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PJM and ISO-NE forward capacity markets: a critical assessment

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Summary

1 Introduction

The increasing penetration of intermittent generation sources, retirement of ageing plants, decommissioning of nuclear power plants and provisions for the decarbonisation of the electricity sector in the medium to long term have led to a revival in forward capacity markets and their ability to encourage the appropriate availability of flexible generation capacity. In France, a forward capacity market based on capacity obligations will be adopted by 2015-2016. Similarly, the UK Government's Electricity Market Reform provides for the implementation of a forward capacity market according to which the first auctions will be conducted in 2014 for the delivery period 2018-2019. In Germany too the adoption of a capacity support scheme is currently under discussion.

Italy has recently adopted a forward capacity market based on reliability options. The first procurement procedures were scheduled to be held in 2012 for the delivery period 2017-2019. However, due to delays in the legislative procedure for approval of the new capacity support scheme, the date on which auctions will be held is still uncertain.

The Italian capacity support scheme relies for its design on the characteristics of two forward capacity markets adopted in the United States: the Reliability Pricing Model (RPM) and the Forward Capacity Market (FCM), implemented respectively by the Regional Transmission Operators (RTOs, henceforth) PJM and ISO-NE[1]. More specifically, much of the Italian design is based on the ISO-NE mechanism. In fact, both forward capacity markets are characterised by the adoption of reliability options. The product exchanged through the procurement process is a relevant part of the design of any capacity support scheme, since it defines the resulting set of obligations and rights pertaining to the capacity resources committing to the capacity market. On the other hand, the RPM of PJM has been the reference for the Italian design of the demand curve expressing the target capacity requirement to be procured through the auctions.

This document provides an analysis of the characteristics of both the RPM and the FCM adopted by PJM and ISO-NE. Specifically, the research will be devoted to answering several research questions aimed at understanding how the PJM and ISO-NE forward capacity markets work in terms of their respective aspects of relevance to the Italian mechanism.

The paper is organised as follows. Section 2 illustrates the resource adequacy problem and its major determinants, and provides a discussion about how forward capacity markets with reliability options address the resource adequacy issue. Section 3 discusses the institutional design of forward capacity markets in ISO-NE and PJM. Specifically, it describes first the institution responsible for definition of the resource adequacy requirement and, more generally, for management of the forward capacity market. Secondly, it illustrates the different types of capacity resources allowed to participate in the FCM of ISO-NE and PJM, as well as the relative qualification process. Section 4 discusses the methods by RTOS define the

[1] The States covered by PJM are the following: all or most of Delaware, District of Columbia, Maryland, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia. Parts of Indiana, Illinois, Kentucky, Michigan, North Carolina and Tennessee. ISO-New England covers the following States: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

resource adequacy target for a given delivery period. In addition, the demand curve expressing the resource adequacy target in the procurement procedures will be considered for both forward capacity markets. Section 5 illustrates the features of the procurement process for the capacity support schemes of both PJM and ISO-NE. Section 6 discusses the characteristics of the capacity products exchanged in the procurement processes of both PJM and ISO-NE. The capacity product is of crucial importance, in fact, for defining the obligations and rights of the capacity resources participating in the forward capacity markets. Finally, Section 7 illustrates the characteristics of the collateral and other financial obligations required by capacity resources for their admission into the forward capacity markets.

2 Forward capacity markets and the resource adequacy problem

This Section discusses the determinants of the resource adequacy problem in electricity generating capacity and the rationale behind the adoption of capacity support schemes.

2.1 The resource adequacy issue

Resource adequacy may be defined as the ability of the "*installed and/or expected to be installed [generating capacity] to meet efficiently demand in the long term*", at all times (Batlle and Rodilla, 2010).

Before the liberalisation of electricity markets, resource adequacy was not a cause for concern. The vertically integrated incumbent could fully appropriate the benefits of its investments. The absence of competition gave investments in generating capacity a low level of commercial risk, thus eliminating a potential disincentive to invest. In addition, the absence of new entries eliminated the problem of coordination in the investment decisions of different market operators. As we will see later in this document, by originating boom and bust cycles in generating capacity investments, the lack of coordination in investment decisions is one of the main concerns regarding resource adequacy. Moreover, vertical integration allowed the incumbent to coordinate investments in both generating and transmission capacity, and to develop investments where most needed.

In addition to the changes produced by liberalisation in terms of investment risk, the increasing penetration of renewable sources of generation represents another cause for concern in terms of generator profitability. renewables lower market price levels and increase price volatility by making investments in conventional generating capacity less attractive. This in turn originates further motivation for providing appropriate incentives to invest. As stated by Pérez-Arriaga (2007), *"energy market liberalization and privatization have led to a more efficient power sector, but also to greater price volatility and increased commercial risk for new capacity investment across all fuel types. In a significant number of systems, energy planners have begun to voice concerns over current limited levels of private sector investment in new generation – also in transmission and distribution networks, in some systems – to meet the projected energy demand growth.* Similarly, Cramton and Ockenfelds (2011) highlight the fact that resource adequacy is a relatively recent challenge for modern electricity markets: "*Appropriate incentives to invest in new generation capacity was not an issue for quite some time in most parts of Europe. This is changing as demand increases, older plants retire and* *investments become increasingly risky due to increased price volatility and a lack of a stable market framework. [Renewables increase] price volatility, tend to reduce market price levels and worsen the capacity utilization of conventional capacity. This makes investments in conventional resources less attractive."*

It is crucial to highlight that resource adequacy is "*a long-term challenge*" (Cramton and Ockenfelds, 2011), which differs from the short-term aspect of system security. As exhaustively examined in Rodilla *et al.* (2010) and Pérez-Arriaga (2007), reliability of supply at generation level involves four key dimensions – including system security and resource adequacy – which differ "*according to their time scope*".

From Rodilla *et al.* (2010): "*The four components (or dimensions) are the following:*

- *Security: the very short-term dimension. Defined by the North American Electric Reliability Council as the "ability of the electrical system to support unexpected disturbances such as electrical short circuits or unexpected loss of components of the system.*
- *Firmness: the short- to medium-term dimension. Defined in Batlle and Pérez-Arriaga (2008) as the ability of the already installed facilities to supply electricity efficiently. This dimension is conditioned by the characteristics of the existing generation portfolio and the medium-term resource management carried out by generators (fuel provision, water reservoir management, maintenance scheduling, etc.).*
- *Adequacy: the long-term dimension. Defined as the existence of enough available generation capacity (installed or expected to be installed) to efficiently meet demand in the long term.*
- *Strategic expansion policy, which concerns the very long-term availability of energy resources and infrastructures. This dimension usually entails the diversification of primary sources of energy through a balanced generation portfolio."*

Similarly, Ruiz (2006) recognises that security and resource adequacy are two distinct dimensions of system reliability. *"Short-term resource adequacy, a key component of system reliability, is the ability of a system with a fixed resource mix to meet the load at all times. Security is the ability of the system to withstand sudden disturbances".* Differently, *"Resource adequacy addresses the need to have 'sufficient' resources in place to meet the forecasted demand taking into account the uncertainty of the environment and the salient characteristics of electricity, including the lack of large-scale storage and the limited demand responsiveness of load to price."*

Many other scholars agree with the distinction between the long-term feature of the resource adequacy issue and the short-term aspect of system security. In fact, it seems that the economic literature on capacity support schemes conclusively considers the two dimensions to be clearly distinct, although they both contribute to system reliability (see e.g. Papalexopoulos, 2010; Roques, 2007; Brattle Group, 2009 Joskow, 2008).

Summing up, the short-term issue of system security may be intended essentially as the efficient employment of existing resources. For example, by scheduling existing generating capacity in such a way to ensure reliability, and by relying on the activity of the System Operator (SO, henceforth) on the ancillary service markets: tertiary reserve capacity reservation, generation shift, etc. Conversely, the long-term issue of resource adequacy implies incentivising the optimal amount of investment in generating capacity in order for generating capacity to be built on time to ensure sufficient supply in the long run: i.e. the capability to meet the anticipated peak demand with certain (high) probability.

Capacity support schemes are devoted to addressing the long-term challenge of resource adequacy by providing appropriate incentives to invest in generating capacity in order to ensure that, in the long run, installed capacity will be sufficient to meet demand at all times. Therefore capacity support schemes do not deal with the short-term issue of system security.

In Section 2.2 we will discuss the distortions in the market outcomes under conditions of scarcity that explain the rationale behind the adoption of capacity support schemes and their role in restoring appropriate incentives to invest in generating capacity.

2.2 Determinants of resource adequacy

Resource adequacy concerns are mostly due to distortions in the market outcome when scarcity occurs. For the electricity industry scarcity hours are of crucial importance. Only when capacity becomes tight are some generators – namely those having invested in peaking generation capacity – able to recover a large portion of their fixed costs. Therefore, even mild flaws in price formation during scarcity hours, or in the number of scarcity hours, could influence generator profitability to a significant extent.

Below we discuss the main causes of distortion for generator profitability during scarcity hours, and thus the motivations behind the introduction of capacity support schemes. In doing this, we will distinguish three broad groups of causes of the resource adequacy problem:

- Demand-side flaws related to the price-inelasticity of the electricity demand, and the impossibility of selectively disconnecting customers.
- The missing money problem and its related determinants.
- Other characteristics of the design and operation of the electricity market that may deter investment in generating capacity.

2.2.1 Demand-side flaws

2.2.1.1 Electricity demand is price-inelastic

One of the main determinants of resource adequacy – and thus for the need of capacity support schemes – relies on the specific features of electricity demand compared with that of other markets. As Ausbel and Cramton (2010) stated: "*The need for regulated forward markets in electricity comes largely from market failures on the demand side. Consumer demand response is limited; consumers have limited exposure to spot prices and have no ability to express preferences for reliability.*"

Actually, due to the technical features of most of the metering systems currently in use, a noticeable portion of the electricity demand is completely price-inelastic in the day-ahead to real-time timeframe (see e.g. Cramton and Ockenfelds, 2011; and Cramton and Stoft, 2005). Most of the meters installed for residential small customers only record consumers' total withdrawal over long periods of time, typically one month. Older meters record only total consumption since the equipment was installed. In addition, despite the increasing penetration of smart meters, the economic literature does not show conclusive results about the effectiveness of smart meters in influencing customers' real-time consumption (see, for example, the literature review in Houde *et al.* 2013).

If hourly consumption is not known by end-customers, retail prices cannot reproduce wholesale market prices. This, in turn, prevents customers from knowing the cost of their consumption during each hour. If electricity demand is price-insensitive, load will not decrease to the level of the installed generating capacity during scarcity events. This feature of electricity demand therefore calls for a regulatory solution for scarcity pricing and involuntary load reduction in order to avoid uncontrolled widespread service disruptions. Cramton and Stoft (2006) argue: *"These demand-side flaws show that an energy-only market approach needs the regulator to intervene in order to set the appropriate market parameters to provide for a reliable level of installed capacity".*

Moreover, as Figure 1 illustrates, a price-inelastic demand (left panel) is responsible for fewer scarcity hours with respect to a price-sensitive demand (right panel). In other words, a price-inelastic demand results in fewer hours in which the market-clearing price is above the incremental cost of the system. Nonetheless, during scarcity hours, the difference between the clearing price and the system's marginal cost is higher when electricity demand is price-insensitive than when it is elastic (see the grey area in both the left and right panels of Figure 1).

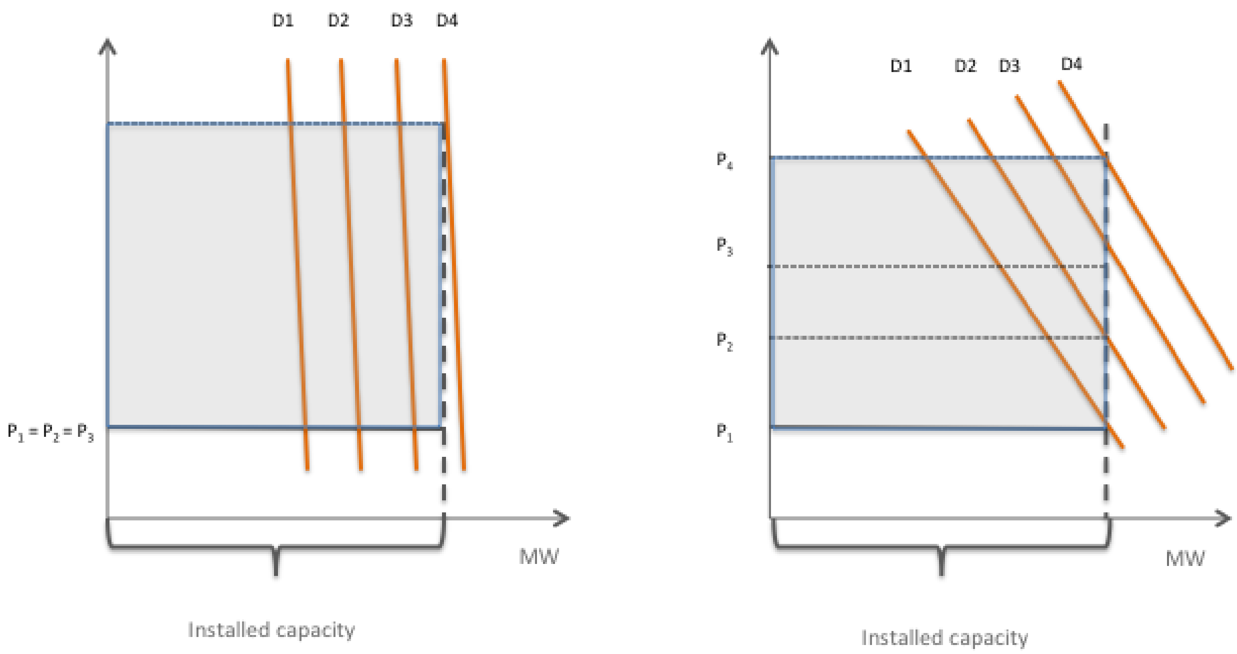

Figure 1: Market equilibrium with different demand elasticities.

Therefore, scarcity hours are of crucial importance for generators to recover their fixed costs.

Given that quantity-rationing events are not linked to a market-clearing price, the electricity price during scarcity hours must be administratively set. Usually, the chosen administratively set price is the so-called Value of Lost Load (VoLL). The VoLL can be defined as the price that makes end-customers indifferent between consuming electricity at that price and not consuming.

However, due to political concerns, the adoption of an administratively set price is unlikely to be feasible. End-customers consider load curtailment as unfair given that, if curtailed, they do not receive payments equivalent to the VoLL from their supplier. Similar considerations hold for price spikes. At the same time, non-disconnected customers are not charged for the VoLL. Moreover, customers are not incentivised to reveal their individual valuation for scarcity given that it is impossible to selectively disconnect them based on their individual valuation of electricity valuation. As Cramton and Stoft (2005) stated: "*Until individualized customer reliability is possible, all approaches except a very responsive demand side require at least one crucial administrative input. Shortage pricing requires an estimate of the VOLL.*"

These concerns thus make it not possible to opt for the adoption of an administratively set price in case of scarcity. Regulators and system operators prefer to adopt regulatory solutions aimed at setting capacity targets more or less explicitly to attract investments in generating capacity in order to avoid unfair and costly service disruptions. That is, they prefer to opt for capacity support schemes rather than extreme price spikes to incentivise investments in generating capacity.

2.2.1.2 Impossibility to selectively ration demand

Electricity demand may be coercively adapted to the level of installed capacity by means of priority rationing contracts (Chao and Wilson, 1987). These contracts allow end-customers to specify in advance the level of wholesale market prices at which they would allow the SO to implement demand curtailments. In return for curtailment, retail customers would receive a lower price per unit consumed on their standard meters. By means of this contractual arrangement, customers would not have to monitor real time prices themselves. Instead, the SO would do so through a parallel contract with the retail consumer's Load Serving Entity (LSE).

However, as argued by Stoft (2002), priority rationing contracts requires the SO to control the flows of power that go to individual customers and to have the capability to curtail individual customer demand at short notice. If this is possible for very large customers, control over power flows does not go very far down into the distribution system, and SOs can only curtail demand in relatively large "areas" comprised of many customers. In other words, "*individual consumers cannot choose their individual preferred level of reliability when rolling blackouts are called by the system operator; their lights go off along with their neighbors' light*", (Joskow, 2007).

Below, we discuss further motivations underlying resource adequacy concerns related to the missing money problem.

2.2.2 The missing money problem

The economic literature looks at the missing money problem as one of the main drivers behind the adoption of capacity support schemes. The missing money problem refers to deficiencies in generator revenues due to the features of the market design, or to industry and regulatory practices which prevent the profitability of generators from attracting the optimal level of investment. Broadly speaking, such flows in the functioning of the electricity market are related to:

- The presence of electricity price cap by market operators to avoid the exercise of market power.
- The adoption of out-of-market procurement of reserve resources.
- The procedures sometimes utilised by the SO to deal with operating reserve shortages.

As argued by Joskow (2007), the features mentioned "*appear collectively to suppress spot market prices for energy and operating reserves below efficient prices during the small number of hours in a typical year when they should be very high*".

In a simplified view, the missing money problem regards the perception that – due to the above-mentioned features of market design and regulatory practices – energy markets and ancillary services markets alone are not sufficient to induce efficient investment in generating capacity in order to ensure resource adequacy. The simplified approach, therefore, looks at the missing money problem as a restriction of shortage-related price spikes caused by the occurrence of regulatory and market-design flows which (i) reduces the opportunities for the peak units to earn profits in the energy markets and cover fixed costs, and (ii) eliminates profits for generators providing capacity margin above the peak demand necessary for resource adequacy.

It is important to highlight that the missing money problem should be assessed empirically. While, indeed, the fact that the electricity demand is price-inelastic is a common feature of all electricity markets, the design flaws generating the missing money problem may not be. In fact the missing money problem may not occur and capacity support schemes may be not needed if, for example, excess capacity is met and capacity margins are not shrinking; the profitability of generating technologies is high given the prices of energy and ancillary services or the market characterises for a significant market power.

2.2.2.1 Market power mitigation measures

A first determinant of the missing money problem is the adoption of regulatory measures aimed at avoiding the exercise of market power by pivotal generators during scarcity events (on the missing money problem see e.g. Ausbel and Cramton, 2010; Batlle and Rodilla, 2010; Joskow, 2007; Kleit et al. 2013; Meunier, 2010; Rious et al. 2012). In fact, when supply becomes tight, even a generator with a negligible market share can enjoy market power by withholding a small amount of capacity and determine a significant increase in the market-clearing price.

Figure 2 shows the effect of the exercise of market power on market-clearing price. If capacity becomes tight and capacity withholding occurs – as indicated by the dashed red line in Figure 2 – the market-clearing price jumps from P' to P.

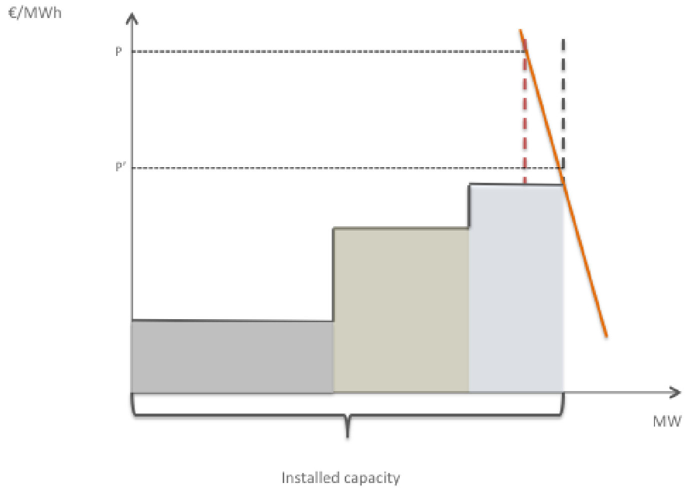

Figure 2: The effect of market power on the market-clearing price.

In some countries, in order to avoid the exercise of market power in condition of scarcity, the generators' incentive to withdraw capacity has been eliminated by capping the scarcity price at a level significantly below the VoLL. For example, similar mitigation measures have been adopted in markets as ERCOT (operating in Texas), NEM (operating in Australia), and in the wholesale market of Alberta and Ontario (Canada).

Usually the scarcity price is administratively set at the level of the marginal cost of the most expensive generating unit in the system. The price cap has the effect of reducing the expected profits of generators to a level not sufficient to encourage an efficient level of investment. Figure 3 shows the effect of introducing a price cap on the scarcity price to avoid the exercising of market power. The area with the grey background represents the profit that 1 MW of generation capacity with variable cost *c* obtains on the wholesale market. The profit is given by the difference between the market-clearing price and the generator's variable cost in each hour. If during scarcity hours the price is capped – and is set at the level of the variable cost of the most expensive generator cost (*cmax*) instead of the VoLL – the generators' profits are reduced by the darker area (the difference between VoLL and *cmax* in the left panel of Figure 3).

In the long-run, standard profitability conditions are restored by means of the entry/exit process. As the generating units with variable cost *cmax* are not replaced, capacity settles at a lower level and the new system's marginal cost becomes *cmax'* (see the right panel of Figure 3). This in turn determines an increase in the number of scarcity hours until the new dark area is large enough to cover the generators' fixed costs (see the right panel of Figure 3).

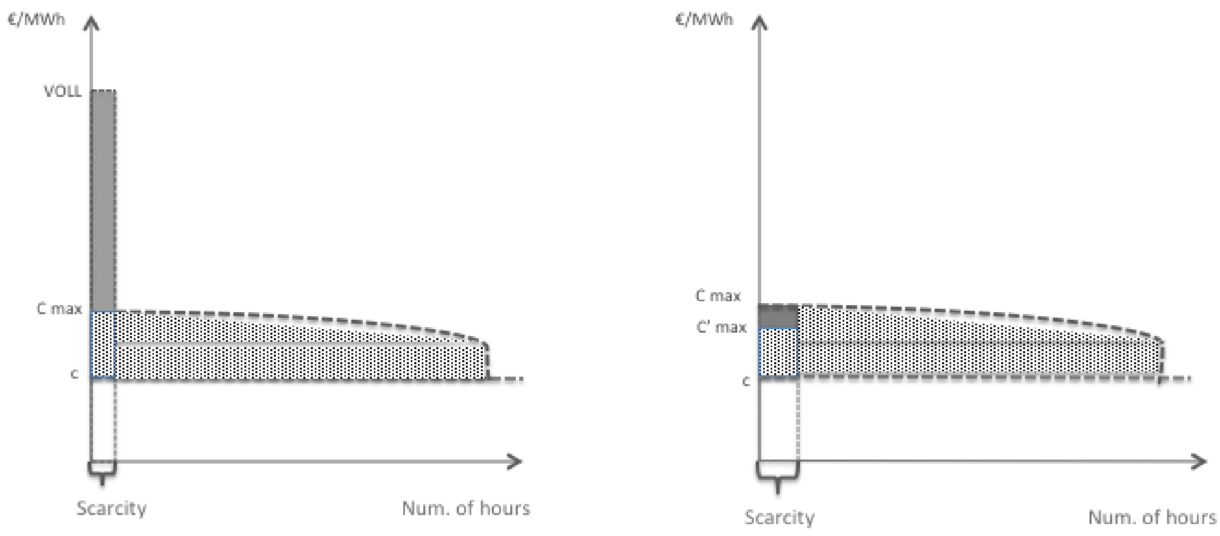

Figure 3: Price duration curves.

2.2.2.2 Out-of-market procurement of reserve services

Most power markets have developed out-of-market backstop mechanisms to guarantee reliability and sufficient capacity. For example, in ERCOT, "*out-of-market capacity purchases have been made in the form of reliability-must-run ("RMR") contracts. These contracts are signed to retain capacity resources that might otherwise be retired or mothballed*" (Brattle Group, 2009). In Nordpool, *"reliability and capacity adequacy are ensured by the member Transmission System Operators ("TSOs") based on a 0.1 percent loss-of-load probability ("LOLP"). When capacity is forecast to be insufficient on a 3-year forward basis to meet the reliability target, the TSO is authorized to procure peaking resources under long-term contracts with the costs of the procurement paid by the state."* (Brattle Group, 2009)

Such backstop measures may prevent market prices rising to VoLL during scarcity events, thus discouraging market-driven investment in generation capacity. As argued e.g. by Brattle Group (2009): *"If high VOLL-based prices occur only during actual service curtailments but the system operator engages in out-of-market measures to prevent curtailments, this will eliminate the scarcity prices that are necessary to attract sufficient capacity investments. The result is a vicious cycle where more and more resources must be maintained by the system operator through out-of-market solutions that keep prices artificially low."*

2.2.2.3 System operator behavior

Protocols adopted by the SO during scarcity events are another cause of the missing money problem. Most scarcity hours occur during operating reserve deficiency conditions when the system is between the target level of operating reserves and the minimum level that triggers non-price rationing of demand. When capacity becomes tight, price formation and thus scarcity rents are also sensitive to decisions made by the SO.

According to Joskow (2007) and Joskow and Tirole (2005), the evidence on the US market supports the idea that during scarcity events "*it is highly unlikely that efficient 'scarcity prices' will emerge during operating reserve shortage contingencies".* In the US, for example, prior to implementing rolling blackouts, the SO reduces system voltage by 5%. The reduction in system voltage produces a reduction in system demand and allows the SO to keep the operating reserves above the level that would trigger rolling blackouts. However, the reduction in system demand determines a reduction in the wholesale price – compared to that occurring in normal voltage conditions. In addition, the reduction in system voltage is costly: it actually causes equipment to run less efficiently, on-site generators to turn themselves on, etc. These costs are not reflected in market prices. *"As long as voltage reductions are employed in this way, market price signals will lead to underinvestment in reliability because the social costs of voltage reductions are not internalized*", (Joskow, 2007).

Another concern relative to the behavior of the SO is that it may declare scarcity discretionally. In fact, scarcity situations may result not in service interruptions but only in the system being run at lower than standard security conditions. In such cases, independently of whether load shedding is actually implemented, the SO should declare scarcity conditions, and energy and reserve prices should be set accordingly (at the value of lost load). Reluctance by the SO to declare scarcity conditions could lead to minor system security violations not triggering the scarcity pricing regime. That would also result in generator' income being below the level that attracts efficient investment.

2.2.2.4 Generator expectations with regard to scarcity hours

In order for generators to be able to increase their bid prices above their marginal costs to set scarcity prices, they need to be able to predict scarcity situations accurately. Incomplete information about demand and supply may mean that market operators are unable to properly detect scarcity events. Let us consider a situation in which the wholesale market clears first, and the operating reserves market clears later. If generators do not correctly anticipate the scarcity events when setting their bids on the wholesale market, the clearing price will not indicate scarcity: the installed available generation capacity will be greater than the demand. However, scarcity will emerge on the operating reserve market and result in high prices. If this is the case, the generating capacity committed on the electricity market will receive a price that does not correctly reflect its value (see e.g. Cervigni and Niedrig, 2011). The following Figure 4 illustrates the example discussed above.

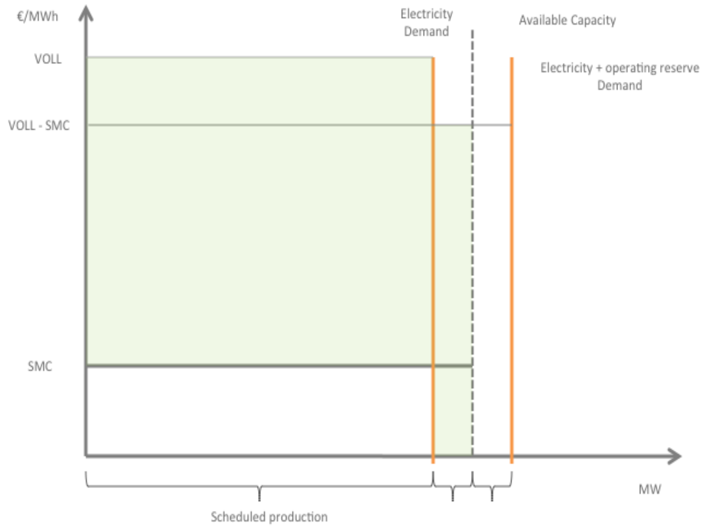

Figure 4: Energy and reserve market equilibrium in conditions of scarcity.

2.2.3 Other determinants of resource adequacy

2.2.3.1 Coordination of investment decisions

Another reason for resource adequacy concerns is the significant level of risk in generation investment. More specifically, the main reason for the high level of risk in generation investment is the lack of coordination in investment decisions. Given that market players have the incentive not to inform their competitors about their intention to invest or the timing of their investments, simultaneous entry may occur. Therefore operators may strategically delay entry and wait for a sufficient increase in market price to allow for a profitable simultaneous market entry. This in turn may promote a boom and bust cycle in generation investment resulting in an inefficient outcome associated with higher electricity prices and an increased reliability risk for customers.

To illustrate the coordination problem, we can consider an investor that wants to build a 1000 MW plant to be in service in year *t*. The profitability of its investment depends on the decisions of other potential investors. If in year *t* two plants instead of just one are brought into service, electricity prices could turn out to be much lower than if only one plant is built. The effect of the simultaneous entry of two plants may influence electricity prices for several years, thus jeopardising the profitability of both projects.

If investors anticipate the risk of simultaneous entry, they will want to reduce the vulnerability of their investments to the decisions of other market operators. They will therefore delay the implementationof their investments compared with the efficient timing. Such behaviour will inevitably determine an inefficient, low level of installed capacity in year *t*.

In this context, as Cramton and Stoft (2006) argue, the forward capacity market, "*serves as a coordination mechanism to assure that the right quantity of capacity is procured each year. This solves the common problem of boom-bust cycles seen in many industries.*" A central entity could set a capacity target for each year, and select the parties that would make the target capacity available in exchange for payment. Selection of the new capacity provider could take place by means of auctions. Similar considerations have been discussed by Ausbel and Cramton (2010), Cramton and Ockenfelds (2011), Kleit *et al.* (2013) and the Brattle Group (2009).

In our example, the target level at time *t* would be such that only the additional 1,000 MW would receive the capacity payment. If the central entity commits to paying for capacity availability well in advance, the scheme coordinates the decisions of the potential investors. Only one of the potential investors would obtain the capacity payment for 1,000 MW capacity at time *t*. The other investors would be unlikely to sink money into making additional capacity available at time *t*, as they know that such an investment would lead to excess capacity overall, and would therefore be unprofitable.

2.2.3.2 Other sources of risk for investments in generating capacity

Coordinating investment decisions is not the only source of risk for investments in generation capacity. Such investments take a long time to be realised. In the time-span between the decision to invest and realisation of the generating unit, political and regulatory changes can occur which can alter the profitability of the investment. Moreover, as we argued previously, the possibility for generators to recover a large part of their fixed costs depends on the number of scarcity hours, *coeteris paribus*. Weather conditions play a fundamental role in achieving this.

As we will see in Section 2.3, forward capacity markets with reliability options may be successful in eliminating the weather-related risk. In addition, forward capacity markets suffer less regulatory uncertainty with respect to other capacity support schemes. Their stronger integration with the design of the energy market makes the institutional commitment to pay a fixed capacity payment over time more credible, thus reducing one of the sources of uncertainty in generator profitability related to regulatory reasons.

2.2.3.3 Wind energy penetration and the missing money problem

The increasing penetration of renewable generation sources – and especially wind energy – has significantly affected the profitability of conventional generation plants, while at the same time increasing their importance for the reliability of the system. While the presence of RES generation has reduced the hours at which conventional plants operate, at the same time the intermittency of wind energy calls for conventional capacity to ensure system reliability.

Therefore, the significant diffusion of renewable generation appears to reinforce the importance of addressing the missing money problem. As argued by Cramton and Ockenfelds (2011): *"The renewables are paid a subsidy for the electricity provided, which is independent of the electricity price. A major economic effect on conventional, market price-driven generation is that residual demand and thus 'normal' price levels decrease, and that price volatility increases. At the same time, however, conventional capacity must exit the market at a much slower rate than renewables enter, because sometimes the sun does not shine and the wind does not blow. As a result, the degree of capacity utilization of conventional generation is significantly reduced. Taken together, all these effects imply that the 'missing money' problem is becoming more severe as the renewables' share grows."*

Joskow (2008) further highlights the interaction between RES penetration and investment in conventional generation sources by looking at the regulatory framework governing RES generation: "*Programs designed to stimulate investments in renewable generation (mostly wind) with special tax subsidies, contractual benefits, or mandatory purchase obligations, further complicate the investment picture for "ordinary" generating plants. What is the problem? Potential private investors in new generating capacity are looking for stable market rules and longer term contractual commitments before they will commit capital for new generating facilities.*"

2.3 How forward capacity markets address the resource adequacy problem

Capacity support schemes may be classified according to three broad approaches:

- Price-based mechanisms. These mechanisms incentivise generation capacity investment by recognising generators additional revenue beyond that which they can earn by participating in the energy and ancillary services markets. Price-based support schemes - more commonly known as *capacity payments* – involve a central entity committing to set a price to be paid for all available capacity. Capacity payments have been adopted extensively across European countries, and differ between them in the way in which the additional revenue is computed. A capacity payment has currently been in place in Spain since 1997, and in Italy since 2004. In UK, a capacity payment was adopted from 1990 to 2000.
- Quantity based-mechanisms. These mechanisms involve the SO procuring a certain capacity target that should be made available in a given future period. The SO sets the volume of available capacity the central entity commits to paying for, either directly or by placing an obligation on the LSEs. This creates the demand for a product – the available capacity – which generators can supply. The interaction between the regulatory-driven demand and the supply of available capacity determines the market-clearing price for the available capacity. Quantity-based mechanisms are usually classified according to the way in which generation capacity is traded. To this purpose, the literature (see e.g. Batlle and Rodilla, 2010) distinguishes between the following two types:

  (i) Centralised capacity markets. Centralised capacity markets involve the use of an auction – usually managed by the SO – for the exchange of capacity products. Centralised organised markets follow a long-term approach: the capacity procured through the market must be made available a few years after the procurement procedure takes place. Centralised capacity markets are implemented in the US, by PJM and ISO-NE, and in Colombia.

  (ii) Capacity markets with bilateral negotiations. Decentralised capacity markets are organised markets where supply and demand meet directly and trade capacity products. Unlike centralised capacity markets, markets with bilateral negotiations adopt a short-term approach. The time horizon to which negotiations refer may range from one day to one year. Decentralised capacity markets have been in place in Australia since 2005, and were adopted by PJM from 1999 to 2007.

- The third approach consists of reserving a certain generation capacity to use only in situations of scarcity, as a substitute for load curtailment. 'Last-resort' reserves involve keeping separate a certain amount of generation capacity, which does not participate in the electricity market unless the SO considers it necessary because of scarcity. Reserves of last resort are currently adopted in Sweden, Finland, and Norway. The SO is in charge of purchasing the strategic reserve and defining the rules for offering last-resort reserve electricity capacity on the market. "*Since the SO becomes an irregular market agent", "this can result in a significant distortion of the price signals*" (Batlle and Rodilla, 2010).

In Italy a centralised forward capacity market to ensure long-term resource adequacy will be adopted starting from 2017[23]. The salient features of the new Italian capacity support scheme may be summarised as follows:

- The procurement process is conducted by means of descending-clock auctions. These involve a main auction (called *asta madre)* – in which capacity is traded four years in advance of the time horizon in which it will be made available (the delivery period) – and adjustment auctions (called *asta di aggiustamento)* plus a bilateral market. The latter and the adjustment auctions aim to allow the SO to reshape the target capacity level it intends to procure, and generators to renegotiate the commitments awarded in the main auction.
- The Transmission System Operator Terna is responsible for defining the target generation capacity to be procured through the auctions, and for the managing the forward capacity market.
- The target resource requirement for a given delivery period is expressed by a negative sloped demand curve similar to the Variable Resource Requirement Curve adopted for the forward capacity market of PJM[4].
- The product traded in the main auction is a call option (namely a reliability option) backed by a physical asset, i.e. the capacity owned by generators participating in the auction. The reliability option gives new and existing generators – which are the only type of capacity resources allowed to participate in the Italian capacity market – the following obligations: (i) to make available on the ancillary services and energy markets the capacity committed in the main auction for the whole delivery period, and (ii) to pay the SO the difference, if positive, between the price the generators receive on the ancillary services or energy markets and the option strike price. The strike price is set as the variable marginal cost of the most expensive generating technology in the

[2]Delibera ARG/elt 98/2011. *Criteri e condizioni per la disciplina del sistema di remunerazione della disponibilità di capacità produttiva di energia elettrica, ai sensi dell'articolo 2 del decreto legislativo 19 dicembre 2003, n. 379.* Available from: *http://www.autorita.energia.it/allegati/docs/11/098-11arg.pdf*.

[3] Terna S.p.A., 2012. *Schema di proposta di disciplina del sistema di remunerazione della disponibilità di capacità produttiva di energia elettrica*. available from: http://www.terna.it/LinkClick.aspx?fileticket=104543.

[4] See Section 4 for a discussion of the Variable Resource Requirement Curve of PJM.

system.

- Participation in the capacity market is voluntary.

Below we discuss the motivations behind the adoption of forward capacity markets – and specifically of those relying on reliability options, as in the Italian case – to address the resource adequacy determinants described in Section 2.2.

Centralised forward capacity markets with call options – currently adopted in Colombia through Firm Energy Obligations, and by ISO-NE in the United States (see Cramton and Stoft (2005), (2006), and (2008) for a review of capacity markets with reliability options) - have the following salient features:

- Descending clock auctions are held a few years in advance of the delivery period.
- The SO is responsible for defining the target capacity level to be procured by means of the descending clock auctions, and for management of the forward capacity market.
- The target capacity level is usually expressed by means of a price-inelastic demand curve. To the best of our knowledge, both Columbia and ISO-NE forward capacity markets adopt a fixed resource requirement curve.
- Descending clock auctions usually include a main auction and subsequent adjustment auctions. A bilateral market is also involved in the design of forward capacity markets.
- The product exchanged on the forward capacity market is a call option which, in exchange for a fixed fee, makes it mandatory for resources offering capacity on the capacity market:

    (i) to make the committed capacity available on the energy and ancillary service markets for the whole delivery period, and
    (ii) to pay the SO the following amount:

$$Max(0, P_t^{Spot} - P^{Strike})$$

Where P_t^{Spot} is the spot price of electricity in the hour t, and P^{Strike} is the strike price of the option. The strike price is set at the variable cost of the system's marginal generation technology. In scarcity hours, when the spot price rises above the strike price the generator must pay the scarcity rent for each MW of hedged capacity. The scarcity rent is equivalent to the difference between the market price and the system marginal cost, i.e. the variable cost of the marginal generator.

Forward capacity markets with call options restore performance incentives

The call option structure provides generators with the appropriate incentives to make capacity available during the delivery period. In fact, if a generator fails to provide the committed capacity during a scarcity hour when the electricity price reaches the VoLL it bears a loss which equals $P_t^{Spot} - P^{Strike}$.

However, the generator can counterbalance this loss by making the committed capacity available during the scarcity hour and achieving a profit which equals $P_t^{Spot} - VC$, where VC is the generator's variable cost. Therefore the net profit to the generator then becomes equivalent to the payment due under the capacity contract:

$$-(P_t^{Spot} - P_t^{Strike}) + (P_t^{Spot} - VC) = (P_t^{Strike} - VC)$$

Let us consider the following example from Cramton and Stoft (2006) in order to understand why reliability options provide appropriate incentives to make available the capacity committed in the procurement auction. Suppose that the reliability option is such that its strike price is €1,000 and the price paid from load to suppliers for each MW of capacity committed is €40,000/MW. The call option gives load the right to buy power from the supplier at a price of €1,000/MWh at any time. Load exercises the option precisely when the market price is greater than €1,000, i.e. when scarcity occurs and the spot price goes to €5,000. Because the reliability option is a financial arrangement, the load will purchase its power from the SO for €5,000 and the generator will sell its power to the SO for €5,000. However, due to the call option structure, the supplier must then pay the load €4,000. This means that in effect load has bought power from the supplier at a net cost of €1,000. This is the equivalent of saying that if the generator supplies energy in the shortage hour it will earns net revenues of €1,000. But if the supplier does not supply energy during a scarcity hour it will lose €4,000/MWh, which must be paid to load to cover the high price.

As highlighted by Cramton and Stoft (2005): *"Notice that at least in shortage situations, the penalty for nonperformance needs to be set administratively at a level above the spot energy price to provide sufficient incentive for investment. Otherwise, the option price would be bounded above by the cost of nonperforming assets, which face a penalty equal to the capped and mitigated spot energy price minus the strike price whenever called to supply energy*." Similar considerations have been stated by Cramton and Stoft (2008), who observe that: *"Efficient performance incentives [in a forward capacity market with reliability options] are maintained from a load-following obligation to supply energy above the strike price."*

Forward capacity markets with call options restore performance incentives but prevent market power

Call options also mitigate market power without jeopardising the incentive to invest in generation capacity. In fact, by capping the revenues for the contracted capacity at the strike price, market power is reduced to nil. However, while the adoption of reliability options caps generator revenues, it does not cap the market-clearing price. This allows the market-clearing price to rise to the VoLL level in case of scarcity, and thus to the level necessary to ration demand when capacity becomes tight. The result is that the incentive to develop demand response resources is not distorted as it would be in the case of a price cap.

To understand how call options work with market power mitigation, let us consider the previous example from Cramton and Stoft (2006): "*Suppose a generator withholding capacity to create an artificial shortage day during a cool summer. Without the call option every MW that the supplier still has in the market will be paid an extra €4,000/MWh for 10 hours. That could be very profitable. With a call option, it will make nothing extra from prices above €1,000 because the hedge does not allow it. In either case the supplier will lose €4,000 per MWh on every MWh it* *withholds when exercising market power. Because of this, with the call option, it will actually lose money any time it tries to exercise market power. The call option completely eliminates the increase in market power that would normally be caused by raising the price cap from €1,000 to €5,000".*

As highlighted by Cramton and Stoft (2006): *"The call option perfectly preserves the performance incentives of higher spot prices, while completely eliminating (in fact reversing) their inducement to exercise market power and eliminating all of the market risk imposed by higher spot prices. The performance risk is fully retained, which is not a benefit, but is necessary for the retention of performance incentives".* In addition, by means of reliability options which through a market mechanism suppress market power and restore performance incentives, *"regulation can be confined to the single task for which it is needed: determining the adequate level of capacity",* (Cramton and Ockenfelds, 2011).

Forward capacity markets with call options and the stabilisation of generator profits

Reliability options allow generators to hedge their investment risk *by replacing peak energy rents (the rents derived from selling energy at very high spot prices during periods of scarcity) with a constant capacity payment,* (Cramton and Ockenfelds, 2011). As we observed in Section 2.2.3, investments in generation capacity are also discouraged by the high level of risk that distinguishes them from other types of investment. Generation capacity is available few years after the investment decision is made – a time horizon which may potentially include significant changes in both the regulatory and political framework. In addition, as explained in Section 2, a large part of generators' fixed costs (in the case of marginal generating units) are recovered during scarcity hours. Therefore, price volatility – which is also exacerbated by the penetration of wind generation resources (see Section 2.2.3.3) – significantly affects the possibility for marginal generating units to restore fixed costs.

In order to understand how reliability options deal with price volatility and thus hedge weather related risk, let consider another example based on Cramton and Stoft (2006): "*Suppose the market has one hot day (10 hot hours) in half the years and two hot days in the other years. Now the market is risky because scarcity revenues are only half as much in cool years as in hot years. Under the €5,000 cap, as compared with the €1,000 cap, Good (full performance) suppliers would make an extra €40,000 in half the years and an extra €80,000 in the other years, €60,000/year on average. If they build their plant and immediately face three cool summers, they will fall 3×€20,000/MW short of the average, earning €40,000 instead of the average €60,000. This is market risk. But, if they sell a call option for €60,000/MW-year, they will eliminate their risk, as will load. More precisely, they will eliminate their market risk. Poor performers will still suffer from performance risk, just as they should, but Good performers will be guaranteed €60,000/MW-year in cool and hot years alike. Similarly load will pay only €60,000/MWh in cool and hot years alike."*

A comprehensive analysis of the hedging properties of reliability options is also provided by Ausbel and Cramton (2010), and Botterud and Doorman (2008). Cramton and Stoft (2008) performed a simulation of the beneficial effects of reliability options in hedging generator' risk. Precisely, these scholars state: "*The mandatory hedge is remarkably successful in reducing risk. In the benchmark case, where we assume demand has constant elasticity of –.05 for prices* *above the strike price (a 20% increase in price produces a 1% decline in demand), the hedge reduces aggregate profit risk by a factor of 7. More importantly, the hedge reduces company risk by a factor of 4.5 in the benchmark case. Even when we assume a high level of demand response so that prices remain low during scarcity periods and there is less profit risk to start with, the hedge reduces company risk by 55%.*"

With reference to the regulatory and political risk affecting generation investment – because of the particularly long time-span between the investment decision and effective realisation – it is worth noting that capacity markets appear to suffer less regulatory uncertainty with respect to other capacity support schemes such as strategic reserves or capacity payments. In fact capacity markets determine a significant change in the electricity market design – becoming part of the market design itself – and their revocation would thus appear more costly than that of capacity payments. For the latter a simple decision by the regulatory authority is sufficient to reduce or eliminate capacity payments. Similar considerations apply to the strategic reserve.

The stronger integration of capacity markets with the electricity market design improves the credibility of the commitment by electricity market institutions to pursue the goal underlying adoption of the capacity support scheme itself. A more credible commitment appears fundamental to improve the expectations of generators regarding a partial reduction in the regulatory risks facing their investments.

Forward capacity markets and coordination of investment decisions

Forward capacity markets may help to coordinate the investment decisions of generators, thus avoiding the typical boom and bust cycle in installed generation capacity caused by investors strategically delaying their investments (see e.g. Ausbel and Cramton, 2010; Batlle and Rodilla, 2010 and Cramton and Ockenfelds, 2011). By awarding capacity contracts well in advance of the delivery period, the forward capacity market signals to the resources not participating in the auction (or that have not won the auction) that: (i) the target capacity will be covered entirely by the resources that won the auction; (ii) should they decide to go ahead with their investment, they would have no protection against excess capacity situations, resulting in too few scarcity hours; (iii) they are less efficient than the resources that won the auction. Conversely, the winners of the auction learn that their revenues are in part hedged, and that they are more efficient than the other participants that did not win the auction and the resources that did not participate into the auction. In addition, the winners will have a strong incentive to invest since the losers will not have the incentive to do so as this would result in excess capacity and hence a lost profit opportunity.

Furthermore, , the advance coordination of investments in generating capacity allows investment by new entrants, thus increasing competition (see the Brattle Group, 2009).

3 The institutional design of the PJM and ISO-NE forward capacity markets

This Section analyses the institutional design of forward capacity markets. Specifically, it discusses the entity responsible for administration of the forward capacity market, and the types of capacity resources allowed to participate in the forward capacity market.

3.1 Institution responsible for administration of the forward capacity market

Forward capacity markets are administered by RTOs. Both PJM and ISO-NE are responsible for definition of the capacity requirement to be procured with reference to a given future delivery period, as well as for administration of the procurement procedures, i.e. auctions. The administration of forward capacity markets by RTOs relies on the information advantages they have over other electricity market institutions. As Cramton and Stoft (2006) argue, *"the determination of what constitutes an adequate level of capacity is based on traditional engineering and reliability standards"*. Similarly, Oren (2005) states: *"all the designs ... worldwide abandoned the principle that 'the market should determine the desirable level of investment' and are relying on engineering based determinations of generation adequacy requirements."*

For the RPM, PJM is responsible for assessing resource adequacy every year for the future ten years. The resource requirement is expressed in terms of Installed Reserve Margin (IRM), a percentage of the forecast peak load. The PJM Board of Directors is then responsible for approving the IRM, (see PJM Manual, 2013).

PJM also administers the procurement auctions for the target reserve margin requirement. As the FERC (2010) states, *"PJM operates the RPM capacity market, under which PJM purchases capacity on a multi-year forward basis through an auction mechanism. Under RPM, PJM conducts a Base Residual Auction three years ahead of each delivery year, in which it procures the majority of the capacity that will be required for that delivery year. Additionally, while RPM is designed to enable PJM to procure the bulk of needed capacity for each delivery year in the Base Residual Auction for that year, during the three-year period between the Base Residual Auction and the delivery year, PJM also conducts three scheduled Incremental Auctions in which it can adjust its capacity position during the three years between the Base Residual Auction and the delivery year."*

Similarly, ISO-NE is responsible for administration of its capacity market and definition of the resource adequacy target. Section III of ISO-NE Market Rules states: *''The ISO shall administer a forward market for capacity ("Forward Capacity Market") in accordance with the provisions of this Section III.13. For each one-year period from June 1 through May 31, starting with the period June 1, 2010 to May 31, 2011, for which Capacity Supply Obligations are assumed and payments are made in the Forward Capacity Market ("Capacity Commitment Period"), the ISO shall conduct a descending clock auction ("Forward Capacity Auction") in accordance with the provisions of Section III.13.2 to procure the amount of capacity needed in the New England Control Area and in each modeled Capacity Zone during the Capacity Commitment Period, as determined in accordance with the provisions of Section III.12."*

Moreover, ISO-NE Market Rules state that: *"Prior to each Forward Capacity Auction, the ISO shall calculate the Installed Capacity Requirement for the New England Control Area for each upcoming Capability Year through the Capacity Commitment Period associated with that Forward Capacity Auction in accordance with this Section III.12.1. The ISO shall calculate the Installed Capacity Requirement for the New England Control Area for any Capability Year during the ICAP Transition Period in accordance with this Section III.12.1 to the extent applicable and practicable."*

3.2 Capacity resources participating in the PJM forward capacity market

The implementation of the PJM RPM began in 2007-2008 with the first delivery year. The delivery period is an annual period – from June 1 to May 31 – for which a given resource adequacy target must be achieved through procurement procedures held three years in advance.

Specifically, the above-mentioned procurement procedures are based on the following market mechanisms: a Base Residual Auction, Incremental Auctions and a Bilateral Market. The Base Residual Auction is held three years prior the start of the delivery year and allows for the procurement of resource commitments to satisfy the resource adequacy target relative to the PJM region. There are at least three Incremental Auctions, which are conducted after the Base Residual Auction to procure additional resource commitments to satisfy the region's resource commitments. These are needed to satisfy potential changes in market dynamics that are known prior to the beginning of the delivery year. In addition to the Incremental Auctions, a Conditional Incremental Auction may be conducted if a backbone transmission line is delayed and results in the need for PJM to procure additional capacity for a given area of the region in order to address the problem. The bilateral market gives resource providers an opportunity to cover any auction commitment shortages.

The following capacity resources are allowed to participate in the procurement procedures conducted by PJM. Specifically, participation is mandatory for:

- Load Serving Entities.
- Existing generation: both internal and external to the PJM footprint.
- Bilateral contracts for available unit-specific capacity resources consisting of existing generation units located within the PJM market footprint.

Conversely, participation in the PJM RPM is voluntary for:

- Planned generation: both internal and external to the PJM footprint.
- Existing and planned demand resources.
- Energy efficiency resources.
- Qualifying transmission upgrades.
- Resource providers with bilateral contracts for unit-specific capacity resources.

Generation capacity includes both conventional and intermittent generating sources.

Load Serving Entities

Participation by LSEs in the RPM for load served in the PJM region is mandatory, except for LSEs that have chosen the Fixed Resource Requirement (FRR)[5].

[5] The Fixed Resource Requirement Alternative provides an LSE with the option of submitting an FRR Capacity Plan and meeting a fixed capacity resource requirement as an alternative to the requirement of participating in the PJM Reliability Pricing Model (RPM), which includes a variable capacity resource requirement.

Each LSE that serves load in a PJM Zone during the delivery year shall be responsible for paying a Locational Reliability Charge equal to their Daily Unforced Capacity Obligation in the zone served (i.e. the load obligation they have to satisfy with reference to a given zone in the region – see Section 6.1 for further details) multiplied by the Final Zonal Capacity Price applicable to that zone (i.e. the final price applying to the total amount of capacity committed at the end of the Third Incremental Auction with reference to a given zone in the region – see Section 6.1 for further details).

LSEs may thus choose to hedge their Locational Reliability Charge obligations by directly offering and clearing resources in the Base Residual Auction and Second Incremental Auction or by designating self-supplied resources (resources directly owned or resources contracted for through unit-specific bilateral purchases) as self-scheduled in order to cover their obligation in the Base Residual Auction. Such actions may wholly or partially offset an LSE's Locational Reliability Charges during the delivery year, depending on how the clearing prices of the resources compare with the Final Zonal Capacity Prices that apply to their unforced capacity obligations.

Existing generation resources internal to the PJM footprint

In order to be admitted to the procurement procedures, existing generation units are pre-certified by PJM as meeting the Generation Deliverability Test. The Generation Deliverability Test is a test aimed at evaluating whether capacity resources within a given area of the region can be exported to other areas of the PJM that are experiencing a capacity emergency. Specifically, the test has the goal of determining whether the aggregate of generators in a given area can be reliably transferred to the remainder of PJM.

The resource owner or operator also submits the required operation and maintenance information to the PJM.

In order to verify the net capability of each unit, a Winter and Summer Test must also be performed. Net capability means the number of MW of electric power that can be delivered by an electric generating unit. This is the gross output of the unit less the power used for unit auxiliaries and other station usage for electricity generation. The Summer (Winter) Test aims to determine the net capability of a generating unit in summer (winter) conditions and at the power factor level normally expected for that unit at the time of the PJM summer (winter) peak load. Summer (winter) conditions reflect 50% probability of the occurrence of temperature and humidity conditions of the time of the PJM summer (winter) peak load. Conditions are based on local weather bureau records for the previous 15 years, updated at 5-year intervals.

For example, for CCGT units summer (winter) conditions mean, where applicable, the probable intake water temperature of once-through or open cooling systems in June, July, and August (December, January and February) at the time of the PJM peak each weekday, and the probable ambient air temperature and humidity conditions at the unit location at the time of the annual summer (winter) PJM peak.

In order to participate in the First, Second, or Third Incremental Auctions for a given delivery period, the unit must have been offered in the Base Residual Auction.

Existing generation resources external to the PJM footprint

External generating units must first of all provide the intended Availability Transmission Capability (ATC) path to deliver the existing external capacity into PJM: that is the firm transmission service from the unit to the border of PJM and generation deliverability in PJM.

As regards internal generating plants, external units submit their maintenance and operational information to PJM, and perform Winter and Summer tests to verify their net capability.

An external unit without a firm transmission service must establish an RPM Credit Limit prior to an RPM Auction. The credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction. A firm transmission service essentially refers to the use of transmission facilities for the transmission of capacity and energy between a Point of Receipt (POR) and a Point of Delivery (POD). A unit that has not yet applied for or obtained the transmission service at the date of the Base Residual Auction is required to perform an RPM Credit Limit request. The purpose of the RPM credit requirement is to encourage future physical performance, but not necessarily to fully guarantee capacity-related financial obligations. Any available unsecured credit or collateral that the unit has not employed for other financial obligations with PJM may be used for the RPM Credit Limit request.

To reinforce its commitment, the owner of an external generating unit must provide PJM with a letter of non-recallability assuring PJM that the energy and capacity from the unit is not recallable to any other control area.

The RPM Credit Limit must be established not only by external generating units without a firm transmission service but also by any planned demand resource, energy efficiency resource, planned internal and external generating units, and qualified transmission upgrade prior to an RPM auction.

Planned generation resources internal to the PJM footprint

In order to be eligible to be offered in RPM Auctions, planned generation must first participate in the PJM's Regional Transmission Expansion Planning Process (RTEPP). PJM transmission expansion planning – which covers upgrades in the transmission system network in order to ensure system reliability over a fifteen-year time-horizon – integrates both transmission and generation projects. Therefore, to be eligible to participate to the RPM new generating facilities must be part of the RTEPP. In addition, the planned unit's of interconnection start date must be on or before the start of the delivery year.

The planned generation unit must fulfill the following obligations to participate into the procurement procedures:

- Performance of an Impact Study Agreement in order to participate in the Base Residual Auction: the Impact Study Agreement is required to maintain the priority of an interconnection request. The Impact Study Agreement is sent by PJM to the generating unit with the aim of starting a System Impact Study devoted to assessing the impact of adding the new generation unit to the system and the deliverability to PJM load in the specific PJM region where the generator is located. The Impact Study Agreement must be then accompanied by a which varies varying according to the size of the generating unit.

- Submission of an Interconnection Service Agreement (ISA) or Wholesale Market Participant Agreement (WMPA) in order to participate in an Incremental Auction. The ISA aims to define the obligation of the new generating unit as regards cost responsibility for any required system upgrade. The WMPA defines the terms and procedures for the generator to operate in the PJM markets if the generating facility is connected to a local distribution facility or sub-transmission facility not subject to FERC jurisdiction.
- Submission of a Capacity Modification for the planned unit. A Capacity Modification is a transaction that allows generation unit owners to request the addition of a new unit or removal of an existing unit from the internet-based application used by market operators to submit their offer in RPM auctions.

Planned generation resources external to the PJM footprint

In order to be eligible to be offered in RMP Auctions, planned generation external to the PJM footprint must follow the same rules that apply to the internal planned generation resources.

Exporting a generation resource

Generation resources may be exported outside the PJM footprint. To do so a bilateral transaction with a party called an External Party must be carried out. The External Party is listed as the 'Buyer' in the unit-specific transaction.

In order to export a generation resource a Capacity Modification must be carried out. Following the export, the generation unit is exempt from the offer requirement for capacity resources.

Importing an external generation resource

Similarly, external generation capacity may be imported. As in the export procedure a bilateral transaction with an External Party called the 'Seller' must be carried out. As in the case of the external units participating to the RPM auctions the ATC path must be submitted to PJM. In addition, external generators must demonstrate generation deliverability to PJM by obtaining transmission service from the border to the PJM transmission system.

Demand resources

Load management programs may be offered in RPM Auctions. Load management is the ability to reduce metered load, either manually by the customer or following a request from the resource provider. Load management programs may be offered as resource providers in the form of Demand Resources (DR) offered in the Base Residual Auction or an Incremental Auction and are paid the Resource Clearing Price.

In order to be eligible to offer capacity in RPM Auctions, a DR must meet the following requirements:

- It must be registered on the Emergency Load Response Programme: this programme allows end customers to be compensated by PJM for reduced load during an emergency event.
- It must have the capability to retrieve electronic messages from PJM notifying curtailment service providers of a load management event.
- It must provide load drop estimates for all Load Management events.

The specifics of the customer contract and tariffs are the responsibility of the resource provider and the regulatory process. PJM does not have direct involvement with customers.

PJM recognises three types of Load Management programmes:

- Direct Load Control (DLC) – Load management that is initiated directly by the resource provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners).
- Firm Service Level (FSL) – Load management achieved by a customer reducing its load to a pre-determined level (the Firm Service Level), on notification by the resource provider's market operations centre or its agent.
- Guaranteed Load Drop (GLD) – Load management achieved by a customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), on notification by the resource provider's market operations centre or agent. Typically, the load reduction is achieved by running customer-owned backup generators, or by shutting down process equipment.

Both existing and planned DRs may participate into the RPM Auctions.

A DR is added to a party's portfolio by the creation of a Demand Resource Modification transaction. Similarly to Capacity Modification, the Demand Resource Modification transaction allows a demand resource to be added to or eliminated from the portfolio of a resource provider in the internet-based application for the submission of offers and bids in the RPM Auctions. Approval of the Demand Resource Modification by PJM is subject to registration of the resource in the Emergency Load Programme.

Energy efficiency resources

According to the definition provided by PJM, an Energy Efficiency (EE) Resource is a project involving the installation of several efficient devices/equipment, or the implementation of several efficient processes/systems that exceed then-current building codes, appliance standards or other relevant standards at the time of installation. As regards Capacity and Demand Response Modification, EE Resources must submit an EE Resource Modification, which allows the resource provider to add or eliminate EE resources on the PJM internet-based application for buying or selling capacity in RPM Auctions.

An EE installation is eligible for RPM auctions if it meets the following criteria:

- The EE installation must be scheduled for completion prior to the delivery year.
- The EE installation is not included in the peak load forecast posted for the Base Residual Auction for the delivery year initially offered.
- The EE installation exceeds relevant standards at the time of installation as known at time of commitment.
- The EE installation achieves load reduction during defined EE Performance Hours (i.e. hours between the hour ending 15:00 and the hour ending 18:00 on all days from June 1 through August 31, excluding weekends and federal holidays).
- The EE installation is not dispatchable.

Both existing and planned EE resources may participate in RPM Auctions. An existing EE resource is defined as an EE resource with a PJM-approved Post-Installation Measurement & Verification Report. A Planned EE resource is defined as an EE resource that does not have a PJM-approved Post-Installation M&V Report.

The Post-Installation Measurement & Verification Report is a document that defines the project-specific M&V methods that will be used to determine and verify the demand reduction produced by an EE resource. An EE resource that clears in an RPM Auction will receive the resource clearing price of the area in which the EE resource resides.

An EE resource may participate in RPM Auctions for a maximum of up to four consecutive delivery years.

Qualified Transmission Upgrades

A Qualifying Transmission Upgrade (QTU) may be offered in the Base Residual Auction. A QTU is a planned enhancement or addition to the transmission network aimed at increasing the Capacity Emergency Transfer Limit (CETL) in a given area. CETL is the capability of the transmission system to support deliveries of electricity to a given area experiencing a capacity emergency.

Unit-Specific Bilateral Transaction

A Unit-Specific Bilateral Transaction aims to transfer the rights or control of a specified amount of installed capacity from a Seller to a Buyer. These bilateral contracts may be offered in RPM Auctions. Specifically, Unit-Specific Bilateral Transactions may wholly or partially offset an LSE’s Locational Reliability Charges, provided that available installed capacity purchased through the bilateral transaction is directly offered and cleared in a Base Residual Auction or Incremental Auction, or is designated as a self-scheduled resource in a Base Residual Auction. The smallest increment of installed capacity that may be reported to PJM as a Specific Bilateral Transaction is 0.1 MW.

3.3 Capacity resources participating in the ISO-NE forward capacity market

The ISO-NE FCM was implemented in 2008, when the first Forward Capacity Auction (FCA) was conducted to ensure resource adequacy for the delivery year 2010-2011. Each FCA is held three years in advance of the delivery period, which runs from June 1 to May 31.

The FCM consists of a main auction, the FCA, and reconfiguration auctions. The FCA is a simultaneous descending-clock auction determining the capacity supplies and clearing prices for each area of the region. Reconfiguration auctions provide secondary markets for adjusting the commitments made in the FCA to respond to changing market circumstances as a capacity commitment period approaches. An annual reconfiguration auction is held before the relevant commitment period, and monthly reconfiguration auctions are held before each commitment month.

The following resources are allowed to participate in the ISO-NE FCM:

- Existing generation resources: both conventional and intermittent generating capacity.
- New generation resources: both conventional and intermittent generating capacity.
- Existing demand resources.
- New demand resources.
- Existing import capacity resources.
- New import capacity resources.

In order to be eligible to participate in the FCM, each resource capacity must be at least 100 kW.

Each resource capacity must comply with qualification and financial assurance requirements in order to be eligible to participate in the FCA. This Section will discuss the specific qualification procedure. The financial requirements for admission to the FCM will be discussed in Section 7.

Existing generation resources

Existing generating capacity resources are defined by ISO-NE Market Rules as generating capacity resources that are not included in the definition of new generating capacity resources (see the following paragraph for a definition of new generating capacity resources). As in the case of new generating capacity resources, ISO-NE must identify the qualified capacity for admission to the FCM also for existing generating capacity resources.

Specifically, ISO-NE specifies that the Summer and Winter Qualified Capacity of an existing generating capacity resource that does not qualify as an intermittent generation resource shall be equal to the median of the existing generating capacity resource's summer seasonal claimed capability ratings of the latest five years, as of the fifth business day in October of each year, with only positive summer ratings included in the median calculation. Similarly, the Winter Qualified Capacity of an existing generating capacity resource that is not an intermittent power resource shall be equal to the median of the existing generating capacity resource's winter seasonal claimed capability ratings of the latest five years, as of the fifth business day in June of each year, with only positive winter ratings included in the median calculation.

ISO-NE specifies the Summer and Winter Qualified Capacity accepted for participation in the FCM also for intermittent generating sources. Specifically, for each of the previous five Summer (Winter) periods, the ISO shall determine the median of the net output in the Summer (Winter) Intermittent Reliability Hours. The Summer Intermittent Reliability Hours are the hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which the ISO declared a system-wide Shortage Event. Conversely, the Winter Intermittent Reliability Hours are the hours ending 1800 and 1900 each day of the winter period (October through May) and all winter period hours in which the ISO has declared a system-wide Shortage Event.

Participation for existing generating resources is mandatory. Unless they submit a 'delist bid', existing resources are automatically entered into the FCA. A delist bid indicates that the resource does not want to assume a capacity supply obligation at a price below bid price. There can be five types of delist bid:

- Permanent delist bids. This type of bid is intended for resources that wish to retire or no longer wish to assume a capacity supply obligation through FCAs.
- Static delist bids. This type of bid is employed by resources that wish to leave the FCM for one year and retain the option to participate in auctions in the future.
- Dynamic delist bids have the same purpose as Static delist bids. However, unlike Static and Permanent delist bids, Dynamic delist bids do not need to be submitted before the auction. In addition, their value must be equal to or less than 0.8 times the Cost of New Entrant[6] (see Section 5 for a discussion of the Cost of New Entrant).
- Export delist bids are bids intended for resources that wish to export capacity for one delivery year and retain the option to participate in auctions in the future.
- Administrative export delist bids are intended to allow for the multiyear sale of capacity from New England to adjacent regions.

New generation resources

New generating capacity includes resources that have never been offered in an FCA and that has never received a capacity payment including before the implementation of the FCM[7]. The category of new generating capacity resources also includes units that have been

[6] The cost of new entry (CONE) is a threshold price used to calculate the starting price for each FCA. This threshold price is based on the estimated fixed costs for developing capacity resources in the region and the clearing price of previous FCAs. CONEs establish a $/kilowatt (kW)-month value of the cost for an investor to develop, site, and maintain a new simple-cycle gas-fired generator in New England's market. This would include such costs as sitting, permitting, developing, and purchasing land, as well as fixed ongoing operation costs, such as staffing, maintenance, taxes, and recovery of the investment over time.

[7] Before implementation of the FCM, ISO-NE relied on a capacity market based on a definition of the capacity requirement that was uniform for the entire regional footprint. That in turn meant that ISO-NE conducted auctions on an ISO-region-wide basis, deriving a single , uniform clearing price for all capacity in the region, regardless of the capacity's location. In 2002, the FERC obliged ISO-NE to review its capacity market because inadequate to provide sufficient revenues to incentivise generator investments. The review of the capacity market in place led in 2005 to the new ISO-NE FCM of which the distinguishing feature is the adoption of locational capacity requirements. Locational capacity requirements aim to mirror different locational values for capacity and thus allow for different locational clearing prices.

deactivated or retired after having been offered in a previous FCA and have decide to assume a supply obligation once again by participating in the FCM.

For a resource to qualify as a new generating capacity resource, the resource's project sponsor must make the following submissions to the ISO:

- A New Capacity Show of Interest Form. This document must include information such as the project name, address and location, the status of the project as regards connection operations, whether the resource has been previously listed as a capacity resource, the capacity (in MW) of the new generating capacity resource and a description of the project's equipment configuration, including a description of the resource type, etc.

- A New Capacity Qualification Package. This document must include the following information:

  - Documentation demonstrating that the project sponsor has control of the project site for the duration of the relevant capacity commitment period. To demonstrate control of the project site, the project sponsor must demonstrate that it is the owner in fee simple of the real property on which the project will be located; that it holds a valid written leasehold interest in the real property on which the project will be located, or that it holds a duly executed written contract to purchase or lease the real property on which the project will be located, etc.
  - Documentation proving that all the major permits have been requested for the project, the dates on which the permit applications are expected to be processed, the expected dates of approval, etc. Major permits include all federal and state permits, local, regional, and town permits and permits for any ancillary infrastructure such as new gas pipelines, new water supply systems, large storage tanks, etc.
  - Documentation showing the amount of project finance required, the expected financing sources, and the expected closing date for the project finance.
  - A list of all of the major components necessary for the project, and the date or dates on which all the major components necessary for the project have been or are expected to be ordered. Examples of major components are turbines, the cooling water system, steam generation system, steam handling system, water treatment system, fuel handling system, emissions control system, etc.
  - The estimated date on which the amount of money spent on construction activities on the project site is expected to exceed 20 percent of the construction financing costs.
  - The dates on which the major equipment of the new generating unit is scheduled to be delivered to the project site.
  - The dates on which each piece of major equipment is scheduled to undergo testing.
  - The date by which the project is expected to achieve commercial operation. This

date must be no later than the start date of the capacity commitment period associated with the FCA.
    - In the case of an intermittent generation source, data on summer and winter performance of the site-specific characteristics must be provided. For example, data such as wind speed data for wind resources, water flow data for run-of-river hydropower resources, irradiance data for solar resources), etc.

- An Interconnection Request prior to submitting a New Capacity Show of Interest. The purpose of the Interconnection Request is for the ISO to examine the overlapping interconnection impacts – based on the information provided in the New Capacity Show of Interest Form – and to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period.

Demand resources

Demand resources are measures that reduce consumer demand for electricity from the bulk power system, such as the use of energy-efficient appliances and lighting, advanced cooling and heating technologies, electronic devices to cycle air conditioners on and off, and equipment to shift load to hours of off-peak demand. They also include facilities that can temporarily curtail load when directed to do so by the ISO, and the use of electricity generated on site (i.e. distributed generation).

Both active and passive demand resources are allowed to participate in the ISO-NE FCM. An active demand resource is a resource designed to reduce load in response to real-time system conditions or ISO instructions. A passive demand resource, such as an energy-efficiency programme or a distributed generation project, reduces load for the most part continually – but not in response to real-time conditions or instructions.

Demand Response resources are not allowed to participate in FCAs prior to the 2017-2018 delivery period FCA. Demand Response resources may also participate in reconfiguration auctions. A Demand resource may continue to offer capacity in FCAs and reconfiguration auctions for a given delivery period for less than or the equivalent of its remaining measure life.

Unlike capacity resources, Demand resources are not allowed to submit import or export bids or Administrative Export Delist Bids. They can only retire only through a Permanent Delist bid no later than 45 days before the beginning of a new FCA. A Demand resource is no longer eligible to participate in the Forward Capacity Market if its Permanent Delist Bid is accepted.

Existing demand resources

Demand resources that have previously been in service and registered with the ISO, and which are not new demand resources, are defined as existing demand resources. Existing demand resources include and are limited to: (i) demand resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past FCA; (ii) other Demand resources in service and registered with the ISO during the capacity market in place before the present FCM of ISO-NE FCM came into force; (iii) Demand resources participating in the Real-Time Demand Response Programme (30-Minute and 2-Hour Response).

For each resource that a project sponsor seeks to offer as an existing demand resource in the FCA, the project sponsor must submit an Existing Capacity Qualification package. The core document of the Existing Qualification Package is the Measurement and Verification Plan, which must demonstrate the measurement and verification performed to verify the achieved demand reduction value of the Demand resource project. The Measurement and Verification Documents must contain a projection of the Demand resource project's demand reduction value for each month of the delivery period and over the expected measure life of the demand resource project. A Demand resource's Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output.

New demand resources

A New Demand resource is a demand resource that has not been in service prior to the applicable existing capacity qualification deadline of the FCA, or distributed generation that has operated only to address an electric power outage due to failure of the electrical supply, on-site disaster, local equipment failure, public service emergencies such as flood, fire, or natural disaster, or excessive deviations from standard voltage from the electrical supplier to the premises during the 12-month period prior to the applicable existing capacity qualification deadline of the FCA, and is not an existing demand resource.

For FCAs a new demand resource must have Summer Qualified Capacity and Winter Qualified Capacity based on the resource's demand reduction value.

For each new demand resource that is a Demand Response resource, Real-Time Demand Response resource or Real-Time Emergency Generation resource, the ISO shall perform an analysis based on the information provided in the New Demand Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated capacity commitment period.

A new demand resource must submit, like new generating capacity, a New Demand Resource Show of Interest Form. The form must include information such as:

- The project name and the load zone within which the demand resource project will be located.
- The dispatch zone within which a Demand Response Capacity resource, Real-Time Demand Response resource or Real-Time Emergency Generation resource will be located.
- The estimated summer and winter demand reduction values (MW) per resource and/or per customer facility expected to be achieved five weeks prior to the FCA.
- The demand resource type (On-Peak Demand Resource, Seasonal Peak Demand Resource, Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource).
- A project description including the resource type (i.e., Energy Efficiency, Load Management, and/or Distributed Generation).

- The type of facilities at which the energy reduction program will be implemented.

For each resource that a project sponsor seeks to offer as a new demand resource in the FCA, the project sponsor must submit a New Demand Resource Qualification Package. As for existing demand resources, the core of the New Demand Resource Qualification Package is the Measurement and Verification Plan, which must illustrate the expected demand reduction value of the demand resource project. To be admitted to the FCM, the project sponsor must provide documentation on the project funding sources.

If a bid from a new demand resource clears in the FCA, the capacity associated with the resulting Capacity Supply Obligation must not be subject to any type of delisting or export bid in subsequent FCAs for capacity commitment periods for which the project sponsor elected to have a Capacity Supply Obligation and receive a capacity clearing price.

In the New Demand Resource Qualification Package, the project sponsor must specify whether, if its New Demand resource offer clears in the FCA, the associated Capacity Supply Obligation and capacity clearing price will continue to apply after the Capacity Commitment Period associated with the FCA during which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such choice is made in the New Demand Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Resource offer shall only apply for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Resource offer clears.

In addition, for a New Demand Resource the Project Sponsor must indicate in the New Demand Resource Qualification Package whether the offer from a New Demand Resource may be rationed.

Import resources

Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction may participate in the FCA and receive payments only for the one-year Capacity Commitment Period associated with the FCA. Both Existing Import Capacity resources and New Import Capacity resources must be backed by one or more External resources or by an external Control Area throughout the relevant capacity commitment period.

Specifically, Existing Import Capacity may include:

- Capacity associated with a multi-year contract entered into before the FCA to provide capacity in the New England region from outside of the New England area for a period including the whole capacity commitment period.
- Capacity from an External Resource that is owned or directly controlled by a market participant and which is committed for at least two whole consecutive capacity commitment periods by a market participant in the FCM.

If the Existing Import Capacity resource has not cleared in a previous FCA, then the import capacity shall participate in the FCA as a New Import Capacity resource.

Existing Import Capacity resources are subject to the same qualification process as Existing Generating Capacity resources**.**

In order to be admitted to participate into the FCA, a market participant submitting Existing Import Capacity must provide the ISO with the following information:

- Documentation from a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole capacity commitment period, including documentation of the MW value of the contract;
- Documentation proving the ownership or direct control over one or more External Resources that will be used to back the Existing Import Capacity resource during the capacity commitment period, together with information establishing the summer and winter ratings of the resource backing the import.

New import resources concern capacity not associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England control area from outside the New England control area for the whole capacity commitment period.

The qualification process for a New Import Capacity resource, whether backed by a new External resource, by one or more existing External resources, or by an external control area, is the same as the qualification process for a new generating capacity resource.

For each New Import Capacity resource, the market participant must submit to ISO-NE:

- Documentation from a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England control area from outside of the New England control area for the entire capacity commitment period, including documentation of the MW value of the contract.
- Documentation from a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England control area from outside of the New England control area for a period including the entire capacity commitment period if the import capacity has not cleared in a previous Forward Capacity Auction, including documentation of the MW value of the contract.
- Proof of ownership or direct control over one or more External resources that will be used to back the New Import Capacity resource during the capacity commitment period, including information to establish the summer and winter ratings of the resource(s) backing the import.
- Documentation for system-backed import capacity showing that the import capacity will be supported by the control area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as the control area’s native load.

Finally, the market participant must indicate whether the import capacity is associated with any investment in transmission that increases New England’s import capability.

4 Resource requirements in the PJM and ISO-NE forward capacity markets

This Section illustrates how the target resource requirement for a given delivery period is determined in both the ISO-NE and PJM forward capacity markets. In addition, a description of the demand curve expressing the target resource requirement is provided.

4.1 The definition of the resource requirement objective in the PJM RPM

This Section provides some insights into the definition of the reliability target to be met by means of the Base Residual Auction and Incremental Auctions in the PJM forward capacity market. To this aim, we will first discuss measurement of the reliability requirement. Given that in the PJM RPM the reliability target is computed with reference to both the whole PJM footprint and various sub-regions, we will describe how the division into sub-zones of the RTO's area is obtained. Lastly, we will illustrate the demand curve employed in the procurement process to clear the target capacity level needed to meet the reliability requirement of PJM.

4.1.1 Resource adequacy measurement

PJM performs an evaluation of resource adequacy for the whole region and for the zones in which the region is divided for the purpose of the auction clearing process, for each year in a ten-year future time-horizon.

The resource adequacy assessment is performed first by considering the installed capacity of the available resources. The reliability value of a resource is then given by two variables: its installed capacity and the probability that the resource will be not available because of forced outages or forced deratings. The latter measure is given by the Loss of Load Expectation (LOLE) which must be not occur more than one in ten years.

The resource requirement is expressed as the Installed Reserve Margin (IRM), a percentage of Forecasted Peak Load.

PJM determines annual Peak Load Forecasts for the whole region and for the zones defined for the purpose of the auctions. Specifically, PJM defines and posts the regional and zonal peak load forecasts before each Base Residual Auction (Preliminary Peak Load Forecasts), and before each Incremental Auction (Updated Peak Load Forecasts in the case of the First and Second Incremental Auctions, and Final Peak Load Forecast in the case of the Third Incremental Auction).

The IRM is approved by PJM's Board of Directors and posted by 1 February prior to its use in the Base Residual Auction for the delivery year. Updated values of the IRM are approved and posted by PJM Board of Managers one month before its use in a First or Second Incremental Auction for the delivery year of reference. The updated value of the IRM for the Third Incremental Auction represents the final value for the delivery year.

In order to obtain the value of the Installed Capacity (ICAP) required to satisfy the regional and zonal reliability targets the IRM must be multiplied by the values of the Peak Load Forecasts.

However, the reliability target to be auctioned in the Base Residual Auction and in the Incremental Auctions should be expressed in terms of Unforced Capacity (UCAP) rather than in terms of Installed Capacity. The measure which expresses the level of UCAP that will provide an acceptable level of reliability consistent with PJM reliability standards is the Forecast Pool Requirement (FPR). More specifically, the total value of UCAP required is given by the FPR multiplied by the Forecasted Peak Load values.

The following variables are used to determine the value of the Forecast Pool Requirement: the Installed Reserve Margin, and the Pool-Wide Average Equivalent Forced Outage Rate (EFORd). The 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. The EFORd computed for each generating unit is then transformed into the Pool-wide Average EFORd. This is the average forced outage rates based on five years history, weighted for unit capability and expected time in service, for all units that are scheduled to be in service during the delivery year. For the Peak Load Forecast, three different types of Pool-wide Average EFORd are computed. A preliminary value is posted on 1 February prior to its use in the Base Residual Auction. An updated value of the Pool-wide Average EFORd is posted one month prior to its use in an Incremental Auction for the delivery year. A final value of the Pool-wide Average EFORd is posted one month prior its use in the Third Incremental Auction.

The Forecast Pool Requirement is given by the following formula:

$$FPR = (1+IRM)(1-PoolWideAverageEFORd)$$

The FPR is approved by the PJM Board of Directors and posted by 1 February prior to its use in the Base Residual Auction. Updated values and the final value of the FPR are posted one month prior, respectively, to the First and Second Incremental Auctions and the Final Auction.

It is important to stress that the Installed Reserve Margin and the Forecast Pool Requirement are both a measure of the level of reserves required to satisfy the resource adequacy target but are expressed in different capacity values. The IRM is expressed as the installed capacity reserve, a percent of the forecast peak load. The FPR multiplied by the value of the Forecasted Peak Load provides the total UCAP required.

As already mentioned, the resource adequacy assessment is performed by PJM with reference to both the RTO's whole region and several sub-regions. In the following Section we discuss how these sub-regions are identified.

4.1.2 The locational deliverability areas for the PJM RPM

In the PJM RPM, the resource requirement to be met by means of the procurement process is also defined with reference to various sub-regions of the PJM footprint. These sub-regions are called Locational Deliverability Areas (LDAs) and their definition has the purpose of assessing any transmission constraints between different zones of the PJM footprint. For this purpose a Load Deliverability Analysis is conducted.

The first step of the Load Deliverability Analysis is to determine the transmission import capability required for each LDA to meet the Loss of Load Expectation reliability criterion of one occurrence in 25 years. This import capability requirement is called the Capacity Emergency Transfer Objective (CETO). The CETO is expressed in MW values and in terms of UCAP.

The second step of the analysis is to determine the transmission capability limit for each LDA. The transmission capability limit is called the Capacity Emergency Transfer Limit (CETL) and is expressed as the CETO in UCAP and MW values.

If the CETL value for each area is less than the CETO value, transmission upgrades are scheduled under PJM's Regional Transmission Expansion Planning Process (RTEPP).

The ultimate aim of identifying transmission constraints between different areas of the PJM footprint is to provide a locational value of capacity. In fact, if a market does not have the ability to price capacity on a locational basis all the resources in the market are valued equally throughout the region. If this occurs, there is the risk of having excess reserve in the region and relatively low capacity prices. In turn, a low capacity price may determine the retirement of some generating units, thus leading to the risk of lack of reliability. These conditions suggest that a higher value for resources must be required in constrained areas in order to encourage existing generating units to remain in service and new capability to be built in the form of generation, demand, or merchant transmission upgrades.

By means of the Locational Deliverability Analysis, the RPM therefore provides for a locational capacity value. Transmission constraints are evaluated for each delivery year and illustrated in the RTEPP. Specifically, preliminary values for CETO and CETL (for each LDA) are posted by 1 February prior to their use in the Base Residual Auction. The updated values of CETO and CETL measures are posted one month prior to their use in a First or Second Incremental Auction. The final values of CETO and CETL measure are posted one month before the Third Incremental Auction.

For the 2013-2014 delivery year the RTEPP identified 25 sub-regions referred to as LDAs for evaluating transmission constraints. If an LDA has a CETL value of less than 1.15 times then the CETO is modelled as a Constrained LDA.

Once LDAs are defined it is then possible to determine the resource adequacy target, expressed in UCAP values, that will be cleared in the PJM Auctions for both the whole PJM footprint and for each LDA. As mentioned at the beginning of Section 4, the resource adequacy target for the whole PJM region is defined UCAP values in the following manner: the RTO Peak Load Forecast multiplied by the approved Forecast Pool Requirement for the PJM Region, less the sum of the Preliminary Unforced Capacity Obligations of the entities participating in the Fixed Resource Requirement Programme[8].

For the LDAs the resource adequacy target is provided by the projected internal capacity (expressed in terms of UCAP) plus the Capacity Emergency Transfer Objective (CETO) for the delivery year, as determined by the RTEPP, less the minimum internal resources (in terms of UCAP) required for the FRR Entities located in the LDA, and less any necessary adjustment for PRD proposed in an approved PRD Plan or committed in any RPM Auction for PRD located in the LDA.

4.1.3 The demand curve in the RPM

A demand curve is defined in advance of each RPM auction to express the amount of resources to be procured for each delivery year – and for both the regional and LDA footprint – through the procurement process.

[8] See note 5.

The demand curve for the PJM RPM is called the Variable Resource Requirement (VRR) Curve. It is a downward sloping curve which defines the resource requirement as a function of price. Each point of the VRR Curve represents a family of price/quantity values that provide a specific price for various levels of resources procured for the target IRM.

The VRR curve for the PJM RPM is shown in Figure 5.The downward sloping curve implies that an amount of capacity greater or less than that expressed by the target capacity level to be procured may be cleared. That means that a capacity amount greater than the target level nevertheless has value. The cost of the supply that is procured at the clearing price will be allocated to the LSEs. The reasons for clearing resources greater than the target reserve margin may be varied:. (i) A capacity amount greater than the target requirement is valuable because it avoids the risk of capacity shortfall due to uncertain load growth, weather and capacity availability; (ii) a second source of value is that the slope of the curve can lessen the risk of large suppliers being pivotal or otherwise able to exercise market power; (iii) a third source of value is that excess resources can reduce the frequency and duration of scarcity energy prices in the system and provide energy savings to Load Serving Entities and (iv) a fourth source of value is the reduction in capacity price volatility and the resulting investment risk to capacity resources, in particular to generating resources. Lower investment costs tend to reduce capacity prices.

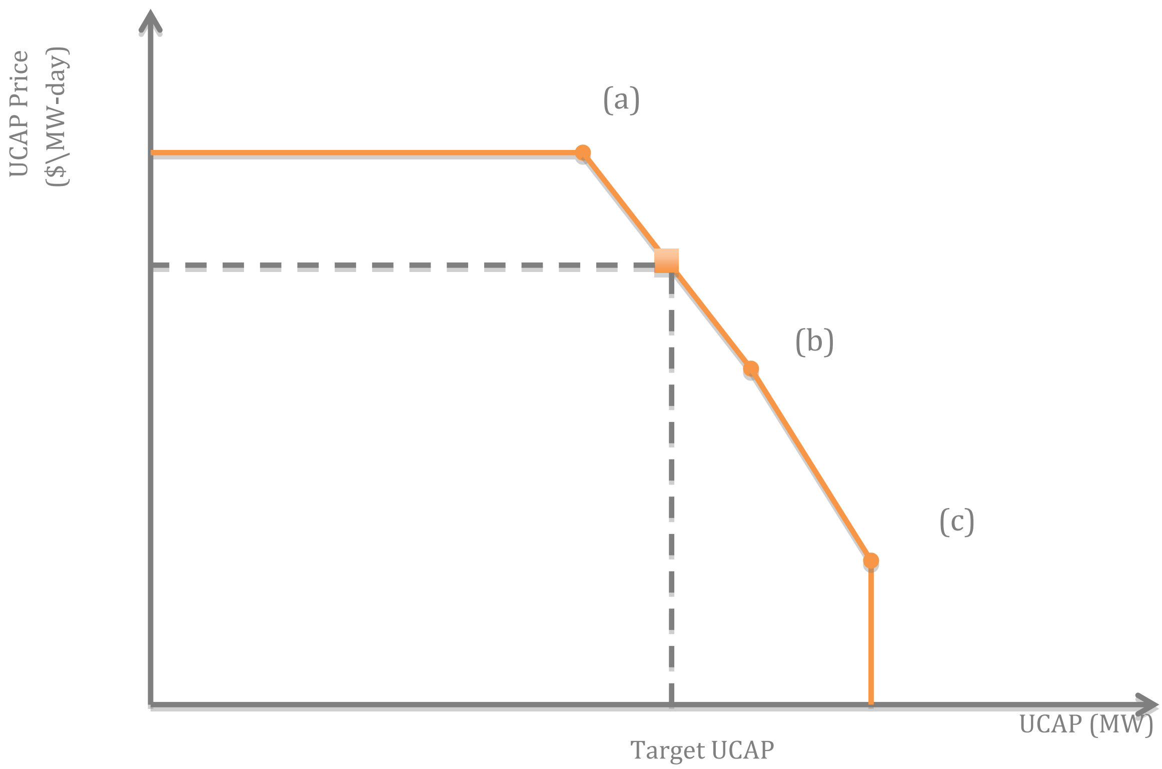

Figure 5: The VRR Curve for the PJM RPM

The VRR Curve is build around three reference points – (a), (b), (c) – which are defined as follows:

- Point (a):

 The price is:

$$\frac{Max[CONE; 1.5(CONE - Energy\ \&\ Ancillary\ Services\ Revenue)]}{1 - Pool\ Wide\ EFORd}$$

 The UCAP value:

$$PJM\ Region\ Reliability\ Requirement\ \frac{(100\% + IRM - 3\%)}{(100\% + IRM)} - Short\ Term\ Resource\ Proc.Target$$

- Point (b):

 The price is:

$$\frac{1.0(CONE - Energy\ \&\ Ancillary\ Services\ Revenue)]}{1 - Pool\ Wide\ EFORd}$$

 The UCAP value:

$$PJM\ Region\ Reliability\ Requirement\ \frac{(100\% + IRM + 1\%)}{(100\% + IRM)} - Short\ Term\ Resource\ Proc.Target$$

- Point (c):

 The price is:

$$\frac{0.2(CONE - Energy\ \&\ Ancillary\ Services\ Revenue)]}{1 - Pool\ Wide\ EFORd}$$

 The UCAP value is:

$$PJM\ Region\ Reliability\ Requirement\ \frac{(100\% + IRM + 5\%)}{(100\% + IRM)} - Short\ Term\ Resource\ Proc.Target$$

The CONE is the Cost of New Entry, and represents the cost of building a new generating unit within the PJM footprint and the cost of its added capacity to the grid. Specifically, the CONE is calculated to determine the potential of a new generating unit coming online between an auction year and a delivery year (three years). To compute the CONE benchmark technology is adopted. Usually the benchmark technology is represented by a combustion turbine to be built in a specific location. The CONE includes both plant capital costs and fixed operational and maintenance costs. Capital costs are incurred when constructing the power plant, before the commercial online date. For example, capital costs involve most of the costs required to engineer and construct the generating plant, including expenses for major equipment and EPC services. The additional expenses an owner must incur in the development and construction of a generating plant are also capital costs: as are all the expenses relative to acquisition of the land, emission reductions credits, gas and electric connection costs, and the costs of start-up fuel during testing, and owner contingencies.

Operational and maintenance costs are incurred once the plant enters commercial operation. They include property taxes, plant insurance, facility fees for labour and minor maintenance, and asset management costs.

To compute the CONE, assumptions about inflation rates have to be made to account for projected increases in operational and maintenance costs over time. Similarly, assumptions about corporate taxes must be made. In addition, hypotheses about the cost of capital and the life cycle of the benchmark technology are fundamental for determining an estimate of the CONE.

Investment costs must be then translated into annualised costs for the purpose of setting annual capacity prices. To this purpose assumptions about how revenues to recover capital and annual fixed costs will be received over time must be made. Usually the assumption is that net revenues will be constant in nominal terms over the plant's 20-year economic life. The CONE is therefore expressed in terms of annual values. Its daily value can be obtained by dividing the annual value by 365. It is important to observe that the VRR Curve illustrates the daily values of both UCAP and price quantities. As we will see in Section 6.1, the obligations to which capacity resources commit by participating in the auctions are defined in terms of daily obligations.

Energy & Ancillary Services Revenue represents the estimated total revenues earned by a benchmark combustion turbine in the PJM's Energy Markets and Ancillary Service Markets, less the variable costs of providing Energy and Ancillary Services. Specifically, the value of Energy and Ancillary Services Revenue is calculated as the average annual revenues that the benchmark combustion turbine would hav received during the most recent three previous calendar years.

The IRM is the Installed Reserve Margin, and the Pool Wide EFORd is an average of the forced outage rates based on five years' history, weighted for unit capability and expected time in service, attributable to all units that are scheduled to be in service during the delivery year (see Section 4.1.1 for more details).

The Short Term Resource Procurement Target is set for the Base Residual Auction as 2.5% of the reliability requirement. In the First Incremental Auction the same measure is set as 2% of the reliability target. In the Second and Third Incremental Auctions it is respectively 1.5% and 0% of the reliability target.

The same process will be used to establish the VRR Curve for each LDA, except that the Locational Deliverability Area Reliability Requirement for the LDAs will be substituted for the PJM Region Reliability Requirement, and the LDA Short-Term Resource Procurement Target for the Zones associated with the LDAs will be substituted for the RTO Short-Term Resource Procurement Target.

The Base Residual Auction for the 2013-2014 delivery year the following reliability measurement values discussed in this Section apply, and for the purpose of constructing the VRR Curve have been established for both the whole RTO region and the Constrained LDAs:

Reliability Requirement Parameters for the whole PJM region (1)	
Installed Reserve Margin (IRM)	15.3%
Pool-Wide Average EFORd	6.3%
Forecast Pool Requirement (FPR)	1.0804
Preliminary Forecasted Peak Load (MW)	160,634

Reliability Requirement Parameters (2)	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO
Reliability Requirement (UCAP MW)	173,549	73,142	40,398	17,899	13,401	6,347	2,996	9,442
Total Peak Load of FRR Entities (UCAP MW)	21,807	0	0	0	0	0	0	0
Preliminary FRR Obligation (UCAP MW)	23,560, .3	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR (UCAP MW)	149,988. 7	73,142	40,398	17,899	13,401	6,347	2,996	9,442
Short-Term Resource Procurement Target (UCAP MW)	3,749.7	1,691.0 3	925.70	397.45	302.18	139.00	63.039	191.60
Net CONE, $/MW-Day (UCAP Price)	317.95	22.,2	261.06	227.2	26.,06	261.06	261.06	227.2

Variable Resource Requirement Curve	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO
Point (a) UCAP Price, $/MW-Day	476.93	340.8	391.59	340.8	391,59	391.59	391.59	340.8
Point (b) UCAP Price, $/MW-Day	317.95	227.2	261.06	227.2	261,06	261.06	261.06	227.2
Point (c) UCAP Price, $/MW-Day	63,59	45.44	52.21	45.44	52,21	52.21	52.21	45.44
Point (a) UCAP Level, MW	142,336.4	69,547.9	38,421.2	17,035.8	12750,1	6,042.9	2,855	9,004.7
Point (b) UCAP Level, MW	147,539.9	72,085.3	39,822.7	17,656.8	13215	6,263	2,958.9	9,332,.
Point (c) UCAP Level, MW	152,743.3	74,622.8	41,224.2	18,277.7	13679,9	6,483.2	3,062.9	9,659.8

In the First, Second, and Third Incremental Auctions capacity suppliers are allowed to purchase replacement capacity and PJM to adjust previously committed capacity levels. For these Incremental Auctions the demand curve is built based on a combination of buy bids submitted by market participants and buy bids, if any, submitted by PJM. Specifically, PJM recalculates for each Incremental Auction the RTO and each LDA Reliability Requirement. The recalculation is based on updated values of the Peak Load Forecasts, Installed Reserve Margin, and CETO. The recalculated Reliability Requirements are compared with those employed in the prior auction for the same delivery year and a calculation is made of the need for the procurement and/or sale of capacity by PJM.

4.2 Definition of the resource requirement objective in the ISO-NE Forward Capacity Market

This Section discusses definition of the resource requirement target in the ISO-NE FCM by focusing on the chosen measure of resource adequacy, the division of the ISO-NE region into capacity zones, and the demand curve expressing the resource requirement target.

The ISO defines the target resource requirement three years in advance of the delivery period. The Installed Capacity Requirement is defined such that the probability of disconnecting non-interruptible customers due to resource deficiency will, on average, be no more than once in ten years. Compliance with this resource adequacy planning criterion is evaluated on the basis of probability, such that the Loss of Load Expectation ("LOLE") of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day each year. The Installed Capacity Requirement is then transformed into a Net Installed Capacity Requirement (NICR) by subtracting what is known as the Hydro-Quebec

Interconnection Credit. This represents the tie benefits from the Quebec Control Area.

Forward Capacity Auctions procure installed capacity to meet the region's resource adequacy requirements as well the capacity required for each capacity zone that has a locational capacity need identified before the auction. The locational needs are local sourcing requirements (LSRs) or maximum capacity limits (MCLs). An LSR is the minimum amount of capacity that must be located in an import-constrained area (which has insufficient capacity). An MCL is the maximum amount of capacity that can be located in an export-constrained area (which has surplus capacity). Capacity zones may comprise a single or several load zones (i.e., aggregations of load pricing nodes within a specific area). Capacity zones are identified before each auction and are included in the auction only if the local sourcing requirement (LSR) is greater than the existing capacity located within the zone. Ideally, in the absence of market power, all the zones would be included in the auction.

The Net Installed Capacity requirement is expressed by a vertical demand curve (see Figure 6).

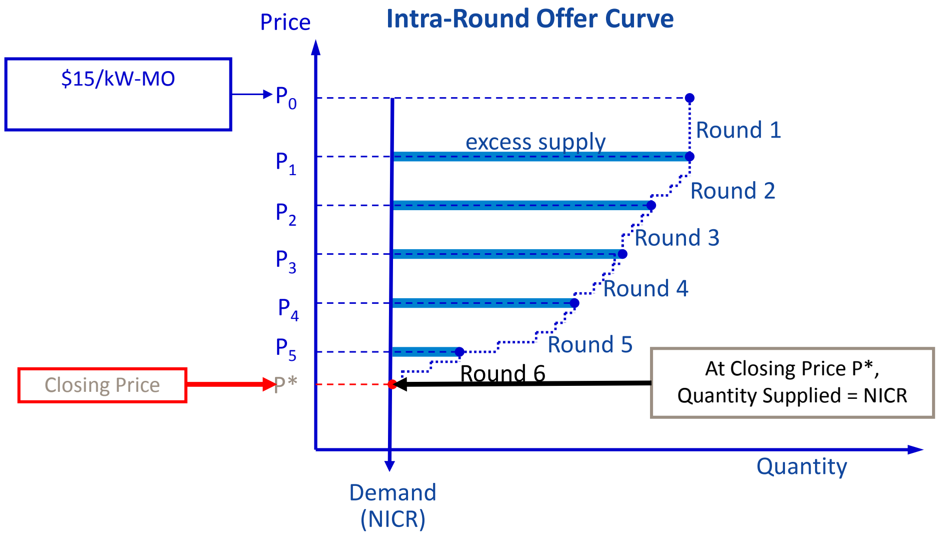

Figure 6: Demand curve in ISO-NE FCM.

The demand curve for the ISO-NE forward capacity market differs significantly from that of the PJM FCM. As we have seen in Section 4.1.3, PJM adopts a Variable Resource Requirement Curve. The Italian forward capacity market relies on a demand curve similar to that of PJM. The adoption of a vertical demand curve for the forward capacity market auctions presents several issues. First of all, a vertical demand curve is vulnerable to the exercise of market power. Given that supply is also inelastic in the short/medium-run, a small amount of withholding can force a relatively large increase in price, particularly if the amount of offered supply is fairly close to the planning reserve margin target. In addition, capacity markets characterised by vertical demand curves and near vertical supply curves may exhibit extreme price volatility. Specifically, when supplies slightly exceed the fixed reserve requirement, capacity prices in the monthly markets can fall close to zero and remain near zero as long as there is just enough capacity to meet the fixed reserve requirement. Conversely, when supplies are slightly less than the fixed reserve requirement, capacity prices rise rapidly to the administrative price cap for capacity. Price volatility determines costs for customers, and may increase investment risk.

5 Procurement procedures in the PJM and ISO-NE forward capacity markets

This Section provides an overview of the procurement procedures adopted for the PJM RPM and the ISO-NE FCM. Specifically, the following paragraphs will focus on the basic design of both forward capacity markets, and on the main bidding rules for the market participants.

5.1 Procurement procedures in the PJM RPM

The RPM is a multi-auction structure relying on the following market mechanism: a Base Residual Auction, Incremental Auctions and a Bilateral Market.

- The *Base Residual Auction* is held during May three years prior to the start of the delivery year.
- *Incremental Auctions* are conducted after the Base Residual Auction to procure additional resource commitments needed to satisfy potential changes in market dynamics that are known prior to the beginning of the delivery year.
- A *Conditional Incremental Auction* may be held if a backbone transmission line is delayed and results in the need for PJM to procure additional capacity in a Locational Deliverability Area to address the resulting reliability problem.
- The *Bilateral Market* provides resource providers an opportunity to cover any auction commitment shortages. The bilateral market also provides LSEs the opportunity to hedge against the Locational Reliability Charge.

An auction is conducted for each of the LDAs. Offers from resources participating in a Base Residual Auction must follow the following rules:

- The smallest increment that may be offered into any auction is 0.1 MW.
- Each resource must indicate the minimum and maximum amount of installed capacity offered in MW.
- Each offer must indicate the base offer segment price acceptable in $/MW-day (in UCAP);
- For generation resources the EFORd to apply to the offered MW must be provided.

In order to incentivise new entries, a specific rule called *New Entry Pricing* is provided for Planned Generation Resources where the size of the new entry is significant relative to the size of the LDA and there is a potential for the clearing price to drop when all offer prices including that of the new entry are capped. New Entry Pricing allows Planned Generation Resources to recover the amount of their cost of entry-based offer for up to two additional consecutive years under certain conditions.

To avoid the exercise of market power a *Sell Offer Cap* rule is put in place. The cap is based on the Avoidable Cost Rate of the generating resource. The Sell Offer Cap in fact only applies to existing generating resources. The Avoidable Cost Rate for a Generation Capacity Resource that is the subject of a Sell Offer is determined using the following formula, expressed in dollars per MW-year:

*Avoidable Cost Rate = [Adjustment Factor * (AOML + AAE + AME + AVE + ATFI + ACC + ACLE) + ARPIR + APIR]*

Where:

- The Adjustment Factor equals 1.10 (to provide a margin of error for understatement of costs) plus an additional adjustment referencing the 10-year average Handy-Whitman Index in order to account for expected inflation from the interval between submission of the Sell Offer and the start of the Delivery Year.
- AOML (Avoidable Operations and Maintenance Labour) consist of the avoidable labour expenses directly related to operation and maintenance of the generating unit for the twelve months preceding the month in which the data must be provided.
- AAE (Avoidable Administrative Expenses) consist of the avoidable administrative expenses directly related to employees at the generating unit for twelve months preceding the month in which the data must be provided.
- AME (Avoidable Maintenance Expenses) consist of avoidable maintenance expenses (other than expenses included under AOML) directly related to the generating unit for the twelve months preceding the month in which the data must be provided.
- AVE (Avoidable Variable Expenses) consist of avoidable variable expenses directly related to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included under AVE are those incurred for (a) water treatment chemicals and lubricants, (b) water, gas, and electricity service (not for power generation) and (c) waste water treatment.
- ATFI (Avoidable Taxes, Fees and Insurance) consist of avoidable expenses directly related to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included under AFTI are those incurred for (a) insurance, (b) permits and licensing fees, (c) site security and utilities for maintaining security at the site and (d) property taxes.
- ACC (Avoidable Carrying Charges) consist of avoidable short-term carrying charges directly related to the generating unit in the twelve months preceding the month in which the data must be provided. Avoidable short-term carrying charges include short-term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts resulting from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term means a period in which a reasonable replacement of inventory for normal, expected operations can occur.
- ACLE (Avoidable Corporate Level Expenses) consist of avoidable corporate level expenses directly related to the generating unit incurred in the twelve months preceding the month in which the data must be provided. Avoidable corporate level expenses shall only include expenses that are directly linked to providing tangible

services required to operate the generating unit proposed for deactivation. The categories of avoidable expenses included under ACLE are those incurred for (a) legal services, (b) environmental reporting and (c) procurement expenses.

- APIR (Avoidable Project Investment Recovery Rate) = PI * CRF

Where:

- PI is the amount of project investment completed prior to 1 June of the Delivery Year, except for Mandatory Capital Expenditures (CapEx) for which the project investment must be completed during the Delivery Year, that is reasonably required to enable a Generation Capacity Resource that is the subject of a Sell Offer to continue operating or improve availability during Peak-Hour Periods during the Delivery Year.

- CRF is the annual capital recovery factor from the following table, applied in accordance with the terms specified below.

Base Residual Auction clearing software is an optimisation algorithm. The objective of this algorithm is to minimise capacity procurement costs given the supply offers, Variable Resource Requirement Curve(s), and Locational Constraints. All the self-scheduled resources in the Base Residual Auction will automatically clear at their maximum MW amount specified in the sell offer. The Base Residual Auction clearing price for each LDA is determined by the optimisation algorithm.

For resources participating into an Incremental Auction, the following business rules apply:

- The smallest increment that may be offered into an Incremental Auction is 0.1 MW.
- Planned generation, planned demand resources, or energy efficiency resources that were not eligible to participate at the time of the Base Residual Auction or prior Incremental Auction are eligible to participate in subsequent Incremental Auctions if the planned generation, planned demand resource, or energy efficiency resource meets the requirements outlined in Section 3.2.

The First Incremental Auction is held during September, twenty months prior to the start of the Delivery Year. The Second Incremental Auction is held duringJuly, ten months prior to the start of the Delivery Year. The Third Incremental Auction is held duringFebruary, three (3) months prior to the start of the Delivery Year.

The costs of the incremental commitments that are cleared in Incremental Auctions are allocated to resource providers that cleared Buy Bids in the Incremental Auction based on the cleared Buy Bid MW quantity and the clearing price and to LSEs by adjusting the Zonal Capacity Price.

The clearing of the Incremental Auctions is determined by the intersection of the supply curve and the demand curve.

The Incremental Auction clearing prices for each Buy Bid or Sell Offer cleared is determined using the same optimisation algorithm as for the Base Residual Auction clearing.

5.2 Procurement procedures in the ISO-NE FCM

A Forward Capacity Auction and Reconfiguration Auctions are conducted to procure the target capacity requirement. Dynamic descending-clock auctions are used to determine the market-clearing prices and the capacity supply obligations, and are conducted for each capacity zone.

Each FCA has a cap and floor set on the prices that can be offered by market participants in the auctions (see Section 5.2.1). The starting price (price cap) in each auction is set at 2 × the CONE, while the ending price at 0.6 × the CONE (the floor price). At these auctions, the auction manager announces the individual prices for each of the zonal products to be procured. The bidders then indicate the quantities of each product they wish to supply at the current prices. Prices for products with excess supply then decrease, and the bidders again indicate equivalent or lower quantities at the new prices. During the auction, bidders are not permitted to increase their supply offers for existing or new capacity resources as prices decrease. This process is repeated until supply equals demand for each capacity product.

To avoid the exercise of market power, Quantity Rules are established to shift some of the capacity purchased from the FCA to the Reconfiguration Auctions. The amount procured in the primary auction depends on the following price ranges:

- *Between Start Price and 1.5 × CONE*: the full NICR quantity, assuming permanent, static, and dynamic delist bids do not clear the auction.

- *Between 1.5 × CONE and 1.25 × CONE:* the full NICR quantity plus a quantity of capacity to replace permanent delist bids in the primary auction that increases in a linear fashion from zero at 1.5 × CONE to the full quantity of permanent delist bids accepted in the primary auction at 1.25 × CONE.

- *Between 1.2 × CONE and 0.8 × CONE:* the full NICR quantity and the full quantity of permanent delist bids plus a quantity of capacity to replace static delist bids in the primary auction that increases in a linear fashion from zero at 1.2 × CONE to the full quantity of static delist bids accepted in the primary auction at 0.8 × CONE.

- *Below 0.8 × CONE*: the full NICR quantity and all accepted permanent, static, and dynamic delist bids.

In the event that an FCA lacks of significant competition, it may be defined as having ‘inadequate supply’ or ‘insufficient competition’:

- Inadequate Supply arises when new capacity in a capacity zone at the FCA’s starting price is less than the new capacity requirement (NCR) for that zone. In such cases, existing capacity in this zone is paid 1.1 × the CONE, new capacity in this zone is paid the starting price, and the capacity deficiency will be made up in subsequent reconfiguration auctions. A resource that applied to delist but had its bid denied in this zone is paid its bid price or 1.1 × the CONE, whichever is higher. Inadequate supply in one or more capacity zones does not affect the FCAs for capacity zones containing adequate supply. If the system-wide NICR cannot be satisfied at the starting price, existing capacity is paid 1.1 × the CONE, new capacity is paid the starting price, and the capacity deficiency is made up in subsequent reconfiguration auctions. A resource that applied to delist but had its bid denied is paid its bid price or 1.1 × the CONE, whichever is higher. System-wide inadequate supply does not affect the FCAs for capacity zones having adequate supply, except that in capacity zones with adequate supply, new capacity is paid the capacity clearing price and existing capacity is paid the lower of the capacity clearing price or 1.1 × the CONE.

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- An FCA is considered to have Insufficient Competition system-wide or within any capacity zone when the amount of existing capacity is less than the NICR (or the LSR, as applicable for a particular zone), and one of the following conditions exists at the starting price:

    - Less than 300 MW of new capacity is offered (to be reconsidered in the case of the creation of import-constrained zones with a total requirement of less than 5,000 MW).
    - The amount of new capacity offered is more than the new capacity required but less than twice the new capacity required.
    - The new capacity of at least one market participant is pivotal, excluding Out Of Market capacity. A market participant is considered pivotal if, at the starting price, any of that participant's potential new capacity is required to satisfy the NICR (or the LSR, as applicable).

Reconfiguration auctions provide secondary markets for adjusting the commitments made in the FCA to respond to changing market circumstances as a capacity commitment period approaches. For each capacity commitment period, the ISO conducts two types of reconfiguration auctions:

- Annual reconfiguration auctions (for trading year-long commitments) before the relevant commitment period.
- Monthly reconfiguration auctions held before each commitment month.

Reconfiguration auctions use a static double auction while preserving the locational elements of the FCA.

5.2.1 The floor in ISO-NE auctions

For each round of the FCA, the auctioneer announces both a Start-of-Round Price – the highest price associated with a round of the FCA, and an End-of-Round Price – the lowest price associated with a round of the FCA.

The starting price in each auction is set at 2 times the Cost Of New Entry, and the ending price at 0.6 times the CONE. The starting price of the first FCA (relative to the 2010-2011 delivery period and held in 2008) was $15.00/kW-month. This means that for the first FCA a CONE of $7.50/kW-month and a price-floor of $4.50/kW-month was set.

The reason for the adoption of a price floor is based on the need to avoid a fall in capacity prices when excess supply occurs: *"The price floor [...] is intended to prevent the firm energy price from falling too low in times of surplus. This provides stability to the firm energy price, which reduces supplier risk and thus reduces consumer cost in the long term"* (Ausbel and Cramton, 2010; Cramton and Stoft, 2007).

The CONE of each FCA determines then the CONE for a next FCA, and thus the price cap and the price floor. Specifically, the capacity zone's CONE for the next FCA uses the CONE of the previous FCA adjusted by a rolling 3-year average of the Handy-Whitman Index of Public Utility Construction Costs. The latter is an index measuring the trend in construction costs of water, gas and electricity utilities.

To understand how the CONE is computed, let us consider the following example for calculating the CONE for the seventh FCA. The CONE for the seventh FCA, relative to the 2017-2018 delivery period, depends on the clearing price of the sixth FCA adjusted for the rolling 3-year average of the Handy-Whitman Index values. Consider thus the following values for the sixth FCA:

- CONE = $5.723/kW-month
- Handy Withman Index values:

2007		2008		2009		2010		2011		2012	
Jan	Jul	Jan	Jul	Jan	Jul	Jan	Jul	Jan	Jul	Jan	Jul
-	543	594	616	635	667	687	700	697	717	765	N/A

Therefore, the adjustment to be applied to the CONE of the sixth FCA will be given by the average of the six most recent values of the Handy Whitman Index at the conclusion of the sixth FCA, divided by a comparable span in periods one full calendar year earlier:

$$(667+687+700+697+717+765)/(616+635+667+687+700+697) = 1.058$$

Therefore, the CONE for the seventh FCA will be:

$$1.058 \text{ x } \$5.723/kW\text{-}month = \$6.055/kW\text{-}month$$

The Price Floor will be:

$$\$6.055/kW\text{-}month \text{ x } 0.6 = \$3.633/kW\text{-}month$$

And the Price Cap will be:

$$\$6.055/kW\text{-}month \times 2 = \$12.11/kW\text{-}month$$

Table 1 below illustrates the CONE and the starting and floor price for the seven FCAs that have taken place since the introduction of the forward capacity market:

Table 1: CONE, price floor and price cap values for the seven FCAs of ISO-NE FCM.

	FCA 1	**FCA 2**	**FCA 3**	**FCA 4**	**FCA 5**	**FCA 6**	**FCA 7**
Delivery period	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017
CONE ($/kW-month)	7.5	6.0	4.918	4.918	5.349	5.723	6.055
Starting Price ($/kW-month)	15	12	9.836	9.836	10.698	11.446	15.0
Floor Price ($/kW-month)	4.5	3.6	2.951	2.951	3.209	3.434	3.150

Table 2 below illustrates the results of the first five forward capacity auctions. The results show that the auctions cleared at the floor price and always with excess capacity. The same results apply to the sixth and seventh forward capacity auctions[9].

Table 2: Results of the FCAs of ISO-NE.

	FCA 1	**FCA 2**	**FCA 3**	**FCA 4**	**FCA 5**	**FCA 6**	**FCA 7**
Delivery period	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017
Capacity resources (MW)	34.078	37.283	36.996	37.500	36.918	36.326	36.220
Target Capacity (MW)	32.305	32.528	31.965	32.127	33.200	33.456	32.968
Surplus (MW)	41.7735	4.775	5.031	5.373	3.718	2870	3252
Clearing Price ($/kW-month)	4.50	3.60	2.95	2.95	3.21	3.434	3.150

ISO-NE market rules establish that when the Capacity Clearing Price reaches 0.6 times CONE offers shall be prorated such that no more than the Net Installed Capacity Requirement is procured in the Forward Capacity Auction, as follows:

(i) The total payment to all listed capacity resources during the associated Capacity Commitment Period shall be equal to 0.6 times CONE multiplied by the Net Installed Capacity Requirement applicable in the Forward Capacity Auction.

(ii) Payments to individual listed resources shall be prorated based on the total MW of capacity clearing in the Forward Capacity Auction (receiving a Capacity Supply Obligation for the related Capacity Commitment Period).

(iii) Suppliers may instead prorate their bid MW in the Forward Capacity Market by partially delisting one or more resources. Regardless of proration, the full amount of capacity that has cleared in the Forward Capacity Auction will be ineligible for treatment as new capacity in subsequent Forward Capacity Auctions.

[9] See FCM Auction Results at: http://isonewengland.com/markets/othrmkts_data/fcm/cal_results/index.html .

(iv) All proration shall be subject to a reliability review. Where proration is rejected for reliability reasons, the resource payment will not be prorated as described in subsection (ii) above, and the difference between the actual payment based on the Capacity Clearing Price and what the payment would have been had prorationing not been rejected for reliability reasons will be allocated to the Regional Network Load within the affected Reliability Region. In this case, the total payment described in subsection (i) above will increase accordingly.

(v) A decision to prorate bid MW associated with a New Capacity Offer clearing in the Forward Capacity Auction will also apply in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor has elected to have the Capacity Supply.

6 Obligations and rights of capacity products exchanged in the PJM and ISO-NE FCMs

6.1 Obligations and rights of capacity contracts in the PJM RPM

This section discusses the obligations and rights pertaining to capacity resources from their participation in the PJM RPM. In addition, we will illustrate the assessments that PJM carries out to verify whether capacity resources meet their commitments during the delivery year, and penalties resources must pay in the event of under-performance. The analysis will provide a specific focus on generating capacity resources.

6.1.1 Load Serving Entity Obligations

The Unforced Capacity measure described in Section 4.1.1 is the basis for the market product cleared in each auction. This measure is also the basis for evaluation of the performance of capacity resources clearing in the auctions – generating capacity, load management, energy efficiency, and qualifying transmission upgrades – and for definition of the load obligation of LSEs.

Load obligations are obligations to serve load or to reduce load during the delivery year which are valued as Unforced Capacity. Load obligations are based on UCAP obligations procured in the Base Residual Auction and Incremental Auctions.

Load obligations are determined for both the whole PJM footprint and the LDAs involved in the procurement process following the Base Residual Auction and Incremental Auctions. A Base Unforced Capacity Obligation is posted after the Base Residual Auction, and a Final Unforced Capacity Obligation is posted after the Third Incremental Auction.

A Base Unforced Capacity Obligation is the sum of the UCAP Obligations met through the Base Residual Auction plus the Regional Short-Term Resource Procurement Target that is set at 2.5% of the Reliability Requirement for the Base Residual Auction (see Section 4.1.3). For each LDA involved in the Base Residual Auction, UCAP Obligations are determined on the basis of zonal Peak Load Forecasts and Zonal Short-Term Resource Procurement Targets.

A Final UCAP Obligation is a load obligation determined after clearing of the final Incremental Auction for a given delivery year. The final RTO UCAP obligation is equal to the RTO UCAP met through all RPM Auctions for a given delivery year. The RTO UCAP Obligation is the total MW cleared in PJM Buy Bids in RPM Auctions less the total MW cleared in PJM Sell Offers in RPM Auctions. The RTO UCAP Final Obligation is allocated to the zones on a pro-rata basis according to the Final Zonal Peak Load Forecasts.

6.1.2 Capacity Resources, Obligations and Rights

All generation resources clearing in PJM's auctions must offer on the PJM Day Ahead Energy Market. Demand Resources participating and clearing in PJM auctions must be registered in the Emergency Load Response Programme and must be thus available for dispatch during PJM's declared emergency events.

The market-clearing price is paid for all the capacity committed in auctions – both in the Base Residual Auction and the Incremental Auctions.

However, these payments may be partially, fully, or more than fully offset by performance-based penalties relating to the resources' availability during the delivery year as well as their availability during peak periods.

For the purpose of evaluating resource availability, PJM performs periodic tests during the delivery year. Specifically, the following tests are performed:

- RPM Commitment Compliance: this test is conducted on both conventional and intermittent generating capacity, and assesses demand response, energy efficiency and qualifying transmission upgrade.
- Peak Hour Period Availability: this test is conducted on conventional and hydro generating capacity only.
- Summer/Winter Capability Testing: like the previous assessment, this test is conducted only on conventional and hydro generating capacity.
- PSM Compliance: this assessment is conducted only on conventional generating resources.
- Load Management Event Compliance: this test is conducted on demand response resources.
- Load Management Test Compliance; like the previous test, this test is conducted on demand response resources.

RPM Commitment Compliance test

The RPM Commitment Compliance test aims to verify whether resources committing in auctions are able to meet their commitment during the delivery year to an extent equal to or greater than the level to which they have committed. The compliance is evaluated daily with a test varying according to the specific type of resource.

For generating units the RPM Commitment Compliance Test is performed by comparing the unit's Daily RPM Position with the unit's Daily RPM Commitment. In other words, the daily obligation to which the unit has committed by participating into the auction is compared with its actual daily position on the Day Ahead Energy Market. If its actual offered capacity is lower than the capacity that the resource has cleared in the auction the generating resource is charged a penalty. The penalty is calculated by applying the following rate to the difference between the committed and effectively offered capacity: the party's weighted average resource clearing prices (in all the RPM auctions in which the resource participated) plus the higher of 0.2 times the party's weighted average resource clearing price or $20/MW-day.

Peak Hour Period Availability test

The Peak Hour Period Availability test is to assess whether committed generation resources are available at the expected levels during critical peak periods, and credits or charges are applied to resource providers if they exceed or fall short of this expected availability.

The assessment is performed by comparing the peak period capacity availability of a generating resource with the expected committed portion of the unit's capacity for the same peak period. The actual peak period capacity is weighted by the probability that the generating unit may be not available due to forced outages or forced deratings when there is a demand to generate on the unit itself. The expected committed peak load capacity is weighted by a measures taking into account five years of the unit's outage data history. The charge applied in the event of resource under-performance is equal to the weighted average of the resource's clearing prices awarded across all RPM Auctions. The clearing prices are weighted by the MW cleared in each auction.

Summer/Winter Capability Testing

The summer/winter capability test aims to assess whether a unit that was committed through the RPM auctions was able to achieve at least its total unit installed capacity commitment during the summer/winter period. The summer test period begins on 1 June 1 and ends on 31 August. The winter test period begins on the first day of December and ends on the last day of February. In the event that a capacity shortfall occurs – i.e. the installed capacity commitment has not been met during the winter or summer period – the following charge is applied to the daily shortfall: the party's weighted average resource clearing price plus the greater of two measures: 0.2 times the party's weighted average resource clearing price, or $20/MW-day. The party's weighted average resource clearing price is the average of the clearing prices awarded by the party in all RPM auctions (for a given Delivery Price) weighted by the MW committed in the auctions.

PSM Compliance test

The Peak Season Maintenance Compliance test aims to assess the impact of planned outages and maintenance outages during a peak season. A peak season is defined as the weeks containing the 24th through the 36th Wednesday of the calendar year. A charge is applied to the generating unit if the provider committed a resource to the RPM and such resource was not available due to a planned or maintenance outage that occurred during the peak season without the approval of PJM. The daily charge applied to the capacity shortfall is equal to the party's weighted average resource clearing price plus the higher of the following values: 0.2 times the party's weighted average resource clearing price or $20/MW-day.

Load Management Event Compliance test

This test aims to assess whether a committed demand resource actually reduced load, as it committed to, during a load management event. In the case in which the Load Management Event Compliance test results in under-compliance a charge is applied per MW-day of under-compliance differentiated for peak and off-peak day windows.

Load Management Test Compliance

In the absence of a PJM-initiated LM event, this assessment determines whether committed demand resource reduced load during a curtailment service programme-initiated test. In the event of under-compliance the charge applied is equal to the provider's weighted daily revenue rate in a zone (i.e. the weighted average of resource clearing prices received across all RPM auctions by zonal DR resource, weighted by MW cleared) plus the higher of the following values: 0.2 times the party's weighted average resource clearing price or $20/MW-day.

6.2 Obligations and rights of capacity contracts in the ISO-NE FCM

A generating capacity resource committing on the ISO-NE FCM undertakes a capacity supply obligation. According to this obligation the generator must offer on both the Day-Ahead Energy Market and Real-Time Energy Market a MW amount equal to or greater than its capacity supply obligation whenever the resource is physically available. If the resource is physically available at a level lower than its capacity supply obligation, however, the resource will be offered on both the Day-Ahead Energy Market and Real-Time Energy Market at that level.

During each month of the delivery period, every resource that has acquired (by means of auctions) or shed a capacity supply obligation (by means of the bilateral market) will receive a payment. Specifically, a resource that participated in a forward capacity auction will receive a monthly capacity payment equal to the product of its cleared capacity and the capacity clearing price in the zone of the ISO-NE footprint to which the auction referred. In the event that the resource participated in a reconfiguration auction, the monthly capacity payment would be equal to the product of its cleared capacity and the clearing price in the zone of the ISO-NE footprint to which the auction referred. In the event that the commitment arises from the bilateral market, the payment will be equal to the product of the capacity supply obligation being assumed or shed, and the price associated with the capacity supply obligation bilateral .

Payments to both new and existing generating capacity resources shall be decreased by the Peak Energy Rents (PER) – if positive – calculated in each capacity zone in which the ISO-NE has been divided to the purpose of the FCM. The PER is defined on a hourly base as follows:

*Hourly PER($/kW) = [(LMP - Strike Price) * [Scaling Factor] * [Availability Factor]*

Where the *Strike Price* is the heat rate times the fuel cost of a PER Proxy Unit described below; the *Scaling Factor* is the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period and capped at an hourly ratio of 1.0; and the *Availability Factor* is set to 0.95. The PER Proxy Unit has the following characteristics:

- The PER Proxy Unit is indexed to the marginal fuel, which is the higher of ultra low-sulphur No. 2 oil measured at New York Harbour plus a seven percent markup for transportation and day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis;
- The PER Proxy Unit is assumed to have no start-up, ramp rate or minimum run time constraints.

The PER Proxy Unit has a 22,000 Btu/kWh heat rate. This assumption must be periodically reviewed by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region to which it would be dispatched as the system enters a scarcity condition.

The hourly PER shall be then totalled for each calendar month in order to determine the total PER for that month. The ISO then calculates the average monthly PER earned by the proxy unit. The average monthly PER is the average of the Monthly PER values for the 12 months prior to the month in which the obligation must be delivered. The PER deduction for each resource is calculated as follows:

PER Adjustment = min(PER cap; Average Monthly PER x PER Capacity Supply Obligation)

Where the PER cap for each resource equals the forward capacity auction payment plus the product of the net value of any other capacity supply obligations assumed or shed after the forward capacity auction for the same delivery period, multiplied by the capacity clearing price applicable to that resource location from the forward capacity auction. Where the calculation results in a PER cap value of less than zero, the PER cap will be revised to zero. The PER Capacity Supply Obligation is the lower of the Capacity Supply Obligation and the Capacity Supply Obligation less any Capacity Supply Obligation MW of any portion of a Self-Supplied FCA Resource. However, if the capacity supply obligation less any capacity supply obligation of any portion of a Self-Supplied FCA Resource is less than zero, it will be zero for the purpose of comparing it with the capacity supply obligation in the PER capacity supply obligation calculation.

In addition, all resources with a Capacity Supply Obligation as of the beginning of the Obligation Month will have their performance measured throughout the month, based on the resource's availability during any Shortage Events in the Obligation Month.

A Shortage Event is any period of thirty or more contiguous minutes of system-wide Reserve Constraint Penalty Factor activation, as a result of being short of operating reserves.

For each Shortage Event, the ISO calculates a Shortage Event Availability Score for each resource, as follows. For each hour containing any portion of the Shortage Event, the ISO multiplies the resource's hourly availability score by the number of minutes of Shortage Event in that hour, and then divides the product by the total number of minutes in the Shortage Event. The resulting values for each hour shall then be added together to determine the resource's Shortage Event Availability Score.

The ISO calculates an availability score for each resource for every hour that contains any portion of a Shortage Event. A resource's availability score for an hour, expressed as a percentage which may not exceed 100 percent, shall be the sum of the resource's available MW divided by the resource's Capacity Supply Obligation. In the event that there are no Shortage Event hours in a month, no availability penalties will be assessed. The availability score has also aim to distinguish between reliable and not reliable resources. Prior to the Forward Capacity Auction qualification process, the ISO determines whether a resource meets the following two criteria: in the most recent four consecutive Capacity Commitment Periods or the most recent 4 years in which the resource assumed a Capacity Supply Obligation, (a) the resource received 3 annual availability scores of less than or equal to 40 percent and (b) the resource has failed to be available in its entirety during ten or more Shortage Events during the same period.

The annual availability score for each Capacity Commitment Period is the average of all the availability scores calculated for each hour of each Shortage Event. If both the above criteria are met, the resource is considered a Poorly Performing Resource and is not eligible to participate in any subsequent Forward Capacity Auctions, nor may it assume an obligation through the reconfiguration auctions, or Capacity Supply Obligation Bilaterals until it either achieves an availability score of 60 percent or higher in three consecutive Capacity Commitment Periods or 3 consecutive years, or demonstrates to the ISO that the reasons for the inadequate availability scores have been remedied.

Availability penalties shall be assessed for each resource with a Capacity Supply Obligation as of the beginning of the Obligation Month. For capacity resources that are partially or fully unavailable during a Shortage Event:

- Penalties are determined and assessed on a resource-specific basis. Penalties are calculated for each Shortage Event during an Obligation Month and assessed on a monthly basis;
- The penalty per resource for each Shortage Event is:

*Penalty = [Resource's Annualised FCA Payment]*PF*[1 – Shortage Event Availability Score]*

Where: the *Annualised FCA Payment* is the relevant Capacity Clearing Price multiplied by the resource's Capacity Supply Obligation at the beginning of the Obligation Month multiplied by 12. The PF stands for penalty factor and it is equal to 0.05 for Shortage Events of 5 hours or less. The PF is increased by .01 for each additional hour above 5 hours.

The following Table 3 summarises the availability penalties applying to capacity generating resources and the caps applying to the penalties.

Penalty	Generators
Penalty formula	Penalty per event =annual capacity payment ($) × PF × (1 - Shortage Event Availability Score)
Minimum penalty per shortage event	5% of annual capacity payment
Daily penalty cap	10% of annual capacity payment
Maximum monthly penalty	250% of monthly capacity payment
Maximum annual penalty	Net annual revenues (i.e., annual capacity payment *peak energy rent)
Capacity value derated for future delivery years	Yes, based on past underperformance
Other penalties	A resource may be excluded from the FCA for three years if in a four-year period, it receives three annual availability scores of 40% and it is unavailable during 10 or more shortage events. FERC referral for failing to offer capacity into the energy market

Table 3: Penalties in FCM of ISO-NE.

7 Collateral for participating in the PJM and ISO-NE forward capacity markets

This Section illustrates the financial requirements for participating in the forward capacity markets of both PJM and ISO-NE.

7.1 Financial requirements for the RPM of PJM

PJM establishes a set of minimum training, risk management, communication and capital or collateral requirements for Participants in the PJM markets. The Credit Policy is the document outlining the rules governing the above requirements.

First of all PJM reviews and verifies, as applicable, participants' risk management policies, practices, and procedures with regard to their activities on the PJM markets. The review must include verification that:

- The risk management framework is documented in a risk policy addressing market, credit and liquidity risks.
- The participant maintains an organisational structure with clearly defined roles and responsibilities that clearly segregate trading and risk management functions.
- There is a clear regulation specifying the types of transactions into which traders are allowed to participate.
- The participant requires traders to have adequate training for their authority in the systems and PJM markets in which they carry out transactions.
- As appropriate, risk limits are in place to control risk exposure.
- Reporting is in place to ensure that risks and exceptions are adequately communicated throughout the organisation.
- Processes are in place for qualified independent reviews of trading activities.
- As appropriate, there is periodic valuation or mark-to-market of risk.

For capitalisation requirements, participants must demonstrate a tangible net worth in excess of $500,000 or tangible assets in excess of $5 million. Demonstration of tangible assets and net worth may be satisfied through the presentation of an acceptable corporate guarantee, provided that both (i) the guarantor is an affiliate company that satisfies the tangible net worth or tangible assets requirement, and; (ii) the corporate guarantee is either unlimited or at least $500,000. If the corporate guarantee presented by the participant to satisfy these capitalisation requirements is limited in value, then the amount usable for satisfying credit requirements will be the face value less $500,000 and less an additional 10% of the reminder; also, any additional collateral will be reduced in value by 10%.

If a participant does not satisfy the minimum capitalisation requirements above, it may still qualify to participate in PJM's markets by posting additional collateral. Such collateral will be restricted as follows:

(i) Collateral provided by other participants that engage in virtual bidding shall be reduced by $200,000 and then further reduced by 10%,

(ii) and (ii) collateral provided by other Participants that do not engage in virtual bidding shall be reduced by 10%.

These reduced collateral values will be considered the financial security available to satisfy the credit policy requirements. In the case of a participant that satisfies the minimum participation requirements through the provision of collateral also providing a corporate guarantee to increase its available credit, then the participant's resulting unsecured credit allowance conveyed through such a guarantee shall be the lesser of (i) the applicable unsecured credit allowance available to the participant by the corporate guarante pursuant to the creditworthiness provisions of the credit policy, or (ii) the face value of the guarantee, reduced by 10%.

In addition, PJM establishes and monitors credit requirements on two general levels: long-term and short-term. The long-term requirement establishes the credit (unsecured or secured) that a participant must maintain with PJM. The short-term requirement involves measuring current obligations and comparing them with a working credit limit to see if current exposure has reached or exceeded a participant's working credit limit.

Resources that are offered into an RPM auction, resources that subsequently clear an RPM auction, and resources that are offered as part of an FRR plan must provide credit if they are 'planned' resources.

The RPM credit requirement is the RPM auction credit rate times the MW submitted or committed. The auction credit requirement is determined separately for each delivery year, and the total RPM credit requirement for a participant is the sum of all of its individual RPM credit requirements. Credit must be provided prior to an auction for planned resources offered in the auction, but the requirement will be reduced after the auction based on the amount of MW that cleared and the auction credit rate resulting from the auction.

The auction credit rate is given by the greater between $20/MW-day or 0.24 times the Capacity Resource Clearing Price in the Base Residual Auction for the Delivery Year for the Locational Deliverability Area within which the resource is located, times the number of days in the Delivery Year.

7.2 Financial requirements for the ISO-NE FCM

Financial requirements for participation in the ISO-NE markets are defined in the ISO-NE Financial Assurance Policy. This document aims to establish:

- The minimum criteria for participation in the New England Markets;
- A financial assurance policy for Market Participants.

Each customer and applicant must annually submit a certificate stating that the customer or applicant has (i) either established or contracted for risk management procedures that are applicable to participation in the New England Markets, and (ii) has established or contracted for appropriate training of relevant personnel applicable to participation in the New England Markets. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant and must be notarised. Applicants failing to provide this certificate will be prohibited from participating in the New England Markets until the omission has been rectified.

The ISO may also require any applicant or customer to submit to the ISO or its designee the written risk management policies, procedures, and controls applicable to its participation in the New England Markets. If an applicant fails to submit the relevant written policies, procedures, and controls as required, then the applicant will be prohibited from participating in the New England Markets

The ISO will assess whether the policies, procedures, and controls conform to prudent risk management practices, which include, but are not limited to (i) addressing market, credit, and operational risk; (ii) segregating roles, responsibilities, and functions in the organisation; (iii) establishing delegations of authority that specify which transactions traders are authorised to enter into; (iv) ensuring that traders have sufficient training in systems and the markets in which they carry out transactions; (v) placing risk limits on control exposure; (vi) requiring reports to ensure that risks are adequately communicated throughout the organisation; (vii) establishing processes for independent confirmation of executed transactions and (viii) establishing periodic valuation or mark-to-market of risk positions as appropriate.must

In order to be deemed to meet the capitalisation requirements, a customer or applicant must either

(i) Be Rated and have a Governing Rating that is an Investment Grade Rating of BBB-/Baa3 or higher;
(ii) Maintain a minimum Tangible Net Worth of one million dollars; or
(iii) A minimum of ten million dollars in total assets. To meet this requirement a customer or applicant may supplement total assets of less than ten million dollars with additional financial assurance in an amount equal to the difference between ten million dollars and the customer's or applicant's total assets.

The capitalisation requirements do not apply to a customer or applicant with a total financial assurance requirement of less than $100,000. Where a customer or applicant with a total financial assurance requirement of $100,000 or greater fails to meet the capitalisation requirements, the customer or applicant will be required to provide an additional amount of financial assurance. An applicant that fails to provide the full amount of additional financial assurance required as described in subsection (ii) above will be prohibited from participating in the New England Markets until the deficiency has been rectified.

In addition, each applicant must submit proof of financial viability with its membership application and at its own expense. All market participanst in the FCM are required to provide additional financial assurance.

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