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Determinants of price variations in US Capacity Markets: An Empirical Analysis

Master's thesis

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Declaration of Authorship

I have written the present thesis myself and have used exclusively the sources and aids mentioned. This thesis has not yet been submitted as an examination in another degree programme. All passages taken word-by-word or the meaning of which are quoted from published or unpublished texts, as well as all indications based on oral accounts, have been marked as such.

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Frankfurt Am Main, May 5th, 2025

Abstract

Capacity markets are designed to ensure resource adequacy by providing fixed payments to generators in addition to energy market revenues. However, concerns have emerged that strategic bidding may allow suppliers to exercise market power and distort clearing prices. This thesis investigates the extent and conditions under which market power arises in the PJM capacity market. Using a bilevel modeling framework adapted from Guo et al. (2023), we simulate strategic and truthful bidding scenarios across varying demand levels. We find that strategic bidding by large baseload generators, particularly nuclear and coal units, significantly increases their capacity revenues and, in some cases, inflates market clearing prices above competitive benchmarks. Peaking resources (e.g., RFO) also exploit tight supply conditions to raise prices, but with less consistent effects. The results highlight how PJM's market design — especially the steep VRR demand curve and high Net CONE reference price — amplifies the vulnerability to market power. Policy reforms, including flattening the VRR curve, longer commitment periods, and adjusting reference technology assumptions could mitigate these distortions. These findings contribute to ongoing debates about the efficacy and fairness of capacity markets in achieving reliable and cost-effective system planning.

List of Abbreviations

BRA	Base Residual Auction
BSM	Buyer-Side Mitigation
CC	Combined Cycle
CM	Capacity Market
CONE	Cost of New Entry
CT	Combustion Turbine
ELCC	Effective Load Carrying Capability
EFORd	Equivalent Forced Outage Rate on Demand
FERC	Federal Energy Regulatory Commission
FRM	Forward Reserve Margin
IA	Incremental Auction
IMM	Independent Market Monitor
IOU	Investor-Owned Utility

IRP	Integrated Resource Planning
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
KKT	Karush-Kuhn-Tucker
LMP	Locational Marginal Pricing
LSE	Load-Serving Entity
MOPR	Minimum Offer Price Rule
MWh	Megawatt-hour
NG	Natural Gas
Net CONE	Net Cost of New Entry
NYISO	New York Independent System Operator
PC	Planning Committee
PJM	Pennsylvania-Jersey-Maryland Interconnection
PUC	Public Utility Commission
RFO	Residual Fuel Oil
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
SMR	Small Modular Reactor
TPS	Three Pivotal Supplier Test
UCAP	Unforced Capacity
EIA	Energy Information Administration
VOLL	Value of Lost Load
VRR	Variable Resource Requirement

Contents

1 Introduction

The Pennsylvania Jersey Maryland Interconnection is responsible for facilitating energy trading, transmission and sale to customers in 13 US states. Its massive footprint and use of a forward capacity market make it an ideal market to study the efficacy of power markets. The recent surge in PJM's Base Residual Auction (BRA) clearing prices has become a focal point in the ongoing debate over the effectiveness of capacity markets in ensuring reliability while controlling costs. In July 2024, the BRA for the 2025/2026 delivery year witnessed a dramatic price increase, with clearing prices skyrocketing from $28.92/MW-day in the previous year to $269.92/MW-day (Monitoring Analytics, 2024c). This ten-fold increase has raised alarms about the design and functioning of capacity markets, a secondary market to electricity markets that trade wholesale electricity, intended to secure adequate resources for peak demand periods and ensure grid reliability[1]. Critics argue that this price surge is not just a reflection of market dynamics but a consequence of an inherently flawed market structure that distorts prices and incentivizes overprocurement. If corrective action is not taken, future auctions, such as the 2026/2027 BRA, could result in what some describe as "the most expensive" capacity auction in history, potentially costing ratepayers as much as $ 74 billion over the next two years (Shapiro and the Commonwealth of Pennsylvania, 2024).

This paper aims to critically evaluate the current capacity market model, particularly focusing on whether it can achieve the dual goals of maintaining grid reliability while minimising costs for consumers. Currently, market power is a huge issue in PJM. In the 2023 State of the Market Report for PJM, the Independent Market Monitor[2] stated:

> *The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM capacity market failed the three pivotal supplier test (TPS[3]), which is conducted at the time of the auction.*

[1]One can think of this as 'insurance'. When a generator 'sells capacity' in the auction, it means it is agreeing to be available during times of peak demand, in case there is not enough electricity to meet demand. Generators get paid regardless of whether they are called upon to operate, just like how insurance protect customers from adverse events.

[2]The Independent Market Monitor (IMM) for PJM is an independent watchdog that monitors, evaluates, and reports on market behavior to ensure fair competition, market efficiency, and compliance with rules in PJM's wholesale electricity markets.

[3]The Three Pivotal Supplier test assesses structural market power in the PJM capacity market by determining whether any combination of three suppliers is jointly essential (i.e., *pivotal*) to meet reliability requirements. The market fails the TPS test if the removal of the three largest suppliers would result in demand exceeding the remaining supply. This implies that at least one supplier (or group of three) is in a position to influence market outcomes unilaterally, indicating a structurally uncompetitive market.

Structural market power is endemic to the capacity market (Monitoring Analytics, 2024a).

This analysis is motivated by the fact that several countries such as Spain and Germany are considering adopting a capacity market model, but the performance of such models has been mixed, as discussed by Simoglou and Biskas (2023). Jenkin et al. (2016) discusses how, as renewables increasingly take a bigger share of grids and suppress wholesale electricity prices, capacity market payments become more and more important for the profitability and survival of thermal generators. Therefore, a critical evaluation is required before implementing such a market, especially given that the German and Spanish grids rely heavily on renewables, and Hittinger and Rogers (2019) discuss how renewables are disadvantaged in capacity markets.

Specifically, the analysis models the market clearing process used by PJM (a mature forward capacity market) to set the price and visualize how different generation technologies have variable and uneven power to set market outcomes. These results are then contrasted with similar metrics in the NYISO market. NYISO, while still a formal capacity market, has shorter horizons and more granular location-based capacity zones, with strict local requirements (e.g., New York City). This thesis also extends to understanding how variations of these market features manifest in price differences across power markets. This paper attempts to use key differences in the PJM and NYISO capacity markets to understand whether varying certain features of the market (such as auction horizon, 1-month in NYISO vs 3 years in PJM) can work as a slider for policymakers to pursue certain market outcomes such as better risk hedging for high-cost entrants[4]. Finally, this paper explores broader issues of capacity market design. The question that arises is whether these markets can adequately fulfill their purpose of ensuring reliability with perhaps a few tweaks, or whether the fundamental structure of the market makes price distortions and inefficiencies a near certainty.

Chapter 2 gives a brief overview of how US power markets came to be, from investor-owned utilities in the 1800s, to the deregulated markets that exist today. Chapter 3 continues the discussion of electricity markets, and how the missing money problem gave rise to these 'pseudo'-insurance markets. Chapter 4 discusses the bi-level optimization model employed by

[4]The NYISO for the state of New York, and the ISONE for New England, and PJM make all the RTOs which operate mandatory capacity markets in the US (Midcontinent Independent System Operator operates a voluntary one). PJM and ISO New England are the most similar in their capacity market structure — both use multi-year forward auctions, sloped demand curves, and performance-based capacity obligations. All three of these are located in the north-eastern part of the US.

this paper to simulate strategic bidding among generators to see whether the current market setup allows exercise of market power (spoiler alert: it does.) Chapter 5 discusses the results of the market clearing under various demand levels, and explains how they differ from the neighboring NYISO.

2 How electricity markets in the US are designed

The institutional landscape of electricity provision in the United States is characterized by a high degree of structural complexity, stemming from a heterogeneous mix of ownership models, regulatory regimes, and market architectures. At its core, the sector comprises a diverse array of entities including municipally owned utilities, customer-owned cooperatives, and investor-owned utilities (IOUs), the latter of which serve the vast majority of electricity consumers. According to data from the U.S. Energy Information Administration (2019), nearly 3,000 distinct entities are engaged in the delivery of electricity, operating under markedly different institutional constraints and incentive structures. This decentralized configuration is not merely a historical artifact but a fundamental feature of the U.S. electricity system, shaping both investment decisions and consumer outcomes.

A defining feature of the U.S. electricity market is its regional heterogeneity. In certain jurisdictions, such as large urban centers, electricity is delivered by municipally owned utilities. Rural areas, by contrast, are frequently served by electric cooperatives. The dominant mode of provision, however, remains the investor-owned utility, particularly in suburban and industrialized regions. These IOUs operate within one of two broad regulatory paradigms: vertically integrated, rate-regulated monopolies, and competitive, market-based frameworks. The regulatory model to which a given utility is subject has profound implications for price formation, investment incentives, and the allocation of risk between producers and consumers.

In states adhering to the vertically integrated model, IOUs function as natural monopolies with exclusive service territories. Their operations are subject to oversight by state public utility commissions (PUCs), which regulate tariffs and review capital expenditures to ensure consistency with public interest objectives. Under this regime, prices are established through a cost-of-service model wherein utilities are permitted to recover their operating and capital costs, along with a regulated rate of return on equity. This model is designed to facilitate capital formation in a capital-intensive industry while safeguarding consumers against monopoly pricing. Major capital investments typically require prior approval from state regulators. In many jurisdictions, this approval process is embedded within an Integrated Resource Planning framework. The IRP process mandates that utilities periodically submit comprehensive demand forecasts and investment roadmaps to demonstrate that future resource needs will be met in an economically efficient and environmentally sustainable manner. While this regulatory architecture promotes transparency and long-term planning, it also shifts investment risk onto ratepayers. The case of the abandoned V.C. Summer nuclear project in South Carolina[5], in which consumers were compelled to bear the costs of an incomplete facility, exemplifies the distributional consequences of this risk allocation mechanism.

Despite their vertical integration, utilities in regulated states routinely engage in bilateral wholesale transactions with neighboring entities. These exchanges, often facilitated during periods of relative scarcity or abundance, enhance operational flexibility and can yield significant cost savings. Such transactions are subject to federal oversight by the Federal Energy Regulatory Commission (FERC), which regulates interstate electricity sales and transmission.

By contrast, states that have adopted market-based frameworks—commonly referred to as deregulated or restructured markets—have decoupled generation from transmission and distribution. In these jurisdictions, IOUs are typically divested of their generation assets and operate solely as distribution utilities. Generation is procured through competitive wholesale markets, and consumers may choose among multiple retail suppliers. Transmission and distribution remain regulated, given their natural monopoly characteristics, but the generation component of electricity service is subject to market forces.

The transition to restructured markets, initiated in the 1990s, was predicated on the belief that competitive forces would enhance efficiency, stimulate innovation, and reduce consumer prices. However, the empirical evidence on these outcomes remains mixed. While retail choice has introduced product differentiation and enabled environmentally conscious consumption, it has also exposed consumers to greater price volatility. Moreover, the disaggregation of system responsibilities among independent system operators (ISOs), regional transmission organizations (RTOs), and market participants has introduced new challenges in coordinating invest-

[5]As detailed in Order No. 2018-804 by the Public Service Commission of South Carolina (2018), customers had already paid approximately $2 billion for the failed V.C. Summer nuclear project.

ment and maintaining reliability.

FERC plays a pivotal role in overseeing wholesale electricity markets in restructured regions. Established in 1977 as the successor to the Federal Power Commission, FERC exercises jurisdiction over interstate electricity transactions, transmission planning, and market conduct. Its mandate includes ensuring just and reasonable rates, promoting reliable service, and fostering efficient market outcomes. The creation of ISOs and RTOs, institutionalized regional coordination of wholesale electricity markets and grid operations. Today, approximately two-thirds of U.S. electricity load is served within ISO/RTO regions.

Table 1: 2023 Summer and Winter Peak Loads by U.S. ISO/RTO

Region	**Summer Peak (MW)**	**Winter Peak (MW)**
PJM Interconnection	146,843	145,000
ISO New England (ISO-NE)	22,335	17,576
New York ISO (NYISO)	28,735	22,754
Midcontinent ISO (MISO)	124,229	107,000
ERCOT (Texas)	85,508	65,632
Southwest Power Pool (SPP)	56,184	48,142

Table 1 shows the latest figures for peak demand in each US transmission authority. Traditionally, US demand for power has been summer-peaking, in contrast to European countries such as Germany, France, Poland where demand peaks during the winter.

The structural evolution of U.S. electricity markets—encompassing both the persistence of vertically integrated models and the emergence of competitive frameworks—reflects a broader policy tension between the objectives of efficiency, equity, and reliability. Each regulatory regime embodies distinct trade-offs: vertically integrated markets offer price stability and long-term planning at the cost of diminished competition, while restructured markets promise efficiency gains and consumer choice but expose the system to heightened investment and operational risks. As the U.S. power sector confronts mounting decarbonization imperatives, aging infrastructure, and evolving demand profiles with the broader integration of technologies that require vast amounts of energy[6], the question of optimal market design remains both salient and contested.

[6]In October 2024, Google announced a partnership with Kairos Power to develop and purchase energy from multiple small modular reactors (SMRs). This agreement aims to supply up to 500 megawatts of carbon-free electricity to support the growing energy demands of AI technologies. The first reactor is expected to be operational by 2030, with additional units coming online by 2035 (Google, 2024) .

3 Capacity Markets

Liberalized electricity markets across the world since the 1980s have operated with only a wholesale electricity market that meets demand. Examples include ERCOT in Texas, NEM in Australia, Nord Pool consisting of Norway, Sweden, Finland, and Denmark. However, the biggest issue that a power market needs to solve is not simply meeting demand, but also ensuring reliability while keeping prices fair for ratepayers. This means encouraging investment in new generation technologies to keep up with growing demand. Traditionally, this has been achieved through scarcity pricing during times of energy shortages. Under the energy-only design, generators earn all of their revenue through the sale of energy and ancillary services. Prices rise substantially during times of scarcity, allowing generators to recover their fixed costs. In practice, a lack of price-responsive demand (most US customers only pay an average cost after 1-3 months for power), combined with inconsistencies between the market clearing process and actions taken by operators on grounds of reliability, has hampered the formation of efficient scarcity prices. An administrative response is to introduce an operating reserve demand curve that reflects the probability that the system operator will need to take emergency actions (e.g., voltage reductions or rolling blackouts) in order to prevent cascading failure (Hogan, 2013). As the probability of those actions approaches one, the price grows to an estimated value of lost load (VOLL), which is typically two orders of magnitude larger than average prices but varies among ISOs. Due to extreme weather events, prices can sometimes jump from average prices around $12.50/MWh to $9000/MWh, as it happened during the Texas power crisis of 2021 (U.S. Energy Information Administration, 2021). This tension between incentivizing investment while keeping prices stable for ratepayers is described as the 'missing money' problem, solutions to which remain widely contentious in the literature, but most authors agree that some form of renumeration mechanism is necessary (Borenstein, 2017; Cramton et al., 2013; Hancher et al., 2015; Hogan, 2016; Platts, 2023; Smith, 2014). There is a rich literature of authors exploring financial instruments such as options to help solve the missing money problem and hedging investor risk[7] . Hausman and Smith (2008) explored the impact of bilateral contracts between different market participants, and Shu and Mays (2022) investigated the different roles forwards and options play in risk sharing. Financial instruments and bilateral contracts take into account that while some forward CMs only look 3 years into the

[7] See Oum et al. (2006); Spyrou et al. (2024); Willems and Morbee (2010); Zhou et al. (2017) for more detailed discussion on the topic of market completeness through alternative means

future (as in case of PJM), the operational lifespan of most baseload generation, that requires high initial investment but is essential for grid reliability, is far longer that. These arrangements help investors hedge their risk more equitably. With the steady entry of renewables such as wind and solar, which have little to no operating costs, electricity prices have steadily fallen over the last decade (Quintana, 2024; Seel et al., 2018; Wiser et al., 2018). This makes it harder for existing generators to recover their investment from wholesale electricity markets, and fails to create the appropriate price signals for future investment in the grid. More investment is necessary as older baseload generators retire, but Mays et al. (2019) suggests that the current structure of capacity markets might share risk disproportionally across different fuel types. Specifically, generation technologies with high fixed cost but low operating costs, such as solar and wind, are not attractive investments when compared to gas-powered plants. Borenstein (2017) even suggested removing price caps altogether, emphasizing that in markets without price caps, prices can rise to levels needed to ensure resource adequacy, thereby addressing the issue. This, of course, ignores that fact that the effects resulting from sharp price spikes and fluctuations affect ratepayers disproportionately more in the long run, with climate change making extreme weather events more frequent (Agency, 2021; Seneviratne et al., 2021) .

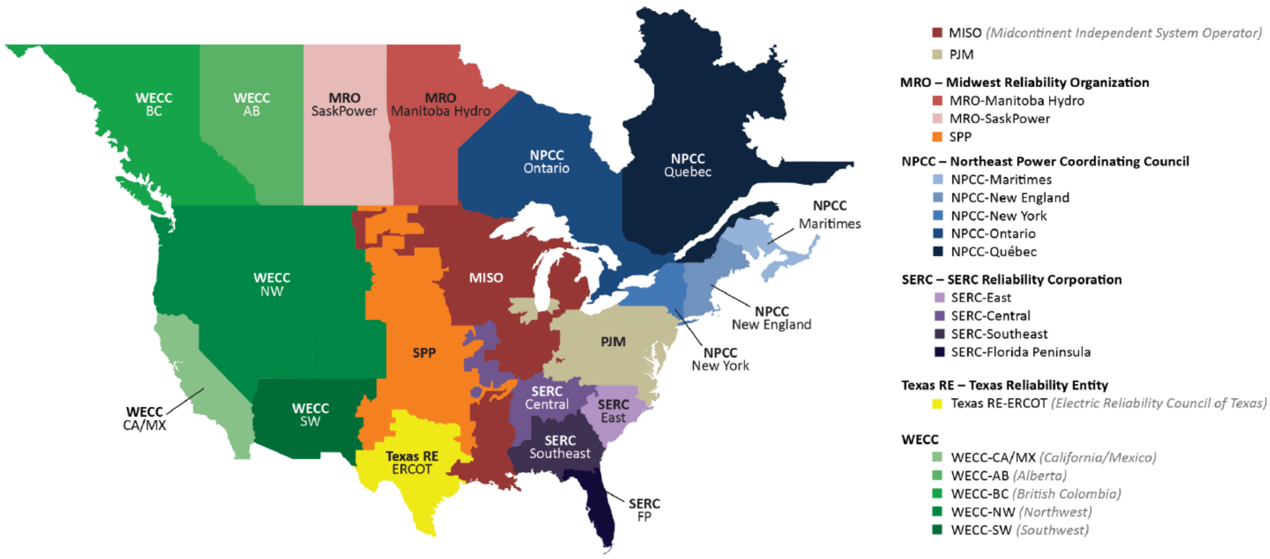


Figure 1: North American Regional Power Entities

Capacity markets were introduced as a solution to the "missing money" problem in electricity markets. Figure 1 shows the North American power systems across the continent (North American Electric Reliability Corporation, 2023). Currently PJM, New York (NYISO) and New England (ISONE) operate mandatory capacity markets, while Midcontinent Independent

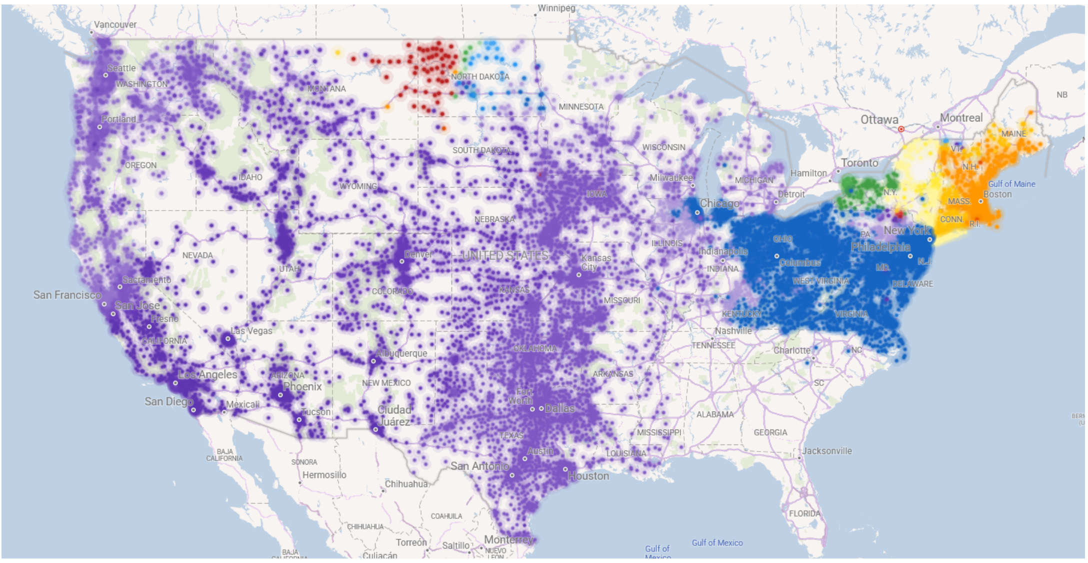
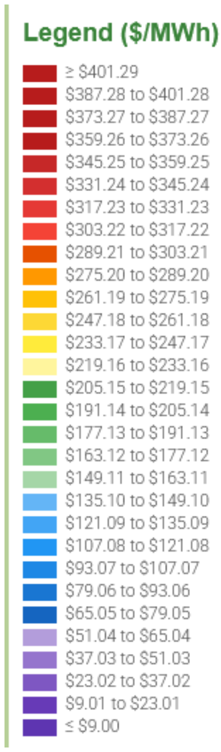


Figure 2: Heat map of electricity prices across the U.S.



Color coding by price per MWh.

System Operator (MISO) operates a voluntary one. The idea is simple: generators need to be compensated not only for the energy they produce but also for being available to generate electricity when demand spikes or during extreme weather events. Traditionally, utilities and grid operators ensured that sufficient generation capacity was available through regulated mechanisms. However, with the advent of deregulated electricity markets, these responsibilities shifted to market-based mechanisms, leading to the creation of capacity markets.

The primary purpose of capacity markets is to ensure that there are enough resources available to meet peak demand, which is critical for preventing blackouts. These markets allow utilities or other load-serving entities (LSEs) to procure the necessary capacity ahead of time, which helps maintain grid reliability during times of stress. In theory, these markets should provide the right price signals to incentivize investment in new generation capacity and ensure that existing resources remain available when needed.

However, capacity markets are not without flaws. Figure 2 (Nicholas Institute for Energy, Environment Sustainability, 2024) shows the electricity prices as they vary regionally in the US[8]. While capacity markets are designed to address the problem of resource adequacy, they often fail to achieve the right balance between ensuring sufficient capacity and avoiding unnecessary over-procurement. In practice, capacity markets can distort investment decisions, resulting in price volatility, inefficient procurement of excess capacity, and higher costs for consumers. Another growing issue is failure to efficiently integrate renewables into the grid, which combined with the growing tide of coal and other older baseload generators retiring artificially constrains supply. The surge in PJM's BRA prices is a glaring example of these problems in action. The rest of this chapter elaborates on this claim.

3.1 Price Distortions and the Minimum Offer Price Rule (MOPR)

One of the key issues contributing to price distortions in PJM's capacity market is the Minimum Offer Price Rule (MOPR), which is intended to prevent market manipulation and price suppression by state-subsidized resources. Under the MOPR[9], resources that receive state incentives (such as renewable energy subsidies) are required to bid into the capacity market at a higher price than they would otherwise. The goal is to prevent these subsidized resources

[8]This snapshot was taken on February 3, 2025.
[9]The analogue for MOPR in the NYISO market would be Buyer-Side Mitigation (NYISO)

from artificially lowering capacity prices, which could harm other market participants. However, the unintended consequence of this rule is that it raises the price of capacity, making it more expensive for consumers, even though the additional capacity may not be necessary for reliability.

The application of the MOPR has led to a situation where state-supported resources—such as wind and solar—are effectively excluded from the market, even though they continue to provide valuable capacity to the grid. As a result, consumers are forced to pay for redundant capacity, as they end up purchasing the same capacity that is already being provided by subsidized resources. but bought at the higher cost of the (usually) gas-powered generator. This redundant procurement drives up costs without improving grid reliability. Figure 3 (Analytics, 2024) illustrates how this manisfests in prices, with capacity making up a larger share of wholesale electricity prices over the years (excluding transmission and administrative costs, as those are exogenous, often reflecting the attitudes of ISOs towards investing in new infratructure over improving current ones). As prices in the wholesale energy markets drop, those savings are overshadowed by the massive inflation of capacity acquired and per-unit capacity prices. While the average wholesale cost of electricity for the year 2025 is yet to be determined, if the enormous jump in capacity price shown in Figure 4[10] is anything to go by, the share of power prices that is due to capacity is sure to pale all other costs in comparison.

3.2 Overprocurement and Excessive Reserve Margins

The problem of overprocurement does not end with the MOPR. Ideally, a capacity market should procure just enough capacity to meet expected demand, with a small margin for safety. However, due to flawed market design and inaccurate load forecasting, capacity markets in regions such as PJM often procure much more capacity than is needed. This is on top of the capacity that is present in the grid but cannot participate as discussed earlier.

In PJM, for example, reserve margins have steadily increased over the past decade and a half, from around 20% in 2008 to more than 36.8% in 2024 (North American Electric Reliability Corporation, 2023). During the same period, the PJM market changed from voluntury

[10] While this figure only shows clearing prices for Rest of RTO, this accounts for the cost of 70-75% of the total capacity bought. Other zones include BGE and Dominion, where the market clearing prices are even higher: $466.35 and $444.26 in 2025. Discussion by McCullough and Absar (2020) explains the 'balkanization' of PJM's operational zones, and how pivotal suppliers are allowed to create isolated operational zones where they operate de facto monopolies.

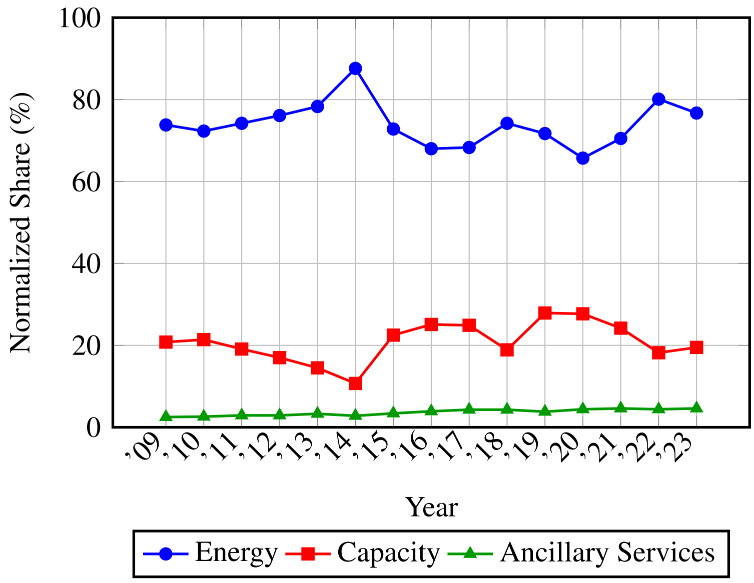


Figure 3: Normalized Shares of Energy, Capacity, and Ancillary Services in Total PJM Wholesale Cost ('09–'23)

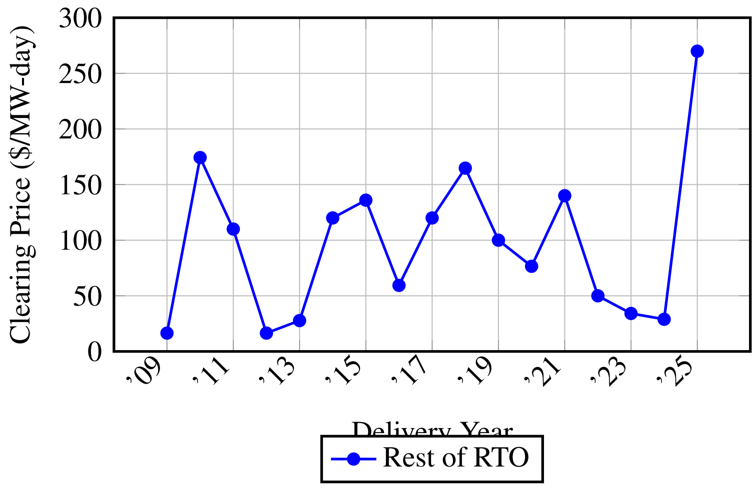


Figure 4: PJM Base Residual Auction Clearing Prices for Rest of RTO (2009–2025)

capacity trading to mandatory participation. This surplus of capacity, while seemingly beneficial for grid reliability, has come at a significant cost. Consumers are required to pay for excess capacity that is not needed to meet peak demand, and much of this capacity remains unused throughout the year. Even according to PJM's own assessment, capacity procured past 20% garners vanishingly little marginal returns (PJM Interconnection, 2017). This overprocurement is a direct result of the misalignment between the capacity market's procurement process and the actual needs of the grid. Table 2 illustrates future outlook on how much reserve margin PJM plans to have. Prospective margin of reserve for 2025 sits at 100% of total internal demand, which far exceeds the reference margin level of 14.7% (i.e. technically required by general reliability standards) 6 times over. While PJM is required to acquire enough capacity to clear the market, they are not given an upper limit on procurement, which creates misaligned incentives for PJM. Politically speaking, blackouts and lack of power due to insufficient supply looks much worse than overprocurement, as the burden to customers is latent.

The problem of overprocurement is exacerbated by the inability of capacity markets to accurately account for the evolving resource mix. As renewable energy sources like wind and solar continue to play a larger role in the energy grid, the capacity market's reliance on traditional fossil-fuel plants with high fixed costs and high variable costs becomes increasingly problematic. As we will discuss on the next section, the capacity market fails to adequately value the contributions of these low-carbon resources, resulting in an inefficient allocation of capacity and higher costs for consumers.

Table 2: PJM Demand, Resources, and Reserve Margins (2024–2033)

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	149,737	150,924	152,736	154,275	155,703	156,923	157,899	158,942	159,917	160,971
Demand Response	7,397	7,453	7,515	7,573	7,617	7,646	7,679	7,710	7,731	7,758
Net Internal Demand	142,340	143,471	145,221	146,702	148,086	149,277	150,220	151,232	152,186	153,213
Additions: Tier 1	13,090	18,234	19,715	19,706	19,706	19,706	19,706	19,706	19,706	19,706
Additions: Tier 2	7,982	88,414	109,210	126,252	135,888	139,177	141,681	141,855	144,220	144,220
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-607	-105	0	0	0	0	0	0	0	0
Existing + Transfers	181,614	180,346	179,338	179,324	179,324	179,324	179,324	179,324	179,324	179,324
Anticipated Reserve Margin (%)	36.8	38.4	37.1	35.7	34.4	33.3	32.5	31.6	30.8	29.9
Prospective Reserve Margin (%)	42.4	100.0	112.2	121.7	126.1	126.5	126.7	125.3	125.5	124.0
Reference Margin Level (%)	14.8	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7

3.3 The Changing Resource Mix: Biases Against Renewables and Storage

The design of capacity markets was initially based on the characteristics of traditional fossil-fuel plants, such as coal and natural gas. These plants, with relatively high operating costs, were the primary resources procured through capacity markets, and these markets in turn were designed to enable generators to recover their investment costs over a relatively short time horizon. However, as the resource mix evolves and renewable energy sources like wind and solar take on a larger role, the capacity market model becomes increasingly outdated (Gramlich and Goggin, 2018).

Renewable energy sources, while critical for reducing greenhouse gas emissions, have different characteristics compared to traditional generation technologies. They are often intermittent and rely on weather patterns, making their capacity value less predictable. Furthermore, storage technologies, which are critical for balancing the variability of renewable resources, are not adequately compensated in many capacity markets. These biases against renewables and storage result in a market structure that favors conventional generation technologies and fails to provide the right incentives for the transition to a low-carbon grid.

PJM has begun using the Effective Load Carrying Capability (ELCC) methodology to accredit the capacity value of intermittent resources like wind and solar. While intended to better reflect reliability contributions, PJM's implementation applies a uniform unforced capacity (UCAP) ratio to entire resource classes rather than evaluating units individually. This class-average approach does not account for historical performance or location-specific reliability, and it penalizes higher-performing renewable facilities while rewarding underperforming ones. As a result, well-sited and consistently reliable solar and wind plants are undervalued in the capacity market.

The ELCC framework also imposes unrealistic expectations on intermittent resources. A particularly revealing example occurred during Winter Storm Elliott in December 2022, when at least one solar plant was penalized for failing to generate electricity at night—an event that should have been anticipated given solar's inherent limitations. For example, a solar plant with nameplate capacity of 100W is given an effective capacity of 50W over all hours of the day, rather than using a historical generation model which NYISO uses. This was meant to account for the fact that solar is not available for half the time. The use of ELCC in forecasting overstated solar availability during critical evening hours and contributed to a mismatch between expected and available capacity, which ultimately exacerbated grid stress and contributed to widespread outages.[11]

As noted by Bothwell and Hobbs (2017), the evolution of the grid requires a shift from traditional capacity markets to models that better account for the unique characteristics of renewable resources and energy storage. The increasing variability of renewable generation and the need for flexibility in managing demand and supply require a more nuanced approach to capacity procurement. Rather than relying on a one-size-fits-all approach, capacity markets should evolve to recognize the different contributions of various types of resources and reward flexibility and responsiveness in meeting demand.

[11] See Utility Dive, "Power plant outages, flawed forecasts led to PJM's emergency alerts during Winter Storm Elliott," April 2023: https://www.utilitydive.com/news/pjm-winter-storm-elliott-grid-outage-forecast-capacity/647604/.

4 Properties of the Capacity Market Model

As discussed so far, a myriad of issues plague the current PJM capacity market design. While most of these issues are outside the scope of our analysis, this paper will narrow its focus to the market clearing process, the investment levels and marginal costs of various generation technologies, and strategic bidding as it relates to pivotal suppliers. We adopt the quadratic convex optimization framework for capacity investment decisions introduced by Guo et al. (2023). This is to ask the fundamental question of this paper:

How do the differences in market structure between PJM and NYISO manifest in clearing prices, revenue and profitability for different technologies under strategic bidding conditions?

This question will help market operators understand which features can be adjusted to bring about desired outcomes. Guo et al. (2023) have performed a similar analysis of the NYISO market, a neighbouring RTO with a capacity market design similar to that of PJM. This allows us to compare and contrast some of the salient features of both markets, while assessing whether either version of the capacity market generates the expected outcomes. For the analysis of the market clearing problem, the paper uses the same notation as (Guo et al., 2023) for ease of comparison.

In the context of the capacity market, load-serving entities (LSEs) function as buyers responsible for procuring sufficient capacity to fulfill their reliability requirements, while generators, as sellers, are obligated to offer the contracted capacity into the energy market. The model developed in this study is based on PJM's specific market design.

In PJM, the capacity market is called the Reliability Pricing Model (RPM). RPM consists of several auctions, including the Base Residual Auction (BRA) and three Incremental Auctions (IAs). The BRA is held three years prior to the delivery year, and it determines most of the capacity obligations. For modeling simplicity, we consider a stylized single-round uniform price auction akin to the BRA.

Throughout this section, we assume participants are price takers, market power is absent, information is perfect, and there are no externalities, satisfying the conditions of perfect competition. In the next chapter, this assumption is relaxed, and market power dynamics are explored in detail.

4.1 Net CONE, the demand curve, and market clearing mechanism

In PJM's capacity market, a key concept is the *Net Cost of New Entry* (Net CONE), denoted W_g for generator g. Net CONE represents the levelized annual cost of building a new representative[12] peaking resource, minus the expected profits from the energy and ancillary services markets. It defines a reference point for capacity market pricing and investment incentives. Formally:

$$\text{Net CONE} = (\text{Annualized investment cost} - \text{Expected energy market profit}). \tag{1}$$

The PJM demand curve, known as the Variable Resource Requirement (VRR) curve, relates capacity prices to cleared quantities. It is defined by three points (Newell et al., 2018):

- At 100% of the reliability requirement (RCP), price is $1.0\times$ Net CONE[13],
- At 103% of the requirement, price is $0.85\times$ Net CONE,
- At 97% of the requirement, price is $1.5\times$ Net CONE.

While the original VRR curve[14] better reflects institutional features—such as sharp price increases when cleared capacity falls below reliability requirements—it introduces non-convexities, making equilibrium computations less tractable.

Figure 5 illustrates market clearing outcomes under two representations: the original kinked PJM VRR curve and its linearized approximation.

[12] In the PJM it used to be a Combined Cycle Gas peaker, but recently they change this to a Combustion Turbine generator that has higher net CONE, which directly influences prices can and clearing prices. PJM Interconnection (2022)

[13] This was approximately $300 / MW-day in the PJM BRA 2024/25

[14] For an extensive discussion on the PJM VRR curve's design, policy objectives, and potential improvements—such as slope adjustments or comparison with NYISO and ISO-NE—see Newell et al. (2018). PJM's curve sits between ISO-NE's flatter and NYISO's steeper demand curves.

(a) Original PJM VRR Curve with Supply

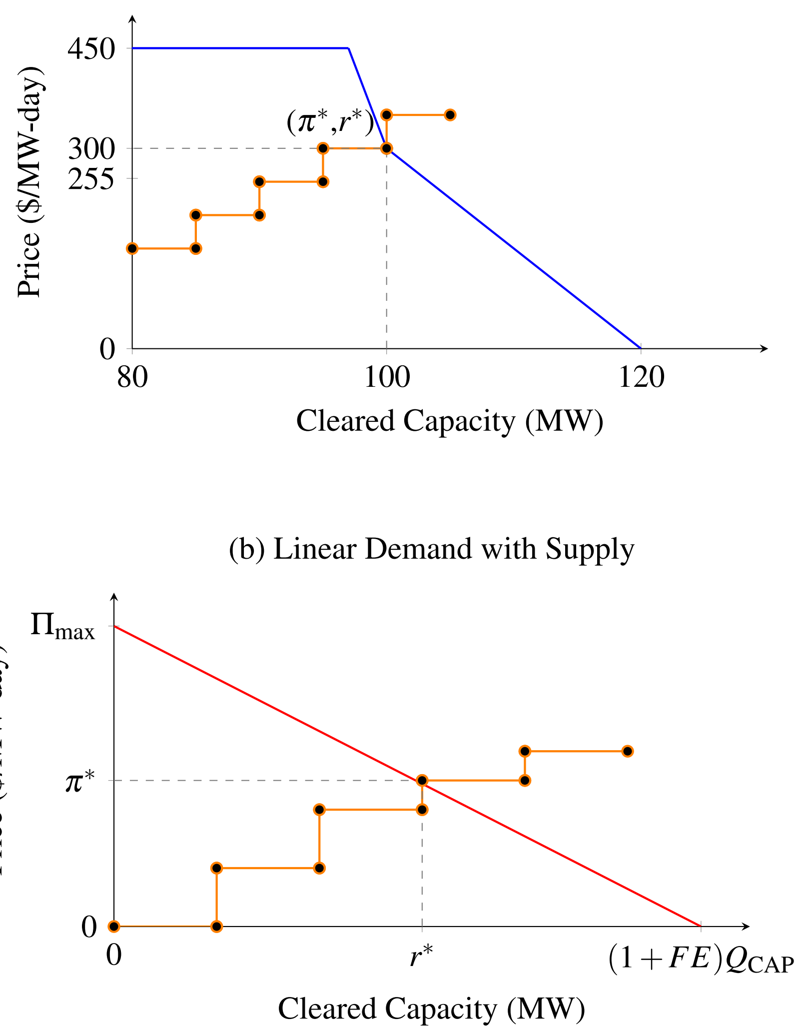


Figure 5: Market equilibrium under (a) original PJM VRR curve and (b) linear approximation.

4.2 Linearized Demand Curve Approximation

To facilitate optimization and analytical tractability, we adopt a linear approximation of the VRR curve. Let $\Pi_{\max}$ denote the price cap and $-A$ the slope. The demand function is then:

$$\pi = -Ar + \Pi_{\max}, \tag{2}$$

where r is the total cleared capacity and π is the market clearing price.

The key points used to construct this linear approximation are:

- $(0, \Pi_{\max})$ = maximum price at zero cleared quantity,
- $((1+FE)Q_{\text{CAP}}, 0)$ = excess capacity threshold beyond which price falls to zero.

Here, Q_{CAP} is determined by:

$$Q_{\text{CAP}} = (1 - EFORd)(1+\Gamma)D_{\text{Peak}}, \tag{3}$$

where Γ is the installed reserve margin, $EFORd$ is the Equivalent Forced Outage Rate on Demand (represented by FU_g in the optimization problem) , F is the excess reserve margin fraction, and D_{Peak} is peak demand. In PJM, typical values are $\Gamma = 31.2\%$, $EFORd = 5.5\%$, and $F = 20\%$[15] (Monitoring Analytics, 2024b).

Given these parameters, the slope and price cap are:

$$A = \frac{C^{\text{CONE}}}{F \times Q_{\text{CAP}}}, \quad \Pi_{\max} = \frac{1+F}{F} C^{\text{CONE}}. \tag{4}$$

4.3 Market Clearing via Convex Quadratic Model

The capacity market clearing problem can be formulated as a convex quadratic optimization:

Capacity Market Equilibrium Problem (CM-QC):

$$\begin{aligned}
\max_{q_g, h_g} \quad & -\frac{A}{2}r^2 + \sum_{g \in G} (\Pi_{\max} - W_g) q_g && (5)\\
\text{subject to} \quad & r = \sum_{g \in G} q_g, && (6)\\
& 0 \le h_g \le FU_g P_g^{\max}, \quad \forall g \in G, && (7)\\
& 0 \le q_g \le h_g, \quad \forall g \in G, && (8)
\end{aligned}$$

where:

- W_g is the net CONE of generator g,
- q_g is the cleared capacity of generator g,

[15]Newell et al. (2018) in their report on the PJM VRR curve, presents the demand curves used in NYISO, PJM and ISO-NE (Figure 17, page 51). Due to the unique values of Γ, $EFORDd$ and F, as well as reference technology C^{CONE} for use in in each ISO, the slope and price cap of the demand functions vary, which in turn has significant effects on the clearing price and clearing quantity. Market operators are able to tweak these feature of their demand curves to achieve certain market outcomes, such as higher clearing price by shifting the demand curve to the right (if they believe current market conditions suppress prices). While the design of the demand curve itself is quite important, it is outside the scope of this paper. However, because this paper uses different values of the aforementioned quantities, as well as D_{Peak} and C^{CONE} for the PJM market, and we find their influence in our results. We shall return to this discussion later.

- h_g is the offered capacity,
- FU_g is the forced outage (unforced) adjustment,
- $P_g^{\max}$ is the qualified maximum capacity,
- r is total cleared capacity.

The objective is strictly concave and the constraints are linear, ensuring convexity. Moreover, the problem's constraints (6),(7), and (8) are linear. Given the convexity of (CM-QC), we can characterize the market equilibrium by applying its Karush-Kuhn-Tucker (KKT) conditions.

Model Component	**Economic Interpretation**
$-\frac{A}{2}r^2$	Falling demand for additional capacity (price declines as supply rises).
$(\Pi_{\max} - W_g)q_g$	Net margin of each generator based on how high its net CONE is compared to the reference generator .
$r = \sum q_g$	Total cleared capacity.
$h_g \leq FU_g P_g^{\max}$	Generator can only offer reliable (derated) capacity.
$q_g \leq h_g$	Cannot clear more than offered.
$\pi = -Ar + \Pi_{\max}$	Market clearing price determined by total cleared capacity.

Table 3: Economic interpretation of CM-QC model components.

4.4 Generator Revenue and Profitability

Generator g's revenue and profit in the capacity market are given by:

$$\text{Revenue}_g = \pi \cdot q_g, \tag{9}$$

$$\text{Profit}_g = (\pi - W_g)q_g. \tag{10}$$

The marginal generator $\hat{g}$, setting the market price, earns zero profit. Generators with $W_g < \pi$ are profitable; those with $W_g > \pi$ incur losses.

Let $\hat{G}$ denote the set of allocated generators, and $\hat{g}$ the marginal generator. Assume accurate estimation of net CONE and $W_{\hat{g}} \neq 0$. Then:

1. If $g \in \hat{G} \setminus \{\hat{g}\}$:

$$\pi_g = (W_{\hat{g}} - W_g)FU_g.$$

2. If $g = \hat{g}$:

$$\pi_{\hat{g}} = W_{\hat{g}} \left(\frac{\Pi_{\max} - W_{\hat{g}}}{A} - \sum_{g \in \hat{G}} FU_g P_g^{\max} \right) \leq 0.$$

3. If $g \notin \hat{G}$:

$$\pi_g = -W_g FU_g P_g^{\max} < 0.$$

Thus, generators with lower net CONE are prioritized and tend to achieve positive profits.

The marginal generator $\hat{g}$ is profitable only if:

$$W_{\hat{g}} = -A \sum_{g \in \hat{G}} FU_g P_g^{\max} + \Pi_{\max}.$$

Otherwise, it operates at a loss.

A peaker unit with the highest net CONE achieves revenue balance if and only if it operates at full capacity:

$$Q_{\text{CAP}} = \sum_{g \in G} FU_g P_g^{\max}$$

and it serves as the marginal supplier. Otherwise, it incurs a loss.

4.5 The leader-follower game: A bilevel optimization problem

Before we dive into the details of our game-theoretic model, let's try to understand why it makes sense to do so. Cramton and Stoft (2006) argue that analyzing capacity markets requires game-theoretic models because market participants behave strategically, and simple optimization methods like greedy algorithms fail to capture the potential for market power exploitation [16]. Joskow (2008) emphasizes that the structure of short-term capacity markets inherently creates incentives for generators to engage in strategic bidding, making it essential for market design analyses to explicitly account for such behavior. Pfeifenberger and Newell (2011) stress that accurately evaluating the reliability and economic performance of capacity markets demands a joint modeling of bidding strategies and market-clearing processes, rather than treating them as separate or sequential decisions.

[16] Greedy algorithms order supplier bids in ascending order of price, then starts buying capacity until the demand level is met. While simple and tractible, this does not take into account that a strategic generator can adjust its bid to go low or high to either make sure their capacity clears or take advantage of being a pivotal generator.

This paper employs the model for market clearing used in Guo et al. (2023)[17] and the BilevelJuMP.jl package formulated by Dias Garcia et al. (2022), adapted for use in Python.

In the full modelling framework, generator behaviour is represented by a trilevel optimisation problem, where a strategic generator (leader) influences both the capacity and energy markets, while the ISO clears each market to maximise social welfare. However, for the purposes of isolating the dynamics within the capacity market, the problem can be reduced to a bilevel structure focusing exclusively on the capacity auction.

In this simplification:

- **Upper Level (Leader Problem):** A strategic generator selects its offer price (w_1) and quantity (h_1) to maximize its own revenue from the capacity market. Unlike competitive fringe generators who all bid truthfully at their net CONE, the strategic player may bid above or below its true net CONE to manipulate the clearing price and its allocation.
- **Lower Level (Follower Problem - Market Clearing):** Given all submitted bids, the ISO clears the capacity market by maximizing social welfare, modeled through a convex quadratic optimization problem, and determines the market clearing price and cleared quantities. R and Q_1 are used to denote that these are constants in the Leader's Problem, and are fixed for the leader.

Formally, the bilevel optimization is structured as follows:

Leader's Problem (Strategic Generator)

$$\max_{h_1,w_1} \quad (\Pi_{\max} - AR)Q_1 \tag{11}$$

$$\text{s.t.} \quad 0 \le h_1 \le FU_1 P_1^{\max}, \tag{12}$$

$$w_1 \ge 0, \tag{13}$$

where h_1 and w_1 are the strategic generator's offer capacity and offer price, respectively.

[17]This paper also hosts a varied discussion on how market power is inevitable in such capacity market settings. Readers are encouraged to refer to this paper for a better understanding of the interaction between the energy and capacity markets, and how decisions in one market might inform decisions in the other. In this paper, we want to instead focus on replicating the analysis for PJM and provide rich insights on the capacity market design itself, and how ISOs with existing capacity markets or those contemplating holding capacity auctions could benefit from understanding the implications of certain design choices, such as demand curve construction and whether to fragment parts of the market.

Follower's Problem (Market Clearing)

$$\max_{q_g} \quad -\frac{A}{2}r^2 + \sum_{g \in G} (\Pi_{\max} - W_g) q_g \tag{14}$$

$$\text{s.t.} \quad r = \sum_{g \in G} q_g, \tag{15}$$

$$0 \leq q_g \leq FU_g P_g^{\max}, \quad \forall g \neq 1, \tag{16}$$

$$0 \leq q_1 \leq h_1, \tag{17}$$

where q_g is the cleared capacity for generator g.

In this setup:

- The strategic generator internalizes the effect of its bid on the market-clearing outcome.
- Non-strategic generators (the competitive fringe) bid their full qualified capacity at their net CONE.
- The ISO clears the market by maximizing social welfare, taking all bids as given.

This bilevel framework captures key features of strategic bidding in the capacity market while excluding interactions with the energy market. It enables analysis of outcomes such as altered market clearing prices, changes in generator revenues, and the manifestation of market power, which we will discuss in the results section. Our bilevel model can be equivalently formulated as a Mathematical Program with Equilibrium Constraints (MPEC), replacing the ISO's market clearing by its Karush-Kuhn-Tucker (KKT) conditions:

Strategic Generator (Upper Level)

$$\max_{h_1, w_1} \quad (-Ar + \Pi_{\max}) q_1 \tag{18}$$

$$\text{s.t.} \quad 0 \leq h_1 \leq FU_1 P_1^{\max}, \tag{19}$$

$$w_1 \geq 0, \tag{20}$$

ISO Market Clearing (Lower Level KKT Conditions)

$$r = \sum_{g \in G} q_g, \tag{21}$$

$$0 \leq q_g \leq \begin{cases} FU_g P_g^{\max}, & \forall g \neq 1, \\ h_1, & g = 1, \end{cases} \tag{22}$$

Next, we simulate bidding and market clearing under strategic bidding when each generation technology is allowed to be the leader (i.e. strategic bidder, when all other generators are bidding truthfully and competitively), compare revenue and market clearing prices between strategic and truthful bidding, discuss whether they match with expectations, and compare the results with NYISO.

5 Results and Discussion: Market Power in the PJM Capacity Market

This section examines the exercise of market power within the capacity market. We identify the types of generators and demand levels under which the market becomes particularly vulnerable to strategic behavior. To quantify the effects of market power, we compare key market outcomes—including generators' revenue, consumer surplus, and the market clearing price—across scenarios with and without the presence of a strategic leader.

In our analysis, we consider a range of generator types as potential leaders, including natural gas (NG), coal, nuclear, solar, wind, hydro, and residual fuel oil (RFO). Table 5 reports the marginal costs, net CONE values, and qualified capacities associated with these leaders. The net CONE values are drawn from the 2023 State of the Market Report by the Independent Market Monitor. The market (i.e. pool of bidders) is populated with generators using the distribution proportions outlined by the IMM, summarized in Table 4. Total peak demand is taken from Table 1 (Summer peak, 2023).

Fuel Type	**Installed Capacity (MW)**	**Share (%)**
Natural Gas (Combined Cycle)	56,124.2	28.6%
Coal	39,949.4	20.3%
Nuclear	33,452.6	17.0%
Solar	9,004.6	4.6%
Wind	4,792.0	2.4%
Hydro	~19,000.0	~10%
Residual Fuel Oil (RFO)	~3,000.0	~1.5%
Other (Diesel, Biomass, Waste, etc.)	Remaining capacity	15.6%
Total	196,380.2	100%

Table 4: Installed Capacity in PJM by Fuel Type as of December 31, 2023. Estimates for hydro and RFO based on typical shares from PJM historical data.

Table 5: Parameters of the Leaders (PJM)

Generation Type	**Marginal Cost ($/MWh)**	**Net CONE ($/MW-day)**	**Qualified Capacity (MW)**
Natural Gas (NG)	18.62	205.3	893.0
Coal	36.54	560.8	1300.0
Nuclear	0.00	820.2	1499.4
Residual Fuel Oil (RFO)	192.70	1280.4	414.7
Hydro	14.90	410.7	477.0
Wind	0.00	0.0	302.0
Solar	0.00	0.0	577.0

Among the resources, RFO units emerge as the peaking plants with both the highest variable costs and the highest net CONE. This is similar to the NYISO fleet of generators, but in our case they have low qualified capacity when compared to Nuclear and Coal. In contrast, wind and solar resources have zero marginal cost and, correspondingly, a net CONE of zero. Based on these differences, we can expect coal and nuclear to be able to exercise the most market power among their peers, and our results confirm these expectations.

In all our simulations, we vary the simulated demand between 60-100%. This allows us to understand how scarcity or near-scarcity instances affect market-clearing outcomes. Figure 6 shows Nuclear increasing their revenue by up to $700,000 at 70% demand. Beyond that, strategic bidding is unable to increase revenues as the demand level approaches 100%. Only generators with high CONE and/or high qualified capacity, i.e. Nuclear, Coal and RFO, are able to exercise market power at all: consistent with our predictions. RFO, similar to the NYISO findings, is able to increase its revenue even at 100% demand, likely because during supply shortages even expensive capacity such as RFO is called upon to meet demand. NYSIO has a tighter supply of capacity (Brattle, 2021; Federal Energy Regulatory Commission, 2022) as a result of a shorter commitment period of 1 year (compared to PJM's three-year ahead auctions) as well a rapidly retiring fleet, which can explain why RFO is able to increase its revenue much more in NYISO (over $700,000) compared to PJM ($345,000). Compared to the NYISO PJM sees a more modest increase in leader's revenue. When taking into account that (a) NYISO has a much tighter supply of capacity (National Renewable Energy Laboratory (NREL), 2024; NYISO, 2024), which allows leaders to leverage prices to greater magnitudes, (b) NYISO has a higher proportion of generators that are RFO[18], and (c) RFO generators in NYISO have higher qualified capacity, the results make intuitive sense.

Figure 7 illustrates how market power can distort market-clearing prices, with coal being able to increase clearing prices by up to $250 /MW- day at 60% demand. This is in sharp contrast to the findings in the NYISO case study, where market leaders are only able to suppress prices. RFO and Nuclear are able to lower prices, which is in line with the model design and predictions made in NYISO case study, which mentioned prices can go in either direction when marginal supplier bids 0 (Guo et al., 2023). This increase in clearing price due to coal remains unconvincing, as a large qualified capacity should supress prices, not increase them. At lower demand levels, leader generators can withhold capacity and influence prices, but at higher

[18]PJM has older generators replaced at a much higher rate than NYISO. Proportion of RFO in PJM is much lower

demand levels this effect goes away as full allocation incentivizes truthful bidding. Nuclear as leader has a similar influence on clearing price in PJM as it does in NYISO, as a large qualified capacity and high net CONE (predictibly) gives it market power.

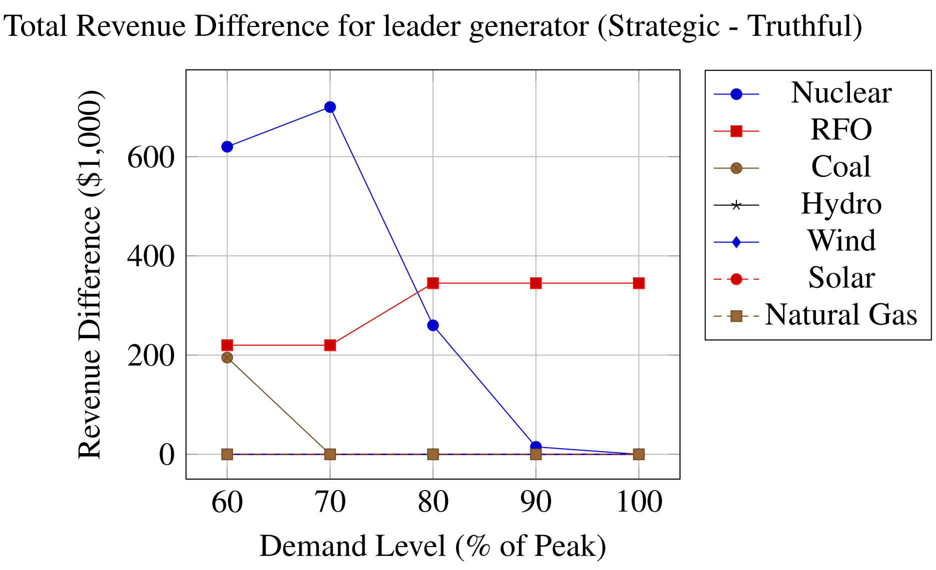


Figure 6: Difference in total revenue for leader generator between strategic and truthful bidding across demand levels, expressed in $1,000.

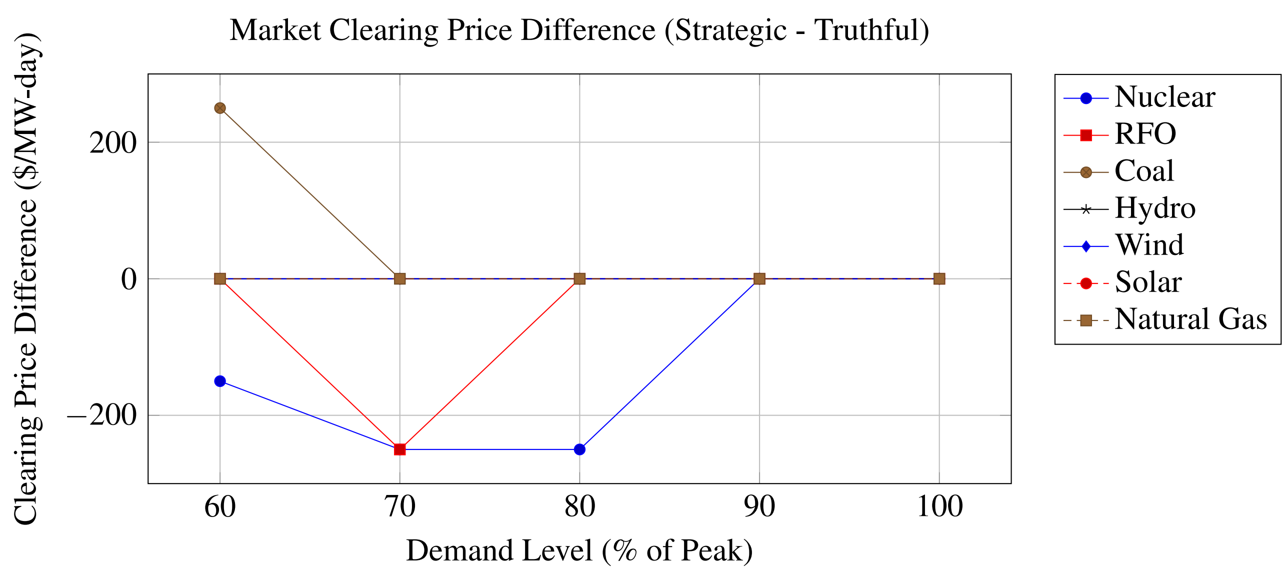


Figure 7: Difference in capacity market clearing price under strategic versus truthful bidding, by leader technology.

Figure 8 shows how total revenue of all cleared generators changes under strategic bidding by capacity market leader. As expected, the plots retain the same shape as Figure 7. Strategic bidding can lower capacity market revenue significantly, with Nuclear being able to lower collective generator revenue by up to $36.4 million dollars. There is a rich literature on how

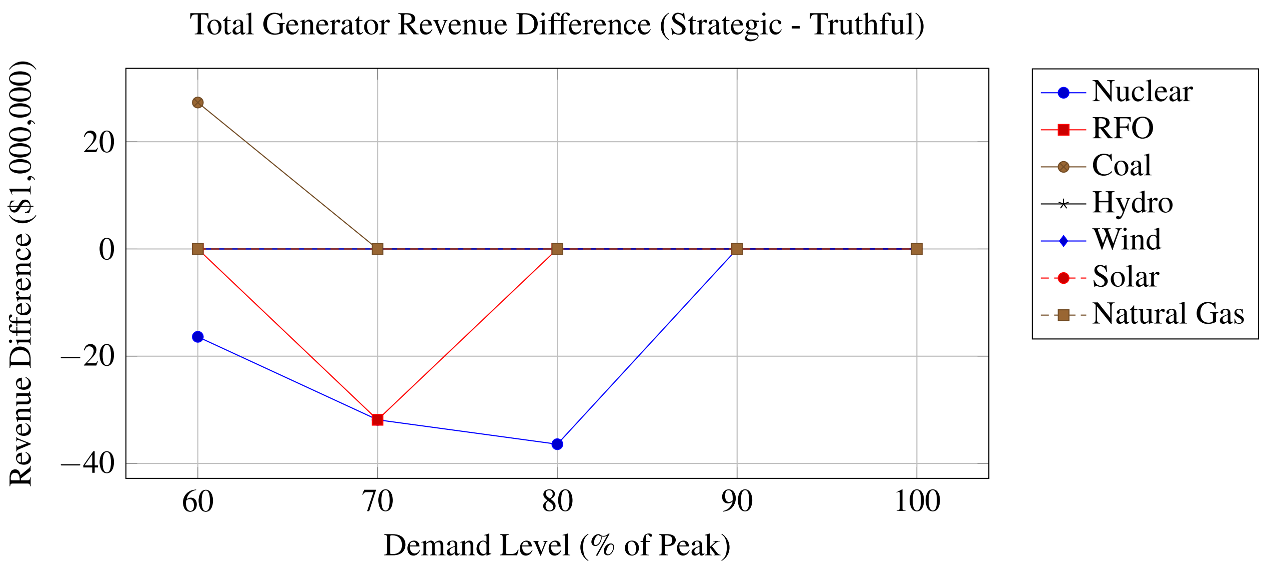


Figure 8: Difference in total generator revenue from capacity payments when the leader bids strategically compared to truthfully, scaled to $1,000,000. Each curve represents a different generation technology acting as the leader.

capacity market mechanism can induce price supression through strategic bidding (Bushnell and Saravia, 2009; Klemperer, 2004), and Chaves-Ávila et al. (2020) hosts a detailed discussion on how market design explicitly affects generator behavior and how mechanisms such as price floors and caps are required to mitigate the effects of market power. Coal is able to raise revenues significantly at lower demand levels, as it is able to undercut bidders by bidding low and taking advantage of its comparatively high qualified capacity. Given that a fifth of the total share of generators in PJM are coal, this is an important result as it shows how aging technologies that are on their way out of the market due to more cost-effective alternatives, are still able to significantly raise market-clearing prices, and the need for price caps is evident. Price floors might also be needed, as we see nuclear and RFO being able to significantly suppress prices.

Figure 9 demonstrates the points made by the paper so far. We can see that lower net CONE generators such as natural gas, solar and wind are always profitable past 60% demand. This is intuitive as solar and wind have net CONE equal to 0, and NG is the lowest among the rest. RFO and nuclear struggle to be profitable at low demand levels, and at 100% demand only nuclear is somewhat profitable. These confirm the findings of the NYISO case study, where peaking plants like RFO are only profitable at high demand levels. While RFO remains unprofitable throughout all demand levels, this might be due the fact that RFO in PJM has lower qualified capacity and higher net CONE when compared to NYISO. This dynamic manifests in the fact that RFOs are exiting the PJM market at a higher rate, and PJM has decided to use a more expensive reference generator to push the price cap up and try to make them more profitable (PJM Interconnection, 2022).

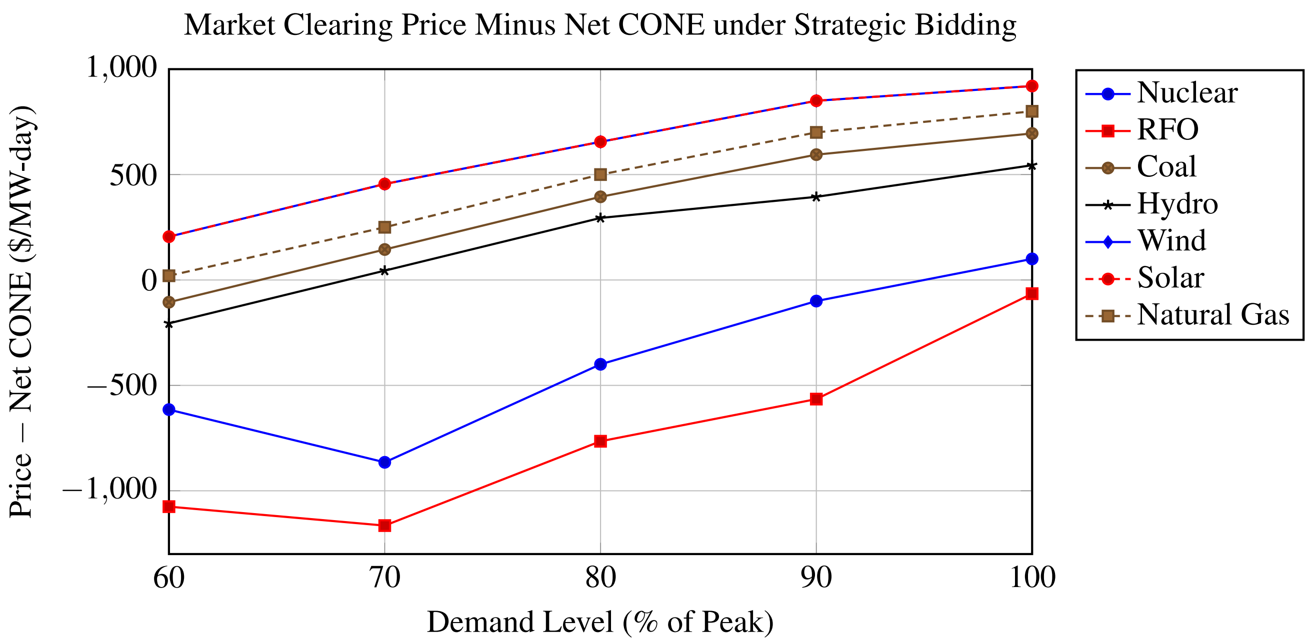


Figure 9: Difference between market clearing price and Net CONE under strategic bidding, by leader technology.

6 Conclusion

The aim of this thesis has been to critically assess whether capacity markets—particularly as implemented in PJM—are worth their complexity and cost. Through a detailed modeling of PJM's market clearing process, this thesis has shown that the incentives embedded in the current structure may not align with the long-term goals of cost-effectiveness, investment neutrality, or decarbonization.

The evidence presented suggests that the existing capacity market design disproportionately benefits high-CONE, high-capacity technologies like coal and nuclear, particularly at lower demand levels where their ability to exert market power is greatest. These technologies are shown to significantly raise or lower clearing prices when bidding strategically, thereby distorting capacity payments while contributing little additional reliability. As demand increases and the market becomes tighter, their capacity to influence prices diminishes, which further undercuts the rationale for sustained investment in these legacy assets. The incentives thus created are deeply problematic: firms holding such technologies have every reason to advocate for tighter reserve margins and delayed infrastructure upgrades, as these conditions maximize their profitability.

In contrast, the most profitable technology under current market conditions is the natural gas peaker plant. Its relatively low net CONE and operational flexibility make it ideally suited to participate competitively across most demand levels. However, while natural gas peakers play an important role in balancing the grid, over-reliance on them—especially as a default investment choice incentivized by market design—raises questions about long-term cost and emissions trajectories. Their role as the marginal resource in both energy and capacity markets means that their cost structure heavily influences clearing prices, tying future electricity costs to volatile gas markets.

Furthermore, the findings highlight how renewables such as wind and solar, despite their increasing grid presence and zero marginal cost, are structurally disadvantaged. The application of the Minimum Offer Price Rule (MOPR) and blunt ELCC methodologies effectively suppress their participation, even when they would otherwise provide cost-effective capacity. This design failure not only results in inefficient over-procurement but also undermines broader decarbonization goals. The market penalizes intermittency without compensating for flexibility contributions or storage pairing, which deters investment in technologies critical for energy transition.

Additionally, the simulation results reaffirm that market power is a persistent feature of PJM's capacity market. High qualified capacity generators, especially coal, can distort prices significantly under low demand conditions. These distortions are not incidental; they are predictable outcomes of the current design. The fact that these dynamics are well understood by market participants only increases the potential for rent-seeking behavior.

What, then, is the future of capacity markets? Reliability becomes an increasingly important issue as nations around the world adopt renewable sources. Spain, for example, achieved a significant milestone by running its entire national electricity grid on 100% renewable energy for the first time during a weekday on April 16, 2025. Not long after, on April 28, Spain and Portugal as well as parts of southern France experienced some of the worst power outages in European history, affecting 60 million people[19]. This makes is clear that while we push towards total renewable reliance, considerations such as grid flexibility and transmission capacities, as well as having a unified power market (relevant for the EU) should not be understated.

One implication of this thesis is that without significant reforms, PJM's capacity market will increasingly drift toward inefficiency and excess. Over time, the market will accumulate too many gas peakers and legacy baseload units that rely on price volatility and regulatory inertia for survival. Consumers will ultimately bear the cost—not only in higher rates but also in lost opportunities for innovation and decarbonization.

Several policy changes emerge as promising avenues from our findings. Flattening the VRR demand curve would reduce price sensitivity to small changes in cleared capacity, weakening the power of marginal bidders. Revising reference technology assumptions away from high-cost combustion turbines could prevent artificial inflation of the price cap. Most crucially, integrating performance-based metrics and dynamic accreditation for renewables and storage would help create a more level playing field, aligning incentives with both cost efficiency and system reliability. With the future integration of Battery Energy Storage Systems (BESS) in our grids, intermittent sources should become more reliable, and their inclusion in our reserve

[19] At the time of the incident, renewable sources like solar and wind accounted for a significant portion of Spain's electricity generation. The lack of mechanical inertia in these systems may have contributed to grid instability(Bernal, 2025)

grid easier. Another useful thing would be to offer longer capacity contracts for new generators to spread the risk of investment over a longer time horizon, such as the UK where 15-year agreements are common for new entrants that meet capacity thresholds. Opting for a voluntary instead of a mandatory auction, and facilitating more long-term bilateral contracts between power entities also creates flexibility and reduces friction for investment.

This thesis does not claim to exhaust the full scope of capacity market challenges. Indeed, further work could model interactions between energy and capacity markets in greater detail, especially under stochastic demand and fuel cost conditions. Future research might also evaluate multi-technology portfolios and hybrid resources to determine how emerging grid architectures would respond to the same incentive structures explored here.

Ultimately, this analysis shows that PJM's capacity market, in its current form, cannot be considered a neutral or efficient tool for ensuring reliability. It is shaped by legacy assumptions and design choices that, while logical in a different era, may now hinder both competition and climate progress. The path forward lies not in abandoning capacity markets altogether, but in fundamentally rethinking how they are structured, who they serve, and what they are for.

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