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Ensuring low-cost generation and resource adequacy: the case of Pakistan's new competitive trading bilateral contract market (CTBCM) model

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List of abbreviations

CRM	capacity remuneration mechanism
CTBCM	Competitive Trading Bilateral Contract Market
DISCOs	distribution companies
FY	fiscal year
HFO	heavy fuel oil
IGCEP	Indicative Generation Capacity Expansion Plan
NEPRA	National Electric Power Regulatory Authority
NTDC	National Transmission and Despatch Company
O&M	operation and maintenance
PPA	power purchase agreement
SRMC	short-run marginal cost
VOLL	value of lost load
VRE	variable renewable energy
WAPDA	Water and Power Development Authority

Abstract

Pakistan has a single-buyer market model, designed for centralized power procurement and investment in generation capacity. However, this model has encountered challenges in achieving both affordability and security of supply of electricity. A key contributing factor to the rise in electricity prices is the surge in capacity payments, which have more than doubled over the last five years. Pakistan has more recently introduced a new Competitive Trading Bilateral Contract Market (CTBCM) model to increase the competitiveness of its electricity market.

This research study conducts an in-depth analysis of the capacity payment mechanism and its associated costs within Pakistan's electricity sector. Furthermore, they study critically evaluates the key features of the CTBCM model, assessing its potential to address the challenges of resource adequacy. The study also offers a comparative assessment of capacity costs and capacity remuneration mechanisms, which are implemented across several liberalized electricity markets. A case study of Pakistan's electricity market is modelled in detail to examine the potential impact of different market designs on energy and capacity prices.

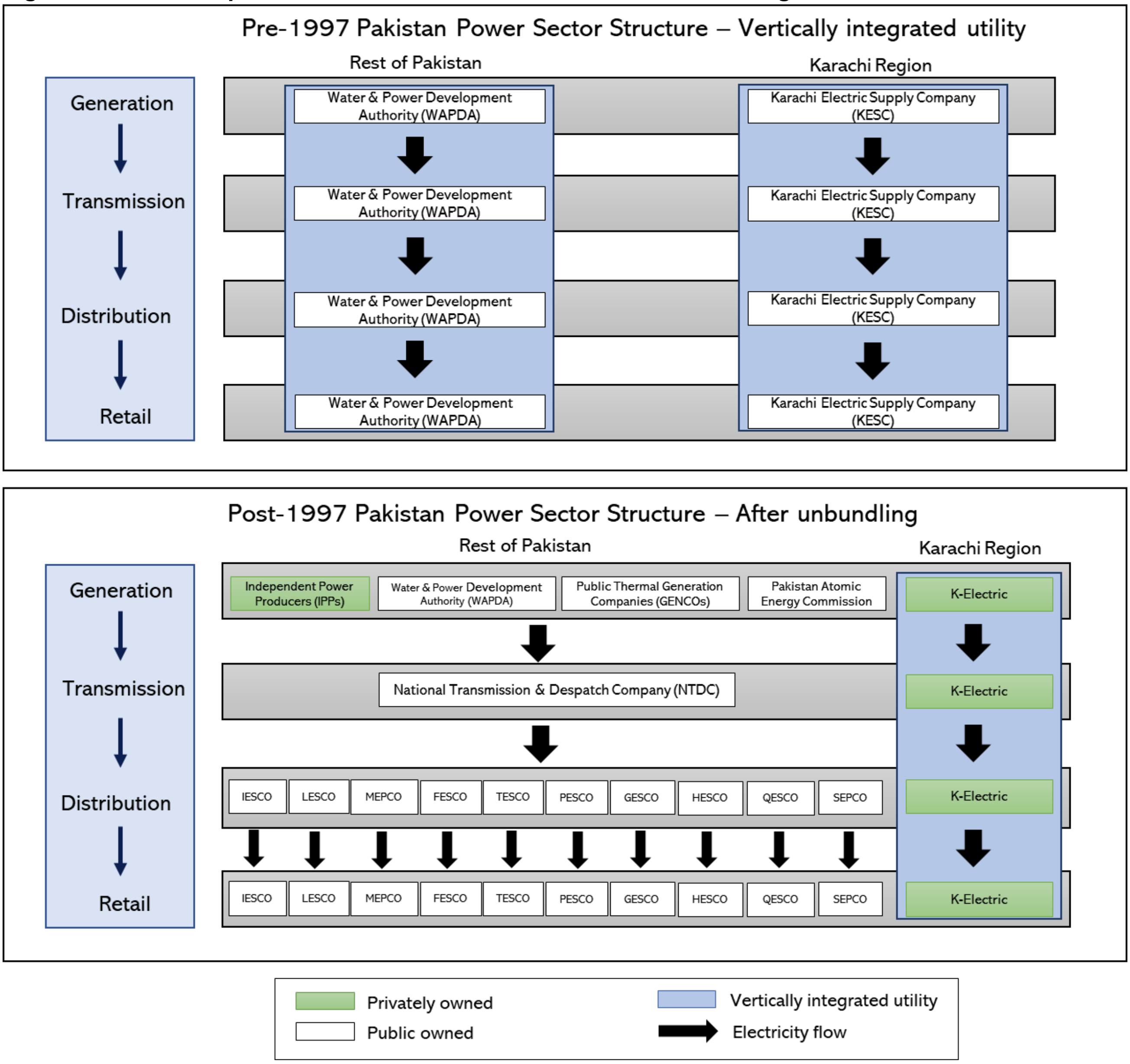
The research study has yielded several significant findings. First, Pakistani consumers bear an average capacity cost around four times than their counterparts in other markets, mainly because of elevated capital costs, the over-procurement of take-or-pay capacity contracts, and the inherent inefficiencies of the capacity payment mechanism. Furthermore, the evaluation of the CTBCM model suggests it has the potential to ensure resource adequacy but that the capacity obligation mechanism will elevate risks for distribution companies. Moreover, the Pakistan power market modelling indicates a projected decrease in short-run marginal costs under the government's capacity expansion plan, but capacity payments are expected to increase. A capacity market mechanism could reduce capacity costs by more than threefold compared with the capacity payment mechanism. However, the establishment of an energy market under the capacity market model is predicted to lead to a 42 per cent increase in overall electricity prices. The research study further establishes that the existing two-part tariff structure in a power purchase agreement-based market model does not promote competition and efficiency. Conversely, the energy and capacity market model, while leading to a short-term escalation in electricity prices, possesses the capability to employ price signals in determining optimal technology deployment, thus ensuring system-wide efficiency. Moreover, the paper presents a comprehensive framework that could assist in the design of a suitable capacity mechanism in Pakistan.

1. Overview and challenges of the electricity sector in Pakistan

Pakistan's power sector has undergone significant transformations since its inception. The Water and Power Development Authority (WAPDA) was established in 1958, consolidating the power and water sectors. Meanwhile, the Karachi Electric Supply Company served the southern region, including Karachi. The National Power Policy of 1994 encouraged private sector investment through incentives like long-term power purchase agreements (PPAs). This policy shift resulted in a significant increase in thermal power generation. Further, the unbundling of WAPDA carried out in 1997–98 led to the creation of thermal power generation companies, regional distribution companies (DISCOs), and the National Transmission and Despatch Company (NTDC). An independent regulator, the National Electric Power Regulatory Authority (NEPRA), was also established. The power sector continued to evolve with the privatization of the Karachi Electric Supply Company in 2005. The transformation of Pakistan's power sector before and after these reforms is depicted in Figure 1. Pakistan's electricity generation is diverse, with hydropower contributing 25 per cent, thermal power 60 per cent, nuclear power 12 per cent, and wind power 3 per cent, and other sources playing a minor role.

Pakistan has, on average, 26 per cent higher electricity prices than other Asian countries (Ahmed, 2020). The overall transmission and distribution losses have surpassed 21 per cent, and the circular debt in the power sector has ballooned to $11.29 billion (NEPRA, 2021). Despite the availability of generation capacity, many cities in Pakistan still experience electricity load shedding, highlighting the magnitude of the issue. The core problem is high electricity prices, and its root cause is the centralized and inefficient generation planning within the electricity sector. The high electricity prices stem from costly and inefficient electricity generation through fossil fuel power plants that heavily rely on imported fuel. Due to the significant addition of excess capacity, the weighted average load factor of thermal power plants declined from 55 per cent in fiscal year (FY) 2014 to 45 per cent in FY 2015. This decline has a profound impact on consumers in the form of an increase in capacity charge. The share of capacity charges in the final consumer tariff surged from 18 per cent in 2015 to 40 per cent in 2022 (ur Rehman, 2022). In the year 2021–22 alone, capacity payments amounted to a total of Rs. 721 billion (approximately $3.26 billion) (NEPRA, 2022).

Figure 1: Pakistan's power sector structure before and after unbundling

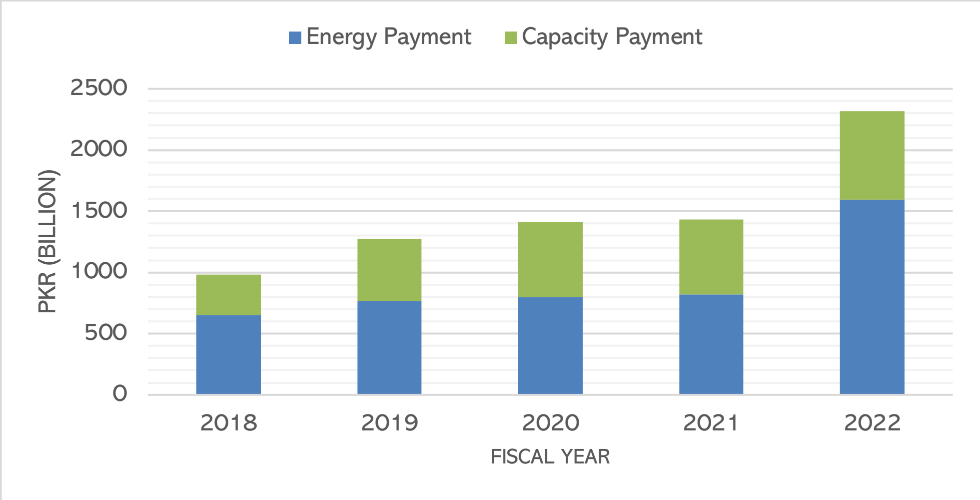


Note: The electricity market operates under the single-buyer market regime. The central buyer (the Central Power Purchasing Agency) signs long-term power purchase agreements with generation companies, and the regulator (the National Transmission and Despatch Company) approves the tariff. The tariff typically comprises two components: energy price and capacity price. The capacity price itself has two components: foreign and local. The capacity price is a fixed payment indexed to the exchange rate between the US dollar and Pakistani rupee and the US inflation rate. The capacity price is paid to the generators regardless of the plant's actual generation. When these plants are not operated because of high fuel prices, the government still has to pay the capacity payments, and that in turn increases the per unit price of electricity for consumers.

Source: Author's own illustration.

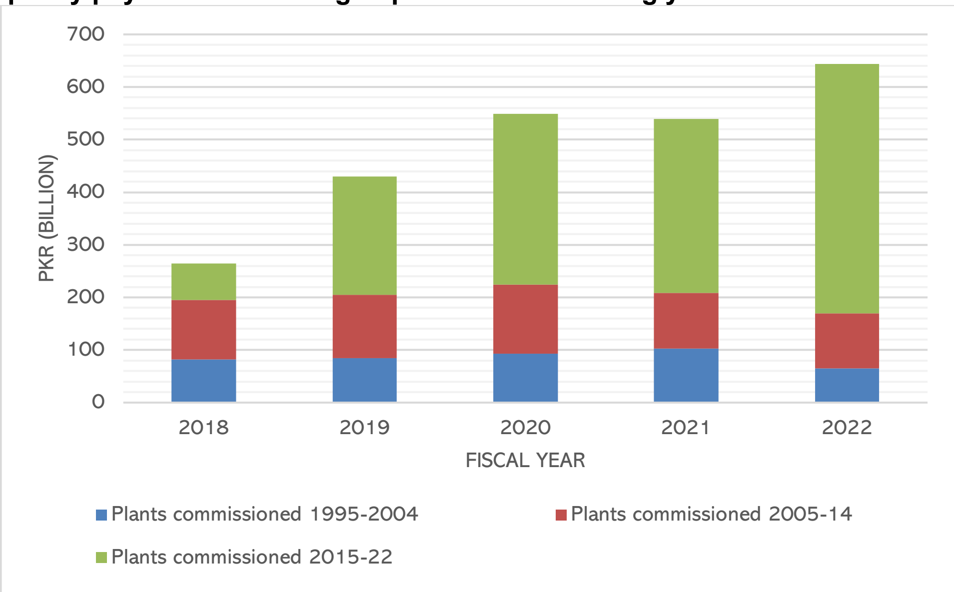
Figure 2 illustrates the evolution of capacity payments over time. The share of capacity payments in the total generation cost rose from 33 per cent in FY 2018 to 43 per cent in FY 2021, declining slightly in FY 2022 due to the impact of very high global fuel prices. The share of capacity payments is projected to increase further in the future, owing to the commissioning of new plants. Figure 3 shows the division of capacity payments disbursed to generators according to their commissioning year. In FY 2022, approximately 75 per cent of the capacity payments were made to plants that were commissioned after 2015. This indicates that the payments are substantially influenced by new generation capacity, which carries higher debt costs; these debt costs must be repaid during the initial decade of plant operations.

Figure 2: Energy and capacity payments paid to power plants



Source: Based on various editions of NEPRA State of Industry reports.

Figure 3: Capacity payments according to plant commissioning year



Source: Author's own illustration based on various editions of NEPRA State of Industry reports.

Next, we introduce the concept of resource adequacy in power systems planning and discuss how it may contribute to higher electricity prices.

2. Resource adequacy

Resource adequacy is a crucial aspect of power system planning, ensuring that the system can consistently meet electricity demand. A primary goal of resource adequacy planning is to minimize costs for consumers, including the cost of unserved energy, while ensuring system reliability at all times (Cramton and Stoft, 2006). The reliability standards have been developed by system planners to deal with this planning challenge. The overarching goal of these standards is to balance the costs of ensuring resource adequacy with the avoided costs linked to unmet energy demand, thereby maximizing social welfare for a society (Beaude, 2023).

2.1 Vertically integrated utilities

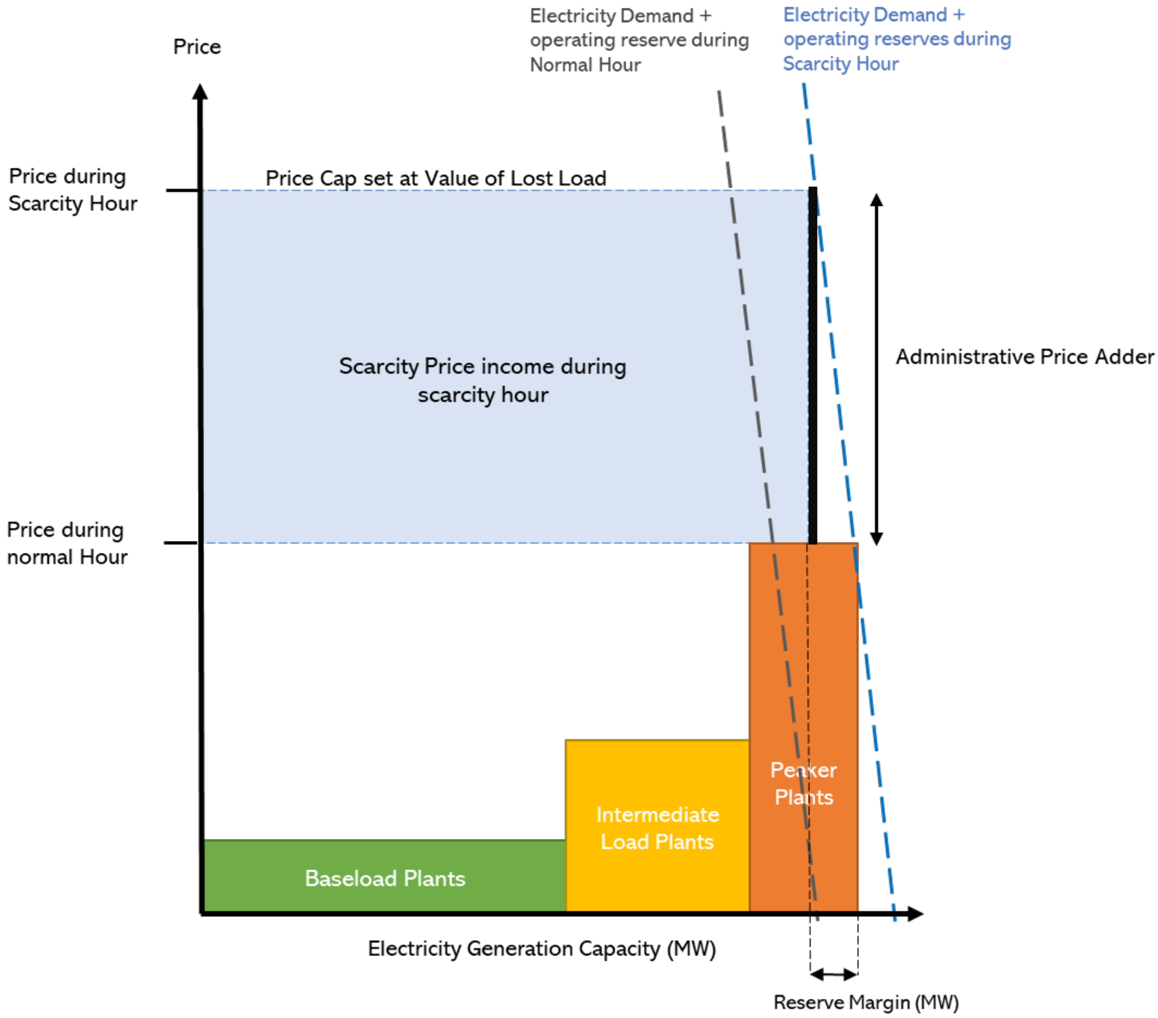
Resource adequacy in a vertically integrated utility model follows a straightforward approach. The planning involves the construction of generation capacity based on load forecasts, loss of load probability calculations, and estimation of the value of lost load (VOLL). The cost of capacity is allocated to consumers through a capacity price, which is often assigned based on time of use, with higher prices during peak hours. In this model, resource adequacy is treated as a public good, and the risks associated with market, construction, and generator performance are shifted predominantly to consumers (Oren, 2003). In a vertically integrated utility or in centralized generation planning, the central planner tends to over-procure capacity due to political considerations and the potential ramifications of insufficient capacity. This approach places the burden of excess capacity on consumers.

2.2 Energy-only markets

Resource adequacy is ensured in an energy-only market through two primary mechanisms: (i) setting a wholesale energy market price cap at the VOLL and (ii) implementing scarcity pricing. In an energy-only market such as implemented in Texas and Australia, the price cap for the wholesale market is set at the VOLL. Setting the price cap at the VOLL serves two purposes: In the short run, it enables peaker plants to recover their fixed costs during scarcity events. In the long run, the expected revenues from the energy market incentivize investment in generation capacity, thereby addressing both short-term system security and long-term resource adequacy issues (Hogan, 2012).

Scarcity pricing is another important aspect of resource adequacy in an energy-only market. It is based on the principle that when generating capacity becomes scarce, it should also become more valuable. (Hogan, 2012). The price of energy or operating reserve should rise enough to reflect the scarcity conditions. Scarcity pricing is implemented through administrative adders on energy and ancillary service prices during periods of shortage. The concept of scarcity pricing (depicted in Figure 4) is that during normal electricity demand hours, the electricity price is determined by the marginal cost of peaker plants. However, during scarcity events with high electricity demand, and when the reserve margin falls below a certain threshold set by the system operator, an additional scarcity price is added to the wholesale energy price. The area between the marginal cost of peaker plants and the VOLL represents the income earned by all the plants. The scarcity price is not fixed but varies based on the reserve margin available to the system operator to balance supply and demand. Both scarcity pricing and capping of the wholesale energy price at the VOLL contribute to enhancing system reliability and long-term resource adequacy in an energy-only market.

Figure 4: Scarcity pricing mechanism

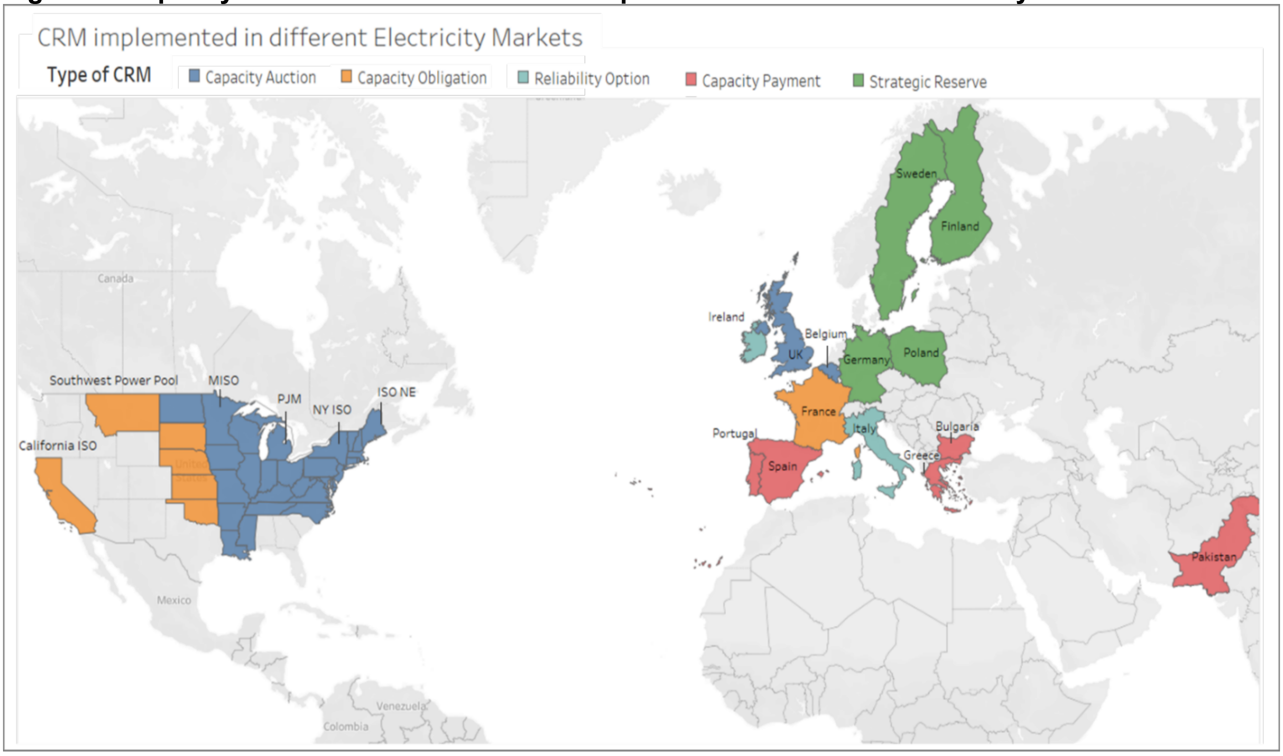


Source: Author's own illustration.

2.3 Capacity remuneration mechanism

The capacity remuneration mechanism (CRM) is another way of ensuring resource adequacy in liberalized electricity markets. One of the primary arguments supporting the implementation of CRMs is that price caps in an energy-only market are often set too low for generators to adequately recover their investment and fixed costs. Even when price caps are set at the VOLL and a scarcity price is added to the energy price, the lack of investment coordination is not effectively addressed. The underlying expectation in the design of an energy-only market is that market incentives will guide investment decisions. However, market participants lack information on the appropriate level of investment, and there is no centralized administrative guidance for investment decisions (Cramton and Stoft, 2006). Both lack of coordination and asymmetric information cause failure in the energy-only market (Creti and Funtini, 2019). This realization has led to the notion that generation capacity should be remunerated explicitly in addition to energy to compensate for the 'missing money' problem. These payment mechanisms are known as CRMs. CRMs can be broadly classified into two categories: price based and volume based. Price-based CRMs are exemplified by capacity payments, while volume-based CRMs encompass capacity auctions, reliability options, capacity obligations, and strategic reserves. These mechanisms can be further classified according to whether they are (i) targeted, benefiting only a select few generators, or (ii) marketwide, allowing participation from all qualified generators. Another classification criterion is whether the mechanisms are centralized or decentralized. Figure 5 shows the CRMs that have been implemented in different electricity markets.

Figure 5: Capacity remuneration mechanisms implemented in different electricity markets



Source: Author's own illustration.

2.4 Capacity costs analysis

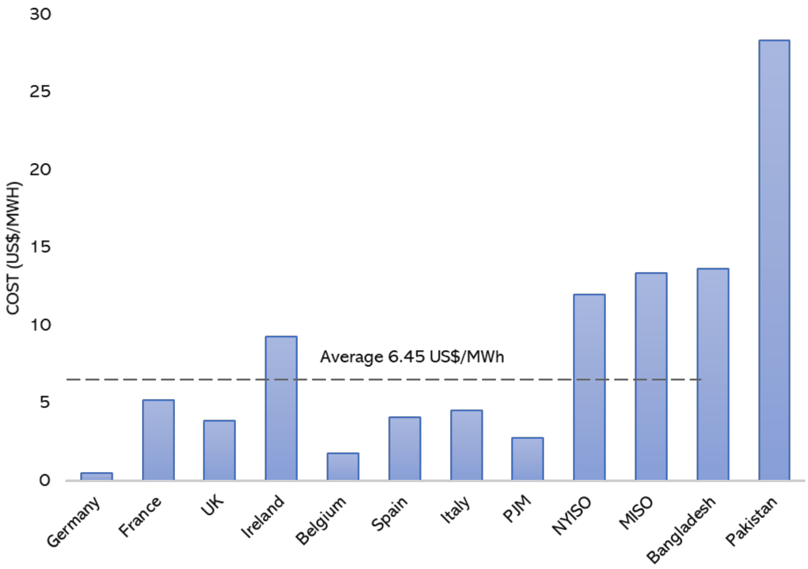
This section aims to compare capacity costs in Pakistan with those in other electricity markets around the world. Data for the comparison were gathered from NEPRA State of Industry reports, market reports, and government power sector reports specific to each electricity market. Figure 6 resents a comparative analysis of capacity costs per unit of demand across different electricity markets. This cost represents the cost of capacity mechanisms for the end consumers. The capacity costs used in the analysis were based on the latest available data for these markets. Notably, the capacity costs in Europe are significantly lower than the average, with the exception of Ireland, which has a small power system and is not well connected with Europe. Moreover, the capacity costs in US markets are higher than those observed in Europe. Interestingly, Pakistan exhibits the highest capacity cost per unit of demand among all the markets considered. This cost is four times the average capacity cost in other markets and more than double that of Bangladesh. The variation in capacity costs across different markets could be attributed to several factors.

2.4.1 Factors influencing capacity costs

The high cost of capital is one of the primary reasons for the high capacity cost in Pakistan, due to elevated interest rates and risk premiums. The country offers a rate of return on equity of up to 25–30 per cent, making the capacity cost of projects very high. The annual weighted average capacity cost per unit of received capacity is shown in Figure 7. This cost in Pakistan is 184 per cent more than the average, but almost at the same level as Bangladesh.

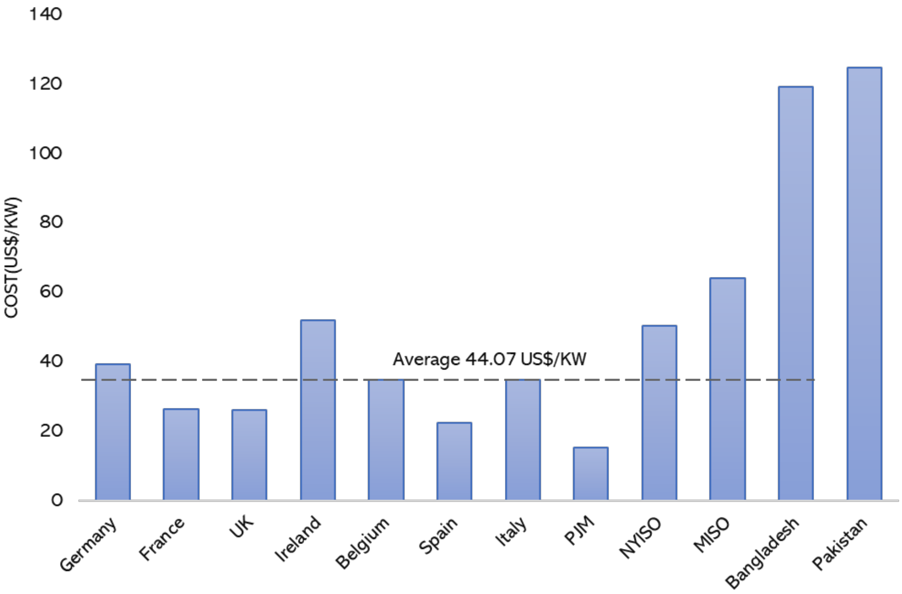
The higher level of capacity procurement in Pakistan is also one of the contributing factors to the increased capacity cost. Bangladesh also has much higher capacity costs than the average, yet their impact on consumer capacity costs is much less than in Pakistan, as shown in Figure 6. The inference is that although the cost of capacity in Pakistan is similar to that of its regional counterpart, its impact on Pakistan's consumers is disproportionately substantial. This suggests that the primary driver behind the increased capacity costs in Pakistan may not solely be the cost of capacity itself but may be the result of over-procurement of capacity. The relationship between capacity costs and the proportion of capacity that receives CRMs is illustrated in Figure 8. Although some outliers exist, a discernible trend shows that as the proportion of capacity that receives CRMs increases, the capacity costs rise. Figure 8 further highlights the various types of CRM implemented in these electricity markets. There is no clear correlation between the type of CRM and capacity costs, a conclusion consistent with the study conducted by Schittekatte and Meeus (2021) that compared the capacity costs across different markets in the European Union and the United States.

Figure 6: Capacity cost per unit of demand for consumers across different electricity markets



Sources: Bangladesh Power Development Board (2021); Flexcity (2022); MISO (2022); National Grid ESO (2023); NEPRA (2022); Nicholas and Ahmed (2020); NYISO (2020); Patton et al. (2022); PJM (2023); Potomac Economics (2022); Red Eléctrica (2023); Rte France (2021); SPR Economie (2022); Terna (2023).

Figure 7: Annual weighted average capacity cost per unit of capacity that received CRM

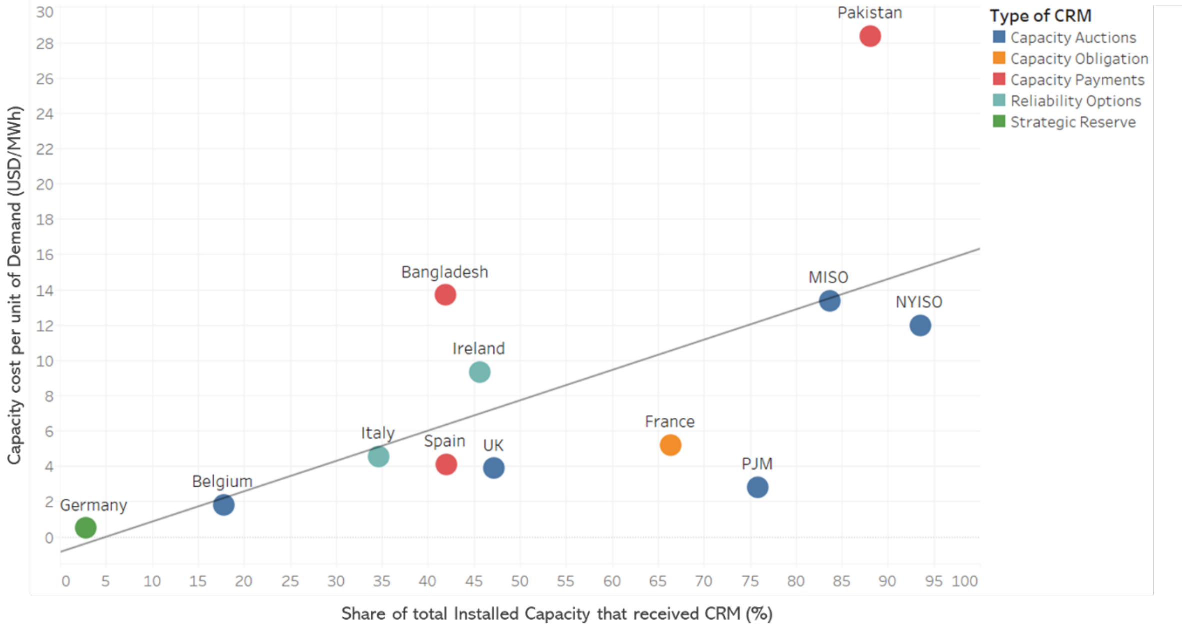


Sources: See Figure 6 sources.

Despite the lack of a direct relationship between the type of CRM and capacity costs, the type of CRM does influence the amount of capacity that receives CRMs. Figure 9 illustrates the ratio between the amount of capacity that receives CRMs and peak load in different electricity markets. In markets where capacity auctions, capacity obligations, and capacity payments are employed, this ratio is around 1, suggesting that amount of capacity that receives CRMs is closely aligned with the peak load, except for Bangladesh and Belgium. Both of these markets exhibit unique characteristics that set them apart from others. The capacity obligation, capacity payment, and capacity auction mechanisms, while different in nature, provide similar outcomes in terms of the amount of capacity that needs to be procured. However, strategic reserve and reliability options, due to their different designs, lead to less capacity being procured to meet requirements. Moreover, although there is no direct relationship between the type of CRM and the capacity price, the type of CRM affects the capacity price in different market settings. For instance, in countries like Pakistan and Bangladesh, where capacity payments are used, the capacity price is based on the fixed costs of generators. These capacity prices tend to be higher than the jurisdictions where there are well-established energy markets, because generators earn a significant part of their revenue from energy markets, leading to lower overall capacity prices.

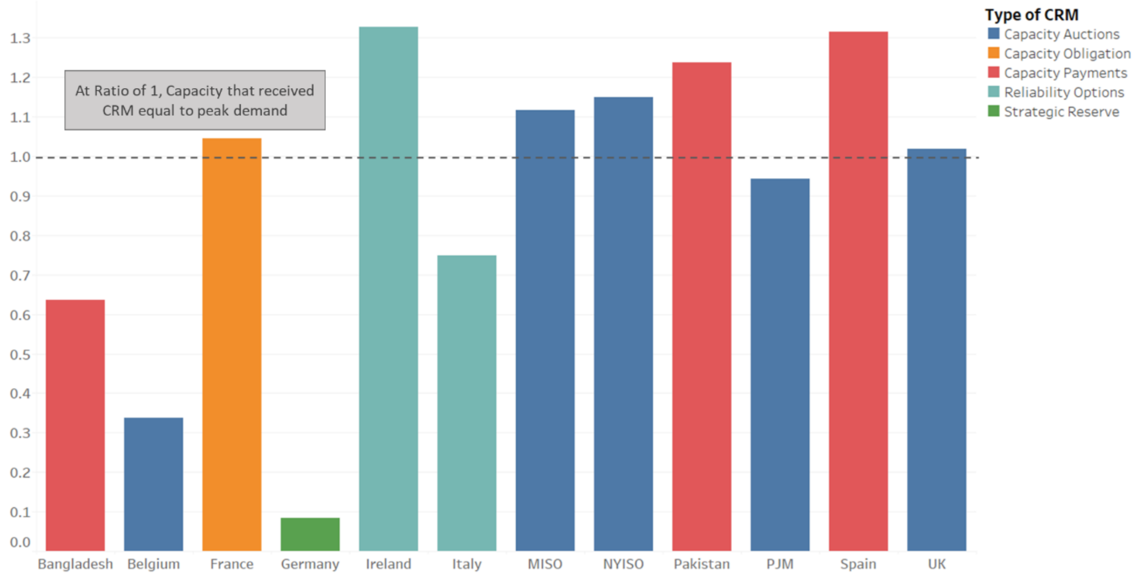
Several other market characteristics significantly impact capacity prices. These include the composition of the electricity mix, the presence of excess capacity, fuel prices, the proportion of variable renewable energy (VRE) sources, new capacity additions, existing capacity retirements, and environmental regulations (Pfeifenberger et al., 2016). Therefore, it is important to keep these differences in mind when comparing capacity costs across different markets.

Figure 8: Relationship between capacity cost and share of installed capacity that received CRM



Sources: See Figure 6 sources.

Figure 9: Ratio between peak load and capacity that received CRM



Sources: See Figure 6 sources.

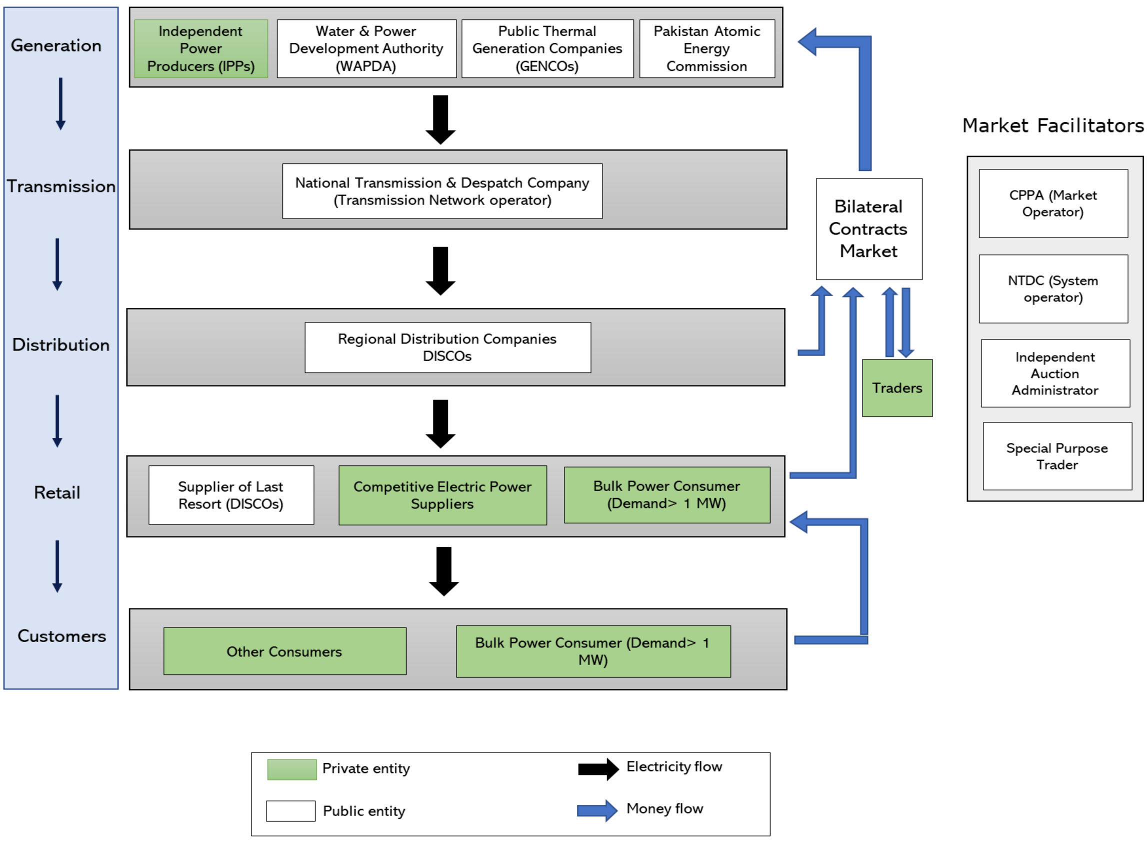
3. Competitive Trading Bilateral Contract Market model

3.1 Overall Market design

The Competitive Trading Bilateral Contract Market (CTBCM) is structured as a contract market that revolves around bilateral contracts, which serve as the primary instruments for wholesale electricity trading. These contracts facilitate the trading of both energy and capacity and are complemented by balancing mechanisms administered by the market operator. Under the CTBCM, two distinct products are introduced: (i) energy, to facilitate market participants meeting their electricity consumption demands, and (ii) firm capacity, to provide adequate capacity for medium- and long-term security of supply of the power system. The overall electricity market structure of the CTBCM model encompasses two main types of entity: market participants and market facilitators. Market facilitators, also referred to as service providers in the CTBCM, are government entities responsible for offering non-discriminatory services to all market participants (*Market Operator Commercial Code*, 2022). These facilitators include the market operator, the system operator, the transmission network operator, the distribution network operator, and the independent auction administrator. Market facilitators have no commercial interest in the market. The roles and functions of these entities have been clearly defined and separated to prevent any overlap or conflicts of interest. Market participants are entities that have a commercial interest in the market. The overall market structure is conceptualized in Figure 10.

The CTBCM model consists of three core features: bilateral contracts, legacy contracts, and a balancing mechanism. Bilateral contracts enable DISCOs and electricity suppliers to independently manage their energy and capacity procurement needs through various types of contract (*Market Operator Commercial Code*, 2022). The legacy contracts from existing PPAs between independent power producers and the Central Power Purchasing Agency are converted into bilateral contracts, with allocation factors tailored to each DISCO's demand profile. As per the *Market Operator Commercial Code* approved by NEPRA, the market operator will periodically determine allocation factors for existing contracts to be allotted to each DISCO, with a review every three years or less (*Market Operator Commercial Code*, 2022).

Figure 10: Electricity market structure under Competitive Trading Bilateral Contract Market model

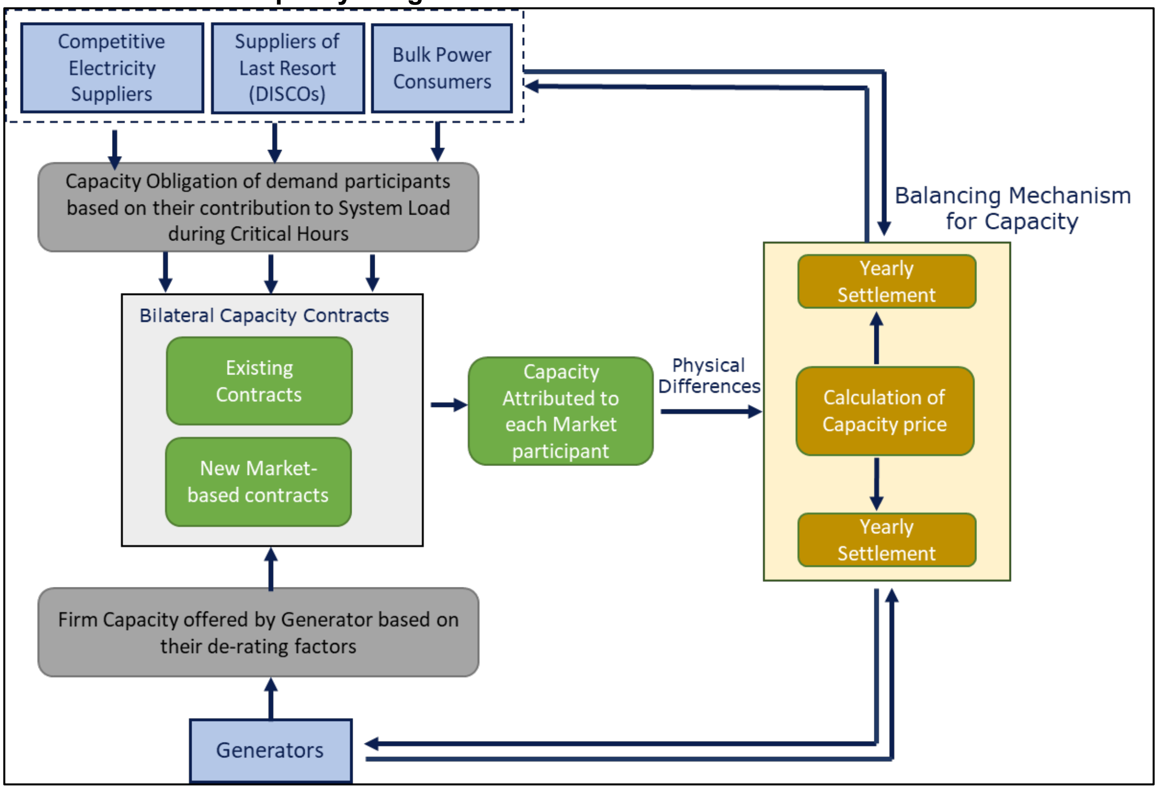


Source: Author's own illustration.

3.2 Capacity obligations and balancing

The CTBCM introduces a capacity obligation mechanism to facilitate capacity trading and ensure medium- and long-term security of supply by incentivizing new generation investments and the availability of sufficient generation capacity (MRC Consultants and Transaction Advisers, 2020). Market participants, including competitive electricity suppliers, DISCOs, and bulk power consumers, are subject to capacity obligations, requiring them to procure a portion of their consumption and demand through contracts (*Market Operator Commercial Code*, 2022). To facilitate capacity trading, the CTBCM introduces a capacity certificate mechanism. Generators interested in selling capacity in the market will need to obtain firm capacity certificates from the market operator (*Market Operator Commercial Code*, 2022). Dispatchable generators' firm capacity will be based on their actual declared availability during system peak hours in the last three years, while non-dispatchable generators' firm capacity will be based on the average hourly energy generation during system peak hours over the same period. For new generators, firm capacity will be determined using de-rating factors specific to each technology. The capacity obligation for each demand participant is based on their contribution to the system peak load. DISCOs, as last resort suppliers, are obligated to meet their forecasted capacity obligations in advance, covering 100 per cent of their obligation for the next two years, 80 per cent for the third year, and 60 per cent for the fourth year (*Market Operator Commercial Code*, 2022). Each market participant will be attributed capacity based on their acquired firm capacity certificates. At times when there is a shortage in capacity, demand participants can procure it through the balancing mechanism for capacity. The overview of the capacity obligation mechanism is provided in Figure 11.

Figure 11: Overview of capacity obligation mechanism



Source: Author's own illustration.

The Market Operator Commercial Code has also outlined a detailed methodology for the balancing mechanism for capacity. The process involves the development of two curves: the supply curve and the demand curve. The supply curve represents the capacity offered by market participants as price takers. The demand curve comprises two sections—the mandatory part and the efficient part—and is determined by the system operator. The mandatory part of the demand curve represents zero capacity and a price equal to twice the levelized fixed costs of the reference technology. The efficient section of the demand curve is determined by the intersection of the levelized fixed costs of the reference technology and the efficient demand level (*Market Operator Commercial Code*, 2022). The efficient demand level, the reference technology, and its fixed costs are calculated by the system operator. The intersection of the supply and demand curve sets the capacity price, and each year the system operator uses this capacity price in the balancing mechanism to settle physical differences.

4. Pakistan case study design

The case study modelling of Pakistan's power market aims to analyse the impact of government generation capacity expansion plans on energy and capacity prices in Pakistan under two distinct market models. The objective is to assess how different market designs could influence energy and capacity prices. To achieve this, two distinct market designs are considered. The first market design is based on the existing long-term contracts and the capacity payment mechanism. Under this framework, generators are dispatched according to their short-run marginal cost (SRMC) and receive hourly energy price on a pay-as-bid basis. The second market design is based on an hourly energy market that operates on the principle of marginal pricing. Under this mechanism, generators are also dispatched according to their SRMC, but they are paid the spot market price (i.e., the bid of the most expensive generator that is dispatched). Additionally, the CRM in this market design consists of an annual capacity market that works on the pay-as-clearing mechanism. Both market designs are characterized distinctly, as shown in the Table. The power system of Pakistan is simulated using the PLEXOS modelling tool provided by Energy Exemplar. The necessary data required for the modelling exercise are sourced from publicly available resources. The data sources include the State of Industry reports published annually by NEPRA, the Indicative Generation Capacity Expansion Plan (IGCEP) 2022–31 developed by NTDC, various editions of Power System Statistics reports from NTDC, NEPRA-published tariffs, and the latest quarterly indexation documents for different power plants. Additionally, some data that were not available from government sources were taken from the Variable Renewable Energy Integration and Planning Study conducted by the World Bank (World Bank, 2020). The power system is modelled from FY 2023 to FY 2031, and the unit commitment and economic dispatch is simulated to hourly resolution. The overall power system modelling methodology is illustrated in Figure 12.

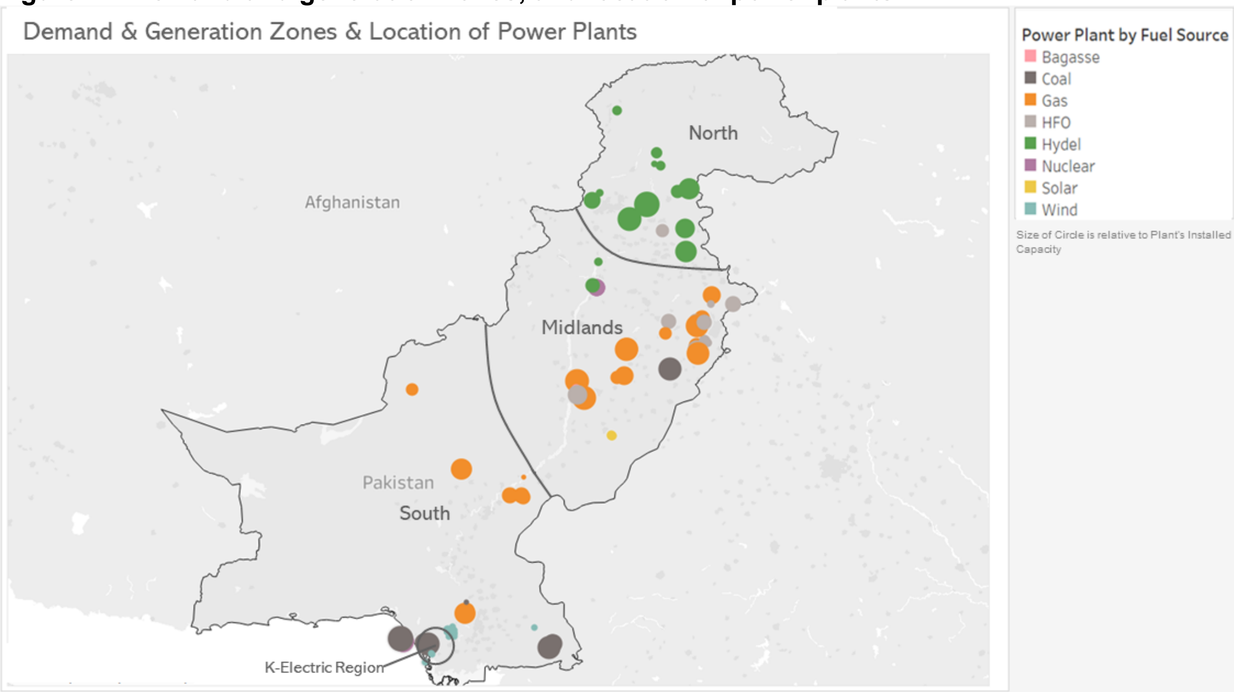
Table 1: Differences between two market designs

Market characteristics	**1st market design** **PPA-based market model**	**2nd market design** **Hourly energy market and annual capacity market**
Electricity dispatch	Based on hourly short-run marginal cost	Based on hourly short-run marginal cost
Generator settlement method	Pay-as-bid (Generator marginal price)	Pay-as-clear (System marginal price)
Capacity remuneration mechanism	Based on individual generator PPAs[a]	Annual capacity market based on pay-as-clear mechanism

PPA = power purchase agreement.

[a] Each power plant has signed a long-term PPA with the single buyer, the Central Power Purchasing Agency. The capacity price is determined and negotiated for each plant separately based on its fixed costs.

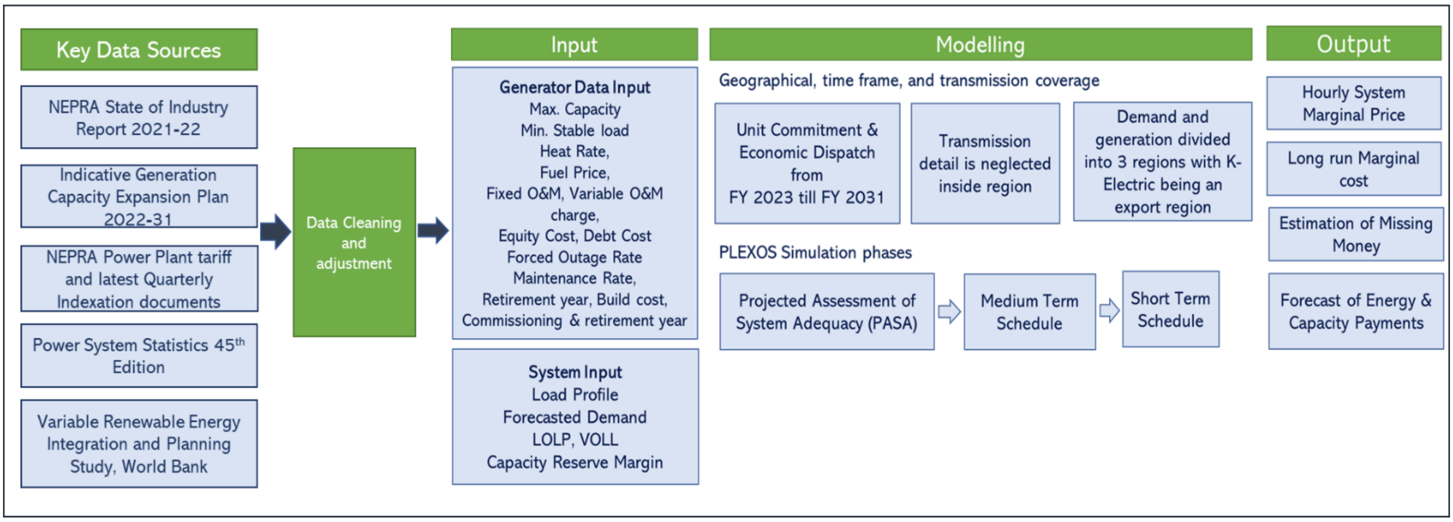
Figure 12: Demand and generation zones, and location of power plants



Source: Author's own illustration.

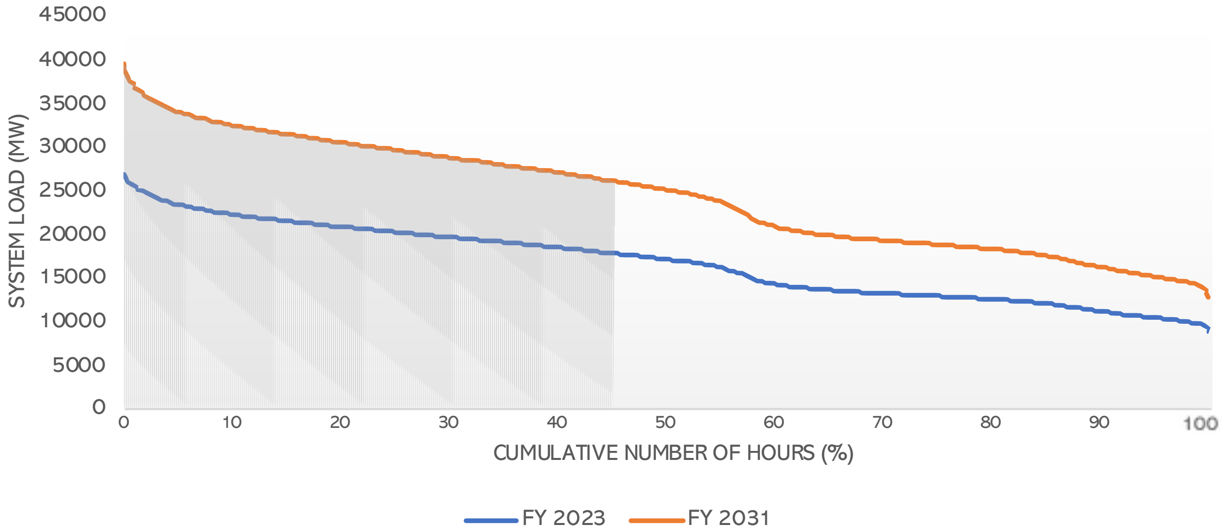
The geographical coverage of the power system model includes the national grid area of Pakistan, with North, Midlands, and South zones (excluding the K-Electric region) as shown in Figure 12. The K-Electric region includes the area of Karachi city, which is modelled as a separate export region. The system load curve was constructed using four typical daily load profiles—weekday and weekend profiles for both summer and winter—using the data from the *State of Industry Report 2022* (NEPRA, 2022). Based on the monthly demand observed during FY 2022, distinct weekday and weekend profiles were created for each month. To incorporate peak load correctly, the daily peak load profile for summer was added for one week during the peak summer months of June and August. These specific months were selected based on historical data indicating peak demand periods. The IGCEP demand forecast for peak load and annual generation was used to develop load profiles for subsequent years. (See methodology in .) The resulting load duration curve for the whole system for FY 2023 and FY 2031 is shown in Figure 14.

Figure 13: Pakistan power market modelling methodology



Source: Author's own illustration

Figure 14: Load duration curve for national grid system, FY 2023 and 2031



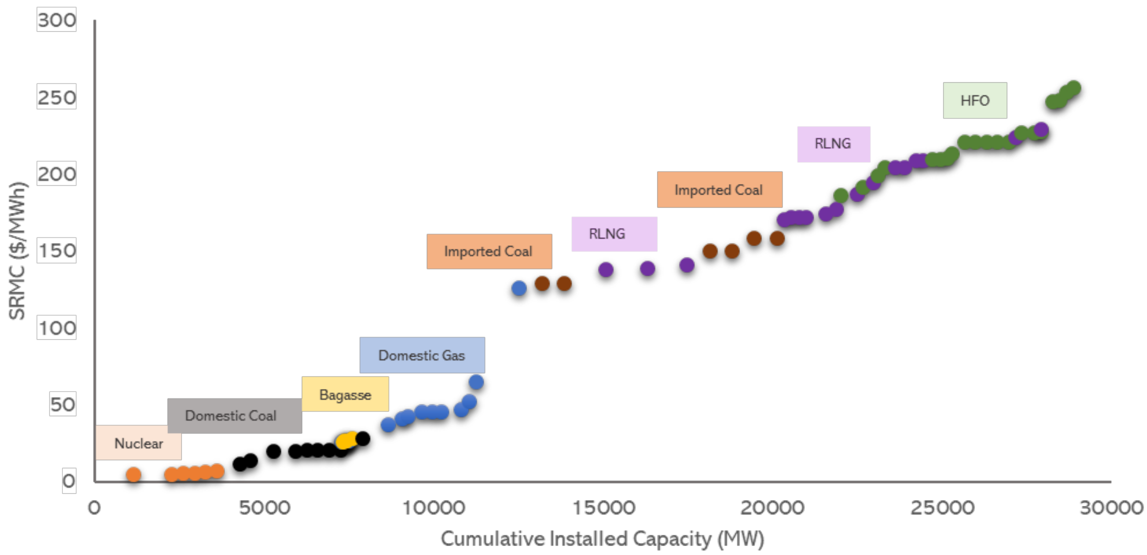
Source: Author's own illustration.

4.1 Modelling of generation technologies

4.1.1 Thermal and nuclear power plants

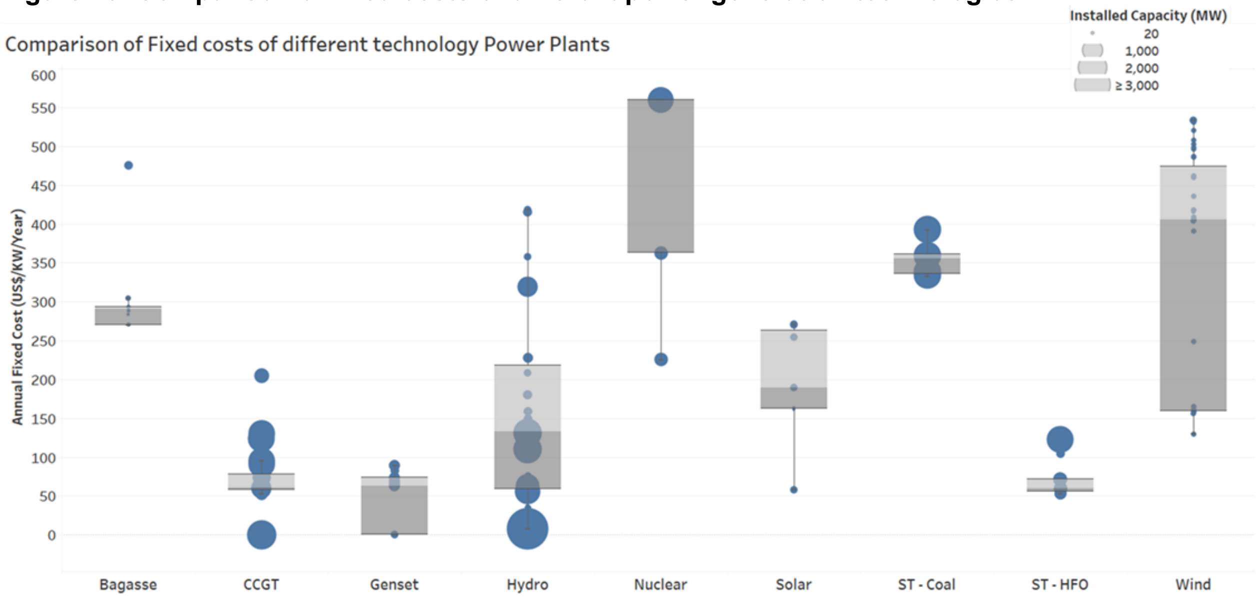
The tariff of thermal power plants comprises two main components: energy price and capacity price. NEPRA adjusts the tariff quarterly based on changes in exchange rates and the consumer price index. For this modelling exercise, the fixed operation and maintenance (O&M) costs, cost of equity, and cost of debt were individually considered for each power plant. These costs were obtained from the latest quarterly indexation and tariff adjustment data published by NEPRA for the January–March 2023 quarter. Fuel prices and variable O&M cost data for each power plant were sourced from IGCEP 2022-31 report (NTDC, 2022), according to the merit order of June 2022. The SRMCs for different types of power plant are presented in Figure 15, and Figure 16 depicts the total fixed annual costs for various power generation technologies. The comparison of fixed costs highlights significant variations in fixed costs, even for plants of the same technology. These variations arise due to differences in equity and debt costs, and for certain plants, the debt repayment period has been concluded. This phenomenon is particularly evident in hydro plants, which, being relatively old, have already amortized their costs. The fixed costs for solar and wind power plants also exhibit considerable variation, mainly because the cost of capital was higher for earlier plants.

Figure 15: Short-run marginal cost of thermal, nuclear, and bagasse power plants



Source: Author's own illustration based on NTDC (2022).

Figure 16: Comparison of fixed costs of different power generation technologies



Source: Author's own illustration based on various tariff documents of power plants and latest quarterly indexation publications from the National Electric Power Regulatory Authority.

For this modelling exercise, various other parameters were considered for thermal power plants, including maximum available capacity, minimum stable load, minimum uptime, minimum downtime, ramp rate, heat rate, forced outage rate, mean time to repair, and annual planned maintenance periods. All thermal, nuclear, and bagasse power plants were modelled at the unit level to optimize the dispatch of power plants. The fuel prices used for each power plant were sourced from the IGCEP 2022–31 report (NTDC, 2022). These fuel prices were then indexed for future years based on the Annual Energy Outlook 2022, following the same methodology employed in the IGCEP 2022–31 report.

4.1.2 Solar and wind power plants

The solar and wind power plants in Pakistan are classified as VRE technologies. These plants receive a fixed price per unit of electricity generated, which is paid for the annual generation based on agreed capacity factors. If the generation exceeds the agreed capacity, the tariff is gradually reduced until it reaches zero. VRE plants hold must-run status, which means the buyer is obligated to purchase the electricity produced by these plants. In cases where curtailment prevents VRE plants from generating electricity, the buyer is still liable to make payments based on the non-project missed volume, which entails payment without procuring electricity. A single hourly generation profile is assumed for all solar plants and all for wind plants, as these plants are concentrated within a specific geographic region. The hourly generation data for both wind and solar technologies were obtained from the renewables.ninja database.[1] In this modelling exercise, wind and solar are treated as fixed loads, neglecting curtailment from these technologies.

4.1.3 Hydropower plants

Hydropower plants in Pakistan can be categorized as small or large hydro plants. For this study, hydro plants with a capacity of less than 30 MW are collectively modelled as small hydropower plants. Hydro plants with capacities greater than 30 MW are modelled individually as large hydropower plant, and each unit of the plant is modelled. The majority of hydropower plants are owned by WAPDA. The cost structure of a typical large hydropower plant includes variable energy charges, water use charges, Indus River System Authority charges, and capacity charges. For the modelling exercise, hydropower plants are modelled based on their monthly maximum generation capability, maximum generation capability in each hour (same for one whole month), and minimum power production in each hour (same for one whole month). This approach enables modelling of the complex and seasonal hydrology of both reservoir-based and run-of-river hydropower plants.

[1] https://www.renewables.ninja.

4.2 Reliability assumptions

The reliability data of generation plants and the national grid region were employed in the projected assessment of system adequacy simulation phase of PLEXOS to compute the reliability indices, such as loss of load probability, firm capacity, and reserve margin. These indices provide insights into the reliability of the power system. The projected assessment of system adequacy module uses these data to optimize generator outages so as to minimize the costs of electricity dispatch. The reliability data used in the simulation, along with their source, are presented in Table. Additionally, the forced outage rates and annual planned maintenance durations were considered for the modelling exercise.

Table 2: System reliability data

Reliability metric	Value	Data source
Value of lost load	$800/MWh	World Bank (2020)
Loss of load probability	1%	Grid Code, 2022
Reserve margin	10%	Market commercial code, 2022
Forced outage rate, annual Planned maintenance duration	Different for each generator type	World Bank (2020)

4.3 Generation capacity expansion and retirement

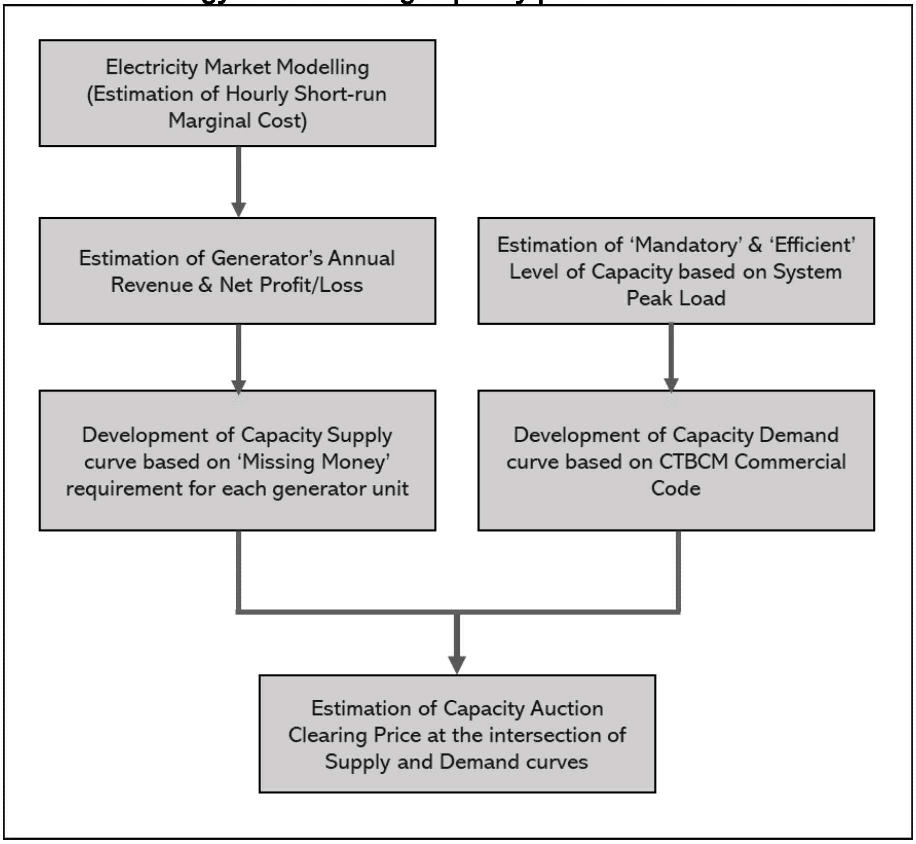
The generation capacity expansion was based on the base case scenario outlined in the IGCEP 2022-31 (NTDC, 2022). The IGCEP encompasses two types of project: committed projects and candidate projects. Committed projects are those that have either already secured funding, have been issued a letter of support, or are federal government projects. Candidate projects are the expansion candidates considered in the IGCEP expansion study. The IGCEP study exclusively optimized the expansion candidates based on an economic assessment of the power system requirements. In contrast, committed projects were executed according to their predefined timelines. For this modelling exercise, capacity expansion was not optimized. Instead, all projects listed in the base scenario of the IGCEP were assumed to be built and retired as planned in their respective time frames. As the study focused solely on the national grid region, projects in the K-Electric region were excluded. To estimate the cost of equity and cost of debt, the project debt–equity ratio was assumed to be 80:20. A 7 per cent interest rate was assumed for the debt, and a 17 per cent return on equity was assumed for the equity component. These parameters were used to calculate the associated financial costs for the projects included in the analysis.

4.4 Estimation of capacity price

In the first market design, the capacity prices are determined in accordance with the negotiated terms specified in the generators' PPAs. The methodology employed for the second market design aims to estimate the economically efficient price of capacity for the existing installed capacity in the system, considering the CTBCM rules. The modelling exercise assumes that generation capacity will be built according to the government's IGCEP, regardless of the existence of the capacity market. The generators earn revenues based on the spot prices prevailing in the hourly energy market. By comparing costs with revenues, the net profit or loss of each generator is determined on an annual basis. The generators then participate in the capacity market by bidding based on the 'missing money' required for each generator unit, which represents the difference between their annual revenues and costs. The premium necessary to cover the losses, if any, is determined as the ratio of generators' profits divided by their firm capacity.

The set of all premium creates a supply curve for the capacity market. The demand curve is created according to the CTBCM balancing mechanism for capacity regulations (*Market Operator Commercial Code*, 2022). The reference technology considered for this modelling exercise is an open-cycle gas turbine power plant, and its levelized fixed cost is assumed to be $50/kW. The efficient capacity demand level is calculated in accordance with the Market Operator Commercial Code (*Market Operator Commercial Code*, 2022). The point where the demand curve intersects the supply curve determines the capacity price, which is to be paid to all the capacity that successfully clears in the market. The overall methodology for estimating the capacity auction price is depicted in Figure 17. The de-rating factors for different technologies used to determine the firm capacity were assumed according to the Market Operator Commercial Code.

Figure 17: Overall methodology for estimating capacity price



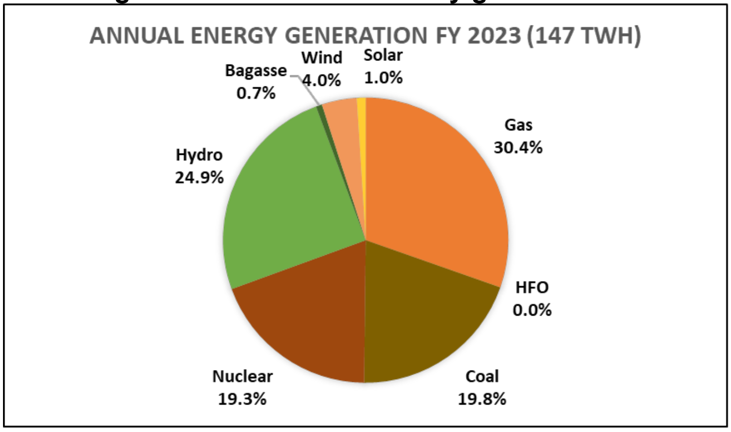
Source: Author's own illustration.

5. Pakistan power system analysis

5.1 Short-run marginal cost and energy generation

The model generates the unit commitment and hourly economic dispatch of power plants to meet the required load, considering all system and generator constraints in the short term and the medium term. Figure 18 illustrates the share of annual energy generation from different sources for FY 2023 and FY 2031. The energy mix changes due to new capacity additions in hydro, solar, and wind power plants. The share of hydro increases from 25 per cent in FY 2023 to 38 per cent in FY 2031. The share of solar and wind also increases significantly. The share of gas generation, however, decreases from 30 per cent in FY 2023 to 13 per cent in FY 2031. Gas generation is mainly replaced by low-SRMC hydro, solar, and wind generation. The average monthly SRMC resulting from this capacity expansion and monthly demand from FY 2023 to FY 2031 is depicted in Figure 19. The annual average energy price decreases from $134/MWh in FY 2023 to $94/MWh in FY 2028. This decrease occurs because low marginal cost generation, such as hydro, solar, and wind, replaces the high marginal cost generation of fossil fuel power plants. After FY 2028, it slightly increases due to an increase in demand and the retirement of some thermal capacity, which also decreases the reserve margin. Figure 19 illustrates the decrease in system SRMC despite the increase in the overall system demand.

Figure 18: Share of electricity generation from different sources in FY 2023 and FY 2031



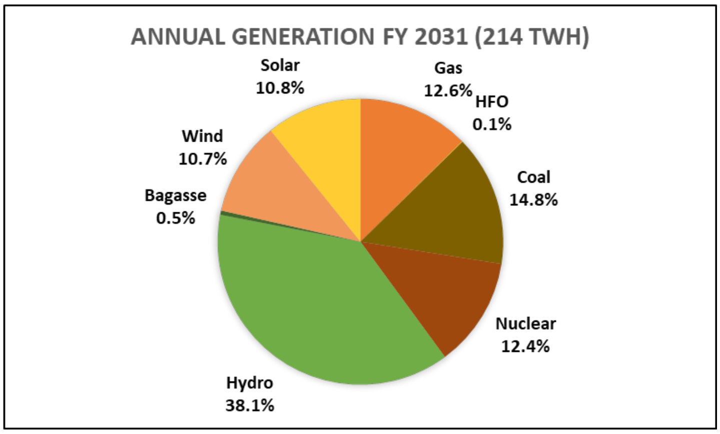
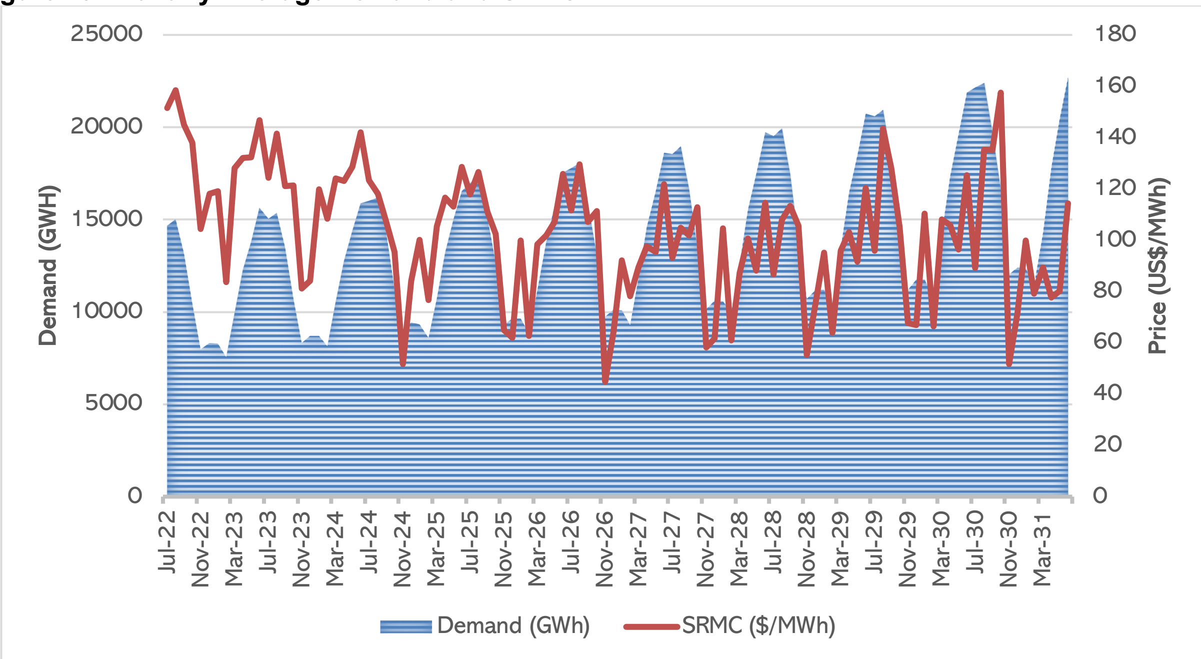


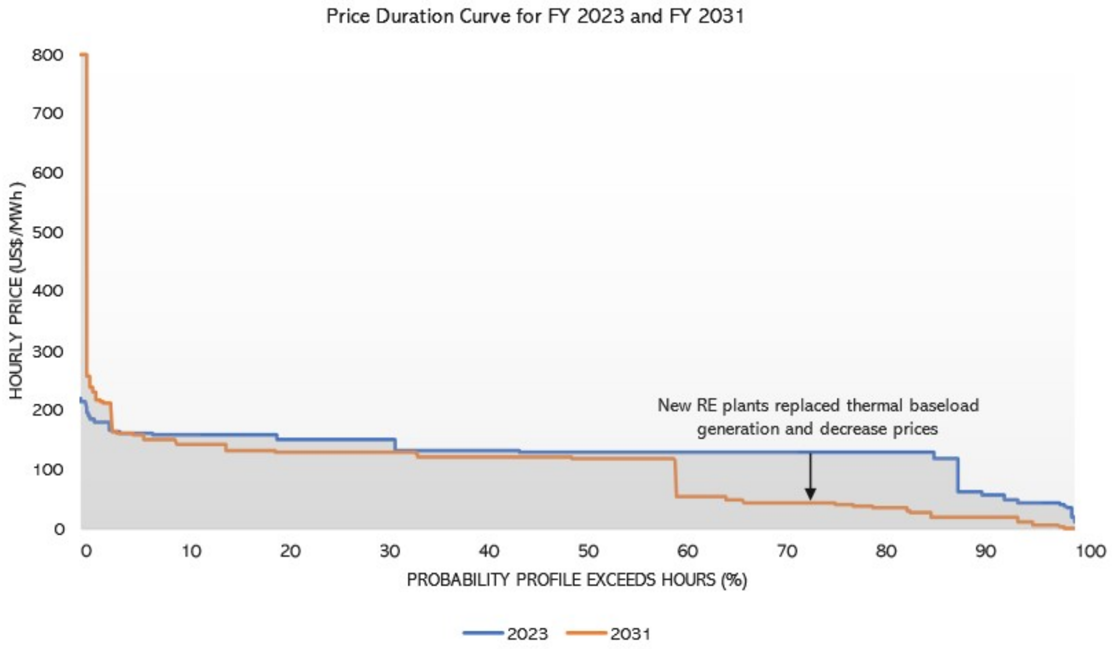
Figure 19: Monthly Average Demand and SRMC



5.2 Reserve margin

Due to the low reserve margin, there are instances during FY 2030 and FY 2031 when the price reaches the VOLL. This is depicted in the price duration curve for FY 2023 and FY 2031, as shown in Figure 20. The price difference between the two curves indicates that thermal baseload generation is being replaced by low-cost hydro generation, leading to a decrease in energy prices. However, there are also more periods during FY 2031 when the price exceeds the marginal cost of generators, primarily because the system reserves are quite low. The reserve margin is expected to decrease under the government capacity expansion plan from 29.3 per cent in FY 2023 to 8.4 per cent in FY 2031. This decline becomes noticeable after FY 2027, when some old thermal power plants will be retired. Most of the new capacity additions come from hydro, solar, and wind, and their firm capacity is less than that of dispatchable power plants, leading to a decrease in the reserve margin.

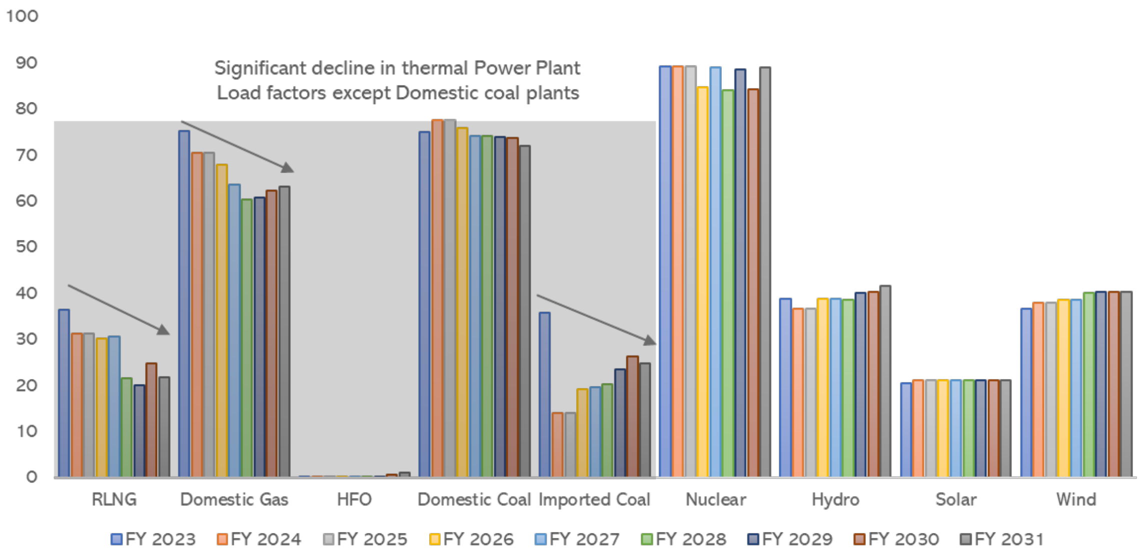
Figure 20: Price Duration Curve for FY 2023 and FY 2031



5.3 Load factors of thermal power plants

The heavy fuel oil (HFO) plants have the highest SRMC, and therefore these plants are not used in an economic dispatch except during a few hours in summer, as shown in Figure 21. The load factors of regasified liquified natural gas and imported coal power plants are also relatively low due to their higher SRMC, dropping from around 40 per cent in FY 2023 to 20 per cent in FY 2031. The domestic gas plants have lower SRMCs, but their load factors also drop from 75 per cent to 60 per cent. This drop in load factors is a result of the significant addition of new hydro and other VRE plants.

Figure 21: Weighted Average Load Factor of thermal Power Plants from FY 2023 to FY 2031



5.4 Analysis of capacity in Pakistan case study

The capacity supply curve is formed by the bids of generators in the capacity market based on their respective missing money, as shown in Figure 22 for FY 2023. Around 20 GW out of the total 35 GW firm capacity can recover its fixed costs from revenues obtained in the energy market, leading them to bid at zero price in the capacity market. The remaining 15 GW of capacity bid is based on its required missing money. The graph also reveals the missing money for different technologies, with imported coal plants exhibiting the highest missing money due to their high fixed costs and higher SRMCs, caused by the higher fuel cost of imported coal. These plants run at lower load factors, around 30 per cent annually, making it challenging for them to recover fixed costs in the energy market. Genset or steam turbine plants running on HFO, in comparison, have very low annual load factors, but they have less missing money than imported coal plants due to their lower fixed costs.

The capacity supply curve moves towards the right side and downwards in the future, as depicted in Figure 23. This shift to the right is influenced by new renewable energy capacity additions, while the downward shift is due to the completion of debt repayment for existing plants. As a result, more capacity can recover their fixed costs from the energy market, leading to fewer generators facing missing money in the future.

Figure 22: Capacity supply curve for FY 2023

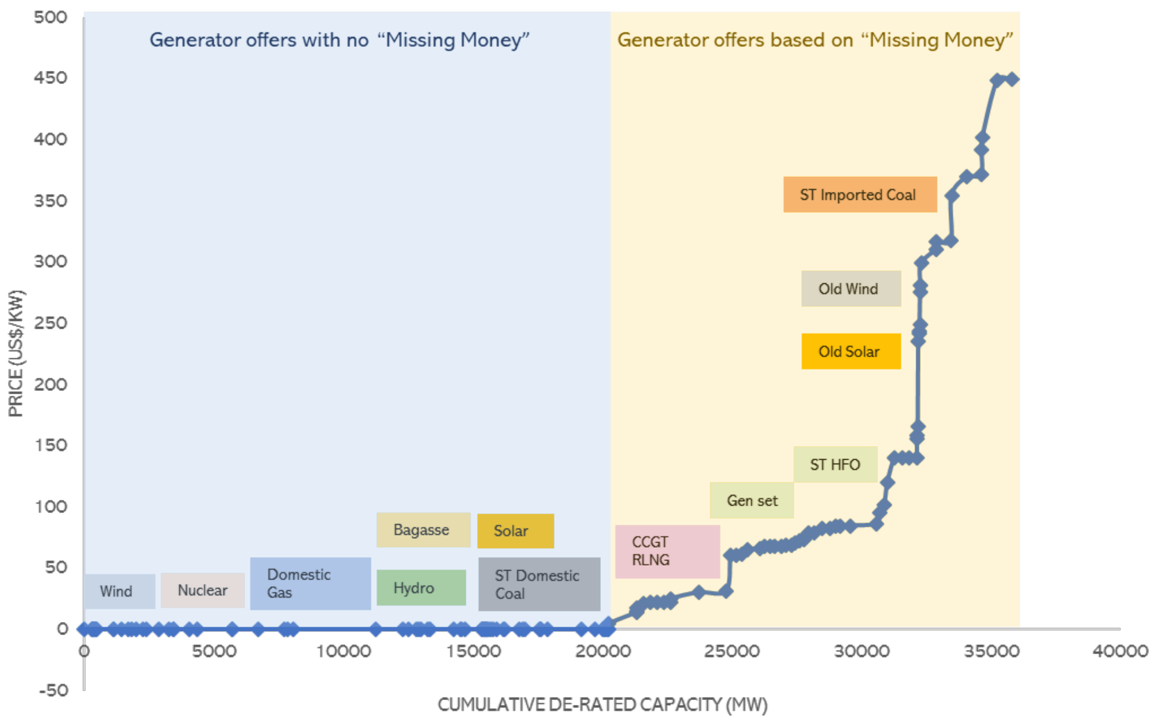
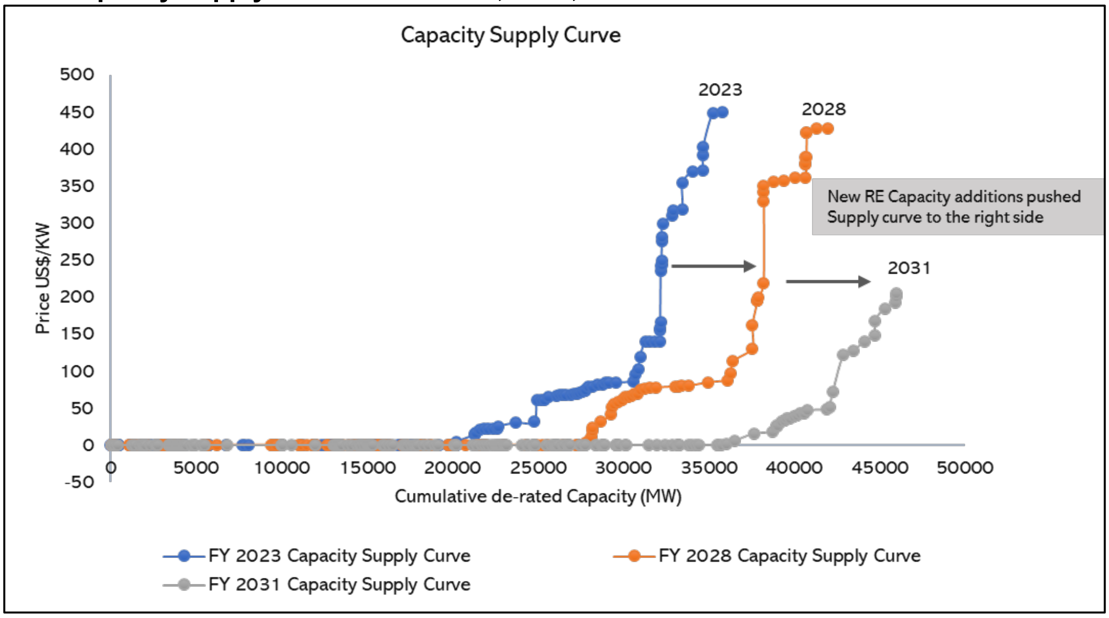


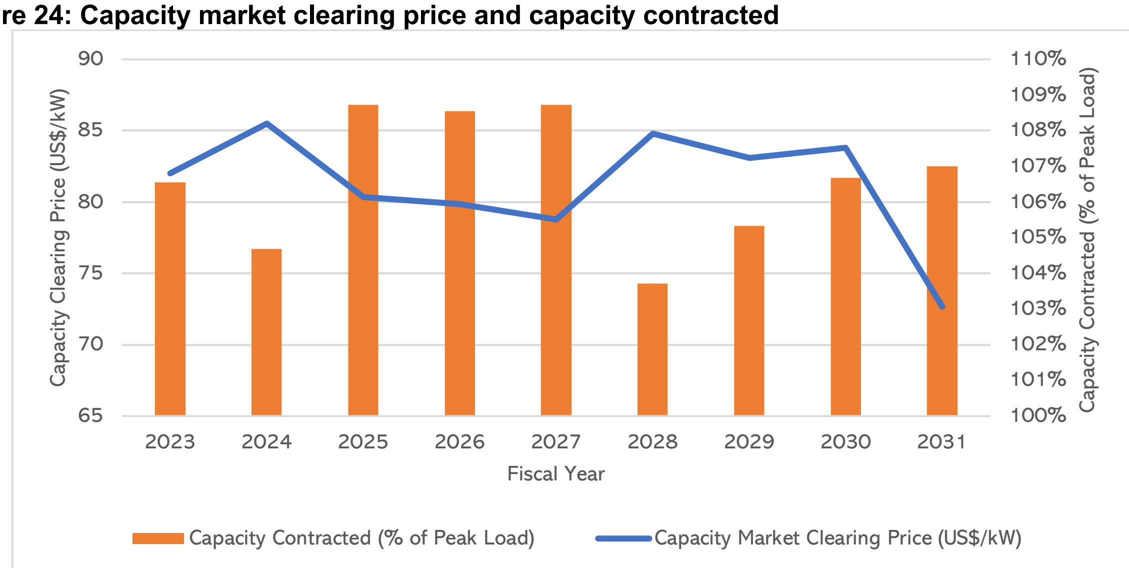
Figure 23: Capacity supply curve for FY 2023, 2028, and 2031



5.5 Capacity price based on demand and supply curve

Approximately 28.8 GW of firm capacity is cleared in the capacity market in FY 2023, which is 1.065 times the peak demand. The capacity market clearing price is assessed at $82/kW. Conversely, around 7 GW of capacity fails to clear the market, primarily due to its high capacity cost. These plants mainly include steam turbine plants running on HFO and imported coal, as well as some older wind and solar plants with high capital costs. The capacity market clearing prices and contracted capacity for the subsequent years are shown in Figure 24. The capacity market clearing price remains relatively stable, ranging between $75/kW and $85/kW throughout the years. The contracted capacity reaches its peak in FY 2027 at 1.087 times the peak demand but experiences a sudden decrease in FY 2028 to 1.037 times the peak demand due to the retirement of several thermal power plants. In the following years, the contracted capacity fluctuates between 1.05 and 1.07 times the peak demand. However, the contracted capacity never meets the reserve margin target of 10 per cent. This reveals some underlying issues, where although there is firm capacity available to meet the reserve margin, it is too expensive to be cleared in the capacity market. Additionally, the increasing share of new capacity comes from VRE sources with low de-rating factors, resulting in their relatively smaller share in the contracted capacity.

Figure 24: Capacity market clearing price and capacity contracted



5.6 Comparison of capacity and energy prices under different market mechanisms

Figure 25 illustrates the annual capacity cost under the capacity market mechanism and the capacity payment mechanism between FY 2023 and FY 2031. The annual capacity market payments are, on average, three times lower than the annual capacity payments under the existing PPA model.

However, the existence of an energy market, operating on the principle of marginal pricing, is a prerequisite for the implementation of a capacity market. While such an energy market enables generators to recover their fixed costs, it also leads to increased overall energy payments for consumers. Figure 26 illustrates the capacity and energy prices under the two different market models. Notably, the energy price in the second market design experiences a significant increase compared with the first market design (PPA contract model). This is because the generators receive the spot market price for the energy they generate, which is higher than the energy price set in the PPA contracts, particularly for baseload plants. This results in higher electricity prices for consumers. Specifically, the overall electricity price is 44 per cent higher in the second market design than in the existing PPA model for FY 2023, and this difference increases to 65 per cent by FY 2031. The total electricity generation costs for the study periods are projected to be $130 billion in the PPA model and $184 billion in the market model.

Figure 25: Annual cost comparison of capacity market and capacity payment mechanism

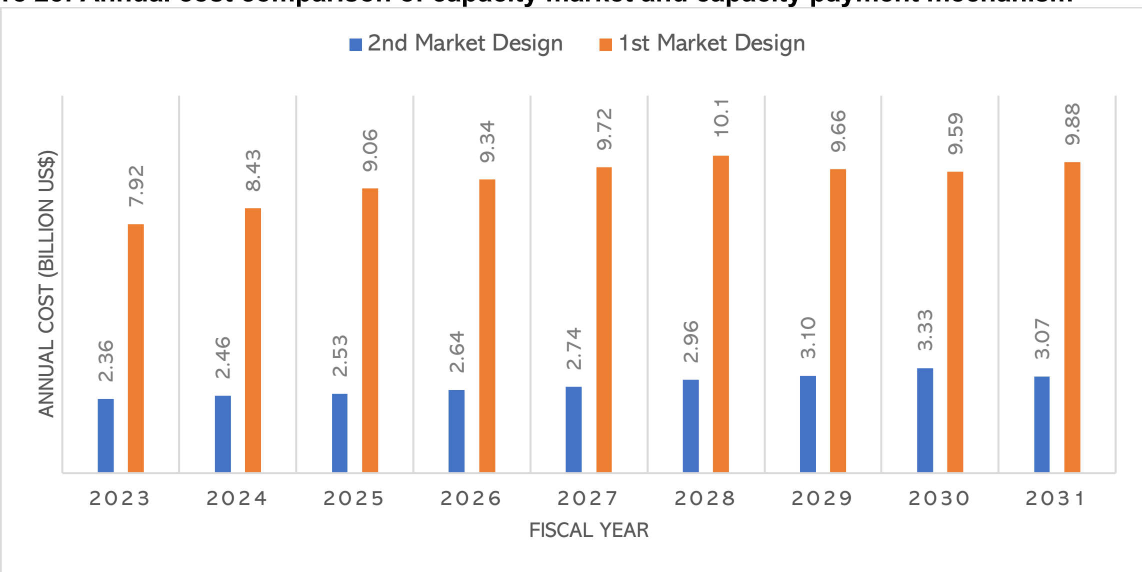
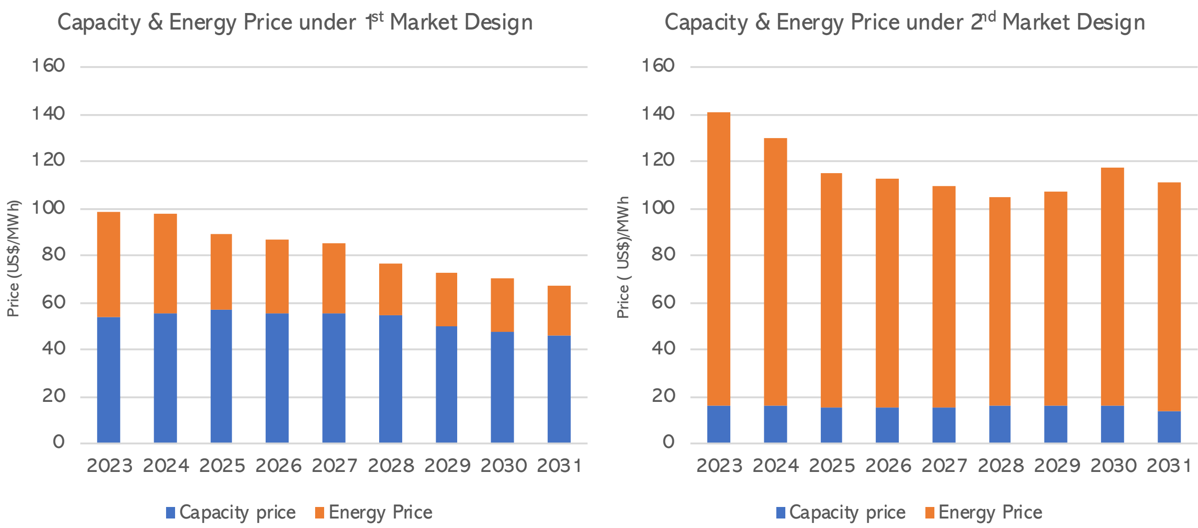


Figure 26: Capacity and energy price under two different market mechanisms



5.7 Inherent inefficiency of existing PPA-based market model (1st market design)

The existing two-part tariff structure in a PPA-based market model does not promote competition and efficiency. In this market model, the energy payment to generators is the sum of fuel costs and variable O&M costs. This effectively means that generators receive energy payments equal to their production costs. Capacity payment, however, is the sum of all annualized fixed costs paid to each thermal, nuclear, hydro, and bagasse generator. In the absence of an energy market that operates on the principle of marginal pricing, there is minimal incentive for a generator to produce electricity while receiving its marginal price, which is equal to its production cost. This incentivizes generators to rely on capacity payments, leading to rent-seeking behaviour and impacting resource adequacy.

For example, in the case of the most expensive generator, with high marginal costs, positioned at the bottom of the merit order, and with a low probability of producing electricity during the whole year, it may still be attractive for it to receive capacity payments without adequately maintaining its plant. Although it could be argued that there are penalties in place for non-availability, they may be too low and offset by the fixed capacity payments. This structural flaw in the two-part tariff of the PPA market model could be addressed by either implementing take-and-pay contracts with only one payment linked to the amount of energy produced or by transitioning towards an energy market based on the hourly SRMC that clears at the price set by the most expensive generator's dispatch.

5.8 Proposed electricity market design in Pakistan

The modelling results indicate that the introduction of an energy market will increase revenues for generators with low SRMCs, leading to an escalation in energy prices. On the other hand, the establishment of a capacity market is expected to decrease annual capacity costs. However, the overall electricity prices are on average 42 per cent higher in the case of the energy and capacity market than in the case of the PPA-based market. The results also show that new hydro, solar, and wind plants will be able to recover all of their fixed costs from the energy market revenues, due to their low SRMCs. While nuclear plants have the highest fixed costs, their exceptionally low SRMCs equip them to also fully recover fixed costs from the energy market. The power plants operating on HFO exhibit the highest SRMCs, yet the most significant amount of missing money relates to imported coal-fired plants. These coal plants, while having lower SRMCs than HFO-based plants, experience very high capacity costs. Because of their lower load factors, the revenues they obtain from the energy market are insufficient for the recovery of their fixed costs. Consequently, the coal-fired plants encounter substantial missing money in the energy market. In the capacity market, their bids based on this missing money are unlikely to clear the market, given that plants with lower fixed costs, such as combined cycle gas turbine power plants and steam turbines running on HFO, already fulfil the required capacity. The outcome of such capacity retirements will be an increase in the near-term rise in SRMC; however, this will be accompanied by a significant reduction in capacity costs.

However, these plants possess take-or-pay contracts with the government, and their debt service remains ongoing. Upon completion of debt repayment for these plants, their fixed costs will decrease by approximately 50 per cent. Notably, the majority of high-fixed-cost plants were commissioned post-2017. Therefore, it is recommended to initiate the development of capacity markets around 2027, a timing that aligns with the projected completion of debt repayment for most plants, excluding nuclear. This temporal alignment will result in most thermal plants having only two types of fixed cost: fixed O&M costs and fixed equity costs. The introduction of a capacity market will promote competition and incentivize generators to minimize their fixed costs, particularly in terms of return on equity, consequently contributing to cost reduction. At the same time, an energy market functioning on the principle of marginal pricing will facilitate the revelation of true marginal costs, decreasing the SRMC of generators and enhancing economic dispatch. The principal rationale underlying the introduction of energy and capacity markets is their capability to employ price signals in determining optimal technology deployment, thus ensuring system-wide efficiency.

5.9 Efficacy of CTBCM in ensuring resource adequacy

Theoretically, the CTBCM's capacity obligation mechanism holds the potential to effectively ensure resource adequacy for Pakistan's electricity system. This is achieved by imposing explicit capacity obligations on DISCOs and competitive electricity suppliers. The mechanism further functions as an incentive for DISCOs to actively manage their peak demand. However, in practice, certain limitations are apparent. Notably, DISCOs often lack the technical and financial capability necessary for the efficient procurement of energy demand and capacity obligations, thereby hindering their capacity to manage associated risks. This may increase the overall cost of capacity borne by regulated consumers. An attempt has been made to address this issue through the establishment of an autonomous entity, the independent auction administrator. Yet the extent to which this entity can effectively facilitate DISCOs in capacity procurement while concurrently mitigating investment risks for new generation capacity remains uncertain.

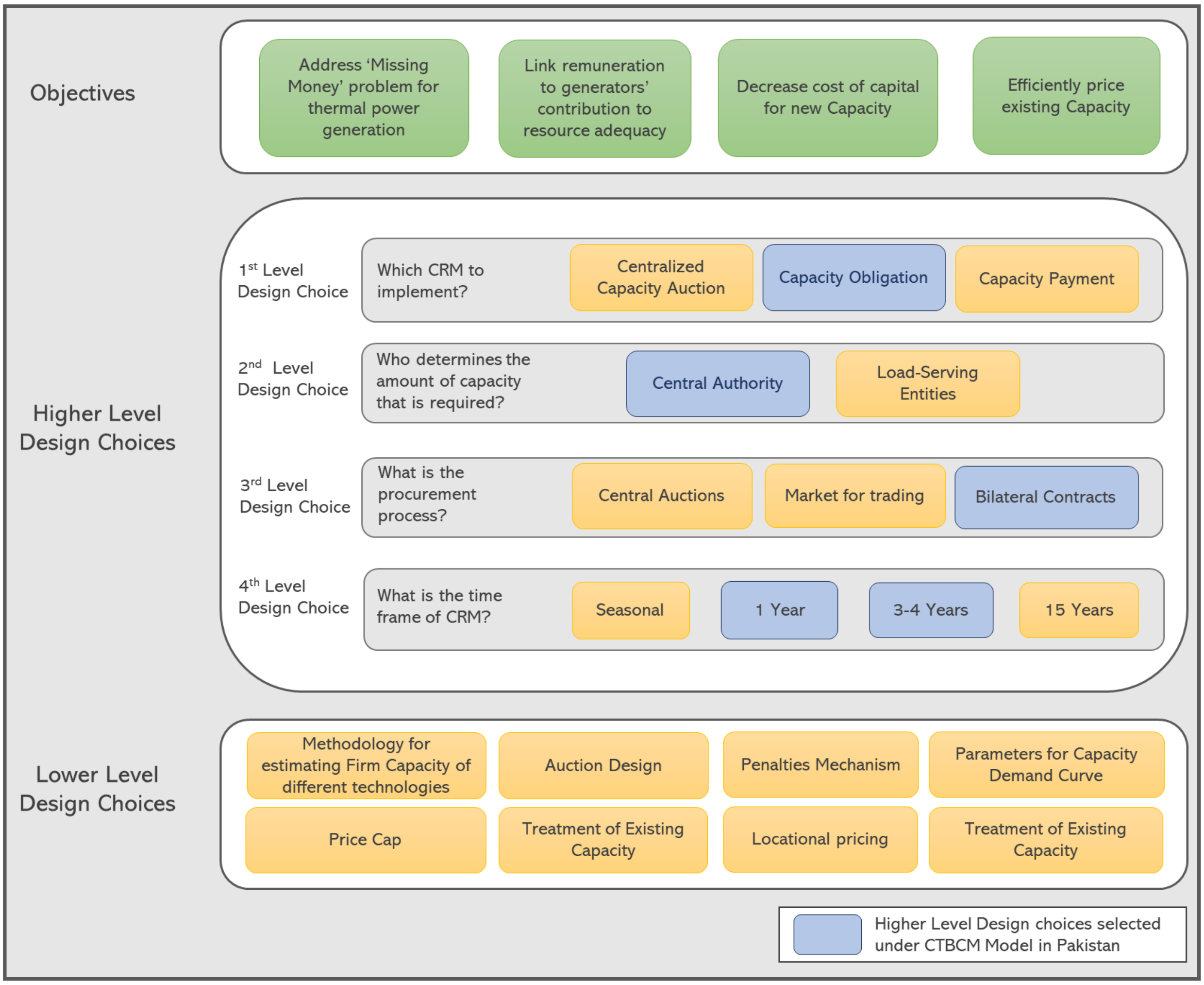
6. Opportunities for capacity remuneration design for Pakistan

Based on the modelling and comparative analysis of the different CRMs, a framework has been proposed for the development of a suitable CRM in the local context of Pakistan. A CRM can serve multiple objectives, depending on the characteristics and challenges of the local power system. In the context of Pakistan, four key objectives have been identified for an efficient CRM design: (i) addressing the missing money problem, (ii) decreasing the cost of capital for new capacity, (iii) linking remuneration to generators' contribution to resource adequacy, and (iv) efficiently pricing existing capacity. The design of a suitable CRM involves various choices, as presented by Riesz et al. (2015) in a framework, which is extended to create a holistic framework in the local context of Pakistan, as illustrated in Figure 27. This framework serves as a comprehensive guide to developing a well-structured and effective CRM tailored to the unique requirements and challenges of Pakistan's power system.

The CRM design choices can be categorized into higher and lower level design choices. The higher level design choices are further subdivided into different levels. The first level involves deciding the type of CRM to implement, which depends on the kind of capacity product to be traded. The options in the case of Pakistan include an existing capacity payment mechanism, a centralized capacity market, or the imposition of capacity obligations on load-serving entities. The selected design choice should align with the overall objectives of the CRM. Given the absence of a mature energy market in Pakistan, reliability options and strategic reserves might not be practical solutions. (The advantage of both of these types of CRM is that they can minimize the distortion in energy markets, but no energy market exists in Pakistan.) The second-level design choice is establishing what type of entity will be responsible for determining the required amount of capacity product to ensure resource adequacy. Two options exist: (i) a central authority, typically the system operator, could determine the required capacity product or (ii) load-serving entities themselves could decide the amount of capacity based on their demand forecasts and only face penalties if they fail to meet the capacity requirement. The third level of design choice involves determining the capacity procurement process. Three potential options are available: (i) a central authority itself procures capacity on behalf of load-serving entities, (ii) load-serving entities procure capacity through bilateral contracts, or (iii) a market mechanism is established by the central authority to facilitate capacity trading, with a balancing mechanism in place to address any shortfalls. The fourth-level design choice is setting the time frame for the capacity mechanism. This time frame could range from short-term periods, such as a day, month, or season, to longer-term periods, such as one year, three to four years, or even 15 years.

At the lower level, other design choices become relevant, depending on the specific type of CRM implemented. These design choices include determining the parameters for the demand curve in the case of capacity auctions or balancing mechanisms. Additionally, establishing a methodology to assess the contribution of different generation technologies to system adequacy and assigning de-rating factors for generation technologies are essential considerations. Decisions regarding whether capacity products should be procured based on location, as well as the auction format and penalty mechanism, are also critical design choices in the implementation of a CRM. Furthermore, the inclusion or exclusion of existing capacity within the CRM constitutes another pivotal design choice.

Figure 27: Framework for designing a capacity mechanism in Pakistan



Source: Author's own illustration

7. Recommendations

The implementation of an efficient CRM in Pakistan has three prerequisites. First and foremost, there should be a well-functioning short-term energy market, ideally operating on an hourly basis. This market should be based on a marginal pricing mechanism, where the market clearing price is determined by the marginal cost of the marginal power plant and paid to all generators producing electricity. Such a set-up will enable the most efficient dispatch of generators based on their marginal costs. Consequently, baseload and other low-SRMC generators will be able to recover their fixed costs from the energy market. This short-term market efficiency is crucial for the success of the CRM, as it will improve efficiency and competition.

Second, it is imperative to enhance the performance of DISCOs through privatization and improved financial health. Strengthening DISCOs will be vital to mitigate the impact of capacity obligation costs, especially for financially weaker DISCOs. Improved financial performance of DISCOs will help them effectively meet their obligations in the capacity market and contribute to the overall efficiency and stability of the CRM.

The third prerequisite is the renegotiation of existing long-term contracts with generators to move away from economically inefficient fixed capacity payments mechanism. Instead, efforts should be made to convince generators to embrace a market-based CRM. In doing so, plants that contribute to resource adequacy in an economically efficient manner will be suitably rewarded through the CRM. This shift away from fixed capacity payments to a market-based mechanism will better ensure the security of supply and promote cost-effective generation.

Without fulfilling these three prerequisites, the implementation of a CRM in Pakistan will not yield substantial reductions in generation cost and improvements in resource adequacy.

7.1 Future prospects of CTBCM model

Looking ahead, the CTBCM model should serve as a foundation for establishing short-term markets for electricity dispatch and trading. Combining long-term contracts with short-term markets will enhance efficient dispatch and encourage long-term investments in power generation capacity. To further this progress, the balancing mechanism for capacity should evolve into an annual capacity market after existing contracts have concluded. Such a market will determine efficient prices for existing capacity, signal investment opportunities in new capacity, and prompt the retirement of uneconomical capacity that is either too expensive or has huge missing money problems. This will result in investment decisions that prioritize economically efficient technologies aligned with the system's requirements.

7.2 Study limitations

The research study also has some limitations. The energy and capacity market model assumes that generators bid in the hourly energy market based on their energy price as agreed in the PPA. In reality, the existence of an energy market would compel generators to reveal their true marginal prices, and this could potentially decrease due to competition for dispatch, leading to a possible reduction in overall energy prices in the spot market. Similarly, a capacity market could push expensive generators with substantial missing money and unsuccessful capacity market bids to retire. This, in turn, would have an impact on both energy and capacity prices. The exact cost reduction of energy prices in the energy market due to the aforementioned factors is beyond the scope of this study. Nonetheless, the modelling exercise highlights that the efficient price of capacity is considerably lower than what generators are currently paid. Further research could be carried out to model the influence of the capacity market on different generation technologies. This would facilitate analysis of how the presence of a capacity market might result in alterations to the energy mix.

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