Domestic Tariff Projection 2040

A Brief Analysis by:

Department of Hydropower and Power Systems

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EXECUTIVE SUMMARY

The domestic tariff projections till 2040, for five tariff cycles starting from July 2025, is carried out considering three generation scenarios and two demand scenarios. Under the generation scenario I, existing generating plants and under-construction hydropower as well as solar projects are considered whereas in scenario II, additional capacities from planned hydroelectric projects are also considered, and in scenario III, further addition of two large hydropower projects are considered. For demand scenarios, all planned loads as per the signed Capacity Reserve Agreements or valid power sanctions are classified as scenario A, while further load addition from industries whose power clearances have been issued are taken into consideration in scenario B. Where projected seasonal demands exceed generation capacity, import scenarios from the Indian energy exchanges have been factored in at the long term marginal costs information as available.

To derive the generation tariff of DGPC plants including MHPA and embedded generations, the cost parameters approved by BEA for tariff period 2022-2025 is used as a baseline. For the planned hydropower projects, the costs of the projects have been escalated using the inflation rate till 2021 and projected based on the past five years' moving average inflation rates published by National Statistics Bureau. The weighted generation costs of scenarios are considered as the energy purchase price. The domestic tariff is computed based on the cost-plus model using the BEA Tariff Determination Regulations.

Among the given scenarios, the most realistic scenario would be the Scenario A-II and under this scenario, the domestic tariff is expected to increase from 2025's prices of Nu. 2.39 per unit for weighted generation price and Nu. 3.38 per unit for cost of supply, to Nu. 3.33 per unit for weighted generation price and Nu. 4.51 per unit cost of supply by 2040. The average increase in generation price and cost of supply in each tariff cycle is 9% and 8% respectively. However, considering the uncertainty in the assumptions used including the broad projections of the generation-load scenarios, the actual domestic tariffs may vary to a large degree. Nevertheless the projected domestic tariff for 2025-2040 for each tariff cycle is depicted below:

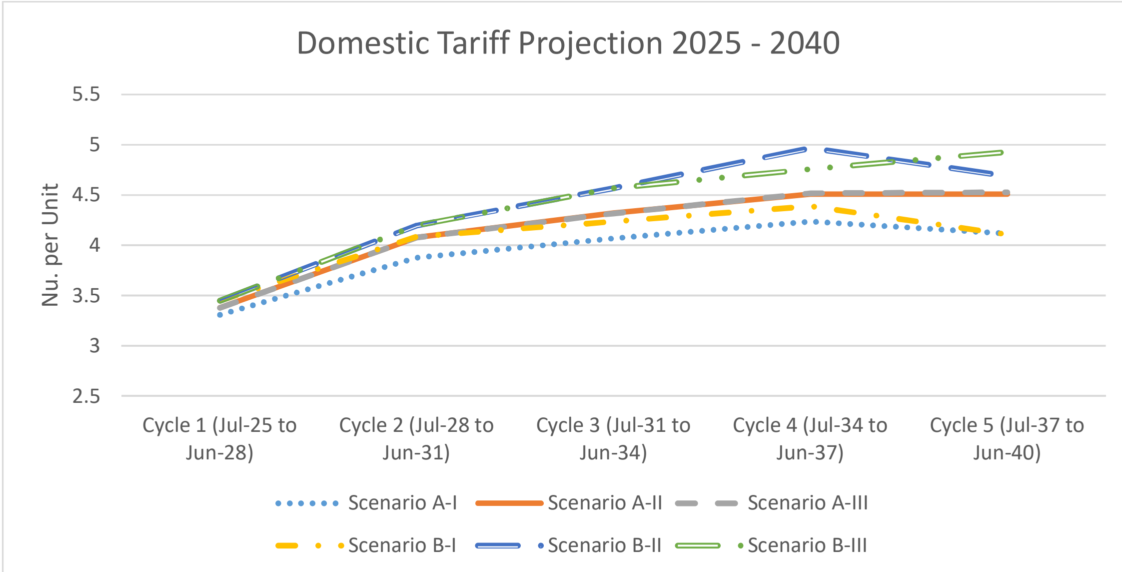

Figure 1: Domestic Tariff Trajectory 2025 – 2040

If an industrial proponent chooses to follow the PPA model, the tariff framework with annual increment of around 4% to 7% over the next 15 years (2025 – 2040) is expected to be applicable. However, this model does not take into account the evolving world energy markets which are subject to frequent and steep changes as is being experienced at the moment with the prices of fossil fuel (especially coal, gas and petroleum products) and high inflation rates. The tariff figures may experience unexpected change and therefore may be subjected to further detailed analyses. Negotiations between the utility and the industrial proponents could be the determining factor for the final PPA-based tariffs with the derived tariffs as a basis for the negotiations.

Due to the increasing domestic demand, power shortages in the lean seasons are expected to continue up to 2030-2031 under the generation-load scenarios considered. The power deficit is expected to be met from import of power. Assuming that India will approve the import of power from Indian Power Exchange markets, the cost of imported power during off-peak hours in the lean months could be around Nu. 4.11 per unit to Nu. 6.39 per unit on an average by 2040. It is also possible that in distant future, the regional power market may be established from which power trade could happen, however this has not been considered in this study.

INTRODUCTION

1.1. Objective

The desired output from this exercise is the domestic tariff projection for 15 years i.e. from 2025 to 2040. The objective of this study is to provide relevant and realistic tariff projections under the following frameworks:

1.1.1. Market projections- Power tariff projection using existing cost-plus model; and

1.1.2. Power Purchase Agreement (PPA) Model – Power tariff projection based on percentage increment on the actual cost of HV tariff as of 2025.

1.2. Approach

A team comprising of members from DHPS, BPC, DGPC and BEA was formed to carry out the domestic tariff projection. The list of working members is provided in Annexure I. The study requires detailed analysis considering several parameters and a considerable amount of data processing. Long-term energy pricing forecasts has not been carried out previously, thus, the approach for this study has been based on the following:

i. Set boundary conditions (mainly due to data and time constraints);
ii. Consider generation-demand scenarios based on plans/ information available;
iii. Review and adopt assumptions/parameters based on prevailing practice/policy/ rules/ regulations;
iv. Disregard external factors and biases such as anticipated change in law, market conditions, etc.;
v. Assume BEA-approved domestic tariffs for 2022-2025 cycle; and
vi. Import tariffs from Indian energy exchanges as per information available.

The ensuing chapters provides the data, explanation of models used, and the assumptions made to produce domestic tariff projections, which is presented for three progressive generation scenarios and two demand scenarios, and consequently, six projections of domestic electricity tariffs. This report also provides an insight on the cost of imported power considering that there will be import of power during the deficit period in lean winter months that will continue beyond 2030 until all planned/anticipated projects are commissioned.

GENERATION

2.1. Current Installed Capacity

As of 2022, the installed capacity stands at 2,326 MW with the last major addition of installed capacity being the 720MW Mangdechhu Hydropower Project in mid 2019. The following tables presents details of existing generating stations and projects under construction.

Table 1: Existing Plants

Sl. No.	Plant Name	Installed Capacity (MW)
1	Chhukha Hydro	336
2	Kurichhu Hydro	60
3	Basochhu Hydro	64
4	Tala Hydro	1020
5	Dagachhu Hydro	126
6	Mangdechhu Hydro	720
7	Mini/Micro Hydro	8
8	Rubesa Wind	0.6
Total		**2,335**

Table 2: Hydroelectric Plants Under Construction

Sl. No.	Hydropower Plant/Project	Installed Capacity (MW)
1	Punatsangchhu-I	1200
2	Punatsangchhu-II	1020
3	Kholongchhu	600
4	Nikachhu	118
Total		**2,938**

Capacity addition of 2,938MW is envisaged from the under-construction hydroelectric projects. However, two of these four projects viz. Punatsangchhu-I and Kholongchhu are delayed due to various challenges and thus the commissioning dates of these two projects are uncertain at the present juncture.

2.2. Planned Hydropower Installed Capacity Addition

Bhutan is endowed with significant hydropower repositories with potential of about 37GW out of which 33GW is techno-economically viable for development[1]. There are four major projects with total capacity of 2,938 MW under construction which are expected to be commissioned

[1] Power System Master Plan-2040

between 2023 and 2028. In addition, there are eight projects in pipeline whose Detailed Project Reports have either been completed or under advanced stages of completion.

The National Transmission Grid Master Plan-2018 reflects eight hydroelectric projects with total capacity of 8,814 MW whose DPR are either under advanced stage of completion or completed and can be pursued for construction.

The Power System Master Plan, 2040 has identified 18 suitable sites with the installed capacity of 6,130MW and annual energy of 26,849 GWh to be developed within the 2040 timeframe. DRE's RE Master Plan also identifies renewable energy projects out of which, solar plants are considered in the generation scenario.

2.3. Generation Scenarios

2.3.1. Scenario I: Baseline

The Business as usual (BAU) scenario considers all existing generating plants (irrespective of their life spans) and all under-construction hydroelectric projects including 14.9 MW Sephu Solar plant. However, it excludes the Dagachhu HPP as all of its generation is sold under deemed export model. Similarly, only 20% of Nikachhu power is considered as 80% of its power is deemed exported. Thus, the following sources are included under this scenario I:

Table 3: Generation Scenario I (Baseline)

Sl. No.	Plant	Installed Capacity (MW)	Firm Power (MW)	Design Energy (MU)	COD (month-year)	Remarks
1	Chhukha	336.0	79.9	1800.0	1986-88	
2	Tala	1020.0	190.8	4865.0	2006-07	
3	Kurichhu	60.0	18.7	400.0	2001-02	
4	Basochhu Upper and Lower	64.0	15.6	291.0	Nov-01(US) Sep-04 (LS)	
5	Mangdechhu	720.0	90.0	2923.7	Jun-Aug 19	
6	Rubesa Wind	0.6	0.0	1.0	Jan-16	
7	Nikachhu	118.0	22.6	491.5	Jul-23	As per BPSCC MoM
8	Sephu Solar	14.9	7*	25.7	Jan-24	firm power during day time only
9	Punatsangchhu-II	1020.0	164.0	4357.0	Dec-24	As per BPSCC MoM
10	Punatsangchhu-I	1200.0	199.0	5429.0	Jul-28	Assumed
11	Kholongchhu	600.0	113.8	2568.9	Jan-31	Assumed

2.3.2. Scenario II

The scenario considers all existing generating plants (irrespective of their life spans), all under-construction hydropower projects and addition of capacities from the following additional generating plants (over and above that of Scenario I):

Table 4: Generation Scenario II

Sl. No.	Plant	Installed Capacity (MW)	Firm Power (MW)	Design Energy (MU)	COD (Month-Year)	Remarks
1	Suchhu	18.0	2.9	76.6	Jul-25	As per FS
2	Yungichhu	32.0	8.0	157.6	Nov-25	As per FS
3	Burgangchhu	54.0	14.3	260.5	Nov-25	As per FS
4	Druk Bindu (I & II)	26.0	4.33	76.5	Jun-26	As per PFS
5	Jomori	85.0	23.0	362.4	Jun-28	As per PFS
6	Begana	20.0	3.3	96.8	Jun-26	As per PFS
7	Gamri -I	45.0	7.5	165.0	Jun-27	As per PFS
8	Gamri -II	85.0	14.2	303.0	Jun-27	As per PFS
9	Dorjilung	1125.0	168.0	4558.0	Jan-31	As per DPR
10	Nyera Amari Integrated	404.0	102.0	1599.0	Jan-31	As per DPR
11	Bunakha	180.0	58.6	707.4	Jan-33	As per DPR
12	New Solar Plants	308.0	149.0	442.7	Jan-26	As per DRE

2.3.3. Scenario III

Under Scenario III, in addition to all the generating plants considered under Scenario-II, the following are added to project a long-range scenario:

Table 5: Generation Scenario III

Sl. No.	Plant	Installed Capacity (MW)	Firm Power (MW)	Design Energy (MU)	COD (Month-Year)	Remarks
1	Gongri	740.0	129.6	2721.5	Jan-35	COD assumed considering pre-construction, investment clearance, etc
2	Sunkosh	2585.0	427.6	6365.4	Jun-35	COD assumed considering pre-construction, investment clearance, etc

2.4. Generation Forecasting Methodology

The generation from the existing plants (Kurichhu, Chhukha, Tala, Basochhu, and Mangdechhu) are determined based on the total design energy less the auxiliary losses. The monthly generation is forecasted based on the month-wise trend of the 2021 actual generation. For the upcoming hydropower projects, the generation forecast is based on the monthly design energy for individual plants.

DEMAND

3.1.Demand 2011-2021

The consumption pattern[2] amongst different categories of consumers in Bhutan are as follows:

Table 6: Energy consumption across different sectors

Particulars		2016	2017	2018	2019	2020	2021
Domestic	Rural	103	112	122	129	146	153
	Urban	134	133	135	140	156	168
Commercial		57	63	68	73	59	59
Industrial		9	9	9	10	8	8
Cottage and Small-Scale Industries		0	0	0	0	7	7
Agriculture		2	2	2	2	2	2
Institutions		62	60	63	67	66	75
Religious Institution		0	4	4	5	5	7
Street lighting		4	4	4	5	5	5
Power house auxiliaries		1	1	1	1	1	1
Temporary connections		23	26	29	31	22	19
Bulk (MU)		65	67	72	81	71	66
LV Total (MU)		**460**	**482**	**511**	**546**	**550**	**569**
MV Industries (MU)		**111**	**114**	**122**	**128**	**81**	**109**
HV Industries (MU)		**1437**	**1590**	**1696**	**1607**	**1330**	**1,797**
Total Consumption (MU)		**2,009**	**2,186**	**2,328**	**2,281**	**1,961**	**2,474**

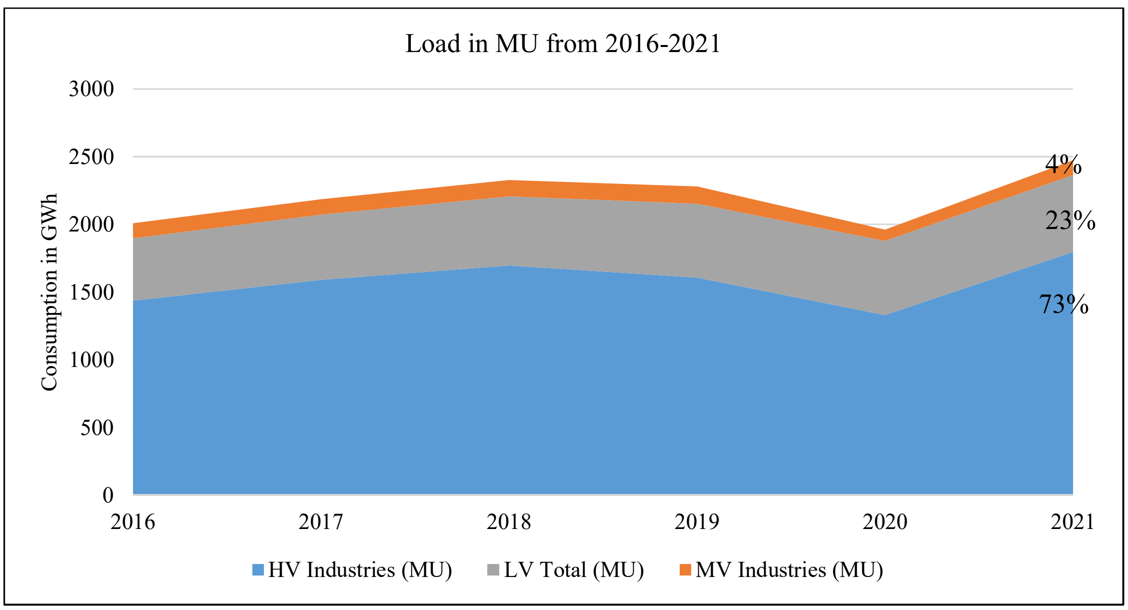

Figure 2: Distribution of Energy consumption by percentage

[2] Power Data Book 2021, Bhutan Power Corporation Limited

3.2. Industry Load

The industries are classified into three different categories based on the voltage level at which they draw power viz. High Voltage (HV), Medium Voltage (MV) and Low Voltage (LV). The number of total customers in each category (LV total includes LV industries as well as all other LV domestic/institutional customers) is shown in the following table:

Table 7: Number of customers

Particulars	2016	2017	2018	2019	2020	2021
LV Total	177,089	185,055	192,780	202,336	213,549	221,964
MV Industries	46	59	70	73	65	73
HV Industries	16	16	16	17	15	19

3.2.1. High Voltage

As per customer classification system, HV customers are those that draw power at 66 kV or higher voltage level or require more than 15 MW of power. There are 20 HV consumers, all of which are heavy industries except for one that is construction power of Punatsangchhu hydroelectric projects. The total energy consumption by HV consumers in 2021 was 1,797 MU and constituted 73% of the total annual demand.

3.2.2. Medium Voltage

The MV customers are those that draw power at the 11 kV or higher voltage level or require more than 300 kW of power. There are 73 numbers of MV industries as of 2021, which cumulatively consumed around 109 MU of electricity in 2021.

3.2.3. Low Voltage

The Low Voltage Customers consist of Rural Residentials, Rural Cooperatives, Rural Micro Trade, Rural Community Lhakhang, Highlanders, Urban, Religious Institutions, Cottage and Small-Scale Industries, Commercial, Industrial, Agriculture, Institutions, Street lighting, Powerhouse auxiliaries, Temporary connections and LV Bulk. There are 221,964 customers as of 2021 and the total electricity consumption in 2021was 569MU[3]. The industry load from LV connections attributed to 1.3% of cumulative load from LV category in 2021.

[3] Power Data Book 2021, Bhutan Power Corporation Limited

3.2.4. Upcoming Industries

There are several upcoming HV industries with total power requirement of 636 MW by 2023. Similarly, there are over 62 upcoming MV industries with a power requirement of around 77 MW being planned to be connected to the grid during the same period.

3.3. Demand Forecast Methodology

There are 18 categories of customers depending on the level of voltage the customers are connected. Based on the past consumption trends, different forecasting methodologies are used to forecast the future demand from each of these categories. The past demand data of majority of LV customer categories show seasonal pattern with increasing trend on year-on-year comparison. For simplicity, the LV consumers' demand has been forecasted based on linear projection of CAGR.

However, the MV and HV industries make the majority of the national electricity demand and therefore the forecast of national load is highly sensitive to any change in the industrial load, especially that of HV industries. Therefore, a mixed approach as explained in ensuing paras, is used to analyze and forecast the industrial load.

For the existing MV and HV industries, i.e., those already established and connected to the grid, the monthly energy demand forecast is based on load factor[4] and peak demand forecast is based on the demand factor[5]. For the existing industries the contracted demand is assumed to be constant.

The forecast for the upcoming industries is based on the expected demand of individual industries. The Department of Hydropower and Power Systems issue power clearance and power sanction to the upcoming industries[6]. Based on the estimated date of connection/commissioning, the forecast for the load from upcoming industries are made.

3.4. Demand Forecast Scenarios

3.4.1. Scenario A

Under Scenario A, all planned loads including the ones which have signed Capacity Reserve Agreements or have been issued power sanctions are considered. Most of the loads are assumed

[4] Load Factor = average load (kWh)/time*peak load
[5] Demand Factor = Maximum demand / Total connected load
[6] From 1 June 2022, all power clearances and sanctions for industries, irrespective of sizes are issued by DHPS.

to be connected to the grid in phases (as per individual plans) and some of the loads are expected to be in operation for 8 months (April – November) in a year.

3.4.2. Scenario B

Under the Scenario B, in addition to the Scenario A's load, other industries whose power clearances have been issued are taken into consideration. The dates of operationalizing the industries are loosely based on the dates reflected by the proponents in the application forms. These loads are highly subjective and has a high probability of not being realized or being altered in terms of the capacity and date of operationalization.

3.5.Demand Projection till 2040

From 2022 onwards peak power shortages are anticipated in the lean seasons due to drastic increase in domestic load. However, in terms of annual energy, surplus is expected. The graph showing the electricity demand till 2040 under the two scenarios are depicted in Figure 3. The HV and MV load addition is assumed based on the application received for power sanction and power clearance for setting up industry in the identified industrial parks and other areas. For the forecast of demand from HV and MV consumers, the load factor of past years (2010 to 2021) and corresponding contract demands were considered in addition to the assumption of the new HV and MV loads coming up as proposed by the industrial proponents. However, since no application has been received for industries commencing beyond 2026 and the lack of data to make assumptions of upcoming industries beyond 2026, no additional load have been considered beyond this period. Nevertheless, the trend of growth in LV demand has been based on historical growth which is 5.5% CAGR on an average.

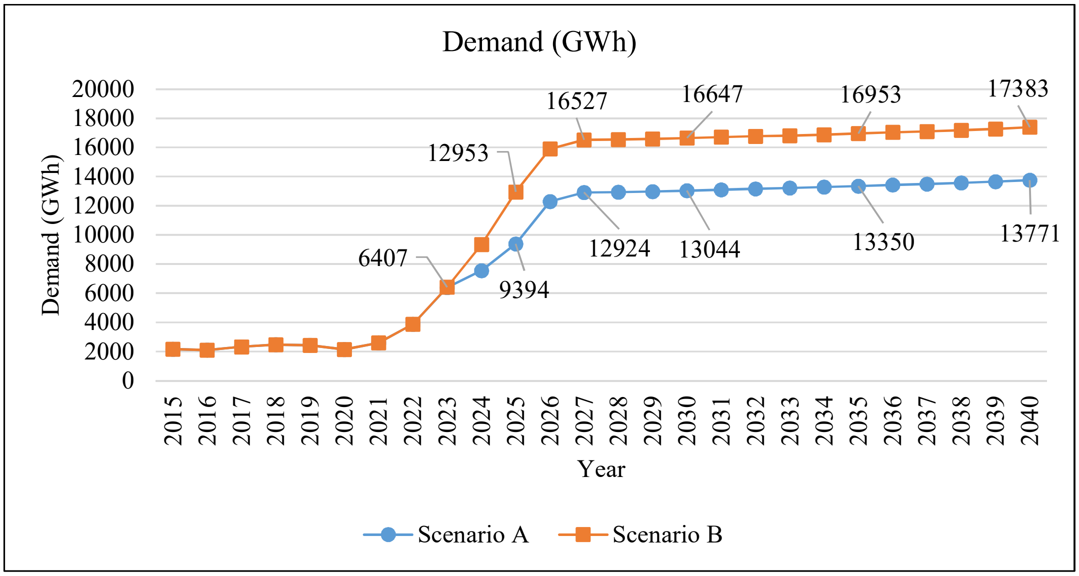

Figure 3: Demand in term of Energy (MU) – Scenario A & B

The customer category wise projections in terms of MU in both scenario is provided below.

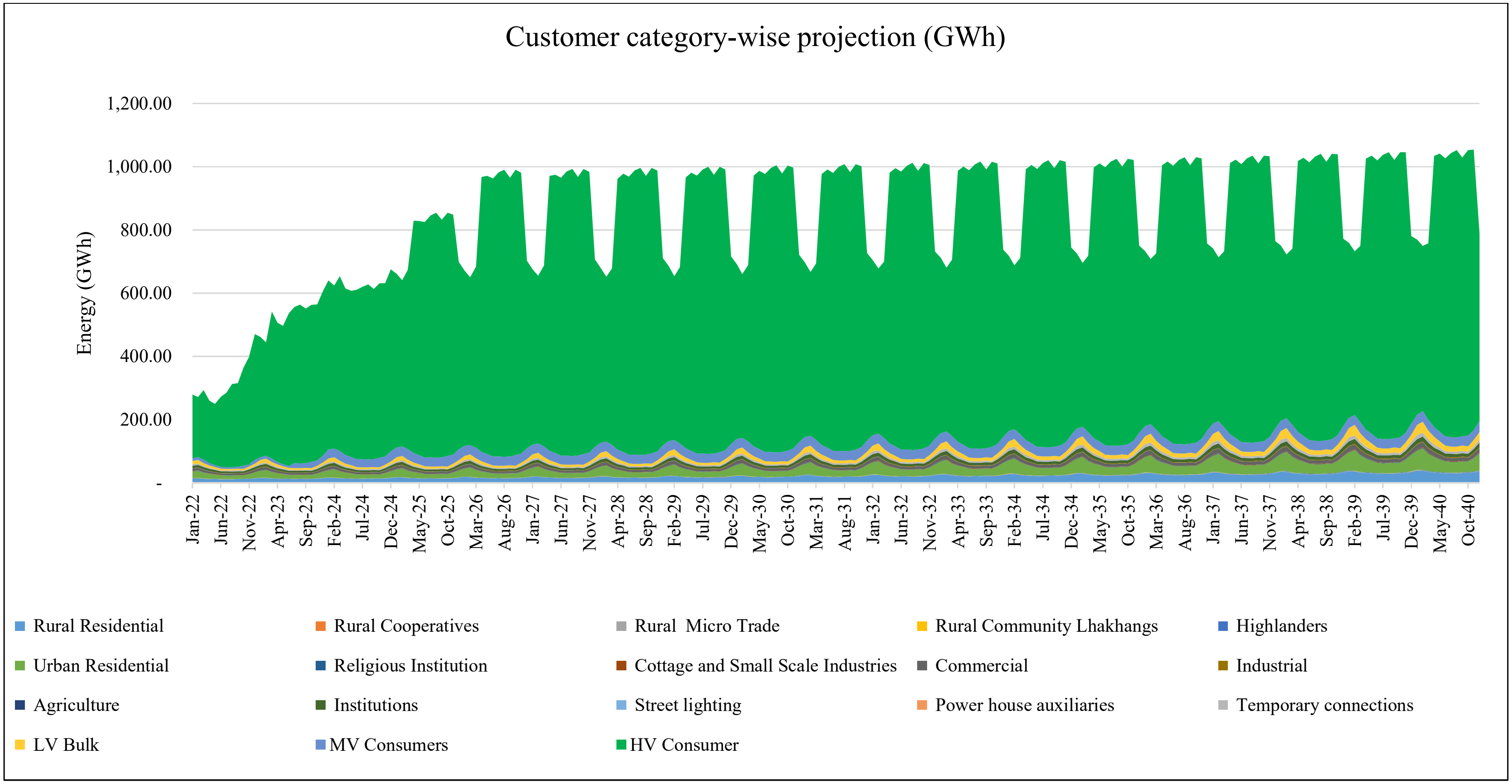

Figure 4 Customer category wise projections (GWh)

SUPPLY - DEMAND

4.1.Generation – Load

The graph showing the electricity supply and demand till 2040 are shown in Figure 5 to Figure 6 considering different generation- load scenarios:

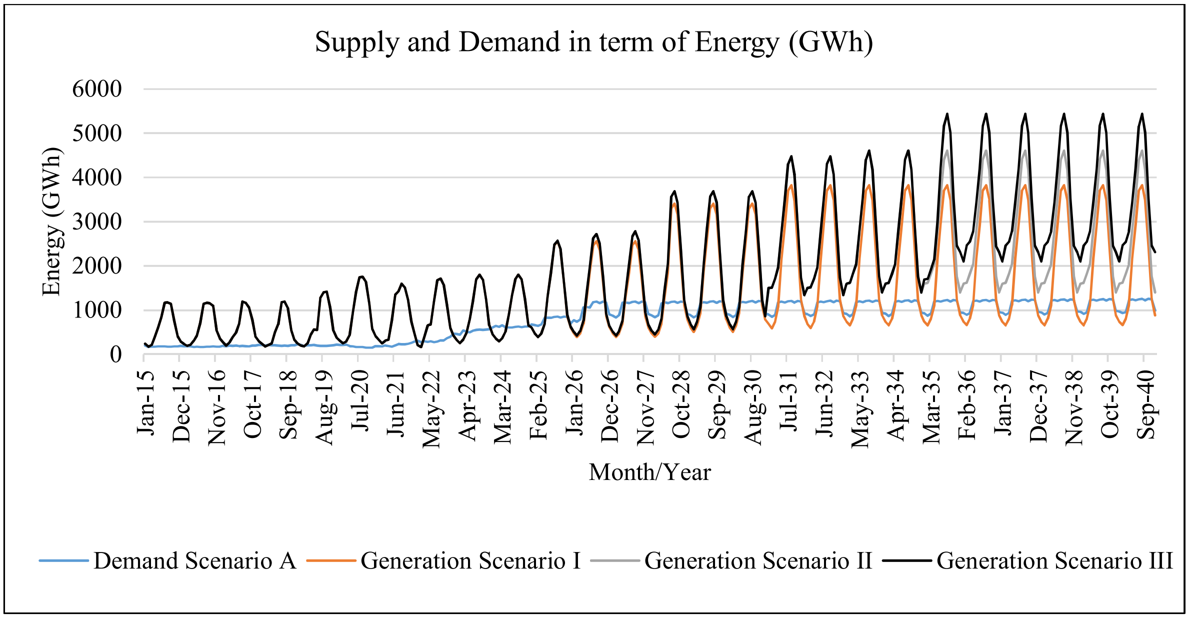

Figure 5: Supply and Demand in term of Energy (GWh) – Generation Scenarios I, II & III under load Scenario A

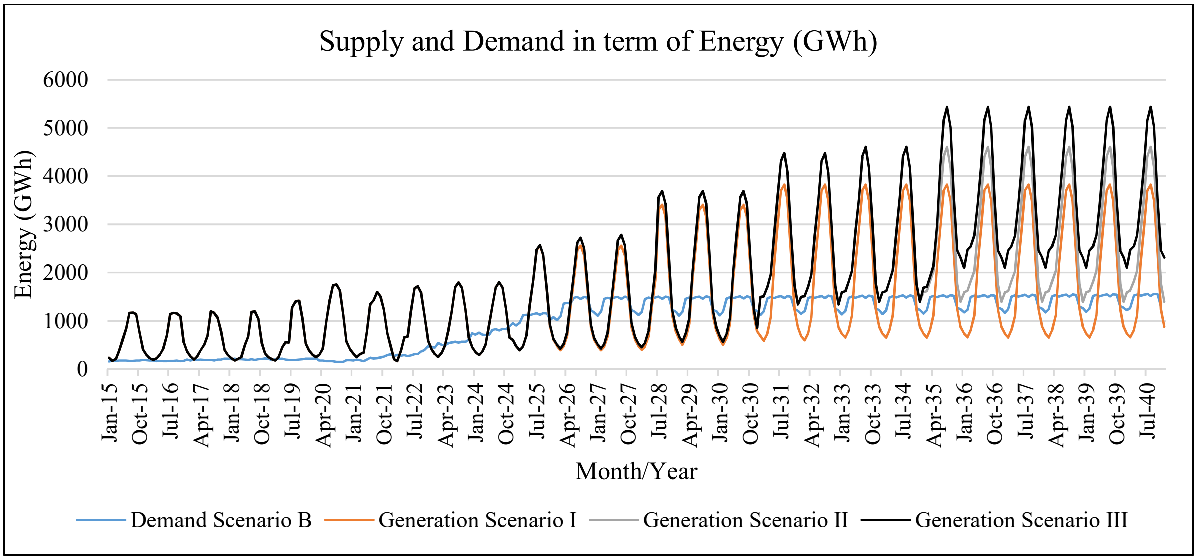

Figure 6: Supply and Demand in term of Energy (MU) – Generation Scenarios I, II & III under load Scenario B

4.2 Power Import

Although the present installed capacity is 2,326 MW from large hydro alone, the corresponding firm power capacity is limited to 410.8 MW and will not be able to meet the growing domestic peak load. The load forecast shows that Bhutan will continue to face power shortages in lean seasons even with the commissioning of under-construction hydropower power projects. As per the Bhutan Sustainable Hydropower Development Policy (SHDP) 2021, although industries have the least priority for supply of power, shutdown of industries due to deficit of power supply, unless during exigencies, is not an option that should be considered unless the cost of imported power is beyond the affordability of the industries. The only viable option to secure power supply during the deficit period is by importing power through a suitable import mechanism. As per the Domestic Electricity Tariff Policy of the Kingdom of Bhutan 2016, the cost of net-import is to be passed through to HV customers. The Tariff Determination Regulation 2016 defines the allocation of the cost of electricity import to the HV consumers prorated on individual HV industry's consumption. Under the extreme case of non-availability of adequate power supply, the order of merit for supply of power is to be as per SHDP 2021.

To meet the power deficit mainly attributable to the shutdown of Tala power plant in the last lean season, the GoI approved the import of power from the Day Ahead Market in Indian Power Exchange (IEX) based on CERC's Import/Export (Cross Border) of Electricity Guidelines 2018. Accordingly, Bhutan imported a total quantum of 203 MU of energy from 1 Jan to 16 March 2022. The projected import was 240MU that was bid in the Day Ahead Market in the IEX. The under drawl of power was mainly due to the unexpected shut down of some of the HV industries and also due to the short term outages during the heavy snowfall during this period.

4.2.1. Power Import in Upcoming Lean Season

As per the demand supply analysis, it is anticipated that there will be power shortage in the upcoming lean season from December 2022 through April 2023 as shown in figure 7. In the upcoming lean season from December 2022 to April 2023, a need to import total energy quantum of around 1009 MU is projected. It is projected that there will be an increasing trend in the import over the next couple of years.

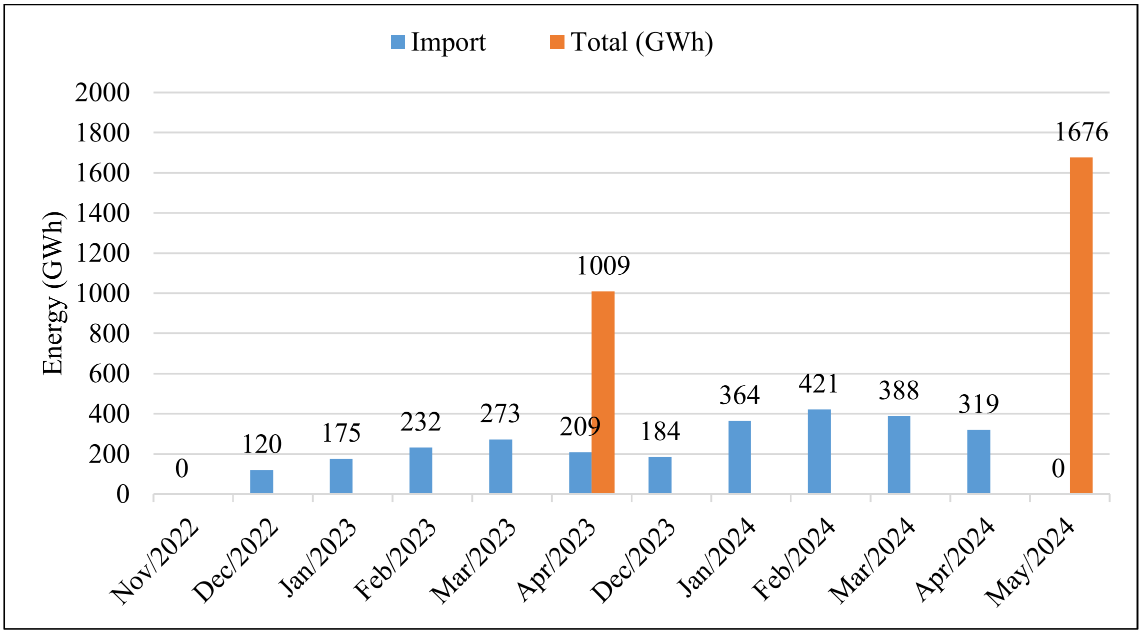

Figure 7: Demand-Supply in Upcoming Lean Season (in MU)

ELECTRICITY TARIFF

5.1. Domestic Electricity Tariff

The tariff for generation, transmission and distribution are computed based on Tariff Determination Regulation 2016, which comprise of O&M, depreciation, return on Assets, Working capital, fees, charges & levies, losses and power purchase. The generation tariff structure comprises of single average energy charge. The tariff structure for general LV customer comprises of energy charges with progressive block. The tariff structure for HV and MV industries consist of fixed and variable charges. The tariff is review in every three years. The existing tariffs is shown in the following tables:

Table 8: Approved tariff for end users from 2019 to 2022

Approved End-User Tariff

Tariff structure	Unit	1st October 2019 to 30th June 2020	1st July 2020 to 30th June 2021	1st July 2021 to 30th June 2022
Low Voltage (LV)				
LV Block I(Rural*) 0-100 kWh	Nu./kWh	0	0	0
LV Block I (High landers) 0-200 kWh	Nu./kWh	0	0	0
LV Block I(Others) 0-100 kWh	Nu./kWh	1.28	1.28	1.28
LV Block II(All) >101-500 kWh	Nu./kWh	2.68	2.68	2.68
LV Block III(All) >500 kWh	Nu./kWh	3.57	3.60	3.64
LV Bulk	Nu./kWh	4.06	4.10	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	1.50	1.50	1.50
Demand Charge	Nu./kVA/Month	292	292	292
Wheeling	Nu/kWh	0.270	0.270	0.270
Generation Tariff	Nu/kWh	1.50	1.50	1.50

Table 9: Approved tariff for generation from 2019 to 2022

Approved Generation Tariff

	Unit	1st October 2019 to 30th June 2020	1st July 2020 to 30th June 2021	1st July 2021 to 30th June 2022
DGPC Tariff	Nu/kWh	1.42	1.42	1.42
MHPA Tariff	Nu/kWh	3.77	3.77	3.77
Weighted Avg. Domestic Generation Tariff	Nu/kWh	1.50	1.50	1.50

5.2. Generation Tariffs

For the determination of the domestic tariff, the primary input is the weighted average cost of generation and for this, the individual cost of generation has been determined.

5.2.1 Existing Hydropower Plants

Generation cost of DGPC Power Plants and MHP

The cost of generation of DGPC existing power plants including embedded generation and that of Mangdechhu HEP is computed based on the BEA- Tariff Determination Regulation 2016 and taking into consideration the provisions as outlined in Bhutan Domestic Tariff Policy 2016. The cost parameters approved by BEA for tariff period 2022-2025 is used as reference for tariff projections till 2040. The following parameters were considered.

Table 10: DGPC Tariff Projection

S. N	Items	Unit	2022-25	2025-28	2028-31	2031-34	2034-37	2037-40	Remarks
1	Cost of Equity	%	13.59%	13.59%	13.59%	13.59%	13.59%	13.59%	*CoE maintained throughout same as approved in 2022-25 tariff period*
2	Cost of Debt	%	8.83%	10.42%	11.09%	11.09%	11.09%	11.09%	*After Basochhu loan is liquidated by 2028, loan is for only new investments at interest rate of 11.09%*
3	Gearing	%	60%	50%	50%	45%	40%	40%	*The actual gearing ratio of DGPC decreases, therefore the proposed gearing is also decreased accordingly*
4	WACC	%	13.06%	14.92%	15.25%	15.67%	16.08%	16.08%	
5	O&M Allowance	MNu.	1,587	*5% escalation as per the inflation rate*					*O&M allowance considered for 2022-25 is as per approval by BEA*
6	O&M Escalation	%	*3.40%*	*5%*	*5%*	*5%*	*5%*	*5%*	*5% annual escalation (based on past inflation rates as per NSB)*
7	O&M Efficiency Gains	%	1%	0%	0%	0%	0%	0%	
8	O&M Benchmark	%	1%	1.5%	1.5%	1.5%	1.5%	1.5%	
9	Inventory	MNu.	455.16	455.16	455.16	455.16	455.16	455.16	*Inventory value maintained same*
10	Arrears	Days	40	40	40	40	40	40	*As approved by BEA*
11	Investments	%	2017.45	*7% annual escalation based on the past approved investments by BEA*					
12	Interest on Working Capital	%	9.23%	9.23%	9.23%	9.23%	9.23%	9.23%	*As approved by BEA*
13	Aux Losses	%	0.90%	1.20%	1.20%	1.20%	1.20%	1.20%	*Aux losses increases as the plants get old*
14	Energy	MU	6,163	6,144	6,144	6,144	6,144	6,144	
15	**Tariff**	**Nu./ Unit**	**1.34**	**1.38**	**1.40**	**1.46**	**1.55**	**1.74**	

Table 11: Mangdechhu Projected Tariff

S.N	Items	Unit	2022-2025	2025-2028	2028-2031	2031-2034	2034-2037	2037-2040	Remarks
1	Cost of Equity	%	*13.59% (11.09% Average lending rates +2.5% premium)*						*CoE maintained same throughout as approved in 2022-25 tariff period*
2	Cost of Debt	%	10%	10%	10%	10%	10%	11.09 %	*MHPA loan repayment will be completed by 2037*
3	Gearing	%	70%	50%	50%	45%	40%	40%	*The actual gearing ratio of MHPA decreases, therefore the proposed gearing is also decreased accordingly*
4	WACC	%	12.82 %	13.30 %	13.77 %	14.28 %	14,71 %	15.67 %	
5	O&M Allowance	MN u.	564.51	-	-	-	-	-	*O&M allowance considered for 2022-25 is as per approval by BEA*
6	O&M Escalation	%	*3.4% annual escalation*	*5% annual escalation (based on past inflation rates as per NSB)*					*5% annual escalation (based on past inflation rates as per NSB)*
7	O&M Efficiency Gains	%	0%	0%	0%	0%	0%	0%	
8	O&M Benchmark	%	1%	1.5%	1.5%	1.5%	1.5%	1.5%	
9	Inventory	MN u.	84.68	145.95	145.95	145.95	145.95	145.95	*Inventory value in reference to Tala Hydropower Plant*
10	Arrears	Days	40	40	40	40	40	40	*As approved by BEA*
11	Investments	%	*As approved by BEA*	*12% annual escalation based on the past approved investments by BEA*					
12	Interest on Working Capital	%	9.23%	9.23%	9.23%	9.23%	9.23%	9.23%	*As approved by BEA*
13	Aux Losses	%	0.90%	1.20%	1.20%	1.20%	1.20%	1.20%	*Aux losses increases as the plants get old*
14	Energy	MU	2,648	2,646	2,646	2,646	2,646	2,646	
15	**Tariff**	**Nu./ Unit**	**3.64**	**3.43**	**3.37**	**3.26**	**3.18**	**3.21**	

5.2.2 Planned Hydropower Projects

The Detailed Project Reports (DPR) and Prefeasibility Reports (PFR) for the hydropower plants under consideration utilized different price levels to determine the cost of the project, and since the hydropower projects would start at various periods, the cost of the projects needed to be escalated to the price level of the corresponding years to determine a realistic cost to completion. For this, the actual inflation rate till 2021 as published by the National Statistics Bureau (NSB) was used. The projection of the inflation is based on the past five year moving average figures.

With the update of the cost to completion, the IDC also changes, and this has also been considered for the determination of the final cost of generation for each plant. In addition, project investment of 1% of the project hard cost has been assumed in the 6th year and onwards.

The cost of generation of upcoming projects is computed based on the BEA- Tariff Determination Regulation 2016 and taking into consideration the provisions as outlined in

Bhutan's Sustainable Hydropower Development Policy-2021. The following parameters were considered as explained in table below.

Table 12: Generation Tariff Parameters

Sl. No.	Items	Unit	BEA Parameters (Domestic Tariffs)
1	Hard Cost of the Project	Mil. Nu.	Escalated to cost of completion using the actual inflation figure as published by NSB and projection based on past five years moving average.
2	Interest During Construction (IDC)	Mil. Nu.	Based on the cost to completion and escalated year phasing value.
3	Total Project Cost including IDC	Mil. Nu.	Cost to completion including IDC and FC
4	Loan (Principal)	Mil. Nu.	70% of total project cost
5	Grant/Equity	Mil. Nu.	30% of total project cost
6	Interest Rate on Loan	%	10.00%
7	Loan Repayment Period	Years	15 years for all plants except for PHPA II (12 years)
8	Land Cost	Mil. Nu.	As per DPR (escalated to cost of completion)
9	Royalty Energy	%	15% (as per SHDP)
10	Transmission Loss	%	2.00%
11	Auxiliary and Transformation Loss	%	1.12%
12	Rate of Return on Equity (Post-tax) (Gen)	%	13.31% (as approved by BEA for the tariff cycle 2019-2022)
13	Discount Rate	%	10%
14	Depreciation Rate (As per loan repayment period of 15 years)	%	(Debt + IDC)/repayment period and spread over to the remaining period
15	Base rate of O&M cost (Gen)	%	1% of hard cost
16	Annual escalation rate on O&M cost (Gen)	%	3.40% per annum
17	Maintenance Spares (% of O&M cost)	%	15% per annum
18	Economic Life	Years	30 years (as per the SHDP 2021)
19	Salvage Value	%	0%
20	Interest rate on working capital	%	9.97%
21	Rehabilitation and Resettlement Cost	Mil. Nu.	As per DPR (escalated to cost of completion)
22	Design Energy	MU	90% dependable energy with 95% plant availability
23	Tax	%	30

5.2.3 Weighted Average Cost of generation

In order to meet the projected demand, the quantum of energy required from the generation plants are computed. The selection of generation plants is carried out in order of the generation tariff price to utilize the cheaper plants for the domestic demand. The energy purchase requirements under two demand scenarios A and B and Generation Scenario I, II and II are calculated. Accordingly, the weighted average costs of generation are worked out for each tariff cycle.

5.2.4 Domestic Tariff Projection

The domestic tariff is projected considering the assumptions in the tariff input parameters given in the table below.

Table 13: Domestic Tariff Parameters

Input parameters		Assumptions
1	Energy Sales Forecast (Scenario A & B)	The HV energy sales is projected considering the additional loads from 2025-2040. The MV energy sales is projected considering the expected upcoming loads at Industrial Parks & Gyalsung Projects. The LV energy sales is projected using the CAGR (Compound Annual Growth Rate) method.
2	Investments	Transmission investment is projected considering National Transmission Grid Master Plan (NTGMP), investment in line to DGPC new plants and upcoming additional loads. Distribution investment is projection considering investments in line to Distribution System Master Plan (DSMP), Smart Grid Investment, meters, upgradation of distribution transformers and distribution lines. The other investment is projected considering the proposed and historical investments.
3	Cost of Equity (CoE)	Considered 13.59% throughout (11.09 % and 2.5 % i.e., 250 basis point)
4	Cost of Debt (CoE)	Projected with past 3 tariff period approved CoD for each customer category.
5	Inflation	Assumed projected inflation figure used in determining the cost of new plants
6	Working Capital	Considered 9.23% same throughout
7	Gearing Ratio (Forced)	i) Wheeling - 70%; ii) HV - 60%; iii) MV - 70% and

		iv) LV - 70% Gearing Ratio considered same throughout
8	Asset Value	New asset value is generated from the tariff model
9	Allocation Factor	The allocation factor is considered same as proposed allocation factor for tariff 2022-2025
10	BPSO Fees, Non-Tariff Revenue, Historical O&M, Replacement Cost	Projected after considering the historical data
11	Generation Average Price	Considering the 3 Generation Scenarios (I-BAU, II & III)

5.2.1. Cost Plus Model

The tariff is determined based on the cost-recovery principle. The tariff approved by BEA is based on the allowable network cost (i.e. BPC network cost) and the energy purchased from generation plants.

BPC network cost comprises of (i) Operating and maintenance costs; ii) Depreciation; iii) A return on fixed assets, including an allowance for company taxation; v) The cost of losses and non-payment of electricity bills; vi) The cost of working capital; and vii) Any regulatory fees, duties or levies that the Licensee is liable to pay under the existing norms.

The weighted generation costs of scenarios are considered as the energy purchase price. Using BEA's model for distribution to calculate the tariff, the end tariff for each tariff cycle is computed and depicted in the table below:

Table 14: Domestic Tariff Forecast from 2025 to 2040

SCENARIO			Cycle 1	Cycle 2	Cycle 3	Cycle 4	Cycle 5
			Jul-25 to Jun-28	**Jul-28 to Jun-31**	**Jul-31 to Jun-34**	**Jul-34 to Jun-37**	**Jul-37 to Jun-40**
Load	**Generation**						
SCENARIO A	SC I BAU	Weighted Generation Price (Nu./kWh)	2.28	2.87	2.98	3.03	2.79
		Cost of Supply (Nu./kWh)	3.31	3.88	4.07	4.24	4.12
	SC II	Weighted Generation Price (Nu./kWh)	2.39	3.13	3.34	3.43	3.33
		Cost of Supply (Nu./kWh)	3.38	4.08	4.32	4.51	4.51
	SC III	Weighted Generation Price (Nu./kWh)	2.39	3.13	3.34	3.44	3.35
		Cost of Supply (Nu./kWh)	3.38	4.08	4.32	4.52	4.53

SCENARIO B	SC I BAU	Weighted Generation Price (Nu./kWh)	2.53	3.18	3.26	3.30	2.92
		Cost of Supply (Nu./kWh)	3.45	4.09	4.24	4.39	4.11
	SC II	Weighted Generation Price (Nu./kWh)	2.56	3.37	3.77	3.87	3.72
		Cost of Supply (Nu./kWh)	3.45	4.2	4.57	4.97	4.69
	SC III	Weighted Generation Price (Nu./kWh)	2.56	3.37	3.77	3.87	3.73
		Weighted Generation Price (Nu./kWh)	3.45	4.2	4.57	4.76	4.93

The Network cost is to be applied as per the existing structure of Nu./kVA/month as fixed cost.

5.2.2. Power Purchase Agreement

The Domestic Electricity Tariff Policy has provision for Industrial customers to opt for Power Purchase Agreement (PPA) with the service provider to ensure long term price predictability upon the approval of BEA.

Currently the generation licensees have PPA for export of electricity. In 2007, BPC had signed a long term PPA with an industrial customer for commencement by 2008. However, in 2013, the customer opted out of the PPA to follow the three-year tariff cycle approved by BEA.

The tariff structure for the MV and HV consist of variable charge (domestic generation cost) and fixed cost (network cost). There are possibilities to sign separate PPAs with generation licensee(s) for energy and transmission and distribution licensee(s) for the network cost.

Instead of following the three-year tariff cycle approved by BEA, if the option of PPA is considered by industrial proponent, the tariff framework with annual increment of around 4% to 7% over the next 15 years (2025 – 2040) is expected.

5.3. Imported Power Tariff

5.3.1. Power Exchange Market

Assuming that the GoI will approve the import of power from India's power exchange market, of which IEX is predominantly the most preferred platform, the current study presents the expected cost of power from IEX for the non-peak hours. It is anticipated that the power plants will be operated under optimal flexible generation modes to avoid the costlier power to the extent possible.

The price discovery through IEX is dynamic and determined for every 15-minute block with the final Market Clearing Price (MCP) for each 15-minute block being most identical across all states in India unless constrained by transmission congestion. The landed cost of imported power is higher than the MCP due to charges, fees and levies from the point of purchase to the delivery point at the Bhutan-India border. The overall energy price per unit is around Nu. 0.50~0.70/unit higher than the price discovered in the Day Ahead Market in IEX. The price scenario in the IEX during the import period (1st Jan-16th March 2022) is shown in figure given below:

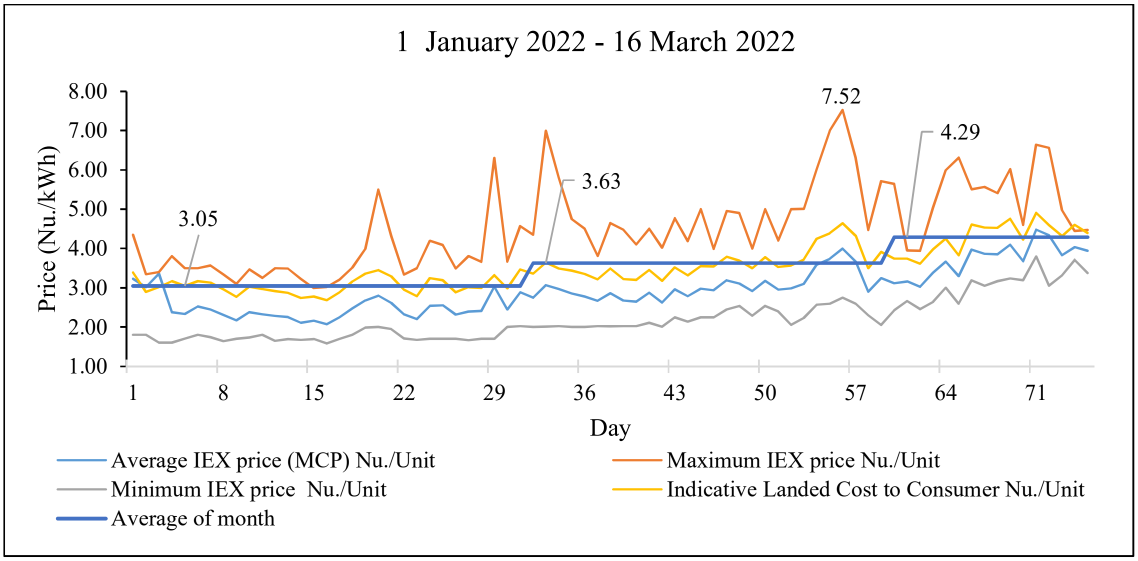

Figure 8: Price in Indian Energy Exchange Market during Jan – March 2022 Import Period

The average landed rate during the given period applicable to the imported power i.e., during non-peak hours, was around Nu. 3.53 per unit. An important aspect of buying power from exchanges is the strict grid discipline and complex energy accounting mechanism. Deviation from the scheduled power demand is heavily discouraged through India's regulated Deviation Settlement Mechanism (DSM), which is based on a regulatory mechanism by which grid stability is achieved by imposing penalty or incentives for over drawl/injection or under drawl/injection from the schedule.

5.3.2. Tariff Projection

Long term price projection of a dynamic market such as the IEX is difficult as it has to factor in numerous parameters and also requires modelling to capture the complexities. There is no price projection from the Day Ahead Market, IEX readily available. Nevertheless, an attempt has been made to estimate the trend and get a sense of what average prices in the Day Ahead Market in IEX could be in the future.

The revised draft report on "Study on Bhutan's Readiness for Regional Power Market Integration" by Deloitte depicts the future annual average prices as follows:

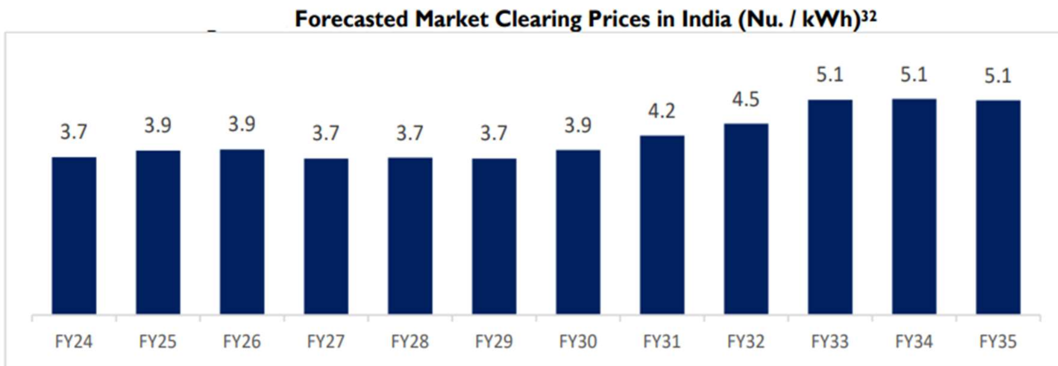

Figure 9: Projected Tariff as per Deloitte Study

However, the above prices do not give insight to the prices during the lean season when Bhutan would be importing power from India. Therefore, for a more realistic approach, the monthly prices were projected based on the historical prices (till May 2022) and the trend projected in the Deloitte's study. The projection of prices at Indo-Bhutan border (landed cost) is shown below for the lean months from Dec to April:

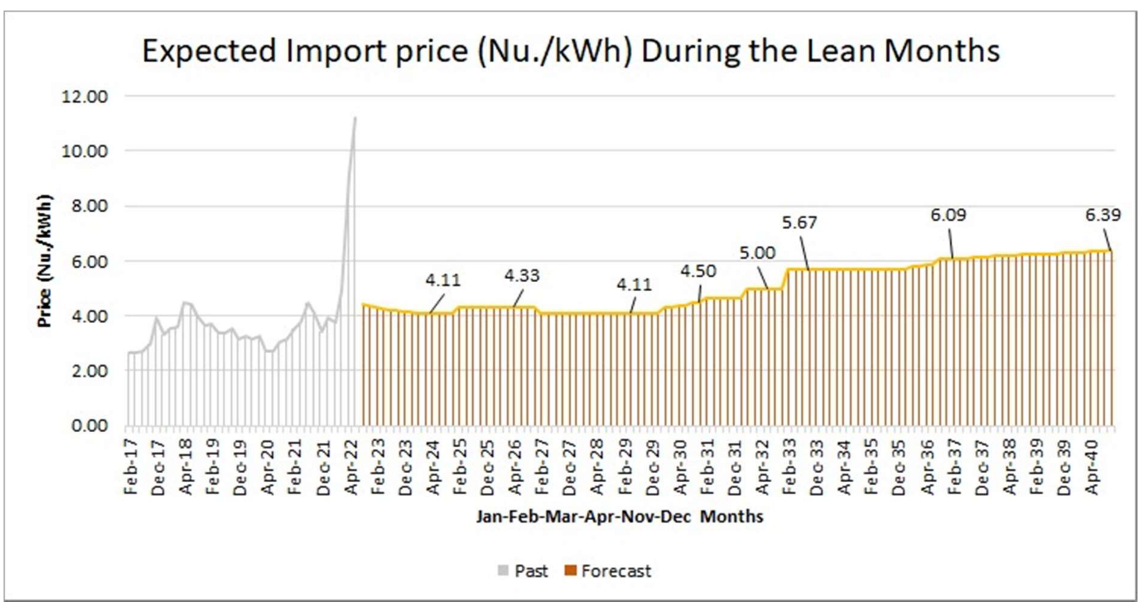

Figure 10: IEX Price Projection from June 2022 to December 2022

As per the projection, the prices are expected to vary across the months. As per the past trend (refer chart below), the Market Clearing Prices in IEX tend to rise towards April month in the beginning of the year before falling during mid-year and again rising towards October month before falling again by December.

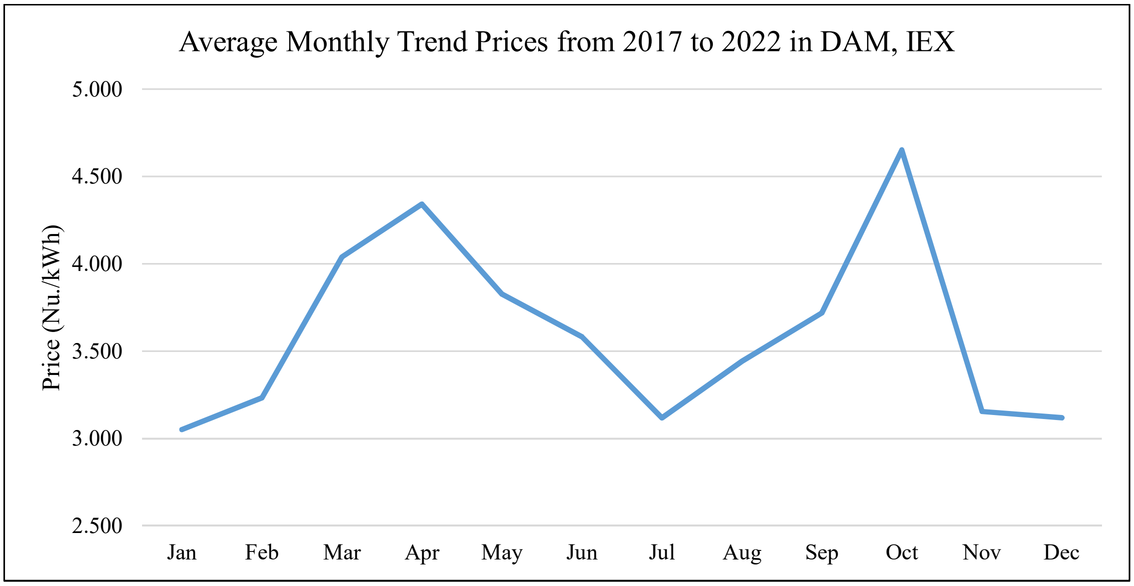

Figure 11: Average Monthly IEX Prices from 2017 to 2022 (not including fees & charges)

CONCLUSION

Under the given scenarios, the most probable generation-load scenario is the Scenario A-II and thus, considering this scenario, the domestic tariff is anticipated to reach Nu. 4.51 per unit by 2040. Highest tariff is expected under Scenario B-III at Nu. 4.93 per unit. Instead of following the three-year tariff cycle, if the option of PPA is considered by industrial proponent, the tariff framework with annual increment of around 4% to 7% over the next 15 years (2025 – 2040) may be applicable, subject to further detailed analyses and negotiations. The latter option would have an advantage over the three-year tariff cycle due to the predictability of tariff over a long term.

On the other hand, the three-year tariff is derived from the rationalization based on efficient business operation by the utilities and scrutinized every three years, it would be closer in representation of the prevailing market/ energy situations at that period of time. The main disadvantage of the three-year cycle tariff is the unpredictability of tariff for which certain policy and other interventions could be considered. For the existing cost-plus model, the Weighted Average Cost of Capital (WACC) is the main parameter, which includes the Cost of Equity (COE) that is derived from the lending rates by the financial institutions and the premium that is considered by BEA. There is possibility of revisiting the policy provisions to offer a predictable pricing regime for the benefit of the industry sector. This may be one of the interventions to create enabling conditions for industry sector development to eventually drive industrialization to realize developed Bhutan.

The forecasted domestic tariff based on the cost-plus model and associated assumptions taken are given in table 11 in preceding sections. However, considering the most probable scenario, the domestic tariff projection under scenario A-II is reproduced in table below:

Table 15: Domestic Tariff Projection - Scenario A-II

Load Scenario A	**Cycle 1**	**Cycle 2**	**Cycle 3**	**Cycle 4**	**Cycle 5**
Generation Scenario II	**Jul-25 to Jun-28**	**Jul-28 to Jun-31**	**Jul-31 to Jun-34**	**Jul-34 to Jun-37**	**Jul-37 to Jun-40**
Weighted Generation Price (Nu./kWh)	2.39	3.13	3.34	3.43	3.33
Cost of Supply (Nu./kWh)	3.38	4.08	4.32	4.51	4.51

The above projection takes into account multiple assumptions, which are again dependent on other factors that are not considered within this study due to the complexities, time, and resources required. In general, the cost of supply is highly sensitive to the generation cost and the demand quantum. On the other hand, the domestic tariffs are affordable compared to the cost of importing power, which is the actual market conditions. With the growing demand, it seems inevitable that there will be power deficit during the lean months till 2030-2031 even under the most optimistic generation scenario considered within this study. Therefore, the industrial proponents, especially those requiring to be operated all-round the year, need to factor in the cost of imported power.

Finally, the domestic tariff projection presented in this study is the reasonably realistic forecast based on information at hand at the moment. However, the sheer number of parameters and its influencing factors may render the forecast uncertain and therefore, should be understood in conjunction with the assumptions taken.

Annexure - I

Name list of Working Members

Sl No.	Name	Designation	Agency
1	Dawa Chhoedron	Chief Engineer	DHPS
2	Ugyen	Chief Engineer	DHPS
3	Sonam Tshering	Exe. Engineer	DHPS
4	Ugyen Chophel	Exe. Engineer	DHPS
5	Kinley Jamtsho	Exe. Engineer	DHPS
6	Tandin Gyeltshen	Engineer	DHPS
7	Sonam	Exe. Engineer	DHPS
8	Yeshi Tenzin	Director	DGPC
9	Karma Gyeltshen	Exe. Engineer	DGPC
10	Dechen Dema	Director	BPC
11	Sangay Wangdi	Senior Engineer	BPC
12	Tashi Lhamo	Engineer	BPC
13	Deki Choden	Chief	BEA
14	Mindu Wangmo	Senior Tariff Officer	BEA
15	Nermin	Senior Tariff Officer	BEA