MARKET SURVEILLANCE ADMINISTRATOR

Mitigation in electricity markets

MSA Discussion Paper

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Taking action to promote effective competition and a culture of compliance and accountability in Alberta's electricity and retail natural gas markets

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1 Executive summary

Alberta has embarked on the design of a capacity market. As a result, Alberta's electricity market would include markets for capacity, energy, and ancillary services. Competition generally results in the best market outcomes for consumers. In this context, this means consumers are provided reliable and safe electricity at the lowest cost over time. However, as electricity markets tend to exhibit characteristics that are advantageous for market participants wishing to exercise market power, these markets may not be competitive. As such, a common characteristic of these markets are rules that mitigate market prices so to ensure competitive market outcomes. Some of these characteristics have been identified as being present in Alberta's current electricity market and may well continue to be present in future capacity, energy, and ancillary services markets.

It is the MSA's view that decisions about whether and, if so, how to mitigate market outcomes cannot be made until after important market design decisions have been made and key parameters have been selected. However, given the experience of other markets, it does appear that addressing the issue of whether, when, and how to mitigate market outcomes are necessary in completing a final design.

1.1 Why and what to mitigate

Mitigation is a kind of price regulation that limits the ability of participants to behave strategically in the market. It can apply to the capacity, energy, and ancillary services markets. The MSA believes that it should be applied only in the circumstances where efficient market outcomes cannot be obtained as a result of competition alone. It is the MSA's view that in a well-designed market there may be minimal need for mitigation.

Poor market design and excessive supplier concentration are two problems that commonly result in mitigation. While these problems manifest themselves differently, each can lead to concerns around efficiency losses that in turn lead to mitigation to address those losses. In some cases, additional considerations apply where outcomes that might naturally result in a competitive and functional market, such as price volatility, are also for reasons other than efficiency loss deemed to be unacceptable. Mitigation or other methods are sometimes used to address those concerns.

The MSA considers market <u>power</u> mitigation to be measures that offset the effect on the market price of a lack of structural competitiveness. We distinguish this from market <u>design</u> mitigation that offsets the effect on the market price of market design choices that create, maintain, or enhance the ability of firms to exercise market power.

It is important not to conflate these rationales for intervention because the problem that market mitigation is intended to address is different in each case and is important to determining whether mitigation is necessary, how to design an appropriate mitigation scheme if it is, and when it may no longer be necessary. Equally, it is important to identify where market mitigation is aimed at an outcome other than reducing efficiency loss.

There is another important problem in markets such as Alberta's electricity market: the inability to credibly commit to sustaining a market design, including its approach to market mitigation, for a long period of time. This problem is important because the long-lived nature of capital investments requires investors to look far forward and make assumptions about the likely nature of the market in the future.

If it is possible to resolve the problems of poor market design or excessive supplier concentration, such approaches should be considered before resorting to market mitigation. Market mitigation should then be understood as necessary only to the extent that the underlying problem could not otherwise be resolved. An understanding of the conditions under which market mitigation is not necessary is also useful because changing technology and market conditions over time mean that the approach to mitigation may change over time and may eventually, under some circumstances, be rendered unnecessary.

The MSA recognises that market mitigation is a common feature of wholesale electricity markets, particularly in the United States. It is the MSA's view that poor market design decisions result in significant demand for market design mitigation, which is conflated with demand for market power mitigation as a result of supplier concentration and market mitigation that is used to achieve other goals. This results in misunderstanding about the rationale for market mitigation and further poor decisions about whether market mitigation is necessary, how to design an appropriate mitigation scheme when it is, and when it may no longer be necessary. In any event, the observation that 'everyone else mitigates' is not a convincing rationale for Alberta to do so as well.

1.2 When and how to mitigate

If there is a clear and convincing rationale why market mitigation is needed, the next questions to ask are when and how mitigation occurs.

There is considerable experience from other jurisdictions that have incorporated mitigation schemes into their electricity market designs. Regarding 'when,' a key issue is whether to prevent perceived problems before they can occur (sometimes called ex ante mitigation) or to deal with them afterwards (sometimes called ex post mitigation). As a practical matter, these approaches are often employed simultaneously.

Regarding 'how,' key issues that arise include the scope, complexity, comprehensiveness, and cost of implementing and following the mitigation scheme. There is a trade-off between comprehensive mitigation schemes that are relatively complex and costly to administer and alternatives that are simpler and less costly to administer. In particular, design elements that reduce the scope or complexity of mitigation, while allowing cost to be avoided and process to be simplified, are suggestive of such trade-offs.

As with whether and what to mitigate, decisions about when and how to mitigate the market cannot be made effectively without a comprehensive understanding of the high-level design characteristics of the capacity, energy, and ancillary services markets.

1.3 Recommendations

The MSA recommends:

- All market design decisions related to the capacity, energy, and ancillary services markets—including those not specifically related to mitigation—should be clearly articulated and documented. This must include documentation of the alternatives that were available and the analysis and reasons why specific decisions were made. Appropriate analysis of market design decisions necessarily involves cost-benefit analysis and a comprehensive understanding of how market design impacts market efficiency and competition.
- The high-level design characteristics of the capacity, energy, and ancillary services markets should be settled before specific decisions about mitigation are made. This is because it is not possible to make meaningful decisions about why, when, and how to mitigate outcomes in these markets without first developing a comprehensive understanding of the nature of each of these markets—capacity, energy, and ancillary services markets—and the inter-linkages between them.
- In comparing different mitigation schemes, it is critical to consider whether a design that includes a more comprehensive mitigation scheme that is relatively complex and costly to administer is preferable to an alternative that includes a mitigation scheme that is simpler and less costly to administer. Assessment of this trade-off should involve consideration of the costs and benefits of comprehensive mitigation compared to simplified mitigation.
- The mitigation scheme—as with broader market design decisions related to the capacity, energy, and ancillary services markets—should be credible and durable. In other words, for the market to efficiently allocate resources and provide benefit consumers over time, market participants must have confidence that the principle that investments in the market are made by forward-looking, risk-taking investors will persist into the future. Of course, there is not, should not, and cannot be a guarantee that the market design will never change. However, there can be a commitment that when change occurs, it will be principle based.

2 Why and what to mitigate

The decision to move to a capacity market still leaves considerable scope for competition to drive efficient market outcomes that lead to lower costs for consumers. In the MSA's view it is important to understand why we rely on competitive markets to allocate resources and why in the electricity markets tend to feature a large number of rules and standards, which we refer to as an administered market.

2.1 Why allocate resources through competitive markets?

Competitive markets are typically the most efficient way to allocate resources: they find the lowest cost way of providing supply on both an hour-by-hour basis and over time by providing price-based incentives to interested market participants to install the best or most appropriate technology (on both the supply and demand sides of the market). The reason for this is that competitively-determined prices reflect the decisions of all market participants together rather than the views, opinions, and objectives of regulators alone who have less information and relatively weak incentives compared to profit-seeking firms to control cost and be forward-looking.

Provided that certain conditions are satisfied (discussed below), there is no reason why electricity markets cannot allocate resources efficiently. Departures from this relate to how the market is designed (or administered), the nature of market participant concentration, and the credibility of the design itself.

2.2 What is special about designed markets?

Electricity markets are designed markets: there are clear and strict rules about how the product is generated and transmitted to consumers, and competitions plays out in a setting that is formally designed, administered, and monitored. This is due, in part, to the requirement that reliability standards be met and a complex real time coordination problem be solved. As such, electricity markets are generally characterised by, among other things:

- the presence of a central auction mechanism and independently operated transmission network that provide the only way that the physical product can be traded between suppliers and consumers (unless they are located at the same physical location),
- a large number of clearly-defined rules and reliability standards, and
  other industry-specific policies (e.g., adequacy standards such as target reserve margins) and climate objectives (e.g., the Renewable Electricity Program, REP),that explicitly effect market outcomes.

The designed nature of electricity markets has a direct effect on their performance because it raises the possibility that poor design decisions may be made and administratively introduced to the market where all market participants—suppliers, consumers, and intermediaries—and required to interact.

In addition to the possibility of poor design decisions, there may also be concerns about the credibility or stability of the market design over time. This is particularly important for areas of the industry where the relevant capital investments, such as those in generation equipment, tend to be in very long-lived assets that are sunk (i.e., have few valuable alternative uses). For potential investors to be willing to make investments in such assets, it is necessary that they believe that they will have a reasonable chance to recover the full cost or their investment over time. Credibility for investors can also be achieved through long-term contracts but these impose other costs on consumers and efficiency losses on society since they are less flexible and may lock-in particular solutions that may appear in the short-term to be ideal for long periods of time.

The issue of credibility also extends to mitigation. If market participants have reason to believe that the exercise of market power will not be tolerated in the future—especially in the energy market, perhaps because it would result in unacceptable levels of electricity price volatility but for any other reason as well—then they will discount the possibility that this will happen. In other words, participants will not expect to receive substantial revenue from high energy prices in the future if high energy prices are not likely to be allowed to occur frequently. It would not be rationale for them to do otherwise.

Thus, if mitigation is expected in the future then it will be incorporated into expectations of future energy market outcomes and into offers made in the capacity market.

2.3 Non-competitive markets and the rationale for mitigation

For each of the reasons why competitive markets may fail, there is a reason to mitigate market power. Another reason is that price outcomes may be unacceptable for some other policy-related reason. It is the MSA's view that it is important not to mix these reasons. Doing so would obscure the underlying rationale for mitigation and therefore understanding of how mitigation is best to occur, should it be necessary, and when it may no longer be required.

2.3.1 Excessive concentration

A market may be sufficiently concentrated such that it is unlikely to be competitive and price will differ systematically from the market's marginal cost. To the extent that the market can correct this outcome, say by providing a potential entrant an incentive to enter, such a circumstance may be tolerable for a period of time. However, if the market does not provide or allow for a credible threat of entry to change this in an acceptable timeframe then the market will not be competitive over time either.

This is a problem in electricity markets. The relevant characteristics of electricity markets include:

a. lack of real time pricing for most consumers;
b. electricity cannot be economically stored;
c. supply from generators may be relatively price inelastic (in the short-run) due to rapidly increasing marginal costs or capacity constraints;
d. there are meaningful barriers to entry since entering the generation market requires sinking a very large fixed cost;
e. electricity is a homogenous product;
f. the spot market clears frequently (technically, it is a repeated game);
g. demand is stable and varies predictably; and
h. limited interconnection capacity with neighbouring jurisdictions.

If there are no elements of the market structure that place a meaningful limitation on the degree of concentration (or even just the size of the largest firms in the market), then the market may fail to be competitive in at least some circumstances. The MSA refers to mitigation that corrects for this kind of market failure as market power mitigation and is distinguished below from mitigation that offsets the effect of poor market design decisions.

2.3.2 Poor market design decisions

The administered nature of electricity markets means that poor market design decisions can result in the market being less competitive than may otherwise be possible. In particular, market design decisions may create, maintain, or enhance the market power of influential firms or reduce the ability of consumers and rivals to offset the exercise of market power (and effectively prevent a competitive response).

For example, in the current market design electricity is not priced until the end of the settlement period (real-time). At this time, there is little price-responsiveness on the part of consumers but generators are able to change the output from a meaningful fraction of the generation fleet. Thus, electricity is priced at a time when generators have substantial relative market power compared to consumers. This is one reason, though certainly not the only reason, for substantial price volatility in the existing energy market. This was a market design decision.

There are alternative market designs, such as day-ahead markets that would price a large fraction of electricity that is produced and consumed well in advance of these actions occurring. In this alternative, both consumers and producers may be somewhat more price-responsive and there would be less of a market power imbalance between market participants, resulting in less price volatility than in the existing energy market. Indeed, pricing electricity on a day-ahead basis would result in electricity being treated much more like other goods and services than it is currently, i.e., not priced right at the time of consumption.

The point here is not that a day-ahead market is desirable but rather that alternative market design decisions can be made that result in more desirable market outcomes. To the extent that certain market design decisions enhance the ability of some market participants to exercise market power, there may be demand for mitigation that is not fundamentally due to market power. The MSA refers to mitigation that corrects for this kind of market failure as market <u>design</u> mitigation.

2.3.3 Lack of design credibility and no reason to pay twice

If market participants have reason to believe that the exercise of market power will not be tolerated in the future—especially in the energy market, perhaps because it would result in unacceptable levels of electricity price volatility but for any other reason as well—then they will discount the possibility that this will happen. From a market design perspective, the cost of committing to mitigation is lessened if it is expected to occur and so it may as well commit to mitigating the exercise of market power to avoid paying generators multiple times for the same costs.

In other words, if market participants are likely to expect that they will not be allowed to exercise market power in the future (and form revenue expectations accordingly), then from a long-run perspective there may be benefit to making this clear at the outset. The MSA refers to mitigation that corrects for this kind of market outcome as <u>design credibility</u> mitigation.

2.3.4 Policy acceptability of market outcomes

There may be policy objectives for the market that go beyond and will not be achieved by allocating resources efficiently. For example, policy may state that it is desirable for prices in the market to be relatively stable; more stable than the market would otherwise achieve. Circumstances such as these may provide another rationale for mitigation. Indeed, market mitigation may be an objective in and of itself. The MSA refers to mitigation that corrects for this kind of market outcome as <u>policy</u> mitigation.

Compared to other reasons that might drive mitigation, this is not necessarily a failure of the market to be competitive. Rather, it is that other outcomes are also sought.

2.4 Mitigation practices in Alberta's current electricity market

While extensive mitigation is a common feature of U.S. electricity markets (capacity, energy, and ancillary services), there are a number of elements of Alberta's current electricity market that have the effect of limiting the ability of market participants to exercise market power. In some cases, the primary, or only, goal of these features is to mitigate market power. In other cases, it may be that rules mitigate market power but that was not the primary, or even intended, purpose. A selection of these elements is reported in Table 1. Similarly, there are other elements of Alberta's current electricity market that enhance the ability of market participants to exercise market power. A selection of these elements is reported in Table 2.

Table 1: Examples of features of Alberta's current electricity market that mitigate market power

Segment	Ex ante	Ex post
Energy and ancillary service	Offer price cap ($999.99/MWh) and floor ($0/MWh) Must-offer, must-comply rule (with exceptions) Imports can't exercise market power as they are required to offer at $0/MWh Restatement requirements, including the T-2 rule and acceptable operating reasons Information-sharing prohibitions and restrictions on trading using non-public outage records in sections 3 and 4 of the *Fair, Efficient and Open Competition Regulation*	Investigations, including the prospect of investigations, and enforcement actions and the levying of penalties of various types (e.g., disgorgement, administrative penalties, and prohibitions on participation) Market monitoring / surveillance and public reporting Analysis to inform market design decisions
Capacity (not an explicit product / market in current design)	Cap of 30% on the share of dispatchable capacity that any one market participant may control Power Purchase Arrangements (which intend to reduce market concentration)	No explicit ex post consideration of this segment because there are no explicit capacity products

Table 2: Examples of features of Alberta's current electricity market that could enable market power

Segment	Ex ante	Ex post
Energy and ancillary service	Design decision to price electricity in real-time rather than day-ahead No restrictions on offer prices aside from them being bounded by a floor and cap Restatement flexibility	Investigations and enforcement actions can occur well after potentially concerning conduct has occurred
Capacity	No explicit ex post consideration of this segment because there are no explicit capacity products	No explicit ex post consideration of this segment because there are no explicit capacity products

3 When to mitigate: Ex ante vs ex post mitigation

3.1 Definitions

If mitigation is to be implemented, a key issue to consider is *when* it is to be done. A key distinguishing feature among the options is whether intervention occurs before the market price is set (ex ante) or after the market price is set (ex post). What constitutes an inappropriate exercise of market power in the definitions below is left undefined.

- Ex ante mitigation: Under an ex ante approach, intervention to mitigate market prices occurs largely before the market price is set. In this way, the realized market price reflects the absence of the exercise of market power because either (i) it was not exercised or (ii) it was exercised inappropriately (say, by the submission of offer prices that reflected the inappropriate exercise of market power) but mitigated (say, by the replacement of offer prices that reflect the exercise of market power with alternative offer prices that do not reflect the inappropriate exercise of market power) before the market price was determined. Under this approach, mitigation occurs only 'largely' before the price is set because the parameters used to implement mitigation may themselves be subject to ex post assessment (i.e., the parameters used to calculate alternative offers may themselves reflect the exercise of market power, e.g., heat rates that are higher than actual heat rates).
- Ex post mitigation: Under an ex post approach, there is no direct intervention to mitigate market prices before the price is set. Instead, the exercise of market power is mitigated by after-the-fact monitoring, with enforcement and / or compliance action taken against those market participants who are found to have inappropriately exercised market power. Critically, market participants know that their behaviour will be subject to this type of monitoring and compliance activity, which gives them incentives to look forward and consider the impact this will have on them should they inappropriately exercise market

power. Ex post mitigation does not recalculate prices or indices already established in capacity market auctions or real-time energy and ancillary services markets.

Table 3 provides a number of examples of each type of mitigation. These are elaborated and expanded upon in following sections.

Table 3: Examples of each type of mitigation

Ex ante	Ex post
Tests are applied to determine whether market power exists and has been exercised. If so, offers that reflect the exercise of market power may be replaced automatically by cost-based offers before dispatch occurs and the market clearing price is set.	Investigations, including the prospect of investigations, into inappropriate exercises of market power may result in enforcement actions and the levying of penalties of various types (e.g., disgorgement, administrative penalties, and prohibitions on participation).

3.2 Advantages and disadvantages of ex ante and ex post mitigation

The differences between ex ante and ex post mitigation give rise to a variety of advantages and disadvantages. Some of these are summarised in Table 4.

To highlight the complexity of these advantages and disadvantages, consider the example of information requirements. Under ex ante mitigation, there is an ongoing requirement that substantial amounts of firm-specific data (e.g., cost data) be collected in advance of each auction (be it for capacity, energy, or ancillary services) so that mitigation occurs if some set of conditions is satisfied. Under ex post mitigation, while there is no similar requirement for data to be collected in advance of each auction, should an investigation and possible enforcement action occur, all of the data (possibly more) may have to be produced anyway. As such, an apparent disadvantage of ex ante mitigation is the upfront cost of satisfying its ongoing requirements. The associated advantage is that these are known in advance without much uncertainty. By comparison, an advantage of ex post mitigation is that it imposes a lower upfront cost, though its associated disadvantage is that there is greater risk that the cost of satisfying the information requirements would be incurred anyway.

Table 4: Comparison of ex ante and ex post approaches

Mitigation option	Advantages	Disadvantages
Ex ante	Predictable cost of satisfying the substantial upfront and ongoing data requirements Clarity of mitigation rules, definitions, and standards facilitates market participant understanding of what is and is not allowed and greater transparency Timely decisions to mitigate or not Administrative efficiency of mitigation implementation Lack of discretion ensures that rules are always applied in the same manner	Substantial upfront and ongoing data requirements; data are preliminary Clarity of mitigation rules, definitions, and standards means that these conditions must be set Prescriptiveness may result in unnecessary mitigation, i.e., over-mitigation Lack of discretion ensures that rules are applied even in special circumstances, necessitating additional process in the event that exemptions are sought
Ex post	Lesser need for specific rules, definitions, and standards Regulatory discretion allows for special circumstances to be handled with minimal additional process May have more comprehensive data	Time consuming; lags inherent in ex post approaches can mean consumers are insufficiently protected against immediate harm from inappropriate exercises of market power Lack of specific rules, definitions, and standards reduces market participant understanding of what is and is not allowed and transparency Regulatory discretion may be viewed as unfair Uncertainty about enforcement risk

3.3 Approaches to ex ante mitigation

There are two different ex ante mitigation approaches to market power mitigation. These are based on assessments of whether the market structure is conducive to the inappropriate exercise of market power (a structural approach) and whether market participant conduct and performance reflects the inappropriate exercise of market power (a conduct-and-impact approach). Some advantages and disadvantages of these approaches are set out in Table 5.

Table 5: Comparison of ex ante mitigation approaches

Approach	Advantages	Disadvantages
Structural Structural approaches to market power mitigation consider whether the market structure itself is conducive to the inappropriate exercise of market power. When it is, such as when the market found to be is sufficiently concentrated, then mitigation may occur.	Tests examine the number and distribution of sellers Mitigation processes based on structural screens have an advantage as market structure information will not generally change materially on an hourly or daily basis May be used readily to identify markets, time periods, and suppliers Purely structural screen avoids political challenges or bid or price-impact thresholds	Difficulty defining relevant product and geographical markets Difficulty accurately identifying potential exercise and abuse of unilateral and multilateral market power Uncertainties regarding reliability of the mitigation process (over- and under-mitigation)
Conduct-and-impact Conduct-and-impact approaches to market power mitigation consider whether market participant behaviour reflects the exercise of market power (conduct) in a manner that inappropriately affects market outcomes (impact).	Directly assesses supplier conduct and its impact on market prices: based on an explicit choice of bid and market impact thresholds Can be observed directly by comparing bids and associated prices with competitive reference levels (e.g., marginal cost) Explicitly identifies and mitigates only substantial or unreasonable exercises of market power Reduces over-mitigation risk Readily accommodates after-the-fact analysis as the process is relatively transparent	Requires that competitive reference levels be observable with sufficient accuracy Regulator must specify the price-cost markup threshold that is unacceptable. The threshold is very difficult to establish without complete information. Over-reliance on conduct-and-impact screens may cause regulators to pay insufficient attention to structural mechanisms supporting mitigation on specific markets where market power concerns are greatest

The structural and conduct-and-impact approaches to mitigation are complements. In practice, structural tests can be used to determine whether market conditions are likely to support the inappropriate exercise of market power, with conduct-and-impact methods used to mitigate price where market power has been inappropriately exercised.

The mechanics of capacity and energy (and ancillary services) markets are very different; for instance, capacity markets clear much less frequently than energy and ancillary services markets, and therefore exhibit a narrower range of market conditions. As such, ex ante mitigation is applied somewhat differently in these markets. A selection of ex ante mitigation approaches in selected U.S. capacity and energy markets is reported in Tables 6 and 7.

Table 6: Ex ante mitigation approaches in selected U.S. capacity markets[1]

Jurisdiction	Must-offer obligation	Minimum offer price rule	Structural	Conduct-and-impact	Other
PJM	✓	✓	Market share test, HHI, TPS test	x	Physical withholding
MISO	✓	x	PST	✓[2]	Physical withholding
NYISO	✓	✓	PST	✓	Physical withholding
ISO-NE	✓	✓	PST, inadequate supply or insufficient competition rule	✓	Physical withholding, de-list mitigation for existing resources

[1] Note on definition of acronyms in Tables 5 and 6: Herfindahl-Hirschman index (HHI), three pivotal supplier (TPS), pivotal supplier test (PST), and automated mitigation procedure / process (AMP).

[2] https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/RASC/2017/20170208/20170208%20RASC%20Item%2002k%20Module%20D%20PRA%20Primer.pdf

Table 7: Ex ante mitigation features in selected U.S. energy markets

Jurisdiction	Day-ahead	Hour-ahead	Real-time	Structural test	Conduct-and-impact test	Price / bid cap
PJM	✓	x	✓	TPS test	x	✓
CAISO	✓	✓	✓	TPS test	AMP	✓
MISO	✓	x	✓	x[3]	AMP	✓
NYISO	✓	Schedule	✓	x	AMP	✓
ISO-NE	✓	x	✓	PST, Constrained Area Test	✓	✓

3.4 Approaches to ex post mitigation

Ex post approaches to mitigation seek to deter inappropriate exercises of market power in advance by raising the prospect of:

- Investigation and enforcement, including the prospect of investigation and enforcement
- Levying of penalties of various types, e.g., disgorgement, administrative penalties, and prohibitions on participation
- After-the-fact mitigation
- Market monitoring / surveillance and public reporting
- Analysis to inform market design decisions

In contrast to ex ante mitigation, the general approaches to ex post mitigation are typically the same in capacity, energy, and ancillary services markets, as well as across jurisdictions.

3.5 Application to mitigation to sequentially clearing capacity and energy markets

Market power in the capacity market and energy market may be mitigated either ex ante or ex post. Four possible combinations are considered in Table 8: (i) ex ante in both markets; (ii) ex post in both markets; (iii) ex ante in the capacity market and ex post in the energy market; and (iv) ex post in the capacity market and ex ante in the energy market.

[3] https://www.ferc.gov/legal/staff-reports/2014/AD14-14-mitigation-rto-iso-markets.pdf

Table 8: Various combinations of mitigation options

Mitigation option	Advantages	Disadvantages
Ex ante in both markets	Regulatory efficiency Greater transparency Reduced risk as MPs understand rules better Timeliness Clearly defined rules	Monitoring requirements: may change to be more data focused / truthful submissions Unnecessary mitigation (over-mitigation) Clarity of definition (may also be incorrect) Structural tests do not differentiate geographical markets and suppliers. Too broad and has a higher probability of failing to observe market power when there truly is market power, leading to higher costs
Ex post in both markets	May have more comprehensive data Do not need specific rules Regulatory / enforcement discretion Several factors make it difficult to know resource's actual costs ex ante	Lack of specific rules Uncertainty about enforcement risk Slow, potentially costly, uncertain and burdensome investigations Delays from ex-post mitigation designs may lead to under-mitigation May not fully undo the harm Lags inherent in ex post approaches can mean consumers are insufficiently protected against immediate harm from market power abuses

Ex ante in capacity Ex post in energy & AS	As energy and ancillary services clears hourly / day-ahead, ex post mitigation could be conducted far enough in advance giving enough time to look at auction results	*Ex ante in capacity:* Ex ante screens have difficulty defining relevant product and geographical markets. If applied to capacity markets, with zonal pricing, the risk of over-mitigation could cause unnecessary resource exit as costs may exceed price they are able to offer into the market. *Ex post in energy and ancillary services:* If prices are not adjusted through ex ante mechanisms, long term contracts in capacity markets could result in higher prices and would be more costly. Risk falls to consumers. Insufficient mitigation: consumer harm Inconsistency of approach across markets
Ex post in capacity Ex ante in energy & ancillary services	If efficient mitigation occurs in energy and ancillary services there may be less likelihood market power is exercised in capacity markets Pool price is adjusted ex ante, which would be reflected in capacity LTCs Despite frequent mitigation of bids down to marginal cost, incentives remain to lower costs in energy and ancillary services to earn infra-marginal rents	*Ex ante in energy and ancillary services:* *Over-mitigation resulting in:* Price distortion (reduced prices) Risk of long term investment loss Reduces incentives for consumers to self-hedge *Ex post in capacity:* Resource adequacy issues Generators not over-mitigated to exercise market power as reliability is reduced in capacity market May result in higher prices at a cost to the consumer Inconsistency of approach across markets

4 How to mitigate: Reducing scope and complexity

If mitigation is to be implemented, another key issue to consider is *how* it is to be done. This section considers two options related to the design of mitigation schemes that reduce the scope of mitigation by creating so-called safe harbours and reduce the complexity of mitigation by incorporating proxies.

Of course real mitigation schemes have many more elements. An extensive jurisdictional review of how mitigation schemes that exist in several U.S. jurisdictions with capacity markets is reported in Appendices A through G.

4.1 Safe harbour

4.1.1 Definition

The scope of mitigation schemes can be reduced by setting out safe harbours. A market participant may be given safe harbour from exercise of market power—that is, not subject to mitigation—if there is reason to believe that they do not have market power and therefore have neither the ability nor the incentive to exercise it in a manner which would not support fair, efficient, and open competition. Generally speaking, safe harbour from action related to the exercise of market power is only provided to sufficiently small firms, where the definition of 'sufficient' is set out in the safe harbour rule.

If they exist, safe harbour rules are typically defined in an explicit and transparent manner such that market participants know in advance whether they are eligible for safe harbour, or not. To be clear, safe harbour rules do not provide a guarantee that market monitors will not monitor and investigate as appropriate.

4.1.2 Purpose of safe harbour

The purpose of market mitigation is to undo the effect of factors—excessive concentration, poor market design decisions, the inability to credibly commit to future market design and enforcement decisions—that can result in market outcomes not being competitive. Since safe harbour is defined by conditions under which market participant conduct likely supports fair, efficient, and open competition, the basic idea is that it provides eligible market participants with some degree of certainty in advance that they will not be subject to mitigation. Ineligible market participants are subject to mitigation as provided by the relevant rules.

From the perspective of the MSA, such a rule saves resources from being applied to circumstances that are likely to be of little competitive concern. A summary of advantages and disadvantages of creating safe harbours is reported in Table 8.

Table 8: Advantages and disadvantages of creating safe harbours

Advantages	Disadvantages
Administratively simple for market participants and regulators Based on a simple proxy for market power Less regulatory uncertainty for market participants Reduces market uncertainty. Predictability is particularly important with competition law application Clear and pre-established parameters	May not effectively mitigate: thresholds and safe harbours based on market shares as a first screen to discriminate between unproblematic and problematic scenarios, may over- or under-estimate the market power of firms and the potential competition effects, i.e., there is some probability that exercises of market power will fail to be identified and mitigated and some probability that mitigation will occur without an exercise of market power May be costly Imperfect information between regulators and market participants Historical data used may not accurately represent current economic conditions

4.1.3 Practicalities and examples of safe harbours

Safe harbours exist or have existed in a number of electricity markets. For example, in the ERCOT market there is a rule that, in simple terms, states that market participants that hold a less than 5 percent share capacity in the market are deemed to not have market power. This rule effectively creates a safe harbour for such firms from allegations of abuse of market power because they have been deemed to not have any.

In the context of the Alberta electricity market, the MSA's now-revoked Offer Behaviour Enforcement Guidelines can be viewed as having provided a safe harbour from concern about economic withholding that was unrelated to conduct that may create, maintain, or enhance the market power of any market participant, including extensive conduct or conduct that impeded a competitive response from any market participant. In this way, the OBEG provided many of the advantages set out in Table 8 but was revoked when sufficient uncertainty emerged around the market design that the overall market ceased to be competitive.

By contrast, the MSA does not view the 30 percent capacity share limitation set out in section 5 of the *Fair, Efficient and Open Competition Regulation* as a safe harbour. For example, a merger of two firms that combined had less than 30 percent share of capacity, while within the limitation of section 5, may not be acceptable for other reasons. The MSA has commented publicly on this particular matter in the past.

4.2 Proxies

Mitigation schemes in jurisdictions with capacity markets are complicated for market participants, system operators, and market monitors alike, and as detailed much further in the appendices, tend to require substantial amounts of information and process to implement.

The complexity of mitigation schemes can be reduced by using proxies. A proxy is an approximation of some variable of interest that can be used in its place. For example, if in the context of an ex ante mitigation scheme a generator's offers are found to be sufficiently far in excess of marginal cost that mitigation is implemented, there must be a process to decide the level to which the offers will be adjusted.

In comparing different mitigation schemes, it is critical to consider whether a design that includes a more comprehensive mitigation scheme that is relatively complex and costly to administer is preferable to an alternative that includes a mitigation scheme that is simpler and less costly to administer. If proxies can be defined that reduce the complexity of mitigation schemes, the comparison of different mitigation schemes will involve consideration of the trade-off between a mitigation scheme's complexity and the cost of its implementation.

To continue the example above, calculating a generator's marginal cost is costly and regulators face an inherent informational disadvantage in doing so compared to the generator's owner. As a practical matter, these problems may be avoided by defining a relatively simple proxy for variable cost that approximates marginal cost. This suggests that there may be a trade-off between design elements that must be considered when designing the mitigation scheme, if there is one.

A summary of advantages and disadvantages of using proxies in a mitigation process is reported in Table 9.

Table 9: Advantages and disadvantages of using proxies in a mitigation process

Advantages	Disadvantages
Administrative simplicity compared to requirements of exact calculations: Data non-intensive process Transparency, foreseeability, and predictability: Application threshold and calculation can be articulated clearly in advance in rules / processes Potentially less scope for gaming and manipulation: To the extent that mitigation is based on proxies that firms have little ability to impact compared to variables they do have the ability to impact, the ability to game or manipulate the extent of mitigation is reduced	Imperfect information between regulators and market participants may lead to the wrong level for the proxy being chosen If the level is 'too high' then market may be under-mitigated and consumers may be harmed If the level is 'too low' then the market may be over-mitigated

Appendices: Overview of mitigation approaches in selected electricity markets

Summary of appendices

Ex ante mitigation

Ex post mitigation

Summary of appendices

This appendix reviews and summarizes the various approaches to market power mitigation in the energy, ancillary services, and capacity markets in NYISO, ISO-NE, and PJM. The mitigation schemes addressed provide a foundation for discussion of Alberta's capacity market design, including the design for market power mitigation. The market monitor plays a fundamental role in market power mitigation across U.S. jurisdictions with capacity markets. This appendix details the functions of the market monitor and the requirements for implementing mitigation.

There is no common definition of market power across the markets studied. Defining market power in electricity markets is important as appropriate product, geographic and temporal markets are essential for the accurate evaluation of market power and subsequent mitigation. The product markets are defined as supply capable of meeting a constraint (PJM), or as a supply bid or output which is compared against a predefined threshold (NYISO, ISO-NE). Temporal markets include hourly spot, real-time, day-ahead, monthly, seasonal and annual markets. Geographic markets are often based on constrained versus unconstrained regions.

As there is no common definition of market power, the manner in which U.S. electricity markets implement market power mitigation, particularly in regard to capacity markets, varies. There is significant variation in the methods and designs of U.S. market power mitigation, each of which is highly complex, requiring a considerable amount of information and public resources to implement and enforce.

Market power mitigation may be applied indirectly prescribing thresholds for offers subject to mitigation, or conduct that distorts market competitive outcomes (ISO-NE and NYISO), or may be applied through the use of market concentration tests (PJM, ISO-NE, and NYISO). Policymakers have a fundamental choice as to when mitigation is applied, as it may be implemented before the market clearing price is set (ex ante) or after the market price is set (ex post). If mitigation occurs ex ante, offers are evaluated against default offer reference levels as determined by the market monitor. The market monitor may also consider the impact of offer prices on market clearing price levels. Alternatively, market monitors may apply mitigation ex post and use cleared offer data to assess whether offers were anticompetitive.

A key role for the market monitor is the measurement of marginal cost for default offer reference levels. The calculation of default offer reference levels requires the calculation of estimated generation costs, particularly opportunity costs and fuel costs. The data gathering and calculations required to generate the cost data requires significant resources. However, there are methods of mitigation that simplify or reduce market monitor decision-making. These include the use of safe harbours or the incorporation of proxies. For example, a safe harbor and proxy may include constrained region identification. Constrained area tests mitigate offers on more stringent and less stringent region thresholds and may trigger further structural mitigation screens (NYISO, ISO-NE, PJM). Structural mitigation may be applied in cases where a market participant is located in a constrained region to determine whether an offer is subject to price mitigation. Alternatively, if a market participant is located in an unconstrained region, it may be assumed that the region is sufficiently competitive and that prices reflect an efficient level.

Market power mitigation highlights the issue of credibility in market design. Threat of mitigation may affect market participants' behaviour as they must form price expectations in each market if they are to profitably enter and stay in the market. Price mitigation may cause a market participant to self-select a default offer reference level (PJM), or to have one selected by the market monitor on the lesser of a price or cost-based level (ISO-NE, NYISO). In order to credibly apply mitigation, the market monitor must collect a significant amount of information relating to costs, not only for the purpose of changing mitigated offers, but also for the evaluation of exemptions to mitigation measures, or ex post filings to impose sanctions or monitor market participants.

A primary motive for an efficient market power mitigation design is to address market failure. As such, regulators must weigh the costs associated with regulation, investor and consumer risk, errors in calculations, insufficient or inaccurate cost information, and foregone alternatives as a result of capacity market policy implementation. This appendix does not assess whether existing market power mitigation designs are appropriate, nor does it recommend how Alberta should mitigate the exercise of market power. It is intended to lead to a more comprehensive understanding of how market power mitigation procedures have been implemented in other jurisdictions.

A PJM energy market mitigation

A.1 Summary of definitions used in this appendix

In this Appendix,

a) **"PJM"** means PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement;
b) **"PJM Manuals"** mean those documents, including business rules, produced by PJM that describe detailed PJM operating and accounting procedures that are made publicly available in hard copy and on the Internet;
c) **"Market Participant"** means an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region. "Market Participant" will not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale;
d) **"Market Monitor"** means the head of the Market Monitoring Unit;
e) **"Commission"** means the Federal Energy Regulatory Commission;
f) **"PJM Open Access Transmission Tariff ("O.A.T.T.")"** or the **"PJM Tariff"** means the Open Access Transmission Tariff of PJM Interconnection, L.L.C., on file with the Federal Energy Regulatory Commission, and as revised from time to time;
g) **"Locational Marginal Price"** means the marginal price for energy at the location where the energy is delivered or received. LMP is a pricing approach that addresses Transmission System congestion and loss costs, as well as energy costs.

A.2 Overview of energy & ancillary services market mitigation

A.2.1 Three pivotal supplier test

PJM's energy market three pivotal supplier test (TPS) is a structural mitigation screen used to test potential exercise of market power. The TPS assists in the evaluation of competitiveness by comparing supply to demand. The test is triggered in real time when PJM's dispatch algorithm determines that a transmission constraint is binding in a particular area.[4]

The TPS test measures the required degree of supply from three generation suppliers against the necessary demand to relieve a constraint. As supply can be constrained by three resource owners, and demand could potentially not be met, all three are considered to have structural market power.[5] As a result, if one supplier fails the test, the largest two suppliers also fail. Upon a test failure, mitigation is implemented as a preventative step. This does not implicate suppliers are attempting to exercise market power. If a resource is brought on because a transmission constraint binds and its owner fails the TPS test, the resource is offered at a reference level-based offer cap, determined as the lower of its cost or offer price. If mitigation is implemented, it

[4] Monitoring Analytics (2007). Page 2. http://www.monitoringanalytics.com/reports/Presentations/2007/20070718-mmu-tps.pdf
[5] PJM (2017). Day-Ahead Energy Market. Page 49. http://www.pjm.com/~/media/training/nerc-certifications/markets-exam-materials/generation-itp/day-ahead-energy-market.ashx

occurs before the algorithm run that determines dispatch and locational marginal prices (LMPs).[6]

For the purposes of conducting a TPS test, the following conditions apply and are detailed in the PJM Tariff:[7]

> (i) All megawatts of available incremental supply for which the power distribution factor ("dfax")[8] has an absolute value equal to or greater than the dfax used by the Office of the Interconnection's system operators when evaluating the impact of generation with respect to the constraint ("effective megawatts") will be included in the available supply analysis at costs equal to the cost-based offers of the available incremental supply adjusted for dfax ("effective costs"). The Office of the Interconnection will post on the PJM website the dfax value used by operators with respect to a constraint when it varies from three percent.
>
> (ii) The three pivotal supplier test will include in the definition of the relevant market incremental supply up to and including all such supply available at an effective cost equal to 150% of the cost-based clearing price calculated using effective costs and effective megawatts and the need for megawatts to solve the constraint.
>
> (iii) Offer price caps will apply on a generation supplier basis (i.e. not a generating unit by generating unit basis) and only the generation suppliers that fail the three pivotal supplier test will have their units that are dispatched with respect to the constraint offer capped.
>
> (iv) In the Day-ahead Energy Market, the Office of the Interconnection will include price sensitive demand, Increment Offers and Decrement Bids as demand or supply, as applicable, in the relevant market.

The TPS is based on the Residual Supplier Index (RSI) rather than the Pivotal Supplier Index (PSI). The PSI considers whether or not a generator is pivotal for meeting demand while the RSI is measured on a continuous scale.[9] This allows more flexibility when evaluating the possibility that a firm can exercise market power.[10]

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[6] FERC (2014). Page A-15. https://www.ferc.gov/legal/staff-reports/2014/AD14-14-mitigation-rto-iso-markets.pdf

[7] PJM Tariff, Section 6.4.1 (f). http://www.pjm.com/directory/merged-tariffs/oa.pdf

[8] "dfax" is the methodology that PJM uses to calculate how much of a firm's generation flows over a particular transmission path and therefore the effect that additional flow would have on that path.

[9] Trebilcock, M and Yatchew, A. (2007). Page 52. https://www.oeb.ca/documents/msp/market_power_framework/submissions/market_power_framework_comments_opgtrebilcock_20070509.pdf

[10] Trebilcock, M and Yatchew, A. (2007). Page 52. https://www.oeb.ca/documents/msp/market_power_framework/submissions/market_power_framework_comments_opgtrebilcock_20070509.pdf

The TPS test for firm *j* is defined as:[11]

$$RSI3_j = \frac{\sum_{i=1}^{N}(s_i) - \sum_{i=1}^{2}(s_i) - s_j}{D}$$

In the above calculation, "*i*" indexes the firms by effective generation capacity in a particular area from largest to smallest, "*D*" is the quantity of electricity that is required to relieve the constraint that distinguishes that area from the broader market, and "s_i" is the supply of firm *i* that is available in that area.[12]

A.2.2 Implementation process for the TPS test

Implementation of the TPS proceeds in three steps:

i. Group effective generation capacity by supplier.
ii. Order suppliers by effective generation capacity in descending order.
iii. Test each supplier against the two largest suppliers to determine TPS score (RSI3).

If $RSI3_j > 1$, then the TPS test is passed and firm *j*'s offers are accepted as submitted.[13] If $RSI3_j \leq 1$, then the TPS test is failed and mitigation is applied to firm *j*'s offers. In such an event, its offer prices are automatically changed to its reference level, which is discussed in section A.4.[14]

Frequency of testing

Tests are applied when binding transmission constraints arise in any interval of the day-ahead and real-time markets. Tests are applied to individual constraints, one at a time. [15] This means for each constraint, the tests are run as frequently as each hour of the day-ahead market and as frequently as every five minutes for the real-time market.[16]

Products analyzed

Each individual local transmission constraint is considered, including regional transmission interfaces. The PJM market as a whole deemed to be competitive.[17]

Structural test exemptions

Structural tests used to mitigate market power only on local transmission constraints, i.e., not on regional interfaces and PJM market as a whole. In PJM, an exemption from mitigation is also applied to generating units installed in certain zones between 1999 and 2003.[18]

[11] PJM Manual 11: Energy & AS Market Operations. Section 3, Page 77.
http://www.pjm.com/~/media/documents/manuals/m11.ashx
[12] Monitoring Analytics. (2008). Three Pivotal Supplier Test Discussion. Page 2.
http://www.monitoringanalytics.com/reports/Reports/2008/20081031-market-monitoring-to-ferc-litigation-staff-rev.pdf
[13] Monitoring Analytics. (2015). Overview of the Three Pivotal Supplier Test. Page 9.
http://www.pjm.com/~/media/committees-groups/committees/mmuac/20151204/20151204-mmu-tps-education-2015.ashx
[14] Monitoring Analytics. (2015). Overview of the Three Pivotal Supplier Test. Page 9.
http://www.pjm.com/~/media/committees-groups/committees/mmuac/20151204/20151204-mmu-tps-education-2015.ashx
[15] Brattle. (2007). Page 82.
http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[16] Brattle (2007). Page 84.
http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[17] Brattle (2007). Page 82.
http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf

A.3 PJM energy market price caps

Generation resource market based incremental energy offers are capped at $1,000/MWh.[19]An exception may be made in the event of a cost based incremental energy offer exceeding $1,000/MWh. If a cost based incremental energy offer exceeds the threshold, the market based incremental energy offer is capped at the lesser of the cost based incremental energy offer or $2,000/MWh.[20]

In the event that a firm submits a cost-based incremental energy offer exceeding $2,000/MWh, the firm may be eligible to receive a credit for operating reserves. Firms must submit all relevant documentation validating the calculation of costs greater than $2,000/MWh to PJM and the market monitoring unit (MMU). PJM's cost information requirements are detailed in section A.4.

A.4 Reference level calculation

Firms specify in advance their choice of LMP-based, cost-based, negotiated, or frequently mitigated unit offer caps. These are reference level offer caps that are calculated by applying methodologies set out in PJM market manuals for use when offers are required to be cost-based as a result of the application of the TPS test as set out above.

A.4.1 Cost-based reference level

Resources that fail the TPS are mitigated to their reference level offers, which reflect estimated marginal costs. Pursuant to Section 6.4.2 of the PJM Tariff, a cost-based offer price cap will be subject to one of the conditions below, as specified in advance by the Market Participant: [21]

1) For offers of $2,000/MWh or less, the incremental operating cost of the generation resource as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals ("incremental cost"), plus up to 10% of such costs, the sum of which must not exceed $2,000/MWh;
2) For offers greater than $2,000/MWh, the incremental cost of the generation resource. The 10% adder will not apply.

Cost-based information requirements

PJM's Manual 15 details instructions, rules, procedures, and guidelines for PJM market operation, planning, and accounting requirements. Manual 15 also includes information relating to PJM actions, and market participant actions and requirements.

Manual 15 formalises the details and standards implemented to determine cost components for market participants submitting cost-based rates to PJM for products or services. Cost-based offers are used by PJM to schedule generation in cases in which structural market power is

[18] Brattle (2007). Page 80. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[19] PJM Manual 11: Energy & AS Market Operations. Page 25. http://www.pjm.com/~/media/documents/manuals/m11.ashx
[20] PJM Manual 11: Energy & AS Market Operations. Page 25. http://www.pjm.com/~/media/documents/manuals/m11.ashx
[21] PJM Tariff, Section 6.4.2. http://www.pjm.com/directory/merged-tariffs/oa.pdf

found to exist. PJM uses the information provided from market participants to determine each unit's production costs.[22]

Resources in PJM submit one incremental energy offer for the entire operating day. PJM defines incremental production costs but resources calculate their own reference level costs, referred to as "cost-based offers".[23] Resource total production costs include components such as: start-up costs, no-load costs, and incremental costs (energy cost per segment of output range). Components of cost are detailed in Manual 15 as follows:

Generator offer curves

Generator offer curves represent a market participant's willingness to provide energy. The market participant may decide how the monotonically increasing slope of the offer curve is defined.

Start-up cost

Start-up costs are incurred once each time the unit turns on, regardless of the length of time that it is in operation. These costs include the requirement to bring the boiler, turbine, and generator from shut-down conditions to the point of breaker closure, which is typically indicated by telemetered or aggregated state estimator production greater than zero.

$$\begin{aligned} Start\ up\ Cost\ \left(\$/_{Start}\right) &= \left(Start\ Fuel\ \left({}^{MMBtu}/_{Start}\right) * TFRC\ \left(\$/_{MMBtu}\right) * Performance\ Factor\right) \\ &+ \left(Station\ Service\ (MWh) * Station\ Service\ Rate\ \left(\$/_{MWh}\right)\right) \\ &+ Start\ Maintenance\ Adder\ \left(\$/_{Start}\right) + Start\ Additional\ Labor\ Cost\ \left(\$/_{Start}\right) \end{aligned}$$

No-load cost

The no-load cost is the cost incurred by a generator to sustain zero net production while remaining synchronised with the network.

- No-load fuel: total fuel to sustain zero net output MW at synchronous generator speed.
- No-load cost: hourly cost required to create the starting point of a monotonically increasing incremental offer curve for a generating unit.

[22] PJM Manual 15. Section 1.7. http://www.pjm.com/~/media/documents/manuals/m15
[23] FERC (2014). Page 4. https://www.ferc.gov/legal/staff-reports/2014/AD14-14-mitigation-rto-iso-markets.pdf

$$
\begin{aligned}
No\ Load\ Cost\ \left(\$/_{Hour}\right) &= (\ Economic\ Minimum\ Heat\ Input * Performance\ Factor) \\
&\quad * (TFRC + VOM\ \ ) \\
&\quad - \Big(Economic\ Minimum\ Incremental\ Cost\ \left(\$/_{MWh}\right) \\
&\quad * Economic\ Minimum\ (MW)\Big)
\end{aligned}
$$

Variable operations and maintenance cost

Variable operations and maintenance cost is defined as:

$$
\begin{aligned}
&(Total\ Maintenance\ Cost_{Next\ Year}) \\
&\quad = \left(Annual\ Maintenance\ Cost * \frac{Escalation\ Index^{next\ year}}{Escalation\ Index^{current\ year}} \right) \\
&\quad + \left(Annual\ Maintenance\ Cost * \frac{Escalation\ Index^{next\ year}}{Escalation\ Index^{\ last\ year}} \right) \\
&\quad + \left(Annual\ Maintenance\ Cost * \frac{Escalation\ Index^{next\ year}}{Escalation\ Index^{last\ year-1}} \right) \dots \\
&\quad + \left(Annual\ Maintenance\ Cost * \frac{Escalation\ Index^{next\ year}}{Escalation\ Index^{last\ year-(maintenance\ period-1)}} \right)
\end{aligned}
$$

where the “escalation index” is annual escalation index derived from the July 1 Handy - Whitman Index Table E-1, line 6, “construction cost electrical plant.”

Maintenance costs for mature and immature units vary and the information requirements for each unit type are detailed in Manual 15.

Incremental cost

Hourly production cost is the cost per hour to operate a unit assuming a start has already occurred. The incremental energy cost is the cost per MWh to produce all of the energy segments above the economic minimum level.

To determine the total production cost of a unit, the following formula is used:

$$
Total\ Production\ Cost = Startup\ Costs + \sum_{0}^{x} Hourly\ Production\ Costs
$$

PJM will schedule generation day-ahead based on the above but dispatch using the incremental (marginal) cost, as represented by its generation offer. The incremental (marginal) cost will represent the cost to generate the next MW from the unit.

Components of cost-based offers for all unit types

Manual 15 also contains information that is relevant for the development of a cost-offer for all types of units pursuant to a fuel cost policy that must be approved by PJM.

Heat rates

The total heat rate for a unit is defined as

$$Total\ Heat\ Rate = \frac{MMBtu}{MWh} = \frac{Heat\ Input}{Net\ MW}$$

A unit's incremental heat rate is defined as the relationship between an additional unit of output and the heat input necessary to produce it. It is defined as

$$Incremental\ Heat\ Rate = \frac{\Delta MMBtu}{\Delta MWh} = \frac{(Change\ in\ Fuel\ Going\ in)}{(Change\ in\ Fuel\ Coming\ Out)}$$

Performance factors

There are three options available for use in determining a unit's performance factor. They are:

- Total fuel, which is defined as

$$Performance\ Factor = \frac{Total\ Actual\ Fuel\ Consumed}{Total\ Theoretical\ Fuel\ Consumed}$$

- Separate, which is defined as

$$Operating\ Fuel\ Performance\ Factor = \frac{Total\ Actual\ Fuel\ Consumed - Actual\ Start\ Fuel\ Consumed}{Total\ Theoretical\ Fuel\ Consumed - Theoretical\ Start\ Fuel\ Consumed}$$

- Fixed start approach, which is defined as

$$Operating\ Fuel\ Performance\ Factor = \frac{Total\ Actual\ Fuel\ Consumed - Total\ Theoretical\ Start\ Fuel\ Consumed}{Total\ Theoretical\ Fuel\ Consumed - Total\ Theoretical\ Start\ Fuel\ Consumed}$$

Fuel costs

A market seller may only submit a non-zero cost-based offer if it has a PJM-approved Fuel Cost Policy consistent with each fuel type on which the resource can operate.

$$Total\ Fuel\ Related\ Costs = Fuel\ Costs + Fuel\ Related\ Costs + SO_2 Allowance\ Cost + CO_2 Allowance\ Cost + NO_x Allowance\ Cost + Maintenance\ Adder$$

Submission of and / or modifications to fuel cost policies

Annual reviews

The MMU will review the Fuel Cost Policy, and will consult with the market participant, to determine whether the fuel cost policy raises market power concerns.

Outside annual review / new resource

If a resource is transferred to another market participant, the market participant must submit an approved fuel cost policy prior to submitting non-zero cost-based offers. Existing resource cost-based offers are based on previously approved fuel cost policy.

Types of fuel cost

There are three types of fuel costs: basic fuel cost, incremental energy cost, and total cost.

- *Basic fuel cost:* The cost of fuel calculated as stated in the market participants' Fuel Cost Policy (excluding fixed lease expenses).
- *Incremental energy cost:* The incremental heat or fuel required to produce an incremental MWh at a specific unit loading level multiplied by the applicable Performance Factor, multiplied by the fuel cost plus the appropriate maintenance cost.
- *Total cost:* The total theoretical heat input minus the no-load heat input at a specific unit loading level, multiplied by the applicable Performance Factor, multiplied by the fuel cost plus the appropriate maintenance cost, plus the No-Load Cost.

Emission allowances

Emissions allowances may be included in total fuel related costs for units that require SO2 /CO2 /NOx emission allowances (EAs) to operate. Compliance requirements and dates may vary by geographic region.

Leased fuel transportation equipment

Expenses incurred using leased equipment to transport fuel to the plant gate. If expenses are fixed, they must be excluded from fuel cost determination.

Regulation service

The cost-based regulation offer is split into two portions; capability and performance are detailed under Manual 15 as follows:

$$\begin{aligned}&Regulation\ Capability\ Regulation\ Costs\ \left(\frac{\$}{MWh}\right)\\ &\leq (Fuel\ Cost\ Increase\ and\ Unit\ Specific\ Heat\ Rate\ Degradation\ due\ to\ Operating\ at\ Lower\ Loads)\\ &+ Margin\ Risk\ Adder\end{aligned}$$

$$\begin{aligned}&Regulation\ Performance\ Costs\ \left(\frac{\$}{\Delta MW}\right)\\ &\leq (Cost\ Increase\ in\ VOM\\ &+ Cost\ Increase\ due\ to\ Heat\ Rate\ Increase\ during\ nonsteady\ state\ operation)\end{aligned}$$

Note: The margin risk adder will not exceed $12.00 per MWh of regulation service provided. The above heat rate factor may not exceed 0.35% plus energy storage unit losses divided by ΔMW/MW.

Opportunity costs

A resource may also include opportunity costs that are verifiable. Opportunity costs may be included as a component of cost under certain circumstances and are defined in the Operating Agreement for various products including energy and regulation. Opportunity costs may include:

i. Energy market opportunity costs: This may include a limit on emissions for units imposed by a regulatory framework: a direct run hour restriction in the operating permit, or a heat input limitation defined by a regulatory decision or operating permit.
ii. Non-regulatory opportunity cost: Physical equipment limitations causing units to experience restrictions in the number of starts or run hours.
iii. Non-regulatory opportunity cost: Fuel limitations.

Long term (>30 days): This method uses monthly forward prices as the basis for forecasts of fuel and electricity costs in the future. Opportunity costs calculated with this method will change frequently.

Short term (<30 days): This method uses daily forward prices as the basis for forecasts of fuel and electricity costs in the future. Market Sellers who include opportunity costs in their cost-based offers must recalculate their short term opportunity cost every day.

A.4.2 LMP-based reference levels

The weighted average Locational Marginal Price (LMP) at the generation bus at which energy from the capped resource was delivered during a specified number of hours during which the resource was dispatched for energy in economic merit order.[24]

A.4.3 Frequently mitigated generator reference levels

For generators that are frequently mitigated, the following three rules may be applied.

i. If mitigated more than 80% of time: incremental cost + 10%, incremental cost + $40 or unit-specific going forward costs;[25]
ii. If mitigated between 70 and 80% of time: incremental cost + 15% (not to exceed incremental cost + $40) or incremental cost + $30;[26]
iii. If mitigated between 60 and 70% of time, incremental cost + 10% or incremental cost + $20.[27]

A.4.4 Negotiated mitigation reference levels

A negotiated level agreed upon in advance between market participant and PJM.[28]

A.5 Withholding provisions

Section 23.3 of PJM's Manual 11 details conditions that constitute withholding as the following:

> "Designation of all or part of a unit's capacity as Maximum Emergency (ME) constitutes withholding in the Day-ahead Market, if:

[24] Brattle (2007), Page 78.
http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[25] Brattle (2007), Page 78.
www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[26] Ibid.
[27] Ibid.
[28] Ibid.

i. The capacity is not designated as ME in the bid for the Real-time Market, or;
ii. There is no physical reason to designate the unit as ME.

The consequence of withholding a unit's capacity under ME is:

i. The unit will be given an outage ticket which reflects a de-rating equal to the positive difference in capacity designated Maximum Emergency in the bid for the Day-ahead Market and capacity designated Maximum Emergency in the bid for the Real-time Market.

Reduction of Economic Max MW constitutes withholding in the Day-ahead Energy Market, if:

i. The Economic Max MW is higher in the bid for the Real-time Energy Market than in the bid for the Day-ahead Market, or;
ii. There is no physical reason to designate a lower Economic Max in the bid for the Day-ahead Market bid than in the bid for the Real-time Market.

The consequence of withholding a unit's capacity by reduction of Economic Max MW is:

i. The unit will be given an outage ticket which reflects a derating equal to the positive difference in Economic Max output designated in the bid for the Real-time Market and in the bid for the Day-ahead Market. "

A.6 PJM ancillary service market price caps

PJM's ancillary services market design includes offer caps and cost-based offers for specified units. PJM's Manual 11 sets out the following ancillary service price caps, as illustrated in the table below:

Table A.1: PJM ancillary services market price caps[29]

PJM ancillary service product	Price cap
Regulation	$100/MWh
Responsive reserve	n/a
Spinning reserve	Cost + $7.50/MWh + lost opportunity cost
Non-Spinning reserve	n/a
Forward reserve	n/a
Demand resource	$1,000/MWh plus the applicable Primary Reserve Penalty Factor, minus $1.00[30]

When a reserve requirement cannot be met, the reserve shortage will be priced using the Operating Reserve Demand Curve (ORDC). The ORDC sets a price that serves as a "penalty factor," which acts as a cap on the market clearing price currently set at $850/MWh for Primary and Synchronized Reserves.[31]

FERC subsequently approved the creation of a secondary reserve requirement and adder both effective for hot / cold weather alerts and includes a $300/MWh adder per Primary and Synchronized reserves.[32]

Manual 11 also details the following conditions for emergency or pre-emergency offer prices submitted by Emergency and Pre-Emergency Demand Resources as not exceeding the following:

- 30 minute lead time: $1,000/MWh, plus the applicable Primary Reserve Penalty Factor, minus $1.00;
- Approved 60 minute lead time: $1,000/MWh, plus the applicable Primary Reserve Penalty Factor divided by 2;
- Approved 120 minute lead time: $1,100/MWh.

[29] Brattle (2007). Page 94. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[30] PJM Manual 11: Energy & AS Market Operations. Page 25. http://www.pjm.com/~/media/documents/manuals/m11.ashx
[31] PJM. (2016). Operating Reserve Demand Curve Education. Page 4. http://www.pjm.com/~/media/committees-groups/committees/mic/20160810/20160810-item-11a-ferc-order-825-shortage.ashx
[32] PJM. (2016). Operating Reserve Demand Curve Education. Page 4. http://www.pjm.com/~/media/committees-groups/committees/mic/20160810/20160810-item-11a-ferc-order-825-shortage.ashx

B PJM capacity market mitigation

B.1 Definitions in this appendix

In this appendix,

a) **"MMU"** means Independent Market Monitor for PJM;
b) **"IMM"** means Independent Market Monitor for PJM;
c) **"VRR Curve"** means a segmented downward - sloping demand curve used in PJM's RPM auctions, supporting the primary RPM objective of attracting and retaining sufficient capacity to meet resource adequacy objectives;
d) **"ACR"** means Avoidable Cost Rates. Default ACR Values are calculated as described in Section 6.7(c) of the PJM OATT, Attachment DD;
e) "**Locational Deliverability Area"** means a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Reliability Assurance Agreement, Schedule 10.1;
f) **"Mothballed Unit"** means a mothballed unit is a generating unit placed on inactive status for a defined amount of time (ex. one-to-two years). This unit would be deactivated but not retired.

B.2 PJM capacity market mitigation description

The provisions of the Market Monitoring Plan (Attachment M Appendix to the PJM Tariff and Section 6) apply to the Reliability Pricing Model auctions. Following PJM's base residual and incremental auctions but prior to the Office of the Interconnection's final evaluation of clearing prices and charges, the Office of the Interconnection will apply the following procedures:[33]

i. Market Structure Test to any Locational Deliverability Area (LDA) having a locational price adder greater than zero and to the entire PJM region;
ii. Apply Market Seller Offer Caps; and
iii. Recalculate the optimization algorithm to clear the auction with Market Seller Offer Caps in place.

PJM's threshold for measuring the incremental supply of congestion relief consists of resources able to provide congestion relief. RPM congestion relief depends upon supply and demand conditions and if the region is constrained or unconstrained. Section 6.3 of the PJM Open Access Transmission Tariff, Attachment DD details the determination of incremental supply used in applying the Market Structure Test:[34]

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[33]PJM OATT, Attachment DD, Section 6.2 (b). http://www.pjm.com/~/media/committees-groups/committees/mrc/20161117/20161117-item-05-urmstf-proposal-draft-oatt-attachment-dd-revisions.ashx
[34] PJM OATT, Attachment DD, Section 6.3 (c). http://www.pjm.com/~/media/committees-groups/committees/mrc/20161117/20161117-item-05-urmstf-proposal-draft-oatt-attachment-dd-revisions.ashx

> In applying the Market Structure Test, the Office of the Interconnection will consider all:
>
> (i) incremental supply (provided, however, that the Office of the Interconnection will consider only such supply available from Generation Capacity Resources) available to solve the constraint applicable to a constrained LDA offered at less than or equal to 150% of the cost-based clearing price; or
>
> (ii) supply for the PJM Region, offered at less than or equal to 150% of the cost-based clearing price, provided that supply in this section includes only the lower of cost -based or priced based offers from Generation Capacity Resources.
>
> Cost-based clearing prices are the prices resulting from the RPM auction algorithm using the lower of cost-based or price-based offers for all Capacity Resources.

PJM's capacity market structural tests include, market share, Herfindahl-Hirschman Index (HHI), and the Three Pivotal Supplier test. If a market seller is tested and fails the Three Pivotal Supplier test in the energy market, the seller's resources are committed on the schedule with the least cost among the cost-based schedule, price-based schedule and price-based parameter limited schedule. [35]

Resources are required to submit two price-based schedules to be offered into the day-ahead market. One schedule must be a price based parameter limited schedule. The second price schedule is a price-based schedule that is not parameter limited. In addition to the price-based schedules, one cost-based schedule will be made available for PJM's use in the event that the resource is used to control a transmission constraint. The cost-based schedule must also be parameter-limited.[36] These are discussed in further detail under section B.3 below.

Frequency of testing

Testing follows PJM's auctions: annually for a single delivery year three years forward; up to three incremental auctions allowed during intervening years to allow for changes in supply and demand for capacity.[37]

Cost recovery incentives for planned generators

After the resource clears for one year, a new unit is treated as existing (and potentially subject to offer capping) in the auctions for subsequent years; such resources may, however, receive

[35] PJM Manual 11, Section 2.3.3. http://www.pjm.com/~/media/documents/manuals/m11.ashx
[36] PJM Manual 11, Section 2.3.3 http://www.pjm.com/~/media/documents/manuals/m11.ashx
[37] Brattle (2007). Page 90.
http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf

certain price assurances for two additional years under a New Entry Price Adjustment mechanism. [38]

Structural test exemptions

Offers from planned generation resources will be presumed to be competitive and not be subject to offer capping; however, offers from planned resources can be rejected if the collective amount of new entry is less than twice the incremental amount required to meet demand in a given region or if all of the new entry comes from only one market participant.[39]

Market structure tests

PJM adopts a Preliminary Market Structure Screen (PMSS), based on unforced capacity available for the delivery year from generation capacity resources located in LDA and the PJM region.[40] The PMSS checks each geographic region (LDA) for which a separate Variable Resource Requirement (VRR) curve has been established by PJM for the delivery year to determine if:[41]

i. Any individual market share exceeds 20 percent;
ii. HHI is at a level of 1800 or higher; or
iii. There are three jointly pivotal suppliers.

If any of the above mitigation screens are failed, entities within the LDA or Regional Transmission Organisation (RTO) region are required to submit cost data for subsequent TPS tests during the auction, or alternatively select a resource class-specific default Avoidable Cost Rate (ACR) value. If data is not submitted and a default value is not selected, offer caps for existing generation resources are set to zero. The PMSS serves as a useful tool to determine when mitigation may be needed and also provides an opportunity to collect relevant cost data from market participants prior to the actual auction week.[42]

B.2.1 Market share

Market share is based on market participant specific volumes cleared in each iteration of the temporal market. For example, PJM's day-ahead energy market clears every hour, and market participant market shares are calculated in each hour based on cleared volumes in the relevant hour.[43]

[38] Brattle (2007). Page 91.
http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[39] Brattle (2007). Page 91.
http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[40] Monitoring Analytics (2010). Page 4.
http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf
[41] Monitoring Analytics (2010). Page 5.
http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf
[42] Brattle. (2007). Page 92.
http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[43] Monitoring Analytics (2010). Page 51.
http://www.monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf

Section 6.3 of the PJM Open Access Transmission Tariff details for constrained regions, congestion relief demand is defined as all accepted bids priced above the PJM unconstrained capacity clearing price. Congestion relief supply in constrained regions is defined as bids above the PJM unconstrained capacity clearing price of that region's constrained market clearing price but must fall below 150 percent of that price. For unconstrained regions, demand is all accepted offers, and supply is all offers at or below 150 percent of the unconstrained market clearing price. Only those suppliers who pass the test avoid default mitigation of bids to a level that reflects avoidable cost rates or, opportunity costs.[44] Table B.1 illustrates how supply and demand are defined in PJM's capacity markets for constrained and unconstrained regions.

Table B.1: Market share definitions

Capacity market definition	Constrained	Unconstrained
Supply	Congestion relief supply in constrained regions is defined as bids exceeding the PJM unconstrained capacity clearing price of that region's constrained market clearing price but must fall below 150% of that price	Supply in unconstrained regions is defined as all offers at or below 150% of the unconstrained market clearing price
Demand	Congestion relief demand in constrained regions is defined as: All accepted bids priced above the PJM unconstrained capacity clearing price	Demand in unconstrained regions is defined as all accepted offers

B.2.2 HHI test

A key element of market structure is market share measurement, specifically, resource concentration ratios. The HHI is a mitigation screen determining concentration ratios. HHI is calculated by squaring the market share of each firm competing in the market and totalling the results. HHI increases as the number of firms in the market decreases. A high concentration implies comparatively small numbers of sellers dominate a market, indicating an increased potential for participants to exercise market power. Conversely, low concentration ratios imply a larger numbers of sellers split market sales more equally. However, low concentration ratios do not determine if a market is competitive, or that participants are unable to exercise market power. [45]

[44] Brattle (2007). Page 92.
http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[45] Monitoring Analytics (2010). Page 52.
http://www.monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf

The HHI test for firm *i* is defined as:

$$HHI = \sum_{i=1}^{N} (q_i)^2$$

where q_i is equivalent to the percentage of market share of the i^{th} firm.

- Markets where HHI < 1,000 points are not considered to be concentrated.
- Markets where 1,000 ≤ HHI ≤ 1,800 are considered moderately concentrated.
- Markets where 1,800 ≤ HHI are considered to be highly concentrated.

B.2.3 Three pivotal supplier test

The TPS test framework performed during the capacity auction week is similar to PJM's energy market test. The TPS test for firm *j* is defined as:[46]

$$RSI3_j = \frac{\sum_{i=1}^{N}(s_i) - \sum_{i=1}^{2}(s_i) - s_j}{D}$$

Unless deemed not jointly pivotal with the two largest capacity suppliers to provide relief for the constraint isolating the region, capacity suppliers are mitigated to cost-based offers. Failing the TPS test results in the market seller's offer cap being committed to the schedule with the least cost among the cost-based schedule, price-based schedule and price-based parameter limited schedule. This is discussed in further detail under section B.3.

B.3 Market seller offer cap calculation

PJM suppliers are permitted to offer capacity in advance of commitment to either enter or exit the market. This allows participants to offer at their expected Avoidable Cost Rates (ACR).[47]

Unless the TPS test is passed for relief of zonal constraint, automatic mitigation of bids apply to units required to serve constrained zones.[48] Mitigation in capacity markets may require capacity owners to submit ACR or opportunity cost data to the MMU for the resources they intend to submit non-zero sell offers, they will need to submit data unless other specific conditions included under PJM OATT Section 6.7 (c) are met:[49]

> Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

[46] Monitoring Analytics. (2010). Page 38. http://www.monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf

[47] CRA (2017). Page 40. https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-P1.pdf

[48] Brattle (2007). Page 76. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf

[49] PJM OATT, Attachment DD, Section 6.7 (c). http://www.pjm.com/~/media/committees-groups/committees/mrc/20161117/20161117-item-05-urmstf-proposal-draft-oatt-attachment-dd-revisions.ashx

that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class identified in the table below as not likely to include the marginal price-setting resources in such auction; or

for which the potential participant commits that any Sell Offer it submits as to such resource will not include any price above: (1) the applicable default level identified below for the relevant resource class, less (2) the Projected PJM Market Revenues for such resource, as determined in accordance with this Tariff.

If Section 6.7 (c) of the PJM OATT is not applicable, market participants may submit avoidable cost rates or opportunity cost data. If the sell-offer is rejected, or the participant fails to request a unit specific ACR, or if the market participant fails to provide evidence as to why the offer should stand or re-submit a compliant sell-offer, the sell-offer is deemed invalid. An invalid sell-offer means the seller's offer fails the TPS test and is therefore mitigated to default reference levels.

If a sell offer is determined to be invalid, a default retirement and mothball ACR rate is applied determined by the most accurate market technology for the unit. To determine the default retirement and mothball ACR values, the Office of the Interconnection multiplies the base default retirement and mothball ACR values then adds the most recent annual average rate of change in the July Handy-Whitman Indices which determines the updated base default retirement and mothball ACR values.[50]

The ACR rates by market technology class are calculated as described in Section 6.7 of the PJM OATT, Attachment DD and are illustrated in table below.

[50] PJM OATT, Attachment DD, Section 6.7 (c). http://www.pjm.com/~/media/committees-groups/committees/mrc/20161117/20161117-item-05-urmstf-proposal-draft-oatt-attachment-dd-revisions.ashx

Table B.2: PJM RPM default avoidable cost rates for the 2017/2018 delivery year[51]

Technology type	2017/18 mothball ACR ($/MW-Day)	2017/18 retirement ACR ($/MW-Day)
Combustion turbine – Industrial frame	$29.27	$40.08
Coal-fired	$166.08	$191.45
Combined cycle	$35.88	$49.36
Combustion turbine – Aero derivative	$31.70	$45.10
Diesel	$30.88	$39.22
Hydro	$83.43	$109.12
Oil and gas steam	$76.61	$93.28
Pumped storage	$24.41	$34.28

B.3.1 Avoidable cost rate

RPM capacity market sellers may establish their own ACRs and are permitted to escalate actual 12 month cost data using the "escalation factor".[52] The most recent 10 year average rate of change in the Handy-Whitman Index results in an escalation factor of 1.03366.[53] As per the PJM OATT, Attachment DD, the Avoidable Cost Rate for an existing generation resource is determined using the formula below and are applied to the unit's base offer segment expressed in $/MW-year:

$$\begin{aligned} Avoidable\ Cost\ Rate \\ &= (Adjustment\ Factor \\ &\quad * (AOML + AAE + AFAE + AME + AVE + ATFI + ACC + ACLE) + ARPIR + APIR \\ &\quad + CPQR \end{aligned}$$

Avoidable cost rate definitions and information requirements

All costs defined below are for the 12 months preceding the month in which the data must be provided to the MMU.

[51] PJM RPM Default Avoidable Cost Rates for the 2017/18 Delivery Year. Retrieved from: https://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/default-acr-values-for-the-2017-2018-dy.ashx
[52] Monitoring Analytics (2016). Page 1-2. http://www.monitoringanalytics.com/tools/docs/IMM_ACR_Escalation_Guidelines_20161205.pdf
[53] Monitoring Analytics (2016). Page 1-2.http://www.monitoringanalytics.com/tools/docs/IMM_ACR_Escalation_Guidelines_20161205.pdf

Adjustment Factor

The Adjustment Factor is equal to 1.10*(Escalation Factor ^n), which accounts for a margin of error for understated costs. An additional adjustment using the 10-year average Handy-Whitman Index is included to account for expected inflation from the time the offer is submitted to the commencement of the Delivery Year, and "n" is equal to the number of years between the actual data and the start of the delivery year.[54]

Avoidable Operations and Maintenance Labour (AOML)

Avoidable Operations and Maintenance Labour costs include historical labour expenses directly related to operations and maintenance of the generation resource.

Avoidable Administrative Expenses (AAE)

Avoidable Administrative Expenses include avoidable administrative expenses relating directly to employees and include categories such as: employee expenses, environmental fees, safety and operator training, office supplies, communications, annual plant test, inspection and analysis.

Avoidable Fuel Availability Expenses (AFAE)

Expenses directly related to fuel availability and delivery for the resource based on historical 12-month data proceeding the month in which the data must be provided or on reasonable projections for the delivery year. The data may include executed contracts, published tariffs, or other data providing evidence of the level of costs incurred. Costs may include: firm gas pipeline transportation, natural gas storage costs, costs of gas balancing agreements, costs of gas park and loan services.

Avoidable Maintenance Expenses (AME)

Expenses may include categories such as: chemical and materials consumed during maintenance of the generating unit, and rented maintenance equipment used to maintain the generating unit.

Avoidable Variable Expenses (AVE)

Expenses may include categories such as: water treatment chemicals and lubricants, water, gas, and electric service (not for power generation), and waste water treatment.

Avoidable Taxes, Fees and Insurance (ATFI)

Avoidable Taxes, Fees and Insurance costs include categories of expenses included in the AFTI and include: insurance, permits and licensing fees, site security and utilities for maintaining security at the site, and property taxes.

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[54] Monitoring Analytics (2016). Page 1-2.
http://www.monitoringanalytics.com/tools/docs/IMM_ACR_Escalation_Guidelines_20161205.pdf

Avoidable Carrying Charges (ACC)

Avoidable Carrying Charges costs consist of avoidable short-term carrying charges to maintain reasonable inventory levels of fuel and spare parts, subsequent short-term operational decisions as measured by industry best practice standards. The time period that defines short-term is a reasonable occurrence and replacement of inventory for normal and expected operations.

Avoidable Corporate Level Expenses (ACLE)

Corporate expenses include those that directly tied to tangible services required for the operation of the generating unit recommended for deactivation. The categories of such expenses include: legal services, environmental reporting, and procurement.

Capacity Performance Quantifiable Risk (CPQR)

Capacity Performance Quantifiable Risk costs include quantifiable and reasonably-supported costs of mitigating the risks of non-performance associated with a capacity performance Resource offer submission (or a Base Capacity Resource offer for the 2018/19 or 2019/20 delivery years). Expenses include: insurance for resource non-performance risk.

Avoidable Project Investment Recovery Rate (APIR)

The Avoidable Project Investment Recovery Rate is defined in the PJM's OATT as follows:

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

The term, "PI", is the amount of project investment prior to June 1 of the delivery year. This excludes Mandatory Capital Expenditures ("CapEx") as CapEx project investment must be completed during the delivery year that is reasonably required to enable a resource subject to a sell offer to continue operating or improve availability during peak-hour periods during the delivery year. "CRF" is the annual capital recovery factor applied in accordance with the terms specified below.[55]

[55] PJM correction to Tariff, Section 6.8 (a). https://pjm.com/~/media/markets-ops/rpm/rpm-auction-info/crf-clarification.ashx

Table B.3: Annual capital recovery factor table

Age of existing units (years)	Remaining life of plant (years)	Levelised CRF
1 to 5	30	0.107
6 to 10	25	0.114
11 to 15	20	0.125
16 to 20	15	0.146
21 to 25	10	0.198
25 Plus	5	0.363
Mandatory CapEx	4	0.450
40 plus alternative	1	1.100

Capital expenditures and project investment

Capacity market sellers may make a one-time election to recover such investment using: (i) the highest Capital Recovery Factor and associated recovery schedule to which it is entitled; or (ii) the next highest Capital Recovery Factor and associated recovery schedule. Three options exist for Resources submitting Annual Capital Recovery Factor costs, these include a mandatory CapEx option, 40-plus alterative option, and multi-year pricing option. Details on cost requirements for each option are discussed in further detail under Section 6.8 of the PJM OATT.

B.3.2 Opportunity cost

In order for opportunity costs to be included in the market seller offer cap, the market participant may provide the documented price available to an existing generation resource in a market external to PJM. Offers are accepted by the MMU on a competitive basis if the total MW of existing generation resources submitting opportunity cost offers in any auction for a delivery year exceeds; (i) firm export capability of the PJM system for the delivery year, or (ii) the capability of external import capacity markets in the delivery year. [56]

Market seller offer caps are equivalent to the ACR less the projected market revenues. The cap is in effect until the maximum level of accepting offers to export is reached. Opportunity cost offers are not accepted from an existing generation resource. The maximum levels of exports is the lesser of the MMU ability to permit firm exports, or the ability of the importing area(s) taking

[56] PJM Tariff, Attachment DD, Section 6.7. http://www.pjm.com/~/media/committees-groups/committees/mrc/20161117/20161117-item-05-urmstf-proposal-draft-oatt-attachment-dd-revisions.ashx

account of relevant export limitations by location. Projected PJM market revenues apply for any generation capacity resource with an ACR applied.

B.3.3 Unit-specific minimum operating parameters for capacity performance and base capacity resources

Price-based parameter-limited schedule

In addition to being subject to pre-determined limits on cost-based offers, generation capacity resources are required to submit and be subject to pre-determined limits on market-based offers. Each generation capacity resource must submit at least one cost-based schedule, one price-based schedule, and a price-based parameter limited schedule.[57]

If a generation capacity resource fails the TPS test in the energy market, the resource is committed on the schedule with the least cost among the cost-based schedule, price-based schedule and price-based parameter limited schedule.[58]

Section 6.6 of the PJM OATT details circumstances under which capacity resources are to submit parameter limited schedules as the following:

i. The Market Seller fails the three pivotal supplier test. When this subsection applies, the parameter limited schedule will be the less limiting, i.e. more flexible, of the defined parameter limited schedules or the submitted offer parameters;
ii. For the 2014/2015 through 2017/2018 Delivery Years, the Office of the Interconnection:
    a. declares a Maximum Generation Emergency;
    b. issues a Maximum Generation Emergency Alert; or
    c. schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert for all, or any part, of an Operating Day;
iii. For Capacity Performance Resources, the Office of the Interconnection:
    a. declares a Maximum Generation Emergency;
    b. issues a Maximum Generation Emergency Alert, Hot Weather Alert, Cold Weather Alert; or
    c. schedules units based on the anticipation of a Maximum Generation Emergency, Maximum Generation Emergency Alert, Hot Weather Alert or Cold Weather Alert for all, or any part, of an Operating Day;
iv. For Base Capacity Resources, the Office of the Interconnection:
    a. declares a Maximum Generation Emergency during hot weather operations;
    b. issues a Maximum Generation Emergency Alert or Hot Weather Alert during hot weather operations; or
    c. schedules units based on the anticipation of a Hot Weather Alert, or a Maximum Generation Emergency or Maximum Generation Emergency Alert during hot weather operations, for all, or any part, of an Operating Day.

[57] PJM Manual 11, Section 2.3.4. http://www.pjm.com/~/media/documents/manuals/m11.ashx
[58] PJM Manual 11, Section 2.3.4. http://www.pjm.com/~/media/documents/manuals/m11.ashx

Following TPS failure, the following unit-specific parameter information is required by the MMU and is illustrated in the table below.

Table B.4: PJM unit-specific parameters and real-time value details[59]

Parameters	Applied to	Specific parameters	Circumstances applied
Unit-specific parameters	CP Resources for Delivery Year 2016/17 an onward Base Capacity Resources for DY 2018/19 and 2019/20	Turn down ratio Minimum down time Minimum run time Maximum daily start Maximum weekly start Maximum run time Start-up time Notification time	When a resource is scheduled on either a price-based parameter limited schedule or cost-based schedule
Real-time values	CP Resources and non-CP Resources	Turn down ratio Minimum down time Minimum run time Maximum run time Start-up time Notification time	When resource is unable to operate according to the unit specific parameters (CP and Base Capacity) or default PLS (non-CP)

A capacity market seller that does not believe its generation capacity resource can meet the unit-specific values determined by PJM due to actual operating constraints, and chooses to establish adjusted unit-specific parameters for those resources, may request adjusted unit-specific parameter limitations. Schedule 1 Section 6.6 of the PJM Operating Tariff specifies the Parameter Limited Schedules as follows.[60]

[59] PJM (2016). Unit Specific Parameters and RTV. Page 3. http://www.pjm.com/~/media/committees-groups/committees/oc/20160120-special/20160120-item-03-unit-specific-operating-parameters-and-rt-values.ashx
[60] PJM Tariff, Attachment DD, Section 6.6. http://www.pjm.com/directory/merged-tariffs/oa.pdf

Table B.5: Parameter-limited schedule matrix

Unit / parameter	Minimum down time (hours)	Minimum run time (hours)	Maximum daily starts	Maximum weekly starts	Turn down ratio
Small-frame CT & AERO CT: Up to 29 MW ICAP	2 or less	2 or less	2 or more	14 or more	1 or more
Medium-frame CT & AERO CT: 30 NW to 65 MW ICAP	2 or less	3 or less	2 or more	14 or more	1 or more
Medium- to large-frame CT: 65 NW to 135 MW ICAP	3 or less	5 or less	2 or more	14 or more	1 or more
Large-frame CT: 135 MW to 180 MW ICAP	4 or less	5 or less	2 or more	14 or more	1 or more
Combined cycle	4 or less	6 or less	2 or more	11 or more	1.5 or more
Petroleum & natural gas steam: Pre-1985	7 or less	8 or less	1 or more	7 or more	3 or more
Petroleum & natural gas steam: Post-1985	3.5 or less	5.5 or less	2 or more	11 or more	2 or more
Sub-critical coal	9 or less	15 or less	1 or more	5 or more	2 or more
Super-critical coal	84 or less	24 or less	1 or more	2 or more	1.5 or more

Note: Turn down ratio = Economic maximum MW / Economic minimum MW

B.4 Must-offer obligation

PJM's must-offer obligation applies to all resources clearing the RPM auction, or those obtaining capacity commitments, both must offer in the day-ahead energy market.[61] Section 5.6.6 of the PJM OATT, Attachment DD, describes how PJM determines the quantity of megawatts of available installed capacity that each capacity market seller must offer in any RPM Auction. Verification of the availability of megawatts of installed capacity is detailed under Attachment DD Section 5.6.6 of the OATT as the following:

[61] CRA (2017). Page 10. https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-Appendices.pdf

(i) All Generation Capacity Resources owned by or under contract to the Capacity Market Seller, including all Generation Capacity Resources obtained through bilateral contract;

(ii) The results of prior Reliability Pricing Model Auctions, if any, for such Delivery Year (including consideration of any restriction imposed as a consequence of a prior failure to offer); and

(iii) Such other information as may be available to the Office of the Interconnection. The Office of the Interconnection will reject Sell Offers or portions of Sell Offers for Capacity Resources in excess of the quantity of installed capacity from such Capacity Market Seller's Capacity Resource that it determines to be available for sale.

Exempt resources

Section 6.6A of the OATT, Attachment DD states the following resources as exempt from the requirement to offer as capacity performance (but may do so voluntarily)[62]:

- Intermittent resources
- Capacity storage resources
- Demand resources
- Energy efficiency resources

Exceptions to must-offer requirement

Exceptions to the must-offer requirement may be allowed if the capacity market seller demonstrates the resource is physically incapable of satisfying the requirement for the relevant delivery year, or has a financial and physical firm commitment (i.e. unit-specific bilateral transactions or demonstrates a financial or physical firm commitment to an external sale); or was interconnected to the transmission system as an energy resource and not subsequently converted to a capacity resource.[63]

Market participant information requirements to establish the resource is physically unable to participate in the relevant auction include:

i. Documentation plan to retire the resource prior or during the delivery year;
ii. Evidence of significant physical operational restrictions causing long term or permanent changes to the installed capacity of a resource, or if it is under repair;
iii. Involvement in an ongoing regulatory proceeding;
iv. Notarized statement confirming that the existing resource which cleared an RPM auction for a delivery year prior to the delivery year of the relevant auction but is unable to achieve full commercial operation.

[62] PJM Tariff, Attachment DD, Section 6.6A http://www.pjm.com/~/media/committees-groups/committees/mrc/20161117/20161117-item-05-urmstf-proposal-draft-oatt-attachment-dd-revisions.ashx.

[63] PJM Tariff, Attachment DD, Section 6.6 (g) http://www.pjm.com/~/media/committees-groups/committees/mrc/20161117/20161117-item-05-urmstf-proposal-draft-oatt-attachment-dd-revisions.ashx.

Non-compliance of the must offer provision results in the resource being unable to partake in any subsequent incremental auctions conducted for such delivery year, the resource is also ineligible to receive any payments for capacity, cannot qualify to satisfy any LSE's unforced capacity obligation, and cannot obtain any obligation for the commitment of capacity resources for the delivery year.[64]

B.5 Capacity performance

PJM has implemented a capacity performance plan for the 2020/21 delivery year and resources will be subject to deficiency charges, availability and capability testing, established using the market clearing price multiplied by a penalty factor.[65]

B.6 Minimum offer price rule (MOPR)

The relationship between earnings in the energy market and prices in capacity markets exists as capacity prices need to account for the net revenues or margins that generators can earn in the energy market.[66] PJM implicitly includes estimated energy market earnings for a proposed peaking plant in the construction of the demand curves for each auction.[67]

Section 5.14 of the PJM OATT, Attachment DD describes the conditions set for clearing prices and charges including the Minimum Offer Price Rules (MOPR). MOPR for new and external resources are only applied to natural gas-fired generators. The MOPR screened generation resource has a MOPR floor offer price applied all sell offers clearing in the RPM auction (except in situations where an exemption was permitted) until and including the first delivery year.

Section 5.14 (h) of the PJM OATT, Attachment DD describes the MOPR floor offer price as being 100% of the Net Asset Class Cost of New Entry (net CONE) for each relevant generator type and location, for the 2018/19 delivery year and every subsequent delivery year. Incremental auctions apply the same MOPR floor offer price as used in the base residual auction for the delivery year.

$$Net\ CONE = (Gross\ CONE) - (Estimated\ Margin\ on\ Energy\ \&\ AS\ Revenues)$$

As per Section 5.14 (h) of the PJM OATT, Attachment DD the following table illustrates the gross cost of new entry component of the net asset class cost of new entry.

[64] PJM Tariff, Attachment DD, Section 6.6 (g) http://www.pjm.com/~/media/committees-groups/committees/mrc/20161117/20161117-item-05-urmstf-proposal-draft-oatt-attachment-dd-revisions.ashx.

[65] CRA (2017). Page 25. https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-P1.pdf

[66] CRA (2017). Page 19. https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-P1.pdf

[67] Monitoring Analytics (2016). Page 16. http://albertamsa.ca/uploads/pdf/Archive/00000-2017/2017-01-18%20Alberta%20Capacity%20Market%20Report%2009.21.16.pdf

Table B.6: Gross CONE of net asset class of new entry for the 2018/19 delivery year

	CONE area 1	CONE area 2	CONE area 3	CONE area 4
CT $/MW-year	132,200	130,300	128,900	130,300
CC $/MW-year	185,700	176,000	172,600	179,400
IGCC $/MW-year	582,042	558,486	547,240	537,306

The estimated energy and ancillary service revenues for each type of plant will be determined as described in the table below.

Table B.7: Estimated energy and ancillary services revenues by asset class

Asset class	Estimated energy and ancillary services revenues
Combustion turbine (CT)	Determined by section 5.10(a)(v)(A) of Attachment DD of the OATT. Highest energy revenue estimate based on Zone within CONE Area used.
Combined cycle (CC)	Determined as above with the following exceptions: Heat rate assumed to be 6.722 MMbtu/MWh VOE is assumed to be $3.23 per MWh Peak-hour dispatch for both DAM and RTM dispatches resource when it is economic to do so and continually during full peak-hour period Ancillary service revenues are assumed to be $3,198 per MW-year
Integrated gasification combined cycle (IGCC)	Determined as above with the following exceptions: Heat rate assumed to be 8.7 MMbtu/MWh VOE is assumed to be $7.77 per MWh Peak-hour dispatch for both DAM and RTM dispatches resource when it is economic to do so and continually during full peak-hour period Ancillary service revenues are assumed to be $3,198 per MW-year

Exemptions include a unit-specific exemption, competitive entry exemption or a self-supply exemption. Resources qualifying as meeting the requirements for either exemption are not subject to a MOPR floor offer price in any subsequent RPM Auction. The requirements for a competitive entry exemption or a self-supply exemption are described under Section 5.14 of the PJM Tariff, Attachment DD.

C ISO-NE energy market mitigation

C.1 Definitions in this appendix

In this appendix,

a) **"Market Rule 1"** means section III Market Rule Appendix A, Market Monitoring, Reporting and Market Power Mitigation;
b) **"IMM"** means the ISO-NE Internal Market Monitor;

C.2 NE energy market ex ante mitigation description

As specified under Market Rule 1, the IMM monitors the impact of particular bidding behaviour, and mitigates behaviour that does not comply with competitiveness and efficiency measures of energy markets, and daily reliability payments.[68] Conduct-and-impact thresholds assist in the determination of default offers applied to mitigated supply offers submitted by market participants. Mitigation screens are applied to all participants located in constrained areas or to participants determined to be system wide pivotal suppliers located in general areas.[69]

C.2.1 Constrained area test

The constrained area test is a structural test used to identify geographic regions subject to more rigorous conduct testing. The test is based on historical transmission patterns to identify "designated congestion areas".[70] This allows the MMU to identify specific transmission constraints that are subject to default offer mitigation.

Transmission constraint information assists in identifying areas vulnerable to market power abuse, as such the MMU categorises two market "areas" defined as: general areas and constrained areas. For the purposes of conducting the constrained area test, as detailed under Section III.A.5.2.2 of Market Rule 1,[71] the following conditions apply:

> "A Resource is considered to be within a constrained area if:
>
> (a) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;
>
> (b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than $25/MWh."

[68] ISO-NE (2013). Page 24. https://www.iso-ne.com/static-assets/documents/pubs/spcl_rpts/2013/markets_overview_051513_final.pdf
[69] ISO-NE (2013). Page 24. https://www.iso-ne.com/static-assets/documents/pubs/spcl_rpts/2013/markets_overview_051513_final.pdf
[70] Brattle (2007). Page 73. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[71] ISO-NE Market Rule 1, Section III.A.5.2.2. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf

Frequency of testing

ISO-NE's definition of a constrained area changes depending on the market a resource submits an offer to. The constrained area test is triggered after a supply offer is entered. Resources are permitted to submit a single incremental energy offer in the day-ahead market (DAM), if it is not cleared, the offer can be re-offered into the real-time market (RTM), the RTM re-offer period closes before operating day. RTM offers consist of DAM self-schedule quantities, cleared day ahead offers, DAM offers that did not clear the DAM, and RTM re-offers in the DAM.[72]

C.2.2 Pivotal supplier test

One method to test the potential (or ability) for dominant or pivotal suppliers is to apply a Pivotal Supplier Test (PST). PST screens are applied to test if the market reaches a point where consumer demand is not met without the inclusion of supply from the pivotal firm.[73]

ISO-NE applies a less stringent single pivotal supplier test in which failure occurs if only one supplier is large enough to prevent unilaterally the constraint from being resolved.[74] If a market participant's aggregate energy offers exceed the difference between aggregate system-wide energy offers and total demand, then it is subject to the general area conduct-and-impact tests.[75]

The formula for the pivotal supplier test for firm *j* is:[76]

$$PST_j = \frac{\sum_{i=1}^{N}(s_i) - \sum s_j}{D}$$

From the above calculation, demand consists of effective quantity required to relieve constraint and supply consists of: market participant aggregate energy supply offers up to and including economic maximum as well as a RTM supply margin. The supply margin is equal to the total energy supply offers from all available resources up to and including the economic maximum less total system load.[77] Resources are then considered available for an interval they can provide energy to. The RTM interval is any hours in the plan, while the UDS interval is the interval for which USD issues instructions.[78]

If the $PST_j > 1.0$, the PST test is passed, and the supply offer is taken on current offer, price or cost. If the $PST_j \leq 1.0$, the PST test is failed, mitigation is applied and offer cap is used, taken

[72] FERC (2014). Page 8. https://www.ferc.gov/legal/staff-reports/2014/AD14-14-mitigation-rto-iso-markets.pdf
[73] Brattle (2007). Page 42. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[74] Brattle (2007). Page 42. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[75] Brattle (2007). Page 82. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[76] ISO-NE, Market Rule 1, Section III.A.5.2.1. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf
[77] ISO-NE, Market Rule 1, Section III.A.5.2.1 https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf

on the lesser of price or cost. A supply offer will be capped for a single hour at a time as the PST is rerun for each hour of the day.[79]

Frequency of testing

Testing occurs on an hourly basis in the DAM. The PST is applied to each supplier in ISO-NE.[80] Under general area mitigation, the PST is applied prior to the DAM clearing, prior to each determination of the new operating day plan, and prior to each execution of the Unit Dispatch Software (UDS).[81]

Structural test exemptions

Resources in constrained areas are not subject to the PST.[82]

C.2.3 Conduct-and-impact test

To determine if a firm has potentially exercised market power, ISO-NE relies on conduct-and-impact tests. Conduct-and-impact mitigation screens are applied twofold: first, to assess if a market participant exercised market power by bidding above an offer level threshold, or engaging in physical and economic withholding of output, and second, to determine if the submitted supply offer had a material effect on market clearing prices. [83]

An individual market participant conduct test can be evaluated ex post or may be applied prior to accepting a specified bid, thereby enabling that bid to be mitigated prior to determining the market-clearing price.[84]

ISO-NE applies its structural tests hourly, followed immediately by conduct-and-impact tests.[85] New England does not permit suppliers to vary their bid curves from hour to hour within a given day, unlike the other U.S. jurisdictions (i.e., NYISO).[86] The flexibility in the energy bid curve is constant each day.[87]

Market Rule 1 specifies that if a supplier is determined to be pivotal, the supply offer is mitigated using conduct-and-impact screens under Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.3 "General Threshold Commitment Mitigation". Similarly, if a

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[79] ISO-NE, Market Rule 1, Section III.A.2.4.5 https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf
[80] Brattle (2007). Page 82. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[81] ISO-NE, Market Rule 1, Section III.A.5.2.1. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf
[82] ISO-NE Market Rule 1. Section III.A.5.2. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf
[83] Brattle (2007). Page 6. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[84] Brattle (2007). Page 43. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[85] Brattle (2007). Page 84. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[86]ISO-NE. (2013). Page 9. https://www.iso-ne.com/static-assets/documents/pubs/spcl_rpts/2013/markets_overview_051513_final.pdf
[87]ISO-NE. (2013). Page 9. https://www.iso-ne.com/static-assets/documents/pubs/spcl_rpts/2013/markets_overview_051513_final.pdf

supplier is determined to be in a constrained area according to the constrained area test, the supply offer is mitigated using conduct and impact screens under Section III.A.5.5.2 "Constrained Area Threshold Energy Mitigation" and Section III.A.5.5.4 "Constrained Area Threshold Commitment Mitigation". This is illustrated in the table below.[88]

[88] ISO-NE Market Rule 1, Section III.A.5.5.4. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf

Table C.1: ISO-NE energy market mitigation by type

Mitigation by type	Conduct	Impact	Failure of both tests
General threshold energy mitigation (GTEM)	Mitigation is applied to market participants deemed pivotal suppliers in the RTM. A Supply Offer fails if any offer block exceeds the Reference Level by an amount greater than 300% or $100/MWh. Whichever is lower.	A Supply Offer failing the GTEM conduct test is subject to impact test. A Supply Offer fails if there is an increase in the LMP exceeding 200% or $100/MWh. Whichever is lower in the DAM or RTM.	The Supply Offer financial parameters set to reference levels. This includes energy offers, start-up fees and no-load fees.
Constrained area energy mitigation (CAER)	Mitigation is applied to all offers in DAM and RTM. A Supply Offer fails if any offer block exceeds the reference level by an amount greater than 50% or $25/MWh. Whichever is lower.	A Supply Offer failing the CAER conduct test is subject to impact test. A Supply Offer fails if there is an increase in the LMP exceeding 50% or $25/MWh. Whichever is lower in the DAM or RTM.	The Supply Offer financial parameters set to reference levels. This includes energy offers, start-up fees and no-load fees.
General threshold commitment mitigation (GTCM)	A Start-up Fee or No-Load Fee fails if the Fee exceeds the Reference Level for that fee by greater than 200%.	N/A	Evaluated for commitment based on Supply Offer set to Reference Level including all financial parameters, offer blocks, and all types of Start-Up Fees and No-Load Fee. If committed, Supply Offer is set to Reference Levels.
Constrained area commitment mitigation (CACM)	A Start-up Fee or No-Load Fee fails if it is submitted with an increase greater than 25% above the Reference Level.	N/A	Evaluated for commitment based on Supply Offer set to Reference Level including all financial parameters, offer blocks, and all types of Start-Up Fees and

			No-Load Fee. If committed, Supply Offer is set to reference levels.
Local reliability commitment mitigation (LRCM)	Minimum run time conduct test Actual run time conduct test	N/A	If Supply Offer fails it is evaluated for commitment based on Supply Offer set to reference level including all financial parameters, offer blocks, and all types of Start-Up Fees and No-Load Fee. If committed, Supply Offer is set to reference levels. If Supply Offer fails, all financial parameters are set to reference levels for the purpose of calculating DAM and RTM energy market revenues.
Start-up fee and no-load fee mitigation	A Supply Offer fails the conduct test if its start-up fee or no-load fee divided by the reference level for that fee is greater than three.	N/A	If a Supply Offer fails the conduct test, all financial parameters are set to reference levels.
Other offer parameters	A 100% increase over reference levels for minimum values or a 50% decrease from reference levels for maximum values	N/A	This category includes: maximum daily / weekly starts and ramp rate curve
Time-based parameters	An increase of two hours over reference level or an increase of six hours across multiple parameters	N/A	This category includes: hot / intermediate / cold notification / start-up times, minimum / maximum run times and minimum down

			time.
Financial offer parameters	With fuel price adj., the start-up fee and no-load fee for the associated Supply Offer is limited to the percent increase in new fuel price relative to the fuel price used by the MMU multiplied by the start-up fee or no-load fee from re-offer period. Without fuel price adjustments, the start-up fee and no-load fee can be changed in RT offer change to no more than the start-up fee and no-load fees submitted in the re-offer period.	N/A	

* "N/A" means there was no impact test in the Tariff associated with the mitigation type.

Frequency of testing

The test is conducted hourly.

Structural test exemptions

Resources in general areas that submit energy offers below $25/MWh are not subject to the conduct test.[89]

Market participant cost information required

Local reliability commitment mitigation

Resources subject to Local Reliability Commitment Mitigation are required to provide one of more of the following cost components as described in Market Rule 1, under Section III.A.5.5.5.2.[90]

[89] ISO-NE Market Rule 1, Section III.A.5.5. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf
[90] ISO-NE Market Rule 1 Section III.A.5.5.5.2 (effective 2018/11/06)

i. Minimum run time conduct test

The MMU evaluates a resource’s supply offer using the following formula:

$$(Low\ Load\ Cost\ Minimum\ Run\ Time\ at\ Offer - Low\ Load\ Cost\ Minimum\ Run\ Time\ at\ Reference\ Level) \leq Commitment\ Cost\ Threshold$$

where

$$Commitment\ Cost\ Threshold = (0.1) * (Low\ Load\ Cost\ at\ Reference\ Level)$$

$$Low\ Load\ Cost = (Cost\ of\ Operating\ the\ Resource\ at\ its\ Economic\ Minimum\ Limit) = \big(Cold\ Start\ Up\ Fee + (No\ Load\ Fee * Minimum\ Run\ Time) + (Price\ of\ Energy\ at\ Economic\ Minimum\ Limit * Economic\ Minimum\ Limit * Minimum\ Run\ Time)\big)$$

$$Low\ Load\ Cost\ Minimum\ Run\ Time\ at\ Offer = Low\ Load\ Cost\ Calculated\ with\ Finicial\ Parameters\ of\ the\ Supply\ Offer$$

$$Low\ Load\ Cost\ Minimum\ Run\ Time\ at\ Reference\ Level = Low\ Load\ Cost\ Calculated\ with\ Financial\ Parameters\ of\ the\ Supply\ Offer\ Set\ to\ Reference\ Levels$$

$$Price\ of\ Energy\ at\ Economic\ Minimum\ Limit = Price\ for\ Energy\ at\ the\ Resource's Economic\ Minimum\ Limit$$

For Low Load Cost Minimum Run Time at Offer, the price for energy is defined as:

$$Price\ for\ Energy = Energy\ Price\ Parameter\ from\ the\ Supply\ Offer$$

For Low Load Cost Minimum Run Time at reference level, the reference level of the offer block at economic minimum limit is used. If a resource’s combined Minimum Run Time and Minimum Down Time exceed 24 hours, then the conduct test will use the greater of 24 hours or the resource’s Minimum Run Time for the Minimum Run Time.

The conduct test is violated if the following condition applies:

$$Low\ Load\ Cost\ Minimum\ Run\ Time\ at\ Offer - Low\ Load\ Cost\ Minimum\ Run\ Time\ at\ Reference\ Level > Commitment\ Cost\ Threshold$$

If the minimum run time conduct test is not violated, the MMU evaluates a resource’s supply offer using the following formula:

$$Low\ Load\ Cost\ Actual\ Run\ Time\ at\ Offer - Low\ Load\ Cost\ Actual\ Run\ Time\ at\ Reference\ Level \leq Commitment\ Cost\ Threshold$$

where

$$\text{Commitment Cost Threshold} = (0.1) * (\text{Low Load Cost Actual Run Time at Reference Level})$$

$$\text{Low Load Cost Actual Run Time} = (\text{Cost of Operating the Resource at its Economic Minimum Limit})$$
$$= \big(\text{Cold Start Up Fee} + (\text{No Load Fee} * \text{Actual Local Reliability Run Time}) + (\text{Price of Energy at Economic Minimum Limit}) * (\text{Economic Minimum Limit}) * (\text{Actual Local Reliability Run Time})\big)$$

where the local reliability run time is the number of hours the resource was operated in the RTM to provide one or more of the services specified in Section III.A.5.5.5.1.

$$\text{Low Load Cost Actual Run Time at Offer} = \text{Low Load Cost Actual Run Time Calculated with Financial Parameters of the Supply Offer}$$

$$\text{Low Load Cost Actual Run Time at Reference Level} = \text{Low Load Cost Actual Run Time Calculated with the Financial Parameters of the Supply Offer set to Refe}$$

$$\text{Price of Energy at Economic Minimum Limit} = \text{Price for Energy at the Resource's Economic Minimum Limit as Reflected in the Supply Offer}$$

For Low Load Cost Actual Run Time at offer, the price for energy is defined as:

$$\text{Price for Energy} = \text{Energy Price Parameter from the Supply Offer}$$

For Low Load Cost Actual Run Time at reference level, the Reference Level of the offer block at economic minimum limit is used. The conduct test is violated if the following condition applies:

$$\text{Low Load Cost Actual Run Time at Offer} - \text{Low Load Cost Actual Run Time at Reference Level} > \text{Commitment Cost Threshold}$$

C.3 Reference level calculation

Mitigation is applied to supply offers failing structural market power tests as described above, this occurs before the locational marginal prices (LMPs) are calculated in the day-ahead and real-time markets.[91] Day-ahead mitigation is executed manually, while the real-time mitigation is executed automatically and runs in tandem with the real-time dispatch model.[92]

The MMU calculates resource reference levels according to the hierarchy of the three reference level offer caps listed in order of preference as; offer-based, LMP, and cost-based. Units that are frequently mitigated must choose a reference level.

If data is unavailable they must use the ISO estimate or average of competitive bids from similar units. However, as detailed under Section III.A.7.2.2 of Market Rule 1, there are cases where cost-based reference levels supersede LMP based and offer-based reference levels:

i. Cost-based reference level exceeds LMP and offer-based reference levels;
ii. The Supply Offer parameter is a start-up fee or no-load fee;
iii. Request for cost-based reference level is submitted;
iv. 90 days prior to Supply Offer submission: Resource flagged for VAR, SCR, or Local Second Contingency Protection Resource for any hour in the DAM or RTM; ratio of the number of hours the resource operated out-of-merit in both DAM and RTM exceeds number of hours the resource operated in economic merit order, to total number of operating hours in DAM and RTM is greater than or equal to 50%; fuel price adjustment is submitted.

Physical parameter offers are expressed in units other than dollars and may include a time-based or quantity level bid or offer parameter. The MMU will calculate a reference level for physical parameter offers on the basis that one or more of the following conditions specified in Market Rule 1 Section III.A.7.1.

Reference levels for financial parameters of offers are calculated separately, these include calculations for start-up fees, no-load fees, and offer blocks.

Exceptions to reference levels

For Peaking Unit Safe Harbor (PUSH) units located in DCAs, an energy reference level can be calculated as:

[Fixed Costs Net of Market Revenues /2002 Actual Output] + Marginal Cost.[93]

Default energy offer cap

ISO-NE's energy market offer cap is currently set at $1,000/MWh.

[91] FERC (2014). Page 37. https://www.ferc.gov/legal/staff-reports/2014/AD14-14-mitigation-rto-iso-markets.pdf
[92] FERC (2014). Page 37. https://www.ferc.gov/legal/staff-reports/2014/AD14-14-mitigation-rto-iso-markets.pdf
[93] FERC (2014). Page A-9. https://www.ferc.gov/legal/staff-reports/2014/AD14-14-mitigation-rto-iso-markets.pdf

C.3.1 Cost-based reference levels

The MMU calculates cost-based reference levels taking into account costs provided by the market participant. Reference levels for that market participant are determined through a consultation process.

The cost-based offer reference levels are based explicitly on costs including: fuel, emissions, and other variable operating and maintenance cost expenditures. Estimates of costs are based on current market prices or replacement costs and wherever possible do not include inventory costs. If cost information relating to market prices or replacement costs is unavailable, then cost estimates must identify if the reported costs are the result of a product or service provided by a market participant.

Components of cost-based offers for all unit types

Fuel costs

Fuel costs are based on market conditions for current fuel delivery, trading volumes, near-term price quotes, expected natural gas heating demand, and market participant-reported quotes for trading and fuel costs. Current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

Incremental operating costs

Incremental energy costs are calculated using the following formula: [94]

$$\begin{aligned} &Incremental\ Energy\ Costs \\ &\quad = (Incremental\ Heat\ Rate * Fuel\ Costs) \\ &\quad + (Emissions\ Rate * Emissions\ Allowance\ Price) \\ &\quad + Other\ Variable\ and\ Operating\ Maintenance\ Costs + Opportunity\ Costs \end{aligned}$$

Opportunity costs

Opportunity costs include but are also not limited to: emissions limits, water storage limits, and other operating permits limiting the production of energy.

No-load

No-load costs are calculated using the following formula:

$$\begin{aligned} &No\ Load\ Costs \\ &= (No\ Load\ Fuel\ Use * Fuel\ Costs) + (No\ Load\ Emissions * Emissions\ Allowance\ Price) \\ &+ (No\ Load\ Variable\ Operating\ and\ Maintenance\ Costs \\ &+ Other\ No\ Load\ Costs\ That\ Are\ Not\ Fuel\ , Emissions\ or\ Variable\ and\ Maintenance\ Costs) \end{aligned}$$

Start-up

Start-up costs are calculated using the following formula:

[94] ISO-NE Market Rule 1, Section III.A.7.5.1. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf

$$\begin{aligned} Start\ Up\ Costs = {} & (Start\ Up\ Fuel\ Use * Fuel\ Costs) \\ & + (Start\ Up\ Emissions * Emission\ Allowance\ Price) \\ & + (Start\ Up\ Variable\ and\ Operating\ Maintenance\ Costs \\ & + Other\ Start\ Up\ Costs\ That\ Are\ Not\ Fuel, \\ & Emissions\ or\ Variable\ and\ Maintenance\ Costs \end{aligned}$$

C.3.2 Offer-based reference levels

The MMU calculates approved offer-based reference levels as the lower of the mean or median of a generator supply offers that have been accepted as compliant and included in the seller's day-ahead or real-time generation obligation during the operating day in which the resource was scheduled in economic merit order, over the prior 90 days before the offer was submitted. The offer is adjusted for changes in fuel prices using fuel indices generally applicable for the location and type of resource.[95]

C.3.3 LMP-based reference levels

The Internal Market Monitor calculates the LMP-based reference level as the average LMP at the resource's node during the lowest-priced 25% of the hours that the resource was dispatched over the previous 90 days for similar days (weekday or weekend day), adjusted for changes in fuel prices.[96]

C.3.4 Frequently mitigated unit reference levels

If a unit is frequently dispatched out of merit order for reliability purposes, it is required to choose the negotiated, cost-based level.

C.3.5 Negotiated reference levels

A negotiated level intended to reflect marginal cost. Negotiated unit reference levels are required to be cost-based.

C.4 Thresholds for identifying physical withholding

Section III.A.4 of ISO-NE's Market Rule 1 identifies potential physical withholding. The initial thresholds are specified as follows:

i. Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;
ii. Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or
iii. Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

[95] ISO-NE Market Rule 1, Section III.A.7.3. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf
[96] ISO-NE Market Rule 1, Section III.A.7.4. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf

C.5 ISO-NE ancillary service price cap

ISO-NE caps regulation service offers at $100/MW and forward reserve offers are capped at $14,000/MW-month. ISO-NE's ancillary service market price caps are illustrated in the table below.

Table C.2: ISO-NE Ancillary Services Market Price Caps[97]

ISO-NE ancillary service product	Price cap
Regulation	$100/MW
Responsive reserve	n/a
Spinning reserve	n/a
Non-spinning reserve	n/a
Forward reserve	$14,000/MW-month

[97] Brattle (2007). Page 93.
http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf

D ISO-NE capacity market mitigation

D.1 Definitions in this appendix

In this appendix,

i. **"De-list Bid"** means a mechanism by which an existing capacity resource may seek a price-based exit from the Forward Capacity Auction; De-list bids can be submitted either for a specific capacity auction (and associated delivery year), to permanently leave the capacity market, or to retire.; include Static de-list bid/Export bid/Administrative export de-list bid/Static De-list bid (ambient air)/ Dynamic de-list bid;
ii. **"FCA"** means the ISO-NE Forward Capacity Auction;
iii. **"FCM"** means the ISO-NE Forward Capacity Market;
iv. **"Capacity Resource or Supply"** means an existing capacity resource or new capacity resource;
v. **"Dynamic Delist Bid"** means the option to remove capacity from the FCM at prices below the dynamic delist bid threshold during a single capacity commitment period;
vi. **"CCP"** means Capacity Commitment Period;
vii. **"CSO"** means Capacity Supply Obligation; used in the must offer obligations (MOO);
viii. **"Hydro-Québec Interconnection Capability Credits"** or **"HQICC"** means a key input into the calculation of the Installed Capacity Requirement (ICR) which reduce a portion of the ICR that is allocated to the interconnection rights holders (IHR), reflecting the capacity benefits of the HQ Interconnection;
ix. **"Net Installed Capacity Requirement"** or **"NICR"** means the Installed Capacity Requirement for the region, minus the tie-reliability benefits associated with the Hydro-Québec Phase I/II Interface.

D.2 ISO-NE capacity market ex ante mitigation description

Capacity market power mitigation tends to follow the procedures used in energy market power mitigation. Capacity market power mitigation is applied by ISO-NE through; bid caps and floors, and structural tests for competitiveness. The particular conduct of individual bidders is subsequently examined.

ISO-NE does not assume a resource will retire and that it may continue to participate in the energy market even if it fails to clear in the capacity market. Existing capacity resources that have cleared in a previous capacity auction and do not wish to participate in subsequent auctions are required to submit a de-list bid to withdraw from the auction.[98]

ISO-NE includes specific provisions for new entrants, and in many ways establishes new entrants as the competitive bid price setter. As such, offers from new resources are generally presumed to be competitive. However, new resource offer floor prices and offer prices for both existing and new resource types are determined and described under Section III.A.21.2 of

[98] FERC (2013). Page 23. https://www.ferc.gov/CalendarFiles/20130826142258-Staff%20Paper.pdf

Market Rule 1,.[99] The ISO-NE internal market monitor (IMM) examines particular bid conduct including low bids from new resources, high bids to retire resources, and bids for quantities that are less than capability levels on file for a unit.[100]

The ISO-NE internal market monitor (IMM) mitigates the exercise of market power through two mechanisms in the Forward Capacity Market (FCM). First, by establishing dynamic-delist bid thresholds and, second, by establishing technology-specific Offer Review Trigger Prices (ORTP). All bids above, or offers below the established thresholds are reviewed by the IMM.[101]

Capacity zones will be determined prior to the auction to identify import constrained zones. Import-constrained capacity zones are used to determine if a supplier is pivotal. Suppliers failing market power mitigation screens face offer capping or rejection of uncompetitive bids.[102]

General offer caps

Market prices are bounded at the general offer price cap thresholds to establish a default mitigation backstop. For first three successful auctions, existing generators face price caps of 1.4 x CONE and a price floor of 0.6 x CONE.[103]

D.3 Structural tests

D.3.1 Pivotal supplier test

Import-constrained capacity zones are used to determine if a supplier is pivotal. ISO-NE determines capacity zones prior to the Forward Capacity Auction (FCA) to identify import constrained zones. Subsequently a Pivotal Supplier Test (PST) is applied prior to the Forward Capacity Auction both at a system level and for each import-constrained capacity zone.[104]

Table D.1: Application of PST in the FCA

Application of pivotal supplier test	Relevant capacity requirement
System level	Installed capacity requirement (net of HQICCs)
Import-constrained capacity zones	Local sourcing requirement

[99] ISO-NE Market Rule 1, Section III.A.21.2. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf
[100] Brattle (2007). Page 90. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[101] CRA (2017). Page 87. https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-Appendices.pdf
[102]Brattle (2007). Page 92. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[103] Brattle (2007). Page 91. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[104] ISO-NE Market Rule 1, Section III.A.23.1. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf

The formula for the PST for firm *j* is: [105]

$$PST_j = \frac{\sum_{i=1}^{N}(s_i) - \sum(s_j)}{D}$$

The PST is a calculation performed in January prior to the start of the FCA to identify if a supplier controls enough capacity in the market such that it can unilaterally exercise market power and profitably set the price at a non-competitive level.[106]

The Pivotal Supplier Test will only include capacity from resources that have a "must offer" requirement in the FCA, these include: existing capacity resources (generation, demand response, and imports) and "existing-new" import capacity resources. [107] The test is conducted using the Net Installed Capacity Requirement, which is the quantity demanded at 0.100 LOLE. Likewise, Pivotal Supplier Tests conducted for capacity zones will utilize the local sourcing requirements.[108]

Test steps[109]

1. Market participants submit de-list bids.
2. IMM reviews delist bids (June-Sept).
3. Qualification Determination Notification (QDN) for resources Note: This is the default price cap used if it is determined that a supplier is pivotal.
4. Pivotal supplier test results published seven days before the auction.

Information required[110]

The IMM requires the following inputs prior to running the PST in the FCM:

- Capacity requirements: Installed Capacity Requirement (ICR) and Local Sourcing Requirements (LSR);
- Capacity supply;
- System constraints (i.e. internal system constraints, constraints from external control areas, capacity transfer limits).

Market Rule 1, Section III.A.23.2 specifies the conditions under which a capacity resource is treated as non-pivotal, and is described as follows:

> (a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone does not change the quantity calculated in

[105] ISO-NE Market Rule 1, Section III.A.23.1. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf
[106] ISO-NE. (2017). FCM Delist. Page 73. https://www.iso-ne.com/static-assets/documents/2017/01/20170126_fcm_delist.pdf
[107] ISO-NE. Hodgdon, Scott. (2015). Comprehensive Competitiveness Test in the FCM. Page 9. https://www.iso-ne.com/static-assets/documents/2015/02/a11a_imm_competitiveness_test_presentation_02_11_15.pptx
[108] ISO-NE. Hodgdon, Scott. (2015). Page 5. https://www.iso-ne.com/static-assets/documents/2015/02/a11a_imm_competitiveness_test_presentation_02_11_15.pptx
[109] ISO-NE. FCM Delist. Page 62. https://www.iso-ne.com/static-assets/documents/2017/01/20170126_fcm_delist.pdf
[110] ISO-NE. Hodgdon, Scott. (2015). Page 5. https://www.iso-ne.com/static-assets/documents/2015/02/a11a_imm_competitiveness_test_presentation_02_11_15.pptx

Section III.A.23.1(c) for that export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.

(b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

Frequency of testing

The PST is conducted annually, as FCAs are held annually, three years in advance of the operating period.[111]

Pivotal supplier test exemptions

PST exemptions include new import capacity resources backed by a single new external resource and associated with an investment in transmission that increases New England's import capability, or associated with an elective transmission upgrade.

D.3.2 "Inadequate supply" and "Insufficient competition" rules[112]

Structural mitigation tests are incorporated to some degree in ISO-NE. The inadequate supply and insufficient competition rules are the structural screens used in cases where a region is short on capacity. The insufficient competition rule sets prices for capacity resources and mitigates bids from planned generation resources and new generating resources. ISO-NE applies different mitigation methods for each resource type.[113] Mitigation in the form of offer caps for existing capacity exists if it is determined that structural market conditions may produce non-competitive outcomes.

[111] ISO-NE, FCM. Retrieved from: https://www.iso-ne.com/markets-operations/markets/forward-capacity-market

[112] In a report prepared by CRA (2017), it is stated the introduction of the downward sloping demand curve reduces the risk of market power and as a result ISO-NE is discontinuing the use of the insufficient competition rule.

[113] ISO-NE, FCM. Insufficient Competition Inadequate Supply. Retrieved from: https://www.google.ca/url?sa=t&rct=j&q=&esrc=s&source=web&cd=2&ved=0ahUKEwjY7P7JrpbVAhUF8GMKHVBxBp8QFggrMAE&url=https%3A%2F%2Fwww.iso-ne.com%2Fstatic-assets%2Fdocuments%2F2016%2F01%2Fa02_iso_memo_01_06_16.docx&usg=AFQjCNEnCxUZu08DMczExrM8scexGk1bdA

The FCA produces a single capacity clearing price for all cleared resource. However under certain conditions the prices paid to cleared resources may be administratively determined by ISO-NE. These conditions and their associated tariff provisions include[114]:

When low supply triggers the Inadequate Supply provisions;

The New England Control Area will be considered to have system-wide Inadequate Supply if at the FCA Starting Prices, the total amount of capacity offered in the FCA is less than the region's net ICR. An import-constrained Capacity Zone will be considered to have Inadequate Supply if at the FCA Starting Price the amount of new resources offered in that Capacity Zone is less than the amount of New Capacity Required in that Capacity Zone[115].

If the Inadequate Supply rule is triggered, existing resources receive 1.1 times the Capacity Clearing Price for the most recent FCA not having Inadequate Supply, and new resources receive the FCA Starting Price.[116]

When low competition triggers the insufficient competition provisions;

The FCA will be considered to have insufficient competition system-wide or in any import-constrained Capacity Zone if, at the FCA Starting Price, the amount of capacity offered from existing resources is less than the net ICR or, for an import constrained Capacity Zone, the Local Sourcing Requirement; and less than 300 MW of capacity is offered from New Generating Capacity Resources and New Demand Resources; or the amount of capacity offered from New Generating Capacity Resources and New Demand Resources is more than the amount of New Capacity Required but less than twice the amount of New Capacity Required; or any Market Participant's total capacity from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources is pivotal. A Market Participant will be considered pivotal if, at the FCA Starting Price, some capacity from that Market Participant's potential New Generating Capacity Resources, New Import Capacity Resources, or New Demand Resources is required to satisfy the net ICR or the Local Sourcing Requirement, as applicable[117].

If the Insufficient Competition rule is triggered, existing resources receive the lower of:

(1) the Capacity Clearing Price, and

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[114] FERC. (2014). Order on Tariff Filing. Retrieved from: https://www.ferc.gov/CalendarFiles/20140124195220-ER14-463-000.pdf
[115] ISO-NE Market Rule 1, Section III.13.2.8.1. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf
[116] FERC. (2014). Order on Tariff Filing. Retrieved from: https://www.ferc.gov/CalendarFiles/20140124195220-ER14-463-000.pdf
[117] ISO-NE Market Rule 1, Section III.13.2.8.2. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf

(2) 1.1 times the Capacity Clearing Price for the most recent FCA not having Insufficient Competition; and new resources the Capacity Clearing Price.[118]

When some but not all of a new resource's offered capacity is needed in an FCA and elects not to prorate its offered capacity down to the level needed, so the resource's excess capacity is carried forward into the subsequent FCA, thereby triggering the Capacity Carry Forward Rule.[119]

The Capacity Carry Forward rule requires a "trigger price" condition and payment schedule that is based on subjective criteria. The Capacity Carry Forward rule was designed to protect suppliers from price drops in import-constrained zones that could occur when a new large generator with excess capacity cleared in the prior year.[120]

When some but not all of a new resource's bid capacity is needed to satisfy the Local Sourcing Requirement, the Tariff allows the amount of excess new capacity to be carried forward into future FCAs, if the relevant new resource elects not to prorate the amount of capacity it is offering down to the level needed in the current FCA. The Capacity Carry Forward Rule is intended to mitigate the price suppressing effects of this over-procurement in subsequent years.[121]

D.4 Must offer obligation

All traditional generation including imports have must offer obligations to offer into the day ahead and real time market.[122] Day-ahead obligations are optional for variable generation. Participation in the day ahead and real time market is required for demand response resources starting in 2018.[123]

Unless the import capacity resource is associated with an external resource that is on an outage, the total offer amount must equal the Capacity Supply Obligation (CSO).[124] ISO-NE capacity requirements are set annually, typically they are set to their peak summer demand season, and by 2018 demand response units will be included in must-offer obligations.[125]

118 FERC. (2014). Order on Tariff Filing. Retrieved from: https://www.ferc.gov/CalendarFiles/20140124195220-ER14-463-000.pdf
119 FERC. (2014). Order on Tariff Filing. Retrieved from: https://www.ferc.gov/CalendarFiles/20140124195220-ER14-463-000.pdf
120 ISO-NE, FCM. Insufficient Competition Inadequate Supply. Retrieved from: https://www.google.ca/url?sa=t&rct=j&q=&esrc=s&source=web&cd=2&ved=0ahUKEwjY7P7JrpbVAhUF8GMKHVBxBp8QFggrMAE&url=https%3A%2F%2Fwww.iso-ne.com%2Fstatic-assets%2Fdocuments%2F2016%2F01%2Fa02_iso_memo_01_06_16.docx&usg=AFQjCNEnCxUZu08DMczExrM8scexGk1bdA
121 ISO-NE Market Rule 1, Section III.13.2.7.9. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf

122 CRA (2017). Page 24. https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-P1.pdf
123 CRA (2017). Page 24. https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-P1.pdf
124 ISO-NE Market Rule 1, Section III .13.1. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf
125 CRA (2017). Page 24. https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-P1.pdf

Resources that fail to comply with "must-offer" provisions are subject to penalties based on capacity or energy market clearing prices, or a combination of both. Underperforming resources in ISO-NE are penalized, the funds collected are used to reward over-performing resources.[126]

D.5 Pay-for-performance

ISO-NE is implementing a performance incentive regime and will move from an availability basis model to a "pay for performance" design for the 2018/19 commitment year.[127]Section III.13.7 of the ISO-NE Market Rule 1 describes the rules pertaining to performance, payments and charges in the FCM.[128]

D.6 Offer review trigger prices (ORTP): New resources

ISO-NE also relies on a MOPR-type concept and establishes separate offer floors (defined under Market Rule 1 as a "trigger price") for each potential capacity resource type. The offer floors represent a low end competitive offer for each capacity resource.

New resource offers to provide capacity below the offer floors are subject to review by the market monitor. If an offer is found to be below the resource's benchmark costs, the market monitor calculates a new offer by replacing all out-of-market compensation with the market monitor's estimate of the energy revenues.

Offer floor type mitigation generally focuses solely on the impact a capacity supply bid has on market clearing prices. In general, MOPR mitigation is applied automatically to offers below the bid floor without regard to the intent of the entity offering the resource into the capacity auction. As a result, mitigation could be applied regardless of intent to impact market clearing prices.

New resources determined to be pivotal suppliers are subject to mitigation. The market monitor is responsible for reviewing certain bids and offers made in the forward capacity market and will establish an Offer Review Trigger Price for each new resource technology type. Offer reviews from new resources in the forward capacity auction are as described in ISO-NE Market Rule 1.

The Offer Review Trigger Prices for each new resource technology type is established by the IMM and used in the FCA it the offer is mitigated. Resource types are defined under Section III.A.21.1.1 of Market Rule 1 as follows:

[126] CRA (2017). Page 24. https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-P1.pdf
[127] CRA (2017). Page 25. https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-P1.pdf
[128] ISO-NE Market Rule 1, Section III .13.7. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf

Table D.2: Offer review trigger prices for new resource technology type

Technology type	Offer review trigger price ($/kW-month)
Generation resources	
Combustion turbine	$6.503
Combined cycle gas turbine	$7.856
On-shore wind	$11.025
Demand resources: Commercial and industrial	
Load management and / or previously installed distribution generation	$1.008
New distributed generation	Based on generation technology type
Energy efficiency	$0.000
Demand resources: Residential	
Load management	$7.559
Previously installed distributed generation	$1.008
New distributed generation	Based on generation technology type
Energy efficiency	$0.000
Other resources	
All other technology types	Forward capacity auction starting price

FCA procedures for new resources[129]

i. The MMU will establish an Offer Review Trigger Price (ORTP) for each new technology type subject to Section III.A.21.1 in Market Rule 1;
ii. The ORTP is applied to evaluate new resource offers in the forward capacity auction. Offers priced equal to or above the ORTP are not subject to further review;

[129] ISO-NE, FCM Delisting, Retrieved from: https://www.iso-ne.com/static-assets/documents/2016/10/20161017-09-fcm101-delisting.pdf and ISO-NE, FCM Delist, Retrieved from: https://www.iso-ne.com/static-assets/documents/2017/01/20170126_fcm_delist.pdf and ISO-NE, FCM101, Retrieved from: https://www.iso-ne.com/static-assets/documents/2016/10/20161017-02-fcm101-fcm-overview.pdf

iii. A rigorous qualification process is intended to assure that only “real” new resources will be allowed to participate: resources that were not already commercial for the first auction must clear as “new” for one (and only one) FCA;
iv. If a new resource submits offers at prices below the relevant offer review trigger price (ORTP) the resource must submit supporting information in their qualification package;
v. If a resource does not submit this information, it is removed from the auction at ORTP, and the information is reviewed by the MMU.[130]

D.6.1 Resources with multiple technology assets

A weighted average of each ORTP asset technology is calculated based on the expected capacity of the contribution from each asset technology type. The market participant must submit sufficient documentation (as described in this section) to be considered for the weighted average ORTP in their qualification package.

D.6.2 New import capacity resources

New import capacity resources have an ORTP equal to the FCA starting price determined using the table above plus an additional $0.01/kW-month.

Components of cost required

The Offer Review Trigger Price is calculated using the following procedures as specified under Section III.A.21.1.2. ORTPs are calculated for each of the technology types adjusted annually between periods every three years.

If the ORTP is to be recalculated for a new resource, the following costs must be provided by the market participant as described under Section III.A.21.1.2 (b):

> Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm’s length between two unrelated parties).

Demand resources comprised of energy efficiency

The methodology used to recalculate the Offer Review Trigger Price pursuant to each of the technology types and uses data no less often than once every three years.

[130] ISO-NE, Overview of the FCM. Retrieved from: https://www.iso-ne.com/static-assets/documents/2016/10/20161017-02-fcm101-fcm-overview.pdf

New demand resources other than demand resources comprised of energy efficiency

The IMM calculates the Offer Review Trigger Price every three years for each of the technology types except that the model discounts cash flows over the contract life.

Additional costs for demand response (DR)

Where DR is composed of large commercial or industrial customers must submit costs relating to: new equipment costs and annual operating costs such as customer incentives and sales representative commissions, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

ORTP for years where no full recalculation was applied may be adjusted using the following tables:

1) Capital costs included in the capital budgeting model are associated with the following indices:

Table D.3: Capital cost component indices

Cost component	Index
Gas turbines	BLS-PPI “Turbines and Turbine Generator Sets”
Steam turbines	BLS-PPI “Turbines and Turbine Generator Sets”
Wind turbines	Bloomberg Wine Turbine Price Index
Other equipment	BLS-PPI “General Purpose Machinery and Equipment”
Construction labour	BLS “Quarterly Census of Employment and Wages” 2371 Utility System Construction Average Annual Pay: o Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Mass. o On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Mn.
Other labour	BLS ““Quarterly Census of Employment and Wages” 2211 Power Generation and Supply Average Annual Pay: o Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Mass. o On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Mn.
Materials	BLS-PPI “Materials and Components for Construction”
Electric interconnection	BLS-PPI “Electric Power Transmission, Control, and Distribution”
Gas interconnection	BLS-PPI “Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)
Fuel inventories	Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit Price Deflator (GDPDEF)”

2) Fixed Operating and Maintenance Costs included in the capital budgeting model are associated with the following indices:

Table D.4: Fixed operating and maintenance cost component indices

Cost component	Index
Labour, administrative, and general	BLS ""Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: - Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Mass. - On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Mn.
Materials and contract services	BLS-PPI "Materials and Components for Construction"
Site leasing costs	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"

3) The ISO will take each item associated with capital costs, fixed operating, and maintenance costs included in the capital budgeting model for the ninth FCA and will adjust the items by the relevant multiplier. The multiplier is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices.
4) Energy and AS offset values for each technology type in the capital budgeting model will be adjusted using the most recent Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub On-Peak electricity prices for the months in the Capacity Commitment Period beginning June 1, 2021, as published by ICE.
5) Renewable energy credit values in the capital budgeting model will be updated based on the most recent MA Class 1 REC price for the vintage closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

D.6.3 New capacity resources, new import capacity resources, and other new capacity resources

Section III.A.21.2 of Market Rule 1 details the Offer Review Trigger Price calculation process for new capacity resources, and excludes resources with an offer floor price greater than the FCA starting price.[131] Offer Review Trigger Price calculations and cost information required for new

[131] ISO-NE, Market Rule 1, Section III.A.21.2. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf

import capacity resources are detailed under Section III.13.1.3.5.7 of Market Rule 1, Appendix A.[132] Other new capacity resource Offer Review Trigger Prices are also calculated and are detailed under Section III.A.21.2. Relevant cost information requirements for other new capacity resources are detailed under Section III.A.21.2[133]

D.7 Forward capacity market de-list mitigation: Existing resources

The IMM reviews de-list bids submitted by existing resources to determine if a de-list bid exceeds a predefined threshold and if it is consistent with resource's going forward and opportunity costs.[134] Opportunity costs are costs that can be avoided by not participating in the capacity market.[135] Existing resources participating in the FCA and deemed pivotal are subject to mitigation.

Existing resources may choose one of two options; (i) take no action and clear as price takers, or (ii) submit one de-list bid type into the FCA.[136]

If an existing generating capacity resource does not submit a static de-list bid, an export bid, an administrative export de-list bid, a permanent de-list bid, or a retirement de-list bid in the forward capacity auction qualification process, the resource will be entered into the forward capacity auction.[137]

De-list types:[138]

i. Static de-list bid
ii. Export bid
iii. Administrative export de-list bid
iv. Static de-list bid (ambient air)
v. Dynamic de-list bid
vi. Retirement and permanent de-list bid

De-list bids are submitted by the existing capacity qualification deadline. Options for existing resources when submitting de-list bids are described below:

[132] ISO-NE Market Rule 1, Section III .13.1.3.5.7. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf
[133]ISO-NE Market Rule 1, Section III.A.21.2. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf
[134] ISO-NE, FCM Delist. Retrieved from: https://www.iso-ne.com/static-assets/documents/2017/01/20170126_fcm_delist.pdf
[135] ISO-NE, FCM Delist. Retrieved from: https://www.iso-ne.com/static-assets/documents/2017/01/20170126_fcm_delist.pdf
[136] CRA (2017). Page 80. https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-Appendices.pdf
[137] https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf, section III.13.1.2.3.
[138] ISO-NE, FCM Delist. Retrieved from: https://www.iso-ne.com/static-assets/documents/2017/01/20170126_fcm_delist.pdf

Table D.5: ISO-NE de-list bid type

De-List bid type	Description
Static	Option to remove capacity from the capacity market at or above the Dynamic De-List Bid Threshold of $5.50/kW-month for a single capacity commitment period. Cost justification required.[139]
Export	Option to export all or part of capacity from the FCA to export that capacity during the commitment period.[140] Export Bids at or above the Dynamic De-List Bid Threshold are subject to review.[141] Cost justification required.
Administrative export	Option to remove capacity from market if an export de-list bid has been entered and cleared in a prior FCA.[142]
Static (ambient air)	Option to remove capacity from market for up to megawatt amount that may not be physically available due to difference between the summer qualified capacity at 90 degrees (Celsius) and expected rating of resource at 100 degrees.[143]
Dynamic	Submitted during the auction, existing resource has the option to remove capacity from capacity market at prices below $5.50kWmonth during a single capacity commitment period.[144]
Retirement	Option to permanently remove capacity from all markets for the entire capacity commitment period, subject to cost justification.[145]
Permanent	Option to permanently remove capacity from the capacity market for the entire capacity commitment period, subject to cost justification.[146]

D.7.1 IMM de-list bid review process

The market monitor examines the validity of a variety of bid types: de-list bids priced above 0.8 x CONE, bids for quantities less than seasonal summer claimed capability (for evidence of physical withholding), all import bids, entities submitting both new capacity and delist bids, new capacity bids below 0.75 x CONE.[147]

[139] ISO-NE, FCM Delist. Retrieved from: https://www.iso-ne.com/static-assets/documents/2017/01/20170126_fcm_delist.pdf
[140] ISO-NE, FCM Delist. Retrieved from: https://www.iso-ne.com/static-assets/documents/2017/01/20170126_fcm_delist.pdf
[141] ISO-NE, Market Rule 1, Section III.13.1.2.3.1.3. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf
[142] ISO-NE, FCM Delist. Retrieved from: https://www.iso-ne.com/static-assets/documents/2017/01/20170126_fcm_delist.pdf
[143] ISO-NE, FCM Delist. Retrieved from: https://www.iso-ne.com/static-assets/documents/2017/01/20170126_fcm_delist.pdf
[144] ISO-NE, FCM Delist. Retrieved from: https://www.iso-ne.com/static-assets/documents/2017/01/20170126_fcm_delist.pdf
[145] ISO-NE, FCM101. Retrieved from: https://www.iso-ne.com/static-assets/documents/2016/10/20161017-09-fcm101-delisting.pdf
[146] ISO-NE, FCM101. Retrieved from: https://www.iso-ne.com/static-assets/documents/2016/10/20161017-09-fcm101-delisting.pdf
[147] Brattle (2007). Page 90. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf

The market monitor may also determine whether delist bids are consistent with resource's net going forward costs (NGFC), risk premium and opportunity costs through evaluation of:

- Going forward costs
- Revenue and production costs
- Risk premiums
- Capacity performance payments

Resources seeking to de-list at or above $1/kW-month, however, must submit data to be reviewed by the Internal Market Monitor. If the bid is judged to be inconsistent with the net risk-adjusted going-forward costs of the unit, it will be excluded from the auction or may select an alternative price determined by the Internal Market Monitor.[148]The IMM review process is illustrated in the table below.

Table D.6: ISO-NE IMM de-list bid review process[149]

Compliant de-list bid	Non-compliant de-list bid
Bid is consistent with net going forward costs (NGFC). Resource may exit the FCA and is subsequently reviewed for reliability.	Bid is inconsistent with net going forward costs (NGFC). An alternate bid is determined by the IMM at a level where the resource may exit the FCA. The alternate bid calculation is based on initial documentation provided and information provided following consultations between the participant and IMM. The resource is subject to a reliability review.

Submission of cost data

Existing generating capacity resource submitting a de-list bid must include detailed cost data to allow the ISO to determine the asset-specific going forward costs for each asset associated with the station and the station going forward common costs.

As described under Section III.13.1.2.3.1.6.3 of Market Rule 1, the IMM will review common costs as follows:

> (i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.
>
> (ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the preferred de-list order.

[148] FERC (2013). Page 23. https://www.ferc.gov/CalendarFiles/20130826142258-Staff%20Paper.pdf
[149] ISO-NE, FCM Delist. Retrieved from: https://www.iso-ne.com/static-assets/documents/2017/01/20170126_fcm_delist.pdf

(iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive delisting of each individual asset in preferred de-list order.

(iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

Section III.13.1.2.3.2 of Market Rule 1 describes the process of review for static de-list bids and export bids, permanent de-list bids and retirement de-list bids at or above the dynamic de-list bid threshold. The IMM subsequently determines if the bid is consistent with net going forward costs, reasonable ex expectations about the resource's capacity performance payments, reasonable risk premium assumptions, the resource's reasonable opportunity costs.

D.7.2 Dynamic de-list bid threshold

Under Section III.13.1.2.3.1A, the dynamic de-list threshold rule presumes that de-list bids below this threshold are not attempts to raise the clearing price through economic withholding.[150]

- The dynamic de-list bid threshold for a FCA is $5.50/kW-month.
- The dynamic de-list bid threshold will be recalculated no less often than once every three years.
- When the dynamic de-list bid threshold is recalculated, the IMM will review the results of the recalculation with stakeholders.[151]

The following table illustrates de-list thresholds and timing used by the IMM to determine if mitigation applies to a particular de-list bid.

[150] ISO-NE, FCM Delist. Retrieved from: https://www.iso-ne.com/static-assets/documents/2017/01/20170126_fcm_delist.pdf
[151] ISO-NE, Market Rule 1, Section III.13.1.2.3.1.A https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf,

Table D.7: De-list thresholds and timing[152]

De-list bid category	IMM review threshold	Timing of de-list bid submission
Static	Bids at or above the dynamic de-list threshold	Existing capacity qualification deadline
Export (including Administrative)	Bids at or above the dynamic de-list threshold	Existing capacity qualification deadline
Dynamic	No IMM review required	During auction cycle
Permanent and Retirement	Each de-list bid greater than 20 MW that is above the dynamic de-list bid threshold	Existing Capacity Retirement Package or the Existing Capacity Qualification Package

D.7.3 Mitigation process for existing resources

As illustrated in Table D.7, the mitigation process for existing capacity resources can be described as follows: [153]

i. If an existing capacity resource does not submit a static, export, administrative export, or permanent/retirement delist bid in the FCA qualification process, the resource is entered into FCA as a price-taker;
ii. Existing resources are qualified to participate based on historical capabilities;
iii. Existing resources must submit permanent de-list, static de-list, or export bids (price/quantity pairs) prior to the FCA for resources attempting to withdraw;
iv. Bid prices are submitted before the qualification deadline ;
v. Bid price will be evaluated against Net Risk Adjusted Going Forward Costs (NRAGFC);
vi. If bid is not deemed to be consistent with their NRAGFC, then the resource has the option to accept the ISO mitigated bid or the de-list will not be used in the auction.

Mitigation by existing resource type is discussed in further detail in the sections that follow.

D.7.4 Mitigation of static de-list bids and export bids

Section III.13.1.2.3.2.1.2.A of Market Rule 1 describes the process of mitigation of static de-list bids and export bids. The IMM determines a resource's net going forward costs, reasonable

[152] ISO-NE, Market Rule 1, Section 13.1.2.3.2.1. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf
[153] ISO-NE, FCM Delist. Retrieved from: https://www.iso-ne.com/static-assets/documents/2017/01/20170126_fcm_delist.pdf and ISO-NE, FCM101. Retrieved from: https://www.iso-ne.com/static-assets/documents/2016/10/20161017-09-fcm101-delisting.pdf

expectations about the resource's capacity performance payments, reasonable risk premium assumptions, and reasonable opportunity costs using the following formula: [154]

$$Net\ Going\ Forward\ Costs = \frac{\big(GFC - (IMR - PER)\big) * InfIndex}{(CQ_{Summer}, kW) * (12, months)}$$

where

IMR = annual infra-marginal rents, in dollars. Calculated by subtracting all submitted cost data representing the cumulative actual cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the existing generating capacity resource's total ISO market revenues. If resource does not participate in energy & AS markets during the capacity commitment period, the value is equal to $0.00.

PER = resource-specific annual peak energy rents, in dollars. As soon as practicable, this value will be calculated by the ISO and available to the lead market participant upon request.

InfIndex = inflation index.

$$InfIndex = (1 + i)^4$$

where "i" is the most recent reported 4-year expected inflation number published by the Federal Reserve Bank of Cleveland at the beginning of the qualification period.

GFC = annual going forward costs, in dollars. These are costs that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the capacity commitment period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders).

Cost components

Cost components may include: staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a capacity supply obligation. These expenses may not be included if the resource does not participate in the energy & AS markets during the capacity commitment period. Service of debt is not a going forward cost.

The market monitor will also consider adjustments; the adjustments must be based on known and measurable conditions and supported by appropriate documentation to reflect those costs.

$$CQ_{Summer}kW = Capacity\ Seeking\ to\ De\ List\ in\ kW$$

In no case shall this value exceed the resource's summer qualified capacity.

[154]ISO-NE, Market Rule 1, Section III 13.1.2.3.2.1.2.A. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf

D.7.5 Mitigation of permanent de-list bids and retirement de-list bids[155]

Section III.13.1.2.3.2.1.2.B of Market Rule 1 describes the process of mitigation of permanent and retirement de-list bids. Mitigation occurs if the de-list bid price(s) submitted by the market participant are more than 10% greater than the IMM-accepted de-list bid price(s).

The IMM calculates a bid that is consistent with the sum of the net present value of the resource's expected cash flows plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable opportunity costs as described under Section III.13.1.2.3.2.1.2.B:

> The net present value of the Existing Capacity Resource's expected cash flows is equal to the net present value of the Existing Capacity Resource's net annual expected cash flows over the resource's remaining economic life plus the net present value of the resource's expected terminal value, using the resource's discount rate, divided by the product of the resource's Qualified Capacity (in kilowatts) and 12 months.

Net annual expected cash flow for the first capacity commitment period is the resource's expected annual net operating profit excluding expected capacity revenues less its expected capital expenditures in the capacity commitment period.

Net annual expected cash flow for each subsequent capacity commitment period is the resource's expected annual net operating profit less its expected capital expenditures in the capacity commitment period.

Cost components

Expected net operating profit

This includes information on expected labor, maintenance, taxes, insurance, administrative and other normal expenses that can be avoided or not incurred if the resource is retired or permanently de-listed may be included. Service of debt is not an avoidable cost and may not be included.

Expected capacity revenues

This includes forecasted expected capacity prices including expected resource additions, resource retirements, estimated installed capacity requirements, estimated local sourcing requirements, expected market conditions, and any other assumptions used to develop the forecasted expected capacity price in each capacity commitment period.

[155] ISO-NE, Market Rule 1, Section III.13.1.2.3.2.1.2.B. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf

Expected capital expenditures

This includes expected capital investments that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the capacity commitment periods.

Expected terminal value

For resources with five years or less of remaining economic life, is the lead market participant's expected revenue less expected costs associated with retiring or permanently de-listing the resource.

For resources with more than five years of remaining economic life, the expected terminal value in the fifth year of the evaluation period is the lead market participant's expected revenue less expected costs associated with retiring or permanently de-listing the resource at the end of the resource's economic life plus the net present value of the existing capacity resource's net annual expected cash flows from the sixth year of the evaluation period through the end of the resource's remaining economic life, using the resource's discount rate.

Discount rate

A detailed description and sources of assumptions associated with the cost of capital, risks and any other assumptions used to develop the weighted average cost of capital for the existing capacity resource adjusted for risk.

Remaining economic life

Evaluation periods range from one to five years. For each evaluation period, the Internal Market Monitor will calculate the net present value of (a) the annual expected net operating profit minus annual expected capital expenditures assuming the capacity clearing price for the first year is equal to the FCA starting price and (b) the expected terminal value of the resource at the end of the given evaluation period.

D.7.6 Additional information requirements for mitigated resources

Expected capacity performance payments

Resources subject to mitigation must include expectations regarding the applicable capacity balancing ratio. The expectations must take into account the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.[156]

Risk premium

Resources that submit a static de-list bid or an export bid at or above the dynamic de-list bid threshold that is to be reviewed by the IMM must provide documentation detailing any risk premium included in the bid. Proper documentation includes all components of physical and financial risk reflected in the bid price. Risk premiums may include, catastrophic events, a higher

[156] ISO-NE, Market Rule 1, section III.13.1.2.3.2.1.3. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf

than expected amount of reserve deficiencies, and performing scheduled maintenance during reserve deficiencies.[157]

Opportunity costs

Resource submitting a static de-list bid or an export bid, permanent de-list bid or retirement de-list bid at or above the dynamic de-list bid threshold may incur opportunity costs that are not reflected in the net going forward costs, net present value of expected cash flows, expected capacity performance payments, discount rate, or risk premium components of the bid. The market participant must provide documentation of such costs in the existing capacity qualification package. [158]

As described under Section III.13.1.2.3.2.1.5 of Market Rule 1, opportunity costs may include items such as:

- Opportunity costs associated with major repairs necessary to restore decreases in capacity;
- Capital projects required to operate the plant as a capacity resource or other uses of the resource as long as the costs are substantiated by evidence of a repair plan;
- Documented business plan and fundamental market analysis;
- Other independent and transparent trading index or indices as applicable.

Static de-list bid incremental capital expenditure recovery schedule

Static de-list bids for reductions in ratings due to ambient air conditions are not subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

Except as described below, the IMM will review all static de-list bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

[157] ISO-NE, Market Rule 1, Section III.13.1.2.3.2.1.4. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf
[158] ISO-NE, Market Rule 1, Section III.13.1.2.3.2.1.5. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf

Table D.8: Static de-list bid incremental capital expenditure recovery schedule[159]

Age of existing resource (years)	Remaining life (years)	Annual rate of capital cost recovery
1 to 5	30	0.106
6 to 10	25	0.110
11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A market participant may request that a different pre-tax weighted average cost of capital be used to determine the resource's annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the existing capacity qualification package.

The annual rate of capital cost recovery may be replaced from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource's annual rate of capital cost recovery will be determined according to the following formula:

$$Adjusted\ Pre\ Tax\ Weighted\ Average\ Cost\ of\ Capital = \frac{Cost\ of\ Capital}{(1 - (1 + Cost of Capital^{Remaining\ Life})}$$

where

Cost of Capital is the adjusted pre-tax weighted average cost of capital and

Remaining Life is the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

D.8 Energy and ancillary services market offer thresholds during shortage events

A supply offer made by each resource with a capacity supply obligation that is off-line during a shortage event is evaluated for competitiveness in the day-ahead and real-time market.[160]

[159] ISO-NE MEMO DELIST BIDS a07_imm_memo_01_14_15.doc. Retrieved from: https://www.google.ca/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=0ahUKEwiToN2rtZbVAhUC4mMKHYdcCaUQFggoMAA&url=https%3A%2F%2Fwww.iso-ne.com%2Fstatic-assets%2Fdocuments%2F2015%2F01%2Fa07_imm_memo_01_14_15.docx&usg=AFQjCNFw5eDitH-yKNQQw6V3AxvIs7gYug

[160] ISO-NE, Market Rule 1, Section III.A.8. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf

Reference levels are calculated using the ISO-NE energy and ancillary services market cost-based method as described earlier under section C.3.1 and are used in the evaluation of offers made during a shortage event. Section III.A.8 of the ISO-NE Market Rule 1 details the evaluation as follows:

> (a) Hours Evaluated. For Supply Offers in the Day-Ahead Energy Market, competitiveness is evaluated for all hours of the Operating Day during which a Shortage Event occurs. For Supply Offers in the Real-Time Energy Market competitiveness is evaluated for the last hour that the Resource could have been committed to be online at its Economic Minimum Limit at the start of the Shortage Event, taking into account the Resource's Start-Up Time and Notification Time.
>
> (b) Competitiveness Evaluation of Energy Offer At Low Load.[161]
>
> (i) If the Resource is not in a constrained area as determined under Section III.A.5.2.2, then the Supply Offer is not competitive if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.
>
> (ii) If the Resource is in a constrained area as determined under Section III.A.5.2.2, then the Supply Offer is not competitive if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.
>
> (c) Competitiveness Evaluation of Energy Offer Above Low Load. If a Supply Offer evaluated for competitiveness pursuant to Section III.A.8 (b) above is competitive for an hour, then the energy price parameter for each incremental Supply Offer block above the Resource's Economic Minimum Limit shall be evaluated for competitiveness using the thresholds identified in Section III.A.5.5.1.2, for Resources not in a constrained area, and the thresholds identified in Section III.A.5.5.2.2, for Resources in a constrained area, in order of lowest energy price to highest energy price. If any Supply Offer block is non-competitive, then that block and all blocks above it must be non-competitive, and all blocks below it competitive.
>
> (d) Low Load Cost test. Low Load Cost is the cost of operating the Resource at its Economic Minimum Limit for its Minimum Run Time, Low Load Costs is calculated as the sum of:
>
> i. The Start-Up Fee (cold start);

[161] ISO-NE, Market Rule 1, Section III.A.5. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf

ii. The sum of the No Load Fees for the Resource’s Minimum Run Time; and

iii. The sum of the hourly values resulting from the multiplication of the price of energy at the Resource’s Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Resource’s Minimum Run Time.

E NYISO energy and ancillary services mitigation

E.1 Definitions in this appendix

In this appendix,

(1) **"OATT"** means Operating Agreement Tariff;
(2) **"IMM"** means the NYISO Internal Market Monitor.

E.2 NYISO energy and ancillary services market mitigation description

Conduct-and-impact tests are implemented as ex ante mitigation mechanisms in New York ISO's energy markets. NYISO does not use explicit structural tests, but have procedures in place to identify regions subject to transmission constraints. As such, structural considerations in the form of more stringent mitigation measures for those regions are considered as they may be more prone to local exercises of market power.[162] For example, the energy and capacity bids of generators located in the transmission-constrained load pocket of New York City are subject to tighter thresholds.[163]

Mitigation is triggered through conduct-and-impact tests. Mitigation is applied if bids and the impact on market clearing prices exceed certain predefined pricing thresholds as specified under Attachment H of the NYISO OATT. The automated mitigation process is completed before the "official" market-clearing price is determined.[164] Conduct-and-impact tests are also in place for ancillary service markets in NYISO.[165]

Conduct subject to mitigation is defined as conduct that would not be in the economic interest of market participants in the absence of market power. This includes conduct relating to: physical withholding, economic withholding, or uneconomic production resulting in increased market clearing prices.[166]

Frequency of Testing

NYISO's real-time market Automated Mitigation Procedure (AMP) executes in conjunction with Real Time Commitment every 15 minutes and incorporates both conduct tests and impact tests.[167]

[162] Brattle (2007). Page 74. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[163] Brattle (2007). Page 74. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[164] Brattle (2007). Page 6. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[165] Brattle (2007). Page 75. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[166] Brattle (2007). Page 32. http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[167] NYISO Market Participant User's Guide. Page 3-3. http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Guides/User_Guides/mpug.pdf

E.3 Real-time commitment (RTC) and automated mitigation process (AMP)

Automated market power mitigation measures are evaluated by the Real Time Commitment (RTC) software. The RTC runs two tandem evaluations these may affect the calculation of real-time LBMPs.[168] If the conduct thresholds are exceeded, a second evaluation occurs to assess the impact of the mitigation measures.

The RTC software runs the first evaluation, which assists in determining the schedules and prices that would result using an original set of offers before any additional mitigation measures are applied. The second evaluation is referred to as the real-time automated mitigation process (AMP). The AMP process assists in determining the schedules and prices that would result from using the original set of offers and bids after any necessary mitigation measures have been applied.[169]

Frequency of conduct-and-impact tests

NYISO will perform the two analogous RTC evaluations in a manner that enables it to implement mitigation measures one RTC run, e.g., every fifteen minutes, in the future.

E.4 Conduct-and-impact test

E.4.1 Physical withholding conduct threshold

The conduct thresholds discussed in this section are defined under Section 23.3 of the NYISO Tariff, Attachment H, where the criteria for imposing mitigation measures are defined. The following initial thresholds will be implemented by the NYISO to identify physical withholding conduct of a generator.[170]

[168] NYISO OATT, Section 17.1.2.1.4. http://www.nyiso.com/public/webdocs/markets_operations/committees/mc/meeting_materials/2013-12-18/4_MST%2017%201%20FID717%20-%20GTDC%20MIWG%2020131112%20redline.pdf

[169] NYISO OATT, Section 17.1.2.1.4. http://www.nyiso.com/public/webdocs/markets_operations/committees/mc/meeting_materials/2013-12-18/4_MST%2017%201%20FID717%20-%20GTDC%20MIWG%2020131112%20redline.pdf

[170] NYISO OATT, Section 23.3.1.1. http://www.nyiso.com/public/webdocs/markets_operations/committees/mc/meeting_materials/2013-12-18/4_MST%2017%201%20FID717%20-%20GTDC%20MIWG%2020131112%20redline.pdf

Table E.1: Conduct thresholds for physical withholding

New York region	Physical withholding
Unconstrained area	Physical withholding exceeding: (i) 10 percent of a Generator's capability; (ii) 100 MW of a Generator's capability; (iii) 5 percent of the total capability of a Market Party and its Affiliates; (iv) 200 MW of the total capability of a Market Party and its Affiliates.
Constrained area Generators having a shadow price greater than $0.04/MWh, are considered to be located in Constrained Area regions	Physical withholding exceeding: (i) 10 percent of a Generator's capability; (ii) 50 MW of a Generator's capability; (iii) 5 percent of the total capability of a Market Party and its Affiliates; (iv) 100 MW of the total capability of a Market Party and its Affiliates.

Pursuant to OATT Section 23.3.1.1.1.1, the prior conduct thresholds apply unless generators are operating in real-time at lower output levels than expected following NYISO's dispatch instructions, and resulting in a difference in output that exceeds:[171]

> (i) 15 minutes times a Generator's stated response rate per minute at the output level that would have been expected had the Generator followed the ISO's dispatch instructions;
>
> (ii) 100 MW for a Generator's capability;
>
> (iii) 200 MW of the total capability of a Market Party and its Affiliates.

Similarly, generators having a shadow price greater than $0.04/MWh, are considered to be located in constrained area regions. The prior constrained area physical withholding conduct thresholds apply unless generators are operating in real-time at lower output levels than would have been expected following NYISO's dispatch instructions, and resulting in a difference in output that exceeds:

> (i) 15 minutes times a Generator's stated response rate per minute at the output level that would have been expected had the Generator followed the ISO's dispatch instructions

[171] NYISO OATT, Section 23.3.1.1.1.2. http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2015-05-20/agenda%208%20MST%2023.3%20redline.pdf

(ii) 50 MW of a Generator's capability

(iii) 100 MW of the total capability of a Market Party and its Affiliates.[172]

If it is determined the generator exceeds the aforementioned conduct thresholds, the resource is subject to mitigation screens to evaluate impact thresholds by the Market Monitor as described under section E.4.4 below.

E.4.2 Economic withholding conduct threshold

Conduct thresholds for unconstrained areas

Pursuant to Section 23.3.1.2 of the NYISO OATT, economic withholding for generators in areas other than constrained areas, or in constrained areas but not subject to transmission constraints affecting the constrained area will be subject to the following thresholds: [173]

[172] NYISO OATT, Section 23.3.1.1.1.2. http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2015-05-20/agenda%208%20MST%2023.3%20redline.pdf

[173]NYISO OATT, Section 23.3.1.2. http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2015-05-20/agenda%208%20MST%2023.3%20redline.pdf

Table E.2: Conduct thresholds for identifying economic withholding of a non-constrained area generator

Types of offers	Threshold for identifying economic withholding for a non-constrained area resource
Incremental energy and minimum generation bids	An increase exceeding 300 percent or $100 per MWh, whichever is lower; provided, however, that incremental energy or minimum generation bids below $25 per MWh will be deemed not to constitute economic withholding.
Operating reserves and regulation service bids	Operating reserves and regulation capacity bids: A 300 percent increase or an increase of $50 per MW, whichever is lower; provided, however, that such bids below $5 per MW will be deemed not to constitute economic withholding.
Regulation movement bids	A 300% increase.
Start-up bids	A 200% increase.
Time-based bid parameters	An increase of 3 hours, or an increase of 6 hours in total for multiple time-based bid parameters. Time-based bid parameters include, but are not limited to, start-up times, minimum run times and minimum down times.
Bid parameters expressed in units other than time or dollars, including the MW component of a minimum generation bid	A 100% increase for parameters that are minimum values, or a 50% decrease for parameters that are maximum values (including but not limited to ramp rates and maximum stops).

Conduct thresholds for constrained areas

Pursuant to Section 23.3.1.2.2 of the NYISO OATT, economic withholding conduct thresholds are applied to generators in Constrained Areas and are illustrated in the table below.

Table E.3: Thresholds for identifying economic withholding of a constrained-area generator

Types of offers	Threshold for identifying economic withholding for a constrained resource
Incremental energy and minimum generation bids	For intervals in which an interface or facility into the area in which a generator is located in a constrained area, the lower of the thresholds specified for areas that are not constrained areas or a threshold determined in accordance with the following formula: $Threshold = \frac{2\% * Average\ Price * 8760}{Constrained\ Hours}$
Operating reserves and regulation service bids	A 300 percent increase or an increase of \$50/MW, whichever is lower; provided that such bids below \$5/MW will be deemed not to constitute economic withholding.
Start-up bids	A 50% increase.
Time-based bid parameters	An increase of 3 hours or an increase of 6 hours in total for multiple time-based bid parameters. Time-based bid parameters include, but are not limited to, start-up times, minimum run times and minimum down times.
Bid parameters expressed in units other than time or dollars, including the MW component of a minimum generation bid	A 100% increase for parameters that are minimum values, or a 50% decrease for parameters that are maximum values, including but not limited to ramp rates and maximum stops.

Energy and minimum generation bids for the real-time market

From the above table, the conduct threshold is determined in accordance with the following formula:

$$Threshold = \frac{2\% * Average\ Price * 8760}{Constrained\ Hours}$$

where

Average Price = real-time or day-ahead average price in the constrained area over the past 12 months, adjusted for fuel prices and out-of-merit generation.

Constrained Hours = total number of minutes of the past 12 months, where the real-time or day-ahead shadow price exceeded \$0.04/MWh. In-city area constrained hours must include the total number of minutes that a formal storm watch is in effect. The constrained area conduct threshold is designed to become less stringent as the number of congested hours falls.[174]

Energy and minimum generation bids for the day-ahead market

For all constrained hours for the generator being bid, a threshold is determined in accordance using the following formula:

$$Threshold = \frac{2\% * Average\ Price * 8760}{Constrained\ Hours}$$

Ancillary service markets conduct thresholds

Constrained area conduct thresholds for the identification of economic withholding in ancillary service markets are described in the table below.

Table E.4: Ancillary service market conduct thresholds for identifying economic withholding of a constrained area generator

Types of offers	Threshold for identifying economic withholding
Operating reserves and regulation service bids	Operating Reserves and Regulation Capacity Bids: A 300 percent increase or an increase of $50 per MW, whichever is lower; provided, however, that such Bids below $5 per MW will be deemed not to constitute economic withholding.
Start-up bids	A 50% increase.
Time-based bid parameters	An increase of 3 hours, or an increase of 6 hours in total for multiple time-based Bid parameters. Time-based Bid parameters include, but are not limited to, start-up times, minimum run times and minimum down times.
Bid parameters expressed in units other than time or dollars, including the MW component of a minimum generation bid (also referred to as the "minimum operating level")	A 100% increase for parameters that are minimum values, or a 50% decrease for parameters that are maximum values (including but not limited to ramp rates and maximum stops).

Generators outside the evaluation process to protect NYCA or local system reliability

The following thresholds are applied by NYISO to identify economic withholding of generators committed outside the ISO's economic evaluation process to protect New York Control Area (NYCA) or local area reliability in non-constrained areas. If conduct thresholds are exceeded, further mitigation is required.

[174] FERC (2014). Page A-12. https://www.ferc.gov/legal/staff-reports/2014/AD14-14-mitigation-rto-iso-markets.pdf

Table E.5: Conduct thresholds for identifying economic withholding for a generator outside evaluation process to protect NYCA or local system reliability

Bid or bid components submitted	Thresholds for identifying economic withholding
Minimum generation bid	Exceeded the generator's minimum generation bid reference level by the greater of 10% or $10/MWh
Incremental energy bid	Exceeded the generator's incremental energy bid reference level by the greater of 10% or $10/MWh
Start-up bid	Exceeded the generator's start-up bid reference level by 10%
Minimum run time, start-up time, and minimum down time	Exceeded the generator's minimum run time, start-up time, and minimum down time reference levels by more than one hour in aggregate
Minimum generation MW	Exceeded the generator's minimum generation MW reference level by more than 10%
Maximum number of stops per day	Decreased the generator's maximum number of stops per day below the generator's reference level by more than one stop per day, or to one stop per day

E.4.3 Uneconomic production conduct threshold

Section 23.3.1.3.1.1 of the NYISO OATT describes conduct thresholds for evaluation of uneconomic production and is illustrated in the table below:[175]

[175] NYISO OATT, Section 23.3.1.3. http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2015-05-20/agenda%208%20MST%2023.3%20redline.pdf

Table E.6: Conduct thresholds for identifying uneconomic production

Type of offer	Uneconomic production threshold
Incremental energy bids	Energy scheduled at an LBMP that is less than 20 percent of the applicable reference level and causes or contributes to transmission congestion.
Output levels	An output difference exceeding: (i) 15 minutes times a generator's stated response rate per minute at the output level that would have been expected had the generator followed the ISO's dispatch instructions; (ii) 100 MW for a generator; (iii) 200 MW of the total capability of a Market Party and its Affiliates.

E.4.4 Market impact thresholds

Section 23.3.2.1 of the NYISO OATT states when conduct thresholds are exceeded, a generator avoids mitigation if the conduct did not cause or contribute to a material change in one or more prices in the ISO Administered Market; or did not substantially increase guarantee payments to participants in the New York electricity market.

The constrained area impact threshold assesses whether the resource offer will raise the clearing price by an amount that exceeds the constrained area conduct threshold.[176] Impact threshold tests for constrained area generator bids are applied in RTM and DAM. The impact thresholds for material price effects or changes in guarantee payments are described in Section 23.3.2.1 of the OATT and are illustrated in the table below.[177]

[176] FERC (2014). Page A-12. https://www.ferc.gov/legal/staff-reports/2014/AD14-14-mitigation-rto-iso-markets.pdf
[177] NYISO OATT, Section 23.3.2.1.
http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2015-05-20/agenda%208%20MST%2023.3%20redline.pdf

Table E.7: Market impact thresholds

Market price	Market impact threshold
Constrained area impact threshold	Assesses whether the resource offer will raise the clearing price by an amount that exceeds the constrained area conduct threshold. Impact threshold tests for constrained area generator bids are applied in RTM and DAM using the following formula: $$Threshold = \frac{2\% * Average\ Price * 8760}{Constrained\ Hours}$$
Hourly day-ahead or real-time energy market LBMP	An increase of 200 percent or $100 per MWh, whichever is lower, in the hourly day-ahead or real-time energy LBMP at any location, or of any other price in an ISO Administered Market.
Bid production cost guarantee payments	An increase of 200 percent, or 50 percent for generators in a constrained area in bid production cost guarantee payments to a Market Party for a generator for a day.

E.5 Ex post mitigation: Filings with FERC

The NYISO may file under section 205 of the *Federal Power Act* with FERC prior to applying mitigation to determine an appropriate mitigation measure if a market participant's conduct does not rise to the conduct thresholds but had a significant effect on market prices or guarantee payments as specified below:

Table E.8: Thresholds for filings with FERC

Market price or guarantee payments	Thresholds for filing with FERC
Day-ahead or real-time energy market LBMP	An increase of 100 percent in the hourly day-ahead or real-time energy LBMP at any location, or of any other price in an ISO Administered Market.
Bid production cost guarantee payments	An increase of 100 percent in bid production cost guarantee payments to a Market Party for a generator for a day, or an increase of 100 percent in any other guarantee payment over the time period used by the ISO to calculate the guarantee payment.

E.6 Ancillary services market price caps

In addition to conduct-and-impact tests, NYISO implements price caps in the ancillary services market. Price caps for different ancillary service markets are illustrated in the table below.[178]

Table E.9: NYISO Ancillary Services Market Price Caps

NYISO ancillary service product	Price cap
Regulation	$1,000/MW
Responsive reserve	n/a
Spinning reserve	$1,000/MW
Non-spinning reserve	$1,000/MW; non-synchronized 10-minute reserve reference levels are capped at $2.52/MW.
Forward reserve	n/a

E.7 Reference-level calculations

Based on available data, the market monitor will select reference level offer caps in the following order: bid-based, LBMP-based, and negotiated cost-based. If data is unavailable, the market monitor will use the ISO estimate or the average of competitive bids from similar units using available operating costs data or physical parameter input of the resource.[179]

E.7.1 Bid-based reference levels

To maintain appropriate reference levels the following rules are applied to offers failing conduct and impact tests. Section 23.3.1.14.1 of the NYISO OATT details the method of calculating reference levels as using the lower of the mean or the median of a generator's accepted bids or bid components, taking effect in the hour beginning at 6 a.m. to the hour beginning at 9 p.m., excluding weekend and designated holiday hours, in competitive periods over the most recent 90 day period.[180]

When developing bid-based reference levels the following bids are excluded: [181]

[178] Brattle (2007). Page 94.
http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[179] NYISO OATT, Section 23.3.1.4.2.
http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2015-05-20/agenda%208%20MST%2023.3%20redline.pdf
[180] NYISO OATT, Section 23.3.14.1.
http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2015-05-20/agenda%208%20MST%2023.3%20redline.pdf
[181] NYISO OATT, Section 23.3.14.1.
http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2015-05-20/agenda%208%20MST%2023.3%20redline.pdf

(i) Incremental energy and minimum generation bids below $15/MWh from its development of bid-based reference level;

(ii) Minimum generation bids submitted for a Generator that was committed on the day prior to the dispatch day for the hours during the dispatch day that the generator needs to operate in order to complete the minimum run time specified in the bid it submitted for the hour in which it was committed; and

(iii) Bids that would cause a reference level to deviate substantially from a generator's marginal cost.

E.7.2 LBMP-based reference levels

Reference levels are calculated for incremental energy and minimum generation levels using the mean of the LBMP at the generator's location during the lowest-priced 50 percent of the hours that the generator was dispatched over the most recent 90 days with available data and is adjusted for changes in fuel prices.[182]

To maintain appropriate reference levels when developing LBMP-based reference levels the following bids are excluded: [183]

(i) LBMPs below $15/MWh from its development of LBMP-based reference levels.

(ii) LBMPs during hours when a Generator was scheduled as a Day-Ahead Reliability Unit or via a Supplemental Resource Evaluation or was Out-of-Merit Generation, from its development of that Generator's LBMP-based reference levels.

(iii) Generators committed on the day prior to the Dispatch Day, LBMPs for the hours during the Dispatch Day that the Generator needs to operate in order to complete the minimum run time specified in the Bid it submitted for the hour in which the Generator was committed from the ISO's development of that Generator's LBMP-based reference levels.

(iv) LBMPs that would cause a reference level to deviate substantially below a Generator's marginal cost.

E.7.3 Negotiated cost-based reference levels

Reference levels for a generator's energy and ancillary service bids are intended to reflect the generator's marginal costs. The generator's marginal costs include an assessment of the incremental operating costs using the following formula:[184]

[182] NYISO OATT, Section 23.3.1.4.2. http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2013-01-10/MST%2023%203%20FID280_v1%20r1.pdf

[183] NYISO OATT, Section 23.3.1.4.2. http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2013-01-10/MST%2023%203%20FID280_v1%20r1.pdf

$$Incremental\ Operating\ Costs = (Heat\ Rate * Fuel\ Costs) + (Emissions\ Rate * Emissions\ Allowance\ Price) + (Other\ Variable\ Operating\ and\ Maintenance\ Costs)$$

E.7.4 Incremental energy bid reference levels

The reference level for incremental energy bids for new capacity for the three year and six month period after the new capacity's first production must be the higher of:

(i) The amount determined using Section 23.3.1.4.1, bid-based, LBMP-based, or negotiated cost-based reference level calculations; or 23.3.1.4.2, an estimate of marginal cost based on available operating costs and competitive bid data.

(ii) The average fuel price-adjusted peak LBMPs over the twelve months prior to the new capacity's first production. Net additions of capacity only apply when an entity owns or controls the output of capacity.

E.7.5 Start-up cost bid reference levels

Section 23.3.1.4.4.3 of the NYISO OATT details the calculations used to determine a generator's reference level for start-up costs bid. The following reference level determinations are listed in the order of preference and are subject to the availability data:

(i) If a generator has accumulated enough start-up costs bidding history, the lower of the mean or the median of the generator's accepted start-up costs are used in the calculation. Bids in competitive periods over the previous 90 days for similar down times are adjusted for changes in fuel prices. However, accepted start-up bids in which the generator is committed can incorporate anticipated costs of operating on the day after the dispatch day to meet its minimum run time is not be used to develop bid-based start-up reference levels.

(ii) A negotiated cost-based level determined for a generator to achieve its specified minimum operating level taking into consideration that the bid or bids at issue reflect the costs incurred from an offline state, a consultation with the generator must of occurred prior to the conduct threshold examination by the ISO, and is subject to the market participant providing sufficient operating cost data.

(iii) Generators committed in the day-ahead market not able to complete their minimum run time within the dispatch day may include expected net costs of operating in their start-up bid on the following day. The start-up reference level will be calculated including the net costs the generator is expected to incur on the day following the dispatch day using the formula below:

[184] NYISO OATT, Section 23.3.1.4.1.3. http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2015-05-20/agenda%208%20MST%2023.3%20redline.pdf

$$Late\ Day\ Adjusted_{g,i} = StrtUpRef_g + \max\left(0,\ MinGenRef_{g,i} * BidMinGen_{g,i} * \sum_{h=0}^{Z_{g,i-1}} SR_{g,h,i}\right)$$

where

"g" represents the generator and "h"& "i" are hours. The generator must run in hour "h" and start in hour "i". Late Day Adjusted reflects the applicable start-up reference level, plus the expected net cost of operating on the day following the dispatch day;

$StrtUpRef_g$ is the dollar start-up reference level for generator g at the time the calculation is performed but does not include the expected net cost of operating on the day following the dispatch day;

$MinGenRef_{g,i}$ is the minimum generation cost reference level for generator g for hour i in $/MW at the time of calculation;

$BidMinGen_{g,i}$ is the generator day-ahead minimum operating level for hour i, in MW;

$Z_{g,i}$ is the number of hours the generator must operate during the day following the dispatch day in order to complete its minimum run time if operation commences in hour i; and.

$SR_{g,h,i}$ is the shortfall ratio for the generator that starts bidding in hour i but must run during hour h in order to complete its minimum run time.

Shortfall ratio calculation

In all cases where a generator's day-ahead minimum operating level departs from the previous seven days' average of the day-ahead minimum operating levels for the same hour by:[185]

(i) less than 5 MW; or by

e.g. $\left|AvgBidMinGen_{g,h,i} - BidMinGen_{g.i}\right| < 5\ MW$

(ii) less than 10 percent.

If both, then

$$BidMinGen_{g,i} < (1.1) * AvgBidMinGen_{g,h,i}\ \&\ BidMinGen_{g.i} > (0.9) * AvgBidMinGen_{g,h,i}$$

In all cases where $AvgBidMinGen_{g,h,i}$ cannot be calculated as the generators minimum operating levels were not submitted for the day-ahead market for hour h on any of the preceding seven days containing hour i, the $SR_{g,h,i}$ will be calculated using the primary method. Otherwise, the alternative formula to calculate $SR_{g,h,i}$ will be calculated.

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[185] NYISO OATT, Section 23.3.1.4.4.3. http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2015-05-20/agenda%208%20MST%2023.3%20redline.pdf

$$Primary\ Method\ of\ Calculating\ the\ Shortfall\ Ratio = SR_{g,h,i} = 1 - \frac{1}{7} * \sum_{d=1}^{7} \frac{LBMP_{g,h,i,d}}{MinGenRef_{g,h,i,d}}$$

$$Alternative\ Method\ of\ Calculating\ the\ Shortfall\ Ratio = SR_{g,h,i}$$
$$= 1 - \frac{AvgLBMP_{g,h,i}}{(AvgRefRate_{g,h,i} * \frac{RefRate2_{g,i}}{RefRate1_{g,h,i}})}$$

where

AvgBidMinGen $_{g,h,i}$ is the average minimum operating level submitted in the day-ahead market for hour h on the seven days preceding the day containing hour i, in MW, this excludes days when the minimum operating level was not submitted in the day-ahead market for generator g, for hour h.

BidMinGen $_{g,i}$ is the minimum operating level submitted in the day-ahead market for generator g for hour i, in MW.

$LBMP_{g,h,i,d}$ is the day-ahead LBMP at the location of the generator in hour h of the day-ahead market for the dispatch day that precedes the day containing hour i by d days.

MinGenRef $_{g,h,i,d}$ is minimum generation cost reference level for the generator in hour h of the day-ahead market for the dispatch day that precedes the day containing hour i by d days.

$AvgLBMP_{g,h,i}$ is the average of the day-ahead LBMPs at the location of the generator for hour h on the seven days preceding the day containing hour i, in $/MWh, but excludes days when a minimum operating level was not submitted in the day-ahead market by the generator for hour h.

$AveRefRate_{g,h,i}$ is the average of the minimum generation reference levels for the generator in hour h on the seven days preceding the day containing hour i, in $/MWh, but excludes days when a minimum operating level was not submitted in the day-ahead market for hour h.

$RefRate1_{g,h,i}$ is the minimum generation cost reference level in $/MWh for the generator for hour i, it is calculated using the most current reference data, and assumes the minimum operating level submitted in the day-ahead market in hour i corresponds to the MWs reflected in the AvgBidMinGeng,h,i

RefRate $2_{g,i}$ is the minimum generation cost reference level in $/MWh for hour i, calculated using the most current reference data, and incorporates the minimum operating level submitted in the day-ahead market in hour i corresponds to the MWs reflected in the BidMinGeng,i.

E.8 Regulation capacity

Real-time reference levels are calculated by the ISO for regulation capacity in accordance with reference level calculations under Section 23.3.1.4.1.1, bid-based; Section 23.3.1.4.1.3, negotiated cost-based; or Section 23.3.1.4.2, an estimate of marginal cost based on available operating costs and competitive bid data.

Day-ahead reference levels are calculated by the ISO for regulation capacity in accordance with the reference level calculations under Section 23.3.1.4.1.1, bid-based; Section 23.3.1.4.1.3, negotiated cost-based; or Section 23.3.1.4.2, an estimate of marginal cost based on available operating costs and competitive bid data.

E.8.1 Regulation movement

Real-time reference levels are calculated by the ISO for regulation movement in accordance with reference level calculations under Section 23.3.1.4.1.3, negotiated cost-based; or Section 23.3.1.4.2.1, estimating the costs or physical parameters of a similar resource including costs relating to operating costs and inputs from the market participant.

Day-ahead reference levels are calculated by the ISO for regulation capacity in accordance with the reference level calculations under Section 23.3.1.4.1.3, negotiated cost-based; or Section 23.3.1.4.2.1, estimating the costs or physical parameters of a similar resource including costs relating to operating costs and inputs from the market participant.

E.8.2 Operating reserve products

It is not required of the ISO to calculate real-time reference levels for the three operating reserve products (spinning reserve, 10-minute non-synchronized reserves and 30-minute reserves) as the generators are capable of providing these products by submitting bids into the real-time market and are automatically assigned a real-time operating reserves availability bid equal to zero for the amount of operating reserves they are capable of providing.

Day-ahead reference levels are calculated by the ISO for the three operating reserves products in accordance with the reference level calculations under Section 23.3.1.4.1.1, bid-based; Section 23.3.1.4.1.3, negotiated cost-based; or Section 23.3.1.4.2, an estimate of marginal cost based on available operating costs and competitive bid data.

E.8.3 Required cost information

Mitigation may be based on a generator's start-up time, minimum run time, minimum down time, minimum generation capacity, or maximum number of stops per day. The market participant must provide sufficient data relating to the above requirements.[186]

Generators may also request to have reference levels adjusted to account for any of the described costs below. These generators must meet the following conditions: first, a generator must be committed out-of-merit or via a supplemental resource evaluation after the DAM has posted, and secondly, a generator must have a posted real-time guarantee payment impact test settlement result.

[186] NYISO OATT, Section 23.3.3.3.1.3.3. http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2015-05-20/agenda%208%20MST%2023.3%20redline.pdf

Alternatively, generators identified under Section 23.3.1.2.3 may also apply for adjusted reference levels. These generators are described as being committed outside the ISO's economic evaluation process to protect New York Control Area (NYCA) or local area reliability in an area that is not a designated constrained area.

Cost components include:

i. Procuring fuel at prices that exceed the index prices used to calculate the generator's reference level;
ii. Burning a type of fuel or blend of fuels that is not reflected in the generator's reference level;
iii. Permitted gas balancing charges;
iv. Compliance with operational flow orders; and
v. Purchasing additional emissions allowances that are necessary to satisfy the generator's supplemental resource evaluation or out-of-merit schedule.

Fuel costs

NYISO may use the best fuel cost information available to adjust reference levels. Unauthorized natural gas charges are not permitted in the development of a generator's reference level.

Unauthorized natural gas use may result from, but are not limited to, the following:

i. Natural gas consumption violating the terms of the Operational Flow Order ("OFO") issued by the Local Natural Gas Distribution Company (LDC) or pipeline;
ii. Violating instructions restricting consumption of natural gas or use of natural gas imbalance service issued by the natural gas LDC or pipeline, when instructions are issued consistent with the LDC's or pipeline's authority under a tariff, rate schedule or contract;
iii. Consuming natural gas during an authorized interruption period of service issued by the natural gas LDC or pipeline and determined in accordance with the terms of the applicable tariff, rate schedule or contract; or
iv. Unauthorised natural gas balancing services explicitly identified in the relevant natural gas LDC's or pipeline's applicable tariff, rate schedule or contract as unauthorized use or penalty gas.

Market participants must notify the ISO of changes in fuel type or fuel. Submitted fuel type information is considered biased if:

i. The fuel type is not the most economic fuel type available to the generator, taking into consideration fuel availability, operating conditions, and relevant regulatory or reliability requirements; and
ii. As a result of the change(s) in fuel type, the fuel prices exceeded the fuel price that the ISO would have used to develop reference levels for that generator by greater than 10%, on average, over a seven-day period.
iii. If the fuel price that the market participant submitted to the ISO's market information system for use in developing reference levels for a generator exceeded the greater of the actual fuel price (as substantiated by supplier quotes or invoices) or the ISO's

indexed fuel price, by greater than 10%, on average, over a seven-day period. For purposes of calculating the seven-day average, only hours in which the fuel price submitted exceeds the ISO's indexed fuel price will be considered. The day-ahead and real-time markets will be considered separately for purposes of this analysis.

F NYISO capacity market mitigation

F.1 Definitions in this appendix

In this Appendix,

(1) **"IMM"** means the NYISO Internal Market Monitor;
(2) **"Offer Floor"** means for a Mitigated Capacity Zone Installed Capacity Supplier that is not a Special Case Resource will mean the lesser of (i) a numerical value equal to 75% of the Mitigation Net CONE translated into a seasonally adjusted monthly UCAP value ("Mitigation Net CONE Offer Floor"), or (ii) the numerical value that is the first year value of the Unit Net CONE determined as specified in Section 23.4.5.7, translated into a seasonally adjusted monthly UCAP value using an appropriate class outage rate, ("Unit Net CONE Offer Floor"). The Offer Floor for a Mitigated Capacity Zone Installed Capacity Supplier that is a Special Case Resource will mean a numerical value determined as specified in Section 23.4.5.7.5. The Offer Floor for Additional CRIS MW will mean a numerical value determined as specified in Section 23.4.5.7.6;
(3) **"Net CONE"** means the localized levelised embedded costs of a peaking unit in a Mitigated Capacity Zone, net of the likely projected annual Energy and Ancillary Services revenues of such unit, as determined in connection with establishing the Demand Curve for a Mitigated Capacity Zone pursuant to Section 5.14.1.2 of the Services Tariff, or as escalated as specified in Section 23.4.5.7 of Attachment H;
(4) **"CRIS" or "Additional CRIS MW"** means Capacity Resource Interconnection Service
(5) **"Mitigated UCAP"** means one or more megawatts of Unforced Capacity that are subject to Control by a Market Party that has been identified by the ISO as a Pivotal Supplier.

F.2 NYISO capacity market mitigation description

NYISO's Installed Capacity Market implements ex ante mitigation mechanisms to test if physical or economic withholding of installed capacity results in a material change of the market clearing price in all or in some percentage of New York.[187] NYISO's ICAP markets are on a spot, monthly and seasonal basis[188]and identify Mitigated Capacity Zones as New York City, and the G-J Locality.[189] Mitigation in the form of price caps also apply to specific generators located within New York City.

ICAP determines the amount of capacity NYISO has and suppliers provide data to support their capability to produce a certain number of MWs, seasonal effects are taken into consideration.

[187] NYISO OATT Section 23.4.5.
http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2015-05-20/agenda%208%20MST%2023.3%20redline.pdf
[188] Brattle (2007). Page 90.
http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[189] NYISO, Installed Capacity Course, Retrieved from:
http://www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/Installed_Capacity_MT_305/9_Installed%20Capacity%20Market%20Mitigation%20Measures.pdf

UCAP on the other hand determines the amount of capacity suppliers are qualified to offer and how much can be sold.

UCAP data requirements

Unforced capacity data requirements include information on past performance, how often the unit is available and how much product can be delivered.[190]

Required Information for Affiliated Entities

Market participants owning or "controlling" capacity in a Mitigated Capacity Zone (MCZ) are required to identify their "Affiliated Entities", based on the criteria in the Market Services Tariff, Attachment H, under Section 23.2.1.

F.3 Pivotal supplier test

The purpose of supply-side mitigation is to prevent physical or economic withholding by ICAP suppliers with an incentive to raise prices.[191] Pivotal suppliers are subject to offer caps and must offer requirements in the ICAP spot market auction for mitigated UCAP.[192]

The Pivotal Supplier Test (PST) is applied by the market monitor to determine if a market participant has engaged in economic or physical withholding.[193] The PST measures are illustrated in the table below.

Table F.1: NYISO pivotal supplier measures for physical and economic withholding

Test	Pivotal supplier measure
Physical withholding	Audit and review of proposals or decisions to retire, remove, or de-rate capacity.
Economic withholding	Spot offer price must not be higher than the greater of (a) the lowest of the applicable UCAP offer reference levels and (b) the going-forward cost of the resource, if applicable. Must offer requirement for ICAP Suppliers to offer mitigated UCAP into spot auction.

[190] NYISO, Market Overview, Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/Market_Overview_MT_101/Installed%20Capacity.pdf
[191] NYISO, Installed Capacity Market Mitigation Measures, Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/services/market_monitoring/ICAP_Market_Mitigation/Training_Materials/ICAP_Market_Mitigation_Mearures_v1-1.pdf
[192] NYISO, Installed Capacity Course, Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/Installed_Capacity_MT_305/9_Installed%20Capacity%20Market%20Mitigation%20Measures.pdf
[193] NYISO, Installed Capacity Market Mitigation Measures, Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/services/market_monitoring/ICAP_Market_Mitigation/Training_Materials/ICAP_Market_Mitigation_Mearures_v1-1.pdf

Pivotal supplier definitions

Section 23.2.1 of the NYISO MST, Attachment H, has varying definitions of a pivotal supplier. The definitions are illustrated in the table below:

Table F.2: NYISO pivotal supplier definitions

Region	Pivotal supplier definitions
New York City	Controls 500 MW or more of unforced capacity; and Controls unforced capacity some portion of which is necessary to meet the New York City locational minimum installed capacity requirement in an ICAP spot market auction. Mathematically represented as: $Portfolio\ Threshold\ Zone\ J = Max(500MW, Total\ UCAP\ Available - UCAP\ Requirement$
Zones G-J	Controls 650 MW or more of unforced capacity; and Controls unforced capacity some portion of which is necessary to meet the zones G-J locational minimum installed capacity requirement in an ICAP spot market auction. Mathematically represented as: $Portfolio\ Threshold\ for\ the\ G - J\ Locality = Max(650MW, Total\ UCAP\ Available - UCAP\ Requirement$
Mitigated capacity zones except New York City and zones G-J	A Market Party that controls at least the quantity of MW of unforced capacity specified for the mitigated capacity zone.

Capacity sales prior to the spot are counted differently in zone J and zones G-J. The zone J PST does not include capacity sold and certified in the capability period (strip) or monthly auctions for the applicable month when performing this test.[194]

PST frequency

Monthly, at the close of the certification period evaluated on a zonal basis.[195]

[194]NYISO, Enhancement of Pivotal Supplier Rules. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2016-09-01/Pivotal%20Supplier%20Rule%20Enhancements%20Updated.pdf

[195] NYISO, Installed Capacity Market Mitigation Measures. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/services/market_monitoring/ICAP_Market_Mitigation/Training_Materials/ICAP_Market_Mitigation_Mearures_v1-1.pdf

F.3.1 Must-offer obligation

All resources clearing the capacity auction are required to either bid into the day-ahead market or declare itself unavailable.[196] Demand response resources (also known as special case resources) submit monthly UCAP offers and are not required to submit daily offers. Other variable resources may not be required to bid into day-ahead provided they perform up to standards used in determining their UCAP.[197]

Must-offer requirement for ICAP suppliers to offer mitigated UCAP into spot auction[198] is implemented unless:

i. Mitigated UCAP has been exported to an external control area or sold to meet ICAP requirements outside of the mitigated capacity zone;
ii. It is Net Unforced Capacity of a behind-the-meter net generation resource that is sold to host load in a transaction.

F.3.2 Performance incentive regime

NYISO currently has ICAP supplier deficiency charges equivalent to 1.5 times the market clearing price.[199] Sections 5.12.8 and 5.14.2 of the NYISO MST state that ICAP suppliers must offer and sell the amount of UCAP calculated using the demonstrated maximum net capability (DMNC) testing and maintenance schedule. DMNC tests are performed each capability period (summer capability period and winter capability period) in which they have supplied UCAP, alternatively existing ICAP suppliers may choose to use 12 month historical production data.[200]

F.3.3 Minimum offer price rule (MOPR) & MOPR mitigation exemption test

Minimum Offer Price Rules (MOPR) are implemented for all resources in New York City zone.[201] The purpose of buyer-side mitigation is to prevent entry from artificially suppressed capacity prices.

Resources subject to the MOPR rule:[202]

- Proposed new MCZ generators and UDR projects with a terminus in an MCZ that request CRIS in a class year or seek to transfer CRIS from the same location;
- Existing generators or UDR projects that seek to increase Capacity Resource Interconnection Service ("Additional CRIS MW") (either through a Class Year or a transfer).

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[196] CRA (2017). Page 24. https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-P1.pdf
[197] CRA (2017). Page 24. https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-P1.pdf
[198] NYISO, Installed Capacity Market Mitigation Measures. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/Installed_Capacity_MT_305/9_Installed%20Capacity%20Market%20Mitigation%20Measures.pdf
[199] CRA (2017). Page 25. https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-P1.pdf
[200] NYISO MST, Section 5.12. http://www.nyiso.com/public/markets_operations/documents/tariffviewer/index.jsp
[201] CRA (2017). Page 33. https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-P1.pdf
[202] NYISO, Installed Capacity Market Mitigation Measures. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/Installed_Capacity_MT_305/9_Installed%20Capacity%20Market%20Mitigation%20Measures.pdf

MOPR applies to offers for UCAP from ICAP suppliers starting from the auction activity after the date of revocation. Offer floor prices are adjusted annually using the most recent inflation rate[203]and cease to apply to that portion of the resource's UCAP after it has cleared for any 12 month period.[204]

Pursuant to Sections 23.4.5.7.2 & 23.4.5.7.6 of the NYISO Tariff, Attachment H, MOPR exemptions apply to ICAP Suppliers and Additional CRIS MW located in a Mitigated Capacity Zones with ICAP Demand Curve subject to prior approval by the Commission.

NYISO uses the first year value of an examined facility's unit net CONE to determine subsequent mitigation exemption or offer floor determinations for Additional CRIS MW.[205]MOPR exemptions are detailed under Section 6.3.2.1 of the NYISO OATT, and are illustrated in in Table F.3: Mitigation Exemption Test (Part A, Part B Test).[206]

Section 23.4.5.7.5 of the NYISO OATT, Attachment H details conditions that apply for special case resources to be exempt from the MOPR provision.

Similarly, Sections 23.4.5.7.7 & 23.4.5.7.8 of the NYISO Tariff, Attachment H include additional resource exemptions from the MOPR provisions, when specific conditions as detailed in the Tariff are met.

Offer floor prices for special case resources are detailed under Section 23.4.5.7.5 of the NYISO Tariff, Attachment H and are calculated as follows:

- Offer floor price for a SCR is equal to minimum monthly payment for providing Installed capacity payable by its responsible interface party, plus the monthly value of any payments or other benefits the SCR receives from a third party for providing installed capacity, or that is received by the responsible interface party for the provision of installed capacity by the SCR.
- Offer floor price for an SCR located in New York City includes any payments or the value of other benefits that are awarded for offering or supplying mitigated capacity zone capacity unless such payment or the value of other benefits is ruled to be exempt by the regulator.
- Offer floor price for an SCR located in a mitigated capacity zone except New York City includes payments or the value of other benefits that are awarded for offering of supplying mitigated capacity zone capacity, except for payments or the value of other benefits provided under programs administered or approved by the state government.

[203] NYISO OATT, Attachment H, Section 23.4.5.7.
http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B39ECCD7C-D1BA-4CCA-941A-2E27B03BE499%7D
[204] NYISO OATT, Attachment H, Section 23.4.5.7.
http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B39ECCD7C-D1BA-4CCA-941A-2E27B03BE499%7D
[205] NYISO OATT, Attachment H, Section 23.4.5.7.2.
http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B39ECCD7C-D1BA-4CCA-941A-2E27B03BE499%7D
[206] NYISO, Installed Capacity. Retrieved from:
http://www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/Installed_Capacity_MT_305/9_Installed%20Capacity%20Market%20Mitigation%20Measures.pdf

Section 23.4.5.7.6.5 of the NYISO Tariff, Attachment H describes the calculations of offer floor prices for additional CRIS MW as follows. The offer floor prices for additional CRIS MW are equal to the lesser of:

- The unit net CONE for additional CRIS MW; or
- A numerical value equal to 75 percent of the mitigation net CONE translated into seasonally adjusted monthly UCAP value for the additional CRIS MW.

Mitigation of offers made below offer floor prices result in penalties associated with the price impact.

F.3.4 Mitigation exemption test[207]

Proposed new generators and Unforced Deliverability Rights (UDR) projects are examined in a two-part test to determine whether an offer floor is applicable, or upon request they are examined for a competitive entry exemption, renewable exemption, or self-supply exemption (special case resources have separate provisions).[208]

Exemption types

i. Competitive entry exemption.
ii. Renewable exemption.
iii. Self-supply exemption.
iv. SCR offer floor exemption.

If either test is passed, the resource is not subject to buyer-side mitigation. If either test is failed, the resource is subject to the offer floor. If the resource does not receive an exemption, it may only offer into the spot market auction.

[207] NYISO, Installed Capacity. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/Installed_Capacity_MT_305/9_Installed%20Capacity%20Market%20Mitigation%20Measures.pdf

[208] NYISO, Installed Capacity. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/Installed_Capacity_MT_305/9_Installed%20Capacity%20Market%20Mitigation%20Measures.pdf

Table F.3: Mitigation exemption test[209]

Mitigation exemption test	Description
Part A test	75% mitigation net CONE vs 1-year ICAP forecast If the following condition applies, the resource fails the part A test: 75% mitigation net CONE > 1-year ICAP forecast
Part B test	Part B unit net CONE vs 3-year ICAP forecast If the following condition applies, the resource fails the part B test: 75% mitigation net CONE > 3-year ICAP forecast

Information required

The market monitor requires general unit information, as well as information regarding capital costs, fixed and variable operating and maintenance costs, financing parameters, and plant performance curves.[210] If an existing facility requests additional CRIS MW, its offer floor exemption test will be based on:[211]

- For facilities grandfathered under the buyer-side mitigation rules (i.e., existing by March 2008) and facilities that secured an exemption from BSM "on their own economics" (passing the part B test), offer floor exemption test will be based only on the revenues and costs associated with the additional CRIS MW.
- For facilities subject to an offer floor, or that secured an exemption under the part A test, the offer floor exemption test will be based on the whole facility, inclusive of the costs associated with increasing to the additional CRIS:
    - o Unit net CONE will be the greater of the net CONE of the additional CRIS MW and the total evaluated MW (additional CRIS MW plus other non-exempt MW).

Competitive entry exemption

An examined facility may also receive an offer floor exemption if it meets the following conditions:[212]

[209] NYISO, Installed Capacity. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/Installed_Capacity_MT_305/9_Installed%20Capacity%20Market%20Mitigation%20Measures.pdf
[210] NYISO, Installed Capacity. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/Installed_Capacity_MT_305/9_Installed%20Capacity%20Market%20Mitigation%20Measures.pdf
[211] NYISO, Installed Capacity. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/Installed_Capacity_MT_305/9_Installed%20Capacity%20Market%20Mitigation%20Measures.pdf
[212] NYISO, Installed Capacity. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/

a) Does not have any "non-qualifying contractual relationship" as defined in MST Attachment H Section 23.4.5.7.9.1.2, with a non-qualifying entry sponsor; and

b) If it is not a non-qualifying entry sponsor.

An unqualified application for a competitive entry exemption will be examined pursuant to the Part A and Part B tests.

Renewable exemption

A renewable exemption can be applied for if the resource is an intermittent power resource, or a limited control run-of-river hydro resource.[213] Intermittent power resources are those solely fueled by wind, solar, or landfill gas. Renewable exemptions are limited to 1,000 MW of ICAP in any class year. Note that this cap is in terms of ICAP, not UCAP.

Self-supply exemption

An examined facility with a "self-supply business model" can apply for a Self-Supply Exemption.[214]

Net long and net short thresholds are calculated to ensure self-supply, the facility does not have incentive and ability to artificially suppress ICAP market prices by developing a unit.

Special case resource offer floor exemption

Upon enrollment, new SCRs in mitigated capacity zones (NYC and zones G-J) are examined pursuant to the SCR BSM test. These provisions are detailed in Attachment H 23.4.5.7.5. An SCR is exempt from the offer floor if the SCR's offer floor determined pursuant to the test is less than the ICAP price forecast:[215]

- The offer floor test is the sum of the minimum monthly payments received from the NYISO ICAP market, and any other benefits it receives for providing installed capacity;
- ICAP prices are forecast over a 12 month period starting with the first month after enrollment.

F.3.5 Mitigated UCAP offer cap

Section 23.4.5 of the NYISO Tariff, Attachment H describes conditions for offers to sell mitigated UCAP in the ICAP spot market auction as not exceeding the higher of:

(a) The UCAP offer reference level for the applicable ICAP spot market auction, or

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Installed_Capacity_MT_305/9_Installed%20Capacity%20Market%20Mitigation%20Measures.pdf

[213] NYISO, Installed Capacity. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/Installed_Capacity_MT_305/9_Installed%20Capacity%20Market%20Mitigation%20Measures.pdf

[214] NYISO, Installed Capacity. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/Installed_Capacity_MT_305/9_Installed%20Capacity%20Market%20Mitigation%20Measures.pdf

[215] NYISO, Installed Capacity. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/Installed_Capacity_MT_305/9_Installed%20Capacity%20Market%20Mitigation%20Measures.pdf

(b) Going-forward costs of the installed capacity supplier supplying the mitigated UCAP.

Where an installed capacity supplier is a pivotal supplier in some, but not all, mitigated capacity zones, the supplier's offer to sell mitigated UCAP in any ICAP spot market auction must not be higher than the higher of:

(a) The lowest of the UCAP offer reference levels for each mitigated capacity zone in which such installed capacity supplier has resources; or

(b) Going-forward costs, if an offer for a resource has an applicable going-forward cost.

F.4 Reference level calculations

F.4.1 UCAP offer reference levels[216] and default reference price[217]

In accordance with Attachment H to the NYISO Services Tariff, for each mitigated capacity zone, seasonally adjusted UCAP offer reference levels will be applied to installed capacity in a mitigated capacity zone that is subject to capacity market mitigation measures as specified under Section 5.12.6 of the NYISO Tariff.[218]

Unit-specific reference level: going-forward cost-based approach

NYSO's forward capacity market period is relatively short, as such, suppliers must commit to exit or enter the market in advance of the auction clearing.[219] Once suppliers are committed, offers may be bid low (at going forward avoidable cost) or not at all (not committed and unable to qualify to offer in the FCM).[220]

In accordance with Attachment H to the NYISO Services Tariff, seasonally adjusted UCAP offer reference levels will be applied to installed capacity supplied by in-city generation that is subject to capacity market mitigation measures. If the owner of an in-city resource requests a unit-specific reference level, then the supplier must provide information on its going-forward costs. If accepted, the NYISO will shape the adjusted UCAP offer reference level for each generator for the summer and winter months as follows:[221]

$$SARP_n = \frac{AGFC_n}{6 * (1 + R_n * \frac{DCL - R}{DCL - 1})}$$

[216] NYISO, Enhancement of Pivotal Supplier Rules. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2016-09-01/Pivotal%20Supplier%20Rule%20Enhancements%20Updated.pdf

[217] NYISO, In-City Mitigation. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/In-City_Mitigation_Documents/In-City_Mitigation/mp_training_InCity_Mitigation.pdf

[218] NYISO OATT, Section 5.12.6. http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2015-10-26/BTMNG_Tariff%20Revisions_MST%20Section%205_10.26.2015%20ICAPWG_MIWG_FINAL.pdf

[219] CRA (2017). Page 40. https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-P1.pdf

[220] CRA (2017). Page 40. https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-P1.pdf

[221] NYISO, Installed Capacity Manual. http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf

$$WARP_n = SARP_n * \frac{DCL - R}{DCL - 1}$$

where

$SARP_n$ is the adjusted UCAP offer reference level during each month of the summer capability period for generator *n*;

$AGFC_n$ is the annual going-forward cost for generator *n*;

R_n is the ratio of (i) the winter generating capacity of generator *n* to (ii) the summer generating capacity of generator *n*;

DCL is the ratio of (i) the amount of mitigated capacity zone ICAP at which the demand curve reaches a zero price to (ii) the mitigated capacity zone ICAP requirement;

R is the ratio of (i) the sum of the winter generating capacities of all mitigated capacity zone to (ii) the sum of the summer generating capacities of all mitigated capacity zone; and

$WARP_n$ is the adjusted UCAP offer reference level during each month of the winter capability period for generator *n*.

The NYISO calculates GFCs as either:

(a) the costs that the ICAP supplier can avoid by ceasing to supply ICAP from the resource, or by derating or by retiring it, net of anticipated energy and ancillary services revenues, or

(b) the opportunity cost of foregone sales outside of the mitigated capacity zone.[222]

Going-forward cost data requirements

Basic unit information, safety or reliability requirements, historical and projected energy and ancillary services revenues, avoidable costs associated with ceasing supply for a period of one year or more while retaining ability to re-enter the market or retire permanently, fixed costs, variable costs, capital expenses, and opportunity costs of foregone sales outside of a mitigated capacity zone, net of costs that would have been incurred as a result of the foregone sale if it had taken place.[223]

[222] NYISO, ICAP Market Mitigation Measures. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/Installed_Capacity_MT_305/9_Installed%20Capacity%20Market%20Mitigation%20Measures.pdf

[223] NYISO OATT, Attachment H, Section 23.4.5. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B39ECCD7C-D1BA-4CCA-941A-2E27B03BE499%7D

G Ex post mitigation

Failure to consider social costs or externalities associated with test errors can result in ex ante judgement errors when identifying market power abuse and similarly failing to identify market power abuse. The IMM recommends across all energy and ancillary services markets in ISO-NE, PJM, and NYISO, ex-post mitigation and filings with FERC to impose sanctions. IMM also recommends market design changes dictated by ex post mitigation results. Ex post mitigation must be used in uncommon market events and is based using data on actual events rather than forecasts based on historical data.[224]

Capacity markets implement ex post mitigation and sanctions for physical withholding; coupled with penalties for the inability to meet must-offer obligations. Incentives are also given in the capacity market for good performance in the form of capacity performance payments and reliability must run contracts.[225]

[224] Brattle (2007). http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf
[225] Ibid.