CAPACITY WATCH

Authors: Paul Flemming, Scott Niemann, and José Rotger

1st Quarter 2018

EXECUTIVE SUMMARY

This issue of *Capacity Watch*™ presents a discussion of the penalties associated with delays or cancellations of new generation projects that cleared in the Northeast capacity auctions. ISO-NE incentivizes performance with a potential termination of the project's capacity supply obligation if certain milestones are not met. PJM has a specific penalty structure for units with a supply obligation that do not perform. In both markets, generators that expect to be delayed can purchase back their supply obligations in the incremental or bilateral auctions.

In the New York section, ESAI provides an update on peak loads and ICR/LCR determinations as well as a discussion of the potential for the elimination of the Lower Hudson Valley capacity zone. In the PJM section, ESAI discusses the reversion to the previous MOPR rules and changes in the load forecast presented in the 2018 PJM Load Report.

ISO-NE has filed a proposal with FERC outlining its Competitive Auction for Sponsored Policy Resources (CASPR) proposal that ISO-NE intends to implement in FCA13. ESAI provides an overview of CASPR and its potential impact on capacity prices.

In This Issue

ESAI POWER LLC

401 Edgewater Place
Suite 640
Wakefield, MA 01880
Tel: 781.245.2036
Fax: 781.245.8706
www.esai.com

Market Flexibility Vs. Resource Adequacy

Although each unique in their own ways, the three Northeast capacity markets are designed to provide price signals to encourage new entry of generation capacity when needed. These price signals provide financial incentives to investors that will provide debt and equity backing to new projects expected to be built several years forward. However, the capacity markets ultimately require physical delivery against financial commitments received in the capacity auctions. RTOs therefore put into place mechanisms to ensure that auction-cleared projects are physically able to deliver their capacity obligations. This presents a tension between the need for a clear and transparent price signal for new development and the need for RTOs to ensure that resource adequacy requirements are physically met.

In New York, the spot market auctions result in all participants, including new entrants, offering as price takers. A new entrant cannot participate in the New York market prior to entering commercial operation. New York represents one end of the spectrum of trade-offs between price signals and physical assurance of resource adequacy. No capacity payments are received until the unit actually starts operations.

At the other end of the spectrum is New England and its three-year forward capacity market. ISO-NE relies on the monitoring of critical path project milestones and the ability to terminate forward capacity obligations in order to manage the physical risk of project delays or cancellations. In practice, ISO-NE has found it difficult to terminate capacity obligations. The FCM also includes a provision for a seven-year lock which significantly changes incentives for new entrants. This strong financial provision encourages timely project completions in order to manage termination risks. The seven-year price commitment also imposes a discipline that limits the competitiveness of offers to levels that are consistent with the underlying economics of the plant (note that electing a price-lock must be declared well in advance of the auction). As New England is a much smaller market than PJM and load growth is modest, there is little room for new supply without retirements. Thus, there is fierce competition for the limited purchase capability in the New England capacity auctions. The seven-year price lock discourages price-taker offers that could result in a low clearing price, worsening overall economics for both new and existing resources.

Somewhere in the middle is PJM, where projects must meet certain qualification milestones but the penalties are less onerous than losing their capacity obligations. In PJM, the combination of less onerous penalties and the one-year commitment in the three-year forward Base Residual Auction (BRA), results in less discipline for new entrant offers than seen in New England. As a result, the majority of PJM new entrants have offered into the BRAs as price takers. Because the BRA has a commitment of one year, an ‘unexpectedly’ low auction result only impacts a new entrant’s economics for one year, with the hope of higher prices in the following years. These price-taking offers are driven by the need to clear and receive a capacity obligation from the auction in order to secure the necessary financing commitments to move the project forward. Although permitting and other issues may not be fully resolved, moving forward with a capacity commitment avoids the high costs associated with keeping the project in development for another year (had the project offered at a higher price that did not clear).

In both PJM and New England, cleared projects that are delayed have the option to buy back or shed their commitments in the incremental auctions or bilaterally. Given declining load forecasts and surplus conditions in both markets, the buyback of capacity has been relatively easy to achieve – and profitable – in most of the auctions to date.

The ease in which projects can cover or shed their obligations is one factor (in addition to lower load projections) in depressing clearing prices in the PJM BRAs and New England FCAs. In PJM, price-taking capacity shifts the supply curve to the right, depressing prices, while new entrants maintain the option to defer timing through buy-backs. In this fashion, existing generators are penalized in the PJM and New England forward auctions for projects that do not complete construction ahead of their cleared commitments. In New England, committed but delayed new capacity must make best efforts to buy back their commitments but if they are unable to do so, they will receive capacity payments even though they are not operating (Footprint Power is an example as described below). Ironically, despite reliance on obligation terminations to encourage timely physical delivery, new entrants in New England are receiving payments for capacity that has not been physically delivered.

The following sections describe the rules and potential penalties for new generators that are committed in the capacity auctions but have not reached commercial operations, and provide more insight into the mechanisms that allow a significant amount of flexibility for planned new generation to avoid capacity obligations obtained in the annual forward auctions. Also included are examples of outcomes from each RTO market that illustrate the trade-offs between price signals for investors and physical delivery of resource adequacy.

ISO-NE: Risk of Terminated Obligations

In New England, the ability to lock in a new project's capacity payment for up to seven years (escalated at the Handy-Whitman index) is invaluable in securing project financing. Every new generating unit cleared in the past several New England FCAs has elected the price lock-in provision, and our understanding is that obtaining project financing would have been extremely difficult if not impossible without this revenue assurance.

But, what happens if the new project cannot be completed in time for its committed capacity delivery date? ISO-NE's FCM qualification process and market rules contemplate the possibility of "non-commercial" new resources. The qualification process requires ISO-NE approval of a critical path schedule with specific project milestones, and the FCM financial assurance provisions require significant deposits to be made. Despite these critical milestones, the FCM market rules also provide the ability for new resources to cover an obligation for up to two years past the start of the subject commitment period. This two-year buyback tariff provision makes it difficult for ISO-NE to terminate a capacity obligation within these two years. Terminating a new resource's capacity supply obligation requires ISO-NE to make a FERC filing. While ISO-NE has done so in several past instances (most notably, for several demand resources that failed to reach commercial operation), the consequences for capacity resources not delivering their capacity obligation have been minimal to date, as illustrated below.

Delays for New Generators Cleared in ISO-NE FCAs

Two recent case studies highlight the incentives created by the FCM rules, with unintended results that are likely to prompt changes to further tighten the rules. The first example involves Footprint Power's new Salem Harbor combined cycle gas-fired unit in Salem, MA. The Footprint unit cleared the 2016/17 FCA (FCA7) at $14.999/kW-mo but was able to get a one-year deferral of its 2016/17 capacity supply obligation (CSO) to 2017/18 for reliability reasons as allowed under the tariff. In April 2017, and after the third and final annual reconfiguration auction (ARA) for the 2017/18 capacity commitment period, ISO-NE announced that the Footprint unit will not achieve its planned June 1, 2017 in-service date at the start of the 2017/18 commitment period. In fact, as of this writing the unit has yet to reach commercial operation.

The NEMA/Boston capacity zone remains tight in meeting its locational capacity requirement despite recent decreases to the requirement stemming from transmission upgrades and lower load forecasts. While the NEMA/Boston requirement has decreased by at least 70 MW, the capacity zone cannot meet the requirement without Footprint's 674 MW CSO. ISO-NE has addressed any reliability concerns in NEMA/Boston by implementing various operating measures, including a transmission switching scheme during real-time deficiencies.

Under the FCM rules, Footprint has a "best efforts" obligation to cover its CSO in the monthly reconfiguration auctions or bilaterally. But, it likely found it impossible to do so as there are few excess capacity MW in NEMA/Boston that do not already have a CSO. The final ARA for 2017/18 (ARA3 held March 1, 2017) assumed Footprint would be in service and cleared at $3.50/kW-month with 101 MW of supply offers and 40 MW of demand bids in NEMA/Boston. The several monthly reconfiguration auctions since June 2017 have similarly not allowed the replacement of this non-commercial capacity.

But, Footprint is being paid its capacity payment regardless of whether it can cover its CSO. Under the FCM rules, absent ISO-NE's termination of Footprint's CSO, Footprint is entitled to be paid its $15 capacity clearing price even though it has not reached commercial operation.

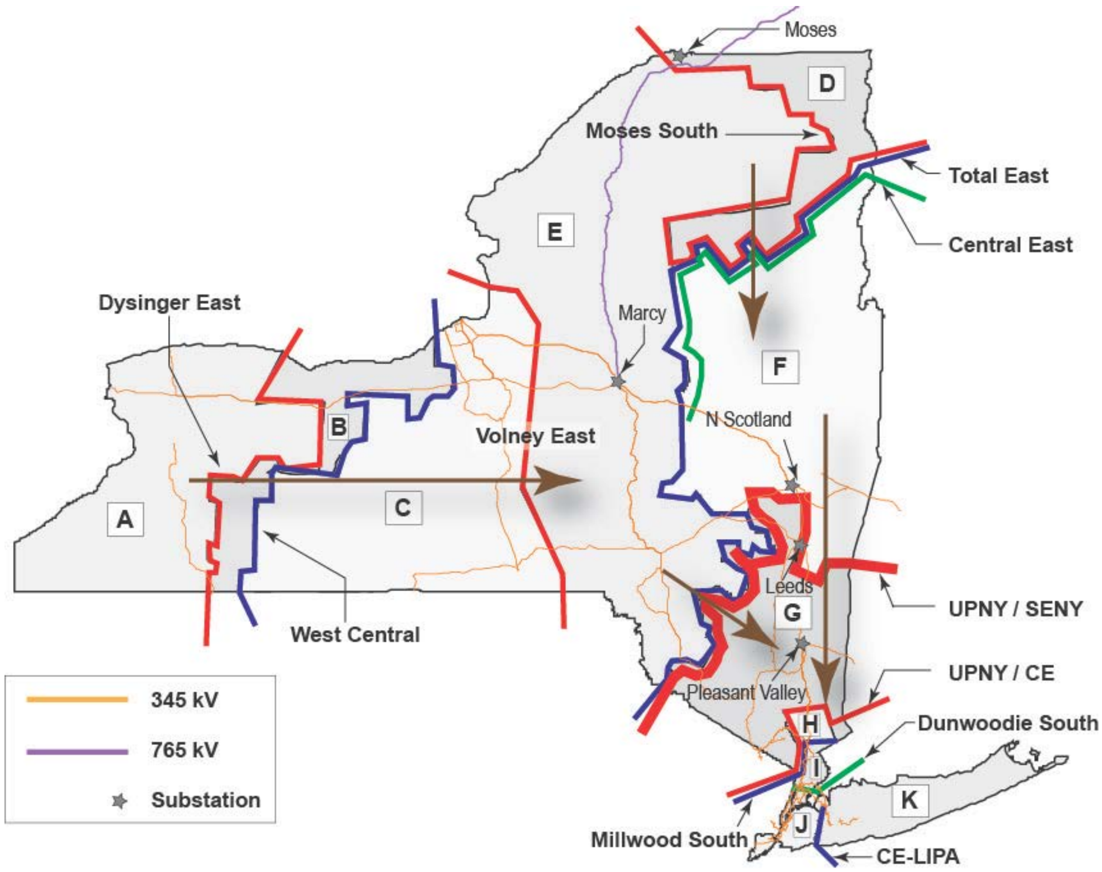
Most observers agree that the lack of a meaningful penalty for not achieving commercial operation (and getting paid for not delivering the capacity) is a flaw in the FCM rules, but ISO-NE has interpreted its rules in a manner that makes it difficult to terminate a CSO. ISO-NE's public response has been to note that the rules for qualifying capacity and terminating a CSO are quite different, and that terminating a CSO is much more difficult than expected. Because of the commercially sensitive and proprietary nature of information surrounding the issue, there is little transparency into ISO-NE's deliberations over whether to pursue a termination of Footprint's CSO. In the meantime, the unit is getting paid without providing

New York

CREATING AND ELIMINATING CAPACITY ZONES

A defining characteristic of the New York bulk power system is the long-standing transmission constraint between upstate New York and southeast New York (SENY), best defined by the UPNY/SENY interface at the border of NYISO Load Zone G and the rest of the NYISO system (see **Error! Reference source not found.**). As a result, capacity located in the Rest of State capacity zone (Zones A through F) is not fully deliverable to load zones in the Lower Hudson Valley (Zones G through I) and the rest of southeast New York.

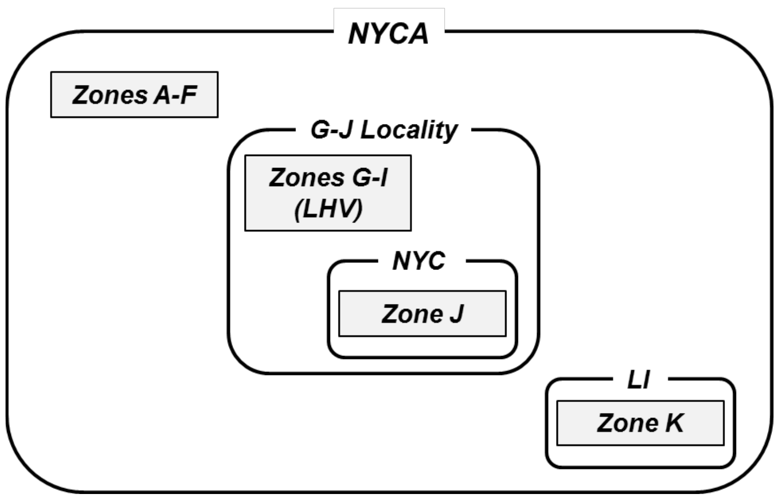
Figure 1: NYISO Interfaces and Load Zones



Historical reliability considerations and transmission constraints justified creation of separate capacity "localities" for New York City (Zone J) and Long Island (Zone K) that have been in place since the start of the New York capacity market. Yet, despite the clear transmission limitations into the Lower Hudson Valley, the need for a separate capacity zone for Lower Hudson Valley has been one of the more controversial and politically charged issues in the NYISO capacity market for over a decade. Downstate load serving entities and consumer advocates strongly oppose any initiatives that would increase capacity prices, and have long had sympathetic ears for their complaints in Albany.

After repeated concerns from several market participants and the NYISO's independent market monitor (Potomac Economics) over the failure of upstate capacity prices to reflect binding deliverability constraints, in June 2009 FERC directed the NYISO to work with stakeholders to develop criteria that would govern the evaluation and potential creation of new capacity zones. NYISO and the New York transmission owners (NYTOs) filed proposed criteria for new capacity zones (the NCZ process) in 2011, which FERC ultimately approved (with revisions) in August 2013. Pursuant to the FERC-approved capacity zone creation process, NYISO determined that a new capacity zone was appropriate to encompass NYISO Load Zones G, H, I, and J (the "G-J Locality"), with New York City Zone J as a nested capacity zone within the G-J Locality (see Figure 2 below). It is important to note that all capacity zones are included in the NYCA zone, often referred to as "Rest of State (ROS)". Thus a reference to the ROS region actually represents all load within the New York Control Area, not just the A-F zones. NYISO implemented the new G-J Locality for the start of the 2014/15 capability year on May 1, 2014.

Figure 2: NYISO Capacity Zones

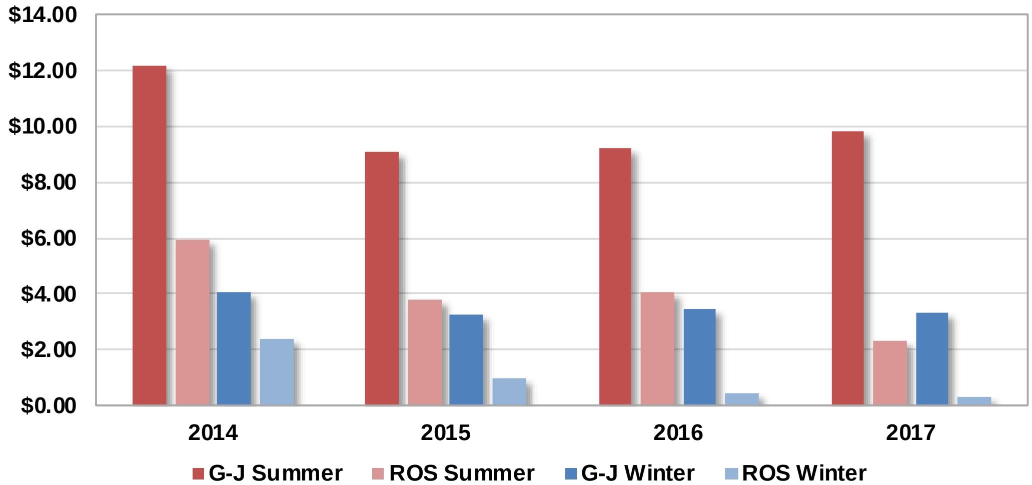


FERC's approval of the NCZ process and creation of the G-J Locality overruled strenuous objections from the New York Public Service Commission (NYPSC), the New York Power Authority (NYPA), and downstate load interests. The NYPSC and other load advocates argued that a Lower Hudson Valley capacity zone was not needed because new transmission planned for the region would alleviate the deliverability constraints that justify creation of the new zone – specifically, the Transmission Owner Transmission Solution (TOTS) projects developed as part of the NYPSC-directed Indian Point retirement contingency plan (which entered service in 2016), and the ongoing upstate-downstate "AC Upgrades" solicitation (now an NYPSC-designated Public Policy Transmission Need (PPTN) under the NYISO Public Policy Transmission Planning process). Relying on similar arguments, these parties also sought (unsuccessfully) an implementation delay and a phase-in of cost impacts for the new zone.

IMPACT OF NEW G-J LOCALITY

As expected by most market participants, the new G-J Locality yielded higher capacity prices than ROS, with G-J prices clearing at substantial premiums to ROS for both summer and winter months (see Figure 3).

Figure 3: G-J Locality and Rest of State Monthly Spot Auction Prices



The higher capacity market prices also encouraged generation investment in Lower Hudson Valley, despite uncertainty surrounding the continued operation of the Indian Point nuclear units (retirements now slated for 2020 and 2021). New Zone G combined cycle investments such as the 650 MW CPV Valley and 1,000 MW Cricket Valley facilities are reflective of this investment opportunity (the Cricket Valley plant moved to financing immediately after the Indian Point retirement announcement). As envisioned by NYISO and many market participants, and as reiterated by FERC, the creation of a new capacity zone that accurately reflects price signals encourages efficient resource decisions, whether capacity additions or retirements.

Current New Capacity Zone (NCZ) Study Process

To establish a new capacity zone, NYISO's tariff requires completion of an NCZ Study with the demand curve reset (now every four years) to determine deliverability across seven high-voltage "Highway" interfaces in the New York system.[2] If the NCZ Study identifies a constrained Highway interface, the interface triggers creation of a new capacity zone.

To determine if a Highway interface is constrained, the study first determines incremental transfer capability under first contingency (N-1) conditions – specifically, the incremental amount of generation in the exporting zone that can flow over interface up to its transmission limit. Termed the First Contingency Incremental Transfer Capability (FCITC), this incremental transfer capability represents the additional generation capacity that could be

[2] Dysinger-East, West Central, Volney-East, Moses-South, Total East/Central East, UPNY-SENY, and UPNY-ConEd. Interfaces into New York City (Millwood South, Dunwoodie South) and Long Island (ConEd-LIPA) are not included as Zones J and K are assumed to be permanent capacity zones.

exported from a given zone(s) above a given base case dispatch level. If the net generation available upstream (in the exporting zone) is greater than the calculated FCITC, that amount of generation above the FCITC is considered to be "bottled-in" capacity and the Highway interface is deemed to be constrained. If instead the net generation available upstream is less than the FCITC (that is, there is not enough generation upstream to reach the transmission limit) the Highway interface is not constrained and can accommodate additional generation resources in the upstream area.

The 2013 NCZ Study performed this analysis for ROS, at the time defined as Zones A through I (*i.e.*, all of New York State except New York City and Long Island). The study simulated generation shifts for combinations of zones within Zones A-I, increasing generation upstream of an interface and reducing generation downstream of that interface. The 2013 study found that the UPNY-SENY Highway interface between Zones G and Zones E and F (see **Error! Reference source not found.**) was constrained, with 849 MW of generation bottled in and unable to be transferred from Zones A-F to Zones G-I. The 2013 study thus triggered creation of the G-J Locality.

Three years later, the 2016 NCZ Study tested transfer capability across Highway interfaces within ROS (Zones A-F) and inside the G-J Locality – the UPNY-ConEd interface between Zones G and H. Consistent with the study process, the study evaluated UPNY-ConEd interface transfer capability by increasing generation upstream of the interface (Zone G) and decreasing generation downstream of the interface (Zones H and I). The 2016 study found no constraints in the studied Highway interfaces.

Proposed Locality Creation and Elimination Process

While the NCZ Study process provided a mechanism for creating a new capacity zone, the rules do not include or even contemplate the elimination of a capacity zone once created. In particular, with substantial transmission upgrades entering service and under development, it is not clear how concomitant increases to transfer capability over Highway interfaces would be factored into ICAP market capacity zones. This omission, coupled with load opposition to the higher-priced G-J Locality and political pressure, led NYISO to re-evaluate the process for forming capacity zones, including the potential elimination of zones.

The NYISO proposed to replace the quadrennial NCZ Study process and deliverability-based analysis for creating new zones (Localities) with a biennial Locality Assessment Study with Locality creation and elimination tests based on a transmission security analysis (TSA) framework. The new Locality assessment study would be aligned and coordinated with NYISO's two-year Reliability Planning Process (RPP). As used in system planning analyses, a TSA is a deterministic analysis that looks at the impact of contingencies (usually more than one) on transmission security needs under peak load conditions. For identified load pocket zones (as determined in the NYISO RPP), the TSA removes a certain amount of generation ("headroom") from a given area to stress the transmission system serving load in that area. If the transmission system does not meet transmission planning design criteria under this stressed condition, that given area should be a Locality.

PJM

SUMMARY

In May 2018, PJM will conduct the Base Residual Auction (BRA) for the 2021/22 Delivery Year under its Reliably Pricing Model (RPM) capacity market. PJM is expected to post parameters for the auction at close of business on February 1. Information about a few of the parameters is already available (Net CONE, IRM, and peak load forecast), but information about the Locational Deliverability Areas (LDAs) that will be included in the BRA and the associated reliability requirements and import limits will not be known before the posting and may significantly affect the outlook for clearing prices. Among the known parameters, the peak load forecast and IRM are both lower than the last BRA, which will result in a leftward shift in the Variable Resource Requirement (VRR) demand curve. Net CONE will be higher than the last BRA, however, resulting in an upward shift in the VRR curve prices, partially offsetting the impact of the lower peak load. Changes in the LDA parameters will affect potential regional price separation. In particular, some significant changes to the Capacity Emergency Transfer Limit (CETL) values are expected for eastern PJM LDAs, potentially supporting significant increases in the clearing prices for those locations and some dampening of prices for the balance of the PJM RTO.

In addition to the auction parameters, changes to the Minimum Offer Pricing Rule (MOPR) will take effect for the upcoming BRA. For the longer-term, PJM and stakeholders continue to consider potential revision and expansion of the MOPR, or potential replacement of the rule with an alternative mechanism. The proposed rule changes are aimed at supporting pricing that is reflective of competitive market outcomes, while also accommodating non-market programs to support public policy initiatives.

CHANGES AHEAD FOR PJM MOPR MECHANISM

PJM MOPR to Revert to Previous (Pre-2013) Rules for Upcoming BRA

In 2013, PJM implemented a set of MOPR rule changes that introduced blanket, class-specific exemptions for merchant supply and qualified self-supply resources and extended the application of the rule to the entire PJM RTO footprint. The previous version of the rule had applied only to resources in LDAs that were included in the BRA (*i.e.*, LDAs with a separate VRR curve specified). Additionally, the prior rule allowed exemptions on a unit-by-unit basis only, subject to approval by the Independent Market Monitor (IMM). After being applied for five BRAs, the 2013 revisions to the MOPR were left null and void for future auctions due to a July 2017 court decision. The D.C. Circuit determined that FERC had inappropriately required revisions to the set of MOPR changes PJM originally filed in December 2012. The rule changes filed by PJM were the product of robust stakeholder discussions and had broad support across multiple sectors. The DC Circuit found that the conditions imposed by FERC overstepped its authority and undermined this stakeholder consensus. Although PJM resubmitted its original 2012 filing following the DC Circuit decision, FERC determined that without the conditions specified in its April 2013 order, the revised MOPR was not just and reasonable and the Commission rejected the resubmitted filing on December 8, 2017. As a result, the MOPR that had been in place prior to the December 2012 PJM filing will apply to future BRAs, included the upcoming auction for 2021/22.

The proposed MOPR changes had been developed by PJM stakeholders in 2012 and the provisions were passed in committee with approval from a significant majority. The primary set of revisions to the MOPR included:

- Elimination of the unit-specific review and exemption process in favor of categorical exemptions for merchant projects and qualified self-supply resources;
- Narrowing of the MOPR to apply to three technologies: CT, CCGT, and IGCC projects;
- Increase in the MOPR floor price from 90 percent of estimated, class-specific Net CONE to 100 percent;
- Extension of the MOPR to cover the full PJM RTO footprint, applying to all new CT, CCGT, and IGCC resources offered into the PJM auctions, rather than just those within the LDAs modeled in each BRA;
- Extending the duration of the MOPR from one year to three years.

In its 2013 order, FERC required PJM to maintain the unit-specific exemption, in addition to the categorical exemptions, and make each resource subject to the MOPR for one year only. PJM accepted those changes through a compliance filing and began applying the rule in the BRA for the 2016/17 Delivery Year (held in May 2013). However, FERC has reaffirmed that it cannot find the rule to be just and reasonable without the conditions it had imposed in 2013. Since the DC Circuit determined that FERC does not have the authority to impose those conditions (rather, it must simply accept or reject the rule) the rule can no longer apply.

Hence, on January 9, 2018, PJM submitted a compliance filing to FERC that restores the 2012 version of the MOPR. That means that in the upcoming BRA, the MOPR will no longer apply to new resources in the rest-of-RTO region. However, new resources (*i.e.*, not yet cleared in previous RPM auctions) within any of the modeled LDAs will be subject to the MOPR offer floors shown in Table 8, unless a unit specific exemption is granted by the IMM. The deadline for requests for unit-specific exemptions is 60-days prior to the BRA. Obtaining a unit-specific exemption requires documented evidence that the Net CONE for a project is below the applicable default value shown in Table 8. If a resource is granted an exemption, the default MOPR floor is replaced with a lower, unit-specific offer floor approved by the IMM (which could be as low as zero). Historically, developers have been successful in obtaining unit-specific offer floors below the PJM default values and been able to clear capacity at prices well below the default floors. For example, in the BRA for 2015/16, several projects cleared at prices significantly lower than would have been allowed without exceptions to the default floor. However, many of those unit-specific determinations were based on forecasts of net energy revenues that were more robust than the historically-based values used to estimate the default MOPR floor. Current forward market prices may not support the same level of premium to historical net energy revenues and may not support unit-specific floors that are low enough to allow new units to clear with the current RPM market conditions.

Table 12: PJM MOPR Offer Floors for 2021/22 BRA ($/MW-day, UCAP)

	***Cone Area 1*:** AE, DPL, JCPL, PECO, PSEG, RECO	***Cone Area 2:*** BG&E and PEPCO	***Cone Area 3*:** AEP, APS, ATSI, COMED, DAYTON, DEOK, DOMINION, DUQUESNE, EKPC	***Cone Area 4:*** METED, PENELEC, PPL
Combustion Turbine	$264.83	$219.90	$265.95	$193.01
Combined Cycle	$296.33	$219.23	$266.48	$209.99
Nuclear, Coal, IGCC, Hydro, Wind, and Solar	$0.00	$0.00	$0.00	$0.00
Other Resource Types	$205.98	$171.03	$206.85	$150.12

The parameters posted by PJM for the upcoming BRA will specify which LDAs will be include in the auction and determine which new projects are subject to the MOPR floors. If the LDAs remain the same as the last BRA, projects in the APS, AEP, Duquesne, Dominion, and EKPC zones will be outside of any modeled LDA and therefore not subject to the MOPR. ESAI has identified the following gas-fired projects as under advanced development and candidates for participation in the auction:

- South Field Energy Center (1,100 MW in ATSI)
- Renaissance (1,000 MW in APS)
- Niles Energy Center (1,000 MW in AEP)
- Hill Top Energy Center (536 MW in APS)
- B.L. England CCGT (500 MW repowering in AECO)
- Apex Guernsey Power Station (1,500 MW in AEP)
- Trumbull Energy Center (900 MW in ATSI)

Of those projects, the Renaissance, Niles, Hill Top, and Apex projects would be in the rest-of-RTO region and exempt from the MOPR. In the other zones, the MOPR floor may prevent new capacity from clearing at low BRA prices and help to minimize the level of oversupply in the market.

Future of the MOPR: Capacity Repricing or MOPR-Ex?

The structure of the MOPR rule beyond the next BRA is likely to be shaped by on-going discussion in the Capacity Construct/Public Policy Senior Task Force (CCPPSTF) and other PJM committees. As discussed in the last issue of *Capacity Watch*™, multiple proposals for mechanisms designed to protect competitive market prices while accommodating public policy initiatives were introduced by CCPPSTF participants. PJM proposed a Capacity Repricing approach, implemented through a two-stage auction mechanism. Although that proposal failed to obtain the simple majority approval needed to move forward to the Markets and Reliability Committee (MRC), PJM continues to advocate for the mechanism and released a white paper discussing its latest version of the proposed rule in January 2018. The leading alternative proposal came from the IMM. The IMM proposed an Extended MOPR (MOPR-Ex) rule, which would apply to both new and subsidized existing capacity and would rely on offer floors, much like the current MOPR. The MOPR-Ex proposal was endorsed by the CCPPSTF.

PJM Capacity Repricing Proposal

The PJM proposal relies on a two-stage auction mechanism. The first stage determines which resources will receive supply obligations and be eligible to receive capacity payments. The second stage determines the price that those resources will be paid. In the first stage, no offer floors are imposed for subsidized resources and those resources are allowed to offer as price-takers. The intersection of the resulting offer curve and the VRR curve determines which resources are selected for supply obligations; all offers to the left of the VRR curve "clear" the first-stage auction.

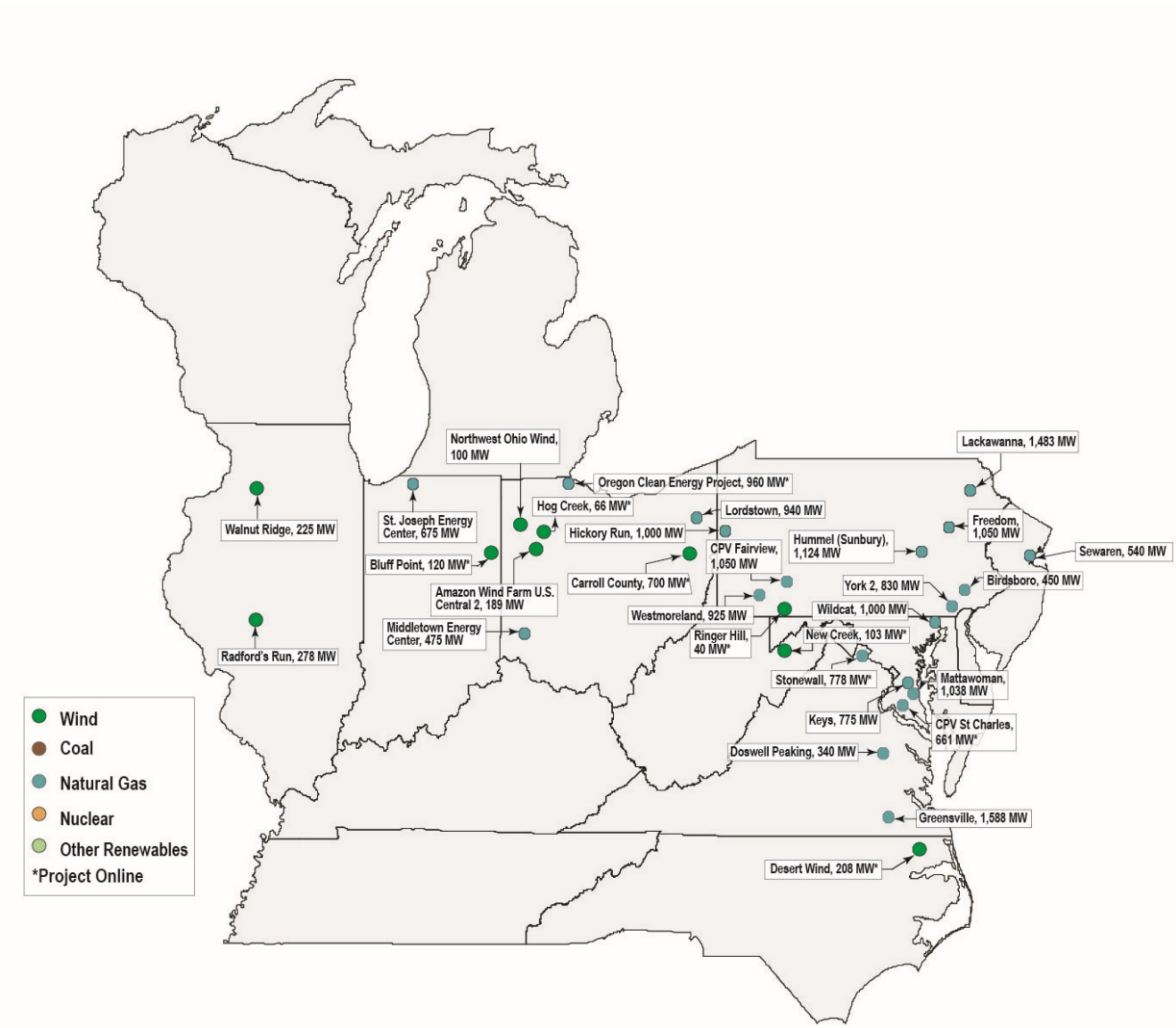
In the second stage, the offer curve is recreated, but with subsidized resources no longer offered as price-takers. Instead, subsidized capacity resources (new and existing) are subject to offer floors based on avoidable going-forward costs and quantifiable Capacity Performance (CP) risk. The intersection of the mitigated offer curve and the VRR curve determines the price for the auction. However, that price would be paid to the resources cleared in the first stage, regardless of whether a different set of resources would be selected with the second-stage offer curve.

This two-stage process results in a higher price than would occur with subsidized resources offered as price-takers. However, it also very likely to result in some resources with offers below the clearing price not getting a supply obligation or capacity payment. Hence the price will be reflective of a competitive market outcome, but subsidized resources will still displace resources that would otherwise be economic sources of supply. This effective squeezing out of "in-between" resources that would be economic but for the subsidies is the primary criticism of the PJM approach.

The PJM approach also includes several conditions that must be met in order to trigger repricing:

- The subsidized resources must not be owned by a vertically integrated utility or muni/coop;
- The subsidy must be from a state program, not a federal program;
- The subsidy must be directly focused on supply-side participation in the electricity market, rather than policies such as economy-wide tax credits;
- The total amount of subsidized capacity in PJM must be at least 3,000 MW;
- The subsidies must account for more than 1 percent of anticipated market revenues.

Figure 16: Select ESAI Project Evaluation Program Projects



New England

CASPR FILED AT FERC

On January 8, ISO-NE filed at FERC its proposal for the capacity market treatment of state-subsidized clean energy purchases, referred to as Competitive Auction for Sponsored Policy Resources (CASPR). ISO-NE intends to implement CASPR for FCA13, the 2022/23 auction scheduled for February 2019 and for which qualification begins in March. ISO-NE requested an effective date of March 9, two weeks before the March 23 deadline for retirement de-list bids.

Rather than focus on changes to the mitigation of buyer-side market power via the existing minimum offer price rule (MOPR) provisions, the CASPR mechanism links new entry of new state-sponsored resources into the capacity market to the retirement of existing resources from the markets. State-subsidized resources would be able to enter the capacity market and receive a capacity payment without being 'MOPRed-out' by buyer-side market power mitigation; but, they can only do so if there are matching MW of retiring existing resources.

CASPR: A Substitution Auction to Replace Retirements with Policy Resources

Under CASPR, ISO-NE would conduct a secondary "substitution" auction after the primary FCA to allow new state-sponsored resources that did not clear the primary FCA to offer a price to obtain the capacity supply obligation (CSO) awarded to resources that wish to retire but retained a CSO in the primary FCA. The retiring resource would then be paid this amount to exit the market, akin to a severance or "cash for clunkers" payment. Because no mitigation would be applied in the substitution auction, new subsidized resources would offer at a lower price than in the primary FCA. The subsequent substitution auction should then produce a lower clearing price than the primary FCA. That price would in turn be used to allow existing capacity resources wishing to retire but that retained capacity obligations in the primary FCA to shed their CSOs. Via this exchange of obligations, the substitution auction would allow new state-mandated resources that would have been MOPRed-out to contribute toward resource adequacy requirements.

Resources seeking to retire (regardless of whether they submitted a retirement or permanent de-list bid) but that retained a CSO would enter the substitution auction as the demand to be purchased in the substitution auction. The supply of offers in the CASPR substitution auction would be new sponsored resources that did not clear the primary FCA likely because of MOPR mitigation (more details on CASPR supply and demand below).

A resource that was MOPRed-out in the primary FCA could then clear and gain a CSO in the secondary substitution auction. That resource would also be entered as an existing resource in the primary FCA for the following year. ISO-NE will not allow the seven-year price lock provision to be used to lock in the substitution auction price (note that in the next year's FCA the substitution auction-cleared resource would be treated as an existing resource and thus would receive a price from that FCA that is likely higher than the prior substitution auction's clearing price).

The retiring resource would then be paid the net of the primary and secondary auction prices. If the primary FCA cleared at $7.00/kW-mo and the substitution auction at $4.00, and assuming a retiring resource's full primary FCA CSO is 'shed' or purchased by resources clearing the second auction, the retiring resource would receive a net payment of $3.00/kW-mo for that one year and then would retire permanently. Note that a partial amount of the retiring resource's CSO could clear the secondary auction, resulting in a partial payment.

Demand in CASPR Auction: Capacity Obligations to Be Procured/Replaced

The demand to be procured in the CASPR substitution auction consists of existing capacity resources that seek to retire from the ISO-NE wholesale power markets. Importantly, any existing resource can elect to participate as demand and be replaced in the substitution auction, regardless of whether it submitted a retirement or other de-list bid. If the resource retains a CSO in the primary FCA and is replaced in the secondary substitution auction, it must permanently exit all ISO-NE markets (except if submitted a permanent de-list bid, as explained below) and give up its capacity interconnection rights.

The surrender of capacity interconnection rights if replaced in the substitution auction is a key requirement for demand bids. Resources participating as demand in the substitution auction must presently have capacity interconnection service, thus effectively excluding all demand resources (demand response and energy efficiency) as well as capacity imports over existing tie lines. (Note that in the future CASPR demand could include capacity imports over an elective transmission upgrade (ETU) with capacity interconnection service and long-term contracts that allow them to qualify as existing capacity; none exist as of today.) Also, note that a new resource cleared in a past auction will need to have reached commercial operation (with active capacity interconnection rights) in order to participate as demand in the substitution auction.

The election to participate as demand in the CASPR auction must be made very early in the FCA qualification process: on the same March date that retirement and permanent de-list bids are due, 11 months prior to the auction and over four years prior to the capacity delivery year. This election deadline is also well before deadlines for static and administrative/export de-list bids, and of course the dynamic de-list bids submitted during the primary auction. A resource that submits a retirement de-list bid is automatically entered into the CASPR substitution auction. A resource with a permanent de-list bid can elect to enter as demand into the substitution auction, but is not forced to do so like retirement de-list bids. Recall that resources with a cleared permanent de-list bid are only required to permanently exit the FCM, not all markets. Should the permanent de-list bid MW clear the substitution auction, the resource would be required to exit the FCM (and surrender its capacity interconnection rights) but not all ISO-NE markets, in contrast to other existing capacity resources replaced in the CASPR auction.

CASPR demand participants will be able to submit a different price in the substitution auction than the prices submitted in the primary FCA. Substitution auction demand bids cannot be rationed and must be submitted in October, roughly four months before the FCA. ISO-NE will also allow negative demand bids and supply offers in the substitution auctions. A negative demand bid would signal that a retiring resource needs a substantial payment (above the FCA clearing price) to exit the markets. ISO-NE noted that negative bids/offers could result in a net severance payment that exceeds the FCA clearing price.

While substitution auction demand bids will be subject to an ISO-NE reliability review (like a retirement de-list bid) and resources could be retained for reliability, demand bid prices will not be reviewed by the IMM.

Supply in CASPR Auction: New Resources Eligible to Offer

New sponsored resources that seek to participate as supply and offer into the CASPR auction must qualify for the FCA as a new resource under the existing (and unchanged) qualification rules. ISO-NE defined a Sponsored Policy Resource as a resource that receives out-of-market revenue as a qualified renewable, alternative, or clean energy resource under a New England state mandate or law in effect as of January 1, 2018 (*e.g.*, a portfolio standard, clean energy procurement, etc.). This definition effectively excludes fossil-fueled generation resources, as well as resources sponsored by public power entities <u>unless</u> they also qualify under a state renewable/clean energy mandate. In addition to actively electing to participate as supply, new sponsored resources must document that it qualifies as a sponsored resource, including substantiation of out-of-market revenue. The determination of what constitutes out-of-market revenue will be consistent with how the IMM determines out-of-market revenue in its review and mitigation of offers under the MOPR.

In essence, participation as supply in the substitution auction is limited to sponsored resources that were MOPRed-out and did not clear the primary FCA. Note that competitive new fossil-fueled resources that were MOPRed-out and did not clear the FCA are excluded from offering into the substitution auction.

The new sponsored resource must also provide a 'preferred' offer price for the substitution auction as part of its primary FCA offer reviewed by the IMM. Offer prices must be submitted by October, concurrent with substitution auction demand bid prices. The desired offer price would be the unmitigated primary FCA offer price. In other words, the resource only participates as supply in the substitution auction if its preferred offer price is below its IMM-reviewed minimum offer price under the MOPR.

In contrast to demand bids, supply offers will be allowed to be rationed. ISO-NE will allow negative supply offers into the substitution auction, subject to a negative offer price floor at minus FCA starting price (-1.6 x Net CONE) to cap the negative value that sponsored resources can offer. For example, a sponsored resource might want to offer at a negative price for the substitution auction (*i.e.,* willing to pay to acquire a CSO) since it will become existing capacity in future FCAs and receive the clearing price in those FCAs. Allowing negative prices also might reduce the prospect that tie-breaking rules will be applied in the substitution auctions (if too many sponsored resources offer at zero).

CASPR Auction Design

The substitution auction will be a single-round, sealed bid auction that will clear resource bids and offers without an administratively determined demand curve. The substitution auction will use a similar 'social welfare maximization' algorithm as used in the primary FCA to address non-rationable supply offers in the FCA. In contrast to the primary FCA, supply offers will be subject to rationing in the substitution auction but demand bids (the 'retiring' MW) will be non-rationable and thus provide some lumpiness.

The substitution auction will also include a constraint to ensure that the system-wide purchase of capacity is unchanged from the value resulting from the primary FCA so that consumers will see the same level of overall system reliability as they pay for in the FCA for the same commitment period. Furthermore, inter-zonal capacity transfers in the substitution auction (*i.e.* using Rest-of-Pool (RoP) capacity in an import- or export-constrained zone) will be allowed only as long as specified zonal threshold quantities are not violated. If these zonal thresholds are violated, the substitution auction will only clear demand (retirements) and supply (sponsored resources) located in the <u>same</u> zone. The intent is to ensure that each MW of new sponsored resource entry is offset by a paired MW of retirement exit while keeping overall system reliability at the same level as procured in the primary FCA.

The zonal threshold quantities are the MW values under the marginal reliability impact (MRI) demand curves at which adding another MW does not provide any incremental reliability value relative to Rest-of-Pool capacity, *i.e*., the MW quantity at which the clearing price premium (for an import-constrained zone) or discount (for an export-constrained zone) goes to zero. For the SENE import-constrained zone for FCA12, this amount is 10,786 MW, meaning that there is no price separation at or above this quantity cleared in SENE. For the NNE export-constrained zone for FCA12, this amount is 8,380 MW, meaning that there is no price separation at or below this quantity cleared in NNE.

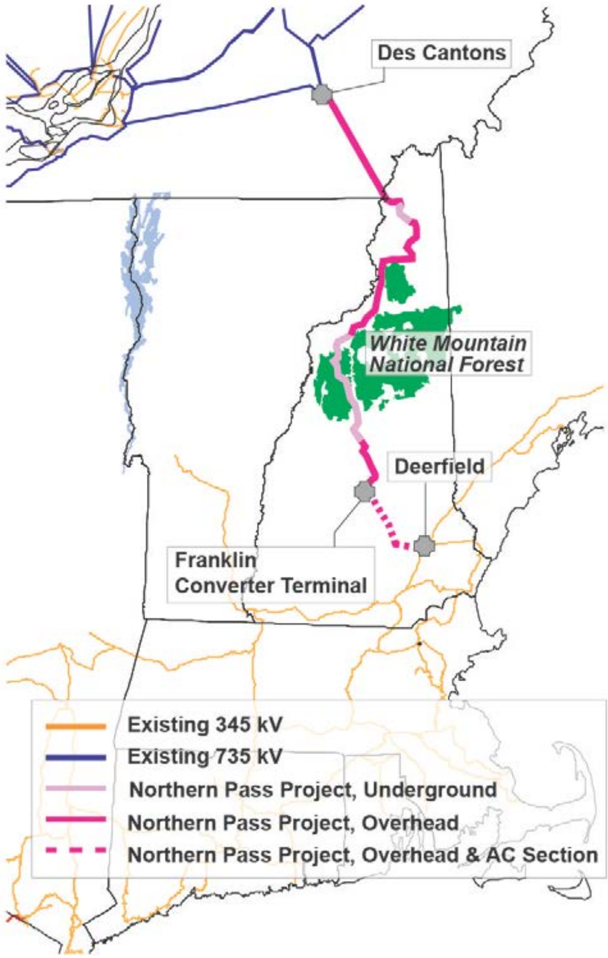
Price-setting by the substitution auction will be subject to two additional properties:

- Substitution auction prices must not exceed the corresponding FCA prices, *i.e.* prices capped at the FCA clearing price for each zone. If not, sponsored resources are paid a greater price than competitive resources, and existing resources that exit via the substitution auction would be charged to do so.
- A partially cleared bid or offer in a zone sets the zone's price.

RTR MOPR Exemption Retained but Phased Out

In an effort to gain support from states and load advocates for the CASPR mechanism, ISO-NE proposed to retain the renewable technology resources (RTR) MOPR exemption but phase it out over a limited period. The present RTR MOPR exemption allows for 200 MW

Figure 17: Northern Pass Project



Will Northern Pass Imports Clear the Capacity Market?

Contracts under the MA Clean Energy RFP provide only energy and/or REC payments, and no capacity payments. Bidders thus retain any capacity market payments received under the ISO-NE FCM. However, proposals were required to interconnect to the ISO-NE bulk power system under the capacity interconnection standard (*i.e.*, not an energy-only minimum interconnection standard). Bidders had to explain how their project would meet the capacity interconnection standard , including resolving any issues identified in the overlapping impact analysis. Under this analysis, capacity deliverability is demonstrated if full dispatch of the new project at the requested capacity amount together with all other existing capacity resources in the project's ISO-NE load zone would not overload transmission elements and interfaces within the load zone.

For Northern Pass, capacity qualification will require the overlapping impact analysis to demonstrate deliverability within the New Hampshire load zone, which should not pose a significant barrier to qualification. Accordingly, it is possible that Northern Pass and linked HQ imports have qualified for the upcoming FCA12 (2021/22). Regardless, it would seem likely that Northern Pass imports will qualify for next year's FCA13 (2022/23), for which qualification begins this April.

FCA-qualified Northern Pass imports would then be subject to the FCM's minimum offer price rule (MOPR). Note that the existing MOPR includes an exemption for Class I REC-eligible resources – the renewable technology resource (RTR) exemption – which would not be available to the hydro-only HQ import selected in the MA Clean Energy RFP. For the upcoming FCA12, we thus expect any FCA-qualified Northern Pass imports to be mitigated and thus 'MOPRed-out' from clearing the auction.

The picture becomes a bit more complicated for next year's FCA13 with the potential advent of ISO-NE's CASPR secondary substitution auction mechanism (see CASPR summary above). Northern Pass imports would remain subject to the FCM MOPR and unable to qualify for the RTR exemption (assuming FERC approval of ISO-NE's proposal for its retention and phase out under CASPR). Under CASPR, Northern Pass imports would clearly meet the definition of sponsored policy resources and thus qualify to participate as supply in the substitution auction. For Northern Pass imports to clear the CASPR substitution auction and gain a CSO, a corresponding amount of retirements would have to be submitted into FCA13. For FCA13, existing capacity considering retirement must either submit a formal (and binding) retirement de-list bid or elect to participate as demand in the CASPR auction by March 23, 2018. Announcement of Northern Pass as the successful bidder in the RFP might factor into this upcoming decision by existing capacity resources. Absent a substantial amount of FCA13 retirements or elections to participate as CASPR demand, we would expect Northern Pass imports to be mitigated and remain MOPRed-out from clearing FCA13.

We further note that the expected provision to require existing resources participating in the CASPR substitution auction to be subject to a MOPR and IMM mitigation in the primary FCA will not be in place for FCA13. Thus, FCA13 would retain an incentive for existing resources considering retirement to ensure clearing the primary FCA so that they can then be bought out in the substitution auction, creating some downside price risk for FCA13. Implementation of a 'floor price' review process for existing resources participating as demand in the substitution auction for FCA14 (2023/24) should ease this downside price risk.

Separately, under the FCM capacity zone determination process, FCA qualification of Northern Pass imports has lasting impact on the persistence of the Northern New England (NNE) capacity zone, comprising of the Maine, New Hampshire and Vermont load zones. Qualification of Northern Pass imports result in the continued modeling of this export-constrained zone in the auctions, allowing the possibility of price separation (discounts) from the Rest of Pool clearing price. Should Northern Pass imports clear the auction (either naturally or via the CASPR secondary substitution auction), the NNE zone will amount certainly clear at a substantial discount to the Rest of Pool price, as set under the zonal MRI demand curve for the NNE zone.

California

INTRODUCTION

A number of capacity related issues are now rising to higher priorities in California including the following:

- Concerns about CAISO backstop designation of generation to maintain reliability,
- Concerns about wholesale early retirement of natural gas generation resources, and,
- The potential impacts of new Community Choice Aggregation that may finally justify needed reforms to California's Resource Adequacy program,
- The CAISO continues to work to define flexible capacity obligations in ways that meet its changing needs as higher levels of renewable resources continue to challenge its operations.
- IOUs, while insisting they are over-procuring renewable resources, continue to meet generation and storage obligations set by the CPUC.

In a surprising twist, a federal court has ruled that California is not abiding by PURPA requirements and ordered suspension of the CPUC-designed feed-in tariffs. Determined to maintain its environmental leadership, California regulators appear determined to find ways for distributed resources and storage to offset new and replace existing natural gas fueled generation. The result could go a long way towards determining the relative cost-effectiveness of "Preferred Resources." To keep things interesting, the CPUC has also approved the shutdown of PG&E's Diablo Canyon Nuclear plant, which produces 2,240 MW of GHG-free baseload generation, while deferring on how to replace Diablo's generation without increasing GHG emissions.

CPUC DECLARES WAR ON RMR CONTRACTS

In response to the CAISO approving Reliability Must Run (RMR) contracts with three Calpine generators (October Capacity Watch), the CPUC approved a Resolution (E-4909) ordering PG&E to hold a solicitation to replace the RMR capacity with preferred resources (renewables, energy efficiency and demand response) and storage by 2019. Details include:

PG&E may solicit bids for energy storage and preferred resources, either individually or in an aggregation.

Resources procured pursuant to this solicitation must be both:

1) On-line and operational by a date sufficient to ensure that the RMR contracts for the three plants – Metcalf Energy Center, Feather River Energy Center, and Yuba City Energy Center – will not be renewed for 2019.
2) Located within the relevant sub-area(s) and be interconnected at location(s) that will mitigate local capacity and voltage issues sufficient to obviate the need for RMR contracts for the aforementioned plants.

3) Resources procured in this solicitation should be at a reasonable cost to ratepayers, taking into consideration the cost and value to PG&E, previous solicitations in which PG&E has awarded contracts to similar resources, the cost of the specific RMR contracts, with adjustments for contract terms such as contract length and expedited delivery date.
4) The portfolio of resources selected and contracted should be of sufficient capacity and attributes to alleviate the deficiencies identified.

Calpine's RMR FERC filing for Metcalf, which requires major maintenance this year, includes an Annual Fixed Revenue Requirement (AFRR) of $72.4 million, roughly $122/kW year. The 593 MW plant emits roughly 0.4 metric tons CO2e/MWh as well. According to the CAISO, there are 2,408 MW available in the South Bay-Moss Landing sub-area to meet a reliability requirement of 2,221 MW, thus only 187 MW of Metcalf's capacity would need to be replaced for reliability purposes. Getting that level of preferred resources and storage on line by 2019 would be a bit of a challenge and it is not clear that the cost of replacement resources would be competitive.

The 47 MW Yuba City plant is needed to meet an 18 MW shortage (100 MW requirement, 82 MW of other resources available), and the Feather River plant is needed for local area voltage control. Cost-effective alternatives to them may be feasible within a year.

The CPUC adopted the resolution even though several parties, including the CAISO, questioned the feasibility of meeting a 2019 in-service target, and noted that transmission projects are under development that would eliminate some of the RMR need, and raised the issue of the net overall impact of the changes.

Oakland RMR Replacement

PG&E has announced its own initiative to identify alternatives to the Oakland RMR units, three distillate-fueled CTs totaling 165 MW near downtown Oakland. PG&E is working with East Bay Community Energy to run a solicitation for distributed energy resource providers to propose innovative and competitive solutions as part of the portfolio. Depending on the exact resource mix, the solicitation is expected to result in 20 to 45 megawatts of clean energy resources. PG&E submitted the proposal to the CAISO TPP. If the project is approved by CAISO, PG&E will open up the RFO process. The Oakland Clean Energy Initiative has a forecasted in-service date of mid-2022.

CAISO BACKSTOP CAPACITY (CPM) DESIGNATION

Adding further evidence to the asserted need for resource adequacy program reform, on December 23, the CAISO issued a 12-month Capacity Procurement Mechanism (CPM) designation for resources shown in Table 25 below, needed for local reliability but not included in LSE RA submissions. The Encina units will roll off as the new Carlsbad units come on line as planned during 2018.

Table 33 - 12-month CPM Designations

Resource	MW	TAC Area
Moss Landing 1	510	PGE
Encina 4	272	SDGE
Encina 5	273	SDGE

COMMUNITY CHOICE AGGREGATION LIMITATIONS

As part of its apparent attempt to rein in the Community Choice Aggregation (CCA) process, the CPUC issued another draft resolution (E-4907) in December. It would require each newly forming CCA to submit registration package to the CPUC and obtain a CPUC-authorized date to begin service. The intent is to coordinate with mandatory resource adequacy forecast filings and to make sure that all CCAs account for RA obligations at start-up. The problem is that If an existing or pre-operational CCA does not submit an annual load forecast, they are not allocated a year-ahead RA obligation for the following year and the local IOU is required to acquire the RA capacity needed to serve the departing load. Existing and new CCAs that were not a part of the year-ahead 2018 RA process but plan to serve load in 2018 would have been allocated a System Peak RA requirement of approximately 3,616 MW and a local RA requirement of approximately 1,793 MW. These year-ahead RA requirements were met by the utilities that currently serve these customers. Some of these costs are recovered by the departing load charge (PCIA), however, any contracts less than one year are not captured by the PCIA and are borne by remaining bundled customers.

To resolve this problem, the Resolution would require new or expanding CCAs to submit their Implementation plan by January 1 for load to be served the following year (e.g., January 1, 2018 for load to be served in 2019). In addition, the Resolution adopts two new deadlines for CCA registration. First, it requires that a CCA submit its registration packet to the CPUC within 90 days of filing its Implementation Plan. Second, if the Registration Packet is complete, the CPUC will confirm the CCA's registration within 120 days of the CCA filings its Implementation Plan. RA forecasts would be submitted in April for the next year to assure that CCAs take responsibility for the RA obligations of their customers at the time they begin serving them.

Existing and proposed CCAs are up in arms and propose that the matter be taken up in the Resource Adequacy proceeding. The CPUC has delayed consideration of the draft Resolution until its meeting in February.

RESOURCE ADEQUACY PROCEEDING

The CPUC issued a scoping ruling in the RA proceeding on January 18 (R.17-09-020). It adopts three tracks for the proceeding. Track 1 will be concluded by June 2018 and will focus on adopting local capacity requirements (LCR) based on CAISO's upcoming LCR study to

