ENERGY POLICY RESEARCH PAPER

Navigating the CTBCM Transition:

Use of System Charges and Battery Energy Storage as Determinants of Industrial Decarbonization Viability in Pakistan

Prepared for: Industrial Associations and Export-Sector Leadership

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Executive Summary

Pakistan's Competitive Trading Bilateral Contract Market (CTBCM) has entered its implementation phase following the notification of **S.R.O. 92(I)/2026**, the establishment of the Independent System and Market Operator (ISMO), and the preparation of the country's first 200 MW (modified 400 MW) wheeling auction (inc. of renewable suppliers). The legal and institutional foundations of a competitive electricity market are now largely in place, including standardized Connection Agreements, Use of System Agreements, Capacity Balancing Mechanism (CBM) procedures, and bilateral trading arrangements. The success of the market, however, will ultimately depend not on the existence of these regulatory instruments alone, but on whether their commercial design encourages meaningful participation by private investors and industrial electricity consumers.

This policy research evaluates two policy issues that are expected to shape the commercial performance of CTBCM during its initial implementation: the proposed **uniform Use of System Charge (UoSC)** framework and the mandatory **Battery Energy Storage System (BESS)** requirements for variable renewable energy (VRE) projects. Together, these two elements determine both the delivered cost of competitively procured electricity and the ability of renewable projects to satisfy firm capacity obligations under Pakistan's Capacity Balancing Mechanism.

The analysis demonstrates that the proposed UoSC establishes an effective wheeling floor of *Rs. 9.92/kWh* before the bilateral energy price is considered. Nevertheless, when assessed against a representative blended *FESCO B-4 industrial tariff of approximately Rs. 26.46/kWh*, CTBCM remains commercially competitive across a broad range of realistic renewable energy prices. For bilateral prices between *Rs. 8 and Rs. 15/kWh*, industrial consumers continue to achieve meaningful savings over regulated supply, while the commercial break-even occurs at an effective bilateral energy price of approximately *Rs. 15.04/kWh*. The analysis further shows that the current proposed UoSC of *Rs. 6.69/kWh* remains comfortably below the estimated commercial break-even threshold of approximately *Rs. 10.03/kWh*, providing regulatory headroom while highlighting the importance of maintaining predictable non-network charges, particularly the Debt Service Surcharge (DSS).

The second part of the brief examines the evolving role of *Battery Energy Storage Systems* within CTBCM. Under the Capacity Balancing Mechanism, firm capacity; not energy alone; determines compliance during Critical Hours. ISMO's post-consultation decision to require a minimum BESS capacity equal to *10% of plant nameplate rating with a two-hour discharge duration* represents a pragmatic compromise between grid reliability and project economics. Modelling presented in this paper indicates that such systems typically achieve simple payback periods of *5–8 years*, shorter than expected project lifetimes of 20 years, while simultaneously reducing capacity deficits and mitigating exposure to volatile System Marginal Prices (SMP).

The research concludes that Pakistan has largely completed the regulatory transition from a single-buyer electricity sector toward a competitive market framework. The priority should now shift toward strengthening implementation by ensuring transparent and predictable wheeling charges, standardizing commercial treatment of storage assets and balancing risks, and providing investors with sufficient regulatory certainty to mobilize long-term private capital. Addressing these implementation issues before the first large-scale wheeling auctions will significantly improve investor confidence while accelerating industrial decarbonization, renewable energy deployment, and export competitiveness.

PART I
Use of System Charges: A Structural Analysis

1.1. Background and Policy Context

The introduction of open-access electricity markets typically involves two distinct cost layers: the price of electricity itself, negotiated bilaterally between buyer and seller; and the cost of using the network to transport that electricity, determined by a regulated tariff. In a well-functioning competitive market, the network access charge should be cost-reflective, predictable, and limited to the genuine cost of transmission and distribution infrastructure. It should not serve as a vehicle for recovering legacy sector obligations that predate the competitive market or that arise from system-wide inefficiencies unrelated to the purchasing consumer.

The uniform UoSC framework proposed by ISMO and presented at the NEPRA consultation on 11 June 2026 departs materially from this principle [1]. While the stated objective; creating a uniform, non-discriminatory wheeling charge applicable across all Distribution Companies (DISCOs) and K-Electric; is sound administrative policy, the mechanism by which uniformity is achieved embeds structural distortions that undermine the commercial viability of competitive electricity procurement precisely at the moment it is being legally enabled.

1.2. The Architecture of the Proposed UoSC

The proposed base UoSC rate for B-4 industrial consumers is Rs. 6.69 per kWh (as per June 2025 tariff, as stated by ISMO). Added to this is a Debt Service Surcharge (DSS) of Rs. 3.23 per kWh, levied under Section 31(8) of the NEPRA Act 1997. The effective wheeling floor; before any bilateral energy price is added; is therefore [1,2]:

$$\mathbf{Wheeling\ Floor = UoSC + DSS = Rs. 6.69 + Rs. 3.23 = Rs. 9.92/kWh - - - (1)}$$

This floor is not a price for electricity. It is a charge payable for the right to use the grid to transport electricity that has already been contracted and priced in a separate bilateral agreement. It exists regardless of the terms of the bilateral contract, the distance between generator and consumer, or the efficiency of either party's operations.

Table 1: Current DISCO Tariff structure and UoSC cost stack for B-4 industrial consumers under the proposed uniform framework. The effective floor of Rs. 9.92/kWh before energy cost leaves a thin margin against the regulated B-4 tariff of approximately Rs. 26.46/kWh.

FESCO Tariff Structure			
Tariff Component	**Rate**	**Applies To**	**Source**
Fixed Charges	Rs. 1,250 per kW per month	Demand charge on sanctioned load	FESCO Tariff Schedule
Variable; Peak Rate	**Rs. 35.68 per kWh**	Peak hours (defined by NEPRA)	FESCO, NEPRA
Variable; Off-Peak Rate	Rs. 23.34 – 23.38 per kWh	Off-peak hours	FESCO, NEPRA
Fixed Minimum Monthly Charge	**Rs. 500,000 per month**	Regardless of consumption	FESCO Tariff Schedule
Blended Effective Rate (for modelling)	**~Rs. 26.46 per kWh (assuming 6 hr.-peak)**	Weighted avg. across peak/off-peak mix; used as benchmark in updated tables	Derived from above rates

UoSC Cost structure			
System Charge Cost Component	**Rate (PKR/kWh)**	**Nature**	**Commercial Implication**
Base UoSC (NEPRA proposed)	6.69	Tariff charge	Includes cross-subsidy element
Debt Service Surcharge (DSS)	3.23	Stranded-cost recovery	Grid debt; not a network-use fee
Effective Wheeling Floor	**9.92**	**Before energy price**	**Market entry threshold**
Bilateral RE energy price (indicative)	8.00 – 20.00	Market-negotiated	Varies by technology and term, Breakeven effective floor at ~Rs. 15.00/kWh (shown in Fig. 5.)
T&D loss gross-up (~10% adjustment)	0.80 – 2.00	Hidden cost	Buyer pays for energy not delivered
Total All-In CTBCM Cost	**18.72 – 31.92**	**Full stack**	**Vs. B-4 blended ~PKR. 26.46/kWh**

Source: NEPRA UoSC Consultation, 11 June 2026 [1]; Framework Guidelines SRO 92/(I)/2026 [3], FESCO Tariff Rates [4,5].

Blended Benchmark Calculation

Assuming an industrial load profile (6 hours peak, 18 hours off-peak), the weighted average B-4 energy tariff is calculated as: [(6/24) × 35.68] + [(18/24) × 23.38] = **Rs. 26.46/kWh**. This blended rate serves as the benchmark (T_{B4}) for assessing CTBCM savings.

1.3. The Four Embedded Distortions

The proposed framework contains four cost categories that distort the purpose of a network-access charge. Each is analyzed below.

1.3.1. Cross-Subsidy Burden

A significant portion of the base UoSC of Rs. 6.69/kWh is attributable to cross-subsidy recovery; the mechanism by which higher-tariff industrial consumers contribute to the cost of below-cost supply to residential and agricultural consumers. Embedding cross-subsidy recovery in the wheeling charge means that an industrial firm choosing to procure power competitively; precisely the kind of market behavior that CTBCM is designed to incentivize; is required to finance subsidies to other consumer categories as a condition of market entry. This inverts the logic of competitive market design: instead of rewarding efficient procurement, the framework imposes an efficiency penalty on market participants.

1.3.2. Debt Service Surcharge

The DSS of Rs. 3.23/kWh represents the single largest distortion in the proposed framework. The DSS is tied to the recovery of accumulated power sector debt and stranded generation capacity obligations that predate the competitive market. It is not a charge for using the transmission or distribution network. It is, in substance, a socialized debt-recovery levy applied uniformly across all wheeling transactions. For investors seeking to model long-term bilateral contract economics, the DSS creates an immovable cost floor that cannot be reduced through technological efficiency, geographic optimization, or contract structure.

1.3.3. Loss Gross-Up and the 100/110 Principle

Under the proposed settlement mechanism, if a consumer requires 100 units of electricity at the metering point, the seller is required to inject approximately 110 units (subject to average T&D losses of DISCO) to account for transmission and distribution losses (taken as average losses in that DISCO). This means the buyer effectively pays for energy that never reaches the point of consumption. The commercial implication is that the quoted bilateral energy price must be scaled upward by the loss factor to determine the true delivered cost. For a project located far from the load center or routed through a loss-heavy network, this can add materially to the all-in cost.

1.3.4. K-Electric Adjustment Uncertainty

The proposed framework does not fully resolve how to treat K-Electric's network, which has a distinct cost structure from the national DISCO system. The use of 'additional charges' as an interim bridging mechanism introduces regulatory uncertainty that is particularly damaging for investor confidence. A project whose wheeling costs include a base rate plus an open-ended adjustment formula lacks the cash flow predictability required to support project financing at commercially acceptable terms.

Figure 1 shows the comparison of proposed All-in CTBCM cost (inc. of assumed floor of bilateral trading cost) with FESCO-regulated tariff for B4 (large industrial consumers) [1,4].

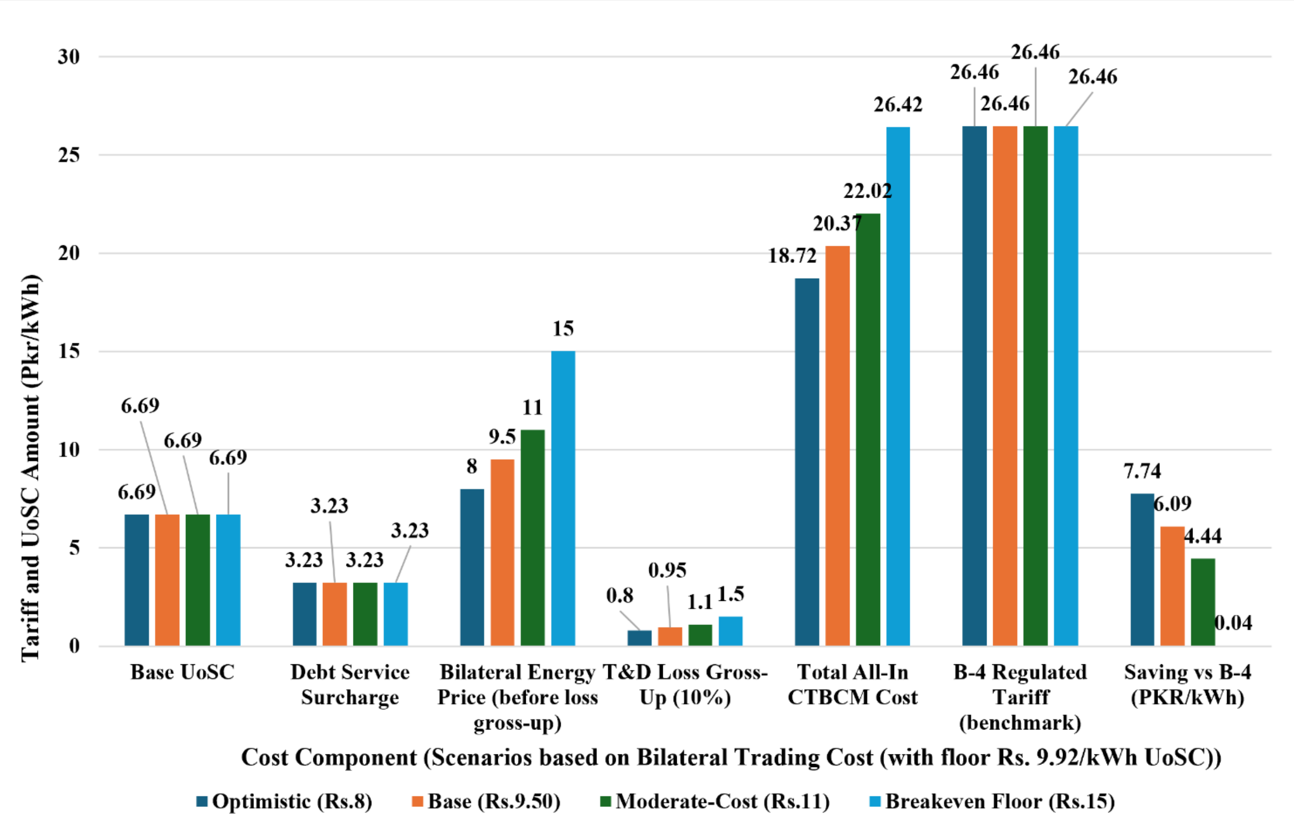

Figure 1: All-in CTBCM cost comparison across bilateral energy price points. At a bilateral energy price of ~Rs. 15.00/kWh, CTBCM reaches the effective breakeven floor against the Rs. 26.46/kWh B-4 benchmark.

1.4. Modelling the Commercial Impact

To assess the commercial viability of CTBCM participation under the proposed UoSC framework, we model total delivered cost and compare it to the prevailing B-4 regulated tariff [1]. Let:

$$T_C = UoSC + DSS + (BP \times LGF) - - - (2)$$

T_C = Total all-in cost of CTBCM-procured electricity (PKR/kWh)

UoSC = Base Use of System Charge (PKR/kWh)

DSS = Debt Service Surcharge (PKR/kWh)

BP = Bilateral energy price negotiated with the generator (PKR/kWh)

LGF = Loss Gross-Up Factor (typically 1.08–1.12; default 1.10)

The saving from CTBCM participation relative to the regulated tariff is:

$$\text{Saving} = T_{B4} - T_C - - - (3)$$

T_{B4} = Current B-4 regulated tariff (discussed in previous section)

Applying *Equations 2 and 3* across three bilateral energy price scenarios:

Scenario	Bilateral Price (PKR/kWh)	All-In Cost (PKR/kWh)	Saving vs B-4 (PKR/kWh)	Assessment
Optimistic: low-cost solar	8.00	18.72	7.74	Highly Viable; strong saving
Base: competitive mid-range	9.50	20.37	6.09	Viable; solid commercial advantage
Moderate-Cost	11.00	22.02	4.44	Viable; clear saving
Effective Breakeven Floor	15.00 – 15.04	26.42 – 26.46	**0.00 – 0.04**	Breakeven Threshold
Adverse / Premium Market / thermal/hybrid	18.00 – 20.00	29.72 – 31.92	**–3.26 to –5.46**	Unviable vs Grid B-4

Source: NEPRA consultation 11 June 2026; LGF = 1.10 (assumed as per consultation) [1]

1.5. Investor Perspective and Implications

Market analysis from APTMA, FPCCI, and independent energy advisory firms indicates that the projected equity Internal Rate of Return (IRR) for wheeling-based renewable energy projects under the current UoSC + DSS framework is in the range of 3–4 percent; well below the minimum acceptable threshold of 14–18 percent typically required for private industrial-scale investment in Pakistan's energy sector [6]. This compression occurs because the UoSC floor erodes the bilateral price advantage that justifies the capital commitment.

A simplified IRR model demonstrates sensitivity [7,8]. For a representative 10 MW bilateral renewable project:

$$\boldsymbol{NPV} = \sum \frac{\boldsymbol{CF_t}}{(\mathbf{1} + \boldsymbol{r})^{\boldsymbol{t}}} - \boldsymbol{I_0} - - - (\mathbf{4})$$

CF_t = Annual net cash flow = ($T_{B4} - T_C$) × Annual kWh − O&M costs

r = Discount rate / required IRR

t = Year (project life: 20 years)

I_0 = Initial investment: Bid Bond + PG + connection costs

Setting NPV = 0 and solving for r gives the project IRR. At a bilateral price of Rs. 12/kWh (base scenario), T_C = Rs. 23.12/kWh, and saving = Rs. 3.34/kWh. For a 10 MW project consuming 60 million kWh/year, gross annual saving = Rs. 200.4 million. After O&M, regulatory fees, and cost of capital, the resulting IRR under the current framework is **approximately 4%** (as shown in **Section 1.5.2**); consistent with industry estimates.

1.5.1. Comparison with Benchmark B-4 DISCO Tariff: Impact on Annual Savings

Figure 2 evaluates the maximum allowable UoSC (inclusive of Base UoSC + DSS + Stranded Costs) when the bilateral energy purchase price is fixed at *PKR 12/kWh*. By incorporating the *10% T&D loss gross-up (PKR 1.20)* and the *Debt Service Surcharge (PKR 3.23)* establishes a base non-wheeling cost of **PKR 16.43/kWh** against the single blended DISCO B-4 grid benchmark of **PKR 26.46/kWh**. Under the currently proposed uniform UoSC of *Rs. 6.69/kWh*, the total CTBCM procurement cost reaches *Rs. 23.12/kWh*, delivering a net tariff reduction of PKR *3.34/kWh*, which yields *PKR 200.4 million* in annual savings for an industrial facility consuming 60 million kWh (assumed). The market feasibility ceiling for this setup occurs at a break-even UoSC of **PKR 10.03/kWh**, where total bilateral costs exactly match the DISCO grid rate; any wheeling charge set above this threshold generates net financial losses for the consumer and eliminates the incentive for industrial off-takers to participate in the market. The net impact is shown in **Table 2** and **Table 3**.

Table 2: Impact of UoSC on net revenue implications

UoSC Rate (PKR/kWh)	All-In CTBCM Cost (PKR/kWh)	Saving vs B-4 (PKR/kWh)	Annual Saving: 60M kWh/year (PKR Million)
4	20.43	6.03	361.8
5	21.43	5.03	301.8
6	22.43	4.03	241.8
6.69	**23.12**	**3.34**	**200.4**
7	23.43	3.03	181.8
8	24.43	2.03	121.8
9	25.43	1.03	61.8
10	26.43	0.03	1.8
10.03	**26.46**	**0**	**0**
11	27.43	-0.97	-58.2
11.5	27.93	-1.47	-88.2
12	28.43	-1.97	-118.2
13	29.43	-2.97	-178.2
14	30.43	-3.97	-238.2
16	32.43	-5.97	-358.2
18	34.43	-7.97	-478.2
20	36.43	-9.97	-598.2
22	38.43	-11.97	-718.2

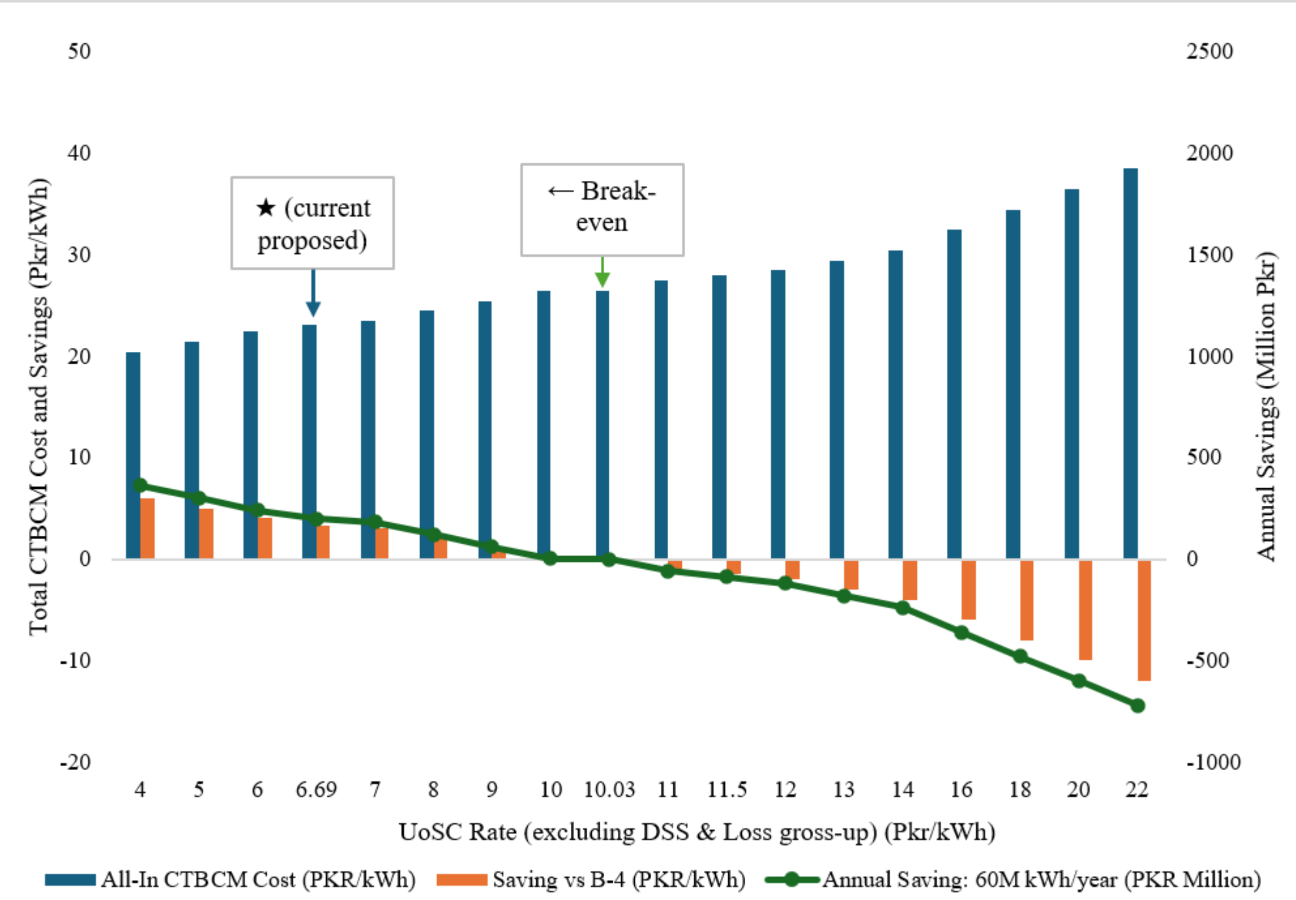

Figure 2: Impact of UoSC on net revenue implications

Table 3: Impact of UoSC on net revenue implications (Part 2, inc. of all wheeling charges)

Effective UoSC (Inclusive of DSS/Taxes)	Total All-In Cost (Pkr/kWh)	Saving vs B-4 (26.46) (Pkr/kWh)	Feasibility / Market Assessment
4.00 (Incentivized Wheeling)	17.2	9.26	Highly Viable; exceptionally strong buyer margin
6.00 (Base UoSC only)	19.2	7.26	Highly Viable; strong buyer margin
8.00 (Mid-level Wheeling)	21.2	5.26	Viable; healthy cost advantage
9.92 (Current Policy Stack)	23.12	3.34	Moderately Viable; stable margin
11.00 (High Wheeling Cost)	24.2	2.26	Moderately Viable; narrow margin
12.00 (Prohibitive Wheeling)	25.2	1.26	Marginal / Near Breakeven
14.00 (Extreme Wheeling)	27.2	-0.74	Unviable; CTBCM cost exceeds B-4

Now, For a 10 MW Bulk Power Consumer (BPC) utilizing 60 million kWh annually. Fixed UoSC = Rs. 6.69/kWh, DSS = Rs. 3.23/kWh (Total Wheeling = Rs. 9.92/kWh). Bilateral energy price evaluated across Rs. 8.00 to Rs. 20.00/kWh range. Breakeven occurs at ~Rs. 15.04/kWh, as shown in **Table 4** and **Figure 3**.

Table 4: Financial Impact of Bilateral Energy Price Variations on a 10 MW BPC (Fixed UoSC & DSS)

Bilateral Energy Price (PKR/kWh)	T&D Loss Gross-Up (10%)	All-In CTBCM Cost	Saving vs B-4 (PKR/kWh)	Annual Saving
8.00 (Min Range)	0.80	18.72	7.74	464.4
9.00	0.90	19.82	6.64	398.4
9.50	0.95	20.37	6.09	365.4
10.00	1.00	20.92	5.54	332.4
11.00	1.10	22.02	4.44	266.4
12.00 (Base case)	1.20	23.12	3.34	200.4
13.00	1.30	24.22	2.24	134.4
14.00	1.40	25.32	1.14	68.4
15.00 (Effective Floor)	1.50	26.42	0.04	2.4
15.04 (Exact Break-even)	1.50	26.46	-0.00	-0.0
16.00	1.60	27.52	-1.06	-63.6
17.00	1.70	28.62	-2.16	-129.6

18.00	1.80	29.72	-3.26	-195.6
19.00	1.90	30.82	-4.36	-261.6
20.00 (Max Range)	2.00	31.92	-5.46	-327.6

As observed, fixing the UoSC and Debt Service Surcharge at a combined **Rs. 9.92/kWh** directly ties market feasibility to the negotiated bilateral energy price. As the generation price increases from **Rs. 8.00** to **Rs. 20.00/kWh**, the 10% T&D loss gross-up scales proportionally, driving up the total all-in CTBCM procurement cost. The absolute economic ceiling against the B-4 grid tariff occurs at a bilateral price of **Rs. 15.04/kWh**, where net savings are entirely neutralized. Securing energy below this threshold yields massive cash flow generation; peaking at **Rs. 464.4 million** annually; whereas procuring energy above this break-even point locks the industrial off-taker into escalating financial deficits.

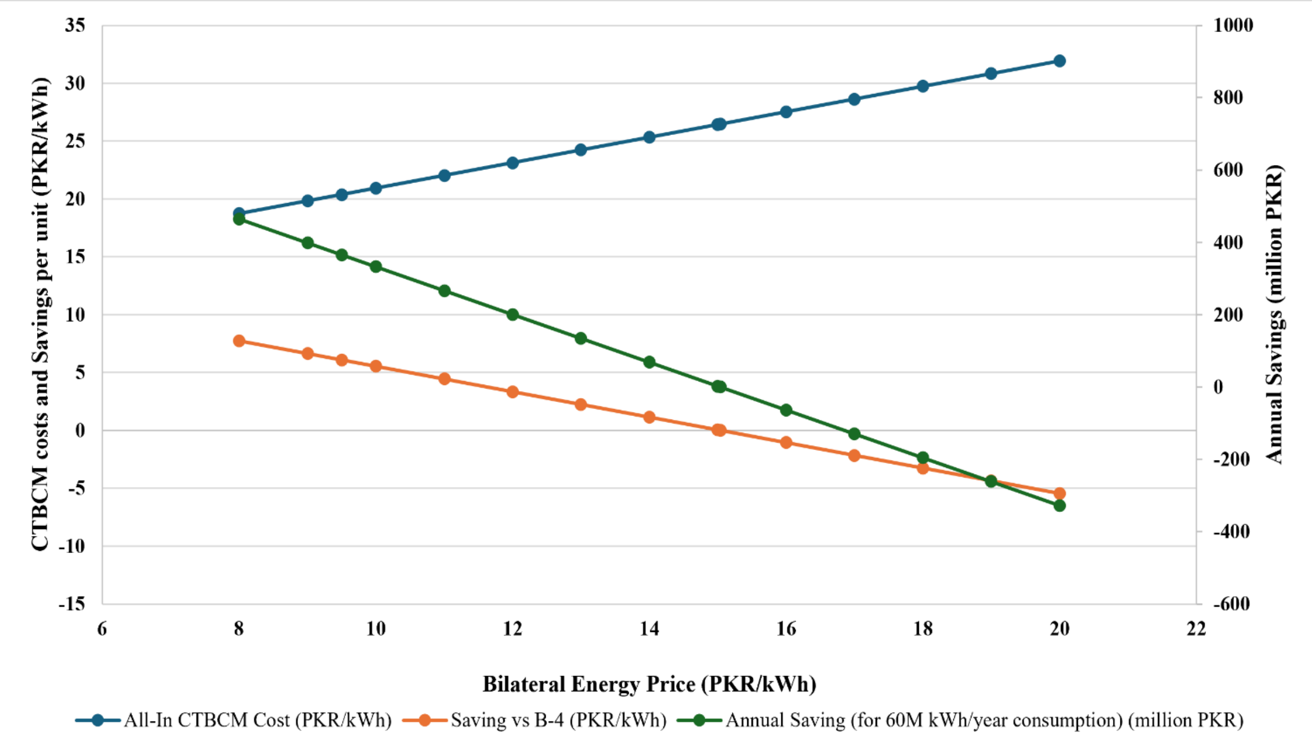

Figure 3: Bilateral Energy Price vs. Total All-In CTBCM Cost and Annual Savings

1.5.2. Comparison with Benchmark B-4 DISCO Tariff: Overall Financial Impact

<u>**Model Baseline Assumptions**</u>

- **Initial Capital Outlay (I_0):** PKR 1,329.1 Million
- **Project Life:** 20 Years; **Annual Generation required:** 60 Million kWh
- **Discount Rate / WACC:** 11.5%
- **Cost Stack Components:** Bilateral Price (PKR 12.00, assumed) + 10% T&D Loss Gross-up (PKR 1.20) + Debt Service Surcharge (PKR 3.23) = **PKR 16.43/kWh Non-UoSC Base**
- **Total All-In Cost (T_C):** $\text{UoSC} + \text{PKR } 16.43/\text{kWh}$
- **Net Margin / Saving:** $\text{PKR } 26.46/\text{kWh} - T_C$

Table 5 shows the impact on IRR, **Table 6** on NPV, **Table 7** on payback period and **Table 8** on ROI over project lifetime. The overall results are presented in **Figure 4** [7,8].

1. Internal Rate of Return (IRR)

The Internal Rate of Return (IRR) evaluates the annualized percentage yield of the project relative to the *PKR 1,329.1 Million* capital layout. Under the highly constrained PKR 26.46/kWh grid benchmark, the project yields a moderate 17.5% return at the lowest PKR 6.00/kWh wheeling rate. The currently proposed UoSC of PKR 6.69/kWh compresses the equity yield to exactly 14.0%, which rests at the absolute bottom of private developer requirements. The cost of capital break-even threshold is violently struck at PKR 7.16/kWh, where returns perfectly match the 11.5% hurdle rate. Any wheeling charges elevated above PKR 8.00/kWh crush profitability into single digits or negative territory, rendering the investment entirely unviable for institutional capital.

Table 5: Impact Analysis: UoSC vs. IRR

Base UoSC Rate (PKR/kWh)	All-In Cost (TC)	Annual Net Margin (PKR/kWh)	Annual Cash Flow (PKR Million)	Project Equity IRR (%)
6	22.43	4.03	241.8	**17.50%**
6.69 ★ (Proposed)	**23.12**	**3.34**	**200.4**	**14.00%**
7	23.43	3.03	181.8	**12.30%**
7.16 ← Break-even (for effective IRR)	**23.59**	**2.87**	**172.2**	**11.50%**
8	24.43	2.03	121.8	**6.60%**
9	25.43	1.03	61.8	**Negative**
10	26.43	0.03	1.8	**Negative**
11	27.43	−0.97	−58.2	**Negative**
12	28.43	−1.97	−118.2	**Negative**
13	29.43	−2.97	−178.2	**Negative**
14	30.43	−3.97	−238.2	**Negative**
15	31.43	−4.97	−298.2	**Negative**

2. Net Present Value (NPV) at 11.5% Discount Rate

NPV quantifies the project's absolute economic wealth generation by discounting 20 years of cash flow at the 11.5% capital cost. The model demonstrates that operating against a strict PKR 26.46/kWh tariff severely restricts financial headroom across all wheeling tiers. At the proposed PKR 6.69/kWh UoSC, the project creates only PKR 215.9 Million in present wealth, signaling high sensitivity to minor operational shocks. Setting the UoSC at exactly PKR 7.16/kWh yields a zero-wealth state, meaning the project precisely covers its financing obligations without generating surplus value. Imposing tariffs at or above PKR 8.00/kWh destroys systemic wealth, resulting in steep present-value deficits that escalate to PKR 3,628.2 Million at extreme rates.

Table 6: Impact Analysis: UoSC vs. NPV

Base UoSC Rate (PKR/kWh)	All-In Cost (T_C)	Annual Cash Flow (PKR Million)	Project NPV @ 11.5% (PKR Million)	Financial Viability Status
6	22.43	241.8	**535.1**	Wealth Creating
6.69 ★ (Proposed)	**23.12**	**200.4**	**215.9**	**Marginally Viable**
7	23.43	181.8	**72.5**	Marginally Viable
7.16 ← Break-even	**23.59**	**172.2**	**0**	**NPV Neutral**
8	24.43	121.8	**−390.0**	Value Destroying
9	25.43	61.8	**−852.6**	Value Destroying
10	26.43	1.8	**−1,315.2**	Value Destroying
11	27.43	−58.2	**−1,777.8**	Severe Deficit

12	28.43	−118.2	**−2,240.4**	Severe Deficit
13	29.43	−178.2	**−2,703.0**	Severe Deficit
14	30.43	−238.2	**−3,165.6**	Severe Deficit
15	31.43	−298.2	**−3,628.2**	Severe Deficit

3. Simple Payback Period

The simple payback period calculates the unadjusted operational timeline required to fully recuperate the original project capital expenditure. At the most favorable PKR 6.00/kWh UoSC, liquidity recovery takes a reasonable 5.5 years, minimizing corporate risk exposure. The proposed PKR 6.69/kWh policy extends this lock-up period to 6.6 years, demanding sustained off-taker stability to guarantee initial capital recuperation. Pushing the wheeling charge past the PKR 8.00/kWh threshold stretches the payback to a dangerous 10.9 years, deeply increasing counterparty default risk. Tariffs approaching PKR 10.00/kWh collapse annual cash flows to near zero, stretching recovery to an un-investable mathematical impossibility greater than project life.

Table 7: Impact Analysis: UoSC vs. Payback period

Base UoSC Rate (PKR/kWh)	All-In Cost (T_C)	Annual Cash Flow (PKR Million)	Simple Payback Period (Years)	Liquidity Risk Profile
6	22.43	241.8	**5.5 yrs**	Low
6.69 ★ (Proposed)	**23.12**	**200.4**	**6.6 yrs**	**Low**
7	23.43	181.8	**7.3 yrs**	Moderate
7.16 ← Break-even	**23.59**	**172.2**	**7.7 yrs**	**Moderate**
8	24.43	121.8	**10.9 yrs**	High
9	25.43	61.8	**21.5 yrs**	Very High
10	26.43	1.8	**Never**	Unacceptable
11	27.43	−58.2	**Never**	Unacceptable
12	28.43	−118.2	**Never**	Unacceptable
13	29.43	−178.2	**Never**	Unacceptable
14	30.43	−238.2	**Never**	Unacceptable
15	31.43	−298.2	**Never**	Unacceptable

4. Total Return on Investment (ROI)

Total Return on Investment (ROI) evaluates cumulative, un-discounted nominal profits relative to the starting capital base over the complete 20-year asset lifecycle. Maximum structural profitability peaks at a 263.9% lifetime return under the highly subsidized PKR 6.00/kWh wheeling condition. The proposed PKR 6.69/kWh mandate restricts the absolute return to 201.6%, meaning the project triples its initial value nominally across two decades. Implementing the break-even PKR 7.16/kWh fee limits cumulative returns to 159.1%, severely limiting the total upside for the developer. Escaping beyond the PKR 9.00/kWh boundary immediately converts the framework into a capital sink, generating severe nominal lifetime deficits.

Table 8: Impact Analysis: UoSC vs. ROI

Base UoSC Rate (PKR/kWh)	All-In Cost (T_C)	20-Year Lifetime Net Income (relative to B-4 tariff) (PKR Million)	Total Lifetime ROI (%)
6	22.43	3,506.90	**263.90%**
6.69 ★ (Proposed)	**23.12**	**2,678.90**	**201.60%**
7	23.43	2,306.90	**173.60%**
7.16 ← Break-even	**23.59**	**2,114.90**	**159.10%**

8	24.43	1,106.90	**83.30%**
9	25.43	−93.1	**−7.0%**
10	26.43	−1,293.1	**−97.3%**
11	27.43	−2,493.1	**−187.6%**
12	28.43	−3,693.1	**−277.9%**
13	29.43	−4,893.1	**−368.2%**
14	30.43	−6,093.1	**−458.4%**
15	31.43	−7,293.1	**−548.7%**

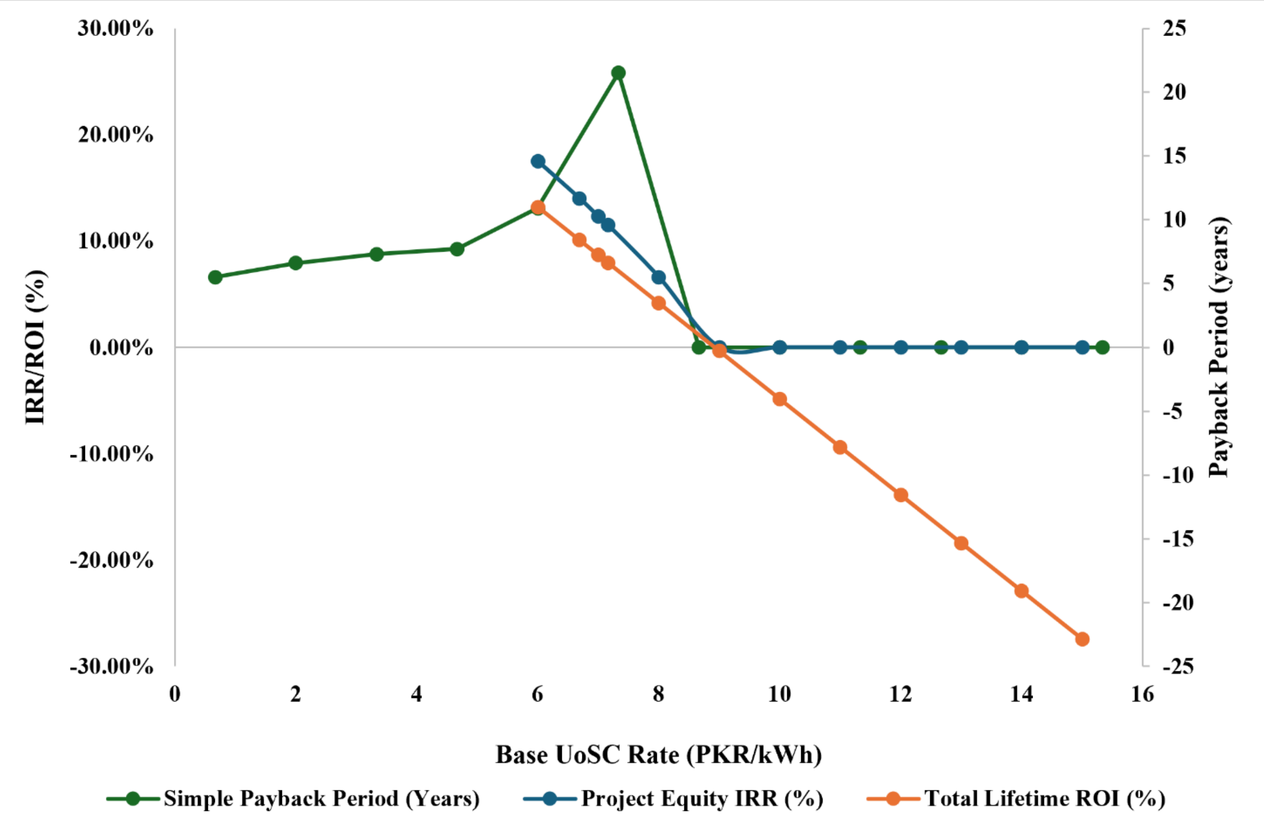

Figure 4: UoSC Analysis: Overall Financial Impact

> **Key Finding**
> The UoSC framework does not prohibit CTBCM participation. It makes it financially unattractive at the base and adverse scenarios. This is equivalent in effect to a structural barrier; one that operates through economics rather than regulation, and which will suppress private capital deployment in renewable wheeling at precisely the scale needed for meaningful industrial decarbonization.

1.6. Policy Recommendations: UoSC

- To transform the CTBCM from a theoretically open framework into a commercially viable platform, regulators must first decouple legacy sector obligations from network transportation tariffs. Cross-subsidy recovery should be completely unbundled from the base Use of System Charge (UoSC) and funded through the federal budget or a dedicated general levy, ensuring that competitive off-takers are not penalized for procuring efficient power. Additionally, the Debt Service Surcharge (DSS); which currently imposes an immovable Rs. 3.23/kWh floor on wheeling transactions; must be converted into a statutory, formula-based rate tied to a published debt-repayment schedule and a strict termination trigger. Finally, NEPRA should eliminate ongoing regulatory uncertainty around K-Electric by codifying its network adjustments into a statutory, formulaic rate, providing equal transparency across all service territories.

- To support project bankability and operational efficiency, network settlement rules must move away from blunt administrative assumptions toward true cost reflectivity. The current uniform 10% T&D loss gross-up should be replaced with a metered, distance-adjusted settlement mechanism that reflects actual physical delivery, rewarding strategically located generation rather than socialized network inefficiencies. Crucially, to shield early investors from regulatory volatility, policymakers should mandate a minimum 5-year rate freeze on wheeling charges for pioneer CTBCM entrants. Providing tariff stability over the initial contract duration protects project cash flows against margin erosion, preventing the severe equity IRR compression that currently deters institutional capital.
- Most importantly, rationalizing the UoSC framework is the single most effective lever for accelerating renewable energy (RE) uptake and driving industrial decarbonization across Pakistan. With private solar and wind projects capable of delivering clean energy at competitive bilateral rates of Rs. 8.00–12.00/kWh, removing the artificial Rs. 9.92/kWh wheeling floor restores the financial headroom needed against the ~Rs. 26.46/kWh B-4 grid benchmark. This expanded margin allows energy-intensive industries; such as textiles and heavy manufacturing; to transition away from expensive grid tariffs or fossil-fuel captive plants without sacrificing bottom-line competitiveness. By creating a predictable, cost-reflective wheeling environment, policymakers can mobilize private capital to expand clean generation, helping export industries meet stringent global carbon standards (like the EU's CBAM) while helping the country meet its renewable energy targets without adding new capacity liabilities to the national balance sheet.

PART II

Battery Energy Storage Systems: The Firm Capacity Imperative

2.1. Background

The co-location of Battery Energy Storage Systems (BESS) with variable renewable energy (VRE) generators; principally solar and wind; has emerged as a central technical and commercial requirement for CTBCM-based renewable procurement. This is not primarily a technology preference but a structural necessity arising from the design of CTBCM's Capacity Balancing Mechanism (CBM).

Under the CBM, every demand-serving entity; including DISCOs, Competitive Suppliers, and Bulk Power Consumers (BPCs) contracting directly; must maintain verified firm capacity sufficient to cover its peak demand during Critical Hours plus a planning reserve margin. Critical Hours are typically the 50 to 100 most stressed hours of the system year, and they occur almost universally during evening peak demand windows from 18:00 to 22:00; when solar irradiance is zero and wind output is temporally unpredictable [9].

2.2. Firm Capacity Requirements Under the CBM

The Annual Capacity Requirement (ACR) for any demand participant is calculated as follows [9]:

$$\mathbf{ACR = PD \times (1 + PL) \times (1 + RM) - - - (5)}$$

ACR = Annual Capacity Requirement (MW)

PD = Average peak demand during Critical Hours, referenced to the transmission system (MW)

PL = Average transmission losses (fraction)

RM = Minimum planning reserve margin (fraction)

To illustrate: a BPC with 14.6 MW peak demand, 3% transmission losses, and a 16% reserve margin must secure:

ACR = 14.6 × 1.03 × 1.16 = 17.44 MW (Illustrative)

The BPC's net capacity position; the Capacity Balance (CB); determines whether it has a surplus to sell or a deficit to cover:

$$\mathbf{CB_i = AAC_i - ACR_i + CP_i - CS_i - - - (6)}$$

AAC_i = Actual Available Capacity during Critical Hours (MW)

CP_i = Firm capacity purchased in registered bilateral contracts (MW)

CS_i = Firm capacity sold through bilateral contracts (MW)

A negative CB indicates a capacity deficit, requiring the BPC to purchase capacity at the market-clearing price in the CBM, capped at 80% of the Levelized Fixed Cost of the reference technology (typically a gas turbine at approximately Rs. 4.8 million per MW per year at current reference values) [9].

2.3. The VRE Firm Capacity Problem

The commercial consequence of CBM design for VRE procurement is stark. Under the current framework:

- Standalone solar plants receive an Actual Available Capacity (AAC) credit of 0% during Critical Hours. The plant produces no power between 18:00 and 22:00.
- Standalone wind plants receive only 5 to 10 % AAC credit due to geographic and temporal variability. A 100 MW wind project may contribute as little as 5 MW toward a BPC's ACR.

- In both cases, the contracting BPC's full ACR remains as an unmet deficit unless supplementary firm capacity is procured through other means; either by purchasing capacity in the CBM or by securing a BESS-backed supply contract.

Without BESS, a BPC contracting with a 100 MW solar generator for its entire energy requirement would still carry 17.44 MW of unmet ACR in the example above, requiring annual CBM settlement payments at the capacity price. This adds a recurring cost to the bilateral contract that is invisible in a pure energy-price comparison but material to total procurement economics [9].

2.4. BESS and the Hybrid Firm Capacity Credit

A BESS co-located with a VRE generator can store energy during daytime generation periods and discharge it during Critical Hours, converting intermittent generation into semi-firm dispatchable capacity. The Actual Available Capacity credit for a hybrid VRE-BESS facility is calculated as [9]:

$$\boldsymbol{AAC_{hybrid}} = \left(\frac{\mathbf{1}}{\boldsymbol{N_{CH}}}\right) \times \sum \left[\boldsymbol{P_{VRE,t}} + \boldsymbol{P_{BESS,dis,t}} - \boldsymbol{P_{BESS,chg,t}}\right] \;\; \boldsymbol{for\ t} \in \boldsymbol{CH} - - - (7)$$

N_{CH} = Total number of Critical Hours

$P_{VRE,t}$ = Direct VRE injection at hour t (MW)

$P_{BESS,dis,t}$ = BESS discharge power at hour t (MW)

$P_{BESS,chg,t}$ = BESS charging power at hour t (MW); should be zero during Critical Hours

A key constraint governs the credited capacity. To claim 100 percent of the battery's nameplate power as firm capacity, the BESS must discharge continuously at its rated output for the full Critical Hour block. Where the battery's discharge duration is shorter than the critical window, credited capacity is proportionally reduced:

$$\boldsymbol{AAC_{credited}} = \boldsymbol{P_{BESS,rated}} \times \left(\frac{\boldsymbol{T_{BESS}}}{\boldsymbol{T_{CH}}}\right) [\boldsymbol{where\ T_{BESS}} < \boldsymbol{T_{CH}}] - - - (8)$$

T_{BESS} = Battery discharge duration at rated power (hours)

T_{CH} = Length of Critical Hour block (typically 2 or 4 hours)

Example: A 10 MW BESS with 2-hour storage, assessed against a 4-hour Critical Hour block, receives a firm capacity credit of 10 × (2/4) = 5 MW; not 10 MW. **Figure 5** (presented below) applies **Equation 8** for a 10 MW BESS under two Critical Hour window scenarios.

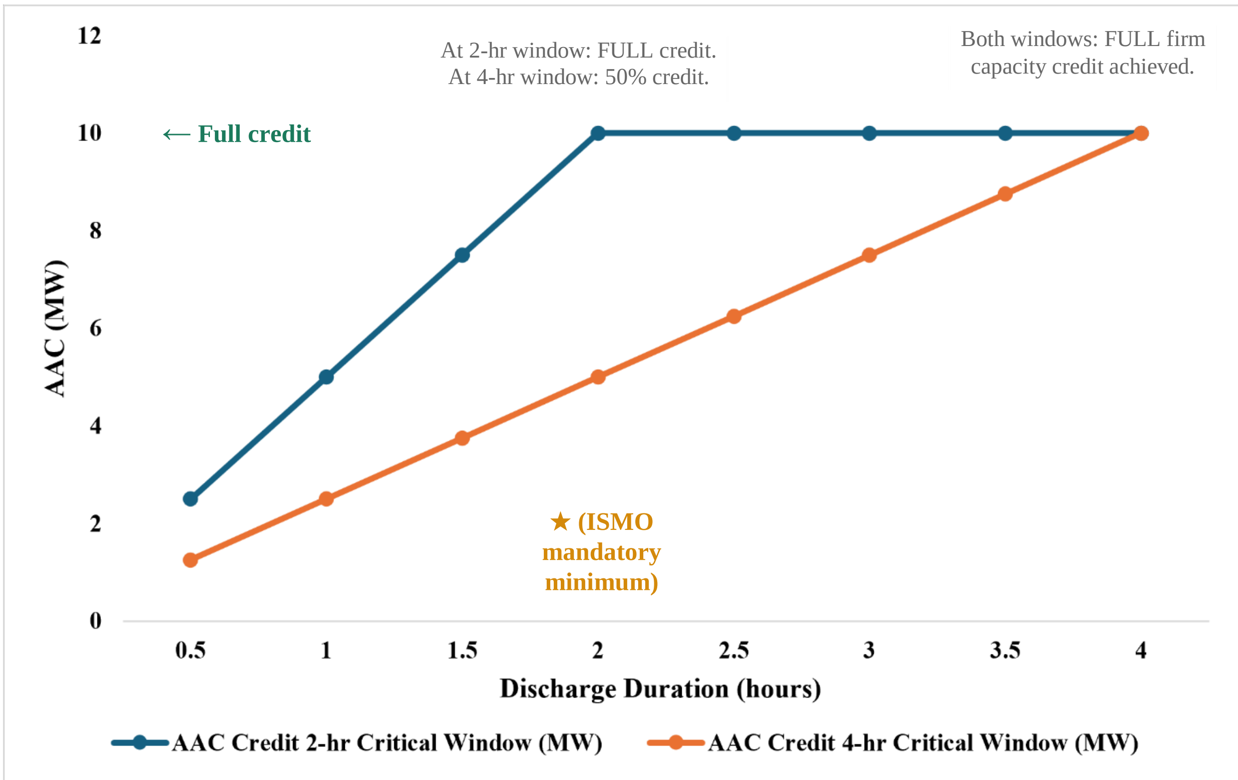

Figure 5: BESS firm capacity credit vs discharge duration for a 10 MW BESS under 2-hour and 4-hour Critical Hour window scenarios

2.5. ISMO's Three Considerations and the Post-Consultation Decision

During the May 2026 consultative process, ISMO evaluated three approaches to BESS requirements in wheeling auctions, as shown in **Table 9**:

Table 9: ISMO's evaluation of BESS integration options and the adopted post-consultation mandatory minimum rule

Option	Approach	Primary Limitation	Outcome
Option 1	Voluntary storage integration; allocation based on lowest LCOE of generation asset	Does not resolve node congestion; VRE wins allocation then faces curtailment	Rejected; fails grid reliability objective
Option 2	Mandatory large storage: 30–50% of nameplate to shift full solar midday block to evening peak	CAPEX too high; bilateral project LCOE uncompetitive; IRRs fall to 3–4%	Rejected; commercially unviable
Option 3	Optimized capacity-to-duration matrix: congestion relief + storage ratio + substation thermal rating	Technically optimal but creates investor uncertainty; unpredictable node-specific scaling formula	Rejected post-consultation despite technical merit
Final Rule	**Mandatory minimum: 10% of plant nameplate as BESS power + 2-hour minimum discharge duration**	Balances grid security with commercial predictability; simple, formula-based rule	**ADOPTED; post-consultation final rule, May 2026**

Source: ISMO BESS Consultation, May 2026 [10]

2.6. Investment Economics and the Round-Trip Efficiency Penalty

BESS co-location adds capital cost to a renewable energy project. However, the investment is commercially justified when the firm capacity credit it provides; and the associated reduction in CBM deficit exposure; are correctly valued [9,10].

A battery system with a round-trip efficiency of approximately 87 percent (typical for a DC-coupled lithium-ion installation) must receive more energy than it delivers. The generation requirement is:

$$Gen_{required} = \frac{Delivered_{energy}}{\eta_{RTE}} \quad - - - (9)$$

η_{RTE} = Round-trip efficiency (DC-coupled: 0.85–0.90; AC-coupled: 0.80–0.85)

This means approximately 115 MWh must be generated to deliver 100 MWh to the grid. The 15 MWh of generation absorbed by battery losses is borne by the generator unless the bilateral contract explicitly allocates it otherwise. Bilateral pricing must account for this efficiency penalty. A simplified payback analysis for the ISMO mandatory minimum BESS on a 100 MW solar project is presented in **Table 10**.

Table 10: Illustrative BESS investment economics for ISMO mandatory minimum co-location on a 100 MW solar project.

Parameter	Value	Basis
Plant nameplate capacity	100 MW	Illustrative
BESS power rating (ISMO 10% minimum)	10 MW	Post-consultation mandatory minimum
BESS energy capacity (2-hour minimum)	20 MWh	10 MW × 2 hours
BESS CAPEX (unit cost)	PKR 15-22.5M / MWh	Bulk supply estimate, 2025–26 market (illustrative, subsidized)
Total BESS CAPEX (base case)	**Rs. 360 Million**	20 MWh × Rs. 18M
Annual capacity deficit savings (10 MW × CBM price)	Rs. 48 Million/yr	10 MW × Rs. 4.8M/MW.year (price cap)
Annual SMP imbalance cost avoided (indicative)	Rs. 15–25 Million/yr	Based on partial-year stress exposure
Annual O&M (1.5% of CAPEX)	Rs. 5.4 Million/yr	Typical BESS O&M rate
Net annual benefit	**Rs. 57.6–67.6 Million/yr**	Capacity savings + SMP savings: O&M
Simple payback period	**5.3 – 6.3 years**	CAPEX ÷ net annual benefit

Source: ISMO BESS Consultation May 2026 [10]; How cheap is battery storage? Ember Energy Institute [11]

CBM capacity price illustrative at 0.8 × LFT = Rs. 4.8M/MW.yr. Payback period of 5–6 years is commercially viable at typical project lifetimes of 20–25 years. Based on **Table 10** (BESS investment economics for ISMO mandatory minimum on a 100 MW solar project); Net annual benefit = capacity deficit savings (Rs. 48M) + SMP savings (Rs. 15–25M) − O&M (Rs. 5.4M). Three CAPEX scenarios: Low (Rs. 300M / Rs. 15M per MWh), Base (Rs. 360M / Rs. 18M per MWh), High (Rs. 450M / Rs. 22.5M per MWh) are presented in **Figure 6**. At the base case (Rs. 57.6M annual net benefit), payback is 5.2–7.8 years against a typical 20-year battery project life; commercially viable at all three CAPEX levels [9,12].

$$\text{Annual net benefit} = \text{Capacity deficit savings (Rs. 48M)} + \text{SMP savings (Rs. 15} - \text{25M)} - \text{O\&M (Rs. 5.4M)}$$

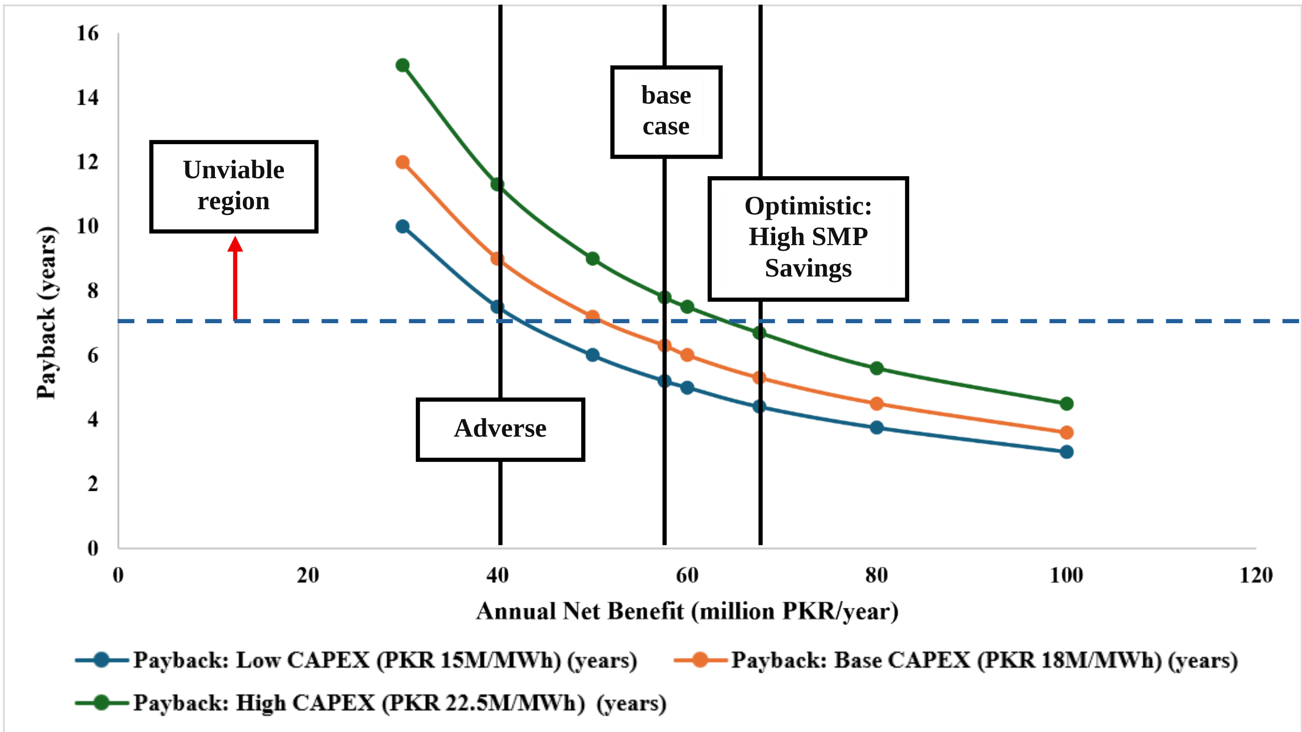

Figure 6: Financial Analysis: Illustrative Solar Project (100 MW)

Note: SMP savings are sensitive to exposure profile and should be modelled at facility level.

2.7. System Marginal Price (SMP): The Hidden Balancing Risk

Beyond the UoSC floor, CTBCM participants face a second, less visible commercial exposure: *SMP risk under the Energy Balancing Mechanism (EBM)*. Under CTBCM, any mismatch between a participant's contracted supply and actual consumption is settled in real time at the SMP; the marginal cost of the most expensive generation unit dispatched at that hour. Unlike Grid Charges or Use of System Charges, SMP is not regulated, not negotiated, and not capped. It is determined by real-time system conditions [12].

In April 2026, the SMP for a single hour reached **Rs. 94 per kWh**; verified by ISMO official data [13]. This figure, nearly four times the prevailing off-peak tariff, is not an anomaly. It reflects a structurally thermal-dominated system with imported fuel exposure, seasonal demand peaks, and persistent supply-side volatility. Firms entering CTBCM without an explicit SMP risk management strategy are, in effect, exposing part of their energy cost to an uncapped spot market. **Table 11** shows the impact of SMP exposure risk in an illustrative 10 MW bilateral contract.

Assumptions: 10 MW bilateral contract. Imbalance = % of contracted supply not matched. Operating hours = 720/month.

Table 11: SMP Imbalance Cost Scenarios: Illustrative for a 10 MW BPC

SMP Scenario	SMP (PKR/kWh)	Imbalance (5% = 0.5 MW)	Imbalance (10% = 1 MW)	Imbalance (20% = 2 MW)
Low: typical off-peak	20	Rs. 7,200/hr → Rs. 5.2M/month	Rs. 14,400/hr → Rs. 10.4M/month	Rs. 28,800/hr → Rs. 20.7M/month
Moderate: stress period	50	Rs. 18,000/hr → Rs. 13.0M/month	Rs. 36,000/hr → Rs. 25.9M/month	Rs. 72,000/hr → Rs. 51.8M/month
High: April 2026 actual	94	Rs. 33,840/hr → Rs. 24.4M/month	Rs. 67,680/hr → Rs. 48.7M/month	Rs. 135,360/hr → Rs. 97.5M/month

Source: ISMO official SMP data (April 2026) [13]; EBM settlement framework [9]

Note: Monthly costs assume imbalance persists for every operating hour; a worst-case planning assumption. Actual exposure depends on the half-hourly demand-generation match profile. The Rs. 94/kWh figure should be treated as a stress-scenario reference point for contract structuring, not an average.

Key risk drivers in Pakistan's context

- **Thermal dominance**: Pakistan's marginal unit is frequently an oil or gas plant; SMP reflects full imported fuel cost at peak hours
- **Seasonal extremes**: June–August peak demand, combined with hydro variability, consistently elevates SMP precisely when industrial production is highest
- **VRE evening mismatch**: Solar-contracted BPCs face systematic imbalance from 18:00 onwards when solar output falls but industrial load continues; BESS co-location directly mitigates this

2.8. DC-Coupled vs AC-Coupled Configurations

The physical configuration of BESS interconnection affects efficiency, round-trip energy loss, integrity of green attributes, and settlement treatment. The choice has commercial implications for bilateral contract pricing and renewable energy certification. DC-coupling is preferred for bilateral renewable contracts where green attribute integrity is required for international buyer compliance. **Table 12** shows the comparison between DC-coupled vs AC-coupled BESS configurations.

Table 12: DC-coupled vs AC-coupled BESS configurations

Parameter	DC-Coupled	AC-Coupled
Integration point	Behind the solar inverter (DC bus)	At the pooling station (AC side)
Round-trip efficiency	**85–90% (higher)**	80–85% (lower)
Clipped energy capture	Yes; captures inverter-clipped generation	No; cannot capture DC-side clipping
Charging source	Co-located generation only	Co-located generation or grid
Green attribute for discharged energy	**100% renewable; fully retained**	Only co-located RE portion; grid-charged energy is not RE
Preferred for	RE100 compliance, SBTi, corporate PPAs	Flexibility and demand-shifting strategies

Source: ISMO BESS Consultation, May 2026 [10]

2.9. Policy Recommendations: BESS

1. Treat the 10% BESS Requirement as a Minimum Threshold Rather than a Fixed Target

The mandatory 10% BESS power rating with a minimum two-hour discharge duration should be explicitly defined as the **minimum qualifying requirement**, rather than the optimum design. Developers proposing higher storage capacities or longer discharge durations should receive additional evaluation credit during competitive allocation. Such an approach preserves investment flexibility while encouraging voluntary deployment of storage where economically justified and systemically beneficial.

2. Publish Critical Hour Window Requirements Before Each Auction

Because firm capacity credit is directly proportional to the ratio between battery discharge duration and the Critical Hour window (Equation 8), ISMO should publish the applicable Critical Hour duration (e.g., two or four hours) before each procurement round. Early disclosure would enable developers to optimize battery sizing, accurately estimate accredited capacity, and reduce bid uncertainty.

3. Establish a Standardized Annual BESS Performance Verification Framework

Long-term project finance requires certainty regarding capacity accreditation throughout the asset life. ISMO should therefore publish a transparent annual testing methodology covering battery degradation, state-of-health assessment, availability requirements, and adjustment factors used in calculating accredited firm capacity. Standardized verification procedures would improve lender confidence and facilitate lower financing costs.

4. Clarify Commercial Treatment of Battery Efficiency Losses

Although battery round-trip efficiency losses are unavoidable, current market documents provide limited guidance regarding their commercial allocation. The Market Commercial Code should explicitly specify whether charging losses, auxiliary consumption, and round-trip efficiency penalties are borne by the generator, the buyer, or allocated proportionally between contracting parties. Standard contractual provisions would minimize commercial disputes and improve pricing transparency.

5. Develop Dedicated Grid Connection Standards for Hybrid Renewable–BESS Projects

Current interconnection procedures were primarily designed for conventional generation. ISMO should issue a dedicated BESS addendum to the Connection Process (Annex XXIV) covering hybrid facility metering arrangements, operational dispatch requirements, settlement categorization, communication protocols, and grid-code compliance [14]. A technology-specific framework would reduce project approval timelines and improve implementation consistency.

6. Standardize SMP Risk Allocation in Bilateral Contracts

The analysis demonstrates that System Marginal Price (SMP) exposure can substantially affect project economics during balancing periods. ISMO should therefore publish a model SMP risk allocation clause as part of the standard bilateral contract documentation (Annex XIV) [15]. The clause should clearly define responsibility for imbalance charges, settlement thresholds, exposure limits, and force majeure treatment. Standardization would reduce contractual uncertainty and improve investor confidence while promoting more consistent market practice.

Conclusion

Pakistan's Competitive Trading Bilateral Contract Market has reached an important milestone. The legislative framework has been enacted, the Independent System and Market Operator has been established, and the first competitive renewable wheeling auction is being prepared. Unlike earlier reform efforts that focused primarily on institutional restructuring, the current challenge is no longer whether a competitive electricity market can legally exist, but whether its commercial design is capable of attracting sustained private investment and delivering affordable, low-carbon electricity to industrial consumers.

The analysis presented in this policy brief suggests that the overall market architecture is fundamentally sound. Under the proposed UoSC framework, competitively procured renewable electricity remains economically attractive across a wide range of realistic bilateral energy prices when compared against prevailing industrial B-4 tariffs. While the combined effect of UoSC, Debt Service Surcharge, and transmission loss adjustments creates a significant cost floor, current modelling indicates that meaningful savings remain achievable for industrial consumers, particularly where competitively priced renewable generation can be secured. Consequently, the principal policy concern is no longer the absolute level of the proposed wheeling charge, but the long-term predictability of non-network charges and the preservation of cost-reflective market signals that support investor confidence.

The findings also demonstrate that Battery Energy Storage Systems are becoming a structural component of competitive renewable procurement rather than an optional technology. The mandatory minimum requirement of *10% nameplate storage with a two-hour discharge duration* appropriately balances system reliability with commercial practicality. The resulting firm-capacity benefits, reduced Capacity Balancing Mechanism exposure, and mitigation of System Marginal Price volatility substantially improve the value proposition of renewable projects. With estimated payback periods of approximately *5–8 years* against expected project lives exceeding 20 years, storage investment appears commercially justified under the current framework, provided that regulatory treatment of capacity accreditation, efficiency losses, and settlement obligations remains transparent and predictable.

The transition from regulatory reform to successful market implementation will ultimately depend on policy certainty rather than additional regulation. Transparent methodologies for determining Use of System Charges, stable treatment of Debt Service Surcharge obligations, clearly defined Critical Hour requirements, standardized Battery Energy Storage System verification procedures, dedicated hybrid interconnection standards, and well-defined allocation of balancing risks within bilateral contracts will collectively improve project bankability and reduce commercial uncertainty. These measures do not fundamentally alter the CTBCM framework; rather, they strengthen its credibility and improve the confidence of investors, lenders, and industrial consumers participating in the market.

CTBCM represents more than a new electricity trading mechanism. It provides Pakistan with an opportunity to accelerate renewable energy deployment, reduce industrial electricity costs, enhance export competitiveness, and improve energy security through private investment rather than public expenditure. As implementation progresses through the first competitive auctions, maintaining regulatory consistency and commercial transparency will be critical. Decisions taken during this initial phase are likely to shape investor confidence and market behavior for years to come, making the successful execution of the current policy framework as important as the reforms that established it.

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