CAPACITY WATCH

Authors: Paul Flemming, Scott Niemann, José Rotger & Phil Muller

4th Quarter 2018

EXECUTIVE SUMMARY

In this issue of *Capacity Watch*™, ESAI Power provides our updated outlook for each of the northeast capacity markets. In New York, spot auction clearing prices are down for the 2018/19 Winter Capability Period due to new supply additions. For Summer 2019/20 and beyond, increases in the locational requirements and peak load forecast result in an increase in the forecast for the G-J Locality and New York City, while a lower expected peak load and a drop in the installed reserve margin dampen the outlook for Rest-of-State.

In PJM, updated parameters for the VRR curve are pending FERC approval, including a significant reduction in the CONE value and a rightward shift of the VRR curve. The updated parameters proposed by PJM will have a downward impact of the next Base Residual Auction (BRA). More significantly, the BRA outcome and long-term market outlook will be shaped by the outcome of the on-going FERC proceeding related to offer price mitigation reforms.

In New England, the ISO has made its informational filing regarding capacity qualified for FCA13, to be conducted in February 2019. The ISO has also released parameters for the zones and demand curve for the auction. Based on expected retirements and potential static delist bids, ESAI has increased its forecast for the FCA13 clearing prices to reflect a moderate reduction in the supply surplus heading into the auction.

In This Issue

ESAI POWER LLC

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

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New York

SUMMARY

New supply that entered the market during the Summer of 2018 has resulted in lower market clearing prices for the Winter 2018/2019 period. Additionally, capacity exports to New England from the Lower Hudson Valley have not materialized due to low Monthly Reconfiguration Auction (MRA) prices in New England. Without the any offsetting exports, the market has cleared with lower prices in the G-J Locality and New York City.

Looking forward to Summer of 2019, the outlook for prices in New York City and the Lower Hudson Valley has improved. Downstate transmission outages are expected to support higher LCR values than were previously expected. Previously, the new optimized methodology for setting LCR will be used for 2019/20 and was expected to result in a significant drop in LCR for the G-J locality. With the transmission outages factored in, LCR will increase for Zone J and drop by a much smaller amount for the G-J Locality. This change in expectation for LCR, along with a more favorable Downstate peak load outlook for Summer 2019, will support higher prices for next summer than reflected in ESAI's last quarterly forecast. Relatively tight supply and demand is expected to continue into the longer-term for New York City, while a decline in prices is expected for the G-J Locality following new transmission additions by 2023.

Due to a lower peak load forecast and drop in the Installed Reserve Margin Requirement, ESAI's forecast for the Rest-of-State (ROS) capacity prices has decreased. The outlook for ROS will improve with expected retirements, but the potential for additional imports (or reduced exports) from surplus capacity in neighboring markets will limit the escalation in ROS prices over the duration of the forecast.

INSTALLED RESERVE MARGIN AND LOCATIONAL CAPACITY REQUIREMENTS

FERC Approves New LCR Methodology

As discussed in more detail in previous issues of *Capacity Watch*™, the NYISO conducted an extensive set of stakeholder discussions over the last few years to develop an alternative methodology for setting the Locational Capacity Requirements (LCR) for the NYISO ICAP market. The original methodology for setting LCR, which was established prior to the addition of the G-J Locality, produced results that were viewed by many as counter-intuitive and volatile. The alternative approach better incorporates the G-J Locality (and other zones that may be added in the future) and is designed to optimize the choice of LCR values among the locations in order to minimize the cost of maintaining the mandated reliability standard. The NYISO filed the proposed rule changes to implement the new methodology with FERC earlier this year and the Commission issued an order approving the methodology on October 5, 2018. The LCR values for 2019/20 will be set based on the new optimized approach.

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Updated Values for 2019/20 IRM and LCR

The New York State Reliability Council (NYSRC) released its draft 2019 Installed Reserve Margin (IRM) Report in October, along with its final IRM Base Case. As shown in Table 1, the 2019/20 IRM value recommended by NYSRC is 116.8 percent, a 1.4 percent drop from 2018/19. If approved by the NYSRC Executive Committee and FERC, the lower IRM will result in lower prices for the Rest-of-State (ROS) region. The drop in IRM follows a series of annual increases since 2011. IRM has been increasing due to additional intermittent capacity on the system and tightening regional reserve margins. Although these factors would have resulted in an increase for 2019/20, all else equal, several other factors contributed to offsetting declines in IRM:

- NYSRC's study assumptions include a lower state-wide peak load forecast and updated hourly load shapes;
- Lower forced outage rates for generators and transmission facilities;
- Increased performance of demand-side resources;
- Higher LCR values for New York City and the G-J Locality, and
- Other changes in modeling assumptions and software.

Beyond 2019/20, ESAI expects the general upward trend in IRM values to continue, with some year-to-year fluctuations (up or down) due to factors similar to those affecting the 2019/20 value. Overall, however, the increases in intermittent generation expected as New York implements its Clean Energy Standard will require increases in IRM in order to maintain the reliability standard.

Table 1: NYISO LCR and IRM Requirements

	2016/17	2017/18	2018/19	2019/20 IRM Study Base Case	2019/20 Delta from 2018/19
Rest of State, IRM	117.5%	118.0%	118.2%	116.8%	-1.4%
G-J Locality, LCR	90.0%	91.5%	95.4%	93.1%	-2.3%
New York City, LCR	80.5%	81.5%	80.7%	83.2%	2.5%
Long Island, LCR	102.5%	103.5%	103.5%	103.5%	0.0%

Note - IRM = Installed Reserve Margin; LCR = Locational Capacity Requirement

Although the IRM value is expected to decline for 2019/20, LCR values are expected to increase relative to ESAI's prior assumptions. The shift to the optimized LCR approach was expected to result in drop LCR values the G-J Locality in 2019 and no increase was expected for Zone J. Downstate transmission outages are now expected to offset that decline for the G-J Locality and result in an increase for Zone J. Specifically, the two transmission feeders between the Hudson substation in New Jersey and the Farragut substation in New York (the "B and C Lines") are expected to remain out of service and the NYISO has updated its assumptions for LCR to reflect the outage. The B and C Lines have been out of service since

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early 2018. The two feeders, built in the 1970s, are oil-filled pipe-type cables under the Hudson River. The lines have been leaking fluid, and although the leak has been repaired, they remain out of service. A dispute between PSEG and ConEdison has emerged over cost responsibility, delaying the restoration process. PSEG favors abandoning the cables, while ConEdison would like to have them back in service. The NYISO and PJM have determined that the cables are not needed for reliability and ConEdison's interconnection agreement will expire at the end of 2020, so the lines may not be returned to service. Given these circumstances, the NYISO decided to treat the lines as out indefinitely in the 2019/20 LCR calculations.

As part of the IRM Study, in August 2018, the NYISO had provided estimates of the LCR values under both the original LCR approach and the new methodology. Those estimates were prepared assuming the B and C Feeders were in service. The results showed LCR under the optimized methodology of 89.7 percent for the G-J Locality and 80.1 percent for New York City. The NYISO estimated that LCR for the G-J Locality would have been 94.9 percent under the original LCR methodology, so a substantial drop was expected for that zone (Zone J LCR would have been similar under the two approaches). With the B and C Lines out of service, the G-J Locality LCR is expected to drop by much less, to 93.1 percent. The New York City LCR is expected to increase to 83.2 percent. The Long Island LCR is not affected significantly by the B/C Line outages and is expected to remain at 103.5 percent.

These higher preliminary LCR values are supportive of higher prices for New York City and the Lower Hudson Valley, as reflected in ESAI's forecast shown below. ESAI's base case assumes the B and C Line outages will continue beyond 2019/20 and support higher LCR values over the next few years, but that an eventual return to service of the lines, or other moderating factors, will offset the impact on LCR in the longer-term. ESAI's assumptions for New York City and the G-J Locality LCR are shown below. Note that ESAI has assumed G-J LCR will decline in 2023, with the addition of the AC Upgrades transmission projects approved under the Public Policy Transmission Needs process. ESAI's forecast assumptions also reflect an increase in the New York City LCR following the retirement of each of the Indian Point nuclear units. As discussed in the Q3 2018 issue of *Capacity Watch*™, the NYISO projected Zone J LCR would increase to 83 percent in 2020 and 85 percent in 2021, following the retirement of Indian Point unit 2 and Unit 3, respectively. These estimates did not reflect the B and C Line outages, so ESAI has assumed moderately higher values, as shown below. ESAI has assumed Zone K LCR will remain at 103.5 percent.

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Figure 1: Historical and Projected G-J Locality LCR

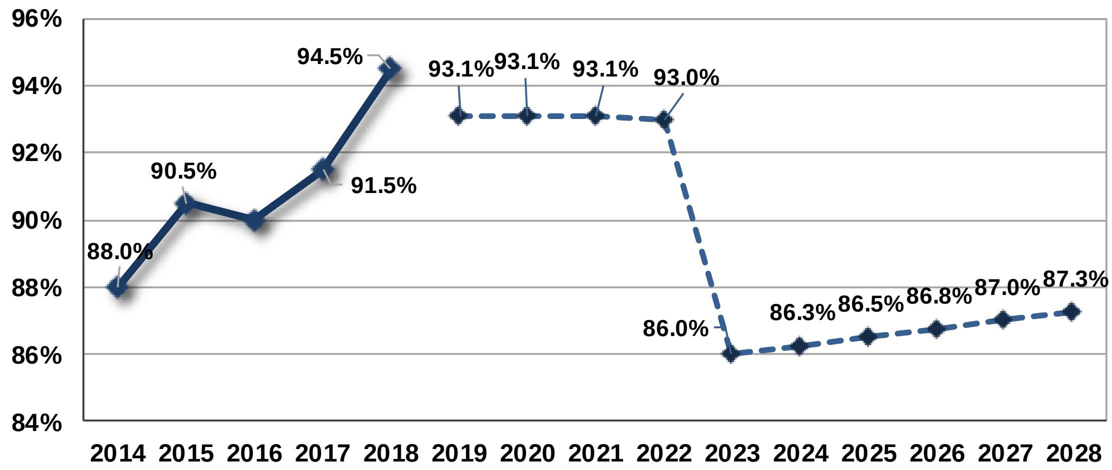
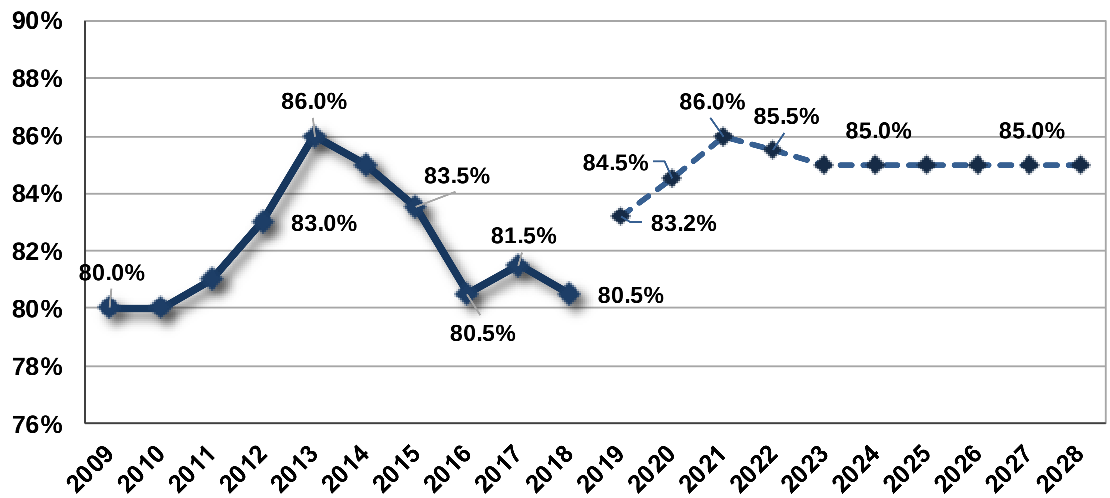


Figure 2: Historical and Projected New York City LCR



PRELIMINARY NYISO PEAK LOAD FORECAST RELEASED

Each year, the NYISO prepares a preliminary updated peak load forecast for the following summer and provides it to the New York State Reliability Council (NYSRC) for use as an input in the process to establish the Installed Reserve Margin (IRM) for the upcoming Capability Year. The forecast is prepared based on weather-normalized[1] peak load values for the New York Control Area (NYCA, which coverall all of New York State) and each of the capacity zones, along with forecasted growth rates for each transmission district

[1] Weather normalized peak loads are assessed based on adjustments to actual metered peak loads. Adjustments to actual loads are based on the variation between actual temperatures and the expected temperature underlying the 50/50 peak load forecast.

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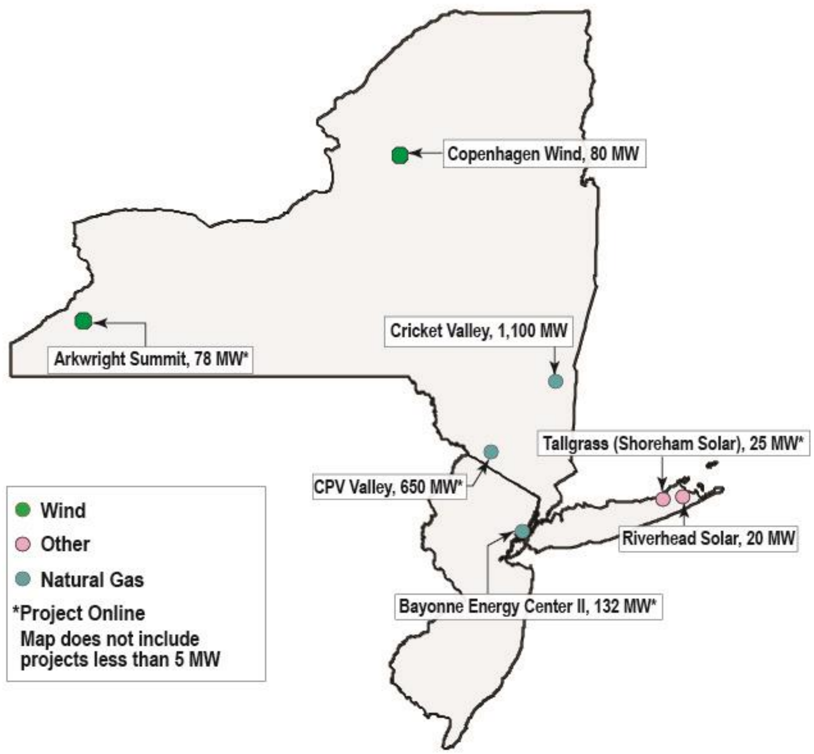
Figure 9: Select ESAI Project Evaluation Program Projects



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PJM

SUMMARY

The outlook for the next few PJM RPM capacity auctions remains uncertain due to several market and regulatory factors:

- As part of its quadrennial process, PJM has filed changes to the VRR curve parameters, including gross CONE, assumptions used to calculate the E&AS offset, and the position of the curve. ESAI's forecast includes these changes. If FERC requires adjustments to the values submitted by PJM, the forecast could be affected.
- The form of revised MOPR rule/carve out approach that is approved by FERC will have a material impact on the incentives for subsidies to existing resources and the BRA clearing prices. Strict mitigation along with a repricing mechanism could substantially reduce artificial price suppression in the RPM market and reduce the probability of significant price drops in future BRAs. However, if a carve out approach for subsidized resources is implemented that allows subsidized new entry without any offsetting mitigation of the impact on clearing prices, RPM clearing prices could be pushed lower and never rise to the level needed to support new entry.
- New Additions: The higher clearing price in the 2021/22 BRA has brought renewed development efforts, which could result in new entry that may dampen prices in upcoming BRAs. ESAI has assumed 3,300 MW of new capacity will clear in the next BRA. If additional resources clear, or if the new plants are located outside of import constrained zones, prices could be lower.
- Changes in natural gas and/or coal prices could materially affect the energy margins of different generator types. As a result, capacity market offers and clearing prices would be affected, along with new entry and retirement patterns. In particular, lower natural gas prices could result in additional entry by new CCGTs unit that may be less dependent on the capacity market to cover new entry costs. This new entry would result in additional economic retirements of coal plants and potentially some nuclear facilities.
- Demand growth forecasts, changes in installed capacity requirements, and intra-PJM import limits have been very volatile over the last five years and are likely to remain difficult to anticipate. Initial indications are that the next peak load forecast will be revised downward. ESAI's current outlook assumes the reliability requirements for all BRAs over the forecast period will reflect the current (2018) PJM peak load forecast.

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These factors will also affect longer-term market outcomes, including the long-run mix of capacity and fuel types. While it is clear that the current level of market surplus is not sustainable, the path for rationalization of supply and demand over time is not yet clear.

The discussion that follows includes a review of recent developments at FERC and within PJM stakeholder processes, followed by ESAI's current forecast for RPM prices.

QUADRENNIAL REVIEW OF VRR DEMAND CURVE UPDATE

PJM's quadrennial review of gross CONE and the VRR curve began this spring with the release of the Brattle Report, which provides recommendations for changes in Gross and Net CONE, including the reference technology and other demand curve parameters. After several months of stakeholder discussions and review of several alternative proposals, the PJM Board approved a set of changes that were included in an October 12, 2018 filing to FERC. Comments from stakeholders will be forthcoming and an order is expected before the end of the year.

The key elements of the PJM filing are as follows:

- The VRR curve will be shifted to the left by 1 percent, removing a 1 percent rightward shift included after the last VRR curve review in 2014. The 1 percent rightward shift was included to mitigate uncertainty from impending retirements of coal-fired capacity and concerns about the economic viability of older, non-gas-fired resources in the fleet. PJM determined these factors have largely been resolved and the shift is no longer needed to protect reliability.
- A simple-cycle CT unit is being maintained as the benchmark unit, but PJM has changed the assumed technology for the reference plant from a pair of F-Class turbines to a single H-Class turbine.
- The Gross CONE estimate has been updated to reflect the new technology and changes in equipment and labor costs, tax rates, and assumed financing costs. In combination, these changes result in a reduction of approximately 20 percent in each of the Gross CONE values, as shown in Table 13.
- The E&AS offset will be estimated using a lower heat rate, reflecting the H-Class turbine assumption and will include a 10 percent cost-adder, as allowed in the PJM Energy Market.

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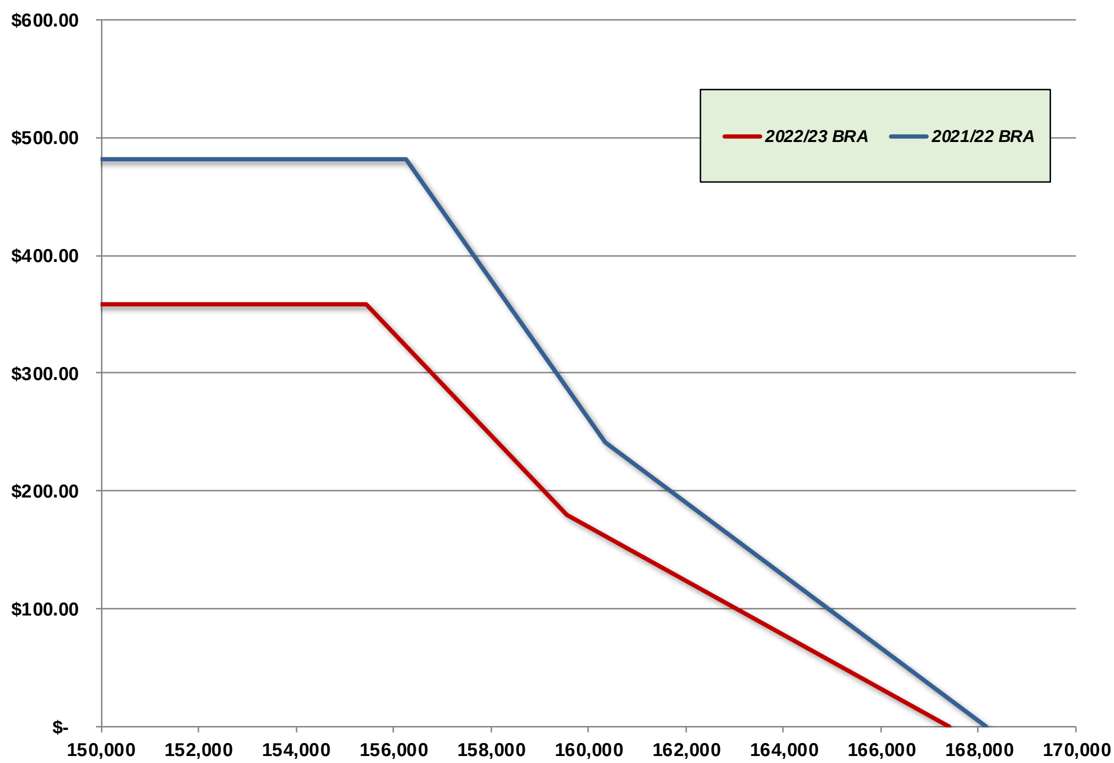
Table 13: Change in Gross CONE for VRR Curve for 2022/23 ($/MW-Year)

	2021/22	2022/23	Delta	
CONE Area 1	133,144	108,000	(25,144)	-19%
CONE Area 2	140,953	109,700	(31,253)	-22%
CONE Area 3	134,124	105,500	(28,624)	-21%
CONE Area 4	133,016	105,500	(27,516)	-21%

Figure 10: PJM VRR Curve: 2021/22 vs. 2022/23



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ESAI RPM MARKET OUTLOOK

ESAI Forecast for 2022/23 BRA

ESAI’s forecast for the 2022/23 BRA is based on the following assumptions:

- Coal and nuclear offer patterns are unchanged from the 2021/22 BRA, with the unsold capacity in the last BRA remaining unsold, but no additional changes in offer patterns;
- Gross CONE decreases to reflect the values for each CONE region reflected in PJM’s FERC filing. ESAI’s preliminary estimates of the Net E&AS revenues result in Net CONE that is approximately 25 percent lower than the 2021/22 BRA;
- New CCGT supply of 3,300 MW offered on a price-taking basis, split between the ATSI LDA, COMED LDA, and the rest-of-RTO region;
- CETL values unchanged for 2020/21;
- Reliability Requirements increase with forecasted demand growth (per 2018 PJM Load Report).

The leftward shift in the VRR curve was not included in ESAI’s Q3 2018 forecast. Incorporating that shift in the VRR curve for each LDA results in lower clearing prices than shown in our Q3 forecast. Under these assumptions, the RTO clearing price is expected to decline slightly in the next BRA, reflecting the impact of a lower Net CONE and new capacity additions. The ATSI LDA is projected to clear with the RTO, as 1,100 MW of new CCGT capacity is sufficient to offset unsold existing capacity and eliminate the LDA price premium. However, if coal-fired units in ATSI are offered higher than in the last BRA, price separation could occur for ATSI. The COMED LDA is expected to continue to clear above the RTO, even with 1,100 MW of new CCGT capacity included. However, the COMED price separation assumes bidding behavior similar to the 2021/22 BRA. If bids are similar to the 2020/21 BRA, in which less capacity was offered at high prices in COMED, the LDA could converge with RTO.

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New England

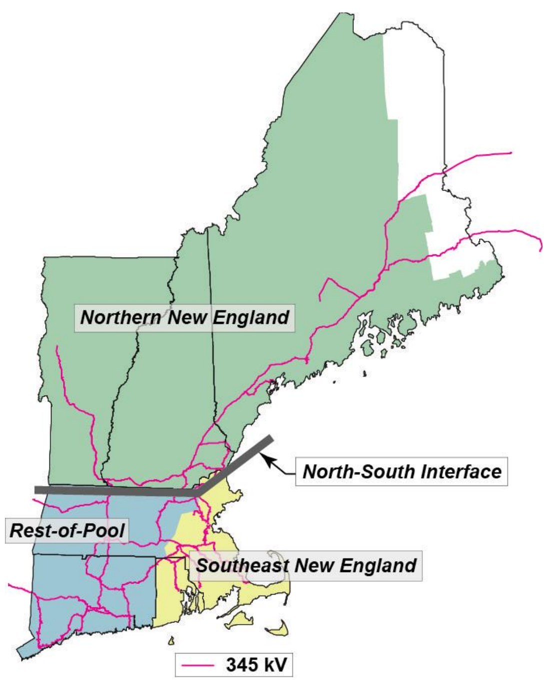
FCA13 2022/23 AUCTION PARAMETERS

Auction parameters for the upcoming 2022/23 FCA13, slated for February 4, 2019, are in place. ISO-NE finalized the installed capacity requirement (ICR), local sourcing requirements (LSR), and maximum capacity limit (MCL) amounts earlier this month, with a FERC filing to be made by November 6. As prescribed in its tariff, ISO-NE updated the Cost of New Entry (CONE) and offer review trigger price (ORTP) values to be used in the auction. The Net CONE and Net ICR values are used to 'anchor' the marginal reliability impact (MRI) system-wide demand curve, with a new set of MRI values developed for FCA13 and used to determine the system-wide and zonal demand curves for the auction.

Maine Remains Part of NNE Export-Constrained Zone

As in the last auction (FCA12 for 2021/22), FCA13 will have three zones: the Southeast New England (SENE) import-constrained zone consisting of NEMA/Boston, SEMA, and Rhode Island; the Northern New England (NNE) export-constrained zone comprising of Maine, New Hampshire, and Vermont; and the Rest of Pool zone which only includes the West-Central MA and Connecticut load zones (see Figure 12). ISO-NE considered designating the Maine load zone as an export-constrained zone instead of the larger NNE zone. However, ISO-NE's capacity zone trigger analysis concluded that not enough new resources would qualify in Maine to trigger that zone as a separate export-constrained zone.

Figure 12: FCA13 (2022/23) Capacity Zones



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Despite the ongoing interconnection cluster study process for northern and western Maine wind resources, ISO-NE signaled that it is unlikely that these resources will qualify for FCA13 because the constrained Orrington-South interface prevents them from passing the capacity deliverability "overlapping impact" analysis. ISO-NE's capacity zone trigger analysis suggests that ISO-NE will not qualify a large amount of imports using Avangrid's 1,200 MW New England Clean Energy Connect (NECEC) HVDC transmission link from Québec into Maine – at least not more than the 375 MW of "headroom" below an indicative MCL for Maine used in the trigger analysis. But, for the larger NNE zone, ISO-NE concluded that there are enough new resources expected to qualify in the three northern New England states to exceed a calculated headroom of 234 MW, thus triggering designation of NNE as an export-constrained zone. It is not known whether this expected qualification includes imports over the Northern Pass tie into New Hampshire, though we believe that to be unlikely. ISO-NE will not release the amount of new capacity qualified in NNE for FCA13 – it will only post the total amount of new resources qualified system-wide (not by zone or type of resource). We will only know if any new capacity cleared in NNE (and Maine) after the auction.

Proposed Termination of Invenergy Clear River Unit 1 CSO

The 2022/23 ICR calculation was somewhat complicated by ISO-NE's proposed termination of the capacity supply obligation (CSO) obtained by Invenergy for Unit 1 of its proposed Clear River combined cycle units in Burrillville, RI. Cleared in FCA10 (2019/20) and likely setting the $7.03/kW-month clearing price for that auction, Invenergy has covered (*i.e*. shed) its 485 MW Unit 1 obligation for 2019/20 and 2020/21, as allowed under the FCM rules. But, the project's inability to meet critical milestones in its critical path schedule led ISO-NE to conclude that the project will be delayed past June 2021, the start of the 2021/22 commitment period (FCA12). As a result, on September 20 ISO-NE filed at FERC seeking to terminate Clear River Unit 1's CSO starting 2021/22 and remove the MW from the existing capacity for the FCA13 (2022/23) ICR calculation. After termination, Invenergy would not have a CSO for 2021/22 or any future commitment periods, despite gaining a seven-year price lock on the CSO when it cleared for 2019/20 (FCA10).

Since Invenergy was able to shed its CSO for 2019/20 and 2020/21 (picked up by other capacity suppliers), the capacity amounts for reconfiguration auctions for these commitment periods are not affected. But, terminating the Clear River 1 CSO starting 2021/22 revises the amount of existing capacity and thus the purchase requirement (ICR) for the 2021/22 first annual reconfiguration auction (ARA1) in June 2019. We note that, under the FCM rules, Invenergy likely made a margin on its 2019/20 and 2020/21 CSOs, with an FCA payment of $7.03 (locked in for both FCAs and escalated at Handy-Whitman) and a cost to cover the CSOs for those years of around $3.50 (2019/20 ARA2 cleared at $3.50, 2020/21 ARA1 at $3.67) plus the loss of posted financial assurance (well below this clearing price arbitrage amount).

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Because FERC is not expected to rule on the CSO termination until November 19, after the November 6 tariff deadline for filing the FCA13 values at FERC, ISO-NE will file two sets of FCA13 ICR values: with and without the Clear River 1 CSO. The difference between the two ICR values is very small, with Net ICR including the Clear River 1 CSO 20 MW higher than the value without the Clear River 1 CSO. We expect FERC to approve termination of the Clear River 1 CSO; thus, we assume that the ICR values will exclude the Clear River 1 CSO.

A Slight Increase to Net ICR

Excluding the Clear River 1 CSO, ISO-NE proposed an ICR for 2022/23 of 34,719 MW including Hydro-Québec Interconnection Capability Credits (HQ ICCs), which equates to a 19.3% reserve margin. The 2022/23 gross ICR is 36 MW higher than the 2021/22 gross ICR. Excluding 969 MW of HQ ICCs leaves a Net ICR to be purchased in the auction of **33,750 MW**, which represents a 16.0% reserve margin and a 25 MW increase from 2021/22. The 2022/23 and 2021/22 ICR values are provided in Table 20.

Table 20: FCA13 vs. FCA12 ICR and Related Values

	2022-2023		2021-2022		CHANGE	
	MW	Reserve Margin	MW	Reserve Margin	MW	Percent
Forecast Peak Demand (50/50)	29,093		29,436		(343)	(1.2%)
Assumed Existing Resources (incl. HQICCs)	33,867		34,567		(700)	(2.1%)
Installed Capacity Requirement (ICR)	34,719	19.3%	34,683	17.8%	36	0.1%
HQ Interconnection Capability Credits (HQICCs)	969		958		11	1.1%
NET ICR (to be purchased in FCA)	**33,750**	**16.0%**	**33,725**	**14.6%**	**25**	**0.1%**
Locational Sourcing Requirements (LSR):						
Southeast New England (SENE)	10,141		10,018		123	1.2%
Maximum Capacity Limit (MCL):						
Northern New England (NNE)	8,545		8,790		(245)	(2.9%)

The primary driver for the increase the ICR between 2022/23 and 2021/22 is ISO-NE's revised assumption in the ICR calculation for the minimum level of operating reserves from 200 MW to 700 MW. The ICR model treats the higher minimum operating reserve requirement as additional load; thus increasing ICR. The minimum operating reserve assumption change increased ICR by roughly 550 MW; but, almost all of this increase was offset by a much lower peak load forecast – note the 343 MW drop in forecast peak demand between summer 2021 (FCA12) and summer 2022 (FCA13). The lower load forecast resulted in a decrease to ICR (as compared to FCA12) of roughly 420 MW. The load forecast decrease continues to reflect the substantial increase in behind-the-meter (BTM) solar photovoltaic (PV) output. Another offsetting factor is a slight decrease in the assumed

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forced outage rates for generation resources stemming from updated performance data, which drove a 120 MW decrease to ICR. Lower forced outage rates from existing resources mean that less capacity must be procured in the ICR.

SENE LSR – Excluding the Clear River 1 CSO, the LSR for the SENE import-constrained zone is **10,141 MW**, set by the higher of the transmission security analysis (TSA) requirement and local resource adequacy (LRA) values for the zone. Using its probabilistic resource adequacy analysis, ISO-NE calculated an LRA for SENE of 9,880 MW. In contrast, the TSA requirement is calculated deterministically based on transmission security needs under 90/10 peak load conditions and N-1 import limits. For LSR purposes, ISO-NE uses a "line-gen" TSA, meaning that the largest generating unit is out. The SENE TSA of 10,141 MW set the LSR value, as seen since the introduction of the SENE zone in FCA10. The primary driver for the SENE TSA increase as compared to FCA12 (10,018 MW, a 123 MW increase) is a 148 MW jump in the 90/10 SENE load forecast (from 13,413 MW for summer 2022 to 13,561 MW for summer 2023). With 10,767 MW of existing SENE resources qualified to participate in FCA13 (excludes Invenergy Clear River 1), there is almost zero chance that SENE will price separate in the auction.

NNE MCL – ISO-NE set the FCA12 NNE MCL at **8,545 MW**, a 245 MW decrease from the FCA12 NNE MCL. The decrease is attributable to the continuing drop in forecast loads in the NNE zone. Note that the zonal MRI curve for export-constrained zones returns a price discount even at quantities below the MCL.

Tie benefits – Tie benefits for 2022/23 are a total of 2,000 MW (a 20 MW decrease from 2021/22), with 1,118 MW from Québec (969 MW on Phase 2 and 149 MW on Highgate), 516 MW from New Brunswick, and 366 MW from New York (AC ties only, including the Northport-Norwalk Cable). The 20 MW decrease in total tie benefits is mostly attributable to the increase in assumed minimum operating reserves implemented for the FCA13 ICR calculation. Tie benefits from New York decreased by 47 MW as compared to FCA12 because under the ICR model the higher assumed minimum operating reserve requirement translates to more installed capacity in New England and less in New York. The lower New York tie benefit value provides more "space" for capacity imports from NYISO.

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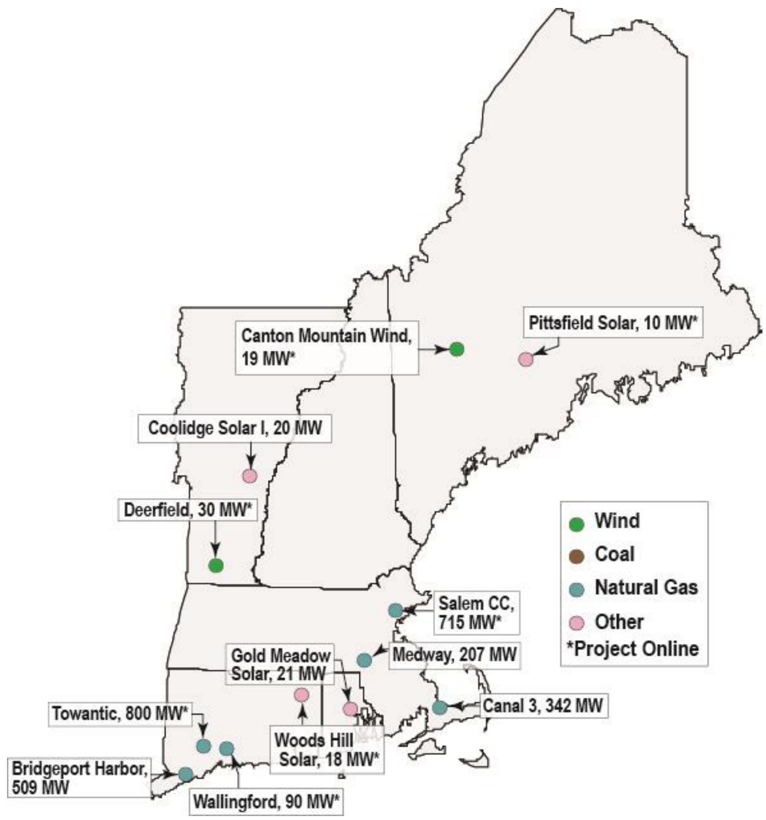
Figure 17: Select ESAI Project Evaluation Program Projects



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California

The Resource Adequacy reforms discussed in ESAI's previous *Capacity Watch* publication continue to expand as described below. It starts with the CPUC's 2017 Resource Adequacy Report which provides some information about California's otherwise opaque RA "Market." That is followed by descriptions of the Resource adequacy proceedings currently underway and recent RA procurement. Beyond this, ESAI discusses demand response, regionalization, CAISO Day-ahead market enhancements, departing load/customer choice and generation interconnection issues.

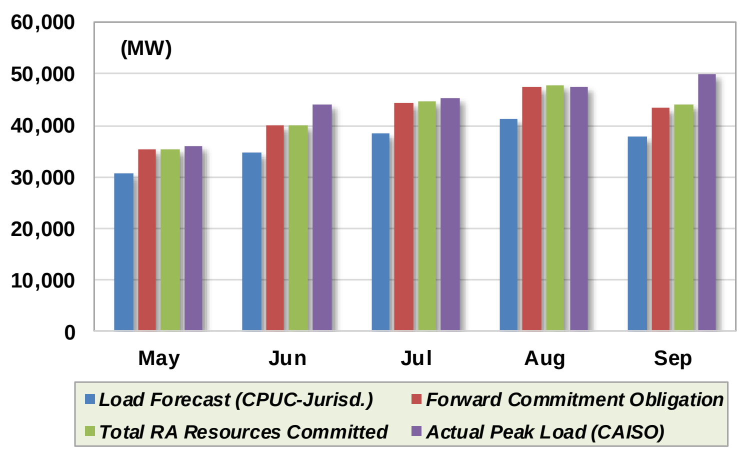
Resource Adequacy

The CPUC issued its 2017 Resource Adequacy report in August. It noted that RA commitments were sufficient to meet the August 2017 peak demand. CAM, RMR, and DR procurement comprised 17% of the overall August RAR. Table 30 shows the monthly RA commitments of CPUC-Jurisdictional entities. Figure 18 compares load forecast, RA requirements, total RA committed resources and actual peak load for the summer months.

Table 30: 2017 RA Filing Summary - CPUC-Jurisdictional Entities (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
RAR without DR, CAM & RMP	32,270	31,327	30,422	31,832	35,247	39,875	44,343	47,484	43,561	37,367	32,932	33,881
Physical Resource	29,121	28,248	28,162	29,191	31,063	35,519	38,615	41,533	37,279	32,502	28,859	30,368
Imports	2,594	2,377	1,885	1,972	2,405	2,421	3,886	3,889	4,463	3,137	3,101	2,456
DR plus 15% PRM	1,171	1,241	1,279	1,456	1,826	1,987	2,101	2,184	2,026	1,932	1,400	1,169
CAM & RMR	6,191	6,222	6,157	6,198	6,148	6,509	6,503	6,240	6,258	6,393	6,470	6,518
Total	33,035	32,015	31,474	32,769	35,444	40,076	44,752	47,756	43,917	37,721	33,510	34,141
Total / RAR	102.4%	102.2%	103.5%	102.9%	100.6%	100.5%	100.9%	100.6%	100.8%	100.9%	101.8%	100.8%

Figure 18: 2017 RA Performance



The report noted that local RA procurement exceeded 100% of the requirement in all months. Average capacity prices for 2017-2021 are summarized in Table 31. Monthly averages are in Table 32.

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Table 31: Capacity Prices by Compliance Year (2017-2021)

	Total RA Capacity Contracts			Local RA Capacity Contracts			CAISO System RA Capacity Contracts		
	Total	NP-26	SP-26	Subtotal	NP-26	SP-26	Subtotal	NP-26	SP-26
Contracted Capacity	**310,917**	167,563	143,354	**234,678**	100,027	134,651	**76,239**	67,537	8,703
Percentage of Total Capacity in Data Set	**100%**	54%	46%	**75%**	43%	57%	**25%**	89%	11%
Number of Monthly Values	**5,347**	3,583	1,764	**3,888**	2,574	1,314	**1,459**	1,009	450
Weighted Average Price ($/kW-month)	**$2.71**	$2.20	$3.31	**$2.92**	$2.24	$3.42	**$2.09**	$2.15	$1.59
Average Price ($/kW-month)	**$2.36**	$2.25	$2.58	**$2.59**	$2.42	$2.91	**$1.76**	$1.83	$1.60
Minimum Price ($/kW-month)	**$0.10**	$0.50	$0.10	**$0.60**	$0.75	$0.60	**$0.10**	$0.50	$0.10
Maximum Price ($/kW-month)	**$10.09**	$10.09	$6.43	**$10.09**	$10.09	$6.43	**$10.09**	$10.09	$5.50
85% of MW at or below ($/kW-month)	**$3.65**	$3.00	$4.19	**$3.65**	$2.75	$4.25	**$3.00**	$3.00	$2.07

Table 32: RA Capacity Prices by Month

	Contracted Capacity	Percentage of Total Capacity in Data Set	Weighted Average Price ($/kW-month)	Minimum Price ($/kW-month)	Maximum Price ($/kW-month)	85% of MW at or below ($/kW-month)
January	22,621	7%	$2.52	$0.60	$6.43	$3.65
February	22,653	7%	$2.51	$0.75	$6.43	$3.65
March	20,335	7%	$2.56	$0.60	$6.43	$3.65
April	21,178	7%	$2.50	$0.50	$6.43	$3.65
May	22,463	7%	$2.51	$0.60	$6.43	$3.65
June	28,853	9%	$2.63	$0.69	$5.80	$3.65
July	31,131	10%	$3.15	$0.75	$10.09	$4.47
August	31,624	10%	$3.13	$0.75	$10.09	$4.45
September	32,148	10%	$2.95	$0.80	$10.09	$4.25
October	27,845	9%	$2.58	$0.58	$5.10	$3.65
November	25,700	8%	$2.53	$0.10	$4.45	$3.65
December	24,368	8%	$2.61	$0.60	$4.45	$3.65

The report also includes a breakdown of CAM resources, NQCs of new resources on line in 2017 (1,264 MW net dependable capacity providing 437.6 MW NQC in August), NQCs of capacity that retired in 2017 (3,851 MW), and NQC changes from 2013 to 2018 (Table 33). The 6,482 MW NQC reduction for 2018 results from 3,850 MW of retirements and implementation of ELCC for establishing NQC for variable resources.

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Table 33: Final NQC Values for 2013-2018

Year	Total NQC (MW)	Total Number of Scheduling Resource IDs	Net NQC Change (MW)	Net Gain in CAISO IDs on List
2013	53,336	733		
2014	53,112	765	-224	32
2015	52,996	802	-116	37
2016	53,173	972	177	170
2017	55,871	1,097	2,698	125
2018	49,389	1,198	-6,482	101
2013-18			**-3,947**	**465**

CPUC RESOURCE ADEQUACY REFORM

Notwithstanding the rather neutral 2017 RA report, the need to reform California's 14-year-old Resource Adequacy program is acknowledged and appears to be well underway. The CPUC has solicited comments from parties regarding a proposal of Southern California Edison to implement a three-year forward central buyer for local RA capacity. System and flexible RA capacity would continue to be acquired bilaterally by LSEs. Elements of the proposal have raised concerns among commenters, particularly the proposal to recover local capacity costs through the Transmission Access Charge (TAC) while reducing the local capacity requirements from resources contracted by LSEs to provide system and/or flexible capacity without specifically crediting the LSEs for that capacity. Parties are also concerned about the identity of the central buyer (CB). Some object to IOUs as transmission owners acting as the CB and prefer that the CAISO take on the role, something that the CAISO does not favor. We can expect a fairly contentious process as the various options and proposals are litigated over the next year to meet the 2020 implementation goal. Other issues include developing a more accurate assessment of Effective Load Carrying Capability (ELCC) for variable resources, particularly solar PV and accounting for the shift in net load peak periods resulting from the massive amounts of solar currently in service and under development.

CAISO RESOURCE ADEQUACY ENHANCEMENTS

The CAISO has initiated its own Resource Adequacy enhancements process, posting an Issue Paper on October 22. CAISO notes that use limitations of the renewable fleet require reexamination of all aspects of the RA program. Passage of the legislative requirement (SB 100) for 100% GHG-free electricity by 2046 enhances the concern. Reforms are being studied in collaboration with the CPUC.

The following issues need to be reevaluated/updated:

- The current RA counting rules do not adequately reflect resource availability, and instead rely on complicated replacement and availability incentive mechanism rules. Issues and potential proposals are outlined below:

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