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Economic Viability of PV-BESS Systems under Time-of-Use Pricing and Price Caps: A Multi-Location Study in Vietnam

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ABSTRACT

Utility-scale photovoltaic (PV) systems are increasingly integrated with battery energy storage systems (BESS) to mitigate curtailment and enhance renewable energy integration. However, the economic viability of photovoltaic-battery energy storage systems (PV-BESS) remains highly uncertain under current electricity pricing mechanisms, particularly in power systems characterized by transmission constraints and regulated price caps. This study develops an integrated techno-economic framework to evaluate the performance of PV-BESS systems under time-of-use (TOU) pricing. The framework combines PV generation and curtailment modeling, rule-based BESS dispatch, and financial evaluation to capture the interactions between system operation, pricing structures, and investment outcomes. The analysis is applied to three representative utility-scale PV plants in Vietnam, capturing variations in solar resource conditions and transmission congestion levels. The results show that transmission constraints strongly affect economic performance, significantly widening the financial viability gap as congestion increases. While TOU pricing improves temporal price signals, it remains insufficient to ensure investment viability under regulated price caps. Notably, stronger TOU price differentials may reduce total revenue under capped peak prices, thereby increasing the required capacity-based compensation. These findings highlight structural limitations of energy-based pricing mechanisms in supporting storage deployment in constrained power systems. Additional compensation mechanisms, such as capacity payments, are required to enable economically sustainable PV-BESS deployment and enhance renewable energy integration.

Keywords: Photovoltaic Systems, Battery Energy Storage, Time-of-use Pricing, Renewable Integration, Curtailment, Financial Viability
JEL Classifications: Q41, Q42, Q48

1. INTRODUCTION

The rapid expansion of PV power plants has introduced significant operational challenges in power systems with limited transmission capacity, particularly in the context of increasing renewable energy integration (Impram et al., 2020; Yasmina Abdelilah and Criswell, 2023). In Vietnam, large-scale PV plants have experienced substantial energy curtailment due to grid constraints, particularly during midday periods when solar generation exceeds local demand (Vietnam Electricity, 2022; Tarek Ketelsen et al., 2023). This curtailment not only reduces energy utilization but also affects the economic viability of PV projects.

Battery energy storage systems (BESS) have been widely recognized as an effective solution to mitigate curtailment and enhance the efficient integration of renewable energy into power systems (Sakib et al., 2025; Susteras et al., 2026). By storing excess energy during low-demand periods and discharging it during peak periods, BESS enables temporal shifting of electricity supply. However, the economic performance of BESS remains highly dependent on the pricing mechanisms applied in the electricity market (Jivaganont et al., 2025).

Traditional economic evaluation approaches, such as the levelized cost of electricity (LCOE), are widely used to assess the cost of electricity generation over the project lifetime. However, LCOE assumes a uniform electricity price and does not capture temporal variations in electricity value (Manzolini et al., 2024; Ueckerdt et al., 2013; Manzolini et al., 2025). This limitation becomes particularly critical in systems with high shares of renewable energy, where the electricity value varies significantly over time.

TOU pricing introduces time-dependent electricity prices that better reflect system conditions and marginal value (Schittekatte et al., 2022; Kahn-Lang and Wolak, 2025). In principle, this pricing mechanism can improve economic efficiency by providing price signals that incentivize shifting electricity consumption and storage operation from low-value to high-value periods (Schittekatte et al., 2022; Kahn-Lang and Wolak, 2025; Lang et al., 2023; Enrich et al., 2024). For PV-BESS systems, such a mechanism is expected to enhance the economic value of storage by aligning operation with system needs.

TOU pricing has been extensively studied as a mechanism to improve electricity system efficiency, reduce peak demand, and enhance demand-side flexibility (Schittekatte et al., 2022; Kahn-Lang and Wolak, 2025; Lang et al., 2023; Enrich et al., 2024). More recent studies have extended these analyses to battery storage applications, focusing primarily on storage sizing, arbitrage operation, and cost optimization under time-varying tariffs (Martinez-Bolanos et al., 2020; Sepúlveda-Mora and Hegedus, 2021; Zhao et al., 2021). These studies generally indicate that the economic performance of storage depends strongly on price spreads and tariff design.

Despite these advances, three important gaps remain. First, many existing TOU-BESS studies simplify or do not explicitly represent transmission constraints, which can significantly affect renewable energy utilization and storage value in highly constrained systems (Zhao et al., 2023). Second, while such pricing schemes has largely been analyzed in liberalized electricity markets, the interaction between time-based tariffs and regulated price-cap environments remains insufficiently explored (Enrich et al., 2024; Robertson et al., 2025). Third, prior studies mainly focus on operational optimization and cost reduction, while limited attention has been given to whether market revenues alone can ensure the financial viability of storage investments (International Renewable Energy and Irena, 2020).

These gaps are particularly relevant in systems with high renewable penetration, where storage technologies play a critical role in enabling reliable and efficient energy transition. In such contexts, the economic performance of PV-BESS systems depends not only on storage technology and TOU price differentiation but also on transmission constraints and regulatory pricing structures. In particular, whether time-of-use pricing alone can support economically viable PV-BESS deployment under constrained grid conditions and regulated electricity prices remains an unresolved question.

This question is especially relevant in Vietnam, where electricity prices for solar plants integrated with storage are currently subject to region-specific price caps. In contrast, actual transaction prices are expected to be determined through negotiation or competitive bidding mechanisms (Ministry of Industry and Trade of Vietnam, 2025), However, an explicit TOU framework for utility-scale PV-BESS systems has not yet been established. This creates a useful policy setting for evaluating whether time-based pricing signals can effectively capture the economic value of energy shifting under existing regulatory constraints.

Against this background, this study proposes a TOU structure as a conceptual framework to examine whether such time-based price signals alone are sufficient to support the economic viability of PV-BESS systems under curtailment conditions and regulated electricity prices.

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This study makes three contributions. First, it develops an integrated framework to evaluate how transmission constraints and renewable curtailment influence the economic performance of PV-BESS systems under TOU pricing framework. Second, it reveals how regulated price caps may weaken the economic incentives intended by such pricing mechanisms, highlighting limitations of energy-based pricing mechanisms under constrained regulatory environments. Third, it quantifies the financial viability gap and estimates the capacity-based remuneration required to restore investment attractiveness.

This paper is structured as follows. Section 1 introduces the research background and objectives. Section 2 presents the methodology and data used in the analysis. Section 3 reports the results of the economic assessment. Section 4 discusses the implications of the findings for electricity pricing and system operation. Section 5 concludes the paper.

2. METHODOLOGY AND DATA

2.1. Overview of the Analytical Framework

This study develops an integrated framework to evaluate the economic performance of PV-BESS systems under TOU pricing. The framework combines three components: (i) Technical simulation of PV generation and curtailment, (ii) operational modeling of BESS dispatch, and (iii) financial evaluation of project cash flows.

Multiple BESS configurations and transmission constraint levels are considered to capture the impact of system design and grid conditions on economic performance.

The analytical process follows a sequential structure. First, PV generation and curtailment are simulated under different transmission constraints. Second, BESS operation is modeled to store excess energy and discharge during high-value periods. Third, electricity sales are calculated under the TOU pricing mechanism. Finally, financial indicators are evaluated to assess project viability.

The PV generation and system performance simulations are conducted using the system advisor model (SAM), ensuring consistency between technical modeling and financial evaluation.

2.2. Modeling of PV Generation and Transmission Constraints

The power output of the PV system at each time step (t) is determined based on solar resource data and system capacity.

Transmission constraints are represented by a capacity limit applied to the grid connection. The actual power delivered to the grid is defined as:

$$E_{PV,t} = min(E_{PV,gross,t}, \alpha x P_{AC})$$

Where $E_{PV,gross,t}$ is the unconstrained PV generation; P_{AC} is the installed AC capacity of the plant (40 MW); α represents the transmission constraint level. In this study, α varies from 1.0 to 0.6, corresponding to increasing levels of curtailment. The curtailed energy is calculated as the difference between gross generation and delivered energy. In practice, solar curtailment in Vietnam has predominantly occurred during midday hours (10:00–14:00) in recent years, when PV generation exceeds local transmission capacity.

Weather data used for PV generation simulation are obtained from the NSRDB database (NREL) with a 30-min temporal resolution. Three representative locations - Lai Chau, Ninh Thuan, and Binh Phuoc - are selected to capture regional climatic differences in Vietnam, with average global horizontal irradiance (GHI) ranging from approximately 4.63 to 5.75 kWh/m^2/day.

A fixed-tilt PV configuration is assumed across all case studies, with a tilt angle of approximately 10°, an azimuth of 180°, and a ground coverage ratio (GCR) of 0.657. Total system losses are set to 4.44%, and an annual degradation rate of 0.5% is applied.

2.3. BESS Configuration and Dispatch Strategy

The BESS is modeled using lithium-ion (NMC) technology. Storage capacity is defined as 10-20% of PV capacity, with storage durations of 2 and 4 h.

BESS operation is modeled using a rule-based dispatch strategy that reflects both system constraints and electricity price signals under the TOU mechanism. During daytime hours (06:00-17:00), PV generation is supplied to the grid subject to transmission constraints. Excess energy that cannot be delivered due to transmission limits, particularly during peak solar generation periods (10:00-14:00), is used to charge the BESS. This ensures that curtailed energy is effectively recovered and stored. During peak demand periods (17:00-20:00), the BESS discharges stored energy to the grid. The discharge is concentrated within this time window to respond to higher electricity prices under the TOU pricing structure. Accordingly, the dispatch strategy is jointly determined by physical constraints and economic signals. It reflects the role of BESS in shifting energy from low-value periods (midday) to high-value periods (evening peak), rather than increasing total electricity generation.

2.4. TOU Pricing Design

The TOU pricing structure in this study is designed to reflect both regulatory constraints and the operational characteristics of PV-BESS systems. A two-period pricing scheme is adopted, consisting of normal and peak periods.

Peak electricity demand is defined from 17:00 to 20:00, creating an economic incentive for energy shifting from midday to peak periods. The normal period includes all remaining hours of the day. This simplified structure is chosen to align with the operational behavior of BESS, which shifts energy from midday periods to evening peak demand.

Given the regulatory constraints in Vietnam, electricity prices are subject to an upper bound. Accordingly, the peak electricity price is assumed to be equal to the regulatory price cap.

$$P_{peak} = P_{cap} \qquad \text{(USD/kWh, or cents/kWh)}$$

The normal-period price is derived from an assumed TOU ratio, which determines the price differential between peak and normal periods:

$$P_{normal} = P_{peak}/TOU \qquad \text{(USD/kWh, or cents/kWh); and TOU>1}$$

In this study, the TOU ratio ranges from 1.2 to 1.3, representing a moderate level of price differentiation under regulatory constraints.

The TOU electricity prices are derived from the regulatory price cap for each region. The peak price is set equal to the price cap, while the normal price is calculated based on the TOU ratio. The resulting price levels for each case study are summarized in Table 1.

The total annual electricity generation is divided into normal and peak components:

$$E_n = E_{normal,n} + E_{peak,n} \qquad \text{(kWh)}$$

Accordingly, the annual revenue is calculated as:

$$R_n = P_{normal} \times E_{off\text{-}peak,n} + P_{peak} \times E_{peak,n} \qquad \text{(USD)}$$

where $E_{off\text{-}peak}$ and E_{peak} are the electricity sold during normal and peak periods, respectively.

This pricing structure enables the valuation of energy shifting by assigning higher economic value to electricity delivered during peak periods, while remaining consistent with regulatory price limits.

2.5. Financial Evaluation

The economic performance of each scenario is evaluated using net present value (NPV). The NPV of the PV-BESS project is calculated as:

The NPV of the project is calculated as:

$$NPV = \sum_{n=0}^{N} \frac{R_n - C_{PV,n} - C_{BESS,n}}{(1+\text{WACC})^n} \qquad \text{(USD)}$$

Table 1: TOU prices for different regions under regulatory price caps in Vietnam

Location	P_{peak}=P_{cap} (cents/kWh)	P_{normal} (cents/kWh)	
		TOU=1.2	TOU=1.3
Lai Chau	6.18	5.15	4.75
Ninh Thuan	4.94	4.12	3.80
Binh Phuoc	4.52	3.77	3.48

Where R_n is the annual revenue; $C_{PV,n}$ and $C_{BESS,n}$ are the costs associated with the PV system and BESS, respectively; N is the project lifetime; and $WACC$ is the weighted average cost of capital. A project is considered financially viable when NPV ≥0, which corresponds to achieving a return equal to or greater than the WACC.

The financial analysis assumes a project lifetime of 20 years. The weighted average cost of capital (WACC) is approximately 10.9%, based on a capital structure of 70% debt and 30% equity.

The investment costs of the PV and PV-BESS systems are derived from the national benchmark used for establishing solar power price frameworks in Vietnam. For the representative 40 MW_{AC} plants located in Lai Chau, Ninh Thuan, and Binh Phuoc, the total capital cost of standalone PV systems ranges from 23.0 to 23.3 million USD, while the integration of BESS increases total investment to approximately 26.1-26.4 million USD. The additional cost associated with BESS reflects both energy-based and power-based components, estimated at 242 USD/kWh and 282 USD/kW, respectively. Operation and maintenance costs are assumed to be 1.8% of total capital expenditure for both PV and PV–BESS systems.

2.6. Capacity-based Payment Mechanism

Under TOU pricing, the total revenue is constrained by both the limited price spread and the regulatory price cap. As a result, energy-based revenue may be insufficient to ensure financial viability. When the project NPV is negative under TOU pricing, the financial deficit (ΔNPV) is converted into an equivalent monthly capacity payment using the capital recovery factor (CRF). The required monthly capacity payment per unit of BESS capacity is calculated as:

$$F = \Delta NPV \times CRF = \frac{\Delta NPV \times WACC_m}{P_{BESS} \times (1 - \left(1 + WACC_m\right)^{-12N})} \quad \text{(USD/kW-tháng)}$$

Where P_{BESS} is the installed BESS capacity (kW), and F is the capacity payment (USD/kW-month).

This mechanism ensures that the project achieves financial viability (NPV = 0) while maintaining compliance with the regulatory price cap. This mechanism transforms a lump-sum financial deficit into a stable monthly payment, reflecting the value of BESS as a capacity and flexibility resource rather than solely an energy provider. It also provides a practical representation of capacity-based compensation mechanisms under regulated electricity markets.

2.7. Scenario Design

The analysis is conducted for three representative PV plants located in different regions of Vietnam: Lai Chau, Ninh Thuan, and Binh Phuoc. Each plant has an installed capacity of 40 MW.

The scenario matrix includes:

- BESS capacity: 10% and 20% of PV capacity;
- Storage duration: 2 h and 4 h;
- Transmission constraint levels: α = 1.0-0.6;
- TOU ratios: 1.2-1.3.

This scenario design enables a systematic assessment of how system configuration and pricing structure influence the economic viability of PV-BESS systems.

3. RESULTS

3.1. Energy Delivery under Transmission Constraints

To support the interpretation of the economic results, the variation in electricity delivery under transmission constraints is first examined. Under unconstrained conditions (α = 1.0), electricity generation differs across locations due to solar resource availability, with Ninh Thuan achieving the highest output (approximately 83.3 GWh), followed by Binh Phuoc (around 79.5 GWh) and Lai Chau (about 67.7 GWh). These differences reflect regional variations in solar irradiation.

As transmission constraints become more restrictive, a growing share of generated electricity cannot be delivered to the grid and is curtailed, leading to a substantial reduction in net electricity output. For example, in Ninh Thuan, reducing the transmission capacity to α = 0.6 decreases delivered energy from approximately 83.3 GWh to 69.3 GWh, corresponding to a loss of nearly 16.7% of potential generation.

The "best configuration" indicates the system configuration that yields the highest annual electricity delivery for each scenario, including the PV-only case where applicable.

The results in Table 2 reveal that the effectiveness of BESS in improving electricity delivery is highly dependent on the level of transmission constraints. Under unconstrained or weakly constrained conditions (α = 1.0 and 0.9), the difference in annual electricity delivery between PV-only and PV-BESS systems is negligible or even slightly negative. This indicates that when curtailment is absent or limited, the integration of BESS does not provide additional benefits in terms of energy delivery, as there is little excess generation available for shifting.

As transmission constraints become more pronounced (α ≤ 0.8), the contribution of BESS becomes increasingly significant. In these cases, part of the curtailed energy can be stored and later discharged, resulting in a measurable increase in electricity delivered to the grid. Under severe constraints (α = 0.6), the improvement becomes substantial, reaching up to approximately 6.2-8.5% depending on the location. This demonstrates that the primary value of BESS in this context lies in its ability to recover otherwise curtailed energy.

It is also observed that larger storage capacities and longer discharge durations (e.g., 20% capacity with 4-h duration) tend to achieve higher levels of energy recovery. However, this does not imply that such configurations are universally optimal. The extent of recoverable energy is fundamentally limited by the magnitude and temporal distribution of curtailment. Therefore, increasing storage capacity beyond a certain level may yield diminishing returns if the available curtailed energy is insufficient to fully utilize the storage system.

Table 2: Energy recovery achieved by PV–BESS systems under transmission constraints, highlighting the additional electricity delivered compared to standalone PV systems

Case study location	α	PV-Only (GWh)	PV-BESS (Best-case) (GWh)	Increase (%)	Best configuration
40MW Lai Chau	1.0	67.72	67.72	0.0	PV-Only
	0.8	66.93	67.41	0.7	4MW×4h
	0.6	60.37	64.09	6.2	8MW 4h
40MW Ninh Thuan	1.0	83.28	83.28	0.0	PV-Only
	0.8	79.76	82.48	3.4	8MW 4h
	0.6	69.33	75.19	8.5	8MW 4h
40MW Binh Phuoc	1.0	79.47	79.47	0.0	PV-Only
	0.8	77.92	79.04	1.4	8MW 4h
	0.6	68.89	74.42	8.0	8MW 4h

Table 3: Economic performance of PV-BESS systems under TOU pricing (TOU=1.2, BESS capacity=10%, storage duration=2 h)

Case study location	BESS capacity (%)	Storage duration (h)	α	TOU ratio	NPV (USD)	F (USD/kW-month)
40MW Lai Chau	10	2	1.0	1.2	−1,918,480	4.92
	10	2	0.8	1.2	−1,922,430	4.93
	10	2	0.6	1.2	−3,745,900	9.62
40MW Ninh Thuan	10	2	1.0	1.2	−2,664,330	6.84
	10	2	0.8	1.2	−3,102,880	7.97
	10	2	0.6	1.2	−5,185,490	13.31
40 MW Binh Phuoc	10	2	1.0	1.2	−5,697,330	14.63
	10	2	0.8	1.2	−5,738,980	14.73
	10	2	0.6	1.2	−7,729,390	19.84

Overall, these findings highlight that BESS improves electricity delivery efficiency only under constrained conditions, and its effectiveness is bounded by system-level limitations. This provides a technical basis for evaluating whether the additional energy recovered can justify the associated investment costs, which is further examined in the following section.

3.2. Economic Performance and Required Capacity Payment

The economic performance of PV-BESS systems under TOU pricing is summarized in Table 3. Across all scenarios, the NPV remains negative, indicating that energy-based pricing alone is insufficient to ensure financial viability under current cost structures and regulatory price constraints.

As a result, although BESS improves energy utilization, the magnitude of additional high-value electricity is insufficient to offset the revenue reduction caused by regulated price caps and TOU pricing structures.

The magnitude of the financial deficit varies across locations and operating conditions. In Lai Chau, NPV ranges from approximately −1.9 million USD to −3.7 million USD across the representative scenarios shown in Table 1. In Ninh Thuận, the deficit ranges from −2.7 million USD to −5.2 million USD, while in Binh Phuoc it reaches approximately from −5,7 million USD to −7.7 million USD. These results indicate that TOU pricing can partially improve revenue opportunities through temporal price differentiation, but the additional market revenue remains insufficient to restore financial viability without supplemental capacity-based compensation.

To restore financial viability, the required capacity payment (F) is calculated for each scenario. As shown in Table 1, F ranges from approximately 4.9 USD/kW-month in favorable conditions to more than 19.8 USD/kW-month in highly constrained cases. The highest values are observed in Binh Phuoc, reflecting less favorable economic conditions compared to the other regions.

Transmission constraints have a dominant impact on economic performance. As illustrated in Figure 1, the required capacity payment increases sharply as α decreases. For example, in Ninh Thuan, F increases from approximately 6.8 USD/kW-month at α = 1.0 to more than 13.3 USD/kW-month at α = 0.6. This trend indicates that, although BESS mitigates curtailment by shifting energy to peak periods, the additional revenue generated under TOU pricing is insufficient to offset reduced energy delivery under constrained conditions.

Building on this, Figure 2 illustrates the impact of BESS capacity on the required capacity payment under different transmission constraint levels. The results reveal a non-linear relationship between storage size and economic performance. Under unconstrained conditions (α = 1.0), increasing BESS capacity leads to higher required payments due to increased investment costs. In contrast, under severe transmission constraints (α = 0.6), larger BESS systems reduce the required capacity payment by enabling greater recovery of curtailed energy. This result highlights that the economic value of BESS depends strongly on system conditions rather than solely on storage size.

Figure 3 further evaluates whether TOU pricing can improve economic performance. The results show that increasing the TOU ratio consistently increases the required capacity payment across all scenarios. For instance, at α = 0.8, the required capacity payment rises from 7.97 USD/kW-month under TOU = 1.2 to 12.83 USD/kW·month under TOU = 1.3, representing an

Figure 1: Impact of transmission constraints on the required capacity payment (F) for PV-BESS systems (TOU = 1.2, BESS capacity = 10%, storage duration = 2 h)

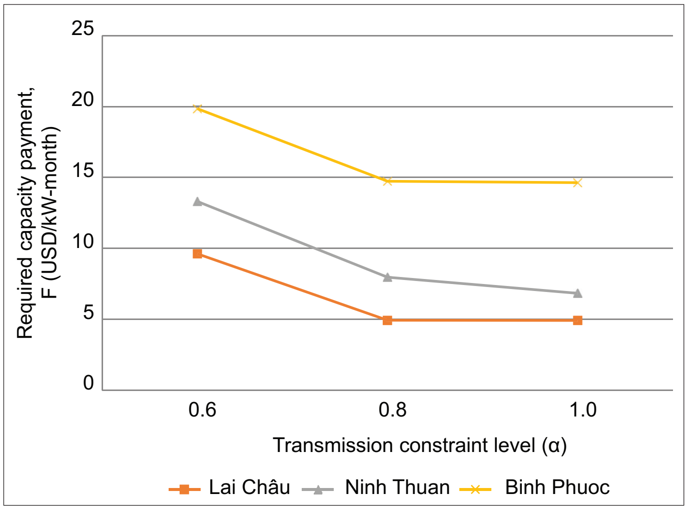


Figure 2: Impact of BESS capacity on the required capacity payment (F) under different transmission constraint levels (Ninh Thuận, TOU = 1.2, storage duration = 2 h)

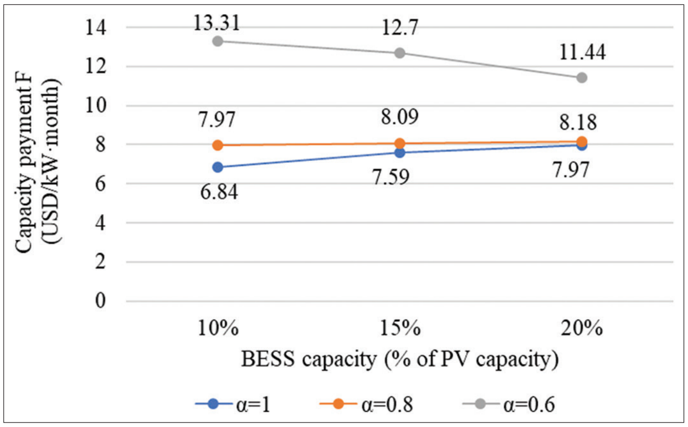
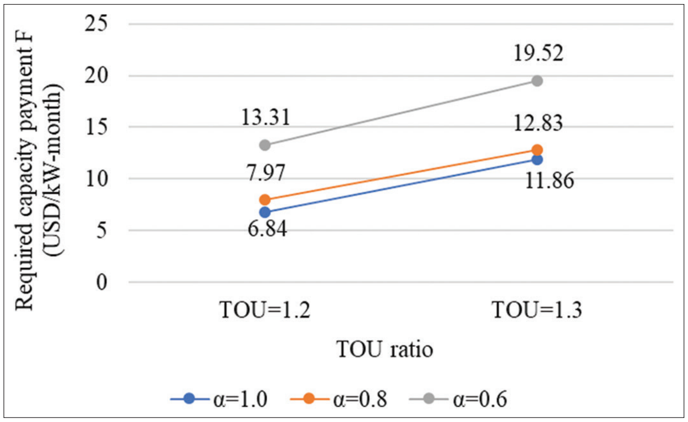


Figure 3: Impact of TOU pricing on the required capacity payment under different transmission constraint levels (Ninh Thuận, BESS capacity = 10%, storage duration = 2 h)



increase of approximately 61%. A similar trend is observed under unconstrained conditions (α = 1.0), where F increases from 6.84 to 11.86 USD/kW·month (approximately 73%). Under severe transmission constraints (α = 0.6), the required payment increases from 13.31 to 19.52 USD/kW-month (approximately 47%). This outcome is explained by the regulatory price cap, which constrains the peak electricity price while forcing a reduction in the off-peak price as the TOU ratio increases. Since a substantial share of electricity is still sold during off-peak periods, the reduction in off-peak prices leads to a decline in total revenue. Although BESS enables partial shifting of energy to peak periods, this effect is insufficient to offset the revenue loss.

Overall, the results demonstrate that transmission constraints are the dominant factor affecting economic performance, BESS provides conditional benefits depending on system conditions, and TOU pricing alone is insufficient to close the financial gap. These findings suggest that additional mechanisms are required to ensure the financial viability of PV-BESS systems.

Detailed economic results for all simulated PV-BESS configurations are provided in Appendix A. Specifically, the results for Lai Chau, Ninh Thuan, and Binh Phuoc are presented in Tables A1, A2, and A3, respectively.

4. DISCUSSION

The results provide new insights into how transmission constraints and pricing mechanisms jointly shape the economic viability of PV-BESS systems.

First, the findings confirm that transmission constraints strongly affect economic performance, particularly under high curtailment conditions. For example, in Ninh Thuan the required capacity payment nearly doubles as α declines from 1.0 to 0.6, increasing from about 6.8 to more than 13.3 USD/kW-month. While this result is consistent with prior studies on renewable curtailment, the present analysis shows that even with the integration of BESS, the financial impact of limited grid capacity remains significant. This suggests that storage alone cannot fully resolve structural limitations in the transmission system, particularly in regions with high solar penetration.

Second, the results reveal that the economic value of BESS is highly context-dependent. Under unconstrained conditions, increasing storage capacity leads to higher costs without proportional revenue gains, resulting in reduced economic performance. In contrast, under severe transmission constraints, larger BESS systems can partially mitigate curtailment and improve revenue recovery. This indicates that the economic value of BESS is highly context-dependent, particularly on the level of transmission congestion.

Third, and most importantly, the analysis demonstrates that TOU pricing alone is insufficient to ensure financial viability under regulated price caps, due to limited revenue expansion despite improved temporal price signals. Unlike prior studies showing that TOU pricing can improve storage profitability (Martinez-Bolanos et al., 2020; Zhao et al., 2021). This study shows that under regulated price caps, higher TOU price differentials may widen, rather than reduce, the financial viability gap under price caps. For instance, increasing the TOU ratio from 1.2 to 1.3 raises the required capacity payment by about 61% under α = 0.8 and by nearly 47% under α = 0.6.

Although TOU mechanisms are designed to reflect temporal variations in electricity value, their effectiveness is fundamentally limited when peak prices are constrained by regulatory ceilings. In such cases, increasing the TOU ratio primarily reduces off-peak prices due to the cap rather than increasing peak revenues, leading to a net decline in total income. This finding highlights a structural mismatch between market signals and regulatory constraints.

From a policy perspective, these results suggest that relying solely on energy-based pricing mechanisms may not adequately compensate for the flexibility services provided by BESS. Instead, additional compensation mechanisms, such as capacity payments or flexibility remuneration, are required to bridge the gap between market-based revenues and investment costs. This is reflected in required compensation levels ranging from about 4.9 to 19.8 USD/kW-month across the evaluated scenarios. Such mechanisms would allow storage systems to be remunerated not only for energy arbitrage but also for their contribution to system reliability and congestion management.

Furthermore, the observed regional differences indicate that a uniform pricing framework may not be appropriate for all locations. Regions with higher curtailment levels and better solar resources may achieve relatively better economic performance, while others remain less viable under the same pricing structure. This suggests the need for region-specific policy design or differentiated support mechanisms.

Overall, the findings emphasize that the effectiveness of TOU pricing depends not only on its design but also on the broader regulatory and system context. Without sufficient flexibility in price formation and complementary compensation mechanisms, TOU pricing alone is unlikely to unlock the full economic potential of PV-BESS systems without complementary regulatory support.

5. CONCLUSION

This study evaluates the economic performance of PV-BESS systems under TOU pricing within constrained power systems and regulatory price caps. By integrating technical simulation, operational modeling, and financial analysis, the study provides a comprehensive assessment of how transmission constraints and pricing mechanisms jointly affect investment viability.

The results show that transmission constraints play a critical role in shaping economic performance, with required capacity payments ranging from about 4.9 to 19.8 USD/kW-month across scenarios and increasing sharply as grid limitations become more severe. While BESS can partially mitigate curtailment and improve energy delivery, their economic value depends strongly on system conditions and, on its own, is insufficient to ensure financial viability.

Furthermore, the analysis demonstrates that TOU pricing, when implemented under regulated price caps, does not necessarily improve economic performance under regulated price caps. Increasing the TOU ratio enhances price differences between peak and off-peak periods but reduces off-peak prices due to the cap on peak tariffs, leading to a decline in total revenue under capped peak prices. As a result, the financial gap persists and, in some cases, becomes larger. For example, increasing the TOU ratio from 1.2 to 1.3 raises required capacity payments by up to 61% under representative constrained conditions.

These findings highlight that energy-based pricing mechanisms alone are insufficient to fully capture the system value of flexibility provided by BESS. Additional compensation mechanisms, such as capacity payments, are required to bridge the gap between market revenues and investment costs.

Overall, this study provides important implications for the design of electricity pricing mechanisms in systems with high shares of renewable energy. It suggests that effective integration of energy storage requires not only advanced technologies but also appropriate market structures and regulatory frameworks that adequately value system flexibility and support efficient system operation.

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Appendix A. Detailed economic results of PV–BESS systems

This appendix presents detailed economic results for all simulated PV-BESS configurations under different TOU pricing ratios and transmission constraint levels across the three case study locations. The results are reported in Tables A1-A3.

Table A1: Economic performance of PV-BESS under TOU pricing and transmission constraints for Lai Chau

BESS capacity (kW)	Storage duration (h)	α	TOU ratio	Total Revenue (USD)	LCOE (cents/kWh)	LCOS (cents/kWh)	NPV (USD)	F (USD/kW-tháng)
4000	2	1.0	1.2	3,476,521	5.53	169,604	−1,918,480	4.92
4000	2	0.8	1.2	3,473,099	5.54	91	−1,922,430	4.93
4000	2	0.6	1.2	3,191,390	5.96	38	−3,745,900	9.62
4000	4	1.0	1.2	3,476,626	6.01	145,084	−4,439,690	11.40
4000	4	0.8	1.2	3,482,016	6.02	129	−4,407,640	11.31
4000	4	0.6	1.2	3,249,660	6.36	37	−5,749,330	14.76
8000	2	1.0	1.2	3,476,664	6.21	168,051	−5,465,760	7.02
8000	2	0.8	1.2	3,482,589	6.21	150	−5,434,650	6.98
8000	2	0.6	1.2	3,267,169	6.56	41	−6,742,510	8.65
8000	4	1.0	1.2	3,476,874	7.17	143,195	−10,508,200	13.49
8000	4	0.8	1.2	3,484,282	7.17	246	−10,471,900	13.44
8000	4	0.6	1.2	3,341,621	7.28	41	−10,534,400	13.52
4000	2	1.0	1.3	3,212,290	5.52	169,604	−3,885,340	9.97
4000	2	0.8	1.3	3,212,087	5.52	91	−3,873,680	9.94
4000	2	0.6	1.3	2,956,331	6.05	43	−6,050,720	15.53
4000	4	1.0	1.3	3,212,375	5.99	145,084	−6,406,570	16.45
4000	4	0.8	1.3	3,221,007	6.00	129	−6,358,780	16.32
8000	2	1.0	1.3	3,212,433	6.19	168,051	−7,432,620	9.54
8000	2	0.8	1.3	3,221,639	6.19	149	−7,385,560	9.48
8000	2	0.6	1.3	3,029,926	6.54	41	−8,537,540	10.96
8000	4	1.0	1.3	3,212,613	7.15	143,195	−12,475,100	16.01
8000	4	0.8	1.3	3,223,310	7.15	246	−12,422,800	15.94
8000	4	0.6	1.3	3,127,911	7.34	40	−12,717,900	16.32

Table A2: Economic performance of PV–BESS under TOU pricing and transmission constraints for Ninh Thuan

BESS capacity (kW)	Storage duration (h)	α	TOU ratio	Total revenue (USD)	LCOE (cents/kWh)	LCOS (cents/kWh)	NPV (USD)	F (USD/kW- tháng)
4000	2	1.0	1.2	3,430,404	4.54	1.576	−2,664,330	6.84
4000	2	0.8	1.2	3,347,501	4.62	42	−3,102,880	7.97
4000	2	0.6	1.2	2,941,300	5.20	33	−5,185,490	13.31
4000	4	1.0	1.2	3,430,512	4.93	2.649	−5,161,090	13.25
4000	4	0.8	1.2	3,389,269	4.98	44	−6,290,310	16.15
4000	4	0.6	1.2	3,007,973	5.53	30	−7,894,880	20.27
8000	2	1.0	1.2	3,430,535	5.09	3.099	−6,211,590	7.97
8000	2	0.8	1.2	3,395,111	5.14	48	−6,373,140	8.18
8000	2	0.6	1.2	3,020,901	5.71	34	−8,914,490	11.44
8000	4	1.0	1.2	3,430,713	5.87	5.180	−11,254,000	14.44
8000	4	0.8	1.2	3,436,708	5.88	59	−11,157,400	14.32
8000	4	0.6	1.2	3,141,992	6.34	31	−12,910,500	22.09
4000	2	1.0	1.3	3,166,398	4.52	1.576	−4,621,420	11.86
4000	2	0.8	1.3	3,093,795	4.61	42	−4,999,340	12.83
4000	2	0.6	1.3	2,720,430	5.18	33	−7,604,420	19.52
4000	4	1.0	1.3	3,166,496	4.91	2.649	−7,142,600	18.34
4000	4	0.8	1.3	3,135,242	4.96	43	−7,241,460	18.59
8000	2	1.0	1.3	3,166,539	5.07	3.099	−8,168,680	10.48
8000	2	0.8	1.3	3,141,020	5.12	48	−8,271,370	10.62
8000	2	0.6	1.3	2,798,957	5.69	34	−10,590,300	13.59
8000	4	1.0	1.3	3,166,697	5.85	5.180	−13,211,100	16.96
8000	4	0.8	1.3	3,182,672	5.86	59	−13,058,400	16.76
8000	4	0.6	1.3	2,919,752	6.32	31	−14,605,200	24.99

Table A3: Economic performance of PV–BESS under TOU pricing and transmission constraints for Binh Phuoc

BESS capacity (kW)	Storage duration (h)	α	TOU ratio	Total revenue (USD)	LCOE (cents/kWh)	LCOS (cents/kWh)	NPV (USD)	F (USD/kW-tháng)
4000	2	1.0	1.2	3,004,998	4.70	109,184	−5,697,330	14.63
4000	2	0.8	1.2	2,992,497	4.72	57	−5,738,980	14.73
4000	2	0.6	1.2	2,694,614	5.19	32	−7,729,390	19.84
4000	4	1.0	1.2	3,005,066	5.11	113,671	−8,227,040	21.12
4000	4	0.8	1.2	3,011,138	5.12	72	−8,181,140	21.00
4000	4	0.6	1.2	2,773,802	5.52	30	−9,727,140	24.97
8000	2	1.0	1.2	3,005,102	5.28	131,898	−9,258,050	11.88
8000	2	0.8	1.2	3,011,929	5.29	81	−9,212,160	11.82
8000	2	0.6	1.2	2,776,843	5.70	33	−10,746,700	13.79
8000	4	1.0	1.2	3,005,250	6.10	126,020	−14,317,500	18.38
8000	4	0.8	1.2	3,018,886	6.10	127	−14,244,700	18.28
8000	4	0.6	1.2	2,915,833	6.36	32	−14,870,000	25.45
4000	2	1.0	1.3	2,777,078	4.69	109,184	−7,381,500	18.95
4000	2	0.8	1.3	2,769,907	4.71	57	−7,394,630	18.98
4000	2	0.6	1.3	2,497,744	5.17	32	−9,208,150	23.64
4000	4	1.0	1.3	2,777,136	5.10	113,671	−9,911,230	25.44
4000	4	0.8	1.3	2,788,758	5.11	72	−9,835,590	25.25
8000	2	1.0	1.3	2,777,182	5.27	131,898	−10,942,200	14.04
8000	2	0.8	1.3	2,789,779	5.27	81	−10,865,800	13.95
8000	2	0.6	1.3	2,580,303	5.69	33	−12,222,800	15.69
8000	4	1.0	1.3	2,777,300	6.09	126,020	−16,001,700	20.54
8000	4	0.8	1.3	2,796,806	6.09	127	−15,897,900	20.41
6000	4	0.6	1.3	2,719,493	6.35	32	−16,344,500	27.97