Memorandum

TO: Richard J. Dewey

FROM: David B. Patton, Pallas LeeVanSchaick, and Joseph Coscia

DATE: October 23, 2023

RE: MMU Comments on the NYISO's 2023-2032 Comprehensive Reliability Plan

As the Market Monitoring Unit ("MMU") for the NYISO, we are required to provide comments on the Comprehensive Reliability Plan ("CRP") regarding the results of the analysis and the extent to which the current market design fails to provide appropriate incentives for the markets to satisfy Reliability Needs.[1] This memo discusses the results of the 2023-2032 CRP and the implications for the NYISO's market design.

A. Executive Summary

The CRP provides an excellent discussion of the policy, market, and regulatory factors that affect NYISO reliability through 2032 and beyond as New York's resource mix is transformed by 2040 in accordance with State law. Key findings and highlights include:

- A Near Term Reliability Need in 2025 in New York City – Transmission security violations may necessitate the deferral of some downstate peaking resource retirements.
- Risk of delayed new entry – As demand increases and some conventional units retire, significant delays in the pace of new additions could undermine reliability.
- Reliability risk is growing for peak winter conditions – Winter demand growth combined with winter natural gas limitations are expected to introduce significant reliability risk to winter in the second half of the current decade.
- If extreme weather conditions occur in combination with the issues above, it could lead to much more significant reliability problems than those identified under normal conditions.

The CRP discusses State and federal policies that are: (a) driving older conventional generation to retire; (b) encouraging electrification of heating and transportation that will increase demand, particularly during the winter; and (c) subsidizing new investment in clean resources. To

1 See NYISO MST Section 30.4.6.8.3. "Following the Management Committee vote," the MMU evaluates "whether market rules changes are necessary to address an identified failure, if any, in one of the ISO's competitive markets."

maintain reliability, large amounts of new investment will be needed to keep pace with retirements and increased demand. The CRP highlights several market design reforms that the NYISO plans to ensure the wholesale market provides appropriate investment incentives. However, there is uncertainty regarding which dispatchable technologies (other than batteries) will qualify as emission-free under New York State law. Although an on-going PSC Case may soon provide clarity, investment is unlikely to occur on a large scale until there is greater certainty regarding the technologies that will be designated as emission-free.

In recent years, we have supported major initiatives to ensure adequate incentives for investment, including:

- Dynamic Reserves and other ancillary services market reforms – Increasing intermittent renewable penetration will drive a need for dispatchable resources in key areas.
- Granular Capacity Pricing – When transmission bottlenecks limit deliverability, this reform will ensure that capacity prices are set appropriately and that the Deliverability Test will not be a barrier to new resource entry.
- Marginal Capacity Accreditation – This uses the probabilistic assessment of the resource adequacy model to estimate the reliability value of resources that have limited availability such as intermittent generation, energy storage, and fuel-limited generation.

This memo reevaluates market design priorities based on the findings of this CRP, which highlights the emergence of reliability needs on the Bulk Power Transmission Facilities that are driven by deterministic "transmission security" criteria under normal operating conditions rather than probabilistic "resource adequacy" criteria which consider emergency operating procedures. The CRP's tipping point analyses find large capacity surpluses under resource adequacy criteria while identifying small surpluses or deficiencies under transmission security criteria. Section B of this memo analyzes the underlying drivers of differences in surplus capacity margin under the two criteria.

The increasing role of transmission security criteria as a driver of reliability needs raises two market design challenges, which we examine in Section C of this memo:

- Transmission security assessment generally assigns a lower reliability value to intermittent and duration-limited resources than does resource adequacy assessment. However, the capacity accreditation reforms are designed to compensate resources based on resource adequacy (rather than transmission security) assessment. *Thus, additional capacity market reforms are needed to account for reliability needs that are driven by transmission security criteria.*
- The assumptions used in transmission security assessment have been evolving over the past several years. Although these are discussed with stakeholders at the beginning of each RNA and quarterly STAR study, uncertainty about the underlying basis for significant assumptions in future studies creates additional risks for clean resource developers. *Thus, NYISO should provide clear justifications for key assumptions in its transmission security assessments to ensure clarity related to factors affecting capacity compensation.*

B. Emergence of Transmission Security Needs on the Bulk Power Transmission Facilities

Over the past decade, most of the reliability needs discussed in NYISO's Reliability Planning Process have involved transmission security criteria violations of facilities below 200kV which were identified in the Local Transmission Planning Process. However, in the past year, reliability needs based on transmission security ("TS") assessment have emerged with violations on Bulk Power Transmission Facilities (while no related reliability need is identified under the resource adequacy ("RA") assessment). This CRP finds a large surplus of capacity in New York City based on RA criteria while finding a capacity deficiency based on TS criteria. In addition, the CRP finds large differences between the RA-based capacity margin and the TS-based capacity margin for other regions of the NYCA as well. In 2026, notable differences include:[2]

- New York City: a 452 MW surplus for TS versus a 1,790 MW surplus for RA,
- Long Island: a 395 MW surplus for TS versus 723 MW for RA, and
- Statewide: a 1,477 MW surplus for TS versus 1,699 MW for RA.

Therefore, the capacity margins calculated in TS assessments have begun to depart significantly from RA-based margins. This section analyzes the reasons for the differences and discusses specific assumptions that have changed in recent years and widened the gap in results.

Comparison of Resource Adequacy and Transmission Security Assessments[3]

There are many similarities between RA and TS assessment. Both consider whether sufficient resources are available to satisfy forecasted demand from generation, imports, internal transmission, and demand response. However, they differ in the treatment of demand forecast uncertainty, generation and transmission outages, and emergency operating procedures. Many of the differences arise from the consideration of emergency operating procedures in RA assessment while TS assessment evaluates the system under normal operating procedures. If an assessment method assumes higher levels of capacity unavailable due to forced outages, it is more likely to find a capacity deficiency. Ultimately, these differences in assumptions lead to different results for the assessment methods.

This section provides a detailed breakdown of key differences in assumptions for three scenarios: New York City in 2025, New York City in 2026, and Long Island in 2025. For each scenario, we categorize six types of differences:

- Transfer limits – RA assessment uses emergency transfer criteria to calculate transfer limits that are applied in a simplified bubble-and-pipe model, while TS assessment

[2] The zonal RA surplus ("ZRAM") values reported in the 2023 CRP are from the 2022 RNA, which used the 2022 Gold Book load forecast. The TS analysis in the 2023 CRP used the 2023 Gold Book load forecast, which included a large upward revision relative to 2022. Throughout this memo, we adjusted the RA surpluses downward based on the difference in forecasted peak loads between the 2022 and 2023 Gold Book reports.

[3] For definitions and discussion of Resource Adequacy and Transmission Security assessment methods, see NYISO's *2022 Reliability Needs Assessment*, pages 48-52.

evaluates the entire BPTF network applying normal transfer criteria following the two worst contingencies.

- SCRs – RA assessment includes SCRs with a 47 percent discount (relative to enrolled SCR capacity) to account for different baseline methods and historical performance, while TS assessment does not consider SCRs as part of normal operations.[4]
- Emergency assistance – RA assessment assumes some amount of surplus resources are available in neighboring regions, while TS assessment does not consider emergency assistance.
- Other EOPs – RA assessment assumes some relief from voltage reduction, public appeals, and voluntary curtailments, while TS assessment does not consider these.
- Generator and cable outages – RA assessment uses probabilistic methods to project outages of generation and underground transmission lines, while TS assessment assumes a class-average rate of generation outages and evaluates the BPTF network to be secured for the outage of any generator or transmission circuit at any given time.
- Load modeling – RA assessment uses probabilistic methods to project demand including very unlikely (e.g., 1-in-100+ year weather events), while TS assessment assumes average annual peak demand levels for expected weather.

The following figures summarize the approximate impacts of these differences on capacity surpluses determined by RA analysis compared to TS analysis. It is important to note that many of the factors driving margins in RA analysis are probabilistic and do not have a single fixed value. We used simplifying assumptions to estimate the average impact of these factors during simulated load shedding events, to allow for an illustrative comparison with the deterministic TS analysis.

The transfer limit assumptions account for the largest differences between the RA and TS assessments. For example, for New York City in 2025, the RA assessment utilizes an emergency import capability from upstate New York of 4,400 MW, which is the level at which normal limits are nearly maximized and a sudden transmission contingency would not cause an exceedance of the short-term emergency rating of any other line. On the other hand, TS assessment utilizes an import capability of 3,090 MW, which would allow the system to operate under normal transfer criteria with the two-largest facilities out-of-service. The significance of this factor will increase significantly in 2026 when the newly installed CHPE line becomes the largest transmission contingency into New York City.

4 Although the deployment of SCRs and other emergency operating procedures are not considered in TS assessment, the NYISO can consider emergency operating procedures when evaluating potential solutions to a reliability need driven by TS criteria.

Figure 1: Factors Causing Higher Surplus Margin in RA versus TS Assessment
NYC, 2025

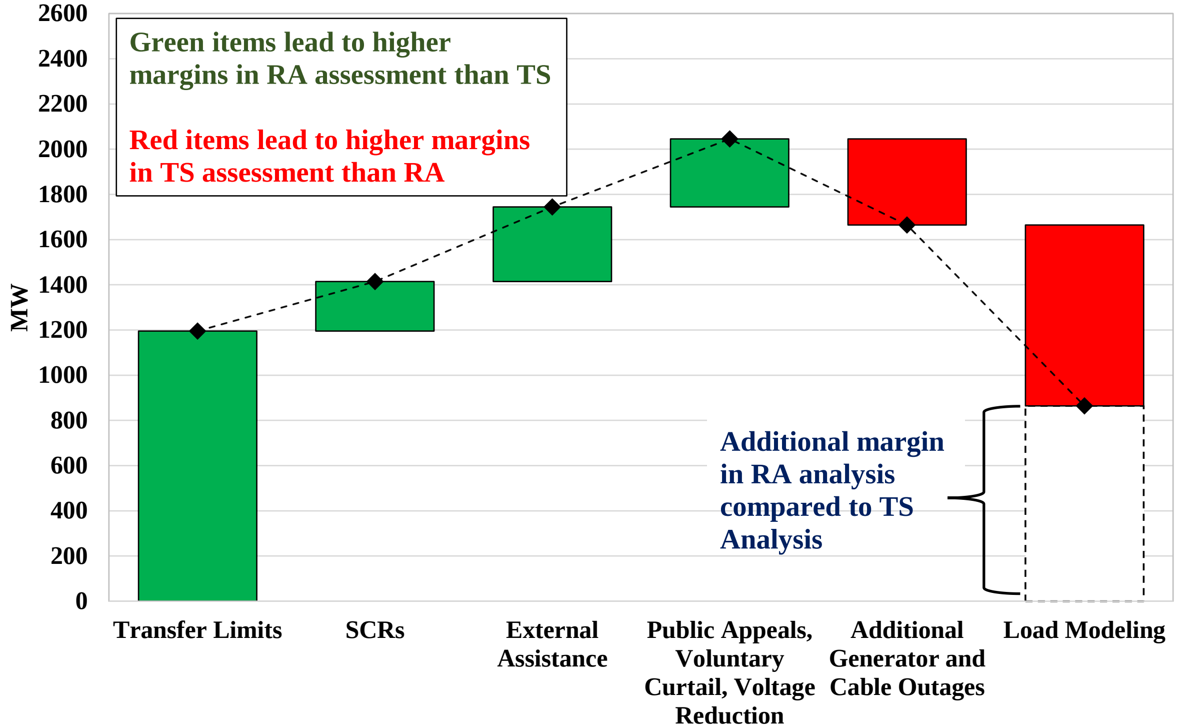


Figure 2: Factors Causing Higher Surplus Margin in RA versus TS Assessment
NYC, 2026

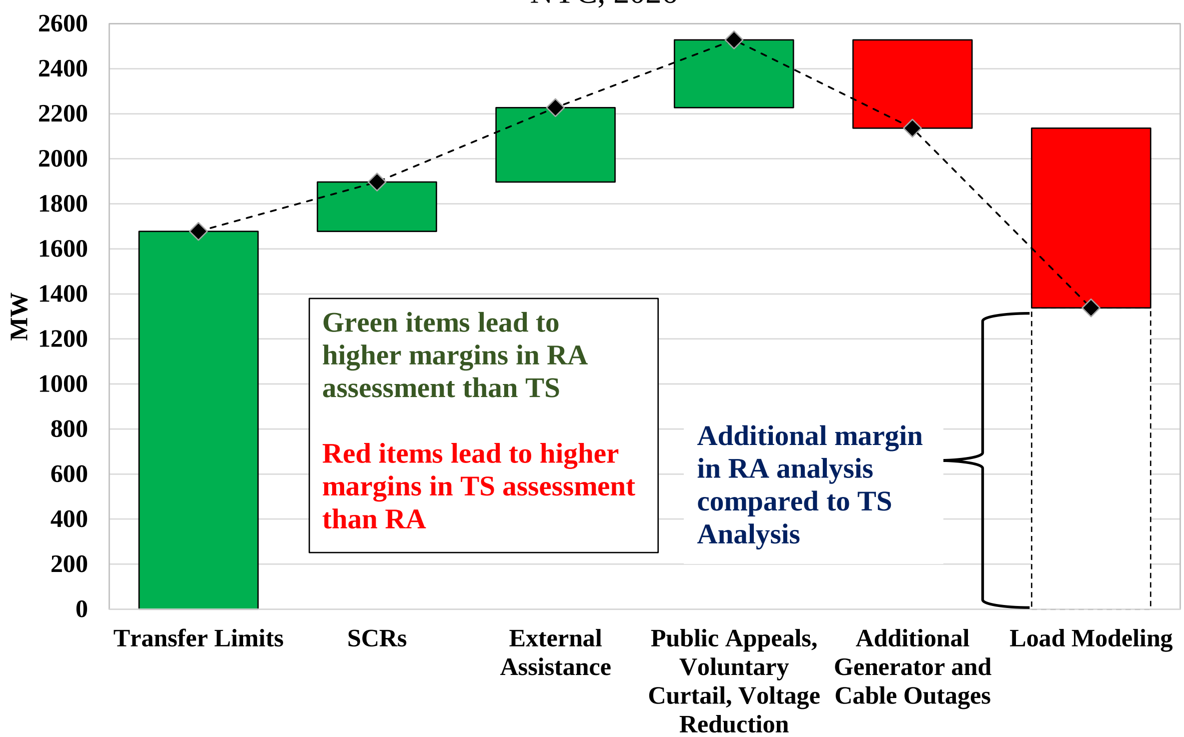
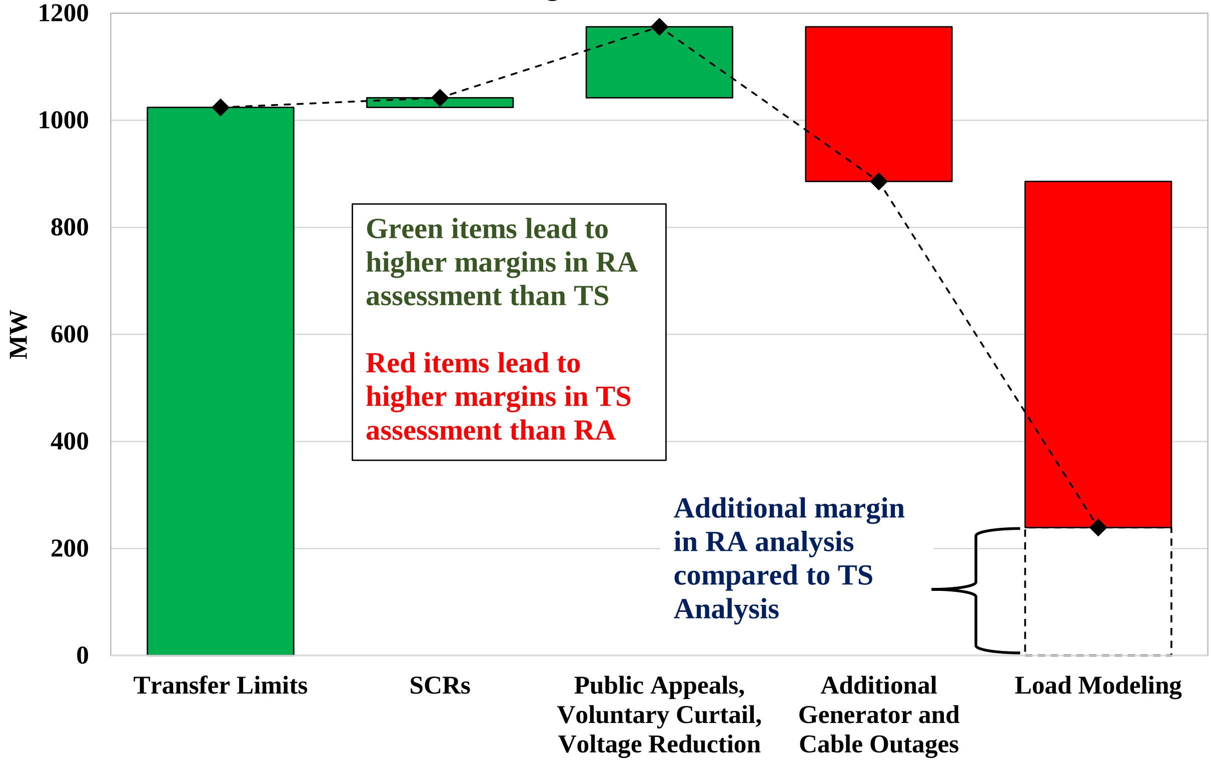


Figure 3: Factors Causing Higher Surplus Margin in RA versus TS Assessment
Long Island, 2026



Emergency actions collectively account for a large portion of the difference in results between the two assessment methods. Resource adequacy assessment counts an estimated 520 to 1,180 MW in New York City in 2025 (depending on the amount of emergency assistance via the HTP facility), including 219 MW of SCRs. Transmission security assessment does not consider emergency actions at all. Figure 1 and Figure 2 assume 330 MW of emergency assistance via HTP in RA, but this amount varies based on probabilistic factors in MARS.

Generator forced outages have a larger impact in RA assessment than in TS assessment for two reasons. First, NYISO uses unit-specific forced outage rates in MARS, which are higher than the class-average rates used in its TS assessment. Second, forced outages are modeled as random events in MARS, which allows for some instances with higher-than-average forced outage rates to be reflected in the RA assessment. Also, MARS considers random outages of underground transmission lines in downstate New York based on their historic forced outage rates.

It is possible for one or both of the contingencies evaluated under TS criteria to be a generator outage. In such cases, we include the difference between the worst generator contingency and the transmission contingency it replaces in the “Additional Generator” category for the TS assessment (in addition to the assumed average forced outage rate for generators). For example, one of the two largest contingencies affecting the New York City TS assessment is the loss of the 980 MW Ravenswood 3 unit. We account for this in our comparison by treating the amount by which the Ravenswood 3 contingency exceeds the next largest transmission contingency (approximately 215 MW) as an assumed generator outage in the TS analysis.

The load forecast is a large source of difference between the two approaches, contributing more to capacity needs under RA criteria. Therefore, the load forecast assumptions tend to offset factors that lead TS assessment to produce higher capacity requirements. The primary TS analysis uses a baseline (average) annual peak load forecast for expected weather, while MARS simulates load forecast uncertainty of 6 to 9 percent (NYC) and 11 to 16 percent (Long Island) above baseline peak loads in its two highest load scenarios. The highest two load scenarios capture low-probability extreme (e.g., heatwave) conditions that would be expected to occur less often than once every 15 years. Additionally, NYISO uses each zone's statewide coincident peak load in TS analysis, which is lower than the single-zone peak loads which may drive locational reliability needs in MARS.

Intermittent generation and duration-limited resources are treated very differently in probabilistic RA versus deterministic TS assessments, but these had very little impact on the results shown above because of the low levels of penetration in the scenarios analyzed.

Discussion

Transmission security-based capacity margins have fallen relative to resource adequacy-based margins in recent years because of a methodological change in the treatment of outages. Previously, transmission security assessments accounted for outages by evaluating the system after the occurrence of the two worst contingencies while assuming all generation was fully available. In the 2020 RNA, however, NYISO began to also assume generating capacity was unavailable based on a class-average forced outage rate. Transmission security-based capacity margins will likely fall further (relative to resource adequacy-based margins) given anticipated changes in the resource mix, including the installation of:

- Two large HVDC cables into New York City, which will become the two largest contingencies when fully utilized;
- Large quantities of intermittent wind and solar generation that are generally assumed to have lower value under transmission security assessment versus resource adequacy assessment; and
- Battery storage systems, which are assumed to have less value in transmission security assessments that do not consider synergies between intermittent generation and batteries.

In addition, NYISO supports refining the NYSRC reliability rules to design the system in the transmission security assessments to a higher level peak load representing extreme weather (e.g., a 90/10 forecast). Since transmission security criteria do not have a singular objective (such as a resource adequacy standard of one day of load shedding in ten years), it is difficult to assess whether proposed methodological changes will yield just and reasonable rates for consumers. Methodological changes to planning criteria also have profound implications for investors, so it is important for them to be transparent and reasonably-based.

C. Market Design Recommendations

Market design enhancements are needed to ensure investors have incentives to develop resources with flexible characteristics that help integrate intermittent renewables and maintain security and reliability. Our recent recommendations have sought to enhance operating reserve markets, capacity accreditation, and locational capacity pricing. However, market design priorities should be reevaluated as transmission security-based reliability needs become more prevalent. The NYISO's current initiative to enhance capacity accreditation is principally focused on compensating resources according to their value in satisfying resource adequacy criteria, but transmission security assessment generally assigns lower value to non-conventional resources. Hence, the current capacity accreditation initiative may provide incentives that are not well-suited to the challenges that NYISO faces in its reliability planning assessments.

Although transmission security is not reflected in the capacity accreditation rules that will be implemented in 2024, transmission security is already reflected in the NYISO's LCR-setting process. This process determines locational minimum requirements for defined capacity regions that satisfy both resource adequacy and transmission security criteria. Since the summer of 2023, the New York City LCR has been set based on transmission security criteria (rather than resource adequacy criteria), and this trend is expected to continue for reasons discussed above in Section B. The initial set of capacity accreditation reforms, which will be implemented in the summer of 2024, base capacity compensation on the reliability value of resources measured using resource adequacy assessment tools. However, in circumstances when the LCR is determined by the transmission security criteria, it would be efficient if the capacity accreditation also considered transmission security criteria.

When LCRs are determined by transmission security criteria, the soon-to-be-implemented capacity accreditation rules will tend to over-compensate several resource categories that provide less reliability benefit under transmission security criteria. These include:

- SCRs – These emergency demand response resources are not counted towards satisfying transmission security criteria (as discussed in Section B).
- Large contingency resources – The top portion of output from the largest two resources does not contribute towards satisfying transmission security criteria.[5]
- Intermittent generation – Offshore wind generators are assumed to produce 10 percent of their nameplate capacity in the transmission security assessments, which is significantly lower than the marginal accreditation value that is likely to be developed under the rules that will be implemented in the summer of 2024.
- Duration-limited resources – It is unclear whether these resources will make less contribution to transmission security than to resource adequacy. It will be important to monitor this as the penetration of duration-limited resources increases.

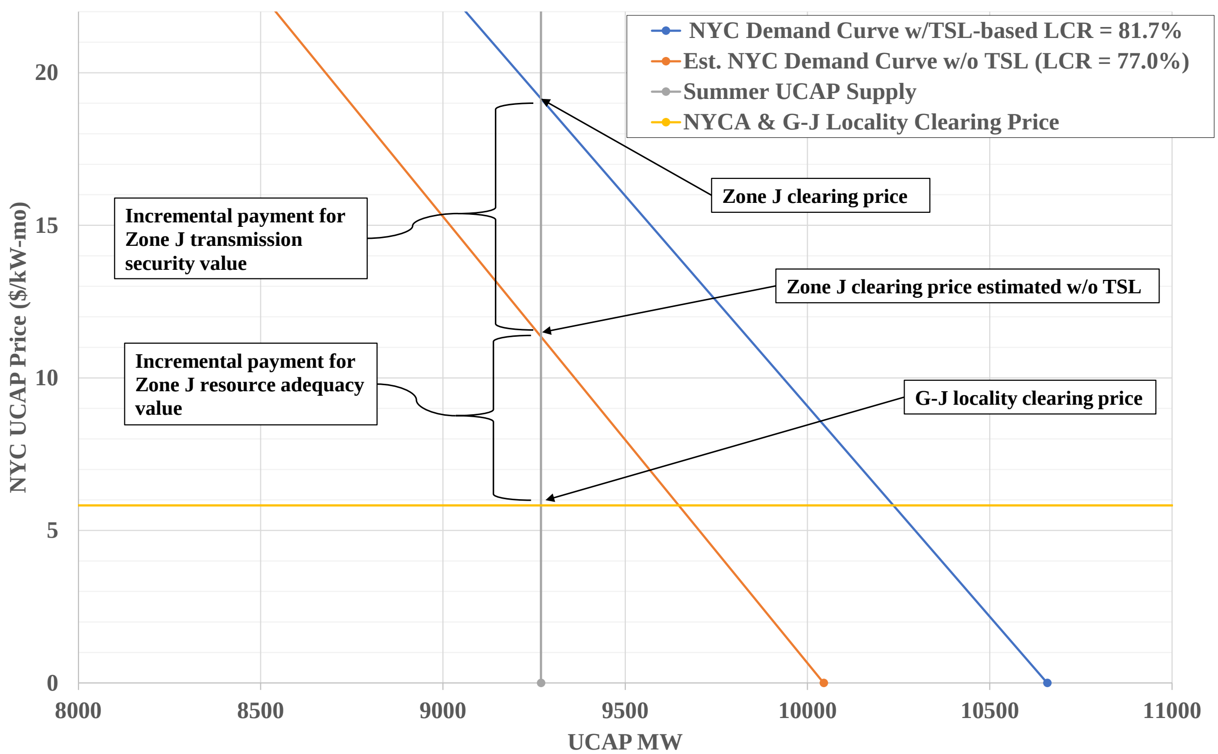
5 Each increment of capacity exceeding the size of the third-largest contingency provides no incremental value because it simply increases the amount of capacity needed to satisfy the transmission security criteria.

Hence, we recommended paying resources the highest capacity price among requirements which they contribute to meeting in our most recent State of the Market Report for NYISO (see Recommendation #2022-1).[6] Likewise, NYISO and stakeholders recognized the need to consider capacity market incentives related to transmission security by designating "Valuing Transmission Security" for "Issue Discovery" in the 2024 project prioritization plan.

The remainder of this section provides additional details of an approach that could be used to implement Recommendation #2022-1. This would require the NYISO to develop two-part pricing for resources in capacity regions where the LCR is set by transmission security criteria. Specifically, the capacity price should be broken into components for resources based on their contributions to resource adequacy and transmission security.

This two-part pricing concept is illustrated in the following figure, which shows a scenario when the Zone J LCR is set by a TSL of 81.7 percent, resulting in the demand curve shown by the blue line. The orange line shows the demand curve corresponding to the LCR that would be set if the TSL was not imposed, which is assumed to be 77 percent in this scenario.

Figure 4: Recommended 2-Part Capacity Pricing when an LCR Is Based on the TSL



In this illustrative scenario, the G-J Locality clearing price is $5.90 per kW-month and the Zone J clearing price is $19 per kW-month. The clearing price for the resource adequacy contribution is

6 See our *2022 State of the NYISO Market Report*, May 2023.

$11.50 per kW-month, which is based on the reduced LCR for Zone J that excludes consideration of the TSL. In this scenario, the incremental price for the resource adequacy value of Zone J resources would be $5.60 (= $11.50 – $5.90) per kW-month, while the incremental price for the transmission security value of Zone J resources would be $7.50 (= $19 – $11.50) per kW-month. Most Zone J resources would be paid the full Zone J clearing price of $19 per kW-month, while Zone J resources that do not contribute to transmission security would be paid $11.50 per kW-month based their resource adequacy value.

To illustrate how this would be used in practice, we show illustrative settlements for three hypothetical resources in Zone J:

- SCRs – These would receive $11.50 per kW-month of UCAP based on the resource adequacy value of Zone J resources.
- 1000 MW generator – If we assume the third-largest contingency for Zone J is 720 MW and the EFORd of this resource is 5 percent, this resource would be paid for:
    - 720 MW of UCAP at the Zone J clearing price of $19 per kW-month; and
    - 230 MW of UCAP at $11.50 per kW-month, the Zone J price for resources that do not contribute to transmission security.
- 800 MW offshore wind unit – If we assume this receives an MRI of 25 percent under the soon-to-be implemented capacity accreditation rules, it would be paid for:
    - 200 MW of UCAP (based on a 25 percent MRI for its of 800 MW of ICAP) at the $11.50 per kW-month clearing price for resource adequacy in Zone J; and
    - 80 MW of UCAP (based on a 10 percent contribution for its 800 MW of ICAP) at the $7.50 per kW-month component for transmission security in Zone J.

We recommend developing a two-part pricing method (as described above) that separates payments for resource adequacy and transmission security when transmission security criteria determines the LCR. This would improve incentives to invest in reliable capacity and reduce overpayments to over-accredited resources. These changes would cause SCRs, large contingency resources, and intermittent generation to be appropriately compensated based on their contributions to the planning reliability requirements. Payments to these resources would be unaffected when LCRs are not set at the TSL-floor.

D. Conclusions and Recommendations

Overall, we continue to find that the NYISO markets are well-designed and generally provide efficient investment signals. However, we have concerns regarding the current market design's ability to provide efficient incentives when planning reliability needs are driven by transmission security criteria. We also note that the planning reliability needs for the Bulk Power Transmission Facilities are increasingly driven by transmission security criteria rather than resource adequacy criteria. Given these developments, we recommend NYISO:

- Develop additional capacity accreditation reforms to account for reliability needs that are driven by transmission security criteria.

- Provide clear justifications for key assumptions in its transmission security assessments to ensure clarity related to factors affecting capacity compensation.