CAPACITY WATCH

Authors: Paul Flemming, Scott Niemann, Julia Criscuolo, José Rotger, and Phil Muller

EXECUTIVE SUMMARY

Fourth Quarter 2019

Our last issue of *Capacity Watch*™ for 2019 updates our outlook for the New York ICAP market, with various factors supporting higher clearing prices. Peak load forecasts and statewide and zonal reliability requirements for 2020/21 are now available, with increases statewide and for New York City but decreases for Zones G-J and Long Island. Other auction parameters available include higher Net CONE values. FERC's acceptance of a substantial increase in PJM transmission rates will affect import levels into New York City and Rest-of-State.

In New England, auction parameters for next February's FCA14 are in place, including procurement amounts and demand curves. ISO-NE also made its FCA14 qualification filing on November 5, with information on the supply of resources qualified for the auction. Overall, there remains a substantial surplus going into FCA14 that will require significant amounts of unsold (de-listed) capacity to sustain meaningful clearing prices.

In PJM, the BRA for 2022/23 remains delayed indefinitely, pending an order from FERC in the ongoing MOPR proceeding. ESAI Power's forecast for the BRA is unchanged from our Q3 2019 issue of *Capacity Watch*™, but the auction delay may result in downward revisions in both the peak load forecast and reliability requirements for PJM which could lead to lower BRA clearing prices.

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ESAI POWER LLC

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

NEW YORK

SUMMARY

ESAI's outlook for the NYISO capacity market has been updated to reflect several recent data postings and market developments:

- Release of draft reliability requirements for the New York Control Area (NYCA) and ICAP market Localities, which include increases statewide and for New York City but declines for the G-J Locality and Long Island;
- Release of a preliminary peak load forecast for Summer 2020, which reflect an upward revision of the statewide forecast, but downward revisions for New York City and the G-J Locality;
- Posting of annual, formulaic updates to the Net CONE value used to set the NYISO ICAP market demand curves, which include increases for all locations that will support higher clearing prices;
- FERC's acceptance, subject to settlement, hearing, and refund, of a filing to increase the PJM firm Point-to-Point transmission rate that applies to exports from PJM to New York; though subject to refund, the rate will go in effect January 1, 2020, and is expected affect import levels into New York City and Rest-of-State (ROS);
- Initiation of a New York Public Service Commission (NYPSC) proceeding to evaluate the effectiveness and appropriateness of the ICAP market in supporting resource adequacy in light of the greenhouse gas reduction requirements for New York State.

INITIAL 2020/21 IRM AND LCR VALUES

Draft values for the 2020/21 reliability requirements for New York were released this fall as part of the annual process conducted by the New York State Reliability Council (NYSRC) to set the Installed Reserve Margin (IRM). NYSRC released its draft 2020 IRM Report in October with a recommended statewide IRM value of 119 percent, a two percentage point increase from the current value for 2019/20. Additionally, NYISO has provided informational values for the Locational Capacity Requirement (LCR) for each of the three localities included in the NYISO ICAP market. Table 1 summarizes the initial values for each region. The initial LCR for the G-J locality, spanning the Lower Hudson Valley (Zones G, H, and I) and New York City (Zone J), is two percentage points lower than the current value, while the preliminary LCR for New York City is almost 4 percentage points higher. The LCR value for Long Island is slightly lower than the current value.

Table 1: NYISO LCR and IRM Requirements

	2017/18	2018/19	2019/20	2020/21 Preliminary Values	2020/21 Delta from 2018/19
Rest of State, IRM	118.0%	118.2%	117.0%	119.0%	2.0%
G-J Locality, LCR	91.5%	95.4%	92.3%	90.3%	-2.0%
New York City, LCR	81.5%	80.7%	82.8%	86.7%	3.9%
Long Island, LCR	103.5%	103.5%	103.5%	103.2%	-0.3%

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

If approved by the NYSRC Executive Committee and FERC, the higher IRM will increase prices for the ROS region. The increase in IRM represents a return to an upward trend in IRM over the last eight years. Although IRM dropped for 2019/20 compared to 2018/19, that drop had been preceded by a series of annual increases since 2011. IRM has been increasing due to additional intermittent capacity on the system and a decreased assumed reliability benefit for neighboring regions. Several of the inputs the IRM calculations fluctuate year-to-year based on recent historical outcomes, with some factors leading to increases and other to decreases. For 2019, more of the year-to-year changes in these factors had a negative impact, resulting in an overall decline. For 2020, several of the factors that had contributed to the decline last year reversed and supported an increase for 2020/21. Additionally, the NYSRC included higher weather uncertainty and implemented a revised methodology for incorporating emergency assistance from neighboring regions, which in combination led to a substantial increase in IRM.

Beyond 2020/21, 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 and 2020/21 values. 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.

The informational LCR values for 2020/21 were calculated using the optimized LCR approach that was first implemented for 2019/20 and for the preliminary IRM assumptions as of September 2019. The NYISO has not yet provided updated LCR values that correspond to the final IRM base case value of 19 percent, but substantial changes are not expected. The NYISO will also update the Net CONE values used in the optimization process before the LCR values are finalized in January 2020.

For New York City, the higher preliminary LCR values are supportive of higher prices for Zone J, while the lower value for the G-J Locality will result in downward pressure on prices for the Lower Hudson Valley. The NYISO has not provided detailed information about the reasons for the changes in the LCR values compared to 2019/20, but the largest factor for New York City is the retirement of Indian Point 2, scheduled for April 2020. Additionally, the B/C feeders, which connected New York City to New Jersey, are assumed to remain out of service for the 2020/21 IRM and LCR calculations (this outage had a significant positive impact on Zone J LCR last year). While some fluctuation in the LCR values is possible with the incorporation of the final IRM assumptions and the updated Net CONE curves, the final values are likely to be close to the indicative values provided in September as the methodology will be unchanged and the changes in most assumptions were relatively minor.

ESAI's longer term LCR assumptions are shown in the figures below. A drop in the LCR for the G-J Locality is expected with the completion of planned transmission upgrades by 2024, while an additional increase in LCR is expected for Zone J with the retirement of Indian Point 3 in 2021.

Figure 1: Historical and Projected G-J Locality LCR

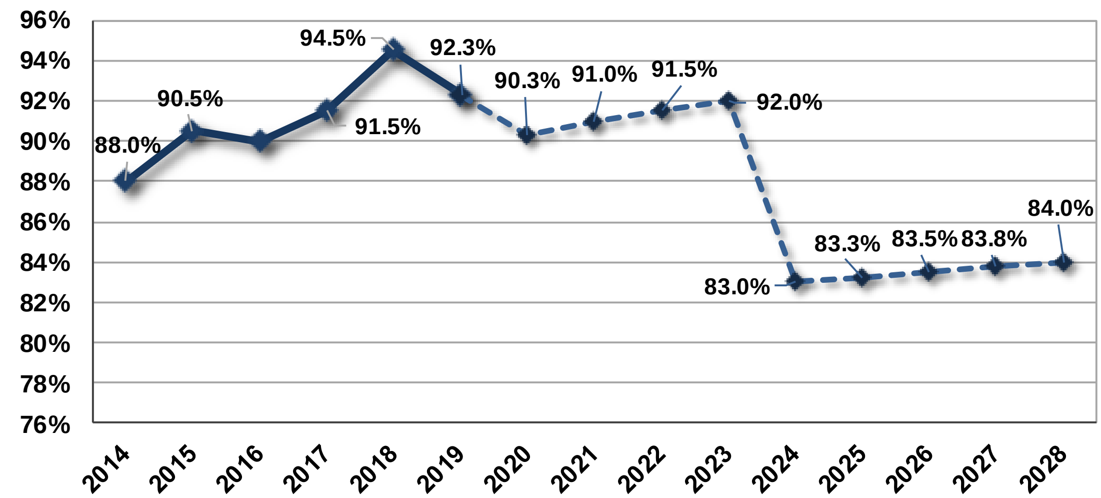
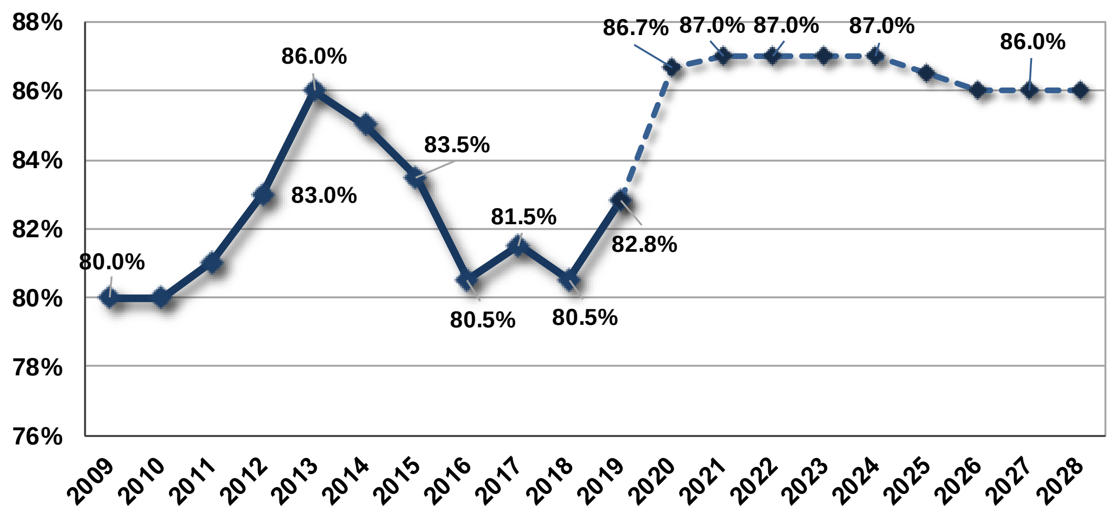


Figure 2: Historical and Projected New York City LCR



PEAK LOAD FORECAST FOR 2020

Each year, the NYISO prepares a preliminary updated peak load forecast for the following summer and provides it to the NYSRC for use as an input in the process to establish the 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 covers all of New York State) and each of the capacity zones and transmission districts with NYISO, along with forecast growth rates for each transmission district provided by the utilities. The updated 2020 peak load forecast is based on initial 2019 weather-normalized values, escalated by preliminary projected peak load growth from 2019 to 2020.

The forecast provided to the NYSRC is not final and does not included a long-term outlook. Revisions to the preliminary 2019 peak forecast may occur before it is finalized for the 2019/20 Capability Year ICAP auctions (final values are expected in December 2019). Changes between the IRM forecast and the final are typically very minor.

Table 2 shows the weather-normalized peak load for 2019. The summer peak load in 2019 for NYCA was significantly below the forecast on an unadjusted basis. The estimated adjustments for weather normalization and demand response make the normalized peak load higher, resulting in a normalized value 85 MW above the forecast. For the downstate zones, the actual peak load was below the forecast for the all locations except Long Island, where the actual peak was higher. The normalization for weather and demand response resulted increases to the New York City and G-J Locality peaks, but a decrease for Long Island. After normalization, the peak loads for Zone J and the G-J Locality were below the forecast, but the peak load for Zone K was 178 MW above the forecast.

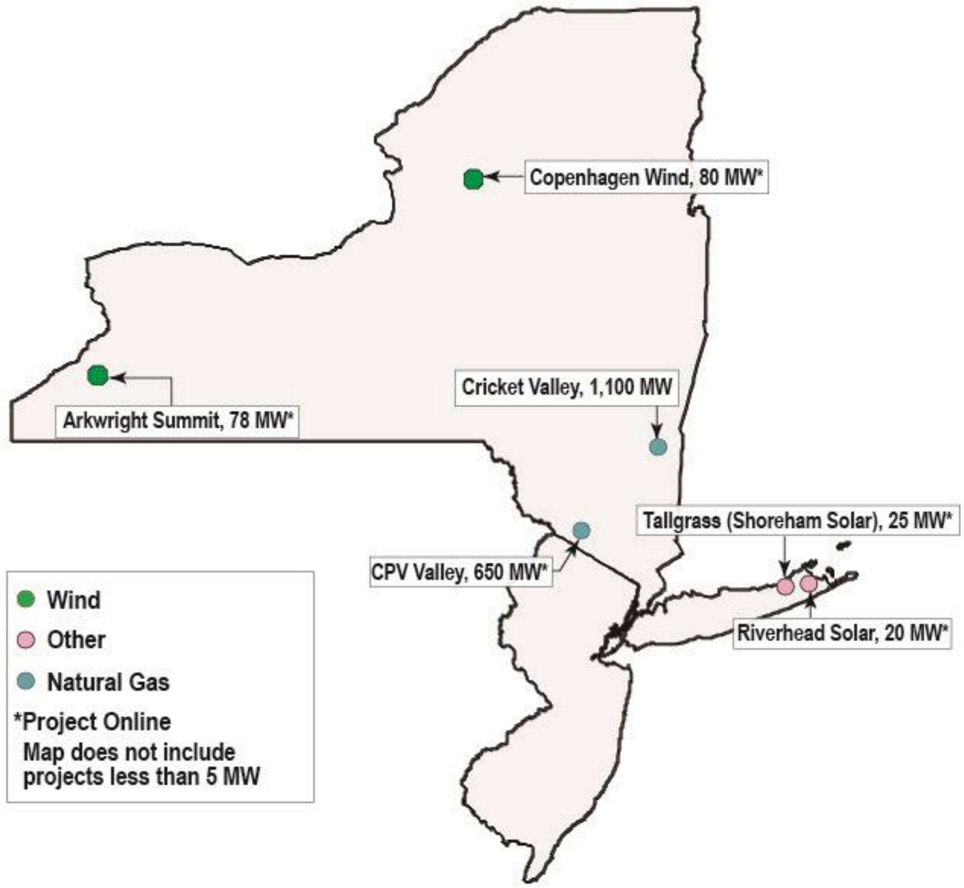
Table 2: NYISO 2019 Weather Normalized Peak Load

	2019 Peak Load Forecast (2019 Gold Book)	2019 Actual Peak Load	2019 Weather Normalized Peak Load	Delta from Forecast (Weather Normalized)
NYCA	32,382	30,410	32,467	85
G-J Locality	15,911	14,585	15,772	(139)
Zone J	11,608	10,769	11,459	(149)
Zone K	5,240	5,452	5,418	178

Table 3 shows the Summer 2020 peak load forecast prepared for the IRM study. The forecasted 2020 peak load forecast reflects positive year-over-year growth (on a weather normalized basis) for the G-J Locality and New York City, but declines for NYCA and Zone K. Accounting for the actual 2019 peak loads and the forecasted growth rates, the updated 2020 summer peak load forecast for NYCA and Zone K is higher than the corresponding forecast in the 2019 Gold Book, but the forecasts for Zone J and the G-J Locality are lower.

[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.

Figure 9: New York Capacity Additions



PJM

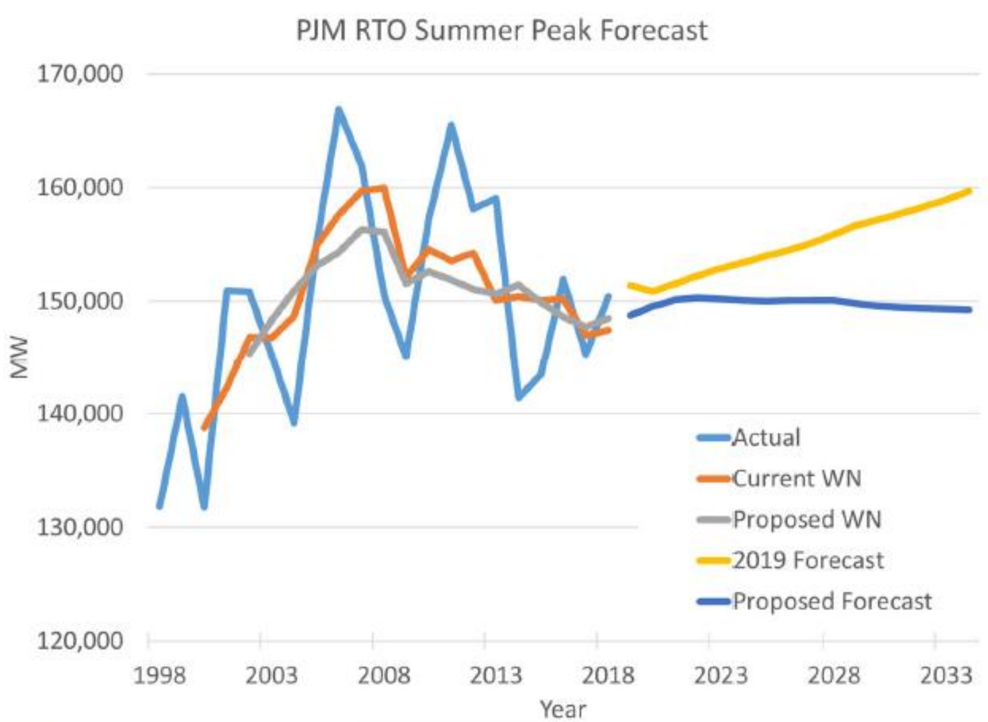
BRA TIMING REMAINS UNCERTAIN

The timing for the BRA for 2022/23 remains uncertain. After FERC ordered the indefinite delay of the auction until new rules for offer mitigation and accommodation of subsidized resources are approved and implemented. With Commissioner LaFleur's term ending in September, resulting in a three-member commission, an order in early fall was expected. However, due to a potential conflict of interest, Commissioner Glick recused himself from the matter until December, leaving the Commission without a quorum. An order could come as early as late December, which could allow the BRA to be conducted in spring of 2020.

AUCTION DELAY COULD RESULT IN BEARISH REVISION IN PARAMETERS

In October 2019, PJM released it updated IRM values for upcoming Delivery Years. Notably, the recommended IRM for 2022/23 was reduced from 15.7 percent to 14.9 percent, which would result in a leftward shift of the VRR curve and dampen clearing prices. Additionally, the PJM load forecast will be updated in December 2019. As shown in the figure below, methodology changes could reduce the forecast substantially. If a lower peak load is used to update the parameters for the 2022/23 BRA, prices could be reduced further.

Figure 10: Indicative PJM Load Forecast Update



ESAI FORECAST FOR 2022/23 BRA

As shown below, ESAI's RPM forecast is unchanged from Q3 2019. ESAI will update the forecast when the PJM load forecast is released and/or when FERC issues an order about the proposed market rules.

ESAI's outlook for the 2022/23 BRA calls for prices significantly lower than the last BRA due to several factors:

- Significant decreases in the Net CONE values used to set the demand curves;
- A leftward shift in the demand curve, due to both a decrease in the peak load forecast and a shift of the curve to left by one percent in order to eliminate a supply buffer that had been built into the curve previously;
- Expectation for significant new generation to be offered into the BRA on a price-taking basis, with new gas-fired capacity totaling between 6 and 8 GW expected;
- Potential changes in bidding for resources that have failed to clear in recent BRAs, including the Perry and Davis Besse nuclear plants in the ATSI zone, which failed to clear in the 2021/22 BRA but now will receive financial support under the recently passed Ohio legislation.

ESAI's base case assumption regarding market rules and state subsidies include mitigation of all existing nuclear units that are already receiving financial support or have approved subsidies in place, along with all new renewable capacity. Specifically, the Quad Cities, Salem, Hope Creek, Perry, and Davis Besse plants are all assumed to remain open and elect RCO treatment, with mitigated offers included in a repricing step in BRA clearing process. ESAI has also assumed an RCO option will be available and elected for 2022/23 each of these subsidized resources. Hence, although the mitigated offers will prevent the subsidized capacity from depressing the price, other resources offered below the projected clearing price will be displace and not receive a capacity payment.

With the delay in the BRA, additional regulatory changes are possible in advance of the auction:

- Mitigation and RCO rules will be implemented or changed as a result of a FERC order in the on-going dockets, as discussed extensively above. ESAI's base case assumes that a Carve Out will be implemented, along with repricing to offset the price suppression from subsidized resources. Our base case assumes that subsidized resources will be included in the repricing step, but at mitigated offer levels.
- The Independent Market Monitor (IMM) for PJM and a group of Joint Consumer Advocates (JCA) have filed separate, but nearly identical complaints to FERC seeking to lower the default Market Seller Offer Cap (MSOC) applied in RPM (Dockets EL19-47 and EL19-63, respectively). The current MSOC is set at approximately 90 percent of Net CONE, under an approach adopted with implementation of the Capacity Performance (CP) rules in PJM. The IMM and JCA are seeking to have the MSOC lowered to a level that is based on an

Avoided Cost Rate (ACR). Had this lower rate applied in recent BRAs, much of the unsold capacity in each auction might have been forced to offer at lower levels, cleared the BRA, and resulted in lower clearing prices. Given the BRA delay, it is possible that these changes could be approved in time for the upcoming BRA for 2022/23. Changes in the approach for calculating the competitive offer level could also affect the implementation of any RCO rules.

- As discussed in the Q1 2019 issue of *Transmission Watch*™, rules affecting imports from neighboring market have been challenged at FERC. Recent rule changes are expected to reduce the level of imports that qualify to be pseudo-tied to PJM, allowing the capacity to be sold into RPM. Suppliers have challenged these new rules and procedures, which could affect the level of imports available in both the upcoming BRA and future auctions.
- Finally, rule changes for the energy market, including pending changes related to operating reserves (FERC dockets EL19-58 and ER19-1486) could affect the mix of compensation between energy and capacity markets in PJM. However, these changes are unlikely in advance of the 2022/23 BRA.

Table 13 shows ESAI's forecast for the 2022/23 BRA. Overall, the clearing prices are similar to ESAI's Q2-2019 forecast. However, because approximately 4,000 MW of capacity is assumed to elect the RCO option, displacing capacity that would otherwise have cleared in the BRA, the capacity mix is different. Specifically, as a result of the RCO elections and related mitigation, cleared nuclear capacity is higher by 3,995 MW, cleared coal capacity is lower by 927 MW, and cleared gas-fired capacity is lower by 381 MW. With the repricing step, the RTO clearing price would have been $81.48/MW-day.

Compared to ESAI's Q2 2019 forecast, the projected clearing price for 2022/23 for the COMED zone has increased. ESAI has assumed a one-year delay for 1,100 MW of new CCGT capacity, raising the 2022/23 price. However, the increase is dampened by the increase in CETL for the COMED zone. ESAI's forecast for the MAAC zone is also slightly higher than shown in our Q2 2019 forecast and reflects a premium over the RTO price. The increase for MAAC is attributable to the increase in the reliability requirement for the LDA, along with refinements to ESAI's offer curve assumptions and an assumption that mitigation will be applied to the New Jersey nuclear units that are receiving subsidies, which previously had been treated as price takers.

Several factors could lead to changes in the BRA results.

- An increase in the amount of subsidized resources electing RCO. If subsidies are extended to additional nuclear capacity in Illinois and Pennsylvania, the amount of RCO resources could be substantially higher. This outcome would not change the clearing price significantly, given the mitigation assumed, but would lead to the displacement of more capacity, especially coal-fired units.
- Approval of RCO without repricing. This scenario would allow all subsidized resources to come in as price takers and substantially lower the clearing price. It would also likely result in approval of more subsidies. This scenario could

Table 17: Changes in Retirements Since Last Project Evaluation Program Update

Plant	Owner	Zone	MW (Nameplate)	Change
Coffeen (Unit 2); Pseudo-tied MISO to PJM	Vistra Energy	MISO; AmerenIL	151	**Added to List:** Submitted request to PJM to deactivate by Nov. 2019. Capacity previously accounted for in ESAI base case import assumptions.
Duck Creek (Unit 1); Pseudo-tied MISO to PJM	Vistra Energy	MISO; AmerenIL	329	**Added to List:** Submitted request to PJM to deactivate by Dec. 2019. Capacity previously accounted for in ESAI base case import assumptions.
Hennepin Power Station (Unit 1); Pseudo-tied MISO to PJM	Vistra Energy	MISO; AmerenIL	75	**Added to List:** Submitted request to PJM to deactivate by Nov. 2019. Capacity previously accounted for in ESAI base case import assumptions.
Hennepin Power Station (Unit 2); Pseudo-tied MISO to PJM	Vistra Energy	MISO; AmerenIL	231	**Added to List:** Submitted request to PJM to deactivate by Nov. 2019. Capacity previously accounted for in ESAI base case import assumptions.
Wheelabrator Frackville Energy	Macquarie Group Ltd.			**Added to List:** Submitted request to PJM to deactivate by March 2020.
Buchanan (Unit 1)	CNX Resources Corp. & LS Power	AEP	44	**Added to List:** Submitted request to PJM to deactivate by June 2023.
Buchanan (Unit 2)	CNX Resources Corp. & LS Power	AEP	44	**Added to List:** Submitted request to PJM to deactivate by June 2023.

NEW ENGLAND

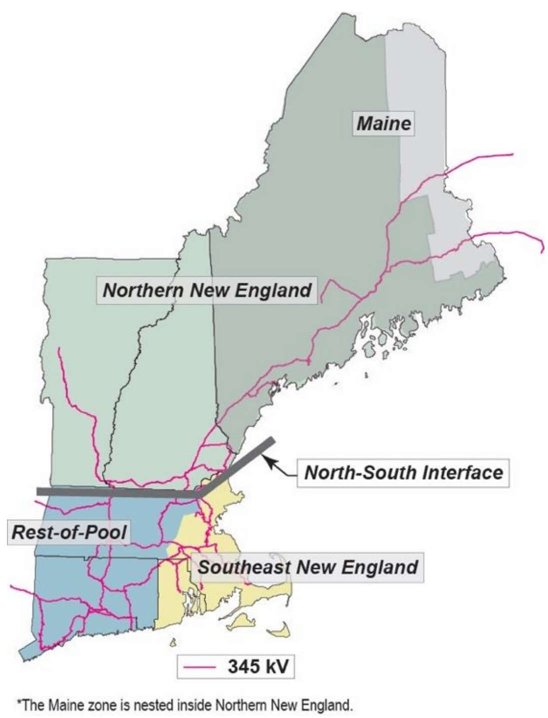
FCA14 2023/24 AUCTION PARAMETERS

Auction parameters for the upcoming 2023/24 FCA14, slated for February 3, 2020, are in place, including procurement amounts and demand curves. 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 made on November 5. 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 FCA14 and used to determine the system-wide and zonal demand curves for the auction. ISO-NE also made its FCA14 qualification filing on November 5, with information on resources qualified for the auction.

Maine Export-Constrained Zone Nested Inside NNE

As reviewed in our last *Capacity Watch*™, ISO-NE set the Maine-New Hampshire (ME-NH) interface (and state border) as a capacity zone boundary for FCA14, with Maine as an export-constrained capacity zone nested inside the Northern New England (NNE) export-constrained zone (comprised of Maine, New Hampshire and Vermont).

Figure 12: FCA14 (2023/24) Capacity Zones



Thus, FCA14 will have four zones: the Southeast New England (SENE) import-constrained zone, the NNE export-constrained zone, the Maine export-constrained zone nested inside NNE, and the Rest-of-Pool zone. As in past FCAs, the SENE zone will comprise of the NEMA/Boston, SEMA, and Rhode Island load zones, and the Rest-of-Pool zone will include only the West-Central MA and Connecticut load zones. The descending clock auction clearing order will first clear the SENE import-constrained zone and then Rest of Pool, followed by NNE (if needed), then Maine (if needed), and then imports from New Brunswick (if needed).

ISO-NE models an export-constrained zone in an FCA if the sum of existing qualified capacity and new capacity that could qualify in the zone (including imports into the zone) is greater than the zone's Maximum Capacity Limit (MCL). The total amount of capacity that could qualify in the zone excludes new resources expected to fail the capacity deliverability "overlapping impacts" test. Designation of Maine as an export-constrained zone stems from the qualification of a substantial amount of new capacity in Maine for FCA14, the identity of which ISO-NE will not disclose. The most likely source of new Maine qualified capacity is up to 1,200 MW of imports from Québec over Avangrid's proposed New England Clean Energy Connect (NECEC), now with state-approved purchased power contracts over the line.

Load Forecast Drives a Massive Drop in ICR

ISO-NE calculated two sets of ICR values: with and without Mystic 8 and 9. The two sets of values are needed because of the uncertainty over whether Exelon will accept ISO-NE's fuel security retention of the units for FCA14 or elect to unconditionally retire them. While ISO-NE announced its intention to retain Mystic 8 and 9 for 2023/24 (after which they must retire), Exelon has until January 20, 2020 (14 days before the auction) to decide whether the Mystic units will retire prior to 2023/24.

The FCA14 ICR with and without the Mystic units is more than 1,200 MW below the FCA13 value. If Mystic Units 8 and 9 remain service as retained for fuel security, the FCA14 ICR net of Hydro-Québec Interconnection Capability Credits (HQICCs) will be **32,490 MW**, a 1,260 MW from the FCA13 Net ICR of 33,750 MW. Excluding Mystic 8 and 9 would increase the Net ICR very slightly to **32,495 MW**.

Table 18: FCA14 vs. FCA13 ICR and Related Values (Including Mystic 8 and 9)

	2023-2024		2022-2023		CHANGE	
	MW	Reserve Margin	MW	Reserve Margin	MW	Percent
Forecast Peak Demand (50/50)	28,838		29,093		(255)	(0.9%)
Assumed Existing Capacity Resources	34,637		33,867		770	2.2%
Installed Capacity Requirement (ICR)	33,431	15.9%	34,719	19.3%	(1,288)	(3.9%)
HQ Interconnection Capability Credits (HQICCs)	941		969		(28)	(3.0%)
NET ICR (to be purchased in FCA)	**32,490**	**12.7%**	**33,750**	**16.0%**	**(1,260)**	**(3.9%)**
Locational Sourcing Requirements (LSR):						
Southeast New England (SENE)	9,757		10,141		(384)	(3.9%)
Maximum Capacity Limit (MCL):						
Northern New England (NNE)	8,445		8,545		(100)	(1.2%)
Maine	4,020		n/a		n/a	n/a

ISO-NE explained that various improvements to weather variables in its 2019 CELT report load forecast resulted in a substantial decrease to ICR. The modeling changes reduced the gross summer peak load forecasts from 2018 by roughly 1.5 percent for the 50/50 forecast and 3 percent for the 90/10 forecast. The bulk of this decrease is attributable to the use of a new cooling degree day weather variable added to the model after benchmarking it against actual summer 2018 loads suggested that this new variable should be included.

The GE MARS probabilistic model used to calculate the ICR uses an hourly load forecast reflecting a probability distribution, and the load forecast model changes push down the extreme load hourly forecast values (*e.g*. 90/10) by much more than the “middle” values (50/50). The roughly 3 percent drop in the higher load forecast values resulted in the probabilistic ICR calculation yielding a significantly lower value for FCA14. ISO-NE estimated that the addition of the second weather variable to the load forecast decreased ICR by roughly 850 MW. Had ISO-NE used the same load forecast methodology as in the 2018 CELT load forecast, the net ICR would have still decreased but only by 300 MW.

Capacity sellers strongly questioned how the forecast methodology changes resulted in such a dramatic decrease to the ICR value, arguing that incorporating more recent weather history and variability should intuitively increase ICR (not decrease it) given climate change and increased extreme weather occurrences. ISO-NE believes its revised hourly load shape and distribution better reflects the substantial changes in load patterns resulting from increases in energy efficiency and behind-the-meter solar resources. While agreeing that the data show a warming trend and increase in variability, ISO-NE noted that overall loads remain much lower and that much of the warming and variability is seen in overnight temperatures and extended heat waves, and not in overall higher peak demands. Load advocates pointed to their past complaints that ISO-NE was consistently over-forecasting load and overstating ICR, and welcomed ISO-NE’s improvements to its modeling.

Further contributing to the drop in ICR is a decrease in the assumed forced outage rates for generation resources stemming from updated performance data, which drove a 460 MW decrease to ICR. Lower forced outage rates from existing resources mean that less capacity must be procured in the ICR. The generation availability rate assumption used in the ICR calculation is a 5-year rolling average of historical values for each generator, and the dropping of 2013 values and addition of 2018 values into the 5-year average for the 2023/24 ICR calculation decreased the overall forced outage rate from 7.0% to 5.7%. Starting 2011 and through 2013, generation outages increased for a variety reasons, including fuel-related issues. Data for these years are starting to drop out from the rolling 5-year average, with better performance seen since 2014.

Offsetting the EFORd-related decrease in ICR are increases attributable to lower tie benefits for 2023/24 as compared to 2022/23, as lower tie benefits will increase ICR (+70 MW). Also offsetting the ICR decrease is the change to the assumed amount of load relief from a 5% voltage reduction under OP 4 Actions 6 and 8. In place for many years, the prior calculation assumed a 1.5% reduction off the 90/10 peak load net of behind-the-meter solar PV and passive demand resources, while the new assumption uses a 1.0% reduction off the net 90/10 peak load. The voltage reduction assumption change increases ICR by 150 MW.

SENE LSR – LSR for import-constrained zones is set by the higher of the transmission security analysis (TSA) requirement and local resource adequacy (LRA) values for the zone. The TSA requirement is calculated deterministically based on transmission security needs under 90/10 peak load conditions and N-1 import limits, while the LRA is determined via a probabilistic resource adequacy analysis (Monte Carlo simulation of many iterations).

Including Mystic 8 and 9, the LSR for the SENE import-constrained zone is **9,757 MW** and is set by the TSA value, as seen since the introduction of the SENE zone in FCA10. But, excluding Mystic 8 and 9 yields the opposite result, with an LRA of **9,560 MW** setting the LSR. In other words, and counterintuitively, the SENE load pocket's LSR decreases after removing the largest generation resource in the load pocket (Mystic). The overall decrease in LSR without Mystic is attributable to the LSR being set by the LRA instead the TSA. The probabilistic LRA does increase without Mystic (by 35 MW) but the TSA drops by a substantial 257 MW because excluding Mystic changes the deterministic second contingency calculation from a line-gen contingency to a line-line contingency. Using a smaller largest contingency drops the TSA requirement by a roughly commensurate amount. The substantial drop in the TSA calculation results in the TSA no longer setting the SENE LSR.

Both the SENE LRA and TSA (regardless of Mystic) decrease as compared to FCA13 (10,141 MW). The primary driver for the SENE TSA decrease as compared to FCA13 (a 384 MW decrease) is a revised assumed unavailability rate for peaking units in SENE. Past calculations assumed a fixed 20% unavailability rate but starting for FCA14 ISO-NE is using actual EFORd and availability data for each peaking unit in SENE. While the assumed value is confidential, note that the 2013-17 five-year average EFORd calculated using NERC GADS data for New England peaking units is 11.58%, well below the prior assumption of 20%. As for the probabilistic LRA, the SENE value decreased from FCA13 because of an improvement (decrease) in the weighted average overall availability rate of SENE resources.

With preliminary amounts of existing SENE resources qualified to participate in FCA14 of 10,928 MW including Mystic and 9,515 MW excluding Mystic, there is little chance that SENE will price separate in the auction.

NNE and Maine MCL – The NNE MCL continues to decrease since introduction of the consolidated export-constrained zone in FCA11. Including Mystic 8 and 9, the NNE MCL is **8,445 MW**. Excluding the Mystic units lowers the NNE MCL by 70 MW to **8,375 MW**. Regardless of the Mystic units, the NNE MCL decrease is attributable to lower loads system-wide and no changes to the transfer limits between NNE and the rest of New England. The Maine MCL including Mystic is **4,020 MW**, and excluding Mystic units lowers the value by 70 MW to **3,950 MW**. Removing Mystic 8 and 9 decreases both NNE and Maine MCL values as a result of the decreased overall availability rate of SENE generation without the relatively more available Mystic 8 and 9 units, thus increasing the probabilistic need for NNE and Maine resources to meet SENE loads.

Note that ISO-NE will not release the amount of new resources qualified in NNE for FCA14 – it only posts the total amount of new resources qualified system-wide (not by zone or type of resource). Any new capacity cleared in NNE will be known after the auction.

Figure 18: Select ESAI Project Evaluation Program Projects

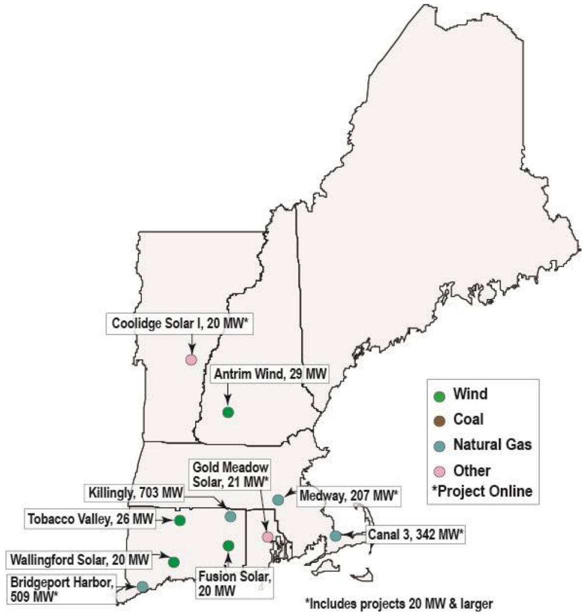


Table 26: New England Generation Additions

Unit	Nameplate (MW)	Summer ICAP (MW)	Unit Type	Month	Year	Location	Included in ESAI Base Case
Footprint Power (Salem CC)	798	730	Nat gas	May	2018	NEMA	Yes
Wallingford Peaker Expansion	100	90	Nat gas	May	2018	CT	Yes
Towantic Energy Center	842	822	Nat gas	May	2018	CT	Yes
Lake Road Uprate	50	42	Nat gas	Jun	2018	CT	Yes
Milford (MA) Power (Units 1 & 2)	53	53	Nat gas	Dec	2018	WMA	Yes
Medway Peaking	200	195	Nat gas	Jun	2019	SEMA	Yes
Bridgeport Harbor CC	576	510	Nat gas	Jun	2019	CT	Yes
Canal 3	330	330	Nat gas	Jun	2019	SEMA	Yes
Newington Energy Center (ST)	38	37	Nat gas	Jun	2020	NH	Yes
Killingly Energy Center	650	632	Nat gas	Jun	2022	CT	Yes
Clear River Energy Center - I	485	485	Nat gas	Jun	N/A	RI	No
NE Clean Energy Connect (MA RFP Award)	1,200	1,000	HVDC	Dec	2023	ME	Yes
Revolution Wind (RI & CT RFP Award)	400	140	Offshore Wind	Jan	2024	SEMA	Yes
Revolution Wind (RI & CT RFP Award)	300	105	Offshore Wind	Jan	2025	SEMA	Yes
Vineyard Wind (MA RFP Award)	400	140	Offshore Wind	Jan	2024	SEMA	Yes
Vineyard Wind (MA RFP Award)	400	140	Offshore Wind	Jan	2025	SEMA	Yes
Other Renewables	72	31			2019		Yes
Other Renewables	112	37			2020		Yes
Other Renewables	416	100			2021		Yes
Other Renewables	343	32			2022		Yes
Other Renewables	168	33			2023		Yes
Other Renewables	173	33			2024		Yes
Offshore Wind	200	70			2028		Yes
Offshore Wind	400	140			2029		Yes
Offshore Wind	400	140			2030		Yes
Offshore Wind	400	140			2031		Yes
	9,505	***5,717***					
Total Fossil	**4,122**	**3,926**					
Total Imports	**1,200**	**1,000**					
Total Renewable*	**3,783**	**1,141**					
Total (2018-2027)	***9,105***	***6,067***					
Total (2018-2027), Included in ESAI Base Case	***8,620***	***5,582***					

**Does not include BTM.*

***For additional historical data, please reference ESAI PEP file.*

CALIFORNIA

INTRODUCTION

Major resource adequacy reforms are underway in California for the first time in at least a decade. Thanks to roughly 20,000 MW of utility-scale and rooftop solar generation, California's peak load hours have shifted from mid-afternoon to evening. Over 40,000 MW of energy storage currently in the interconnection queue to help integrate all that solar creates additional issues. The availability of import capacity to provide reliability is also becoming a concern as more and more coal plants retire in the West. These resource adequacy issues are front and center and reviewed in the following sections.

INTEGRATED RESOURCE PLANNING (IRP)

On October 21, the CPUC issued a Revised Proposed Decision on Electric System Reliability Procurement for 2021-2023. The Decision would order procurement of 4,000 MW of "new" System Resource Adequacy Capacity – a total of 2,400 MW by August 2021, 3,200 MW by August 2022 and 4,000 MW by August 2023. In addition, it would recommend that the State Water Resources Control Board (Water Board) extend the once-through-cooling compliance deadline[3] for up to 3,750 MW of resources in Southern California that are scheduled to retire on January 1, 2020, for up to three years. The new resource procurement would include new generation (excluding greenfield fossil-fueled resources) and existing generation that is not included in the list of baseline resources to be published by Commission Staff by December 1. Resources must be contracted for a minimum of ten-years for new construction and three-years for existing resources. Each Load Serving Entity (LSE) would be responsible for procuring its share of the totals as shown in Table 30. The respective IOU will procure capacity on behalf of LSEs in their service territory that do not meet their procurement obligations and charge the deficient LSE accordingly. The proposed decision is on the agenda for the November 7 CPUC voting meeting.

[3] Applies to old steam power plants that use once-through ocean cooling (OTC). They have been ordered to mitigate the marine impact of OTC, which, for these plants, all built before 1980, generally means shutting down, by the end of 2019. The Water Board can grant extensions of the compliance date if necessary.

Table 30 - LSE Procurement Responsibility

Load Serving Entity	Minimum By August 1, 2021 (MW)	Minimum By August 1, 2022 (MW)	Minimum By August 1, 2023 (MW)
PG&E (Bundled)	521.4	695.2	869.0
PG&E Direct Access (Aggregated)	82.9	110.6	138.2
Clean Power San Francisco	41.5	55.3	69.1
East Bay Community Energy	72.5	96.6	120.8
King City Community Power	0.5	0.7	0.8
Marin Clean Energy	63.6	84.8	106.0
Monterey Bay Community Power Authority	41.8	55.7	69.6
Peninsula Clean Energy Authority	40.0	53.3	66.7
Pioneer Community Energy	13.4	17.9	22.4
Redwood Coast Energy Authority	7.8	10.4	13.0
San Jose Clean Energy	56.4	75.2	94.0
Silicon Valley Clean Energy	48.9	65.2	81.5
Sonoma Clean Power	31.5	42.0	52.5
Valley Clean Energy Alliance	9.1	12.2	15.2
SCE (Bundled)	861.6	1,148.8	1,436.0
SCE Direct Access (Aggregated)	102.0	136.0	170.0
Apple Valley Choice Energy	2.8	3.7	4.6
Clean Power Alliance of Southern California	143.2	190.9	238.6
Lancaster Clean Energy	6.9	9.2	11.4
Pico Rivera Innovative Municipal Energy	1.9	2.5	3.2
Rancho Mirage Energy Authority	3.5	4.6	5.8
San Jacinto Power	2.0	2.7	3.4
SDG&E (Bundled)	213.0	284.0	355.0
SDG&E Direct Access (Aggregated)	31.0	41.4	51.7
City of Solana Beach	0.8	1.0	1.3
Total	**2,400.0**	**3,200.0**	**4,000.0**

RESOURCE ADEQUACY FROM IMPORTS

Another resource adequacy decision (D.19-10-021) was issued on October 17, regarding non-resource-specific imports. It was issued in response to concerns that, due to tightening reserves throughout the WECC, such resources may be more speculative in nature and not constitute "real" capacity that can be relied on at peak load periods. The concern is based on the fairly common practice of import RA capacity to bid at the $1,000/MWh price cap in the CAISO day ahead market, intent on not being dispatched. Because, unlike resources within California, imports do not have must offer obligations after the day ahead market (DAM). As a result, they would not to be available to meet capacity needs identified after the close of the DAM. To respond to this concern, the decision "clarifies" "that a non-resource-specific RA import is required to self-schedule into the CAISO markets consistent with the timeframe reflected in the governing contract." It does not specify the identity of the "governing contract," but it also states "that a contract for an import energy product that is available only when called upon in the CAISO's day-ahead market or residual unit commitment process does not qualify as an "energy product" that "cannot be curtailed for economic reasons."

This appears to mean that the current WSPP Resource Adequacy confirm for import RA is no longer valid for non-resource-specific imports into the CAISO. The decision further notes that existing RA contracts would not be grandfathered and orders that "Import RA resources should be accounted for in the current MCC buckets and aligned with identified reliability needs." This is intended to assure that self-scheduling can somehow be limited by categorizing import RA resources as use-limited. LSEs subject to the RA program will be required to document compliance with the requirement in the form of contract language or attestation from the resource provider. The Energy Division will verify compliance by evaluating import data provided by the CAISO. It is highly likely that the decision will result in a substantial reduction in the amount of non-resource-specific import RA capacity that will be available, a substantial increase in non-economically bid (self-scheduled) energy into CAISO markets, and/or a significant increase in RA import prices due to the potential price-taking risk of additional self-scheduling.

Not surprisingly, at least one rehearing request has been filed. Cal-CCA, an advocacy group for Community Choice Aggregators (CCAs), questions the viability and legality of the decision and also requests a stay of the decision (which is planned for implementation in the 2020 RA year) and delayed implementation until 2021 to provide parties time to develop an alternative solution. A number of parties, including the CAISO, have filed in support of the proposed stay.

Resource Adequacy Central Procurement Entity

A Resource adequacy decision issued in February (D.19-02-022) implemented a three-year obligation for local RA and also ordered parties to develop a proposal for a Central Procurement Entity (CPE) to procure some or all local RA capacity in future years. After a series of stakeholder workshops, parties generally fell into two camps – those favoring a CPE that would procure all local RA capacity and allocate the capacity to all LSEs based on their share of load served and those that preferred residual procurement by the CPE. The residual procurement group developed a joint motion for adoption of a central procurement entity (CPE) that would procure residual RA needs for all three resource adequacy products (system, local and flexible). The proposal is comprehensive and would resolve all the following issues except for the identity of the CPE.

Scope of Procurement

Implement a CPE that would procure residual local, system and flexible RA for up to three-year procurement period, as shown in Table 31. LSEs may voluntarily procure RA capacity for any portion of their overall RA requirement. CPE will procure any residual amount needed to meet total requirements. Month-ahead filings by LSEs or CPE would not be required.

Table 31 - Proposed Forward RA Procurement Obligation

Product Type	Showing Year		
	Year n-1	Year n-2	Year n-3
System RA	100%	75%	50%
Local RA	100%	100%	75%
Flex RA	100%	75%	50%

Implementation Cost Allocation

Formation costs of CPE will be recovered from LSEs over a ten-year period based on their share of total System RA requirement the prior year. CPE RA procurement costs will be allocated to LSEs in arears in proportion to the RA capacity of that type of RA procured on the LSE's behalf based on the difference between the LSE's actual load, scaled to the prior year's forecast of the Collective RA Requirement, and the LSE's Shown RA.

Procurement Details

- CPE will determine eligibility of resources based on CAISO NQC or EFC list.
- Ensures against costly out-of-market RA procurement by:
- requiring the RA-CPE to procure resources on a least cost basis at prices no greater than (or not unreasonably in excess of) the CAISO Soft Offer Cap (on an annualized basis) until the residual requirement is met; and
- providing the RA-CPE with an opportunity to cure any procurement deficiency that remains after it has shown its procured resources to the Commission, the CAISO and the Energy Commission, thereby reducing the need for CAISO backstop procurement.
- Limits CPE procurement to a three-year term
- Eliminates need for monthly RA showings and eliminates the need for CPUC-imposed penalties and/or waivers on individual LSEs
- Expands three-year forward procurement obligation to include system and flexible RA requirements.

CPE procurement would commence for the 2021 RA year.

The CPUC is holding a workshop on November 1 to try to address the conflict.

EXTENDED DAY AHEAD MARKET (EDAM)

Western EIM (Energy Imbalance Market) is considering a potential Extended Day-Ahead Market for EIM participants. EDAM would be an additional voluntary day-ahead market layered on top of the EIM. It would not be the equivalent of membership in the CAISO or any other RTO. Transmission control, planning and cost allocation, resource adequacy and resource planning would remain with member utilities. EDAM is not intended to result in any changes to state regulatory authority. Potential benefits of EDAM would include:

- Potential production cost savings through
  - More efficient day-ahead hourly trading and use of available transmission
  - More efficient day-ahead unit commitment
- Co-optimized footprint wide resources for more efficient and cost-effective scheduling