Report

On

Long Run Marginal Cost Estimation and Tariff Design for Nepal's Evolving Power Sector

This report has been prepared for the Electricity Regulatory Commission by:

Rabin Shrestha
Senior Power Economist
rabin333025@outlook.com

Disclaimer

This report (including any enclosures and attachments) has been prepared exclusively for the use and benefit of the Electricity Regulatory Commission of Nepal and Nepal Electricity Authority, solely for the purpose for which it has been provided, and is issued pursuant to Clause 6 Item 3 of the Electricity Consumer Tariff Determination Directives , 2083. This should/will just serve as one of the references for the determination of consumer tariff.

July 2026

Table of Contents

List of Abbreviations and Acronyms

ERC	Electricity Regulatory Commission
FY	Fiscal Year
GWh	Giga Watt-hour (million kWh)
kW	kilo Watt
kWh	kilo Watt-hour
MUV	Manufacturing Unit Value
LRMC	Long Run Marginal Cost
MW	Mega Watt (1000 kW)
MWh	Mega Watt-hour
NEA	Nepal Electricity Authority
NPR	Nepalese Rupees
O&M	Operations and maintenance
SRMC	Short run Marginal Cost
TOU	Time of Use
USD	United States (of America) Dollar

List of Figures

List of Tables

1. Introduction

Nepal's electricity sector is undergoing rapid transformation with shifts in demand patterns, generation mix, infrastructure development, and cross-border power trade. However, electricity tariffs have not kept pace with these changes and continue to fall short of reflecting the true cost of supply. This misalignment results in inefficiencies, distorts consumption behavior, and limits the financial sustainability of power utilities. Accurate pricing based on long run marginal cost (LRMC) is therefore essential to ensure efficient investment, consumption, and resource allocation.

Long Run Marginal Cost (LRMC) provides the economic foundation for efficient, forward-looking tariff design. LRMC-based tariffs signal to consumers how their consumption patterns influence long-term system costs and guide utilities in making prudent investment decisions in generation, transmission, and distribution infrastructure. Basing electricity tariffs on LRMC can send accurate price signals to consumers, encouraging efficient consumption and investment decisions. It helps avoid situations where prices are too low, leading to underinvestment, or too high, leading to inefficient consumption.

LRMC provides investment signals by providing a benchmark for investors, indicating the long-term cost of supplying electricity and guiding decisions on building new power plants and infrastructure. If market prices consistently exceed LRMC, it signals a need for new investment. Furthermore, understanding LRMC helps system planners make informed decisions about long-term capacity expansion, choosing the most cost-effective mix of generation, transmission, and distribution assets.

Regulators and market designers use LRMC to evaluate the efficiency of electricity markets, identify potential market power issues, and develop policies that promote efficient outcomes. Finally, while short-run marginal cost (SRMC) pricing may not always cover fixed investment costs, LRMC is designed to ensure the recovery of both operational and capital costs over the long run.

There has not been a periodic and systematic study of LRMC in Nepal. Three previous studies of LRMC were conducted in 1990 by EDF, in 1998 by Norconsult and a similar assessment by the International Resources Group in 2005.

The objective of the study is to estimate the Long Run Marginal Cost (LRMC) of electricity supply and develop a cost-reflective, equitable, and revenue-neutral tariff structure.

This report is systematically organized to provide a comprehensive analysis of Nepal's electricity sector, tariff design, and regulatory frameworks. Section 2 examines the historical development of Nepal's electricity sector, highlighting key trends and shifts in generation capacity, demand patterns, and the mix of energy sources over time. This context sets the stage for understanding current challenges and opportunities within the sector. In Section 3, the report reviews load forecasts, providing insights into expected future electricity demand. Accurate forecasting is essential for effective system planning and investment decisions, ensuring that supply meets the evolving needs of consumers.

Section 4 presents the results of demand elasticity analysis and discusses how these findings can be applied to tariff setting. Understanding how consumers respond to changes in price and income is crucial for designing tariffs that promote efficient electricity use and financial sustainability. Section 5 outlines the methodology for calculating the Long Run Marginal Cost (LRMC) of electricity supply and presents the results. Section 6 introduces the principles of Ramsey pricing and details the approach to designing tariffs that are both revenue-neutral and equitable. The section explains how tariff structures can be optimized to balance efficiency, equity, and financial requirements.

Section 7 provides a brief overview of different types of electricity sector regulations, describing the regulatory approaches that impact tariff setting, market functioning, and sector governance. Finally, the report concludes in Section 8, summarizing key findings and outlining recommendations for achieving an efficient, equitable, and sustainable electricity sector in Nepal.

2. Historical Perspectives

The Figure 1 compares Nepal's peak electricity demand with installed capacity from 1997 to 2025. Installed capacity is shown as stacked bars comprising NEA-owned major hydropower, IPP hydropower, imports from India, and Solar PV, while the blue line represents peak demand. Until the mid-2000s, capacity growth is modest and dominated by NEA owned hydropower. From around 2010 onward, IPP hydropower and imports contribute increasingly to capacity expansion. Solar PV appears only in the later years (early-2020s onward) and grows gradually, adding a new component to the supply mix. By 2023–2025, total installed capacity including available in import rises well above peak demand, indicating improved supply adequacy.

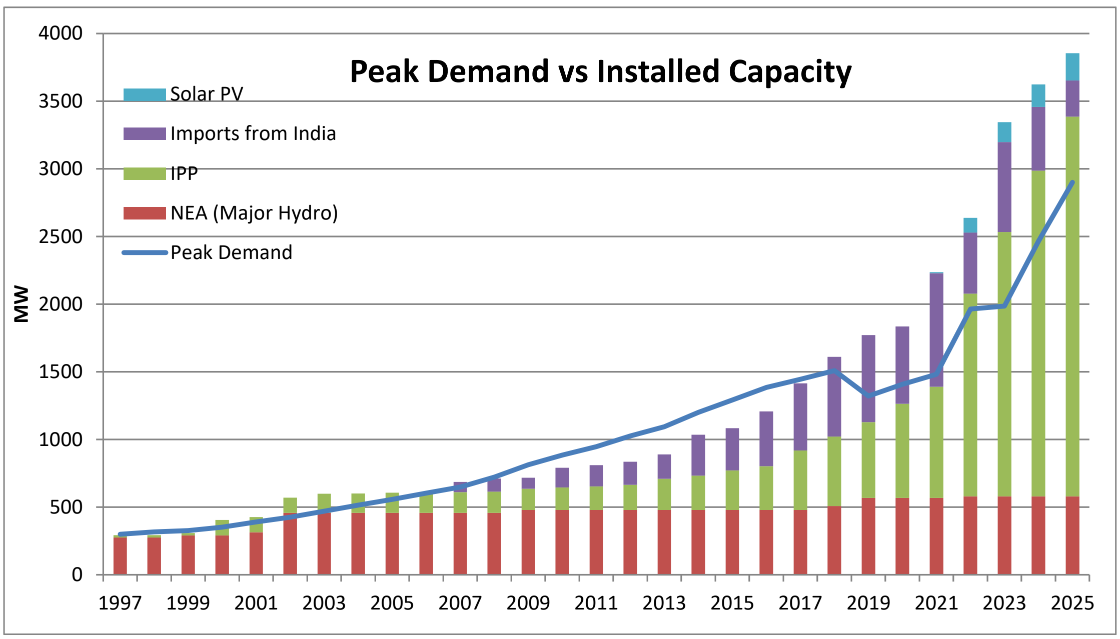

Figure 1: Peak Demand and Installed Capacity of different sources

Overall, the graph illustrates Nepal's evolution from a hydropower-constrained system toward a capacity-surplus and more diversified power system, with Solar PV beginning to play a strategic—though still modest—supporting role. The following key conclusion can be made:

- **Transition from deficit to surplus**: For much of the period up to the mid-2010s, peak demand closely tracks or exceeds dependable capacity, implying tight supply conditions. The widening gap after 2020 reflects a transition to surplus capacity.
- **Role of IPPs and imports**: Rapid growth in IPP hydropower is the primary driver of capacity expansion, while imports provide short-term flexibility during high-demand or dry periods.
- **Emergence of Solar PV**:

- Solar PV emerges as a new, non-hydro resource in the early 2020s, marking the beginning of diversification away from an almost exclusively hydropower-based system.
    - Although its capacity share remains small relative to hydropower, Solar PV contributes daytime energy and peak-shaving potential, particularly during the dry season when hydro output is constrained.
    - The addition of Solar PV improves system resilience, reduces dependence on imports during daylight hours, and complements run-of-river hydropower through resource diversity.
- **System planning implications**: The coexistence of surplus hydropower capacity and emerging Solar PV underscores the need for better load management, storage, export strategies, and tariff signals to efficiently utilize capacity and integrate variable renewable energy.

The Figure 2 shows the evolution of Nepal's electricity supply mix from 1997 to 2025, expressed as percentage shares of total energy supplied. The mix is composed of NEA-owned hydropower, IPP hydropower, and imports from India. In the late 1990s and early 2000s, NEA hydropower dominates the supply, contributing more than half of total generation, while IPP hydropower plays a smaller but growing role and imports account for a modest share.

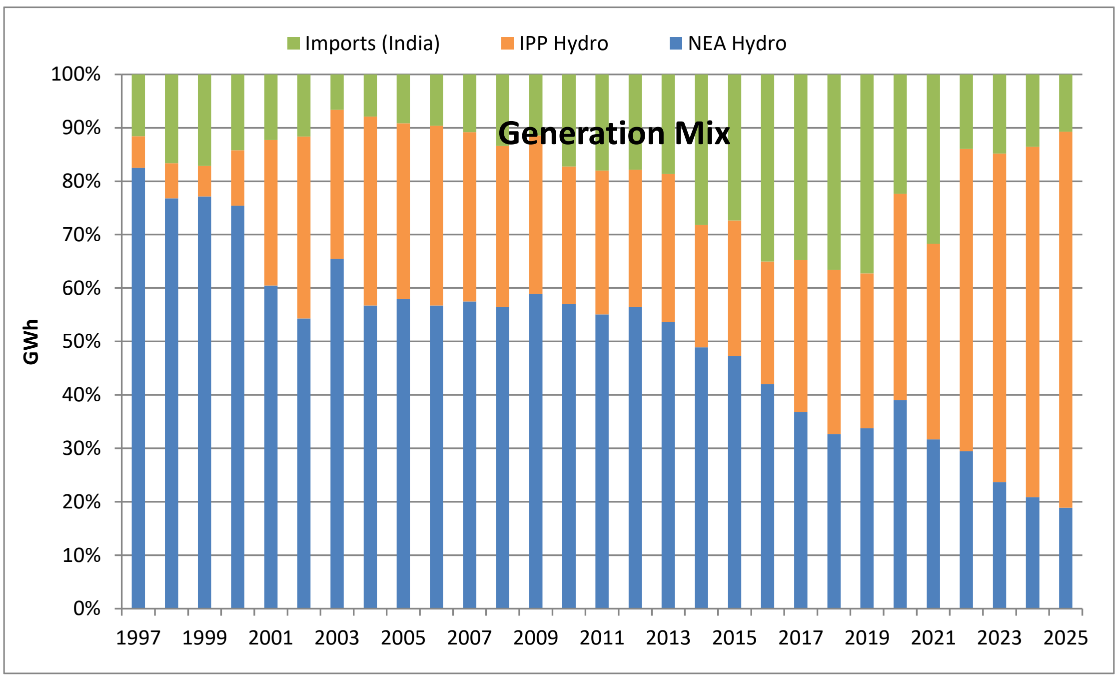

Figure 2: Electricity Supply Mix

Over time, the share of IPP hydropower increases steadily, while the share of NEA hydropower declines in relative terms. Imports rise during the mid-2010s, peaking around the load-shedding period, and then fall sharply in the early 2020s as domestic generation expands. The share of unserved energy during load shedding and Solar PV generation data is not included here due to unavailability of data. From this chart, the following observations are made:

- **Structural shift in ownership**: The declining share of NEA hydropower alongside the rising share of IPPs reflects a deliberate policy shift toward private sector participation in generation.
- **Supply deficit to surplus transition**: The higher reliance on imports during the mid-2010s indicates domestic supply shortages and hydrological constraints. The subsequent reduction in imports signals Nepal's transition toward power surplus conditions.

- **Hydropower-led system**: Despite changes in ownership, the system remains overwhelmingly hydropower-based, underscoring continued exposure to seasonal and hydrological variability.
- **Improved energy security**: The growing contribution of IPP projects in recent years reduces dependence on imports and strengthens domestic supply adequacy.

Table 1 presents the average annual growth rates of key electricity sector indicators in Nepal over the period FY 1995–2025, disaggregated by consumer category. The table covers growth in the number of consumers, electricity sales, average consumption per consumer, revenue, and average tariff, along with overall system-level growth in generation and peak load.

Across all categories, the number of consumers shows strong and sustained growth, ranging from about 6.8 percent to 17.4 percent per year, reflecting rapid electrification and expansion of access. Sales growth is also robust across most categories, broadly tracking consumer growth but with notable variation in average consumption per consumer. Revenue growth significantly exceeds sales growth in all categories, driven by consistent increases in average tariffs over the period. At the system level, total electricity sales grew at 9.3 percent per year, closely matched by generation growth, while peak load increased at 8.8 percent per year, indicating steadily rising capacity requirements.

Table 1: Average Annual Growth Rate (FY 1995-2025)

Particulars	Consumers	Sales	Avg Con	Revenue	Avg Tariff	Generation	Peak Load
Domestic	8.8%	9.5%	0.7%	16.2%	6.4%		
Non-Commercial	7.3%	5.9%	-0.9%	12.6%	6.6%		
Commercial	9.9%	10.1%	1.2%	17.0%	6.5%		
Industrial	6.8%	9.6%	2.7%	16.1%	6.1%		
Water Supply & Irri.	17.4%	10.5%	-6.9%	13.9%	6.3%		
Total (Nepal)	8.7%	9.3%	0.4%	15.9%	6.1%	9.3%	8.8%

From the above the following conclusions can be derived.

First, electrification and customer expansion have been the dominant drivers of sector growth. Consumer numbers grew at an average of 8.7 percent per year nationally, with particularly rapid expansion in water supply and irrigation connections, highlighting the role of electricity in supporting basic services and productive uses.

Second, sales growth has been driven more by new connections than by higher per-customer consumption. Average consumption per consumer increased only marginally for domestic users and declined for non-commercial and water supply and irrigation consumers, while industrial consumers show the strongest increase in average consumption. This suggests that load growth is becoming more diversified but remains relatively shallow at the household level.

Third, revenue growth has outpaced both sales and consumer growth across all categories. Average annual revenue growth of nearly 16 percent at the national level reflects not only rising demand but also sustained increases in tariffs, which grew at around 6 percent per year. This indicates a gradual strengthening of cost recovery through price adjustments.

Fourth, commercial and industrial consumers play a disproportionate role in revenue generation. These categories exhibit high growth in sales and revenue, combined with relatively strong growth in average consumption, underscoring their importance for system revenues and cross-subsidization.

Finally, the close alignment between generation growth (9.3 percent) and sales growth (9.3 percent), together with slightly lower growth in peak load (8.8 percent), suggests that capacity expansion has broadly kept pace with demand growth over the long term. However, the sustained increase in peak demand underscores the continuing importance of capacity planning and investment to maintain system reliability.

Overall, the table indicates a power sector characterized by rapid access expansion, moderate deepening of electricity use, strong revenue growth driven by tariff increases, and steadily rising system capacity requirements.

The Figure 3 presents the trend in average electricity tariffs (current prices, NPR/kWh) for different consumer categories—Domestic, Commercial, Industrial, the overall average for internal sales, and Export—over the period FY 1995-2025. The domestic consumer categories show a long-term upward trend, reflecting periodic tariff revisions and rising system costs. Commercial tariffs remain consistently the highest among internal consumers, followed by industrial and domestic tariffs. The internal sales average closely tracks the weighted movement of these three categories. Export prices are more volatile than domestic tariffs, with sharp year-to-year fluctuations. The following observations can be made from the graph.

- **Cost recovery and cross-subsidy**: The persistent gap between commercial and domestic tariffs indicates continued cross-subsidization, where commercial consumers contribute a higher share toward revenue adequacy.
- **Industrial competitiveness**: Industrial tariffs increase over time but remain below commercial tariffs, suggesting an effort to maintain industrial competitiveness while still improving cost recovery.
- **Tariff stability vs. market exposure**: Domestic and overall tariffs change gradually, reflecting regulatory smoothing, whereas export prices fluctuate sharply, reflecting market-based pricing and hydrological or regional market conditions.
- **Structural break after mid-2010s**: A noticeable step-up in tariffs around the mid-2010s across all internal categories suggests a major tariff revision aligned with higher supply costs and investment needs.
- **Recent moderation**: After peaking around 2019–2020, overall internal tariffs stabilize or slightly decline, indicating improved supply conditions and reduced short-run cost pressure.

Overall, the graph highlights a regulated and relatively stable tariff structure for Nepal’s internal consumers, differentiated by consumer category, alongside a volatile but market-responsive export price, consistent with Nepal’s transition from power deficit to surplus conditions.

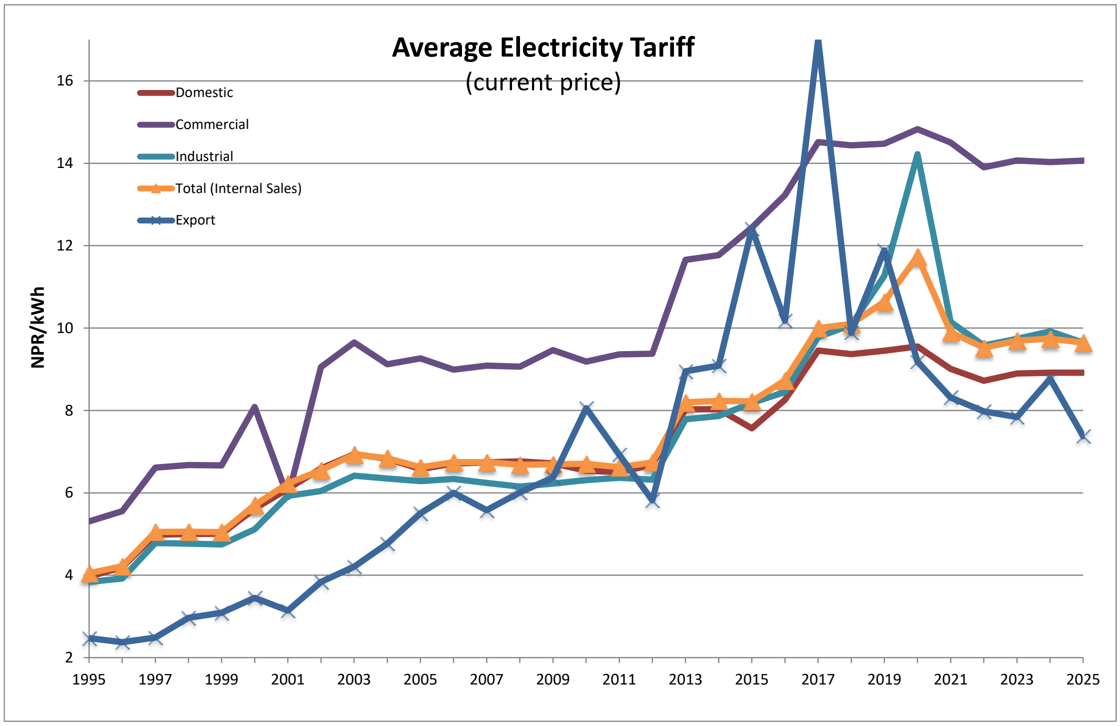

Figure 3: Historical Average Electricity Tariff of different Consumer Class

3. Conceptual Framework for LRMC and Tariff Design

The flow chart in Figure 4 presents an integrated framework linking electricity demand behavior, system planning, cost determination, and tariff design. It illustrates how technical, economic, and regulatory elements interact to determine electricity prices in a power system.

At the foundation of the framework are electricity demand characteristics, including elasticities, coincidence factors, load factors, and power factors. These parameters define how consumers use electricity and how demand responds to changes in price and income. Together, they inform the demand growth study, which projects future electricity consumption across different consumer categories and time horizons.

The demand projections feed into the least-cost generation, transmission, and distribution master plan, which identifies the optimal expansion path of the power system to meet projected demand at minimum cost. This planning process is supported by an assessment of generation options and merit order dispatch, ensuring that available resources are utilized efficiently and that new investments are economically justified.

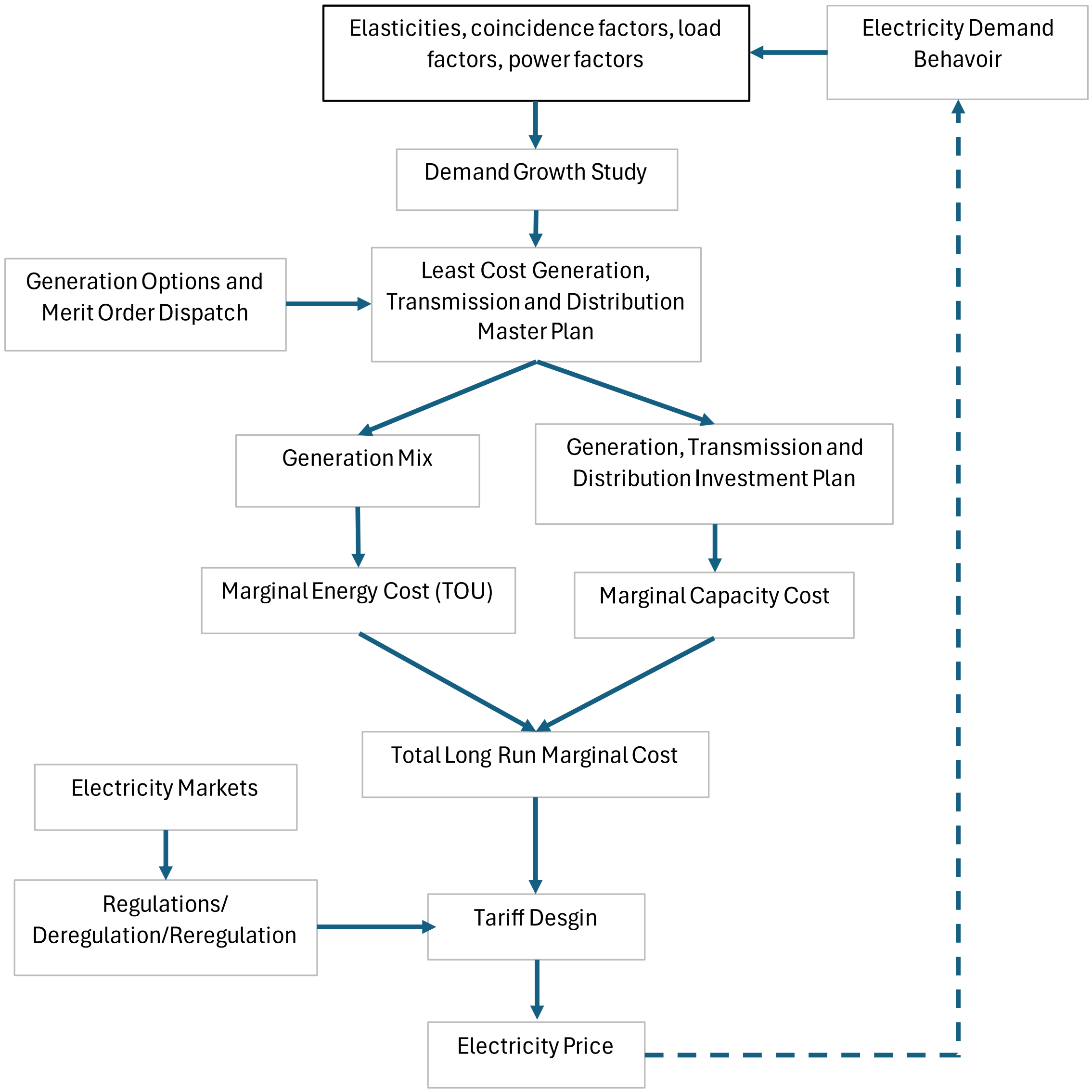

Figure 4: Conceptual Flow Chart of Electricity Pricing

The master planning process produces two key outputs. First, it determines the generation mix, which reflects the combination of generation technologies (e.g., hydropower, thermal, renewables) used to meet demand. This, in turn, is used to estimate the marginal energy cost, often differentiated by time of use (TOU), reflecting variations in system operating costs across peak and off-peak periods. Second, the planning process results in a generation, transmission, and distribution investment plan, from which the marginal capacity cost is derived. This represents the cost of expanding system capacity to meet incremental demand.

These two components—marginal energy cost and marginal capacity cost—are combined to estimate the total long-run marginal cost (LRMC) of electricity supply. LRMC serves as a key economic benchmark for efficient pricing, as it reflects the cost of supplying an additional unit of electricity over the long term, including both operating and investment costs.

The LRMC then feeds into the tariff design process, where economic principles, policy objectives, and practical constraints are applied to translate costs into consumer tariffs. This process is influenced not only by cost considerations but also by the broader electricity market structure and regulatory environment, including policies related to deregulation, re-regulation, and market reforms.

The outcome of the tariff design process is the electricity price, which determines the charges faced by different consumer categories. Importantly, the framework highlights a feedback loop between electricity price and electricity demand behavior. Changes in tariffs influence consumption patterns, load profiles, and demand growth, which in turn affect future planning and cost estimation.

Overall, the flow chart demonstrates that electricity pricing is the result of a dynamic and interconnected process involving demand analysis, system planning, cost estimation, and regulatory decision-making. It underscores the importance of aligning tariff design with both economic efficiency and system sustainability, while recognizing the iterative relationship between prices and consumer behavior.

4. Demand Behavior and Elasticities

Electricity demand behavior is first modeled econometrically to estimate price and income elasticities by consumer category. These elasticities are then used to inform the allocation of tariff mark-ups above LRMC across consumer groups in accordance with Ramsey pricing rules, subject to revenue-neutrality and policy constraints.

Model Structure
Electricity demand is modeled using an Auto-Regressive Distributed Lag (ARDL) framework, which allows demand to respond dynamically to both current and lagged changes in price and income while explicitly accounting for gradual adjustment and persistence in consumption behavior. The ARDL approach is particularly suitable for annual data and provides a coherent framework for estimating both short-run and long-run elasticities. The ARDL specification offers several advantages in the present context. The ARDL model is particularly suitable for electricity demand forecasting in Nepal due to both data characteristics and structural features of the power sector.

First, ARDL models are well-suited for small sample sizes, which is a common constraint in Nepal. Reliable annual electricity demand data are typically available for only a few decades, and ARDL performs well even with limited observations compared to other time-series techniques.

Second, ARDL can handle variables with mixed orders of integration (i.e., a combination of stationary and non-stationary variables). In the Nepalese context, key variables such as electricity consumption, GDP, and prices often exhibit different statistical properties. ARDL avoids the need for strict pre-testing and allows these variables to be modeled together without requiring all series to be integrated of the same order.

Third, the model effectively captures both short-run dynamics and long-run relationships, which is critical for electricity demand analysis. In Nepal, demand responds gradually to changes in income, tariffs, and electrification. ARDL allows inclusion of lagged demand, price, and income variables, reflecting adjustment delays due to appliance adoption, infrastructure expansion, and behavioral changes.

Fourth, ARDL is flexible in incorporating structural breaks and policy variables, such as:

- load shedding periods
- tariff reforms
- electrification programs

These factors have significantly influenced electricity demand in Nepal and must be explicitly accounted for in forecasting models.

This formulation avoids over-parameterization while retaining sufficient flexibility to capture key economic dynamics. The estimated ARDL(1,1,1) demand model is specified as:

$$\ln Q_t = \alpha + \phi \ln Q_{t-1} + \beta_0 \ln P_t + \beta_1 \ln P_{t-1} + \gamma_0 \ln Y_t + \gamma_1 \ln Y_{t-1} + \theta LS_t + \varepsilon_t$$

where:

- Q_t= electricity consumption,
- P_t= real electricity tariff,
- Y_t= real income (GDP at constant prices),
- LS_t= load-shedding dummy variable,
- ϕ= coefficient capturing demand persistence,
- ε_t= error term.

The model is estimated separately for major consumer categories (domestic, industrial, commercial/non-commercial, and aggregate demand).

Treatment of Load Shedding

To isolate true demand behavior from supply-side constraints, a load-shedding dummy variable is introduced for the period during which electricity supply was rationed. This dummy captures the suppression of observed demand due to availability constraints rather than price or income effects. Including the load-shedding variable ensures that estimated elasticities reflect underlying consumer behavior under normal supply conditions and avoids downward bias in long-run demand projections. The estimated coefficients are subsequently used to quantify demand suppression during the load-shedding period. The dummy takes a value of one during load-shedding years and zero otherwise. Including this variable ensures that:

- price and income elasticities reflect underlying demand behavior under normal supply conditions, and
- suppressed demand during rationing periods does not bias long-run elasticity estimates downward.

Short-Run Elasticities

Short-run elasticities are obtained directly from the contemporaneous coefficients:

- Short-run price elasticity: $\varepsilon_P^{SR} = \beta_0$
- Short-run income elasticity: $\varepsilon_Y^{SR} = \gamma_0$

These represent the immediate response of electricity demand to changes in tariffs and income.

Long-Run Elasticities

Long-run price and income elasticities are derived from the ARDL structure as:

$$\varepsilon_P^{LR} = \frac{\beta_0 + \beta_1}{1 - \phi} \qquad \varepsilon_Y^{LR} = \frac{\gamma_0 + \gamma_1}{1 - \phi}$$

These elasticities capture the full adjustment of demand over time, incorporating behavioral change, appliance adoption, and structural economic responses. Long-run elasticities are used as the primary inputs for LRMC-based tariff design and Ramsey pricing analysis.

A multiple regression analysis was performed to examine the relationship between average tariff, consumption, and gross domestic product (GDP) for different consumer categories. In this analysis, the average tariff was adjusted to reflect real prices by deflating it with the Consumer Price Index (CPI). GDP served as a proxy for income, with specific sectoral GDPs used for each consumer group: domestic, industrial, and commercial/non-commercial consumers were matched with agricultural, industrial, and service sector GDP, respectively.

Detail results of the regression analysis are provided in Annex 4. This annex also contains a table that guides the interpretation of the results generated from the excel output. For each scenario analyzed, key statistical indicators were calculated to assess the performance of the demand model. These indicators include the coefficient of determination (R^2), the Standard Error of Estimate (SEE), and the F-statistic. The results indicate that the demand model demonstrates strong explanatory power, as evidenced by high R^2 values and relatively low SEE.

The regression analysis yields consistently high F-values across all evaluated cases, which demonstrates the overall robustness of the proposed demand model. This strong F-value suggests that the model is effective at explaining the variations in electricity demand based on the included independent variables.

However, it is important to note that not every explanatory variable within the model achieves statistical significance at the 95% confidence level. While the model itself is reliable, some of the individual factors do not meet the conventional threshold for statistical significance, indicating that their impact on demand may be uncertain or weaker within this framework.

Based on the results of the regression analysis, the following demand model are proposed.

$$Domestic\ Q_t = 0.013 + Q_{t-1}^{0.543} + P_t^{-0.064} + P_{t-1}^{-0.00007} + Y_t^{1.117} + Y_{t-1}^{0.151} + 0.949LS_t$$

$$Industrial\ Q_t = 0.372 + Q_{t-1}^{0.75} + P_t^{-0.067} + P_{t-1}^{0.055} + Y_t^{1.763} + Y_{t-1}^{-1.246} + 0.978LS_t$$

$$Comm\&N\_Com\ Q_t = 0.384 + Q_{t-1}^{0.757} + P_t^{-0.107} + P_{t-1}^{0.018} + Y_t^{0.758} + Y_{t-1}^{-0.36} + 0.977LS_t$$

$$NEA\ Q_t = 0.213 + Q_{t-1}^{0.792} + P_t^{-0.02} + P_{t-1}^{-0.016} + Y_t^{1.534} + Y_{t-1}^{-1.08} + 0.971LS_t$$

Table 2: Price and Income Elasticities with Load Shedding (2010-2025)

Consumer Category	Price elasticity		Income elasticity		Demand Reduction
	Short-run	Long-run	Short-run	Long-run	
Domestic	-0.064	-0.139	1.117	2.775	-5.15%
Industrial	-0.067	-0.045	1.763	2.062	-2.16%
Com+Non-Com	-0.107	-0.364	0.758	1.635	-2.28%
Aggregate (NEA)	-0.020	-0.175	1.534	2.192	-2.85%

Interpretation of Electricity Demand Elasticity Results

The estimated dynamic demand models provide short-run and long-run price and income elasticities for major consumer categories, with explicitly accounting for the load-shedding period (2010–2015). Overall, the results are economically consistent and highlight the importance of income growth and supply constraints in shaping electricity demand in Nepal.

Price elasticity

Across all consumer categories, short-run price elasticities are small in magnitude, confirming that electricity demand is relatively price-inelastic in the short term. This reflects the essential nature of electricity, limited short-term substitution possibilities, and the presence of administered tariffs.

In the long run, price responsiveness increases in absolute value, particularly for commercial and non-commercial consumers, indicating greater scope for adjustment through efficiency improvements and behavioral changes over time. The domestic and industrial sector remains the least price-responsive, while the aggregate NEA demand shows weak price sensitivity, underscoring the limited role of price signals in driving demand adjustment at the system level.

Introducing the load-shedding dummy generally makes long-run price elasticities slightly more negative, suggesting that failure to control supply constraints can understate the true price responsiveness of demand.

Income elasticity

Income elasticity is positive and economically significant across all categories, both in the short run and the long run. Short-run income elasticities are already sizable, indicating that electricity demand responds quickly to changes in economic activity.

Long-run income elasticities are substantially larger than short-run values, particularly for the domestic and industrial sectors, reflecting structural demand growth driven by electrification, appliance adoption, and industrial expansion. This confirms that income growth is the dominant driver of electricity demand in Nepal over the long term.

The inclusion of the load-shedding dummy slightly moderates long-run income elasticities, indicating that part of the observed demand growth in earlier models reflected the release of suppressed demand once supply constraints eased.

Load-shedding effects

The estimated demand reductions during the load-shedding period range from about 2–5 percent, with the largest impact observed in the domestic sector. This confirms that load-shedding had a material but not overwhelming suppressing effect on observed electricity consumption. Importantly, much of this impact is captured through dynamic adjustment in demand rather than a large contemporaneous level shift.

Overall assessment

The results indicate that:

- Electricity demand in Nepal is price-inelastic, especially in the short run.
- Income effects dominate demand growth, particularly in the long run.
- Accounting for load-shedding improves the realism and stability of elasticity estimates.

These findings imply that tariff-based demand management alone is unlikely to significantly curb demand growth, while long-term planning should primarily focus on accommodating income-driven demand expansion and avoiding supply constraints.

Interpretation of Demand Elasticities for LRMC and Tariff Design

The estimated electricity demand elasticities provide important guidance for the application of Long-Run Marginal Cost (LRMC)–based tariff design in Nepal. Across all consumer categories, short-run price elasticities are small in magnitude, indicating that electricity demand is largely unresponsive to price changes in the short term. This reflects the essential nature of electricity, limited substitution possibilities, and the prevalence of administered tariffs. As a result, short-run tariff adjustments are unlikely to induce significant immediate demand reduction and should not be relied upon as a primary demand management tool.

5. Review of the Demand Forecast

A critical step in estimating system marginal costs is the use of demand forecast data as a foundational input. The accuracy and reliability of marginal cost depend heavily on the quality of the underlying demand forecasts. Therefore, before applying the load forecast to marginal cost calculations, this section reviews several historical load forecasts and provides a critical analysis of the NEA demand forecast model. By examining past forecasts and evaluating the methodology used by NEA, the aim is to ensure that the load projections incorporated into marginal cost estimation are robust and reflective of actual system requirements.

The Figure 5 compares peak electricity demand forecasts prepared in different planning years with the actual observed peak demand in Nepal, over fiscal years from 2007 to 2030. The y-axis shows peak demand in MW, while the x-axis shows fiscal year. The forecast series includes NEA 2007, NEA 2010, NEA 2015, NEA 2019, and WECS Reference. These are forecasts prepared by NEA and the Water and Energy Commission Secretariat. WECS forecast has presented various scenarios and for the comparison here a reference case is used. The WECS forecast has not calculated the peak demand forecast, so peak demand forecast is calculated here by assuming a suitable system load factor used by NEA for its peak demand forecast. The Actual series (green line) represents realized peak demand up to recent years. Earlier forecasts (2007, 2010, 2015) show relatively smooth and moderate growth. Later forecasts (especially NEA 2019 and WECS-Ref) project a much steeper increase in peak demand after about FY 2020. Actual demand rises steadily until around 2018, dips around 2019, and then recovers gradually, but remains well below the recent high-growth forecasts. Based on this chart, the following observations can be made:

- Short- to medium-term forecasts were reasonably accurate. Up to around 2016–2018, actual peak demand tracks earlier forecasts (NEA 2007, NEA 2010, NEA 2015) fairly closely. This suggests that incremental, trend-based forecasting worked reasonably well during periods of stable economic and electricity sector conditions.
- Systematic overestimation in recent forecasts. From about 2019 onward, actual demand falls significantly below the projections, particularly relative to NEA 2019 and WECS-Ref. The divergence widens over time, indicating persistent over-forecasting of peak demand in recent planning exercises.
- Failure to anticipate structural breaks. The drop and slower recovery in actual demand around 2019–2021 point to structural changes (e.g., economic slowdown, demand shocks, delayed industrialization, load pattern changes, or efficiency improvements) that were not adequately captured in later forecasts.
- Optimism bias in long-term planning. The very steep growth assumed in NEA 2019 implies strong assumptions about electrification, industrial load growth, and economic expansion. Actual outcomes suggest that these assumptions were too optimistic, leading to systematic upward bias in long-term demand projections.

- Increasing forecast error with horizon. Forecast accuracy clearly deteriorates as the projection horizon lengthens. While near-term forecasts are acceptable, long-term projections (10–15 years ahead) show large deviations from realized demand.

Overall, the chart indicates that Nepal's peak demand forecasts have been reasonably accurate in the short run but increasingly inaccurate in the long run, with a clear tendency toward overestimation in recent planning cycles. This has important implications for generation and network investment planning, as optimistic demand forecasts can lead to overcapacity risks, higher fixed costs, and tariff pressures if demand does not materialize as expected.

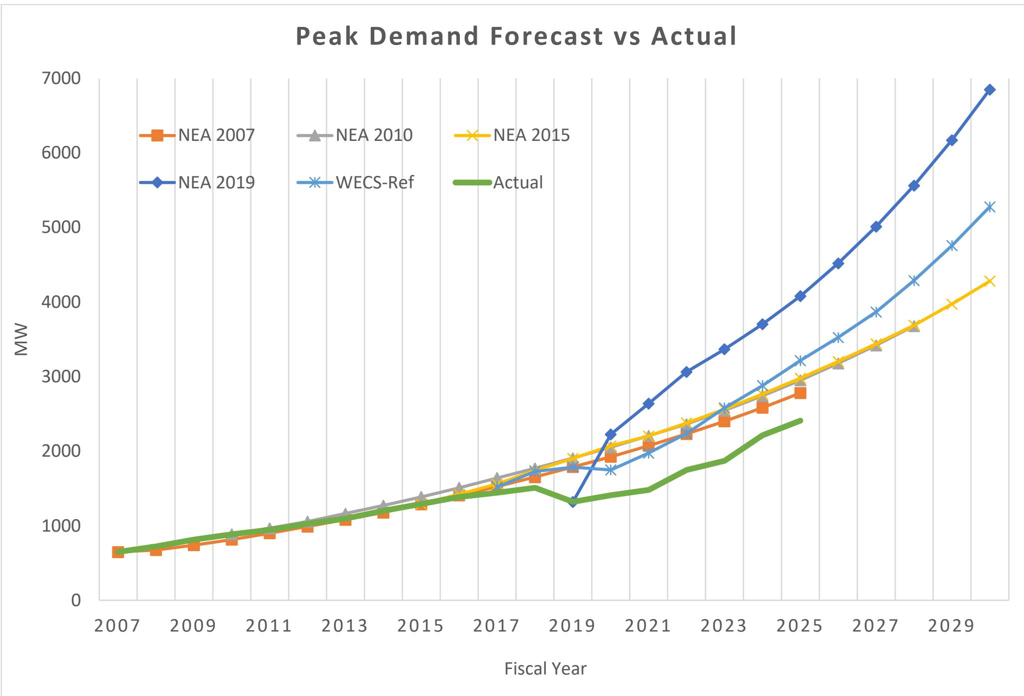

Figure 5: Peak Demand Forecast and Actual Peak

The Figure 6 presents a comparison between electricity generation forecasts prepared at different times and the actual electricity generation in Nepal, over fiscal years roughly from 2007 to 2030. The y-axis measures total annual generation in GWh, while the x-axis shows fiscal year. Forecast series include NEA 2007, NEA 2010, NEA 2015, NEA 2019, and WECS Reference. The Actual series (green line) represents realized electricity generation up to recent years. All forecast series show a steadily increasing trajectory, reflecting expectations of rapid growth in hydropower capacity and electricity consumption. Earlier forecasts project relatively moderate growth, while NEA 2019 and WECS-Ref assume a much sharper acceleration in generation after about 2020. Actual generation increases gradually up to the mid-2010s, dips or stagnates around 2019–2020, and then grows strongly in the early 2020s, but still remains below the most optimistic projections.

Interpretation: accuracy of generation forecasting in Nepal

- Reasonable accuracy in the early years. Up to around 2015–2017, actual generation broadly aligns with the earlier forecasts (NEA 2007, NEA 2010, NEA 2015). This suggests that, during periods of stable hydrological conditions and incremental capacity additions, generation forecasts were reasonably reliable.

- Overestimation in recent long-term forecasts. From about 2019 onward, actual generation falls below the levels projected by NEA 2019 and WECS-Ref. The gap widens over time, indicating systematic overestimation of future generation requirement, particularly in forecasts that assume rapid commissioning of new hydropower projects.
- Sensitivity to project delays and hydrology. Unlike demand, generation is highly sensitive to project completion schedules, commissioning delays, hydrological variability, and system constraints. The divergence between forecast and actual outcomes suggests that recent forecasts did not fully account for implementation risks and year-to-year water variability.
- Improved growth but still below high-growth paths. The post-2021 increase in actual generation reflects the commissioning of several new projects and improved system utilization. However, actual output still tracks closer to earlier, more conservative forecasts than to the aggressive NEA 2019 or WECS-Ref trajectories.

Compounding forecast error over time. As with peak demand, forecast errors increase with the projection horizon. Small deviations in assumed commissioning dates or plant availability compound into large differences in total generation over a decade or more.

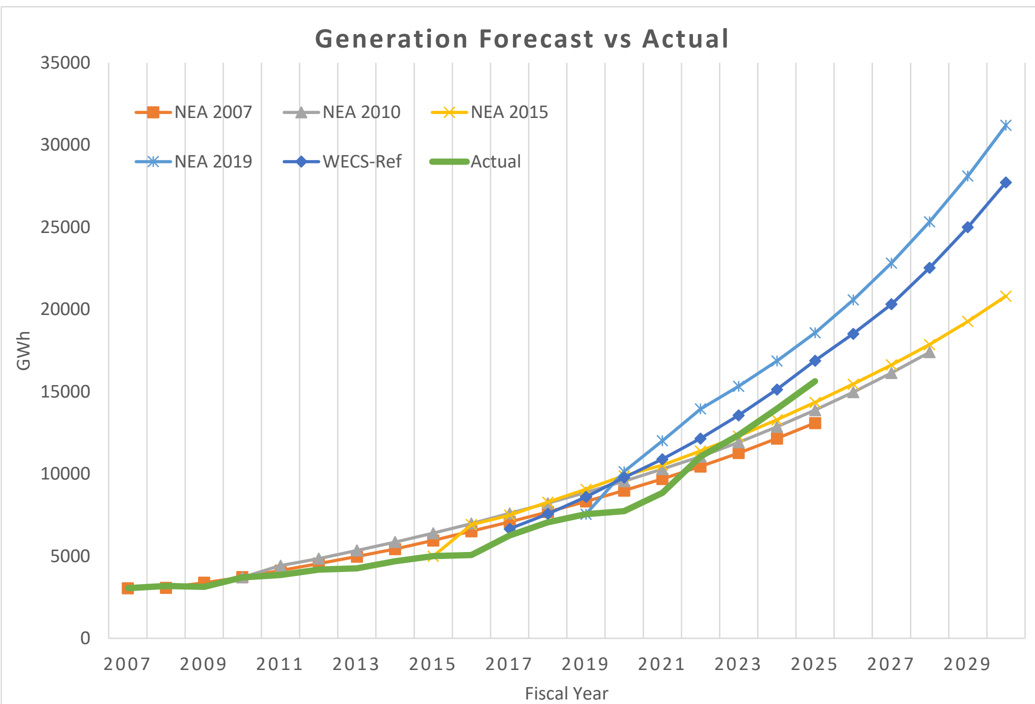

Figure 6: Generation Forecast and Actual Generation

Overall, the chart indicates that generation forecasts in Nepal have been fairly accurate in the short term but increasingly optimistic in the long term, particularly in recent planning cycles. Overestimation appears to stem from ambitious assumptions about capacity addition timelines and utilization levels. For planning and tariff analysis, this highlights the need for more conservative baseline scenarios, explicit treatment of project and hydrological risks, and regular forecast updating to avoid overestimating system revenues and underestimating financial risks.

Importance of Accurate Electricity Demand Forecasting and its Link to LRMC
Accurate electricity demand forecasting is a cornerstone of prudent power system planning and tariff setting. Demand forecasts directly determine generation and network investment decisions, which in turn shape the LRMC of electricity supply. Both overestimation and underestimation of demand can impose significant economic costs on the power system and consumers.

When demand is over-forecast, utilities tend to over-invest in generation, transmission, and distribution assets. This leads to excess capacity, underutilized plants, and stranded network investments. Although such assets may enhance short-term reliability, they represent a wastage of resources, as capital is locked into facilities that are not required to meet actual demand. Since LRMC reflects the cost of providing an incremental unit of demand using optimally planned capacity, excess and poorly utilized assets inflate the calculated LRMC and the associated revenue requirement. Ultimately, consumers bear the cost of excess capacity through higher tariffs, despite not receiving commensurate benefits in terms of energy consumption or service quality.

Conversely, when demand is under-forecast, the power system is inadequately prepared to meet actual load growth. This results in power shortages, forcing utilities to rely on obsolete, inefficient, or high-cost emergency plants, such as temporary diesel generators or short-term power imports. These stop-gap solutions significantly increase the short-run marginal cost of supply and disrupt the smooth evolution of LRMC. Operationally, under-forecasting leads to brownouts, scheduled load rationing, and, in severe cases, blackouts, imposing high economic and social costs on consumers and the broader economy.

From an LRMC perspective, inaccurate demand forecasts distort the optimal timing, scale, and composition of capacity expansion. Over-forecasting pushes investment too early, raising fixed costs and lowering asset utilization, while under-forecasting delays necessary investment, resulting in costly and inefficient supply responses. In both cases, the resulting LRMC no longer reflects the true least-cost path of system expansion.

Therefore, accurate demand forecasting is essential to ensure that LRMC represents the cost of efficiently supplying future electricity demand under optimal planning. Reliable forecasts help align investment decisions with actual system needs, minimize total system costs, maintain security of supply, and support economically efficient and stable tariff outcomes.

NEA Demand Model

NEA has been adopting a disaggregated demand forecast model for a long time. However, NEA's domestic and industrial demand formulations share common weaknesses arising from imposed behavioral responses, nonstandard price treatment, and the absence of a stochastic, equilibrium-based framework. For the purposes of rigorous demand analysis, tariff design, and LRMC estimation, it is preferable to adopt log-linear dynamic demand models in which price, income, and customer base effects are estimated empirically within a consistent econometric structure. A detailed review of the NEA demand model is presented in Annex 4 highlighting the limitations and overall assessment.

6. Calculation of LRMC

Review of Past LRMC Studies in Nepal

Historically, Nepal has not undertaken regular or systematic studies focused on Long-Run Marginal Cost (LRMC). Only a few LRMC studies have been conducted, and with the exception of the 1990 study, none of these were accompanied by a related tariff study. These efforts, while significant, remain isolated and do not constitute an ongoing process.

- **1990:** A comprehensive long-run marginal cost and tariff study was carried out by Electricity de France. This study is notable for being the only one among the listed efforts to include a tariff component alongside the LRMC analysis.
- **1998:** Norconsult conducted a long-run cost study, focusing exclusively on LRMC without an associated tariff study.
- **2005:** The International Resources Group (IRG) also prepared a long-run marginal cost study. Like the 1998 effort, this did not include a tariff study.

In summary, while these studies have provided valuable insights into the LRMC in Nepal, the lack of regularity and the limited integration with tariff studies highlight a gap in the country's approach to cost-reflective and sustainable tariff setting.

Objective of LRMC-Based Pricing

The rationale for marginal cost pricing is rooted in economic theory, which holds that resources are most efficiently allocated when prices reflect marginal cost. When electricity prices equal the cost of supplying an additional unit, both producers and consumers receive the correct economic signals. This alignment promotes market equilibrium and ensures that electricity is supplied and consumed in a manner that maximizes the efficient use of scarce resources.

If prices are set below marginal cost, consumers are led to believe that electricity is cheaper to produce than it truly is. This encourages excessive and inefficient consumption. Because investment in the electricity sector diverts resources from other critical national priorities—such as education and health—it is essential that the sector uses these resources as efficiently as possible.

In tariff planning, the objective of efficiency is therefore closely linked to the marginal cost structure of the power system. These costs typically vary across service voltage levels, seasons, and times of day, reflecting the differing cost of supplying electricity under varying system conditions.

LRMC represents the incremental cost of all long-term system adjustments—both in development and operation, required to meet a sustained increase in demand. LRMC-based pricing focuses on striking the right balance between providing economically efficient signals and maintaining price stability over time. Although short-run marginal cost (SRMC) pricing can offer greater allocative efficiency in the moment, policymakers, producers, and consumers generally value the stability that LRMC provides for long-term planning. A long-run approach also captures the evolving cost structure of electricity supply; ignoring these long-term effects could lead consumers to make suboptimal investment decisions regarding electricity-consuming equipment.

SRMC versus LRMC

The difference between the short-run marginal cost (SRMC) and the long-run marginal cost (LRMC) is primarily based on the cost responsibility when there is an increase in demand:

In the short run, the installed capacities of the power system are fixed, meaning no immediate expansion or investment can be undertaken to accommodate increased demand. When there is a rise in electricity demand within this period, the operational strategy of the system must be adjusted. This adjustment results in additional fuel consumption, increased variable operating and maintenance (O&M) costs, and the possibility of higher outage costs.

Outage costs occur when the system either replaces energy with sources that have higher marginal costs or suffers a shortfall in generation capacity. In such cases, some energy demand remains unserved, which imposes additional costs on consumers due to disruptions or the need to seek alternative, potentially more expensive sources.

Consequently, the short-run marginal cost is comprised solely of an energy component. It reflects the incremental variable costs associated with supplying an extra unit of electricity using the existing resources and infrastructure, without any immediate capacity expansion.

On the other hand, in the long run, the electricity sector is able to undertake new investments with the goal of minimising overall costs and reducing the risk of outages. When there is a sustained increase in demand projected into the future, this alters system expansion plans, leading to adjustments in fuel requirements, operational and maintenance (O&M) expenditures, as well as capacity investments. As a result, the LRMC includes both an energy component—reflecting the additional fuel and O&M costs—and a capacity component, accounting for the investment needed to expand generation and network capabilities. The optimal timing for commissioning new projects is reached when the SRMC equals the LRMC. At this point, both capacity and system reliability are considered to be at their most efficient levels.

In general, the SRMC is used for planning the day-to-day operation of the system, i.e. for setting the order of merit of the power plants in the generation system. The LRMC is important for system expansion planning, sub-optimisation of projects (feasibility studies and detailed design) and particularly for electricity pricing. Given the purpose of the present study, the focus will here be on the LRMC.

In the context of electricity pricing and cost allocation, SRMC values are used as energy components within the calculation of LRMC. This approach is both theoretically sound and practical for tariff planning. Specifically, when determining the total price of electricity purchased from Independent Power Producers (IPPs) and from India, the capacity component is separated and deducted. As a result, only the energy-related costs—as captured by the SRMC—are included as the energy portion of the LRMC. This ensures that the pricing structure accurately reflects the incremental variable costs of energy supply without double-counting the capacity charges.

Modeling Assumptions for MC Calculations

An Excel-based model is developed for purposes of estimating marginal costs of the NEA power system. Briefly, the model's structure embodies the theoretical considerations outlined in the preceding discussion of methodology, and permits the calculation of three components of marginal cost:

- the marginal cost of energy by time of day and by season,

- the marginal cost of generation capacity, and
- the marginal cost of network capacity for different voltages of service.

Each of these components is described briefly in the following paragraphs.

Marginal Energy Cost. Marginal energy costs represent the incremental variable costs of the most expensive generating unit that is running for the purpose of "picking up incremental load at the margin." For a thermal plant, these costs would include fuel and other variable O&M. If marginal energy is hydroelectric energy, the marginal cost is typically estimated from a proxy plant in one of two ways: (i) calculate the levelized cost of the plant, separating civil works and electro/mechanical works, treating the former as energy and the latter as capacity; or (ii) calculate the total levelized cost less the cost of "pure capacity", assumed to be the cost of a combustion turbine (as discussed in the following section on "Marginal Generation Capacity Cost").

Once this plant is identified, the marginal energy cost can be calculated directly from the characteristics of each plant at the margin. Depending on specific operating circumstances, the marginal energy cost during a time period (e.g., the peak evening hours) may represent a weighted average of two or more units which share responsibility "at the margin."

Another issue to be considered is how to value the "unserved energy" for purposes of LRMC analysis. There are many complex ways to estimate the value of this "unserved energy", sometimes including the value of production lost due to the lack of electricity. If load shedding is still required for the year on which marginal energy cost is based, we recommend using the cost diesel generating set energy as a proxy for the marginal cost of this energy. Since NEA could provide energy to eliminate load shedding at this cost if it chose to do so, this cost is the *minimum* value of marginal energy that is unserved.

This analysis presumes that system operations will reflect merit order stacking (i.e., based on operating cost) of existing and planned generation capacity. Marginal energy costs are typically calculated based on expected system operation 3 to 5 years into the future so as to provide a signal as to the expected future structure of marginal costs. The marginal energy costs are estimated for a future year (2024/25) in the constant prices of 2024.

The calculation depends on both the forecast cost of energy and the time that each generator group is expected to be providing marginal energy. Table 3 shows the derivation of the marginal cost of energy. The table reports the operating characteristics of the plant groups providing marginal energy during different times of day. The table also reports the share of each season that each plant group is estimated to be "at the margin".

The table shows that diesel-fired capacity (i.e., our proxy for unserved energy) is expected to be at the margin for about 4.6 percent of the dry season, with Indian imports serving about 30 percent of the load. During the wet season, proxy diesel is used only for 1.8% while the Indian imports are estimated to be 6.9 percent of the wet season, with IPP hydro serving marginal load at other times.

Table 3: Marginal Energy Cost Assumption by Plant

Marginal Unit	Proxy Diesel 1/	Imports	NEA STO	NEA ROR	IPP-Hydro
Dry Season Gene Share 2/	4.6%	30.8%	2.1%	16.6%	46.0%
Wet Season Gene Share 2/	1.8%	6.9%	1.6%	23.2%	66.4%
Heat Rate (kcal/kWh)	2180				
Cost of Fuel (NPR/lit)	140				
Energy Content of fuel (Kcal/lit)	10984.8				
Station Use (% of Gross Generation)	2.5%	0.50%	0.50%	0.50%	0.50%
Fuel Cost (NPR/kWh)	27.8				
Non-Fuel Generation Cost (NPR/kWh)		8.28			5.29
less Proxy capacity cost (NPR/KWh) 3/		-4.86			-4.86
Variable O&M Cost (NPR/kWh)	0.92	0.10	1.66	0.69	0
Station Losses (NPR/kWh)	0.736	0.042	0.008	0.003	0.027
Marginal Cost at Busbar (NPR/kWh)	29.44	3.56	1.67	0.69	0.46

1/ Assumed proxy value for load shedding/interruption
2/ Based on 2023-2025 Average Generation Mix (NEA Transmission Annual Reports)
3/ Proxy capacity cost @80% PF removed to establish energy share of total purchase cost

For the purpose of calculation of time-of-day marginal cost the following dispatch logic (Merit order approach) is used to calculate the marginal energy cost. A standard way to do it is:

- Off-peak (lowest demand) Use cheapest units only (base units)
- Normal Use cheapest first, then next, until Normal energy is met
- Peak (highest demand) Use all cheaper units + add expensive peakers if needed

So practically:

- Off-peak is filled from the bottom (cheap units)
- Peak is filled from the top (expensive units)
- Normal gets the leftover balance in the middle

Step 1: Allocate Peak from most expensive units (top-down)
Peak total = 0.25 (six hours in wet and dry season))
$S_{i,peak} = \min(S_i$,remaining Peak after higher-cost units)

Step 2: Allocate Off-peak from cheapest units (bottom-up)
Off-peak total = 0.25 (six hours in wet season)
$S_{i,off} = \min(S_i - S_{i,peak}$,remaining Off-peak after lower-cost units)

Step 3: Normal is whatever remains
Normal total = 0.50 (12 hours in wet season), 0.75 (18 hours in dry season)
$S_{i,normal} = S_i - S_{i,peak} - S_{i,off}$
This guarantees each unit's energy share is fully allocated.

Marginal Generation Capacity Cost. While there is no universally accepted method for calculating the marginal cost of generation capacity, the most frequently applied method worldwide is the "peaker method". The peaker method is based on the premise that a combustion turbine peaking unit is the least-cost means of adding peaking capacity to a system, and thus the appropriate value of incremental capacity. By comparison, other types of generating units are built at higher capital cost to derive energy savings. Marginal generation capacity cost is the annualized cost of a peaking unit -- appropriately adjusted for reserve margin and losses and discounted from the year of first need to the year for which marginal costs are being calculated. This cost (in constant prices) is subsequently adjusted upwards for incremental fixed O&M expenses, as well as any downstream losses up to the point of delivery. The resulting marginal cost of generation capacity can be allocated to the peak period.

In the case of NEA, since no thermal capacity is planned, it is recommended that a hypothetical low speed diesel generator set be identified as the proxy to estimate the value of marginal generation capacity. An alternative approach to estimating marginal generation capacity, known as the "system re-optimization method", is also possible, but would require multiple runs of a system expansion planning model (e.g., WASP) by NEA's System Planning Department to isolate the energy cost associated with of an incremental capacity addition. Since experience in other jurisdictions has found the two methods to yield similar results, we recommend the proxy method for its clarity and simplicity.

Marginal Network Capacity Cost. The transmission and distribution (T&D) network's capacity is designed to accommodate peak power flows from generation to end-users. In a growing system, network capacity is sized to meet future load growth. Generally, all investment costs for T&D are allocated to incremental capacity because these facilities are designed to meet peak load (kW). The most frequently used approach, and the one adopted for the present study, is the long-run average incremental cost (AIC) method.

$$\mathrm{AIC} = \left[\sum_{i=0}^{T} \frac{I_i}{(1+r)^i}\right] \Bigg/ \left[\sum_{i=L}^{L+T} \frac{\Delta MW_i}{(1+r)^i}\right]$$

The LRAIC represents the present value of all T&D investments over the planning horizon divided by the present value of the corresponding annual increments in peak load. This value, expressed in NRs per incremental kW, is then annualized over the life of the facilities -- resulting in the annualized network capacity cost (NRs/kW/year).

In this study Short-run marginal cost is estimated by taking only the marginal energy cost.

7. Data and Assumptions

This section presents the data and assumptions used in the study. Table 4 and 5 shows the load forecast and Network parameters used in calculation of marginal cost.

Table 4: NEA Load Forecast 2025

FY	Sales (GWh)	Network Losses	Gross Gen (GWh)	Sys Load Factor	Peak (MW)
2026	12,477.5	13.0%	14,342.0	60%	2729
2027	13,163.1	12.7%	15,078.0	60%	2869
2028	14,899.0	12.4%	17,008.0	60%	3236
2029	16,875.0	12.1%	19,198.0	60%	3653
2030	19,077.7	11.8%	21,630.0	60%	4115
2031	21,592.8	11.5%	24,398.6	60%	4642
2032	24,439.2	11.2%	27,521.7	60%	5236
2033	27,660.6	10.9%	31,044.4	60%	5906
2034	31,306.2	10.6%	35,018.1	60%	6663
2035	35,431.9	10.3%	39,500.4	60%	7515

Source: NEA and consultant own calculations

Table 5: Network Parameters

	Stn Use	400kV	220kV	132-66kV	33-11kV	400-230V	Total
LF		1.00	1.00	0.70	0.60	0.50	
Peak CF		1.00	1.00	0.70	0.80	0.95	
Network Losses	0.0%	0.5%	1.0%	2.5%	3.5%	6.5%	14.0%
Share of losses		3.6%	7.1%	17.9%	25.0%	46.4%	100.0%

Network Power Flow and Losses. The network power flow and losses are based on the losses and consumptions at the different voltage level. Figure 7 shows the schematics diagram of the network power flow at different voltage levels for the year 2026.

The projected peak electricity generation for the year 2026 is estimated at 2729 MW, which is transmitted through multiple voltage levels before reaching end users. As electricity flows through the system, technical losses are incurred at each stage of the transmission and distribution network, and consumption occurs primarily at lower voltage levels.

At the highest voltage levels (400 kV and 200 kV), the system functions purely as a bulk transmission network, with no direct consumption observed. Initial transmission losses amount to 13 MW, followed by 35 MW and 88 MW, reducing the available power to 2593 MW at the sub-transmission level (132–66 kV). At this stage, a modest level of consumption of 260 MW is recorded, reflecting demand from large industrial or regional loads connected at medium voltage levels. As power flows further downstream to the distribution network (33–11 kV), additional technical losses of 131 MW occur, leaving 2202 MW available. This level accounts for a significant share of consumption, with 686 MW supplied to medium-scale consumers such as commercial establishments and small industries.

At the lowest voltage level (400–230 V), which serves residential and small commercial users, the system experiences the highest loss of 278 MW, indicative of relatively lower efficiency in the distribution network.

The remaining 1238 MW is delivered to end users, representing the largest share of total electricity consumption.

Overall, total system losses are estimated at 545 MW, accounting for approximately 20% of total peak generation, while total consumption reaches 2184 MW. The analysis highlights that losses are disproportionately higher in the lower voltage distribution network, suggesting that improving distribution efficiency could yield significant system-wide benefits.

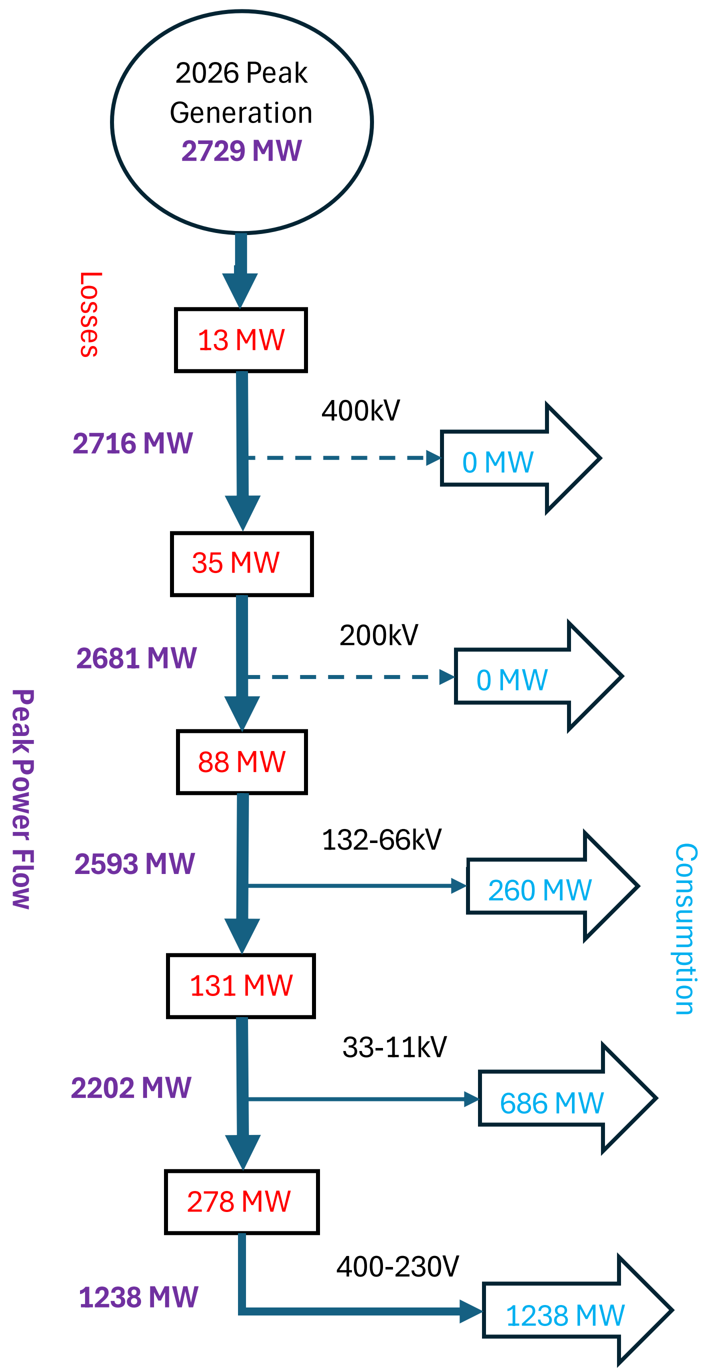

Figure 7: Schematic diagram of the network power flow for the year 2026

Table 6 shows the capital investment for different voltage levels in FY 2025 prices. NEA data provides the total cost, so FC is assumed to be 80% of the total cost for 400 kV, 220 kV and 132-66 kV network. In case of 33-11 kV and 400-230 V network FC is assumed to be 70%.

Table 6: Network Capacity Cost in million NPR

	400kV			220kV			132-66kV			33-11kV			400-230V		
FY	Total	FC	LC	Total	FC	LC	Total	FC	LC	Total	FC	LC	Total	FC	LC
2026	18839	15072	3768	25119	20095	5024	18839	15072	3768	14190	9933	4257	14190	9933	4257
2027	14677	11742	2935	19570	15656	3914	14677	11742	2935	14698	11758	2940	14698	10289	4409
2028	19073	15258	3815	25430	20344	5086	19073	15258	3815	15224	12179	3045	15224	10657	4567
2029	25265	20212	5053	33687	26950	6737	25265	20212	5053	15769	12615	3154	15769	11038	4731
2030	29603	23682	5921	39470	31576	7894	29603	23682	5921	16333	13066	3267	16333	11433	4900
2031	21491	17193	4298	28655	22924	5731	21491	17193	4298	15243	12194	3049	15243	10670	4573
2032	21491	17193	4298	28655	22924	5731	21491	17193	4298	15243	12194	3049	15243	10670	4573
2033	21491	17193	4298	28655	22924	5731	21491	17193	4298	15243	12194	3049	15243	10670	4573
2034	21491	17193	4298	28655	22924	5731	21491	17193	4298	15243	12194	3049	15243	10670	4573
2035	21491	17193	4298	28655	22924	5731	21491	17193	4298	15243	12194	3049	15243	10670	4573

Source: NEA and consultant own calculations

Table 7 shows consumer technical characteristics. This information is based on NEA data and assumptions used by the consultant based on the technical characteristics of utilities in South-Asia.

Table 7: Consumer technical characteristics

Category	Service Voltage	Coincidence Factor	Load Factor	Power Factor
Domestic	230V	0.80	0.40	0.9
Domestic	400V	0.80	0.40	0.9
Domestic	33-11kV	0.80	0.35	0.9
Non-Commercial	400-230V	0.40	0.40	0.85
Non-Commercial	11kV	0.30	0.20	0.9
Non-Commercial	33kV	0.30	0.20	0.9
Commercial	400-230V	0.60	0.40	0.85
Commercial	11kV	0.30	0.50	0.9
Commercial	33kV	0.30	0.50	0.9
Industrial	400-230V	0.40	0.35	0.8
Industrial	11kV	0.40	0.20	0.95
Industrial	33kV	0.40	0.20	0.95
Industrial	66kV	0.80	0.70	0.95
Industrial	132kV	0.80	0.70	0.95
Irrigation	400-230V	0.30	0.20	0.8
Irrigation	11kV	0.40	0.30	0.8
Irrigation	33kV	0.40	0.30	0.8
Water Supply	400-230V	0.30	0.20	0.8
Water Supply	11kV	0.40	0.30	0.8
Water Supply	33kV	0.40	0.30	0.8
Street Light	400-230V	0.30	0.50	0.9
Temporary Supply	400-230V	0.40	0.30	0.9
Temporary Supply	11kV	0.80	0.70	0.9
Transport (Public+Charge Stn)	400-230V	0.80	0.40	0.8
Transport (Other)	400-230V	0.80	0.40	0.8
Transport (Public+Charge Stn)	11kV	0.80	0.40	0.8
Transport (Other)	11kV	0.80	0.40	0.8
Transport (Public+Charge Stn)	33kV	0.80	0.40	0.8
Transport (Other)	33kV	0.80	0.40	0.8
Religious Places	400-230V	0.50	0.50	0.9
Religious Places	11kV	0.80	0.70	0.9
Non-Domestic	400-230V	0.80	0.40	0.8
Non-Domestic	11kV	0.80	0.70	0.8
Non-Domestic	33kV	0.80	0.70	0.8
Entertainment	400-230V	0.60	0.60	0.8
Entertainment	11kV	0.80	0.70	0.8
Entertainment	33kV	0.80	0.70	0.8
Community	400-230V	0.60	0.40	0.9
Community	33-11kV	0.80	0.70	0.9

8. Result of the LRMC Calculations

Table 8 presents the estimated marginal capacity cost, expressed in NPR/coincidentkW/month, representing the cost of providing an additional unit of dependable capacity to meet system peak demand. This cost reflects investments required in generation capacity (and implicitly associated network adequacy) driven by peak demand growth. The major interpretation of the results is as follows:

- The marginal capacity cost captures the long-run cost of meeting incremental peak demand, rather than average historical investment costs.
- Higher marginal capacity costs indicate that new capacity additions are increasingly capital-intensive for peaking requirements, reserve margins, and system reliability constraints.
- This cost is demand-driven, not energy-driven, and therefore varies with assumptions on peak growth, capacity mix, and availability.
- In tariff design, this cost is most appropriately recovered through capacity-related charges, such as fixed charges, demand charges (kW-based), or customer charges—rather than volumetric (kWh) tariffs.
- The results justify separating capacity and energy components in a two-part tariff, especially under LRMC-based pricing.

Table 8: Marginal Capacity Cost (NPR/ckW/month)

	Generation	Transmission and Distribution						System
		400kV	220kV	132-66kV	33-11kV	400-230V	T&D Total	Total
Busbar	2836.3						0.0	2836.3
400kV	2852.8	449.2					449.2	3302.0
220kV	2886.3	454.5	604.2				1058.7	3945.0
132-66kV	2973.3	468.2	622.4	463.4			1554.0	4527.3
33-11kV	3130.6	492.9	655.4	487.9	401.3		2037.5	5168.1
400-230V	3746.2	589.9	784.3	583.9	480.2	665.1	3103.4	6849.6

Table 9 reports the estimated marginal energy cost, expressed in NPR/kWh. This represents the cost of supplying an additional unit of electricity and includes variable generation costs, marginal imports, losses, and short-run operating costs. It also presents the tariff differentiated by time of day and season. In line with the methodology, marginal energy cost, when considered on its own, is equivalent to the short-run marginal cost. The main interpretations of the results are as follows:

- Marginal energy costs are lower and more stable than marginal capacity costs, reflecting Nepal's hydropower-dominated system with low variable operating costs.
- Variations in marginal energy cost primarily reflect:
    - Seasonal hydrology,
    - Reliance on imports during dry periods,
    - Changes in marginal loss factors.

- The results confirm that the economic cost of energy (kWh) is significantly lower than the cost of capacity (kW), reinforcing the importance of not recovering capacity costs through volumetric tariffs.
- Marginal energy cost provides the appropriate basis for energy charges in tariffs, promoting efficient consumption and dispatch decisions.

Table 9: Marginal Energy Cost (NPR/kWh)

	Dry Season			Wet Season				Annual			
	Peak	Normal	Avg	Peak	Normal	Off-Peak	Avg	Peak	Normal	Off-Peak	Avg
Busbar	6.89	1.45	2.81	3.39	0.59	0.54	1.28	4.56	0.88	0.36	1.79
400kV	6.93	1.46	2.82	3.41	0.59	0.54	1.28	4.58	0.88	0.36	1.80
220kV	7.01	1.47	2.85	3.45	0.60	0.55	1.30	4.64	0.89	0.36	1.82
132-66kV	7.22	1.50	2.93	3.56	0.61	0.56	1.33	4.78	0.91	0.37	1.87
33-11kV	7.60	1.56	3.07	3.74	0.63	0.58	1.40	5.03	0.94	0.39	1.95
400-230V	9.09	1.77	3.60	4.48	0.72	0.66	1.64	6.02	1.07	0.44	2.29

Note: Adjusted to local prices and for losses

Taken together, the result of the capacity and energy marginal cost highlight a structural asymmetry in Nepal's power system:

- Capacity is scarce and expensive at the margin → driven by peak demand.
- Energy is relatively cheap at the margin → driven by hydropower availability.

This has several important implications:

- Need for tariff unbundling. Recovering both costs through a single energy tariff would distort consumption signals and under-recover fixed costs.
- Justification for two-part or multi-part tariffs:
    - Capacity cost → fixed or demand-based charges
    - Energy cost → per-kWh charges aligned with marginal energy cost
- Relevance for Ramsey pricing and revenue neutrality. Marginal capacity and energy costs provide the technical foundation for Ramsey mark-ups when revenue recovery exceeds LRMC.
- System planning consistency. The results are consistent with a system transitioning to surplus energy but still constrained by peak capacity and seasonal adequacy.

Table 10 shows the LRMC as per the consumer category as per the NEA Tariff Policy. The LRMC for electricity supply is determined according to the consumer categories defined by the NEA Tariff Policy. For each category, both the capacity charge and the energy charge are drawn from the strict LRMC calculation. This approach ensures that the tariff accurately reflects the costs associated with providing capacity for peak demand and supplying energy resulting from hydropower availability.

To present a consistent comparison across consumer categories, the total tariff is also represented as an energy cost. This is achieved by converting the capacity charge into its energy equivalent. The conversion utilizes suitable load factors specific to each consumer category, allowing for a standardized expression of the total tariff in terms of energy cost. This method facilitates a clear understanding of the cost structure and enables assessment of tariff reflectivity for each group.

Table 10: Strict LRMC based tariff for different tariff categories

Category	Service Voltage	Capacity (NPR/kW/mo)	Energy (NPR/kWh)	Total (NPR/kWh)
Domestic	230V	5480	2.29	21.06
Domestic	400V	5480	2.29	21.06
Domestic	33-11kV	4134	1.95	18.14
Non-Commercial	400-230V	2740	2.29	11.68
Non-Commercial	11kV	1550	1.95	12.57
Non-Commercial	33kV	1550	1.95	12.57
Commercial	400-230V	4110	2.29	16.37
Commercial	11kV	1550	1.95	6.20
Commercial	33kV	1550	1.95	6.20
Industrial	400-230V	2740	2.29	13.02
Industrial	11kV	2067	1.95	16.11
Industrial	33kV	2067	1.95	16.11
Industrial	66kV	3622	1.87	8.95
Industrial	132kV	3622	1.87	8.95
Irrigation	400-230V	2055	2.29	16.37
Irrigation	11kV	2067	1.95	11.39
Irrigation	33kV	2067	1.95	11.39
Water Supply	400-230V	2055	2.29	16.37
Water Supply	11kV	2067	1.95	11.39
Water Supply	33kV	2067	1.95	11.39
Street Light	400-230V	2055	2.29	7.92
Temporary Supply	400-230V	2740	2.29	14.81
Temporary Supply	11kV	4134	1.95	10.05
Transport (Public+Charge Stn)	400-230V	5480	2.29	21.06
Transport (Other)	400-230V	5480	2.29	21.06
Transport (Public+Charge Stn)	11kV	4134	1.95	16.11
Transport (Other)	11kV	4134	1.95	16.11
Transport (Public+Charge Stn)	33kV	4134	1.95	16.11
Transport (Other)	33kV	4134	1.95	16.11
Religious Places	400-230V	3425	2.29	11.68
Religious Places	11kV	4134	1.95	10.05
Non-Domestic	400-230V	5480	2.29	21.06
Non-Domestic	11kV	4134	1.95	10.05
Non-Domestic	33kV	4134	1.95	10.05
Entertainment	400-230V	4110	2.29	11.68
Entertainment	11kV	4134	1.95	10.05
Entertainment	33kV	4134	1.95	10.05
Community	400-230V	4110	2.29	16.37
Community	33-11kV	4134	1.95	10.05

Similarly, Table 11 shows time of use tariff derived from the strict LRMC, applicable for four dry months and eight wet months and for different times of day.

Table 11: Strict LRMC based tariff for Time-of-Use Tariff categories

		Wet Season (Baishak-Mansir)				Dry Season (Poush-Chaitra)		
	Service	Demand Charge	Peak Time	Off Peak Time	Normal time	Demand Charge	Peak Time	Normal time
Category	Voltage	NPR/kVA/month	NPR/kWh	NPR/kWh	NPR/kWh	NPR/kVA/month	NPR/kWh	NPR/kWh
Non-Commercial	11kV	1395	3.74	0.58	0.63	1395	7.60	1.56
Non-Commercial	33kV	1395	3.74	0.58	0.63	1395	7.60	1.56
Commercial	11kV	1395	3.74	0.58	0.63	1395	7.60	1.56
Commercial	33kV	1395	3.74	0.58	0.63	1395	7.60	1.56
Industrial	11kV	1964	3.74	0.58	0.63	1964	7.60	1.56
Industrial	33kV	1964	3.74	0.58	0.63	1964	7.60	1.56
Industrial	66kV	3441	3.56	0.56	0.61	3441	7.22	1.50
Industrial	132kV	3441	3.56	0.56	0.61	3441	7.22	1.50
Irrigation	11kV	1654	3.74	0.58	0.63	1654	7.60	1.56
Irrigation	33kV	1654	3.74	0.58	0.63	1654	7.60	1.56
Water Supply	11kV	1654	3.74	0.58	0.63	1654	7.60	1.56
Water Supply	33kV	1654	3.74	0.58	0.63	1654	7.60	1.56
Temporary Supply	11kV	2466	3.74	0.58	0.63	2466	7.60	1.56
Transport (Public+Charge Stn)	400-230V	4384	4.48	0.66	0.72	4384	9.09	1.77
Transport (Other)	400-230V	4384	4.48	0.66	0.72	4384	9.09	1.77
Transport (Public+Charge Stn)	11kV	3308	3.74	0.58	0.63	3308	7.60	1.56
Transport (Other)	11kV	3308	3.74	0.58	0.63	3308	7.60	1.56
Transport (Public+Charge Stn)	33kV	3308	3.74	0.58	0.63	3308	7.60	1.56
Transport (Other)	33kV	3308	3.74	0.58	0.63	3308	7.60	1.56
Religious Places	11kV	3721	3.74	0.58	0.63	3721	7.60	1.56
Pk Time = 17:00-23:00, Off Pk Time = 23:00-05:00, Normal Time = 05:00-17:00						Pk Time = 17:00-23:00, Normal Time = 23:00-17:0		

Table 12 compares existing NEA tariffs (converted into an equivalent NPR/kWh using assumed power factor and load factor) with the estimated LRMC of electricity supply across consumer categories and voltage levels as shown in Table 10. The objective is to assess the degree of cost reflectivity, identify cross-subsidies, and highlight areas of under- and over-pricing relative to marginal cost.

A dominant feature of the table is that most consumer categories are priced significantly below LRMC, particularly at low and medium voltage levels. These results indicate severe under-recovery of incremental supply costs, implying that additional consumption by these users increases system costs without corresponding revenue recovery.

The largest negative deviations are observed for Irrigation, Water supply, Street lighting, Religious and community services. These tariffs are multiple times lower than LRMC, confirming that:

- They are policy-driven tariffs, not cost-based tariffs
- Subsidies are embedded within the tariff structure, rather than being explicitly funded

From an economic perspective, these prices cannot be justified within a marginal-cost or Ramsey-pricing framework and require explicit subsidy recognition.

Table 12: Comparison of NEA current tariff with estimated LRMC

		NEA Electricity Tariff (2025)			LRMC			Deviation from LRMC		
	Service	Capaci Charge	Energy Charge	Total Tariff	Capacity	Energy	Total	Fixed	Energy	Total
Category	Voltage	NPR/kVA/mo	NPR/kWh	NPR/kWh	NPR/kVA/mo	NPR/kWh	NPR/kWh	Charge	Charge	Charge
Domestic	230V	100	9.50	9.88	4932	2.29	21.06	-4832%	76%	-113%
Domestic	400V	1450	11.00	16.52	4932	2.29	21.06	-240%	79%	-28%
Domestic	33-11kV	10000	10.75	54.24	3721	1.95	18.14	63%	82%	67%
Non-commercial	400-230V	215	12.00	12.87	2329	2.29	11.68	-983%	81%	9%
Non-commercial	11kV	240	11.40	13.23	1395	1.95	12.57	-481%	83%	5%
Non-commercial	33kV	240	11.50	13.33	1395	1.95	12.57	-481%	83%	6%
Commercial	400-230V	325	11.20	12.51	3493	2.29	16.37	-975%	80%	-31%
Commercial	11kV	315	11.10	12.06	1395	1.95	6.20	-343%	82%	49%
Commercial	33kV	315	10.80	11.76	1395	1.95	6.20	-343%	82%	47%
Industrial	400-230V	110	9.60	10.14	2192	2.29	13.02	-1893%	76%	-28%
Industrial	11kV	255	8.60	10.44	1964	1.95	16.11	-670%	77%	-54%
Industrial	33kV	255	8.40	10.24	1964	1.95	16.11	-670%	77%	-57%
Industrial	66kV	240	8.30	8.79	3441	1.87	8.95	-1334%	78%	-2%
Industrial	132kV	230	8.20	8.67	3441	1.87	8.95	-1396%	77%	-3%
Irrigation	400-230V		2.25	2.25	1644	2.29	16.37	NA	-2%	-628%
Irrigation	11kV		2.60	2.60	1654	1.95	11.39	NA	25%	-338%
Irrigation	33kV		2.50	2.50	1654	1.95	11.39	NA	22%	-356%
Water Supply	400-230V	160	7.20	8.57	1644	2.29	16.37	-927%	68%	-91%
Water Supply	11kV	150	5.80	6.66	1654	1.95	11.39	-1003%	66%	-71%
Water Supply	33kV	160	5.60	6.51	1654	1.95	11.39	-934%	65%	-75%
Street Light	400-230V		7.30	7.30	1849	2.29	7.92	NA	69%	-9%
Temporary Supply	400-230V		19.80	19.80	2466	2.29	14.81	NA	88%	25%
Temporary Supply	11kV	330	12.00	12.72	3721	1.95	10.05	-1028%	84%	21%
Transport (Public+Charge Stn)	400-230V	200	5.75	6.61	4384	2.29	21.06	-2092%	60%	-219%
Transport (Other)	400-230V	220	8.90	9.84	4384	2.29	21.06	-1893%	74%	-114%
Transport (Public+Charge Stn)	11kV	230	5.60	6.58	3308	1.95	16.11	-1338%	65%	-145%
Transport (Other)	11kV	255	8.80	9.89	3308	1.95	16.11	-1197%	78%	-63%
Transport (Public+Charge Stn)	33kV	230	5.60	6.58	3308	1.95	16.11	-1338%	65%	-145%
Transport (Other)	33kV	255	8.60	9.69	3308	1.95	16.11	-1197%	77%	-66%
Temple	400-230V		6.10	6.10	3082	2.29	11.68	NA	62%	-91%
Temple	11kV	220	9.90	10.38	3721	1.95	10.05	-1591%	80%	3%
Non-Domestic	400-230V	350	13.00	14.50	4384	2.29	21.06	-1152%	82%	-45%
Non-Domestic	11kV	350	12.90	13.76	3308	1.95	10.05	-845%	85%	27%
Non-Domestic	33kV	350	12.55	13.41	3308	1.95	10.05	-845%	84%	25%
Entertainment	400-230V	350	14.00	15.00	3288	2.29	11.68	-839%	84%	22%
Entertainment	11kV	350	13.90	14.76	3308	1.95	10.05	-845%	86%	32%
Entertainment	33kV	350	13.50	14.36	3308	1.95	10.05	-845%	86%	30%
Community	400-230V	30	6.00	6.11	3699	2.29	16.37	-12229%	62%	-168%
Community	33-11kV	30	6.25	6.32	3721	1.95	10.05	-12303%	69%	-59%

The table clearly demonstrates that:

- NEA’s current tariff structure is not aligned with marginal cost principles
- There is systematic under-pricing of electricity for several consumer groups
- Cross-subsidies are large, implicit, and non-transparent
- Cost reflectivity improves with voltage level, but remains incomplete
- Marginal cost estimates provide a critical benchmark for tariff reform, even if tariffs are not moved fully to LRMC levels

Table 13 and 14 provides a comparison between NEA’s current time-of-use tariff and the estimated TOU LRMC. As previously discussed, the demand charge under the current tariff is substantially lower than the marginal capacity cost. In contrast, the energy charge is set higher than the marginal energy cost. This misalignment results in an imbalance in electricity consumption, as consumers are not faced with prices that reflect the true economic cost of providing capacity and energy. Consequently, the tariff structure does not send accurate price signals, which undermines the effectiveness of demand side management initiatives and can lead to inefficient consumption patterns.

Table 13: Comparison of NEA current Wet Season Time-of-Use Tariff with estimated LRMC

		NEA Tariff Rate from Baishakh to Mangsir (Wet Season				**LRMC Wet Season**				**Deviation from LRMC**			
	Service	Demand Charge	Pk Time	Off Pk Time	Norm Time	Demand Charge	Pk Time	Off Pk Time	Norm Time	Demand	Peak	Off Peak	Norm
Category	Voltage	NPR/kVA/mo	NPR/kWh	NPR/kWh	NPR/kWh	NPR/kVA/mo	NPR/kWh	NPR/kWh	NPR/kWh	Charge	Time	Time	Time
Non-Commercial	11kV	240	13.50	7.15	12.25	1395	3.74	0.58	0.63	-481%	72%	92%	95%
Non-Commercial	33kV	240	13.20	7.00	12.00	1395	3.74	0.58	0.63	-481%	72%	92%	95%
Commercial	11kV	315	12.60	6.90	11.10	1395	3.74	0.58	0.63	-343%	70%	92%	94%
Commercial	33kV	315	12.30	6.75	10.80	1395	3.74	0.58	0.63	-343%	70%	91%	94%
Industrial	11kV	250	10.50	5.40	8.55	1964	3.74	0.58	0.63	-686%	64%	89%	93%
Industrial	33kV	250	10.20	5.25	8.40	1964	3.74	0.58	0.63	-686%	63%	89%	92%
Industrial	66kV	240	10.10	4.75	8.30	3441	3.56	0.56	0.61	-1334%	65%	88%	93%
Industrial	132kV	230	10.00	4.65	8.20	3441	3.56	0.56	0.61	-1396%	64%	88%	93%
Irrigation	11kV	NA	6.40	2.00	3.10	1654	3.74	0.58	0.63	NA	42%	71%	80%
Irrigation	33kV	NA	6.30	2.00	3.00	1654	3.74	0.58	0.63	NA	41%	71%	79%
Water Supply	11kV	150	10.50	5.40	8.50	1654	3.74	0.58	0.63	-1003%	64%	89%	93%
Water Supply	33kV	150	10.20	5.25	8.40	1654	3.74	0.58	0.63	-1003%	63%	89%	92%
Temporary Supply	11kV	330	14.40	6.60	11.75	2466	3.74	0.58	0.63	-647%	74%	91%	95%
Transport (Public+Charge Stn)	400-230V	200	7.25	4.30	5.75	4384	4.48	0.66	0.72	-2092%	38%	85%	87%
Transport (Other)	400-230V	220	9.75	4.30	8.60	4384	4.48	0.66	0.72	-1893%	54%	85%	92%
Transport (Public+Charge Stn)	11kV	230	7.15	4.20	5.60	3308	3.74	0.58	0.63	-1338%	48%	86%	89%
Transport (Other)	11kV	255	9.65	4.20	8.50	3308	3.74	0.58	0.63	-1197%	61%	86%	93%
Transport (Public+Charge Stn)	33kV	230	7.00	3.70	5.50	3308	3.74	0.58	0.63	-1338%	47%	84%	88%
Transport (Other)	33kV	255	9.35	3.70	8.40	3308	3.74	0.58	0.63	-1197%	60%	84%	92%
Religious Places	11kV	220	11.30	5.15	9.10	3721	3.74	0.58	0.63	-1591%	67%	89%	93%
Peak Time = 17:00-23:00, Off Peak Time = 23:00-05:00, Normal Time = 05:00-17:00													

Table 14: Comparison of NEA current Dry Season Time-of-Use Tariff with estimated LRMC

		NEA Tariff Rate from Poush to Chaitra (Dry Season)			**LRMC Dry Season**			**Deviation from LRMC**		
	Service	Demand Charge	Peak Time	Normal Time	Demand Charge	Peak Time	Normal Time	Demand	Peak	Normal
Category	Voltage	NPR/kVA/mo	NPR/kWh	NPR/kWh	NPR/kVA/ mo	NPR/kWh	NPR/kWh	Charge	Time	Time
Non-Commercial	11kV	240	13.50	12.25	1395	7.60	1.56	-481%	44%	87%
Non-Commercial	33kV	240	13.20	12.00	1395	7.60	1.56	-481%	42%	87%
Commercial	11kV	315	12.60	11.10	1395	7.60	1.56	-343%	40%	86%
Commercial	33kV	315	12.30	10.80	1395	7.60	1.56	-343%	38%	86%
Industrial	11kV	250	10.50	8.55	1964	7.60	1.56	-686%	28%	82%
Industrial	33kV	250	10.20	8.40	1964	7.60	1.56	-686%	25%	81%
Industrial	66kV	240	10.10	8.30	3441	7.22	1.50	-1334%	29%	82%
Industrial	132kV	230	10.00	8.20	3441	7.22	1.50	-1396%	28%	82%
Irrigation	11kV	NA	6.40	3.10	1654	7.60	1.56	NA	-19%	50%
Irrigation	33kV	NA	6.30	3.00	1654	7.60	1.56	NA	-21%	48%
Water Supply	11kV	150	10.50	8.50	1654	7.60	1.56	-1003%	28%	82%
Water Supply	33kV	150	10.20	8.40	1654	7.60	1.56	-1003%	25%	81%
Temporary Supply	11kV	330	14.40	11.75	2466	7.60	1.56	-647%	47%	87%
Transport (Public+Charge Stn)	400-230V	200	7.25	5.75	4384	9.09	1.77	-2092%	-25%	69%
Transport (Other)	400-230V	220	9.75	8.60	4384	9.09	1.77	-1893%	7%	79%
Transport (Public+Charge Stn)	11kV	230	7.15	5.60	3308	7.60	1.56	-1338%	-6%	72%
Transport (Other)	11kV	255	9.65	8.50	3308	7.60	1.56	-1197%	21%	82%
Transport (Public+Charge Stn)	33kV	230	7.00	5.50	3308	7.60	1.56	-1338%	-9%	72%
Transport (Other)	33kV	255	9.35	8.40	3308	7.60	1.56	-1197%	19%	81%
Religious Places	11kV	220	11.30	9.10	3721	7.60	1.56	-1591%	33%	83%
Peak Time = 17:00-23:00, Normal Time = 23:00-17:00										

9. Electricity Tariff Design

There are three commonly used approaches to the electricity tariff design

1. Ramsey Pricing

Ramsey pricing is an economic principle used to set tariffs in a way that allows a utility to recover its total costs while minimizing the loss of economic efficiency. It prescribes that prices should be set above marginal cost in inverse proportion to the price elasticity of demand, meaning that consumer groups with less price-sensitive (inelastic) demand bear higher mark-ups, while those with more elastic demand face lower mark-ups. This approach ensures that the required revenue is collected with the least distortion to consumption and overall welfare, making it a widely used framework in regulated sectors such as electricity.

Ramsey rule: $\frac{P_i - MC}{P_i} = \frac{k}{|\varepsilon_i|}$

Rearranging: $P_i = \frac{MC}{1 - \frac{k}{|\varepsilon_i|}}$

Normally:

- $k > 0$ and prices are above marginal cost

2. Uniform Scaling of MC (Revenue-Neutral Marginal Cost Pricing)

In hydropower-dominated systems (like Nepal, Bhutan, parts of India, Norway), it is quite common that annual revenue with LRMC would be higher than required revenue. This is because long-run marginal cost reflects the cost of new capacity, which is often higher than the average cost of existing hydro plants. When this happens, regulators normally do not use pure Ramsey pricing. Instead, LRMC studies usually apply a revenue-neutral scaling of marginal cost. This is the method most commonly used in tariff design studies.

Revenue-neutral marginal cost pricing is a practical method used when pricing at marginal cost would generate more or less revenue than the utility's required revenue. Under this approach, all marginal cost-based tariffs are multiplied by a common scaling factor so that total revenue matches the allowed revenue requirement. This preserves the relative cost signals across consumer categories while ensuring revenue neutrality, although the resulting prices deviate slightly from true marginal cost and introduce some distortion compared to first-best pricing.

Therefore, when: $LRMC \times Q > ARR$

a commonly used practical method is: $P_i = \alpha \cdot MC_i$

With $\alpha = \frac{ARR}{MC\ Revenue}$

3. Equal Percentage Reduction from MC

Another approach is to subtract a constant amount: $P_i = MC_i - \delta$

Where $\sum(MC_i - \delta)Q_i = ARR$

This maintains price differences between categories but may produce negative prices for some classes.

Tariff Design Approaches: Simulation Cases

Electricity tariff setting is not determined solely by economic principles such as marginal cost pricing or efficiency. In practice, it involves balancing a range of socio-political, economic, and institutional considerations, particularly in developing and transitioning economies. As a result, tariffs often reflect broader policy objectives in addition to cost recovery.

A primary consideration is affordability and social equity. Electricity is an essential service, and governments seek to ensure that basic consumption remains accessible to low-income households and vulnerable groups. This often leads to the introduction of lifeline tariffs, subsidized domestic rates, or targeted support mechanisms. In many systems, these measures are financed through cross-subsidies, where industrial and commercial consumers pay higher tariffs to support lower-income residential users.

Closely linked to this is political acceptability. Electricity tariffs are highly visible and sensitive, and significant tariff increases can lead to public resistance and political pressure. Consequently, governments and regulators often adopt gradual tariff adjustments rather than immediate moves to cost-reflective levels. Maintaining public acceptance can, in practice, take precedence over strict economic efficiency, especially in periods of economic stress.

Another important factor is economic competitiveness. Electricity prices directly affect the cost structure of industries and businesses. High tariffs for industrial and commercial consumers can reduce competitiveness, discourage investment, and impact economic growth. Therefore, regulators often seek to limit tariff burdens on productive sectors, even if this implies maintaining some level of cross-subsidy or deviating from strict cost-based pricing.

Tariff design also reflects policy objectives related to demand-side management and energy transition. Pricing structures may be used to influence consumer behavior, such as encouraging energy efficiency, reducing peak demand, or promoting electrification in sectors like cooking and transport. Instruments such as time-of-use tariffs, seasonal pricing, and targeted incentives are commonly used for this purpose.

In addition, institutional and regulatory constraints play a significant role. The design and implementation of tariffs depend on the capacity of regulatory bodies, the availability and quality of data, and the broader legal and policy framework. In many systems, limitations in data—such as lack of detailed load profiles or demand elasticity estimates—restrict the application of more sophisticated pricing approaches.

Finally, public perception and trust are critical. Tariffs must be perceived as fair, transparent, and justified. A lack of trust in the utility or regulatory process can lead to resistance to tariff reforms, non-payment of bills, and broader governance challenges. Clear communication and stakeholder engagement are therefore essential components of successful tariff setting.

The Ramsey pricing approach to tariff design is not applicable in this context, as the LRMC exceeds the NEA current tariff levels. To address this, an Excel-based model has been developed to simulate and compare different tariff design scenarios. The following cases have been constructed to evaluate various approaches to tariff setting:

Case 1: Economically Optimal: Revenue-neutral LRMC structure

Case 2: Unreformed tariff structure; equal percentage increase to all classes

Case 3: Manually assigned tariff increases to achieve targeted revenue

Case 4: Develop suitable tariff cases as per other Socio-economic Policy scenarios

These cases allow for a systematic assessment of different tariff structures, providing insights into their implications for revenue sufficiency, affordability, and policy objectives.

Table 15 presents the outcomes from the simulation conducted for Case 1, which evaluates a revenue-neutral LRMC tariff structure. The table provides a comparison among three key elements: the strict application of LRMC, the revenue-neutral LRMC, and the proposed tariff rates as determined for Case 1. These simulation results are intended solely for illustrative purposes and should not be interpreted as a formal recommendation by the study.

Table 15: Tariff Design and its Economic and Financial Implications

	Service	Strict LRMC	Revnue Neural LRMC		Proposed Tariff		Implied Financial Subsidy/Tax		Implied Economic Subsidy/Tax	
Category	**Voltage**	**NPR/kWh**	**NPR/kWh**	**% Change**	**NPR/kWh**	**% Change**	**NPR/kWh**	**MNPR**	**NPR/kWh**	**MNPR**
Domestic	230V	21.06	14.34	61%	14.34	61%	5.42	16329	12.14	36580
Domestic	400V	21.06	14.34	61%	14.34	61%	5.42	6998	12.14	15677
Domestic	33-11kV	18.14	12.35	38%	12.35	38%	3.43	1640	9.22	4408
Non-commercial	400-230V	11.68	7.95	-44%	7.95	-44%	-6.13	-638	-2.41	-250
Non-commercial	11kV	12.57	8.56	-39%	8.56	-39%	-5.52	-671	-1.51	-183
Non-commercial	33kV	12.57	8.56	-39%	8.56	-39%	-5.52	-671	-1.51	-183
Commercial	400-230V	16.37	11.14	-21%	11.14	-21%	-2.92	-771	2.30	608
Commercial	11kV	6.20	4.22	-70%	4.22	-70%	-9.84	-3031	-7.86	-2422
Commercial	33kV	6.20	4.22	-70%	4.22	-70%	-9.84	-3031	-7.86	-2422
Industrial	400-230V	13.02	8.86	-8%	8.86	-8%	-0.78	-161	3.37	698
Industrial	11kV	16.11	10.97	14%	10.97	14%	1.33	1235	6.47	6021
Industrial	33kV	16.11	10.97	14%	10.97	14%	1.33	1235	6.47	6021
Industrial	66kV	8.95	6.10	-37%	6.10	-37%	-3.55	-2935	-0.69	-571
Industrial	132kV	8.95	6.10	-37%	6.10	-37%	-3.55	-4402	-0.69	-856
Irrigation	400-230V	16.37	11.14	193%	11.14	193%	7.34	216	12.56	369
Irrigation	11kV	11.39	7.76	104%	7.76	104%	3.95	448	7.59	860
Irrigation	33kV	11.39	7.76	104%	7.76	104%	3.95	448	7.59	860
Water Supply	400-230V	16.37	11.14	193%	11.14	193%	7.34	92	12.56	158
Water Supply	11kV	11.39	7.76	104%	7.76	104%	3.95	299	7.59	574
Water Supply	33kV	11.39	7.76	104%	7.76	104%	3.95	299	7.59	574
Street Light	400-230V	7.92	5.40	-23%	5.40	-23%	-1.60	-225	0.92	129
Temporary Supply	400-230V	14.81	10.08	-42%	10.08	-42%	-7.32	-51	-2.59	-18
Temporary Supply	11kV	10.05	6.84	-61%	6.84	-61%	-10.56	-32	-7.35	-22
Transport (Public+Charge Stn)	400-230V	21.06	14.34	91%	14.34	91%	6.82	73	13.54	145
Transport (Other)	400-230V	21.06	14.34	91%	14.34	91%	6.82	18	13.54	36
Transport (Public+Charge Stn)	11kV	16.11	10.97	46%	10.97	46%	3.45	55	8.59	138
Transport (Other)	11kV	16.11	10.97	46%	10.97	46%	3.45	55	8.59	138
Transport (Public+Charge Stn)	33kV	16.11	10.97	46%	10.97	46%	3.45	37	8.59	92
Transport (Other)	33kV	16.11	10.97	46%	10.97	46%	3.45	37	8.59	92
Temple	400-230V	11.68	7.95	22%	7.95	22%	1.42	22	5.15	79
Temple	11kV	10.05	6.84	5%	6.84	5%	0.31	1	3.52	6
Non-Domestic	400-230V	21.06	14.34	-7%	14.34	-7%	-1.13	-73	5.59	361
Non-Domestic	11kV	10.05	6.84	-56%	6.84	-56%	-8.63	-1115	-5.43	-701
Non-Domestic	33kV	10.05	6.84	-56%	6.84	-56%	-8.63	-1115	-5.43	-701
Entertainment	400-230V	11.68	7.95	-51%	7.95	-51%	-8.36	-27	-4.63	-15
Entertainment	11kV	10.05	6.84	-58%	6.84	-58%	-9.47	-73	-6.27	-48
Entertainment	33kV	10.05	6.84	-58%	6.84	-58%	-9.47	-49	-6.27	-32
Community	400-230V	16.37	11.14	0%	11.14	0%	11.14	0	16.37	0
Community	33-11kV	10.05	6.84	58%	6.84	58%	2.50	458	5.71	1044

Additionally, Table 15 highlights the implied financial and economic subsidy or tax associated with each consumer category, reflecting the impact of the proposed tariff structure. In light of the broader objectives of tariff design discussed previously, it is recommended that the NEA and the ERC utilize these findings as a basis for setting appropriate tariffs. The NEA can use the excel model developed here to simulate other tariff design cases.

10. Electricity Sector Regulation

Electricity sectors around the world apply different regulatory frameworks depending on market structure, institutional capacity, and policy objectives. These regulatory approaches determine how tariffs are set, how risks are allocated between utilities and consumers, and how efficiency and investment incentives are created. Some of the key regulations are briefly discussed below.

Cost-of-Service (Rate-of-Return) Regulation

Under cost-of-service regulation, the regulator allows the utility to recover its prudently incurred operating costs, depreciation, taxes, and a "fair" rate of return on the regulated asset base. **Allowed revenue is typically calculated as the sum of operating and maintenance expenses, depreciation, taxes, and the approved rate of return multiplied by the rate base.** The core principle is full cost recovery combined with financial viability of the utility.

$$\text{Allowed Revenue} = \text{O\&M} + \text{Depreciation} + \text{Taxes} + (r \times \text{Rate Base})$$

Tariffs under this framework are fundamentally cost-driven, and revenues are adjusted periodically to ensure that actual costs are recovered. As a result, most investment and volume risks are borne by consumers rather than the utility. While this approach provides strong revenue certainty and low financial risk for utilities, it offers weak incentives for cost efficiency. Utilities may have an incentive to over-invest in capital assets—a phenomenon known as the Averch–Johnson effect—and there is a risk of cost padding. Cost-of-service regulation is commonly applied in vertically integrated utilities, particularly in developing countries and in systems at early stages of sector reform where data availability and benchmarking capacity are limited.

Revenue Cap Regulation

Revenue cap regulation differs fundamentally from cost-of-service regulation by placing a ceiling on total allowed revenue rather than on unit prices. The regulator sets an allowed revenue path, typically for a multi-year period, based on a base revenue adjusted for inflation, expected efficiency improvements, and specific pass-through items for uncontrollable costs. Actual tariffs are then adjusted automatically depending on demand realization.

$$\text{Allowed Revenue}_t = \text{Base Revenue} \times (1 + \text{Inflation} - X \pm Z)$$

- X: expected efficiency gain
- Z: pass-through / uncontrollable factors

Under this framework, revenue is decoupled from energy sales, meaning that fluctuations in demand do not directly affect the utility's ability to recover its allowed revenue. Cost overruns are not automatically passed through to consumers, creating stronger incentives for cost control. At the same time, utilities face reduced incentives to promote electricity sales, which supports demand-side management and energy efficiency objectives. Revenue cap regulation is particularly well suited to transmission and distribution networks and to systems with demand uncertainty.

Compared with cost-of-service regulation, revenue cap regulation shifts sales risk from consumers to the utility, strengthens efficiency incentives, reduces over-capitalization bias, and generally results in greater tariff stability. It also aligns more naturally with long-run marginal cost (LRMC)–based tariff structures, as revenue gaps created by marginal-cost pricing can be addressed through fixed charges or structured mark-ups rather than frequent tariff revisions.

The distinction between these two frameworks is critical for tariff design. Under cost-of-service regulation, tariffs tend to reflect average costs, and the application of LRMC-based prices often leads to revenue shortfalls, requiring frequent tariff adjustments. Under revenue regulation, LRMC can be used as the basis for price structure, while revenue adequacy is ensured through non-distortionary mechanisms such as fixed charges or Ramsey-type mark-ups. In simple terms, cost-of-service regulation can be summarized as "spend first, justify later—consumers pay," whereas revenue regulation operates on the principle of "here is your revenue—manage efficiently." For LRMC-based electricity tariffs, revenue regulation is generally the superior framework.

Price Cap Regulation (RPI–X or CPI–X)

Price cap regulation limits the maximum price that utilities can charge using a formula that adjusts previous-period prices for inflation minus an expected efficiency factor, commonly referred to as the X-factor. This approach provides strong incentives for cost reduction, as utilities can retain efficiency gains during the regulatory period. It also offers predictable prices for consumers.

However, if the efficiency target is set too aggressively, price cap regulation may discourage necessary investment and compromise service quality. Successful implementation therefore requires robust benchmarking and forecasting capacity. Price cap regulation is widely applied to transmission and distribution utilities in jurisdictions such as the United Kingdom, the European Union, and Australia.

Incentive-Based Regulation (IBR)

Incentive-based regulation links a portion of a utility's revenue or earnings to measurable performance indicators such as loss reduction, reliability (for example, SAIDI and SAIFI), service quality, and renewable energy integration. The objective is to align utility behavior with broader policy goals while retaining regulatory flexibility.

While incentive-based schemes can be highly effective, they require strong monitoring systems, reliable data, and regulatory capacity to design and enforce performance metrics. This approach is increasingly used in reforming power sectors and in systems transitioning toward smart grids.

Performance-Based Regulation (PBR)

Performance-based regulation represents a more advanced form of incentive-based regulation. Instead of focusing on individual inputs or short-term metrics, PBR ties utility earnings to multi-year performance outcomes related to reliability, affordability, decarbonization, and customer satisfaction. By emphasizing outcomes rather than inputs, PBR encourages innovation and supports long-term energy transition objectives. However, it is complex to design and demands high regulatory expertise and institutional capacity.

Yardstick or Benchmark Regulation

Yardstick regulation determines a utility's allowed costs or prices by comparing its performance with that of peer utilities. Best-practice performance serves as the benchmark, thereby reducing information asymmetry between the regulator and the regulated entity. This approach provides strong efficiency incentives but requires a sufficient number of comparable utilities. Its application is therefore challenging in small systems or unique operating environments.

Franchise or Contract Regulation

Under franchise or contract regulation, utilities operate under concession or license agreements that specify tariffs, investment obligations, and performance standards. This model provides clear contractual obligations and is often used to facilitate private sector participation. However, it carries risks related to renegotiation and enforcement, particularly where institutional capacity is weak.

Market-Based Regulation in Liberalized Markets

In liberalized electricity markets, generation and retail prices are determined competitively through wholesale and retail markets, while transmission and distribution networks remain regulated monopolies. Market-based regulation promotes efficient price discovery and investment signals but requires strong oversight to mitigate market power and ensure system reliability. This model is prevalent in regions such as the United States, the European Union, and Australia.

Typical Regulatory Approaches by Segment

In practice, different segments of the electricity sector are subject to different regulatory approaches. Generation is commonly governed by market-based mechanisms or power purchase agreements, transmission by price cap or revenue cap regulation, distribution by cost-of-service or incentive-based regulation, and retail tariffs by a combination of Ramsey pricing principles, social tariffs, and price caps.

11. Conclusion and Recommendations

The results of the consumer analysis indicate that:

- Electricity demand in Nepal is price-inelastic, especially in the short run.
- Income effects dominate demand growth, particularly in the long run.
- Accounting for load-shedding improves the realism and stability of elasticity estimates.

These findings imply that tariff-based demand management alone is unlikely to significantly curb demand growth, while long-term planning should primarily focus on accommodating income-driven demand expansion and avoiding supply constraints.

Nepal's power system shows a structural imbalance: capacity is limited and costly due to peak demand, while energy remains cheap thanks to hydropower. This suggests several key actions:

- Unbundle tariffs to avoid distorting costs and under-recovering fixed expenses.
- Use two-part tariffs: fixed or demand charges for capacity, per-kWh rates for energy.
- Apply marginal cost data for Ramsey pricing and ensure revenue neutrality.
- Align planning with surplus energy availability but ongoing capacity and seasonal constraints.

The result of the capacity and energy marginal cost highlight a structural asymmetry in Nepal's power system:

- Capacity is scarce and expensive at the margin → driven by peak demand.
- Energy is relatively cheap at the margin → driven by hydropower availability.

This has several important implications:

- Need for tariff unbundling. Recovering both costs through a single energy tariff would distort consumption signals and under-recover fixed costs.
- Justification for two-part or multi-part tariffs:
    - Capacity cost → fixed or demand-based charges
    - Energy cost → per-kWh charges aligned with marginal energy cost
- Relevance for Ramsey pricing and revenue neutrality. Marginal capacity and energy costs provide the technical foundation for Ramsey mark-ups when revenue recovery exceeds LRMC.
- System planning consistency. The results are consistent with a system transitioning to surplus energy but still constrained by peak capacity and seasonal adequacy.

Comparison of current tariff with LRMC

The comparison of NEA's current tariffs with estimated marginal costs reveals significant deviations from cost-reflective pricing across most consumer categories. In particular, domestic, irrigation, water supply, street lighting, and religious consumers are priced far below LRMC, indicating substantial embedded subsidies and under-recovery of incremental supply costs. While tariffs at higher voltage levels are closer to marginal cost, industrial and commercial consumers remain largely below LRMC. These findings underscore the importance of using LRMC as a benchmark for tariff rebalancing, improving transparency of cross-subsidies, and strengthening economic efficiency while maintaining revenue neutrality and social policy objectives.

Typical Regulatory Approaches by Segment

In practice, different segments of the electricity sector are subject to different regulatory approaches. Generation is commonly governed by market-based mechanisms or power purchase agreements, transmission by price cap or revenue cap regulation, distribution by cost-of-service or incentive-based regulation, and retail tariffs by a combination of Ramsey pricing principles, social tariffs, and price caps.

References:

DOED, Power Sector Reform in Nepal, Final Report, Annex 3: Long Run Marginal Cost Study (International Resources Group), 2005

NEA, Long-run Marginal Cost and Tariff Study (Electricity de France), 1990

NEA, Long Run Marginal Cost: Final Report, Power System Master Plan for Nepal, (Norconsult), 1998

NEA, Load Forecast, 2015

NEA, Annual Reports 2000-2025

WECS, Electricity Demand Forecast Report (2015-2040), January 2017

Annex 1: Electricity Tariff of NEA 2025

Domestic Consumers

1.1 Single Phase Low Voltage (230 Voltage)

kWh (Monthly)	5 Ampere		15 Ampere		30 Ampere		60 Ampere	
	Minimum Charge (NRs.)	Energy Charge (NRs./kWh)	Minimum Charge (NRs.)	Energy Charge (NRs./kWh)	Minimum Charge (NRs.)	Energy Charge (NRs./kWh)	Minimum Charge (NRs.)	Energy Charge (NRs./kWh)
0-20	30.00	0.00	50.00	4.00	75.00	5.00	125.00	6.00
21-30	50.00	6.50	75.00	6.50	100.00	6.50	125.00	6.50
31-50	50.00	8.00	75.00	8.00	100.00	8.00	125.00	8.00
51-100	75.00	9.50	100.00	9.50	125.00	9.50	150.00	9.50
101-250	100.00	9.50	125.00	9.50	150.00	9.50	200.00	9.50
Above 251	150.00	11.00	175.00	11.00	200.00	11.00	250.00	11.00

Note: If 5 Ampere consumers use more than 20 units, they have to pay NRs.3.00 per unit for 1-20 unit.

1.2 Three Phase Low Voltage (400 Volt)

kWh (Month-ly)	Up to 10 kVA			Above 10 kVA		
	Minimum Charge (NRs.)	Month	Energy Charge (NRs./kWh)	Minimum Charge (NRs.)	Month	Energy Charge (NRs./kWh)
All Consumers	1100.00	Ashad -Kartik	10.50	1800.00	Ashad -Kartik	10.50
		Marg-Jestha	11.50		Marg-Jestha	11.50

1.3 Three Phase Voltage (33/11 kV)

kWh (Monthly)	Minimum Charge (NRs.)	Month	Energy Charge (NRs/kWh)
All Consumers	10,000.00	Ashad-Kartik	10.50
		Marg-Jestha	11.00

Billing Method (For Single Phase 5 Ampere)

S. No.	kWh (Monthly)	Energy Charge (NRs./kWh)	Billing Method
1	Up to 20 units	0.00	Monthly Minimum Charge Rs. 30.00 for up to 20 units and Energy Charge Rs. 0.00 per unit
2	21 to 30 units	6.50	Monthly Minimum Charge Rs. 50.00 and Energy Charge per unit Rs. 3.00 for per unit up to 20 units and Rs. 6.50 per unit for 21 units to 30 units
3	31 to 50 units	8.00	Monthly Minimum Charge Rs. 50.00 and Energy Charge per unit Rs. 3.00 for per unit up to 20 units and Rs. 6.50 per unit for 21 units to 30 units and Rs. 8.00 per unit for 31 units to 50 units
4	51 to 100 units	9.50	Monthly Minimum Charge Rs. 75.00 and Energy Charge per unit Rs. 3.00 for per unit up to 20 units and Rs. 6.50 per unit for 21 units to 30 units and Rs. 8.00 per unit for 31 units to 50 units and Rs. 9.50 per unit for 51 units to 100 units
5	101 to 250 units	9.50	Monthly Minimum Charge Rs. 100.00 and Energy Charge per unit Rs. 3.00 for per unit up to 20 units and Rs. 6.50 per unit for 21 units to 30 units and Rs. 8.00 per unit for 31 units to 50 units and Rs. 9.50 per unit for 51 units to 250 units
6	Above 251 units	11.00	Monthly Minimum Charge Rs. 150.00 and Energy Charge per unit Rs. 3.00 for per unit up to 20 units and Rs. 6.50 per unit for 21 units to 30 units and Rs. 8.00 per unit for 31 units to 50 units and Rs. 9.50 per unit for 51 units to 250 units and Rs. 11.00 per unit for above 251 units

Billing Method (For Single Phase 15 Ampere)

S. No.	kWh (Monthly)	Energy Charge (NRs./kWh)	Billing Method
1	Up to 20 units	4.00	Monthly Minimum Charge Rs. 50.00 for up to 20 units and Energy Charge Rs. 4.00 per unit (e.g.: 5 unit: Rs. 50 + 5 × 4 = Rs. 70.00)
2	21 to 30 units	6.50	Monthly Minimum Charge Rs. 75.00 and Energy Charge per unit Rs. 4.00 for per unit up to 20 units and Rs. 6.50 per unit for 21 units to 30 units (e.g.: 25 unit: Rs. 75 + 20 × 4 + 5 × 6.5 = Rs. 187.50)
3	31 to 50 units	8.00	Monthly Minimum Charge Rs. 75.00 and Energy Charge per unit Rs. 4.00 for per unit up to 20 units and Rs. 6.50 per unit for 21 units to 30 units and Rs. 8.00 per unit for 31 units to 50 units (e.g.: 35 unit: Rs. 75 + 20 × 4 + 10 × 6.5 + 5 × 8 = Rs. 260.00)
4	51 to 100 units	9.50	Monthly Minimum Charge Rs. 100.00 and Energy Charge per unit Rs. 4.00 for per unit up to 20 units and Rs. 6.50 per unit for 21 units to 30 units and Rs. 8.00 per unit for 31 units to 50 units and Rs. 9.50 per unit for 51 units to 100 units (e.g.: 55 unit: Rs. 100 + 20 × 4 + 10 × 6.5 + 20 × 8 + 5 × 9.5 = Rs. 452.50)
5	101 to 250 units	9.50	Monthly Minimum Charge Rs. 125.00 and Energy Charge per unit Rs. 4.00 for per unit up to 20 units and Rs. 6.50 per unit for 21 units to 30 units and Rs. 8.00 per unit for 31 units to 50 units and Rs. 9.50 per unit for 51 units to 250 units (e.g.: 105 unit: Rs. 125 + 20 × 4 + 10 × 6.5 + 20 × 8 + (50 + 5) × 9.5 = Rs. 952.50)
6	Above 251 units	11.00	Monthly Minimum Charge Rs. 175.00 and Energy Charge per unit Rs. 4.00 for per unit up to 20 units and Rs. 6.50 per unit for 21 units to 30 units and Rs. 8.00 per unit for 31 units to 50 units and Rs. 9.50 per unit for 51 units to 150 units and Rs. 10.00 per unit for 151 units to above 250 units and Rs. 11.00 per unit for 251 units to 400 units. (e.g.: 255 unit: Rs. 175 + 20 × 4 + 10 × 6.5 + 20 × 8 + (50 + 150) × 9.5 + 5 × 11 = Rs. 2435.00)

Billing Methods will be similar for Single Phase 30 and 60 Ampere.

2. Other Consumers

2.1 Low Voltage (230/400 V)

Consumer Category	Demand Charge NRs./kVA/ month	Energy Charge (NRs./ kWh)
1. Industrial		
a) Rural and Domestic	60.00	7.80
b) Small Industry	110.00	9.60
2. Commercial	325.00	11.20
3. Non-Commercial	215.00	12.00
4. Irrigation	-	2.25
5. Water Supply		
a) Community Water Supply	-	4.20
b) Other Water Supply	160.00	7.20
6. Transportation		
a) Public Transportation (Charging Station)	200.00	5.75
b) Other Transportation	220.00	8.90
7. Religious Place	-	6.10
8. Street Light		
a) Metered	-	7.30
b) Non-Metered	2475.00	-
9. Temporary Supply	-	19.80
10. Non-Domestic	350.00	13.00
11. Entertainment Business	350.00	14.00

2.2 High Voltage

Consumer Category	Demand Charge NRs./ kVA/month	Energy Charge NRs./ kWh
A. High Voltage		
1. Industrial (132 kV)	230.00	8.20
2. Industrial (66 kV)	240.00	8.30
B. Medium Voltage (33 KV)		
1. Industrial	255.00	8.40
2. Commercial	315.00	10.80
3. Non-commercial	240.00	11.40
4. Irrigation	-	2.50
5. Water Supply		
a) Community Water Supply	-	4.60
b) Other Water Supply	160.00	6.60
6. Transportation		
a) Public Transportation (Charging Station)	230.00	5.60
b) Other Transportation	255.00	8.60
7. Non-Domestic	350.00	12.55
8. Entertainment Business	350.00	13.50
C. Medium Voltage (11 kV)		
1. Industrial	255.00	8.60
2. Commercial	315.00	11.10
3. Non-commercial	240.00	11.50
4. Irrigation	-	2.60
5. Water Supply		
a) Community Water Supply	-	4.80
b) Other Water Supply	150.00	6.80
6. Transportation		
a) Public Transportation (Charging Station)	230.00	5.60
b) Other Transportation	255.00	8.80
7. Religious Place	220.00	9.90
8. Temporary Connection	330.00	12.00
9. Non-Domestic	350.00	12.90
10. Entertainment Business	350.00	13.90

3. Time of Day (ToD) Tariff Rate

3.1 Tariff Rate from Baishakh to Mangsir

Consumer Category	Demand Charge NRs./ kVA/ month	Peak Time (17.00-23.00)	Off Peak Time (23.00-5.00)	Normal time (5.00-17.00)
A. High Voltage (66 kV or above)				
1. Industrial (132 kV)	230.00	10.00	4.65	8.20
2. Industrial (66 kV)	240.00	10.10	4.75	8.30
B. Medium Voltage (33 kV)				
1. Industrial	250.00	10.20	5.25	8.40
2. Commercial	315.00	12.30	6.75	10.80
3. Non-Commercial	240.00	13.20	7.00	12.00
4. Irrigation	-	6.30	2.00	3.00
5. Water Supply				
a) Community Water Supply	-	6.20	3.10	4.60
b) Other Water Supply	150.00	10.20	5.25	8.40
6. Transportation				
a) Public Transportation (Charging Station)	230.00	7.00	3.70	5.50
b) Other Transportation	255.00	9.35	3.70	8.40
7. Street Light	80.00	8.40	3.50	4.20
C. Medium Voltage (11 kV)				
1. Industrial	250.00	10.50	5.40	8.55
2. Commercial	315.00	12.60	6.90	11.10
3. Non-commercial	240.00	13.50	7.15	12.25
4. Irrigation	-	6.40	2.00	3.10
5. Water Supply				
a) Community Water Supply	-	6.30	3.40	4.70
b) Other Water Supply	150.00	10.50	5.40	8.50
6. Transportation				
a) Public Transportation (Charging Station)	230.00	7.15	4.20	5.60
b) Other Transportation	255.00	9.65	4.20	8.50
7. Street Light	80.00	8.80	3.75	4.40
8. Religious Place	220.00	11.30	5.15	9.10
9. Temporary Connection	330.00	14.40	6.60	11.75
D. Low Voltage (230/400 V)				
Transportation				
a) Public Transportation (Charging Station)	200.00	7.25	4.30	5.75
b) Other Transportation	220.00	9.75	4.30	8.60

3.2 Tariff Rate from Paush to Chaitra

Consumer Category	Demand Charge NRs. /kVA/ month	Peak Time (17.00-23.00)	Normal Time (23.00-5.00)
A. High Voltage			
1. Industrial (132 kV)	230.00	10.00	8.20
2. Industrial (66 kV)	240.00	10.10	8.30
B. Medium Voltage (33 kV)			
1. Industrial	250.00	10.20	8.40
2. Commercial	315.00	12.30	10.80
3. Non-Commercial	240.00	13.20	12.00
4. Irrigation	-	6.30	3.00
5. Water Supply			
a) Community Water Supply	-	6.20	4.60
b) Other Water Supply	150.00	10.20	8.40
6. Transportation			
a) Public Transportation (Charging Station)	230.00	7.00	5.50
b) Other Transportation	255.00	9.35	8.40
7. Street Light	80.00	8.40	4.20
C. Medium Voltage (11 kV)			
1. Industrial	250.00	10.50	8.55
2. Commercial	315.00	12.60	11.10
3. Non-commercial	240.00	13.50	12.25
4. Irrigation	-	6.40	3.10
5. Water Supply			
a) Community Water Supply	-	6.30	4.70
b) Other Water Supply	150.00	10.50	8.50
6. Transportation			
a) Public Transportation (Charging Station)	230.00	7.15	5.60
b) Other Transportation	255.00	9.65	8.50
7. Street Light	80.00	8.80	4.40
8. Religious Place	220.00	11.30	9.10
9. Temporary Connection	330.00	14.40	11.75
D. Low Voltage (230/400 V)			
Transportation			
a) Public Transportation (Charging Station)	200.00	7.25	5.75
b) Other Transportation	220.00	9.75	8.60

3.3 Transportation for Automatic Swap Card Users without Demand Charge

3.3.1 Public Transportation (Charging Station)

Description	Energy Charge NRs./kWh		
	Peak Time (17.00-23.00)	Off Peak Time (23.00-5.00)	Normal Time (5.00-17.00)
Tariff Rate from Baisakh to Mangsir			
Medium Voltage (33 kV)	8.40	4.45	6.60
Medium Voltage (11 kV)	8.60	5.05	6.70
Low Voltage (230/400 V)	8.70	5.05	6.90
Tariff Rate from Paush to Chaitra			
Description	**Peak Time (17.00-23.00)**	**Normal Time (23.00-17.00)**	
Medium Voltage (33 kV)	8.40	6.60	
Medium Voltage (11 kV)	8.60	6.70	
Low Voltage (230/400 V)	8.70	6.90	

3.3.2 Other Transportation

Description	Energy Charge NRs./kWh		
	Peak Time (17.00-23.00)	Off Peak Time (23.00-5.00)	Normal Time (5.00-17.00)
Tariff Rate from Baisakh to Mangsir			
Medium Voltage (33 kV)	11.20	4.45	10.10
Medium Voltage (11 kV)	11.60	5.05	10.20
Low Voltage (230/400 V)	11.70	5.15	10.30
Tariff Rate from Paush to Chaitra			
Description	**Peak Time (17.00-23.00)**	**Normal Time (5.00-17.00)**	
Medium Voltage (33 kV)	11.20	10.10	
Medium Voltage (11 kV)	11.60	10.20	
Low Voltage (230/400 V)	11.70	10.30	

Note: Charging Station Operators will be able to get maximum 20 percent additional charge in given tariff proving charging service to electric vehicles.

4. Community Wholesale Consumer:

Consumer Category	Minimum Charge (NRs.)	Energy Charge (NRs./kWh)
1. Medium Voltage (11kV/33kV)		
Upto (N x 20) units, monthly	N x 30.00	0.00
Above (N x 20) units, monthly		6.00
2. Lower Voltage Level (230/400 Volt)		
Upto (N x 20) units, monthly	N x 30.00	0.00
Above (N x 20) units, monthly		6.25

N= Total Number of Consumers of a Community Group

Annex 2: Terms of Reference

1 Context

Nepal's electricity sector is undergoing rapid transformation with shifts in demand patterns, generation mix, infrastructure development, and cross-border power trade. However, electricity tariffs have not kept pace with these changes and continue to fall short of reflecting the true cost of supply. This misalignment results in inefficiencies, distorts consumption behavior, and limits the financial sustainability of power utilities. Accurate pricing based on long run marginal cost (LRMC) is therefore essential to ensure efficient investment, consumption, and resource allocation.

The Electricity Regulatory Commission (ERC), with support from GIZ through the REEEP-GREEN Programme, is initiating a comprehensive study to estimate the marginal cost of electricity supply in Nepal. This study will assess power system characteristics, evaluate demand profiles, and apply robust methodologies to estimate marginal costs at various voltage levels. It will also identify how these estimates can guide the design of cost-reflective, socially equitable, and economically sustainable tariffs that respond to Nepal's evolving power market dynamics.

By updating Nepal's marginal cost structure for the first time since 2005, the initiative will lay the groundwork for transparent and evidence-based tariff reforms. It will involve consultations with key stakeholders such as NEA, IPPs, consumer groups, and government agencies, ensuring broad ownership and relevance. The outcome will help ERC implement pricing frameworks that support long-term sector growth, consumer protection, and regulatory credibility.

2 GIZ shall hire the contractor for the anticipated contract term, from 10 September 2025 to 10 November 2025.

3 The contractor shall provide the following services:

I. Review of Existing Literature and Data
- Analyze previous marginal cost studies (1998, 2005) and other relevant reports.
- Review current tariff structures, regulatory frameworks, and power system data.

II. Assessment of Power System Characteristics
- Evaluate the current generation mix, transmission and distribution infrastructure.
- Analyze demand profiles by consumer category, voltage level, season, and time of day.

III. Estimation of Marginal Costs
- Develop a methodology for estimating short-run and long-run marginal costs.
- Calculate marginal costs at different voltage levels (generation, transmission, distribution).
- Account for seasonal and diurnal variations in demand and supply.

IV. Tariff Design Implications
- Analyze how marginal cost estimates can inform efficient and equitable tariff structures.
- Provide recommendations for incorporating marginal cost principles into tariff planning.

V. Stakeholder Engagement
- Conduct consultations with key stakeholders including NEA, IPPs, consumer groups, and government agencies.
- Present preliminary findings and incorporate feedback and suggestions to the final report.

VI. Reporting:
- Prepare a comprehensive report detailing methodology, findings and recommendations

Milestones/partial works	Date/location/responsibility	Criteria for acceptance
Inception Report Submission	By 10 September 2025 / Kathmandu / Key Expert 1	Report submitted on time; includes detailed work plan, methodology, and data requirements
Stakeholder Consultation Round 1	17 September 2025 / Kathmandu / Key Expert 1	Key stakeholders consulted (e.g., NEA, IPPs, consumer groups); summary notes documented
Power System and Tariff Structure Assessment Completed	By 25 September 2025 / Kathmandu / Key Expert 1	Review of existing studies, tariff framework, demand patterns, and infrastructure completed
Draft Marginal Cost Estimation Model and Results	By 30 September 2025 / Kathmandu / Key Expert 1	Draft model developed; preliminary LRMC results shared with ERC and GIZ for review
Draft Final Report with Tariff Design Implications	By 20 October 2025 / Kathmandu / Key Expert 1	Report includes updated LRMC estimates, analysis of tariff implications, and recommendations
Final Stakeholder Consultation and Feedback Incorporation	By 31 October 2025 / Kathmandu / Key Expert 1	Consultation conducted; stakeholder feedback documented and integrated into final report
Final Report Submission	By 10 November 2025 / Kathmandu / Key Expert 1	Comprehensive final report delivered; includes methodology, findings, and accepted by ERC

Annex 3: List of Person Met

ERC:
Ram Prasad Dhital, Chairman
Hari Bahadur Khatry, Senior Divisional Engineer

GIZ:
Narayan Prasad Chaulagai
Bikash Uprety
Manav KC

NEA:
Hitendra Dev Shakya, MD
Durgananda Bariayat, DMD Planning
Ganesh Kumar Upreti, Director, Regulatory Compliance Department
Poonam Pokhrel, Economist, Regulatory Compliance
Rishesh Amatya, Deputy Manager, System Planning Department
Manil Tiwari, Manager, System Planning Department
Sandeep Shrestha, Manager, Smart Metering Division

Annex 4: Limitations and Overall Assessment of the NEA Electricity Demand Models

This section reviews the limitations of NEA's domestic and industrial electricity demand models. While both formulations reflect intuitive drivers of electricity consumption—such as income growth, price changes, and demand persistence—they exhibit common conceptual and econometric weaknesses that limit their suitability for rigorous demand analysis, long-term forecasting, and tariff or LRMC studies.

1.Domestic Electricity Demand Model

The proposed domestic electricity demand model extends a growth-based framework by explicitly incorporating the effect of new consumer connections on total electricity consumption. The model is specified as:

$$Q_t = \quad Q_{t-1}(1 + a_t b)\left(\frac{\Delta P_t}{\Delta CPI_t}\right)^c + 0.5 \cdot \Delta N_{t-1} \cdot d_{t-1}(1 + a_t b)\left(\frac{\Delta P_t}{\Delta CPI_t}\right)^c + 0.5 \cdot \Delta N_t \cdot d_t$$

where Q_t denotes domestic electricity consumption, ΔN_t represents new consumer connections, and d_t is average consumption per new consumer.

The proposed domestic electricity demand model extends a growth-based framework by explicitly incorporating the contribution of newly connected consumers alongside income and price effects. Although this structure reflects important features of domestic demand growth in developing electricity systems, the formulation suffers from several limitations.

First, the treatment of price effects through the term $(\Delta P_t / \Delta CPI_t)^c$ is inconsistent with standard demand theory. Price elasticity is defined with respect to proportional changes in quantity and real price levels, not ratios of absolute changes in nominal prices and inflation indices. Consequently, the parameter cannot be interpreted as a conventional price elasticity. The formulation may also behave erratically when price or inflation changes are small or volatile, reducing the robustness of the model's projections.

Second, income effects are imposed mechanically through the factor $(1+a_t b)$, rather than being estimated from observed consumption behavior. This assumes a stable and proportional response of domestic electricity demand to income growth across all periods and household types. In reality, domestic electricity demand often exhibits declining income elasticity over time due to appliance saturation, efficiency improvements, and behavioral adjustments—dynamics that the model cannot capture.

Third, the model is deterministic and lacks an explicit stochastic error term. As a result, it cannot be estimated econometrically, nor can it support statistical inference, hypothesis testing, or diagnostic checking. Domestic electricity demand is influenced by unobserved factors such as weather variability, supply constraints, policy interventions, and data measurement errors, all of which are implicitly ignored in the formulation.

Fourth, the strong multiplicative dependence on lagged consumption introduces path dependence and potential instability. Any measurement error or abnormal shock in earlier periods propagates indefinitely into future demand levels, as the model does not define a stable long-run equilibrium relationship between electricity demand, income, prices, and customer base growth.

Finally, while the explicit inclusion of new consumer connections is intuitively appealing, the treatment is ad hoc. The use of fixed weights for current and lagged new connections is not derived from behavioral evidence or statistical estimation, and average consumption per new consumer is treated as exogenous, ignoring its dependence on income, appliance ownership, tariff structure, and efficiency standards.

In conclusion, the domestic demand model may be useful as a simple accounting or planning tool for decomposing demand growth into electrification effects and consumption growth among existing households. However, due to its nonstandard price treatment, imposed income response, deterministic structure, ad hoc handling of new connections, and absence of a defined long-run equilibrium, it does not constitute a theoretically sound or econometrically robust demand model for elasticity estimation, tariff design, LRMC analysis, or policy evaluation.

2. Industrial Electricity Demand Model

The proposed industrial electricity demand model, specified as

$$Q_t = Q_{t-1}(1 + a_t \cdot b)\left(\frac{\Delta P_t}{\Delta CPI_t}\right)^c,$$

The proposed industrial electricity demand model similarly links current consumption to past demand, income growth, and real price changes using a multiplicative growth structure. While the model reflects the importance of industrial activity and price signals in shaping electricity demand, it exhibits limitations analogous to those identified in the domestic demand formulation.

First, the use of $(\Delta P_t/\Delta CPI_t)^c$ to represent price effects is inconsistent with elasticity theory. Elasticities relate proportional changes in demand to proportional changes in real price levels, not ratios of nominal price and inflation changes. As a result, the parameter lacks a clear economic interpretation and may yield unstable results under small or irregular price movements.

Second, the income effect is mechanically embedded through a growth factor rather than estimated from data. This structure assumes a fixed relationship between industrial output growth and electricity demand, precluding the possibility of efficiency improvements, technological change, fuel substitution, or structural shifts in industrial production. Empirical evidence frequently shows that industrial electricity intensity evolves over time, a feature the model cannot accommodate.

Third, the model is deterministic and omits a stochastic disturbance term. This prevents econometric estimation, hypothesis testing, and diagnostic analysis, and implicitly assumes perfect predictability of industrial electricity demand. Such an assumption is inconsistent with observed industrial behavior, which is affected by business cycles, supply constraints, outages, and policy shocks.

Fourth, the multiplicative dependence on lagged demand implies that shocks or measurement errors persist indefinitely, with no mechanism for adjustment toward a long-run equilibrium. The model therefore does not define a stable long-run relationship between electricity demand, prices, and economic activity, limiting its usefulness for long-term forecasting and welfare analysis.

Finally, the formulation does not align with established industrial electricity demand literature, which typically employs log-linear or dynamic econometric models (such as partial adjustment or Auto

Regressive Distributed Lag (ARDL) specifications) that allow elasticities to be estimated consistently and long-run equilibrium relationships to be identified explicitly.

Overall, the industrial demand model may serve as a rough growth-based projection tool, but it lacks the theoretical rigor and statistical foundations required for applied demand analysis. Its nonstandard treatment of price effects, imposed income response, deterministic nature, and absence of a well-defined long-run equilibrium render it unsuitable for elasticity estimation, tariff design, LRMC studies, or policy analysis.

Annex 5: Detail Results of Regression Analysis for Various Cases

Excel's regression output and its interpretation.

A: Regression Statistics Table

Excel Output Field	Purpose	How to Interpret for Model Validity
Multiple R	Correlation between actual (Y) and predicted (Ŷ)	Closer to 1 → stronger linear relationship.
R Square (R^2)	Proportion of variance in Y explained by predictors	$R^2 = 0.80$ → model explains 80% of Y's variation. High R^2 is good but not proof of predictive validity.
Adjusted R Square	Adjusts R^2 for number of predictors	Always check this — if it's much lower than R^2, some variables may not add real value.
Standard Error	Standard Error of Estimate (SEE) = average prediction error	Lower SEE = more precise model. Compare SEE to the mean or std. dev. of Y.
Observations	Sample size	Used for degrees of freedom in ANOVA and t-tests. More observations = more reliable estimates.

B. ANOVA Table (This is for overall model significance test)

Statistic	Purpose	Can be used for
F-value	Tests if the overall model is significant	Checks model-level validity
Significance F (p-value)	Tests if all coefficients = 0	Confirms model usefulness

If Significance F < 0.05, the regression explains a significant part of the variance in Y.

C. Coefficients Table (Identifying which variables meaningfully contribute to Y)

Statistic	Purpose	Can be used for
Coefficients (b's)	Estimated effect of each predictor	Interpreting relationships
Standard Error, t-Stat, P-value	Tests for individual variable significance	Identifies important predictors
Lower/Upper 95%	Confidence intervals for each coefficient	Statistical reliability check

Summary Output: Domestic Demand Analysis

Regression Statistics	
Multiple R	0.9990
R Square	0.9979
Adjusted R Squa	0.9975
Standard Error	0.0456
Observations	35

ANOVA

	df	SS	MS	F	ignificance F
Regression	6	28.2134	4.7022	2256.7763	3.035E-36
Residual	28	0.0583	0.0021		
Total	34	28.2718			

	Coefficients	tandard Err	t Stat	P-value	Lower 95%	Upper 95%	ower 95.0%	Jpper 95.0%
Intercept	-4.3606	1.7052	-2.5573	0.0163	-7.8535	-0.8677	-7.8535	-0.8677
X Variable 1	0.5433	0.1750	3.1044	0.0043	0.1848	0.9019	0.1848	0.9019
X Variable 2	-0.0636	0.1142	-0.5566	0.5822	-0.2976	0.1704	-0.2976	0.1704
X Variable 3	-0.0001	0.1047	-0.0007	0.9994	-0.2145	0.2143	-0.2145	0.2143
X Variable 4	1.1166	0.4512	2.4747	0.0197	0.1924	2.0409	0.1924	2.0409
X Variable 5	0.1505	0.5040	0.2987	0.7674	-0.8819	1.1829	-0.8819	1.1829
X Variable 6	-0.0528	0.0318	-1.6611	0.1078	-0.1180	0.0123	-0.1180	0.0123

Summary Output: Industrial Demand Analysis

Regression Statistics	
Multiple R	0.998803
R Square	0.9976074
Adjusted R Squa	0.9970947
Standard Error	0.0452989
Observations	35

ANOVA

	df	*SS*	*MS*	*F*	*ignificance F*
Regression	6	23.956	3.99275	1945.7935	2.407E-35
Residual	28	0.057	0.002052		
Total	34	24.014			

	Coefficients	*tandard Err*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*ower 95.0%*	*Jpper 95.0%*
Intercept	-0.9895	0.3076	-3.2164	0.0033	-1.6197	-0.3593	-1.6197	-0.3593
X Variable 1	0.7496	0.1356	5.5271	0.0000	0.4718	1.0274	0.4718	1.0274
X Variable 2	-0.0666	0.0917	-0.7255	0.4742	-0.2545	0.1214	-0.2545	0.1214
X Variable 3	0.0554	0.0755	0.7333	0.4695	-0.0993	0.2101	-0.0993	0.2101
X Variable 4	1.7627	0.2051	8.5952	0.0000	1.3426	2.1827	1.3426	2.1827
X Variable 5	-1.2464	0.3179	-3.9205	0.0005	-1.8976	-0.5952	-1.8976	-0.5952
X Variable 6	-0.0219	0.0242	-0.9059	0.3727	-0.0714	0.0276	-0.0714	0.0276

Summary Output: Commercial and Non-Commercial Demand Analysis

Regression Statistics	
Multiple R	0.9976
R Square	0.9951
Adjusted R Squa	0.9941
Standard Error	0.0604
Observations	35

ANOVA

	df	*SS*	*MS*	*F*	*ignificance F*
Regression	6	20.9031	3.4839	956.0905	4.839E-31
Residual	28	0.1020	0.0036		
Total	34	21.0051			

	Coefficients	*tandard Erro*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*.ower 95.0%*	*Jpper 95.0%*
Intercept	-0.9562	0.5531	-1.7289	0.0948	-2.0891	0.1767	-2.0891	0.1767
X Variable 1	0.7565	0.1508	5.0172	0.0000	0.4477	1.0654	0.4477	1.0654
X Variable 2	-0.1068	0.1564	-0.6829	0.5003	-0.4271	0.2135	-0.4271	0.2135
X Variable 3	0.0181	0.1372	0.1318	0.8961	-0.2629	0.2990	-0.2629	0.2990
X Variable 4	0.7578	0.4397	1.7234	0.0958	-0.1429	1.6584	-0.1429	1.6584
X Variable 5	-0.3596	0.4933	-0.7290	0.4721	-1.3701	0.6509	-1.3701	0.6509
X Variable 6	-0.0231	0.0336	-0.6861	0.4983	-0.0919	0.0458	-0.0919	0.0458

Summary Output: Total NEA Demand Analysis

Regression Statistics	
Multiple R	0.9989
R Square	0.9978
Adjusted R Squa	0.9974
Standard Error	0.0450
Observations	35

ANOVA

	df	*SS*	*MS*	*F*	*ignificance F*
Regression	6	26.1899	4.3650	2152.413	5.88E-36
Residual	28	0.0568	0.0020		
Total	34	26.2467			

	Coefficients	*tandard Err*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*.ower 95.0%*	*Jpper 95.0%*
Intercept	-1.5441	0.8659	-1.7833	0.0854	-3.3179	0.2296	-3.3179	0.2296
X Variable 1	0.7925	0.1372	5.7772	0.0000	0.5115	1.0734	0.5115	1.0734
X Variable 2	-0.0200	0.1077	-0.1858	0.8539	-0.2406	0.2006	-0.2406	0.2006
X Variable 3	-0.0162	0.0937	-0.1734	0.8636	-0.2081	0.1756	-0.2081	0.1756
X Variable 4	1.5340	0.3810	4.0259	0.0004	0.7535	2.3145	0.7535	2.3145
X Variable 5	-1.0791	0.4700	-2.2961	0.0294	-2.0417	-0.1164	-2.0417	-0.1164
X Variable 6	-0.0289	0.0270	-1.0722	0.2928	-0.0842	0.0263	-0.0842	0.0263

Annex 6: Integrated Nepal Power System Single Line Diagram