Accreditation, Performance, and Credit Risk in Electricity Capacity Markets

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Abstract

Many liberalized electricity markets use capacity mechanisms to ensure that sufficient resources will be available in advance of operations. Recent events have called into question the ability of capacity mechanisms to provide sufficient incentives for reliability. A core resource adequacy challenge is that, given the high value of reliable electricity, penalties for non-performance on capacity obligations are lower than what theory would suggest is economically efficient. Weak non-performance penalties give suppliers an incentive to overstate their contributions to reliability. However, stronger penalties will often not be enforceable because suppliers can discharge their obligations through bankruptcy. In principle, system operators can mitigate the effect of weak incentives by conducting accreditation studies that limit the size of the capacity obligation taken on by suppliers. However, political, economic, and technical factors lead to accreditation values that are systematically too high. We discuss the ensuing threats to reliability, the difficulty of implementing "pure market" solutions, the inefficient around-market actions that system operators may take in response, and the potential for the size of the effects to grow with a shift to variable renewable resources.

Keywords: Electricity markets, capacity markets, resource adequacy, bankruptcy, incomplete markets

1 Introduction

In systems that rely on private investment in electricity generation, the resource adequacy problem is addressed through market mechanisms that create an incentive for investors to build a portfolio of assets capable of delivering an appropriate level of reliability. A fundamental issue in this context is the significant volatility of electricity prices, driven by the high value of reliable power combined with our limited ability to shift consumption. Providing full-strength incentives for investors would entail that system operators allow prices to reach levels commensurate with this extraordinary value. Allowing such prices to reach end-use consumers is typically a political impossibility given the critical importance of electricity and the difficulty of differentiating in real time between genuine scarcity and the exercise of market power. Moreover, as witnessed in the catastrophic generation shortfalls experienced in Texas in February 2021, even a credible political commitment to full-strength spot prices in an "energy-only" market design is not sufficient to

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ensuring resource adequacy given risk aversion and barriers to contracting (Mays et al., 2022). In light of these challenges, regulators in most market areas have introduced a resource adequacy mechanism (e.g., a capacity market) that mandates contracts between loads and generators (Joskow and Tirole, 2007; Cramton et al., 2013; Bushnell et al., 2017). With a well-defined contract in place, suppliers that cannot deliver energy must purchase energy from a replacement provider, typically at high prices. When system operators resort to rolling blackouts, suppliers that fail to meet their capacity obligations must reimburse load at an estimated value of lost load.

But recent events, most notably the approximately 57,000 MW of unplanned outages PJM experienced during Winter Storm Elliott, suggest that this model is not working as expected. (PJM Interconnection, 2023). In response to the perception that capacity markets are not working, regulators and market participants have begun to question whether price-based mechanisms can address the resource adequacy problem. For example, Commissioner Mark Christie has written that "it is past time to reconsider whether [capacity] constructs, certainly those in the large, multi-state RTOs, are still capable of performing the important duties expected of them" (Christie, 2023).

In this paper, we discuss some of the reasons that existing resource adequacy mechanisms do not deliver on their theoretical promise. From an economic perspective, the core issue is that penalties for non-performance are weaker than what theory suggests they should be. A second set of reforms has focused on refining resource accreditation, i.e., determining the quantity of the resource adequacy product that suppliers should be allowed to sell. By restricting offers to an accredited quantity, systems attempt to prevent suppliers from taking advantage of the incentive that weak penalties give to over-promise and under-deliver. From a physical perspective, the core issue is that accreditation values are likely too high, especially for gas-fired plants, and do not sufficiently account for correlated outages.

In terms of penalties, one explanation is that the supply side of the market has undue influence in stakeholder processes (Yoo and Blumsack, 2018). We set aside these political economy issues, however, and focus on the more fundamental challenge to price formation related to generator credit risk. As we show, the availability of bankruptcy protection places an implicit cap on non-performance penalties based on the wholesalers' ability to pay the penalty. In terms of accreditation, one problem is that the ability to perform on capacity obligations can be affected by decisions taken after the accreditation is performed (e.g., the amount of fuel to hold in inventory). Without strong incentives backing up the accreditation, suppliers therefore have an incentive to behave differently than assumed in the accreditation process (e.g., by holding less fuel). A second challenge is more narrowly technical. Accreditation amounts to an estimate of the conditional expectation of resource performance during times of system stress. Since instances of severe system stress are rare by design, the tendency of accreditation methods is to draw from a too-large sample of performance hours. If system stress were driven purely by high demand, this too-large sample could still give a reasonable estimate of the conditional expectation of resource performance. In situations where system stress is driven by supply outages, however, it leads to too-high estimates of resource availability in the most severe stress events.

Three other proposed explanations for recent reliability challenges warrant mention in the context of our diagnosis. First, some have suggested that fuel security issues challenge the logic of capacity markets because they are outside the purview of electricity market operators and regulators (Makholm and Olive, 2020). However, there is little evidence that fuel supply issues present a fundamental problem with market-based resource adequacy solutions: since regulators have never imposed meaningful non-performance penalties, we do not have a true test of whether such penalties would induce additional investments along the supply chain. Concretely, the presence of constraints on gas pipeline capacity into ISO New England (ISO-NE) does not invalidate the basic theory of capacity markets, which would simply predict a shift away from gas due to the constraints (e.g., by keeping coal or nuclear plants open or by ensuring dual-fuel capabilities in plants that primarily use gas). A more compelling version of this argument is that fuel security challenges have been underestimated in the accreditation process, contributing to elevated estimates of the reliability contribution of gas-fired plants. Second, some have argued that the entry of wind and solar into the markets creates additional risk due to their variability and uncertainty. Since these attributes should in principle be handled by assigning those resources a lower accredited value, wind and solar are also compatible with the idealized theory of capacity markets. With low penalties, wind and solar have the same incentive as other resources to overstate their reliability contribution. Given their low share of total capacity in current markets, however, over-accreditation of wind and solar is a less convincing explanation for current reliability challenges than over-accreditation of traditional resources. With that said, since the degree of correlation among suppliers is likely to grow even stronger with a shift to weather-dependent generation, the effect of the issues discussed in the paper may grow stronger in future systems (Energy Systems Integration Group, 2021). Additionally, it could be argued that the expectation of a continued energy transition supported by State and Federal policies could contribute to insufficient maintenance practices at fossil plants (cf., Grubert and Hastings-Simon (2022)), further exacerbating overestimates in their accreditation. However, the superior performance of coal relative to gas plants in recent winter storms works against this hypothesis. Third, recent years have seen a significant shift away from nuclear and coal toward gas across the Eastern U.S. markets, prompting some to suggest that resilience attributes of nuclear and coal are undervalued by the markets. This argument was core to the 2017 Grid Resiliency Pricing Rule issued by the U.S. Department of Energy but subsequently rejected by FERC as inconsistent with principles of competition (U.S. Department of Energy, 2017). Based on the preliminary data for Winter Storm Elliott in Bryson et al. (2023), PJM saw outage rates of 38% for gas, 17% for coal, and 11% for other capacity. While a full quantification of the effect is beyond the scope of this paper, our analysis highlights that the overpayment of gas plants implicit in low non-performance penalties could have induced changes in the resource mix beyond what would have otherwise occurred, resulting in more exposure to reliability risk in extreme events.

Our diagnosis suggests two potential routes to addressing the reliability threats currently apparent in capacity markets. The first would pair stronger prices with stronger performance bond or credit requirements for suppliers, with amounts corresponding to their non-performance risk. Beyond the higher risk premia that would likely result from stronger penalties (Shu and Mays, 2022), this approach could stifle competition and lead to market power concerns if only a few companies are able to post the collateral required. The second, more administrative approach would be through refined accreditation methods. However, this approach could lead to continued socialization of risk and misdirected investment due to moral hazard. We do not develop either of these approaches within the paper, instead leaving it to future work.

We provide a selective history of the ISO-NE and PJM capacity markets in Section 2. Section 3 provides background on the nominal payments, penalties, and accreditation values that idealized capacity markets would exhibit. Section 4 develops a toy example to illustrate various departures of real-world markets from that idealized picture as well as workarounds that market operators have implemented to maintain resource adequacy. We connect the discussion to currently active debates and conclude in Section 5.

2 Accrediting and penalizing capacity: history

A more complete history of PJM and ISO-NE's capacity markets is available in Aagaard and Kleit (2022). The review here discusses how both grid operators have struggled to strengthen non-performance penalties, turned to out-of-market interventions, over-accredited resources' contribution to reliability, and failed to implement performance bonds that would force generators to fully bear the costs of higher non-performance penalties.

2.1 Implementing capacity markets

In the mid-2000s, both PJM and ISO-NE became concerned that generator retirements would lead to resource adequacy issues. Until 2006, PJM required Load Serving Entities (LSEs) to procure an amount of capacity sufficient to serve peak load plus a fifteen percent reserve margin. However, because LSEs could identify capacity resources twenty-four hours before they were needed, they often relied on short-term markets instead of procuring capacity through long-term contracts. One goal of capacity market reforms was to reduce the investment uncertainty that this strategy implied (Hobbs et al., 2007). A second goal was to improve resource accreditation: procurement requirements in both PJM and ISO-NE did not account for deliverability issues. Because PJM did not have unlimited transfer capacity, the lack of a deliverability requirement gave LSEs an incentive to purchase the cheapest available capacity, even if that capacity was unable to serve load in their service territory. As a result, PJM effectively overaccredited resources that could not meet local capacity needs and underaccredited resources that could. ISO-NE similarly lacked a locational deliverability requirement, leading them to turn to cost-of-service reliability-must-run contracts to prevent generating units needed to maintain reliability from retiring (Federal Energy Regulatory Commission, 2006).

To address these problems, PJM proposed the reliability pricing model (RPM) in August 2005. The modified version of that proposal, which FERC approved in December 2006, continues to provide the framework for PJM's capacity market. That proceeding led PJM to conduct auctions three years in advance of the capacity commitment and create capacity zones to ensure that cleared capacity could deliver energy to load. ISO-NE followed suit shortly thereafter, introducing a Forward Capacity Market (FCM) with many design elements based on the RPM reforms.

2.2 ISO-NE

ISO-NE began raising concerns about fuel security issues in 2004 during an extended cold snap. Between 2007 and 2014, ISO-NE had excess capacity, yet the overall rate of unplanned outages across the New England generating fleet more than doubled. In that time, there was only a 71 percent average response rate for generators dispatched following a contingency (Federal Energy Regulatory Commission, 2014).

Recognizing the growing fuel security risks, ISO-NE implemented short- and long-term reforms. In 2013, FERC conditionally accepted ISO-NE's proposed Tariff revisions under the 2013–2014 Winter Reliability Program, which compensated resources for fuel inventory procured ahead of the winter through a monthly payment derived from suppliers' as-bid price, rather than a uniform clearing price (in addition to the compensation they received in the capacity market). A year later, partly in response the the 2014 Polar Vortex, FERC accepted a 2014–2015 Winter Reliability Program that provided additional compensation to generators that had excess oil inventory at the end of the winter or LNG contracts that went unused at the end of the reliability period. At the time, FERC described the Winter Reliability Program as a temporary solution and ordered ISO-NE to develop a market-based solution to address its reliability issues.

To that end, the central long-term reform was to strengthen shortage penalties with a pay-for-performance (PFP) mechanism, which was approved in 2014 but did not go into effect until 2018. Prior to PFP, the capacity market compensated resources as though they were fully available, even when they were unable to meet their obligations. Consequently, the region had provided "capacity payments of 674 million to a set of resources that have provided on average only 17 percent of their Capacity Supply Obligations" (Federal Energy Regulatory Commission, 2014), leading FERC to determine that ISO-NE's existing tariff was unjust and unreasonable.

Because of PFP, ISO-NE's capacity market now operates as a two-settlement process. Resources that clear the capacity auction receive a Capacity Base Payment determined by multiplying the quantity of their Capacity Supply Obligation (CSO) by the clearing price. The Capacity Performance Payment, which intends to provide a financial incentive for resources to meet their supply obligations, is determined by measuring suppliers' performance against their CSO multiplied by a Balancing Ratio. The Balancing Ratio, in turn, is calculated by dividing the total load and reserve requirement in an assessment interval by the total CSO of all resources in the system, while also being capped at 1. If a resource provides more than its share of energy and reserves, it receives revenue from resources that underperformed. If it provides less, it pays a penalty. The administratively-determined performance rate was set at $2,000/MWh from 2018 and 2021, increasing to $3,500/MWh from 2021 to 2024, and then increasing again to $5,455/MWh in 2024. All told, ISO-NE calculated that the combination of reserve shortage pricing and the PFP penalty rate in the capacity market "will create an effective energy price that can exceed $9,000/MWh during real-time scarcity conditions" (ISO New England, 2020).

Even though PFP has increased generators' performance incentives, ISO-NE has undermined the strength of these incentives by setting an upward limit on losses generators incur for failing to meet their obligations. First, due to the Balancing Ratio adjustment, transfers due to PFP are made among suppliers (potentially between generators owned by the same parent company) rather than being structured as a reimbursement to load. Second, the PFP contains a "stop-loss" mechanism that places monthly and annual caps on the revenue that resources can lose as a result of non-performance. In any month, the maximum that can be subtracted from a resource's Capacity Base Payment is the resource's Capacity Supply Obligation quantity times the auction starting price. In any year, the maximum amount that a capacity resource can lose is three times the resource's maximum monthly potential net loss. The stop-loss provisions prevent generators from accruing more than approximately 1.5 hours worth of losses in a given month (ISO New England, 2022). In other words, the penalty structure fails to cover New England's most significant reliability concerns, which involve cold weather leading to high demand and supply disruptions that last several days or longer.

Perhaps because of these limits, ISO-NE does not treat penalties for under-performance as though they create sufficient performance incentives. In 2018, shortly after PFP went into effect, ISO-NE created an Inventoried Energy Program (IEP) to compensate generators that maintain up to three days' worth of fuel on-site and convert it into electricity. After a court vacated part of the IEP, ISO-NE filed Energy Security Improvements (ESI) to address the region's fuel security needs, explaining that "the energy market may not provide sufficient incentives for resource owners to invest proactively in energy supply arrangements." Moreover, "when the risks of a reserve shortage are low, the incentive PFP creates for performance are significantly muted—too muted for it to be privately financially beneficial for the generator to incur the up-front costs of arranging fuel, the costs of which will be a total loss most of the time" (ISO New England, 2020).

ISO-NE has also reformed its process for determining whether resources will in fact be able to meet their capacity obligations. As mentioned previously, one of the primary reasons ISO-NE implemented its FCM in 2006–2007 was that its prior capacity requirement did not accurately distinguish between suppliers that made a significant contribution to resource adequacy and those that did not (Federal Energy Regulatory Commission, 2006). Beyond increasing the strength of non-performance penalties and introducing out-of-market payments for onsite fuel storage, the 2014 PFP reforms also improved capacity accreditation. In that proceeding, FERC pointed out that the FCM "allows numerous exemptions for non-performance under which resources are deemed fully 'available' despite their inability to provide energy or reserves" (ISO New England, 2022). ISO-NE emphasized the relationship between over-accrediting capacity resources and low non-performance penalties: "the existing FCM treats many resources as if they are fully available to operate during Shortage Events, and pays them accordingly, even when those resources are unable to deliver energy or reserves at that time" (ISO New England, 2022). In response, the 2014 PFP rule limited non-performance exceptions.

Despite these improvements, a challenge with accreditation in ISO-NE is that the grid operator continues to accredit resources based on historical performance. Accreditation for non-intermittent resources is based on the resource's qualified capacity value, which is determined by measuring the resource's maximum output capability while accounting for the Equivalent Forced Outage Rate on demand (EFORd). EFORd "is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate." Accreditation for intermittent resources is based on their median output during a set of administratively determined "reliability" hours. This is based on their average performance over five years. We discuss the potential for such an approach to underestimate the importance of correlated supply outages and overestimate the contribution that units make to reliability in Section 4.

2.3 PJM

Like ISO-NE, PJM has historically imposed weak non-performance penalties, over-accredited resources, and neglected to account for correlated generator failures. However, the region's recent experience with generator defaults suggests that bankruptcy protection and limited liability partly counteract strong non-performance penalties.

As in ISO-NE, the 2014 polar vortex highlighted deficiencies in PJM's RPM. PJM experienced a 22 percent forced outage rate amounting to 40,000 MW of forced outages, approximately half of which were gas-fired plants (PJM Interconnection, 2014). Non-performance charges for that period totaled 38.9 million, which amounted to just 0.6 percent of total capacity revenues (Federal Energy Regulatory Commission, 2015). As FERC explained, "even poorly performing resources can expect to pay only minimal penalties, placing most of the risk of under-performance on load." For that reason, "a seller can earn substantial revenues through PJM's capacity auctions by committing its resource as capacity, with little concern that it will lose much of that revenue even if it performs poorly" (Federal Energy Regulatory Commission, 2015). PJM was also concerned about over-accrediting resources. PJM measured resources' contribution to resource adequacy by looking at resource performance during peak hours. PJM pointed out that its non-performance charge "assesses the performance or availability of a resource over too many hours, allowing poor performance during the most critical times to be masked by adequate performance during other, less critical times."

In 2014, PJM adopted reforms to strengthen non-performance charges and improve the accreditation process. First, PJM began measuring capacity performance during a narrower set of Performance Assessment Hours (PAH). PAH are triggered when PJM declares that there is an Emergency Action. Emergency Actions refer to situations in which there are locational or system-wide capacity shortages (Federal Energy Regulatory Commission, 2015). Second, when a capacity resource does not meet its expected performance obligation, it is subject to a larger non-performance charge. PJM's non-performance charge functions in much the same way as ISO-NE's. Resources that do not meet their capacity obligations, scaled by a balancing ratio, pay a penalty while those that exceed their obligations receive a bonus payment. This bonus payment is called a performance credit and can be distributed both to resources that committed to providing capacity for that hour as well as those that did not participate in or clear in the RPM. And third, PJM limited exemptions to non-performance charges to planned outages and non-dispatch instructions issued by PJM. Resources that did not meet their capacity obligations can now only avoid non-performance charges if PJM approved the outage and did not instruct them to deliver energy during the PAH.

Despite these reforms, FCM continues to overcompensate resources that do not perform during peak hours. Since the penalty rate charged for non-performance is determined by taking the net cost of new entry (net CONE) divided by the number of expected performance hours, a higher number of expected performance hours reduces the penalty for not being available in a PAH. Relying on a large number of PAH dilutes the penalty for not being available during the smaller number of genuine scarcity events. As Chairman Norman Bay said when he dissented to the 2015 Order, "A rational profit-maximizing resource could simply seek a capacity award in the auction, fail to perform during each performance assessment hour, and likely pay a penalty less than the carrot it has received. To put it more bluntly, the resource could be paid for doing nothing during the emergency hours of the year when it is most needed and for which it has been well compensated" (Federal Energy Regulatory Commission, 2015).

PJM further limited generators' exposure by creating a stop-loss mechanism similar to that employed by ISO-NE. PJM initially proposed stop-loss mechanism limits non-performance penalties to 0.5 times net CONE for any calendar month and 1.5 net CONE for any calendar year. However, in response to concerns that the monthly stop-loss limit would weaken the incentives created by the non-performance charge, FERC ordered PJM to eliminate the monthly stop-loss limit. Like ISO-NE, PJM phased in its penalties, but its annual stop-loss provisions were approximately four times as high as in ISO-NE (Federal Energy Regulatory Commission, 2015).

These limits notwithstanding, the potential for non-performance penalties has increased substantially in recent years. For that reason, it is noteworthy that the region's non-performance penalties are effectively weakened by generator credit risk. PJM experienced approximately 46,000 MW of forced outages during Winter Storm Elliott, with a total of approximately 57,000 MW unavailable when accounting for all causes (PJM Interconnection, 2023). One generator has already filed for bankruptcy. Others have filed a complaint with FERC warning that "Non-Performance Charges penalties" could "drive generators into default, suspension or termination from the market, and potential bankruptcies" (Coalition of PJM Capacity Resources, 2023).

While still weak relative to what would be suggested by theory, PJM's penalties are thus strong enough to cause at least three issues. First, even though high non-performance penalties should in theory give suppliers a stronger incentive to meet their capacity obligations, the ability to default on those obligations weakens the strength of those incentives. Second, as evidenced by the complaint, the PJM Market Monitor argues that "the process of defining excuses and retroactive replacement transactions is complex and very difficult to administer, and includes subjective elements," leading to "unacceptable uncertainty" for the market as to how penalties will be enforced (Monitoring Analytics, LLC, 2023). Third, as a market power mitigation strategy, PJM places a must-offer obligation on all resources with Capacity Interconnection Rights to prevent physical withholding of supply, as well as a Market Seller Offer Cap (MSOC) to prevent economic withholding. These measures are a response to the structural market power present in PJM and inefficient barriers to reallocation of Capacity Interconnection Rights (Petropoulos and Willems, 2020; Mays, 2023). Stronger penalties imply greater risk for suppliers, which in equilibrium should lead to resources either taking on a smaller obligation or demanding a higher risk premium (Shu and Mays, 2022). Accordingly, stronger penalties necessitate assumptions about unit-specific risk for inclusion in MSOC calculation, potentially opening an avenue for exercise of market power. Due to these complications, the PJM Market Monitor proposes to eliminate non-performance penalties altogether, relying instead of ex ante accreditation of capacity resources (Monitoring Analytics, LLC, 2023).

3 Accrediting and penalizing capacity: theory

This section develops an idealized point of reference for capacity payments, from which we can define nominal targets for capacity accreditation and non-performance penalties that preserve an efficient trade-off between cost and reliability.

A capacity expansion model can be written as

$$\underset{x\geq 0}{\text{maximize}} \qquad -\sum_{g\in\mathcal{G}} C_g^{INV} x_g + \mathbb{E}\left[h(x;\xi)\right]. \tag{1}$$

We choose capacity $x = (x_g)_{g\in\mathcal{G}}$ of technologies $g \in \mathcal{G}$ at an annualized investment cost of C_g^{INV} per unit. Here $\mathbb{E}\left[h(x;\xi)\right]$ is the expected annual surplus from operating the system over time given uncertainty in parameters. For our purposes, we assume $\xi = (A, C^{OP}, D)$ includes uncertainty in the availability of generators A, the operating cost of generators C^{OP}, and the level of demand D. The model is agnostic about why a generator is unavailable (e.g., planned maintenance, unexpected plant failures, or lack of fuel).

A simplified model for operations can be written as:

$$h(x,\xi) = \quad \underset{p,d}{\text{maximize}} \quad \sum_{l\in\mathcal{L}}\sum_{t\in\mathcal{T}} B_l d_{lt} - \sum_{g\in\mathcal{G}}\sum_{t\in\mathcal{T}} C_{gt}^{OP} p_{gt} \tag{2a}$$

$$\text{subject to} \qquad \sum_{l\in\mathcal{L}} d_{lt} - \sum_{g\in\mathcal{G}} p_{gt} = 0 \qquad \forall t\in\mathcal{T} \tag{2b}$$

$$d_{lt} \leq D_{lt} \qquad \forall l\in\mathcal{L}, \forall t\in\mathcal{T} \tag{2c}$$

$$p_{gt} \leq A_{gt} x_g \qquad \forall g\in\mathcal{G}, \forall t\in\mathcal{T} \tag{2d}$$

$$p, d \geq 0. \tag{2e}$$

For consistency, we assume that the time periods $t \in \mathcal{T}$ cover one year of operations. The problem is simplified in that we omit uncertainty in the operational stage, binary unit commitment variables, power flow laws, and intertemporal physical constraints that are not germane to the core issues of the paper. We serve loads $l \in \mathcal{L}$ valued at B_l. Equation (2b) enforces system-wide power balance in each time period, Eq. (2c) specifies the maximum potential demand that can be served within each load block, and Eq. (2d) limits generators to produce no more than the amount available given the installed capacity and an availability percentage A_{gt}.

In a perfectly competitive market with complete markets in risk and at least one risk-neutral market participant, a generic equilibrium condition for the long-run capacity mix can be written as

$$0 \leq x_g \perp \mathbb{E}\left[\pi_g^k(x;\xi)\right] - C_g^{INV} \geq 0 \quad \forall g\in\mathcal{G}. \tag{3}$$

Here $\pi_g^k(x;\xi)$ represents the annual operating profit per unit of a given technology under a remuneration policy $k \in \mathcal{K}$. In the idealized case, a uniform price in each time period $t \in \mathcal{T}$ is set equal to the dual variable λ_t corresponding to the power balance constraint in Eq. (2b). It can be shown through standard duality arguments that the competitive equilibrium arising under these assumptions and with this remuneration policy is also a socially optimal resource mix solving Eq. (1). Under this idealized policy, operating profit per unit of installed capacity for technology g with $x_g > 0$ can be calculated as

$$\pi_g^{IDEAL}(x;\xi) = \sum_{t\in\mathcal{T}} (\lambda_t - C_{gt}^{OP}) p_{gt}/x_g. \tag{4}$$

Standard duality arguments in the simplified operational model lead to the conclusion that whenever $\lambda_t - C_{gt}^{OP} > 0$, a generator will be operating at its maximum availability $A_{gt}x_g$. In the remaining time periods it will either be off or marginal, during which it will not have operating profit. In this case, Eq. (4) can be simplified to

$$\pi_g^{IDEAL}(x;\xi) = \sum_{t\in\mathcal{T}} (\lambda_t - C_{gt}^{OP}) A_{gt} \mathbb{1}\{\lambda_t - C_{gt}^{OP} > 0\}. \tag{5}$$

In the simplest case, we have a price cap $\bar{\lambda}$ that is assumed to be higher than C_{gt}^{OP} for all generators g in all time periods t. A remuneration policy k that only compensated suppliers to the level of this capped price would lead to less investment and lower reliability in equilibrium. In order to restore this "missing money," a capacity payment per unit of installed capacity of technology g can be estimated as

$$\mu_g = \mathbb{E}\left[\sum_{t\in\mathcal{T}} (\hat{\lambda}_t - \bar{\lambda}) \hat{A}_{gt} \mathbb{1}\{\hat{\lambda}_t - \bar{\lambda} > 0\}\right], \tag{6}$$

where we use the notation $\hat{\lambda}_t$ and $\hat{A}_{gt}$ to reflect that these values come from a simulation rather than being actual observations. Here, the appropriate payment depends on an assessment of availability in intervals of relative scarcity, when the estimated price $\hat{\lambda}_t$ exceeds the cap $\bar{\lambda}$. A unit of capacity with 100% availability would therefore be entitled to a payment of

$$\mu_{100} = \mathbb{E}\left[\sum_{t\in\mathcal{T}} (\hat{\lambda}_t - \bar{\lambda}) \mathbb{1}\{\hat{\lambda}_t - \bar{\lambda} > 0\}\right]. \tag{7}$$

Capacity accreditation procedures estimate the amount of capacity a resource should be allowed to sell by comparing its value during scarcity to a fictional unit of perfect capacity (Bothwell and Hobbs, 2017; Schlag et al., 2020; Energy Systems Integration Group, 2023). For every dollar paid to a perfect resource, the appropriate payment to resource g is $\alpha_g = \mu_g/\mu_{100}$. In other words, when participating in a capacity market with a uniform price, the fraction α_g represents an efficient accreditation value for resource g. We note that this economic interpretation of accreditation differs slightly from the more common approach to estimating effective load carrying capability (ELCC), in that it includes all intervals in which prices are suppressed rather than only those in which load is involuntarily curtailed.

Under a remuneration policy that includes a price cap along with a capacity payment determined in this way, profit per unit capacity can be calculated as

$$\pi_g^{CAP}(x;\xi) = \mu_g + \sum_{t\in\mathcal{T}} (\min\{\bar{\lambda}, \lambda_t\} - C_{gt}^{OP}) A_{gt} \mathbb{1}\{\lambda_t - C_{gt}^{OP} > 0\}. \tag{8}$$

If the values $\hat{\lambda}_t$ and $\hat{A}_{gt}$ are simulated perfectly, then $\mathbb{E}\left[\pi_g^{IDEAL}(x;\xi)\right] = \mathbb{E}\left[\pi_g^{CAP}(x;\xi)\right]$, and thus either policy gives the same result for the equilibrium condition in Eq. (3).

In Appendix A, we describe several assumptions in this basic analysis that are violated in practice. For our purposes, however, the most important challenge with capacity payments is in the computation of availability at times of scarcity, i.e., determining the values of $\hat{\lambda}_t$ and $\hat{A}_{gt}$ relevant for Eq. (6). Along these lines, a major focus in practice has been the development of methods for capacity accreditation. A connected challenge is that, by relying on the estimate $\hat{A}_{gt}$ rather than measuring actual availability A_{gt} in times of scarcity, a capacity payment weakens the incentive to actually perform in times of scarcity. Accordingly, a second focus has been to increase penalties for non-performance that can claw back unearned capacity revenues under certain conditions. In principle, strong penalties can recreate the full-strength incentives provided under the idealized policy. Suppose we assess a penalty or credit $\lambda_t - \bar{\lambda}$ based on the performance of a supplier against its assessed availability. Then profit per unit capacity can be calculated as

$$\pi_g^{PERF}(x;\xi) = \mu_g + \sum_{t\in\mathcal{T}} \left[(\min\{\bar{\lambda}, \lambda_t\} - C_{gt}^{OP}) A_{gt} \mathbb{1}\{\lambda_t - C_{gt}^{OP} > 0\} + (\lambda_t - \bar{\lambda})(A_{gt} - \hat{A}_{gt}) \mathbb{1}\{\lambda_t - \bar{\lambda} > 0\} \right]. \tag{9}$$

Real-world markets typically do not produce full-strength spot prices, necessitating the use of a proxy in place of the value λ_t. The goal is that expected profits under this "capacity performance" remuneration policy are the same as in the idealized policy and thus lead to the same equilibrium. The difference is that this policy ultimately relies on the actual availability A_{gt} rather than the estimated availability $\hat{A}_{gt}$, ensuring that suppliers have the incentive to deliver on their obligations.

4 Accrediting and penalizing capacity: practice

In this section we discuss the various ways real-world markets have attempted and failed to match the idealized picture presented in Section 3. Using a toy example for which market equilibria can be easily identified, we demonstrate how moving from an idealized penalty or accreditation policy leads to a competitive equilibrium that is inferior in terms of reliability and efficiency.

4.1 Benchmark case

Suppose two technologies are available. Technology 1 is perfectly reliable, i.e., $A_{gt} = 1 \; \forall t \in \mathcal{T}$ in all realizations of ξ. Technology 2 has a forced outage rate of 10%. To enforce some correlation in outages, investment in the second technology is split equally between ten groups, where failures within each group are perfectly correlated but failures between groups are independent. Specifying an equal split among the ten groups allows us to construct an example in which the likelihood of scarcity events depends only on the level of resource investment and not the mix. The binomial distribution for availability of Technology 2 across all ten groups is shown in Table 1. Demand is certain at 100 MW in every time period, so uncertainty is entirely on the supply side. Suppose we target a reliability level of 2.4 hours of lost load per year,implying

Table 1: Probability mass function for fleetwide availability of the second technology. In each time period $t \in \mathcal{T}$, availability for each group is a Bernoulli random variable that takes the value 1 with probability 90% and 0 with probability 10%. Accordingly, the overall availability of the second type of generator takes a binomial distribution with 10 trials, each with a success probability of 90%.

Fleet-wide Availability	Probability
100%	0.349
90%	0.387
80%	0.194
70%	0.0574
60%	0.0112
50%	0.00149
40%	0.000138
30%	8.75×10^{-6}
20%	3.65×10^{-7}
10%	9×10^{-9}
0%	1×10^{-10}

that shortfalls occur with probability no higher than $2.4/8760 = 0.000274$. Since this is larger than the sum of probabilities for 0–40% availability but less than the probability of 50% availability in Table 1, a resource mix using entirely the second technology would require 200 MW of installed capacity to meet the reliability target given the 100 MW demand. Since the first technology is always available, only 100 MW of installed capacity would be required.

Suppose the investment cost C_1^{INV} of Technology 1 is \$87,600/MW-yr and that both generators are free to operate. An equilibrium that includes the perfectly reliable resource needs to average \$87,600/MW-yr in total net revenue, or \$10/MWh when amortized over its production. Without operating costs or a responsive demand side, the analysis is somewhat complicated due to the presence of multiple optimal dual solutions, but we take this complication to be an artifact of the simplicity of the example. Assuming we meet the reliability target precisely, this remuneration could be achieved by scarcity prices of \$36,500/MWh arising in the most severe 2.4 hours per year, or 0.0274 percent of total hours. If the equilibrium includes the second technology, then we can identify the most severe 2.4 hours as occurring whenever availability is below 50% (0.0147 percent of total hours) plus a fraction of the hours when availability is at 50%. Assuming a price cap of $0 for convenience, equal to the operating cost, this implies an idealized capacity payment under Eq. (6) of $87,600/MW-yr for the first technology and $38,799.04/MW-yr for the second. This remuneration equates to an accreditation value of $\alpha_2 = 44.29\%$ for the second technology, which we note is below 50% since the conditional expectation of its availability during scarcity includes the rare occasions when more than 50% of the fleet is offline. Alternatively, if the second technology were accredited at a higher level, then efficient penalties would preserve this expected annual profit. For example, if an accreditation value of 100% were granted to the second technology, then it would in principle expect $87,600 - $38,799.04 = $48,800.96 in penalties per MW of installed capacity per year.

The example makes it easy to identify the competitive equilibrium that will arise for a given remuneration policy. Suppose the investment cost C_2^{INV} of the second technology is $45,000/MW-yr. Since this exceeds $38,799.04/MW-yr, a socially optimal resource mix would include 100 MW of technology 1 and none of technology 2. As long as the net revenue available to the second technology stays below the $45,000/MW-yr level, it will not be able to enter the market and the socially optimal resource mix will be achieved in equilibrium. However, several mechanisms could inflate the value that the second technology would be entitled to receive, pushing the system to an equilibrium containing only the second technology that fails to meet the reliability target of 2.4 hours of lost load per year.

4.2 Penalization

We first describe how real-world penalty structures would be inadequate if applied to our example. As a point of reference, we use the $48,800.96/MW-yr in penalties assuming 1 MW of technology 2 represented itself as 100% available. With lighter penalties, the remuneration available to technology 2 could rise to cover its investment cost of $45,000/MW-yr.

4.2.1 Expected penalty hours

Penalties could be expected in 2.4 hours per year, consistent with the reliability target. To reflect the entire capacity value, this low frequency of penalties entails that a charge of $36,500/MWh be applied to shortfalls. Given that such sharp penalties may not be enforceable, systems may choose to spread the capacity value over a larger number of expected hours. Using an expected 30 hours per year, as in PJM, reduces the penalty charge to $2,920/MWh. Two potential problems arise. First, the conditional expectation of resource performance is likely to fall with the criticality of the hour in question. In our system, expanding the number of performance assessment hours to 30 leads to the inclusion of sub-critical hours in which the fleet-wide availability of the second technology is 60%. Accordingly, even with penalties applied in 30 hours, the total expected penalty drops to $39,622.12/MW-yr. We note that this second effect would not arise in a system where shortfalls were driven by uncertainty in demand rather than supply. In the former case, the conditional expectation of resource output would be more stable in tail events, leading to more accurate penalization.

The second potential problem is if the actual number of assessment hours is substantially lower than the 30 used to compute the penalty. If a penalty of $2,920/MWh were applied in only the highest risk 10 hours, for example, a MW accredited at 100% would only be exposed to $15,000.08/MW-yr of penalties in expectation. The Complaint submitted by PJM generators after being assessed penalties in Winter Storm Elliott argues in favor of this underpenalization, stating that "in many cases throughout Elliott, PJM power prices and ancillary service prices were inconsistent with the idea that PJM was in any kind of emergency conditions" (Coalition of PJM Capacity Resources, 2023). Without assessing the overall merit of the Complaint, we highlight that in order to have any chance to succeed in providing efficient incentives, penalties must be applied in many hours that cannot be considered emergencies, simply because emergencies are so infrequent.

4.2.2 Balancing ratio

In both PJM and ISO-NE, the system operator applies a balancing ratio in which resource performance is assessed not against its own capacity obligation, but instead against the overall performance of resources in the system. The unfortunate effect from the standpoint of reliability is to insulate the supply side of the market from any net penalization. In our system, suppose a fleet of 200 MW of Technology 2 collectively has a capacity obligation of 100 MW. Suppose the overall availability of the fleet in a given performance assessment hour is 40%, so the system experiences a 20 MW shortfall. To provide efficient incentives, a penalty of $36,500/MWh would be applied to the shortfall and the unserved load would be compensated. Instead, the effect of the balancing ratio is to reduce the collective obligation of the suppliers to 80 MW; the penalty transfers money from the non-performing to the performing suppliers, but returns nothing to load. In other words, the expected penalty from capacity performance mechanisms using a balancing ratio adjustment is $0.

4.2.3 Intertemporal correlation and stop loss provisions

The above calculations do not consider the timing of penalties and assume that all penalties can be collected. However, in practical terms there is a difference between, e.g., one 2.4-hour performance penalty event occurring every year versus a 24-hour event occurring every 10 years, since stop-loss provisions prevent the accrual of significant penalties within a short time frame. In our example, the PJM limit of 1.5 times the net CONE (if set by Technology 1) can be calculated as $131,400. If 24-hour events occur once every ten years, this caps the expected penalty at $13,140/MW-yr for Technology 2, substantially lower than the efficient penalty of $48,800.96/MW-yr.

4.3 Accreditation

Any of the above mechanisms could lead to a situation where the revenue available to the second technology is higher than theory would dictate, giving owners of this technology an incentive to overstate its contribution to reliability. If the net revenue available to the second technology exceeds its investment cost of $45,000/MW-yr, the remuneration policy leads to an inefficient equilibrium comprising only the second technology. The market pushes the system toward an inferior resource mix, the reliability of which is determined by an administrative assessment of how much of the resource adequacy product the second technology should be allowed to sell. If the assessed accreditation value $\hat{\alpha}_2$ exceeds $\$45,000/\$87,600 = 51.4\%$, then the clearing price of capacity will fall below $87,600/MW-yr to the level of $\$45,000/\hat{\alpha}_2$, forcing the first technology out of the system. The overall reliability of the system is compromised in this alternative equilibrium. Since there is no demand uncertainty, the only plausible demand forecast is 100 MW. Given an estimated accreditation of $\hat{\alpha}_2 > .514$, this implies that $100/\hat{\alpha}_2 < 200$ MW of the second technology will be procured, while 200 MW is required to achieve the reliability target of 2.4 hours of lost load per year.

Given that they cannot rely on market incentives alone to ensure reliability, the attention of market operators has turned to the administrative process of capacity accreditation. The challenges encountered in establishing efficient accreditation values are both statistical and political. Given the one-day-in-ten-years standard, instances of lost load due to resource inadequacy are rare. With historical data providing little help in estimating the conditional expectation of output from resources in a given future scarcity event, operators must rely on simulation. Suppliers have an incentive to push for higher accreditation values due to the direct financial benefit, while loads may also be hesitant to pay in advance to protect against rare events that are not in the recent historical record. All told, there is reason to suspect that accreditation values are biased high in practice. The analysis of PJM South in Dison et al. (2022), for example, suggests that instead of a standard accounting that would give a 95% winter capacity credit to gas, a calculation including the effects of outage correlations and fuel supply risks would give a substantially lower value of 76.1%. While the rarity of weather extremes makes it difficult to empirically verify this estimate, the 38% forced outage rate for gas plants during Winter Storm Elliott reported by PJM is suggestive (Bryson et al., 2023).

Because gas resources constitute a significant fraction of the capacity resources in most U.S. systems, over-crediting gas likely represents the most pressing threat to reliability in present systems. However, existing methods for estimating ELCC also likely over-credit wind and solar. In MISO and SPP, for example, a separate ELCC for wind and solar is calculated for many historical weather years, then an average of these estimates is used for accreditation (Midcontinent Independent System Operator, 2022; Southwest Power Pool, 2022). In a system achieving something like the one-day-in-ten-year standard, no scarcity events should occur in most years and the contribution of resources in those years should not be relevant for capacity accreditation. As discussed in Section 4.2.1, the conditional expectation of wind and solar output in the severe scarcity events is likely to be lower than in more moderate stress events currently included in the average.

4.4 Workarounds

In recent years, both PJM and ISO-NE have employed several strategies with dubious economic and legal justification as part of a broader attempt to retain adequate resources. While these strategies could be interpreted as either conservatism or bias toward incumbents, a more favorable explanation is that operators are simply attempting to use any tool available to them to compensate for underpenalization and overaccreditation in their resource adequacy constructs. This subsection discusses such strategies in broad terms, highlighting that even if they do succeed in meeting reliability targets they do so in inefficient ways, failing to address the underlying issues.

4.4.1 Overprocurement

Perhaps the most straightforward route to creating a reliable mix of overaccredited resources is to overprocure them. During Winter Storm Elliott, PJM was able to avoid load shedding despite a high failure rate because it entered the winter with a reserve margin of around 46%, substantially above its nominal target of 15% (North American Electric Reliability Corporation, 2022b). The PJM capacity market demand curve is based on summer peaks, against which its 2022 reserve margin was around 32% (North American Electric Reliability Corporation, 2022a).

Suppose that the second technology has been inaccurately accredited at the level of 60%. Using an accurate demand forecast of 100 MW would imply installed capacity of 100 MW/.6 = 167 MW clearing in the capacity market at a price of $(\$45,000/\text{MW-yr})/0.6 = \$75,000/\text{MW-yr}$, with a quantity lower than the 200 MW needed to meet the reliability target and a price too low to support Technology 1. Market operators could instead use a demand forecast of $200 \text{ MW} \cdot 0.6 = 120$ MW to induce enough capacity. This level translates to an actual reserve margin of 100% instead of its nominal target of 67%. It can be argued that the system is not “overprocuring” at all, since it procures the correct amount of capacity overall. However, it has done so in an inefficient way, with a consequence that the more efficient Technology 1 cannot economically enter the system.

4.4.2 Removing supply

An alternate strategy is to prevent some resources from supplying the resource adequacy product. If these resources nevertheless remain in the system, the effect can be to obtain a reliable solution. Extending the example above, suppose the market operator prohibited 33 MW of installed capacity from participating in the capacity market. This 33 MW could combine with 167 MW that cleared in the capacity market to yield a fleet of 200 MW sufficient to meet the reliability target.

In recent years, both PJM and ISO-NE sought to effectively remove state-sponsored renewable and nuclear resources receiving out-of-market payments for their clean attributes from the capacity market. The means of removing the resources was to apply a Minimum Offer Price Rule (MOPR) requiring them to offer at a level above what was likely to clear, allowing unsubsidized generation to remain in or enter the system alongside the subsidized resources (Macey and Ward, 2021). Regardless of the economic or legal merit of the MOPR, of interest for our discussion is the claim made by proponents that it was needed to ensure reliability. Since subsidies to supply in general are expected to increase supply in equilibrium and thus improve reliability, this argument was not convincing. In a context with significant overaccreditation, however, removing resources from the supply side can restore a reliable solution.

4.4.3 Targeted subsidies

A third strategy is to directly subsidize actions that will improve reliability. Suppose that at a cost of \$7,000/MW-yr, investors in Technology 2 can take additional steps to raise average availability from 90% to 94% (e.g., holding additional fuel in inventory), and suppose that non-performance penalties in the capacity market are too weak to induce this investment. With this higher level of unit availability, the reliability target can be met with 167 MW of installed capacity, but the socially optimal solution is still to install 100 MW of Technology 1. In this case, targeted subsidies totaling 167 MW $\cdot \$7,000$/MW-yr $= \$1,169,000$/yr would be a less expensive way of meeting the reliability target than spending an additional 33 MW $\cdot \$45,000$/MW-yr $=$ $\$1,485,000$/yr on lower-quality capacity. However, such an approach would still not enable Technology 1 to enter the system. This failure to restore the efficient mix holds in this case even if Technology 1 were granted a subsidy of $\$7,000$/MW-yr$/0.6 = \$11,667$/MW-yr, since this amount does not overcome the gap between its investment cost of \$87,600/MW-yr and the clearing price of capacity, which remains \$75,000/MW-yr.

5 Conclusion and policy implications

Recent events have called into question the ability of capacity markets to address resource adequacy challenges. Our analysis suggests that some skepticism about proposals to resolve the resource adequacy problem in a "pure market" by strengthening non-performance penalties is warranted. Policymakers are faced with two suboptimal choices: either they can keep low non-performance penalties, in which case generators will not have sufficiently strong incentives, or they can increase non-performance penalties, in which case generators that are unable to pay the penalties will default on their obligations. Both options allow generators to avoid fully bearing the costs of a failure to deliver. In areas that pursue a market-based paradigm, our analysis suggests that the key challenge is how to avoid moral hazard given the potential for under-penalization of non-performance. Options for avoiding moral hazard include a) combining stronger prices with stronger performance bond, insurance, or credit requirements and/or b) more active regulation and monitoring to ensure accurate accreditation. A pure market approach may not be credible, and exclusive reliance on accreditation may not be effective. Thus, a hybrid approach may be required to resolve resource adequacy challenges. Recognizing that some failures are inevitable, an additional challenge is to differentiate between bad luck versus mismanagement in assessing penalties.

The consequences of an implicit overpayment to generators that fail to deliver on their obligations are significant if left unaddressed. Defenders of market approaches have pointed out that despite the challenges, PJM avoided rolling blackouts during Winter Storm Elliott and even exported power to neighboring non-market areas in the Southeast that did experience outages. While we do not address incentives for resource adequacy in vertically integrated areas within this paper, we note that the comparison is not a fair one: compared to PJM's 46% anticipated reserve margin entering the winter, the SERC-Central and SERC-Eastern regions were assessed at 25.1% and 23.9% respectively (North American Electric Reliability Corporation, 2022b). Given that the extra margin in PJM resulted from substantial overprocurement relative to the system's nominal targets, its comparative ability to avoid blackouts in the event cannot be attributed to the efficiency of markets. Observing that the storm led to significant generation failures across the Eastern Interconnection in areas with different resource adequacy paradigms, a clearer conclusion is that the problem of modeling correlated outages in tail events is one that is shared by all systems regardless of market structure. While not quantified in this paper, a risk of capacity markets relative to integrated resource planning is that they may push the capacity mix toward resources prone to these correlated outages. As a case in point, despite ISO-NE's ongoing concern about winter reliability and the fact that nuclear performs comparatively well during winter storms (Murphy et al., 2020), the Pilgrim Nuclear Power Station in ISO-NE shut down in 2019 citing economic considerations. To be sure, the decision to close a nuclear power plant involves many factors beyond capacity market remuneration. However, it may be reasonably asked whether implicit overpayment of natural gas units since the inception of the ISO-NE capacity market contributed to the plant's exit from the market.

After the catastrophic failures in Texas during Winter Storm Uri, several commentators asked if a capacity market could have helped. The analysis in Mays et al. (2022) argues that the strong performance incentives provided in an energy-only market are not sufficient to ensuring resilience to extreme events, justifying the imposition of a mandatory forward contracting obligation on load-serving entities. While capacity markets are one form that such an obligation may take, as currently instantiated they weaken the direct incentives for performance during scarcity. Consistent with many early analyses of capacity markets (Vazquez et al., 2002; Oren, 2005; Hogan, 2005), Mays et al. (2022) suggests that obligations could instead be structured as contracts around full-strength energy prices, ideally combining the strong performance incentives provided by energy-only markets with the risk sharing facilitated by capacity markets. The analysis in this paper identifies a key failure mode in such an approach, namely, generator credit risk, and demonstrates that it is not enough to ask whether a capacity market is present: the details of its implementation are ultimately what determines its success.

A Assumptions in the idealized benchmark

A rich literature has developed analyzing ways in which assumptions in the basic model of Section 3 could be relaxed. We describe five important assumptions here. The first is that price suppression happens solely during peak periods, i.e, when all generators are operating to their maximum availability. In practice, price suppression can also occur in less critical operating periods due to operational uncertainty and physical constraints (Joskow and Tirole, 2007; Mays, 2021a). The implication is that some fraction of missing money should be allocated to resources on the basis of their production in those periods, rather than on the basis of their availability during scarcity situations. A second is that the capped price is above the operating cost of generators. In practice, temporary spikes in the cost of natural gas and fuel oil can violate this assumption, and many systems authorize a make-whole payment to generators that would otherwise operate at a loss. These make-whole payments are inefficient in terms of overall remuneration, effectively granting undue scarcity rents to the generators with expensive fuel in those scenarios. Instead, a uniform capacity price should in principle cover such losses, which could be avoided if the generator contracted for fuel supply to match their capacity obligation. A third is that generators are producing to their full availability whenever the price cap is binding. This assumption can be violated due to intertemporal technical constraints (e.g., ramping limits) or transmission congestion. Determining capacity payments on the basis of availability without taking into account these other factors affects total compensation and leads to a different equilibrium (Holmberg and Lazarczyk, 2015; Bravo et al., 2016; Mays, 2021b). Fourth, while the equilibrium condition in Eq. (3) uses expected value, most investors are risk averse. Since the distribution of profits under $\pi_g^{IDEAL}(x;\xi)$ is different from that under $\pi_g^{CAP}(x;\xi)$ despite having the same expected value, the two policies can lead to different equilibria assuming risk aversion (de Maere d'Aertrycke et al., 2017; Mays et al., 2019). Fifth, this analysis assumes that despite the presence of a price cap, loads choose to consume the same quantity that they would facing full-strength prices. While in principle this could occur if consumers were allocated the cost of capacity in an efficient way and had access to information on the stochastic process of capacity cost implicitly allocated in each time period, the pass-through of capacity costs is typically done in a much coarser way.

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