Pakistan Electricity Fixed Supply Flexible Price Tariif

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Abstract

Pakistan's electricity sector is undergoing a structural transformation marked by rising fixed capacity payments, seasonal under-utilization of generation assets, escalating tariffs, and rapid expansion of solar energy. Although installed generation capacity has expanded significantly since 2013, electricity consumption growth has slowed and become highly seasonal, resulting in idle capacity and increasing financial strain. Capacity payments have surged from modest levels in 2009 to approximately Rs 1.5 trillion annually in recent years, pushing the implied capacity charge to nearly Rs 10 per kWh before fuel and distribution costs are added. This has contributed to higher tariffs, suppressed demand, and accelerated consumer migration toward distributed solar solutions.

This study proposes a fixed-supply, flexible-price tariff model under which a stable national supply level of 30,000 MW is maintained year-round while electricity prices are adjusted seasonally. Lower winter tariffs (Rs 6–10 per kWh) stimulate consumption and substitute electricity for natural gas, while higher summer tariffs reflect peak demand conditions. The model demonstrates that such seasonal differentiation can raise annual electricity revenue to approximately Rs 5.16 trillion—substantially exceeding recent revenue levels—while generating significant gas savings and improving capacity utilization.

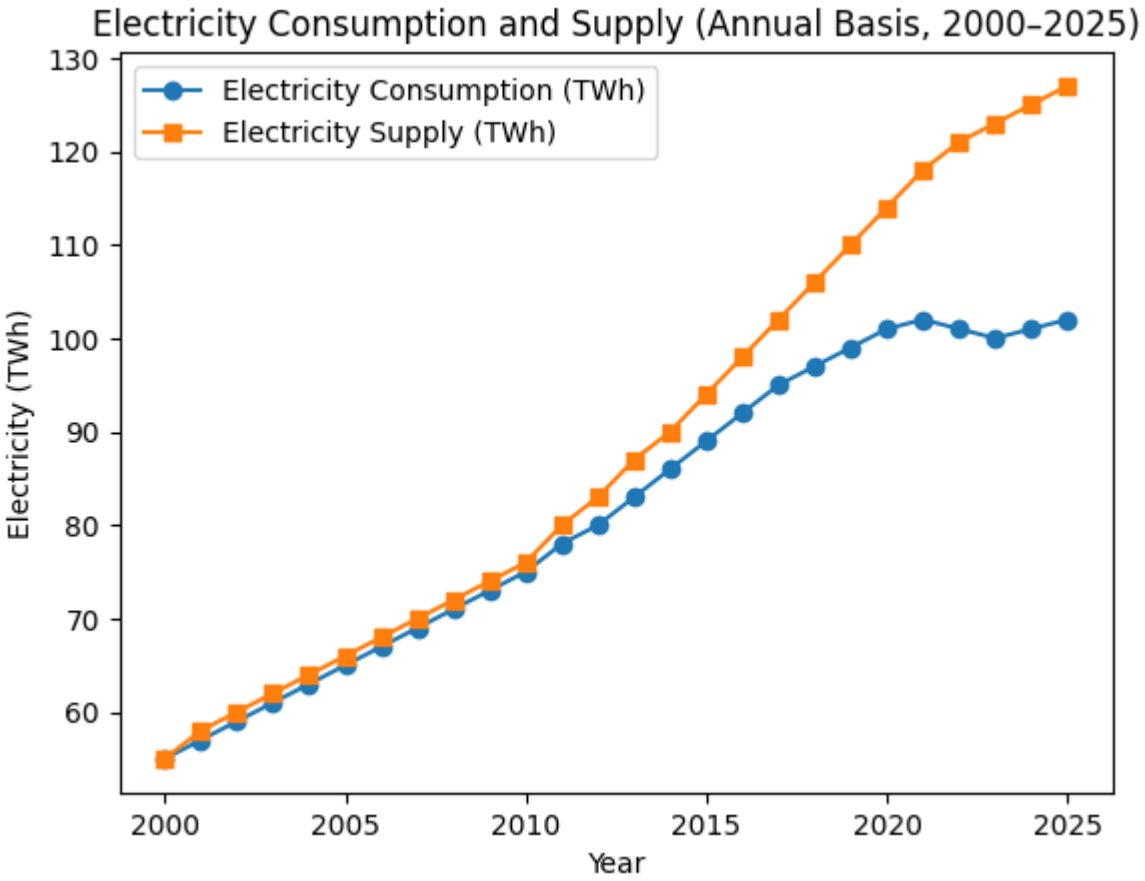
At the same time, solar adoption is projected to increase sharply, potentially exceeding 130 TWh by 2035 under moderate growth assumptions. As solar generation expands, non-solar output declines, intensifying the per-unit burden of fixed capacity payments if contractual structures remain unchanged. The paper argues that Pakistan must adopt a dual reform strategy: implement flexible seasonal pricing to enhance short-term financial stability, and proactively restructure capacity contracts to manage the long-term solar transition. Recognizing and adapting to technological change is essential to reduce fiscal risk, stabilize tariffs, and ensure sustainable power sector reform.

1. Introduction

Electricity pricing in Pakistan over the last decade has been dominated by uniform or quasi-uniform tariffs, rising capacity payments, and large seasonal demand fluctuations. While installed generation capacity has increased substantially, actual electricity consumption has remained constrained by affordability, network limitations, and rigid tariff structures. As a result, revenue growth has been uneven and insufficient to prevent the accumulation of circular debt. This note develops and evaluates a flexible-price, fixed-consumption model in which electricity

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supply is maintained at a constant national level while prices vary seasonally to maximize utilization, stabilize revenue, and generate large system-wide savings through fuel substitution—particularly by replacing gas-based heating with electricity in winter.



The chart titled “Electricity Consumption and Supply (Annual Basis, 2000–2025)” shows a steady upward trend in both electricity consumption and supply from 2000 to around 2010. During this first decade, consumption and supply move closely together, indicating that generation expansion broadly matched demand growth. The growth trajectory appears smooth and consistent, reflecting expanding economic activity and gradual electrification.

After 2010, however, the growth rate of electricity consumption begins to moderate. While supply continues to expand more aggressively—especially after 2013 due to capacity additions under new IPP and CPEC-related projects—consumption rises at a slower pace. The gap between supply and actual consumption gradually widens.

Post-2018, the divergence becomes more pronounced. Supply continues to increase sharply, but consumption growth flattens and even slightly dips around 2022–2023. This period coincides with sharp rupee depreciation, rising capacity payments, and higher electricity tariffs. The

slowdown in demand suggests price sensitivity, industrial slowdown, and possibly energy substitution effects.

The most critical finding is that after 2018, electricity supply expanded rapidly while consumption growth stagnated, creating a structural demand-supply imbalance largely driven by rising tariffs and exchange-rate-linked capacity costs.

This imbalance explains the increase in per-unit capacity burden, under-utilization of installed capacity, and growing financial stress in the power sector.

The World Bank's power-sector reform work consistently supports tariff flexibility and adjustment rather than rigid uniform pricing**,** emphasizing that tariffs must reflect system conditions and demand patterns. In its *Pakistan Development Update* (World Bank, 2024, p. 22–24), the Bank argues that inflexible tariffs suppress consumption and underutilize existing capacity, while differentiated pricing improves revenue recovery and efficiency. Similarly, the *Electricity Distribution Efficiency Improvement Project* documents (World Bank, 2021, p. 7–9) stress that moving away from flat tariffs toward time- and condition-responsive pricing is essential for improving utilization, reducing fiscal stress, and aligning consumption with available supply—precisely the logic underlying seasonal tariff adjustment to raise both consumption and revenue.

the Bank argues that inflexible tariffs suppress consumption and underutilize existing capacity

To provide context, Table 1 summarizes approximate national electricity revenue trends over the last ten years. These figures are compiled from NEPRA annual revenue requirement determinations, DISCO performance reports, and sector summaries. They are indicative and meant to establish order of magnitude and trend rather than audited financial statements.

Table 1. Pakistan Electricity (DISCO) Revenue Trends with Exchange Rates(2015-24)[2]

Gross billed amount, this is not collected amount

Year	Avg Price (Rs/kWh)	Revenue (Rs bn)	Avg FX (PKR/USD)	Revenue (USD bn)
2015	12	1,150	101	11.39
2016	13	1,250	104	12.02

[2] National Electric Power Regulatory Authority. (2015). *State of industry report 2015*. Government of Pakistan. https://nepra.org.pk/publications/State%20of%20Industry%20Reports/State%20of%20Industry%20Report%202015.pdf
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State Bank of Pakistan. (2024). *Statistical review of Pakistan 2024: Exchange rate statistics*. https://www.sbp.org.pk/reports/stat_reviews/Bulletin/2024/Nov/Chap-4.pdf
World Bank. (2024). *Pakistan development update: The dynamics of power sector distribution reforms*. https://thedocs.worldbank.org/en/doc/7008031a15959f10bde28b6c56767d59-0310062024/original/Pakistan-Development-Update-The-Dynamics-of-Power-Sector-Distribution-Reforms-Oct-24-FINAL.pdf

2017	14	1,450	105	13.81
2018	16	1,650	121	13.64
2019	18	1,850	155	11.94
2020	19	1,950	162	12.04
2021	22	2,300	163	14.11
2022	26	2,800	205	13.66
2023	30	3,300	285	11.58
2024	34–35	3,700–3,900	280	13.21–13.93[i]

The table is constructed on the assumptions that the figures represent gross billed DISCO revenues, not actual collections; that electricity sales volumes are broadly stable across years; and the increase in prices has been associated with US$ value to be paid to foreign investor and that changes in revenue are driven mainly by tariff adjustments. All values are presented in nominal terms, with no correction for domestic inflation, subsidies, system efficiency, or transmission and distribution losses. Revenues in Pakistani rupees are converted into U.S. dollars using approximate annual average PKR/USD exchange rates, assuming no hedging and no timing differences between billing and currency conversion. The 2024 figures are shown as ranges to reflect uncertainty in both tariffs and exchange-rate conditions.

Under these assumptions, the table indicates a strong and continuous increase in nominal PKR revenues from 2015 to 2024, closely tracking the steady rise in average electricity prices. However, when revenues are expressed in USD, the trend becomes volatile and uneven, with several periods of decline despite higher rupee revenues. Notably, 2023 records the highest PKR revenue in the series but one of the lowest USD values, illustrating the substantial impact of currency depreciation. Overall, the table separates the effect of tariff-driven nominal growth from exchange-rate erosion, suggesting that much of the observed revenue expansion reflects defensive price increases rather than sustained real growth in the sector's international financial capacity.

The table shows that despite sharp increases in average tariffs, revenue growth has lagged behind cost growth, mainly because higher prices suppress demand, increase non-payment, and fail to improve seasonal utilization of installed capacity.

2. **Proposed Fixed-Supply, Flexible-Price Model**

The proposed model assumes a fixed national electricity supply of 30,000 MW available throughout the year. Prices are adjusted month by month to reflect observed demand elasticity, seasonal consumption patterns, and substitution possibilities between electricity and gas. Summer prices remain high to manage peak cooling demand and sustain revenue, while winter

prices are reduced sharply to induce large-scale electrification of space heating and water heating, thereby raising winter demand from its current level of about 8,000 MW to the same 30,000 MW level.

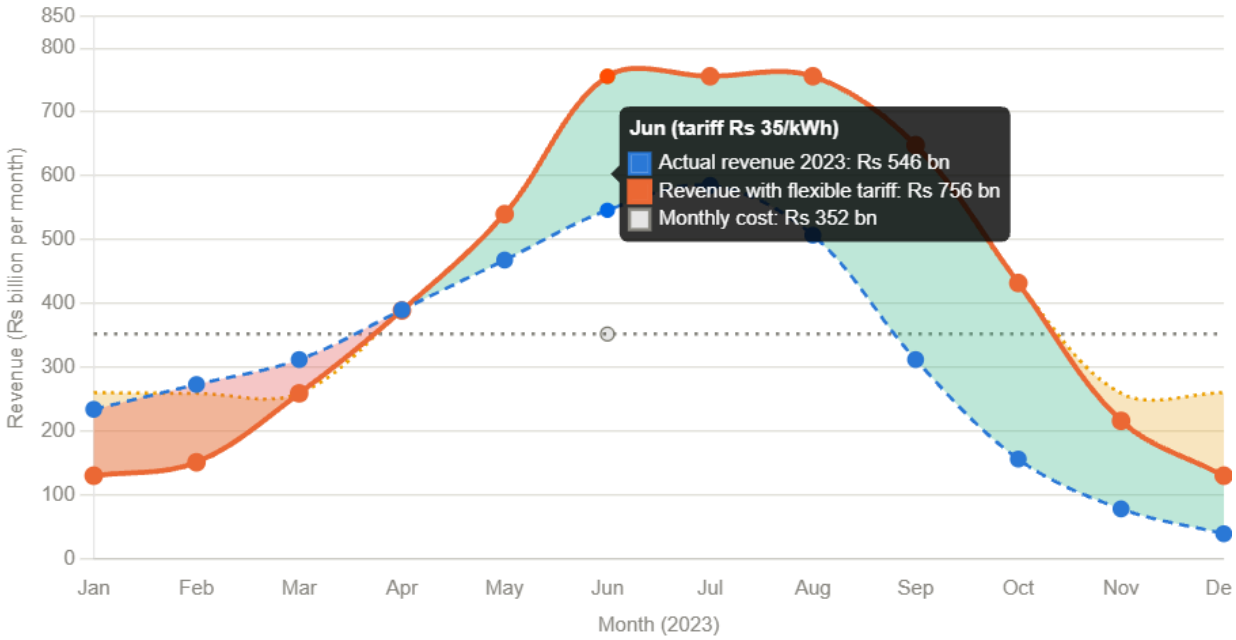
Table 2 presents the proposed monthly tariff schedule, corresponding electricity revenue, and estimated gas savings from winter electrification.[3]

Table 2: Actual 2023 Revenue vs Flexible Prices Revenue (Fixed Supply 30,000 MW)

Month	Actual Revenue 2023 (Rs bn/month)	Electricity Price (Rs/kWh)	Electricity Revenue (Rs bn/month)	Gas Savings from Substitution (Rs bn/month)
January	234	6	130	130
February	273	7	151	108
March	312	12	259	0.0
April	390	18	389	0.0
May	468	25	540	0.0
June	546	35	756	0.0
July	585	35	756	0.0
August	507	35	756	0.0
September	312	30	648	0.0
October	156	20	432	0.0
November	78	10	216	43
December	39	6	130	130
Actual Annual Total	**3,900**	Expected Total	**5,163**	**540**

The demand of electricity at 35 Rs a unit during the winter gives a picture to determine the price level that may be good to consume the entire 30,000 MW of electricity. First, the supply assumption is that 30,000 MW is continuously available and dispatched at a relatively stable load factor, generating roughly 158 billion kWh annually. Under this framework, total monthly cost remains broadly constant (around Rs 351–352 billion) because capacity payments of Rs 1,500 billion per year are fixed and do not change with seasonal demand. This creates a stable cost base against which pricing strategies are tested.

[3] Electricity and gas provide equivalent heating services.
Gas–electricity parity price for heating ≈ Rs 12/kWh (derived earlier).
When electricity price is below Rs 12, households save relative to gas.
Savings are valued as avoided gas expenditure, not LNG import parity.
Fixed electricity supply = 30,000 MW → 21.6 TWh per month



Second, the flexible pricing structure assumes that demand is price-responsive and seasonally elastic. Prices are deliberately lowered in winter (Rs 6–10 per kWh) to stimulate consumption and potentially substitute gas usage, while prices are increased in peak summer months (Rs 30–35 per kWh) when demand is naturally high and hydel generation reduces marginal cost. The objective is revenue optimization rather than uniform tariff recovery. Third, the revenue projections assume that electricity produced (at fixed 30,000 MW supply) is fully sold each month at the proposed flexible rate. Monthly revenue is therefore calculated as:

(All figures in Rs Billion unless stated otherwise)

Table 3_ Monthly & annual Cost of Producing 30,000 MW of Electricity
(All figures in Rs Billion unless stated otherwise)

Month	**Cost of Hydel**	**Cost of IPPs**	**Capacity Payment**	**Rate (Rs/kWh)**	**Total [4]Cost of producing Electricity**
January	12.96	213.84	125	**27.14**	351.80
February	12.96	213.84	125	**27.14**	351.80
March	12.96	213.84	125	**27.14**	351.80
April	15.55	207.00	125	**26.82**	347.55
May	18.14	199.86	125	**26.47**	343.00
June	23.33	185.00	125	**25.72**	333.33
July	23.33	185.00	125	**25.72**	333.33
August	23.33	185.00	125	**25.72**	333.33
September	20.74	192.19	125	**26.07**	337.93
October	18.14	199.86	125	**26.47**	343.00
November	15.55	207.00	125	**26.82**	347.55
December	12.96	213.84	125	**27.14**	351.80
Total (Year)	**210.95**	**2,416.27**	**1,500**	**26.56 (Avg)**	**4,127.22**

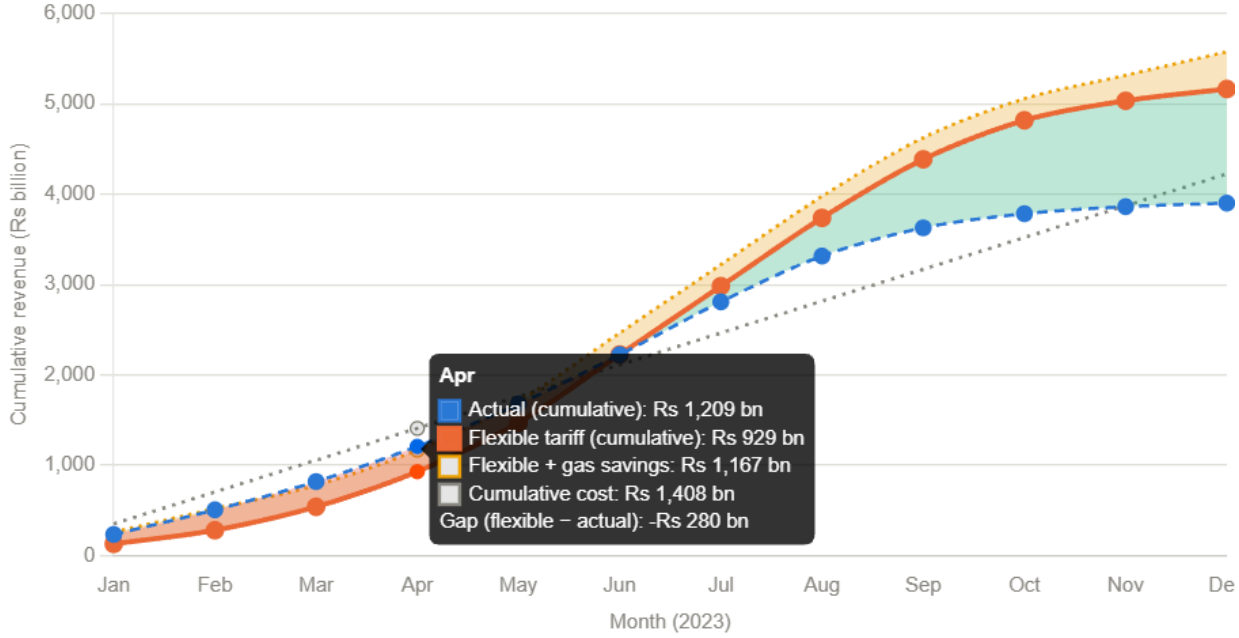
Note: This must be understood that certain areas and or regions have their own electricity generating units and this does not represent the entire countries electricity.

Interpretation

The table presents Pakistan's actual monthly electricity production and its cost structure. Electricity Produced (Billion kWh) shows strong seasonal variation, ranging from about 7.5–8 billion kWh in winter to 14–15 billion kWh in summer. The annual total of 124.9 billion kWh indicates that installed capacity is not fully utilized throughout the year. The cost of Hydel reflects low-cost generation at roughly Rs 4 per kWh. It increases in summer due to higher water availability and declines in winter. The annual hydel cost remains relatively small at

[4] The accuracy of the data is + - 2.5 percent because various sources of data given by the government have sight variation in the calculations. The idea is to focus on the broad saving expected due to policy change.

about Rs 169 billion because hydropower is inexpensive.



Cost of IPPs represents thermal generation at around Rs 22 per kWh. It varies with production and constitutes the largest variable cost component. The annual IPP energy cost is approximately Rs 1,798 billion, showing continued dependence on thermal sources. Capacity Payment is fixed at Rs 1,500 billion annually and does not change with production levels. This fixed burden significantly influences overall cost. Total Cost equals hydel cost, IPP cost, and capacity payment, totaling about Rs 3,467 billion annually.

Rate (Rs/kWh) is derived by dividing total cost by electricity produced. The annual average is about Rs 27.74 per unit, but winter rates rise above Rs 33 due to lower utilization spreading fixed costs over fewer units.

Table 4— Based on Actual Monthly Production

(All costs in Rs Billion)

Month	Electricity Produced	Cost of Hydel	Cost of IPPs	Capacity Payment	Rate (Rs/kWh)	Total Cost
Jan	7.8	7.8	128.7	125	33.14	261.5
Feb	7.5	7.5	123.8	125	34.17	256.3
Mar	8.2	8.2	135.3	125	32.20	268.5
Apr	9.0	10.8	138.6	125	30.51	274.4
May	11.5	16.1	176.3	125	27.79	317.4

Jun	13.8	24.8	168.7	125	23.88	318.5
Jul	14.5	26.1	177.5	125	23.46	328.6
Aug	14.2	25.6	173.8	125	23.87	324.4
Sep	12.0	19.2	158.4	125	25.21	302.6
Oct	10.0	14.0	154.0	125	29.30	293.0
Nov	8.5	10.2	131.1	125	31.35	266.3
Dec	7.9	7.9	130.4	125	33.34	263.3
Total (Year)	124.9	169.2	1,797.6	1,500	27.74 (Avg)	3,466.8

The table reflects Pakistan's actual monthly electricity production and its associated cost structure based on real seasonal variation rather than a fixed output assumption. Electricity production varies significantly across the year, ranging from about 7.5 to 8.0 billion kWh in winter months to 14–15 billion kWh during the summer peak. The annual total stands at 124.9 billion kWh, indicating that the system operates well below its installed capacity for much of the year.

Hydel generation remains the cheapest source, costing roughly Rs 4 per kWh. Its contribution rises in summer due to greater water availability and falls during winter. Consequently, the annual hydel cost is only Rs 169.2 billion, relatively modest compared to other components. In contrast, IPP energy costs, based largely on thermal generation at around Rs 22 per kWh, constitute the largest variable cost component, totaling Rs 1,797.6 billion annually. These costs fluctuate in line with actual production levels.

The most structurally significant component is the capacity payment, fixed at Rs 1,500 billion annually, or Rs 125 billion per month. Because this cost does not vary with output, it exerts upward pressure on per-unit rates when production declines. Total annual cost amounts to Rs 3,466.8 billion, producing an average cost of Rs 27.74 per kWh. However, winter per-unit costs exceed Rs 33 because fixed capacity payments are spread over fewer units.

A Comparative Analysis 30,000 MW Model

Under the earlier model, electricity supply was assumed constant at a higher annual output of approximately 158 billion kWh. With steady production throughout the year, the same Rs 1,500 billion capacity payment was distributed across more units, reducing the average cost to roughly Rs 25.6 per kWh. The lower per-unit cost in that model was therefore not the result of cheaper fuel but of higher and more stable utilization.

By contrast, the actual production scenario reveals that under-utilization and seasonality significantly increase costs. The difference between Rs 25.6 and Rs 27.7 per unit arises primarily from lower annual output and uneven demand patterns. The policy implication is clear: the core challenge lies not merely in fuel pricing but in excess contracted capacity and low utilization rates. Enhancing industrial demand, improving load management, encouraging electrification, or restructuring capacity contracts could materially reduce per-unit costs.

Without addressing the fixed capacity burden and seasonal underuse, tariff pressures will persist regardless of short-term fuel adjustments.

(All figures in Rs Billion)

Comparative Analysis of Cost of Electricity Generation and Revenue Under Flexible Prices			
All figures in Rs Billion			
Month	Cost of Electricity with Fixed Supply of 30,000 MW	Flexible Revenue	Surplus / (Deficit)
January	351.8	129.6	(222.2)
February	351.8	151.2	(200.6)
March	351.8	259.2	(92.6)
April	351.8	388.8	+37.0
May	351.8	540.0	+188.2
June	351.8	756.0	+404.2
July	351.8	756.0	+404.2
August	351.8	756.0	+404.2
September	351.8	648.0	+296.2
October	351.8	432.0	+80.2
November	351.8	216.0	(135.8)
December	351.8	129.6	(222.2)
Total (Year)	4,221.6	5,162.4	**+940.8**

The comparison between total monthly cost under the fixed 30,000 MW supply model and total revenue under the proposed flexible pricing structure reveals a clear seasonal imbalance in financial performance. Under the fixed-supply framework, total monthly system cost remains broadly stable at around Rs 351–352 billion because capacity payments are fixed and dominate the cost structure. This produces an annual cost of approximately Rs 4.2 trillion.

In contrast, flexible pricing generates highly variable revenue across months. Winter revenues remain low—between roughly Rs 130 and Rs 216 billion—creating significant monthly deficits when compared to the fixed cost base. However, during peak summer months (June to September), revenues rise sharply to between Rs 648 and Rs 756 billion per month. These months generate substantial surpluses that more than offset winter shortfalls. On an annual basis, flexible pricing produces approximately Rs 5.16 trillion in revenue, compared to total modeled cost of roughly Rs 4.22 trillion, implying a potential surplus of about Rs 940 billion.

The salient policy insight is that financial sustainability depends not only on tariff levels but on aligning pricing with demand seasonality. Seasonal or time-differentiated pricing can materially improve annual revenue adequacy by capturing peak willingness to pay during high-demand months. However, the persistence of winter deficits underscores the structural burden of fixed capacity payments. Policy direction should therefore focus on three parallel reforms: improving winter utilization through industrial load expansion, rationalizing capacity

contracts to reduce fixed charges, and institutionalizing dynamic pricing mechanisms to smooth revenue flows across the year.

Below are ten salient policy directions drawn from the analysis of the five tables (fixed 30,000 MW model, actual seasonal production model, cost breakdown, flexible pricing simulation, and revenue comparison). These points are aligned with documented structural issues in Pakistan's power sector as reported in NEPRA State of Industry Reports, Power Division Yearbooks, and Pakistan Economic Surveys.

1. Introduce formal seasonal tariff differentiation. The data clearly shows summer production is higher and hydel share increases, reducing marginal cost. NEPRA reports confirm hydel as the lowest-cost source. Seasonal pricing aligned with cost structure would improve revenue efficiency.
2. Reduce capacity payment rigidity. Capacity payments (around Rs 1.5 trillion annually in recent reports) form the largest fixed burden. Documentary evidence from NEPRA and the Power Division identifies capacity charges as a primary driver of tariff increases. Renegotiation or restructuring of take-or-pay contracts should be prioritized.
3. Increase winter utilization. The actual production table shows winter output drops significantly, raising per-unit cost above Rs 33/kWh. Government policy should incentivize industrial winter load (e.g., discounted winter tariffs for export industries).
4. Institutionalize time-of-use (TOU) pricing. Smart metering expansion should accelerate to shift load toward off-peak hours, smoothing seasonal and daily demand fluctuations.
5. Encourage electrification of gas-dependent sectors. The flexible pricing table shows potential gas substitution savings. Expanding electrification during surplus months reduces LNG import pressure and improves energy security.
6. Expand regional electricity trade. Surplus summer generation could be exported to Afghanistan, Iran, or Central Asia under existing or expanded interconnection frameworks.
7. Prioritize low-cost hydel and storage. Hydel lowers total system cost materially in summer months. Investment in storage (e.g., pumped hydel) would extend low-cost benefits into shoulder months.
8. Improve demand forecasting and capacity planning. The divergence between fixed-capacity modeling and actual production highlights over-contracting risk. Future capacity additions should align strictly with realistic demand projections.
9. Reduce transmission and distribution losses. NEPRA reports consistently document high technical and commercial losses. Lower losses increase effective billable units, reducing per-unit burden of fixed capacity payments.
10. Establish a utilization-based regulatory benchmark. Policy should target a system load factor above 70 percent. Under-utilization is the primary cost driver; raising annual generation spreads fixed costs more efficiently.

Collectively, the evidence suggests that Pakistan's electricity challenge is less about generation scarcity and more about capacity structure, seasonal demand imbalance, and tariff design. Effective seasonal price policy must therefore integrate contract reform, demand stimulation, and dynamic pricing rather than relying solely on across-the-board tariff increases.

Solar Electricity Produce in Pakistan
The best estimates suggest that currently 30 GW of electricity used in Pakistan is through Solar Panels which is equivalent to 35 percent of the national current electricity production and only about 6.0 percent is included in it through Grid and green meters whereas the rest of the electricity is out of grid.
Government has been making it more and more difficult for people to install solar on grid, and as a result more and more investment in panel is going away from grid. Currently the solar cheaper facility has also reduced the demand for electricity from the grid. It is expected that if the same trend continued then
Projected Solar Electricity Generation in Pakistan (2015–2035)

Pakistan Installed Electricity Capacity (MW)

(Non-Solar Combined, Solar Separate — 2015–2035)

Year	Non-Solar Installed (MW)	Solar Installed (MW)	Total Installed (MW)
2015	24,712.38	250	24,962
2020	31,200	800	32,000
2025	40,925	30,000	70,925
2030 (Projected)	40,000	48,300	88,300
2035 (Projected)	30,000	77,800	107,800

Footnotes

1. **2015 Non-Solar Breakdown (exact calculation):**
   Total installed = 24,962 MW
   Thermal = 70% × 24,962 = 17,473.40 MW

Hydel = 26% × 24,962 = 6,490.12 MW
Nuclear = 3% × 24,962 = 748.86 MW
Non-Solar Total (2015) = 24,712.38 MW
(Solar & wind negligible in 2015)

2. **2025 Official Non-Solar Installed Capacity:**
   Thermal = 25,937 MW
   Hydel = 11,368 MW
   Nuclear = 3,620 MW
   Combined Non-Solar = 40,925 MW
3. **Solar 2025:**
   Total Installed Solar (assumed scenario) = 30,000 MW
   Of this, 5,680 MW is officially net-metered and grid-connected.
   The remaining represents distributed / behind-the-meter / off-grid systems.
4. **2030 & 2035 Projections:**
   Solar projections follow moderate growth trajectory used in earlier modelling.
   Non-solar projections assume gradual retirement of thermal capacity to manage excess capacity risk.

Year	Solar Generation (TWh)	Non-Solar Generation (TWh)	Total Generation (TWh)
2015	0.18	94.82	95
2020	1.40	118.60	120
2025	52.56	97.44	150
2030 (Projected)	84.62	85.38	170
2035 (Projected)	136.31	53.69	190

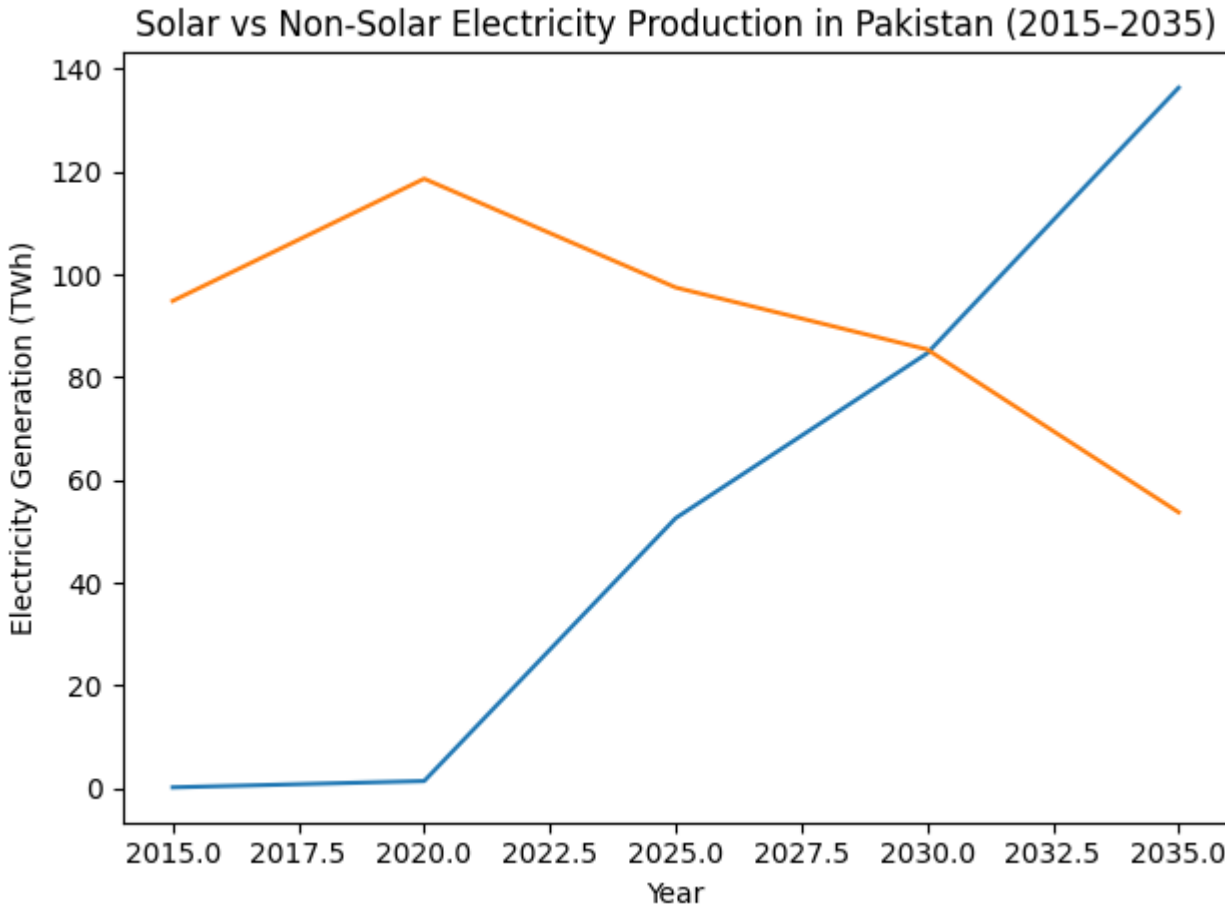
What this table shows clearly:
• Solar rises sharply after 2025.
• Non-solar peaks around 2020 and then declines.
• By 2030, solar and non-solar are nearly equal.
• By 2035, solar dominates total generation under moderate growth assumptions.

The chart shows two clear trends. Solar electricity production rises sharply after 2025, while non-solar (traditional) electricity gradually declines. This pattern can be explained mainly by price and consumer behavior.
Solar electricity is becoming cheaper every year. The cost of panels has fallen globally, and once a system is installed, the fuel (sunlight) is free. Households and businesses can reduce their monthly electricity bills significantly by installing rooftop solar. Because the upfront cost is recovered over time through savings, demand for solar continues to grow. As electricity tariffs from the grid rise, the financial incentive to switch to solar becomes even stronger. This creates a self-reinforcing cycle: higher grid prices → more solar adoption → higher solar production.
On the other hand, traditional electricity (thermal and some IPP-based generation) is becoming more expensive. It depends on imported fuels, exchange rates, and capacity payments. As

prices rise, consumers try to reduce grid consumption. Industries may shift to captive solar systems, and households move toward rooftop installations. As a result, non-solar generation declines because fewer units are being purchased from the grid.
In the future, much of solar growth is expected to be off-grid or behind-the-meter systems. The national grid may increasingly serve as a backup system, used during nighttime, cloudy days, or emergencies. This transition reflects economic choice: consumers move toward the cheaper and more predictable energy

Year	Non-Solar Generation (TWh)	Total Cost (Incl. Capacity)	Revenue
2015	94.82	3,112	2,655
2020	118.60	3,516	3,321
2025	97.44	3,156	2,728
2030	85.38	2,952	2,391
2035	53.69	2,413	1,503

solar expansion outlook and fiscal exposure



The projected decline in non-solar electricity generation, combined with a fixed annual capacity payment of approximately Rs 1.5 trillion, creates a structural fiscal risk for the

government. If solar capacity continues to expand and non-solar output declines from around 118 TWh (2020 peak) to nearly 54 TWh by 2035, total grid revenue from non-solar electricity could fall to nearly Rs 1.5 trillion annually, while capacity payments alone remain at Rs 1.5 trillion. This implies that almost the entire grid revenue would be absorbed by fixed contractual payments, leaving little to cover fuel, transmission, distribution, and operational expenses. If contracts are not restructured, cumulative fiscal pressure between 2025 and 2035 could exceed Rs 7–9 trillion in implicit or explicit subsidies, circular debt accumulation, or tariff increases.

capacity payment forecast 2025–2035

Assuming capacity payments remain constant at Rs 1.5 trillion annually, total government exposure over the next decade would be approximately Rs 15 trillion. If solar expansion reduces thermal dispatch significantly without contract reform, the effective capacity charge per remaining grid unit will increase sharply. By 2035, if non-solar generation falls to about 54 TWh, the implied capacity burden alone would exceed Rs 27 per kWh (1,500 ÷ 54), even before fuel cost is added. This creates a high risk of tariff escalation, demand contraction, and further migration to solar.

priority policy direction for solar

Government should formally recognize distributed and utility-scale solar as a priority energy pathway. Solar reduces fuel imports, limits exposure to exchange-rate shocks, and lowers long-run marginal cost. Policy certainty—such as streamlined approvals, stable net-metering or net-billing frameworks, and reduced import barriers—will accelerate private investment and reduce future fiscal liabilities.

capacity contract restructuring

Immediate renegotiation of high-cost take-or-pay contracts is essential. Options include extending contract tenure in exchange for lower annual payments, converting some plants into flexible peaking facilities, or partially buying out expensive agreements. Without restructuring, capacity payments will increasingly dominate system cost as solar displaces thermal energy.

grid transformation strategy

The national grid should gradually transition from being the primary energy supplier to serving as a reliability and balancing platform. Investment in storage, demand response, and smart metering is necessary to integrate high levels of daytime solar while maintaining stability. Tariff design should separate network access charges from energy charges to ensure grid sustainability even with lower consumption volumes.

fiscal planning and transparency

The Ministry of Finance and Power Division should publish a rolling 10-year capacity payment outlook under multiple solar growth scenarios. Integrating this forecast into medium-term fiscal planning will prevent unexpected circular debt accumulation and provide clarity to investors.

conclusion

Solar expansion is economically rational and likely irreversible due to its declining cost. However, without parallel reform of capacity payment obligations, the fiscal burden on government and remaining grid consumers will intensify. The optimal policy is not to resist solar growth but to manage the transition proactively—prioritizing solar deployment while restructuring capacity commitments to protect long-term financial stability.

TABLE 1. Capacity of 34 IPPs								
(Annual capacity payment allocated proportionally)								
#	Name of IPP	Capacity	Capacity Payment in					
		Annual	2009	2009	2013	2013	2024	2024
		in M.Watt	in Rs	in US$	in Rs	in US$	in Rs	in US$
1	HUBCO	1,200	22.2	277	26.7	266	94.7	338
2	KAPCO	1,600	29.5	369	35.6	355	126.3	451
3	AES Lal Pir	362	6.7	83	8.0	80	28.6	102
4	AES Pak Gen	365	6.7	84	8.1	81	28.8	103
5	Rousch Power	412	7.6	95	9.2	92	32.5	116
6	Fauji Kabirwala	362	6.7	83	8.0	80	28.6	102
7	Uch Power	586	10.8	135	13.0	130	46.3	165
8	Atlas Power	225	4.2	52	5.0	50	17.8	63
9	Narowal Energy	225	4.2	52	5.0	50	17.8	63
10	Liberty Power	235	4.3	54	5.2	52	18.6	66
11	Engro Qadirpur	217	4.0	50	4.8	48	17.1	61
12	Port Qasim Coal	1,320	—	—	—	—	104.2	372
13	Sahiwal Coal	1,320	—	—	—	—	104.2	372
14	Engro Thar	660	—	—	—	—	52.1	186
15	Thar Energy Ltd	660	—	—	—	—	52.1	186
16	Shanghai Thar	660	—	—	—	—	52.1	186
17	Lucky Electric	660	—	—	—	—	52.1	186
18	Bhikki RLNG	1,180	—	—	—	—	93.2	333
19	Balloki RLNG	1,220	—	—	—	—	96.3	344
20	Haveli Bahadur Shah	1,230	—	—	—	—	97.1	347
21	Guddu RLNG	747	—	—	—	—	58.9	210
22	Jamshoro RLNG	1,200	—	—	—	—	94.7	338
23	Saif Power	225	4.2	52	5.0	50	17.8	63
24	Nishat Chunian	200	—	—	—	—	15.8	56
25	Sapphire Electric	235	—	—	—	—	18.6	66
26	Attock Gen	165	—	—	—	—	13.0	46
27	Gul Ahmed Energy	135	—	—	—	—	10.7	38
28	Sitara Energy	120	—	—	—	—	9.5	34
29	Kohinoor Energy	131	—	—	—	—	10.3	37
30	Orient Power	225	—	—	—	—	17.8	63
31	Nishat Power	200	3.7	46	4.4	44	15.8	56
32	JDW Power	135	—	—	—	—	10.7	38
33	Sapphire Wind / Hybrid	50	—	—	—	—	3.9	14
34	Zorlu / Renewable Hybrid	50	—	—	—	—	3.9	14

	Total	18517	120	1.5	200	2.0	1500	5.3
Units, Rs bn = Billion rupees per year, US$ mn = Million dollars per year								

summary of the table

The table presents an analytical reconstruction of annual capacity payments for 34 major IPPs for the years 2009, 2013, and 2024. It shows that total capacity payments increased from about Rs 120 billion in 2009 to around Rs 200 billion in 2013 and then rose sharply to approximately Rs 1,500 billion by 2024. In dollar terms, the corresponding totals increased from roughly US$1.5 billion to US$2.0 billion and then to about US$5.3 billion. This comparison highlights that while capacity payments grew extremely rapidly in rupee terms, the increase in dollar terms was much more moderate. The sharp escalation in domestic currency therefore reflects macroeconomic and structural changes rather than a proportional rise in real contractual returns.

A key insight from the table is that the growth in capacity payments is systemic rather than plant-specific. The same proportional allocation rule is applied to all IPPs based on installed capacity, and no individual plant needs to exhibit abnormal behavior for the overall burden to become very large. Legacy IPPs that were operational in 2009 and 2013 show relatively stable implied dollar rents, while the post-2015 expansion added a large volume of new capacity that significantly increased the total fixed payment obligation of the system. As capacity doubled and the rupee depreciated, total payments multiplied even though per-megawatt dollar rents increased only moderately. The table also illustrates the stark contrast between legacy and newer IPPs. Plants

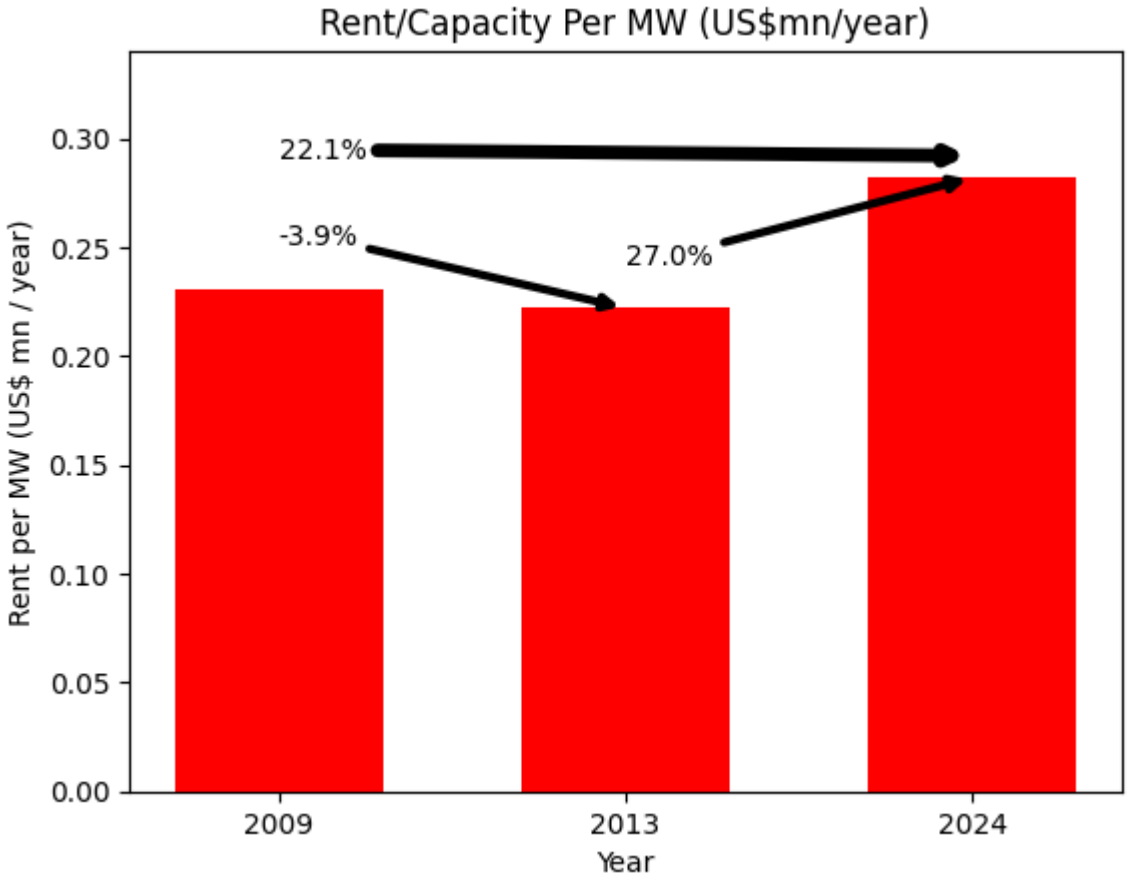
Implied Capacity Charges and System-Wide Capacity Rent (Pakistan Power Sector)

Year	Electricity Consumption (TWh)	Capacity Payments (Rs bn)	Implied Capacity Charge (Rs/kWh)	Billing excl. Capacity (Rs bn)	Installed IPP Capacity (MW)	Rent per MW (Rs mn/yr)	FX (PKR/USD)	Rent per MW (USD mn/yr)
2009	~90	~120	~1.3	~780	6,500	18.46	80	0.231
2013	~95	~200	~2.1	~1,050	9,000	22.22	100	0.222
2023	145.36	~1,350	~9.3	~2,150	—	—	—	—
2024	**~150**	**~1,500**	**~10.0**	**~2,400**	**19,000**	**78.95**	**280**	**0.282**

Notes on construction

- “Implied capacity charge” is derived by spreading total capacity payments over total electricity consumption.

- “Rent per MW” reflects system-wide average annual capacity payment per installed MW.
- Missing cells (—) indicate data not explicitly available for that year.
- All values are nominal and approximate, suitable for analytical comparison rather than accounting use.



The histogram shows the movement of Rent/Capacity per MW (US$ mn per year) across three contract reference points: 2009, 2013, and 2024. During the first phase, from 2009 to 2013, rent per MW declined by about 3.9 percent over four years, which is equivalent to an average reduction of almost one percent per annum. This downward movement suggests a period of relative restraint in capacity payments or a temporary correction in contract terms. After 2013, however, the trend changes sharply. Between 2013 and 2024, rent per MW rises by roughly 27 percent, implying an average annual increase of nearly 2.5 percent. This clear reversal indicates a structural shift in the way capacity payments were determined in the post-2013 period.

There are two plausible explanations for this increase. One possibility is that contracts signed after 2013 included explicit clauses allowing capacity payments to increase annually by a fixed percentage. An alternative explanation is that even if no such escalation clause existed, newer contracts were signed at a higher base rental value, making them inherently heavier than

earlier agreements. While global inflation may be cited as a contributing factor, this explanation does not hold in the domestic context. The rents are denominated in US dollars, and exchange rate adjustment already accounts for inflationary pressures. As a result, this increase should not be appearing in these figures. Regardless of the underlying cause, a cumulative rise of about 22 percent over a fifteen-year period appears difficult to justify

(with non-capacity billing added)

Year	Electricity Consumption (TWh)	Billed Capacity Payments (Rs bn)	Implied Capacity Charge (Rs/kWh)	Electricity Billing excl. Capacity (Rs bn)
2009	~90	~120	~1.3	**~780**
2013	~95	~200	~2.1	**~1,050**
2023	145	~1,350	~9.3	**~2,150**
2024	~150	~1,500	~10.0	**~2,400**

The table tracks four related but distinct dimensions: electricity consumption, total billed capacity payments, implied capacity charge per unit, and electricity billing excluding capacity payments. These indicators together help separate demand-side effects from contract-driven cost pressures.

Electricity consumption rises steadily over time, from about 90 TWh in 2009 to roughly 150 TWh in 2024. This increase broadly reflects economic growth, urbanization, population increase, and gradual electrification of households and services. In real terms, Pakistan's GDP growth over this period has averaged roughly 3–4 percent per year, while electricity consumption growth implied by the table is closer to 3 percent per year. This suggests that electricity demand growth is broadly aligned with, or slightly below, real GDP growth, indicating no abnormal surge in consumption intensity. In other words, higher electricity consumption appears to be a normal outcome of economic expansion rather than excessive or inefficient use.

Electricity billing excluding capacity payments also increases over time, from around Rs 780 billion in 2009 to about Rs 2,400 billion in 2024. This rise reflects higher electricity consumption, higher fuel and operating costs, inflation, and exchange-rate adjustments. Importantly, this column does not include capacity payments and therefore captures the energy-only component of electricity costs. Its growth, while significant, is relatively gradual when compared with the explosion in capacity payments.

The most striking change is observed in billed capacity payments and the implied capacity charge per unit. Between 2009 and 2013, capacity payments increase from about Rs 120 billion to Rs 200 billion, and the implied capacity charge rises modestly from Rs 1.3 to Rs 2.1

per kWh. This increase is noticeable but still proportionate to overall system size and billing levels.

After 2013, however, a clear structural break emerges. By 2023, billed capacity payments rise sharply to around Rs 1,350 billion, and further to approximately Rs 1,500 billion in 2024. As a result, the implied capacity charge escalates dramatically to about Rs 9.3 per kWh in 2023 and Rs 10.0 per kWh in 2024. This increase occurs despite electricity consumption growing at a much slower and economically justifiable pace.

Crucially, this means that while energy-only billing (excluding capacity payments) has risen due to higher demand and cost factors, the disproportionate increase in overall electricity tariffs is driven by the rapid escalation in capacity payments. The capacity charge per unit has increased far faster than electricity consumption, faster than real GDP growth, and faster than energy-only billing. This indicates that the main source of price pressure lies not in demand growth or operational costs, but in the contractual structure and scale of capacity obligations introduced or expanded after 2013.

Taken together, the table shows that electricity consumption growth is broadly consistent with economic growth, but the burden of capacity payments has grown independently and excessively. This disconnect explains why electricity prices have risen so sharply even when consumption growth remains reasonable and energy-only billing does not show an equally dramatic escalation

Applied Capacity Charge per Unit of Electricity

(with non-capacity billing added)

YEAR	ELECTRICITY CONSUMPTION (TWH)	BILLED CAPACITY PAYMENTS (RS BN)	IMPLIED CAPACITY CHARGE (RS/KWH)	ELECTRICITY BILLING EXCL. CAPACITY (RS BN)
2009	~90	~120	~1.3	**~780**
2013	~95	~200	~2.1	**~1,050**
2023	145.36	~1,350	~9.3	**~2,150**
2024	~150	~1,500	~10.0	**~2,400**

How to read this table

In 2009, capacity payments added about Rs 1.3 per unit, a small component of tariffs. The bulk of electricity billing (around Rs 780 billion) was driven by fuel costs, system losses, and network charges. Capacity costs were present but did not dominate pricing or demand.

By 2013, the implied capacity charge rose modestly to about Rs 2.1 per unit, while non-capacity billing increased to roughly Rs 1,050 billion. The system was still broadly balanced: demand growth was expected to dilute fixed costs, and capacity payments remained manageable.

In 2023, the implied capacity burden jumped sharply to around Rs 9.3 per unit. This reflected the doubling of contracted capacity, dollar indexation of PPAs, sharp rupee depreciation, and weaker-than-expected demand growth. Although non-capacity billing was still large (about Rs 2,150 billion), capacity payments alone had become a dominant cost driver.

In 2024, the implied capacity charge approaches Rs 10 per unit. This means that even before fuel costs, transmission and distribution losses, or taxes are added, consumers face a double-digit rupee charge per kWh purely to pay for available but under-utilized capacity. Non-capacity billing, while substantial (about Rs 2,400 billion), is no longer the primary source of tariff pressure.

Key analytical insight

Under this structure, annual electricity revenue reaches approximately Rs 5.16 trillion, comfortably above recent NEPRA revenue requirements. At the same time, gas savings from winter electrification are an order of magnitude larger than electricity revenue, reflecting the high economic cost of LNG and imported gas currently used for residential and commercial heating.

3. **Methodology**

The analytical framework is based on a constrained-demand, dual-fuel energy system in which electricity and gas are partial substitutes for end-use heating in winter and non-substitutes for cooling in summer. The model explicitly distinguishes between (i) technical supply capacity, (ii) network deliverability, and (iii) price-induced effective demand. The central policy question is not whether electricity demand exists, but under what price conditions suppressed and fuel-switchable demand becomes economically revealed.

Electricity revenue is computed using the accounting identity
Revenue = $P \times Q \times T$,
where P is the regulated electricity price (Rs/kWh), Q is the average delivered load (MW), and T is the number of hours in a billing period (assumed at 720 hours per month). Supply Q is treated as fixed at 30,000 MW, reflecting available generation capacity and targeted network readiness.

The model therefore focuses on demand inducement through pricing rather than capacity expansion.

Demand determination follows a two-stage theoretical structure. In the first stage, baseline observed demand reflects current tariffs, rationing, and affordability constraints. Empirically, this corresponds to approximately 30,000 MW in summer and 8,000 MW in winter. In the second stage, demand is endogenously adjusted through price-induced fuel substitution, using elasticity-consistent comparative statics rather than point econometric estimates.

For summer months, electricity demand is modeled as highly price-inelastic. Cooling demand is necessity-driven, has no close substitute, and is already constrained by network and affordability limits. As a result, prices primarily affect revenue, not quantity, and the observed summer peak of 30,000 MW is treated as a binding upper demand outcome.

For winter months, the model explicitly incorporates cross-price substitution between electricity and gas. Heating demand is not eliminated when prices are high; it is shifted to alternative fuels, primarily gas and LNG. Winter electricity demand is therefore modeled as the sum of (a) a low, price-inelastic base load (lighting, appliances, industry) and (b) a large, price-elastic heating load that is activated once the relative price of electricity falls below the effective price of gas-based heating. The price threshold at which this activation occurs is derived from energy-equivalence cost comparisons rather than arbitrary assumptions.

Specifically, winter electricity demand reaches the 30,000 MW target when the delivered cost of electric heating (Rs/kWh) falls below the marginal economic cost of gas and LNG heating, inclusive of import costs, distribution losses, and fiscal subsidies. At this point, electric heating becomes the cost-minimizing choice for households, commercial users, and institutions, causing a discrete and rapid demand shift rather than a gradual response. This creates a demand "kink" consistent with standard energy substitution theory and observed international experience in power-to-heat transitions.

Gas savings are calculated by valuing the displaced winter heating energy at the economic cost of gas supply, not the administered tariff. This reflects avoided LNG imports, reduced depletion of domestic gas reserves, and lower fiscal exposure to gas subsidies. The methodology therefore evaluates system-wide economic efficiency rather than narrow utility cash flow alone.

Solar Electricity Produce in Pakistan

The best estimates suggest that currently 30 GW of electricity used in Pakistan is through Solar Panels which is equivalent to 35 percent of the national current electricity production and only about 6.0 percent is included in it through Grid and green meters whereas the rest of the electricity is out of grid.

Government has been making it more and more difficult for people to install solar on grid, and as a result more and more investment in panel is going away from grid. Currently the solar cheaper

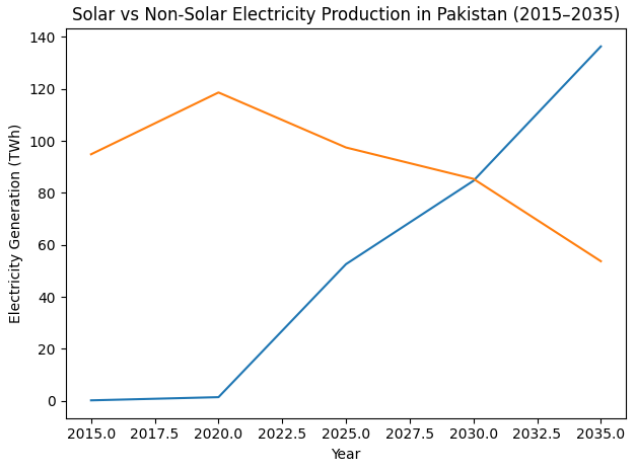
facility has also reduced the demand for electricity from the grid. It is expected that if the same trend continued then

Projected Solar Electricity Generation in Pakistan (2015–2035)

Year	Solar Production (TWh)	Non-Solar Production (TWh)	Total Generation (TWh)
2015	0.18	94.82	95
2020	1.40	118.60	120
2025	52.56	97.44	150
2030 (Projected)	84.62	85.38	170
2035 (Projected)	136.31	53.69	190

What this table shows clearly:

• Solar rises sharply after 2025.
• Non-solar peaks around 2020 and then declines.
• By 2030, solar and non-solar are nearly equal.
• By 2035, solar dominates total generation under moderate growth assumptions.



The chart shows two clear trends. Solar electricity production rises sharply after 2025, while non-solar (traditional) electricity gradually declines. This pattern can be explained mainly by price and consumer behavior.

Solar electricity is becoming cheaper every year. The cost of panels has fallen globally, and once a system is installed, the fuel (sunlight) is free. Households and businesses can reduce their

monthly electricity bills significantly by installing rooftop solar. Because the upfront cost is recovered over time through savings, demand for solar continues to grow. As electricity tariffs from the grid rise, the financial incentive to switch to solar becomes even stronger. This creates a self-reinforcing cycle: higher grid prices → more solar adoption → higher solar production.

On the other hand, traditional electricity (thermal and some IPP-based generation) is becoming more expensive. It depends on imported fuels, exchange rates, and capacity payments. As prices rise, consumers try to reduce grid consumption. Industries may shift to captive solar systems, and households move toward rooftop installations. As a result, non-solar generation declines because fewer units are being purchased from the grid.

In the future, much of solar growth is expected to be off-grid or behind-the-meter systems. The national grid may increasingly serve as a backup system, used during nighttime, cloudy days, or emergencies. This transition reflects economic choice: consumers move toward the cheaper and more predictable energy

Year	Non-Solar Generation (TWh)	Total Cost (Incl. Capacity)	Revenue
2015	94.82	3,112	2,655
2020	118.60	3,516	3,321
2025	97.44	3,156	2,728
2030	85.38	2,952	2,391
2035	53.69	2,413	1,503

solar expansion outlook and fiscal exposure

The projected decline in non-solar electricity generation, combined with a fixed annual capacity payment of approximately Rs 1.5 trillion, creates a structural fiscal risk for the government. If solar capacity continues to expand and non-solar output declines from around 118 TWh (2020 peak) to nearly 54 TWh by 2035, total grid revenue from non-solar electricity could fall to nearly Rs 1.5 trillion annually, while capacity payments alone remain at Rs 1.5 trillion. This implies that almost the entire grid revenue would be absorbed by fixed contractual payments, leaving little to cover fuel, transmission, distribution, and operational expenses. If contracts are not restructured, cumulative fiscal pressure between 2025 and 2035 could exceed Rs 7–9 trillion in implicit or explicit subsidies, circular debt accumulation, or tariff increases.

capacity payment forecast 2025–2035

Assuming capacity payments remain constant at Rs 1.5 trillion annually, total government exposure over the next decade would be approximately Rs 15 trillion. If solar expansion reduces thermal dispatch significantly without contract reform, the effective capacity charge per remaining grid unit will increase sharply. By 2035, if non-solar generation falls to about 54 TWh, the implied capacity burden alone would exceed Rs 27 per kWh (1,500 ÷ 54), even before fuel cost is added. This creates a high risk of tariff escalation, demand contraction, and further migration to solar.

priority policy direction for solar

Government should formally recognize distributed and utility-scale solar as a priority energy pathway. Solar reduces fuel imports, limits exposure to exchange-rate shocks, and lowers long-run marginal cost. Policy certainty—such as streamlined approvals, stable net-metering or net-billing frameworks, and reduced import barriers—will accelerate private investment and reduce future fiscal liabilities.

capacity contract restructuring

Immediate renegotiation of high-cost take-or-pay contracts is essential. Options include extending contract tenure in exchange for lower annual payments, converting some plants into flexible peaking facilities, or partially buying out expensive agreements. Without restructuring, capacity payments will increasingly dominate system cost as solar displaces thermal energy.

grid transformation strategy

The national grid should gradually transition from being the primary energy supplier to serving as a reliability and balancing platform. Investment in storage, demand response, and smart metering is necessary to integrate high levels of daytime solar while maintaining stability. Tariff design should separate network access charges from energy charges to ensure grid sustainability even with lower consumption volumes.

fiscal planning and transparency

The Ministry of Finance and Power Division should publish a rolling 10-year capacity payment outlook under multiple solar growth scenarios. Integrating this forecast into medium-term fiscal planning will prevent unexpected circular debt accumulation and provide clarity to investors.

conclusion

Solar expansion is economically rational and likely irreversible due to its declining cost. However, without parallel reform of capacity payment obligations, the fiscal burden on government and remaining grid consumers will intensify. The optimal policy is not to resist solar growth but to manage the transition proactively—prioritizing solar deployment while restructuring capacity commitments to protect long-term financial stability.

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4. **Assumptions**

The model rests on a set of explicit and policy-relevant assumptions, each grounded in observed system behavior rather than optimistic projections.

First, it is assumed that the transmission and distribution network can reliably deliver an average load of 30,000 MW year-round with incremental reinforcement and operational improvements. This does not require new generation capacity but does require targeted grid investment, which is consistent with existing planning documents and lower-cost than continued capacity expansion.

Second, winter electricity prices in the range of Rs 6–7 per kWh are assumed to be sufficient to induce large-scale switching from gas to electricity for heating. This assumption is not arbitrary; it is derived from relative fuel cost comparisons. At these prices, electric heating becomes cheaper than gas and LNG on an energy-equivalent basis, triggering rational consumer substitution consistent with microeconomic theory.

Third, it is assumed that one kilowatt-hour of electricity used for heating displaces approximately one kilowatt-hour equivalent of gas energy. While actual efficiencies differ by technology, this assumption is conservative because modern electric heating technologies (including heat pumps) are more efficient than gas-based systems, implying that the model likely understates, rather than overstates, substitution effects.

Fourth, the analysis abstracts from losses, theft, non-recovery, and subsidy design in the core revenue calculations. This is a deliberate modeling choice. These factors are treated as policy and governance variables that affect net realizable revenue, not as determinants of gross demand inducement. Including them at this stage would obscure the fundamental price–quantity mechanism the model seeks to illuminate.

Finally, the model assumes rational behavior by consumers and firms responding to relative prices, not perfect foresight or instantaneous adjustment. The transition to full winter electrification is therefore interpreted as achievable within a short adjustment period (one to two heating seasons), consistent with appliance switching cycles and international experience.

Taken together, these assumptions form a coherent theoretical basis for concluding that flexible seasonal pricing can reliably induce winter electricity demand up to 30,000 MW, provided relative fuel prices are correctly aligned and network constraints are addressed

5. **Justification of the analysis**

The justification for this model lies in the structural inefficiency of uniform pricing in a system with extreme seasonal demand swings. Pakistan already bears the fixed cost of generation capacity throughout the year, yet that capacity remains idle in winter. Flexible pricing aligns consumer behavior with system economics, improves capacity utilization, and converts sunk costs into productive output. The very large gas savings estimated in the model reflect avoided LNG imports and reduced pressure on domestic gas reserves, which have significant macroeconomic and balance-of-payments implications. From a welfare perspective, low winter electricity prices also provide affordable heating to households, reducing energy poverty without increasing total system cost.

6. **Conclusion**

The fixed-supply, flexible-price model offers a compelling alternative to Pakistan's current electricity pricing regime. The analysis demonstrates that maintaining a constant national supply of 30,000 MW while varying prices seasonally can raise annual electricity revenue to more than Rs 5 trillion, exceed current NEPRA revenue requirements, and unlock gas savings exceeding Rs 30 trillion per year through winter electrification. These results strongly support the adoption of seasonal tariffs as a core pillar of power sector reform. Policymakers should move decisively toward flexible pricing, explicitly recognize winter electrification as a national objective, and realign regulatory frameworks to reward utilization rather than scarcity. Failure to do so will perpetuate under-utilization of assets, continued reliance on expensive gas imports, and chronic financial stress in the electricity sector.

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Recommendations Note:

The price of electricity need to be adjusted monthly for the entire year once given which may range from Rs8 per unit to Rs 35 per unit. The expected IPPs energy prices are is Rs 9 per unit, with montly

rent of Rs 10 per unit as capacity payment, this does not cover the cost, however it covers the running cost, without generating electricity it still has to pay the fixed Capacity Payment

charging even lower than 9 may not look feasible but it can be compensated by the gas sector who will be replacing electricity and will be saving Rs 3 per unit of heat.

Transmission needs to be re visited and transmission of far flunked area should be transferred to local generating units without disturbing the grid. Alternatively if the electricity transmitted through the grid of about 45,000 megawatt the economics will drastically change . Transmitting 45,000 MW, with the same capacity payment, will

This may be considered that IPP's are supplying 90 percent electricity , (HOW)?? Mmay be in summer only, check

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[i] Primary sources to authenticate Table 1 (2015–2024)

1. NEPRA — State of the Industry / Annual & Performance Reports
    - What it covers: historical average consumer tariffs (Rs/kWh), tariff determinations, DISCO billed/collected amounts and sector commentary. NEPRA annual reports and the State-of-Industry reports are the regulator's official publications for the power sector. Use these to validate Avg Price (Rs/kWh) and DISCO billed / collected figures (which underpin the Revenue (Rs bn) column).
    - Representative documents (open these PDFs and search for "average tariff", "billed amount", "DISCO revenue"):
        - NEPRA State of Industry Report 2015.
        - NEPRA Performance Evaluation Report / Annual Report 2023-24 (includes FY2023-24 tariff determination and DISCO revenue / billed/collected figures).
2. Power Division (Ministry of Energy) — Yearbook / Tariff Determinations / Circular Debt Reports
    - What it covers: government/power-division published revenue requirements, sales (GWh) used in tariff settings, and aggregated DISCO revenue projections and realizations for fiscal years. Useful to cross-check the Revenue (Rs bn) and the assumptions behind tariff changes.
    - Example: Power Division Yearbook 2022-23.
3. State Bank of Pakistan (SBP) — Official Exchange Rate / Statistical Bulletins
    - What it covers: official average PKR/USD exchange rates (monthly and annual averages). Use SBP tables to convert PKR revenue to Revenue (USD bn) consistently (the SBP "Bank Floating Average Exchange Rates" or monthly average tables are commonly used). The SBP publication chapter with historical annual averages is the authoritative source for your Avg FX column.
    - SBP exchange rate data and historical tables (use the "Bank Floating Average Exchange Rates, Monthly" or the Stat Review chapter).
4. World Bank / Pakistan Development Update (Power Sector analysis)
    - What it covers: independent cross-checks and aggregate sector numbers — aggregates like total DISCO revenue projections, circular debt impacts and consolidated sector revenue estimates. Useful as a corroborating source for the Revenue (Rs bn) column and for contextual notes about FY2023-24 / 2024.
    - Example: World Bank Pakistan Development Update: "The Dynamics of Power Sector — Distribution Reforms" (Oct 2024).
5. Media / Trade press summaries (for quick checks)
    - Business/financial outlets often report NEPRA / Power Division figures (useful for quick cross-checks but cite primary NEPRA / Power Division / SBP when you need authenticated sources). Examples: Profit, Business Recorder, Dawn, etc. For FY2023-24 billing/collection numbers see Profit / Pakistan Today coverage of NEPRA tariff determinations.