analysis, Mangdechhu power is expected to be used in the domestic market only during the winter months (January – May and November – December) and to be supplemented with import, and in other months the energy will be met either from power plants. Therefore, it is proposed that the Mangdechhu domestic proposed tariff of Nu. 3.85/kWh be applicable for the domestic consumers only during the period when the energy from MHPA is used in the domestic market i.e. from January – May and November – December unlike in the last tariff period where a weighted average generation tariff of DGPC and Mangdechhu of Nu. 1.50/kWh was determined for the domestic consumption.

6. Conclusion

The tariff proposal has been prepared in line with the provisions of the TDR and the Tariff Policy. From the results, the cost of generation for the Mangdechhu works out to Nu. 3.85 per kWh, considering cost of equity of 13.56%, cost of debt 10 % and gearing of 70%. The proposed tariff is considered reasonable with increase of 2.12% over the existing tariff of 3.77 per kWh. Therefore, it is proposed to consider the upward revision of the domestic generation tariff to Nu. 3.85 per kWh for the July 2022 - June 2025 tariff period. The proposed tariff will enable Mangdechhu to earn returns as permissible within the Tariff Policy and the regulatory framework.

7. Annexures

7.1 Annexure I: Audited Financial Statement as 31st December 2021

Statement of Financial Position as at 31st December 2021

Particulars	Note No.	2021	2020	2019
Assets				
Non- current assets				
Property, plant & equipment	1	224,573,354.75	4,453,746.30	-
Total non - current assets		**224,573,354.75**	**4,453,746.30**	**-**
Current assets				
Trade and other receivables	3a	1,648,267,554.64	1,572,746,585.58	2,883,526,031.37
Prepayments and advances	2	94,388,789.45	7,339,800.62	-
Cash and cash equivalents	3b	1,909,484,707.18	3,463,107,669.35	199,999,950.00
Total current assets		**3,652,141,051.27**	**5,043,194,055.55**	**3,083,525,981.37**
Total assets		**3,876,714,406.02**	**5,047,647,801.85**	**3,083,525,981.37**
Equity and liabilities:				
Equity				
Share capital		-	-	-
General reserves		-	-	-
Retained earnings		3,639,923,616.37	4,836,696,273.06	2,520,319,629.96
Accumulated other comprehensive income				
Total shareholders' equity		**3,639,923,616.37**	**4,836,696,273.06**	**2,520,319,629.96**
Current liabilities				
Trade and other payables	3c	229,602,654.48	209,960,513.51	563,206,351.41
Other current liabilities	4	7,188,135.17	991,015.28	-
Current tax liabilities	5	-	-	-
Total liabilities		**236,790,789.65**	**210,951,528.79**	**563,206,351.41**
Total shareholders' equity & liabilities		**3,876,714,406.02**	**5,047,647,801.85**	**3,083,525,981.37**

Income and Expenditure Statement for the year ended on 31st Decemebr 2021

Particulars	Note No.	2021	2020	2019
Income				
Electricity revenue	6	10,421,867,552.82	11,259,876,769.29	4,528,684,485.01
Royalty Income		1,791,489,243.02	1,929,696,313.50	791,051,794.61
Other income	7	8,518,239.74	1,410,407.00	-
		12,221,875,035.58	**13,190,983,489.79**	**5,319,736,279.62**
Expenditure				
Wheeling charges		794,943,810.17	848,406,644.84	289,261,384.36
Royalty Expense		1,674,085,821.75	1,803,235,632.75	748,346,190.18
Insurance		96,839,005.00	70,823,836.57	-
Running and maintenance expenses	8	86,462,572.18	12,745,678.64	-
Employees' remuneration and benefits	9	331,150,871.90	219,798,427.08	-
Depreciation/amortisation		6,527,312.03	429,558.70	-
Remittances to RGOB		10,402,927,611.97	7,916,805,183.33	1,761,809,025.12
Other expenses	10	25,710,687.27	2,361,884.78	50.00
		13,418,647,692.27	**10,874,606,846.69**	**2,799,416,649.66**
Operating profit		**(1,196,772,656.69)**	**2,316,376,643.10**	**2,520,319,629.96**

Statement of Cash flows for the year ended December 31, 2021

Particulars	2021	2020	2019
Cash flows from operating activities			
Profit before taxation	- 1,196,772,656.69	2,316,376,643.10	2,520,319,629.96
Adjustment for:			
Depreciation / amortisation	6,527,312.03	429,558.70	-
(Increase)/decrease in trade receivables and other receivables	- 75,520,969.06	1,310,779,445.79	- 2,883,526,031.37
(Increase)/decrease in prepayments and advances	- 87,048,988.83	- 7,339,800.62	-
Increase/(decrease) in trade and other payables	19,642,140.97	- 353,245,837.90	563,206,351.41
Increase/(decrease) in other current liabilities	6,197,119.89	991,015.28	-
Cash generated from Operation	**- 1,326,976,041.69**	**3,267,991,024.35**	**199,999,950.00**
Income tax paid			-
Net cash from operating activities	**- 1,326,976,041.69**	**3,267,991,024.35**	**199,999,950.00**
Cash flows from investing activities			
Purchase of PPE & intangibles assets	- 226,646,920.48	- 4,883,305.00	-
Net cash used in investing activities	**- 226,646,920.48**	**- 4,883,305.00**	**-**
Cash flows from financing activities			
Issue of share capital			
Increase/(Decrease) in Reserve			
Repayment of loan			
Proceeds/(Repayment) of Short-Term Loan			
Interest paid			
Dividend paid			
Net cash used in financing activities	**-**	**-**	**-**
Net increase/(decrease) in cash and cash equivalents	**- 1,553,622,962.17**	**3,263,107,719.35**	**199,999,950.00**
Cash and cash equivalents at the beginning of the period	**3,463,107,669.35**	**199,999,950.00**	
Cash and cash equivalents at the end of the period	**1,909,484,707.18**	**3,463,107,669.35**	**199,999,950.00**
Component of cash and cash equivalents:-			
Cash in hand	**-**	**-**	**-**
Balances in current accounts with banks	**1,909,484,707.18**	**3,463,107,669.35**	**199,999,950.00**
Total	**1,909,484,707.18**	**3,463,107,669.35**	**199,999,950.00**

7.2 Annexure II: Final Revised Cost Estimate

Abstract of MHEP Projected Completion Cost

SN	Asset description	Acquisition cost (Nu.)	References
1	Land and Land Development	11,183,553.68	*01. Asset List, 31.03.2021*
2	Civil Structures, Permanent	949,851,295.18	*01. Asset List, 31.03.2021*
3	Civil Structures, Semi-Permanent	5,726,334.30	*01. Asset List, 31.03.2021*
4	Civil Structures, Temporary	321,315,965.22	*01. Asset List, 31.03.2021*
5	Civil Structures, Walls, fencing, Gates.	2,060,173.26	*01. Asset List, 31.03.2021*
6	Civil Structures, Roads, Culverts	664,858,959.19	*01. Asset List, 31.03.2021*
7	Civil Structures, Others	351,573,258.77	*01. Asset List, 31.03.2021*
8	Electro-Mechanical, DG sets, Distribution Systems	266,546,123.01	*01. Asset List, 31.03.2021*
9	Machinery	5,671,804.00	*01. Asset List, 31.03.2021*
10	Tools and Plants	18,640,080.15	*01. Asset List, 31.03.2021*
11	Fire Fighting	6,170,115.10	*01. Asset List, 31.03.2021*
12	Office Equipment	14,568,580.69	*01. Asset List, 31.03.2021*
13	Furniture and Fixtures	25,940,875.63	*01. Asset List, 31.03.2021*
14	Vehicles/Bikes	100,726,537.25	*01. Asset List, 31.03.2021*
15	IT Equipment	20,501,260.25	*01. Asset List, 31.03.2021*
16	General Assets, not included in above	19,544,710.48	*01. Asset List, 31.03.2021*
17	CWIP including TL/ ATS	41,216,730,375.44	*01. Asset List, 31.03.2021*
18	**Value of Assets as per SAP**	**44,001,610,001.60**	***01. Asset List, 31.03.2021***
19	Add: Pre-operating Expenses	6,573,338,032.58	*02, Preoperative expenses*
20	Add: Balance cost to completion as per proposed final RCE (21-18+19)	535,051,965.82	*03, Balance amount of the RCE*

21	**Total Projected Completion Cost (Proposed final RCE under approval)**	**51,110,000,000.00**	***04, Final RCE proposal***
21	Add: Prorated IDC for MHEP (86.66% of the IDC considered for export tariff)	12,118,703,009.90	*05, Prorated IDC*
22	Less: MHEP TL/ATS handed over to BPC	(6,716,980,316.10)	*01. Asset List, 31.03.2021*
23	Less: Yurmo Substation handed over to BPC	(144,208,263.52)	*01. Asset List, 31.03.2021*
24	***Projected MHEP Cost excluding the Assets handed over to BPC***	***56,367,514,430.28***	

7.3 Annexure III: MHEP Energy Estimates

MHEP Energy Estimates: The average annual energy for MHEP calculated from DPR flow

Energy (GWh)							
10 Daily		**100% PA/no overloading**	**100% PA/10% overloading**	**95% PA/no overloading ***	**95% PA/10% overloading**	**100% PA/5 % overloading**	**5% over loading/ 95% PA**
JUN I	10	106	106	106	106	106	106
JUN II	10	135	139	135	139	139	139
JUN III	10	165	176	164	176	176	172
JUL I	10	163	175	163	175	175	172
JUL II	10	169	184	164	181	181	172
JUL III	11	190	208	181	199	200	190
AUG I	10	173	190	164	181	181	172
AUG II	10	172	188	164	181	181	172
AUG III	11	190	209	181	199	200	190
SEP I	10	169	181	164	181	181	172
SEP II	10	161	170	161	170	170	170
SEP III	10	142	144	142	144	144	144
OCT I	10	118	119	118	119	119	119
OCT II	10	88	88	88	88	88	88
OCT III	11	76	76	76	76	76	76
NOV I	10	52	52	52	52	52	52
NOV II	10	45	45	45	45	45	45
NOV III	10	38	38	38	38	38	38
DEC I	10	33	33	33	33	33	33
DEC II	10	30	30	30	30	30	30
DEC III	11	29	29	29	29	29	29
JAN I	10	25	25	25	25	25	25
JAN II	10	23	23	23	23	23	23
JAN III	11	25	25	25	25	25	25
FEB I	10	23	23	23	23	23	23
FEB II	10	22	22	22	22	22	22
FEB III	8	17	17	17	17	17	17
MAR I	10	23	23	23	23	23	23
MAR II	10	26	26	26	26	26	26
MAR III	11	35	35	35	35	35	35
APR I	10	36	36	36	36	36	36
APR II	10	45	45	45	45	45	45
APR III	10	53	53	53	53	53	53
MAY I	10	65	65	65	65	65	65
MAY II	10	80	81	80	81	81	81
MAY III	11	111	111	111	111	111	111
Energy (Gwh)		**3,054.88**	**3,191.16**	3,008.32	**3,150.74**	**3,155.77**	**3,093.40**

** MHEP annual energy forecast is based on 95% power plant availability with No overloading*

7.4 Annexure IV: Tariff Output

Total Cost of Supply (mill Nu.)					
	2022	2023	2024	2025	2026
OM	630	672	665	689	713
DEP	2,073	2,112	2,146	2,169	2,179
RoA	7,023	6,812	6,578	6,343	6,094
RoWC	151	150	190	187	185
TC	9,876	9,746	9,578	9,389	9,170
Energy volumes (GWh)					
	2022	2023	2024	2025	2026
$ENERGY_i$	2,528	2,528	2,528	2,528	2,528
ENERGY	2,528	2,528	2,528	2,528	2,528
ROYALTY	451	451	451	451	451
Average Cost of Supply					
Tariff period	1	2	3	4	5
Discounted TC	8,755	16,413	23,085	28,882	33,901
Discounted ENERGY	2,241	4,228	5,989	7,550	8,934
AC	**3.85**	**Nu/kWh**			