New York ISO
Independent System Operator

Appendices

2021-2030
Comprehensive Reliability Plan

A Report from the
New York Independent
System Operator

Draft Report
For October 25, 2021, TPAS/ESPWG

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Appendix A – Glossary

The following glossary offers definitions and explanations of terms used in the Comprehensive Reliability Plan it appends, as well as references to additional source information published by the NYISO and other energy industry entities.

Annual Transmission Reliability Assessment (ATRA): An assessment, conducted by the NYISO staff in cooperation with Market Participants, to determine the System Upgrade Facilities required for each generation project and Class Year Transmission Project to interconnect to the New York State Transmission System in compliance with Applicable Reliability Standards and the NYISO Minimum Interconnection Standard. See NYISO OATT

Area Transmission Review (ATR): An annual report provided to the Northeast Power Coordinating Council Compliance Committee by the NYISO, in its role as Planning Coordinator, in regard to its Area Transmission Review. See NPCC.org

Baseline Forecast: Prepared for the NYISO Gold Book, baseline forecasts report the expected New York Control Area load and include the projected impacts of energy efficiency programs, building codes and standards, distributed energy resources, behind-the-meter energy storage, behind-the-meter solar photovoltaic power, electric vehicle usage, and electrification of heating and other end uses. The baseline forecasts are used in the Reliability Needs Assessment Base Cases for determining Bulk Power Transmission Facilities Reliability Needs for the Reliability Needs Assessment Study Period.

Best Technology Available (BTA): Performance goal established by the New York State Department of Environmental Conservation for cooling water intake structures at proposed and existing electric generating plants with intake capacity greater than 20 million gallons per day. See DEC.NY.gov

New York State Bulk Power Transmission Facility (BPTF): Facilities identified as the New York State Bulk Power Transmission Facilities in the annual Area Transmission Review submitted to the Northeast Power Coordinating Council by the NYISO. See NYISO OATT

Clean Energy Standard (CES): New York State initiative requiring 70% of electricity consumed in the State to be produced from renewable sources by 2030. See NYSERDA.NY.gov

Climate Leadership and Community Protection Act (CLCPA): New York State statute enacted in 2019 to address and mitigate the effects of climate change. Among other requirements, the law mandates that; (1) 70% of energy consumed in New York State be sourced from renewable resources by 2030, (2) greenhouse gas emissions must be reduced by 40% by 2030, (3) the electric generation sector must be zero greenhouse gas emissions by 2040, and (4) greenhouse gas emissions across all sectors of the economy must be reduced by 85% by 2050. See CLIMATE.NY.gov

Contingencies: Actual or potential unexpected failure or outage of a system component such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are related by situations leading to simultaneous component outages. See NYSRC.org

Dependable Maximum Net Capability (DMNC): Sustained maximum net output of a Generator, as demonstrated by the performance of a test or through actual operation, averaged over a continuous time period. See NYISO OATT

Disturbance: Severe oscillations or severe step changes of current, voltage and/or frequency usually caused by faults. See NYSRC.org

Electric System Planning Work Group (ESPWG): The stakeholder forum that provides Market Participant input on the NYISO's comprehensive system planning processes. See Committees at NYISO.com

Emergency Transfer Criteria: In the event that adequate facilities are not available to supply firm load within Normal Transfer Criteria, emergency transfer criteria may be invoked. Under emergency transfer criteria, transfers may be increased up to, but not exceed, emergency ratings and limits, as follows:

> a. Pre-contingency line and equipment loadings may be operated up to LTE ratings for up to four (4) hours, provided the STE ratings are set appropriately. Otherwise, pre-contingency line and equipment loadings must be within normal ratings. Pre-contingency voltages and transmission interface flows must be within applicable pre-contingency voltage and stability limits.
>
> b. Post-contingency line and equipment loadings within STE ratings. Post-contingency voltages and transmission interface flows within applicable post-contingency voltage and stability limits. See NYSRC.org

Fault: An electrical short circuit. See NYSRC.org

Federal Energy Regulatory Commission (FERC): The United States federal agency that regulates the transmission and wholesale sale of electricity and natural gas in interstate commerce.

FERC Form No. 715: Annual report by transmitting utilities on transmission planning, constraints, and available transmission capacity. See FERC.gov

Forced Outage: Unscheduled inability of a Market Participant's Generator to produce energy that does not meet the notification criteria to be classified as a scheduled outage or de-rate as established in NYISO Procedures. See NYISO.com

Gold Book: Annual NYISO publication, also known as the Load and Capacity Data Report. See Library/Reports at NYISO.com

Installed Capacity (ICAP): External or Internal Capacity that is made available pursuant to Tariff requirements and NYISO Procedures. See NYISO Services Tariff

Installed Capacity Requirement (ICR): The annual statewide requirement established by the New York State Reliability Council in order to provide resource adequacy in the New York Control Area. See NYSRC.org

Installed Reserve Margin (IRM): The amount of installed electric generation capacity above 100% of the forecasted peak electric demand that is required to meet New York State Reliability Council resource adequacy criteria.

Local Transmission Plan (LTP): The Local Transmission Owner Plan, developed by each Transmission Owner, which describes its respective plans that may be under consideration or finalized for its own Transmission District. See NYISO OATT

Local Transmission Planning Process (LTPP): The Local Planning Process conducted by each Transmission Owner for its own Transmission District. See NYISO OATT

Loss of Load Expectation (LOLE): A New York State Reliability Council resource adequacy criterion requiring that the probability (or risk) of the unplanned disconnecting of any firm load due to resource deficiencies shall be, on average, not more than once in ten years, expressed mathematically as 0.1 days per year. See NYSRC.org

- LOLE is generally defined as the expected (weighted average) number of days in a given period (e.g., one study year) when for at least one hour from that day the hourly demand is projected to exceed the zonal resources (event day). Within a day, if the zonal demand exceeds the resources in at least one hour of that day, this will be counted as one event day. The criterion is that the LOLE not exceed one day in 10 years, or LOLE < 0.1 days/year.
- LOLH is generally defined[1] as the expected number of hours per period (e.g., one study year) when a system's hourly demand is projected to exceed the zonal resources (event hour). Within an hour, if the zonal demand exceeds the resources, this will be counted as one event hour.
- EUE, also referred to as loss of energy expectation (LOEE), is generally defined[2] as the expected energy (MWh) per period (e.g., one study year) when the summation of the system's hourly demand is projected to exceed the zonal resources. Within an hour, if the zonal demand exceeds the resources, this deficit will be counted toward the system's EUE.

Market Monitoring Unit: The consulting or professional services firm, or other similar entity, responsible for carrying out the Core Market Monitoring Functions and other functions assigned to it in the NYISO's tariffs. . See NYISO OATT Attachment O

Market Participant: An entity, excluding the NYISO, that produces, transmits, sells, and/or purchases for resale unforced capacity, energy, or ancillary services in the wholesale market, including entities that buy or sell Transmission Congestion Contracts. See NYISO Services Tariff

Market Administration and Control Area Services Tariff (NYISO Services Tariff): The document addressing the Market Services and the Control Area Services provided by the NYISO, and the terms and conditions, regulated by the FERC, under which those services are provided.

New York Control Area (NYCA): The area under the electrical control of the NYISO, including the entire state of New York, divided into eleven load zones. See NYISO.com

New York State Department of Environmental Conservation (NYSDEC): The agency that implements the New York State Environmental Conservation Law, with some programs also governed by federal law.

New York Independent System Operator (NYISO): A not-for-profit organization that operates New York's bulk electricity grid, wholesale electricity markets and conducts interconnection and transmission planning.

NYISO Procedures (Manuals, Guides, Technical Bulletins): NYISO Manuals specify and explain the procedures and policies used to operate the bulk power system of the New York Control Area and to conduct wholesale electricity markets, consistent with the NYISO Tariffs and Agreements. NYISO Guides serve to assist users with information needed to participate in NYISO Administered Markets. NYISO Technical Bulletins explain changes to, and provide instruction for, NYISO processes and procedures. See NYISO.com

[1] NYSRC's "Resource Adequacy Metrics and their Application": https://www.nysrc.org/PDF/Reports/Resource%20Adequacy%20Metric%20Report%20Final%204-20-2020[6431].pdf

[2] NYSRC's "Resource Adequacy Metrics and their Application": https://www.nysrc.org/PDF/Reports/Resource%20Adequacy%20Metric%20Report%20Final%204-20-2020[6431].pdf

New York State Department of Public Service (NYDPS): The New York State agency that supports the New York State Public Service Commission. See DPS.NY.gov

New York State Energy Research and Development Authority (NYSERDA): The New York State public authority charged with conducting a multifaceted energy and environmental research and development program to meet New York State's diverse economic needs, including administering the state System Benefits Charge, Renewable Portfolio Standard, energy efficiency programs, the Clean Energy Fund, and the NY-Sun Initiative. See NYSERDA.NY.gov

New York State Public Service Commission (NYPSC): The decision-making body of the New York State Department of Public Service, which regulates the state's electric, gas, steam, telecommunications, and water utilities, oversees the cable industry, has the responsibility for setting rates and overseeing that safe and adequate service is provided by New York's utilities, and exercises jurisdiction over the siting of major gas and electric transmission facilities.

NY-Sun Initiative: A program run by NYSERDA for the purpose of obtaining more than 6,000 MW-DC of behind-the-meter solar photovoltaic systems by the end of 2023. See NYSERDA.NY.gov

New York State Reliability Council (NYSRC): A not-for-profit entity the mission of which is to annually establish the Installed Reserve Margin, and to promote and preserve the reliability of electric service on the New York State Power System by developing, maintaining, and updating the Reliability Rules with which the NYISO and all entities engaging in electric transmission, ancillary services, energy, and power transactions on the New York State Power System must comply. See NYSRC.org

Normal Transfer Criteria: Measures established, in accordance with the North American Electric Reliability Corporation, Northeast Power Coordinating Council, and the New York State Reliability Council's Reliability Rules, to determine that adequate facilities are available to supply firm load in the bulk power transmission system within applicable normal ratings and limits. See NYSRC.org

Normal Transfer Limit: The lowest limit based on the most restrictive of three maximum allowable transfers, calculated based on thermal, voltage, and stability testing, considering contingencies, ratings, and limits specified for normal conditions. See NYSRC.org

North American Electric Reliability Corporation (NERC): A not-for-profit international regulatory authority the mission of which is to assure the effective and efficient reduction of risks to the reliability and security of the grid. See NERC.com

Northeast Power Coordinating Council (NPCC): The entity to whom the North American Electric Reliability Corporation has delegated Electric Reliability Organization functions in the New York Control Area. See NYISO OATT

Open Access Transmission Tariff (OATT): The document setting forth the rates, terms, and conditions, accepted or approved by the FERC, under which the NYISO provides transmission service and conducts interconnection and transmission system planning.

Order No. 890: Order issued by the FERC in 2007 that amended the regulations and the *pro forma* open access transmission tariff to provide that transmission services and planning are provided on a basis that is just, reasonable and not unduly discriminatory or preferential. See FERC.gov

Order No. 1000: Order issued by the FERC in 2011 that amended the transmission planning and cost allocation requirements established in Order No. 890 to provide that Commission-jurisdictional services, including transmission planning, are provided at just and reasonable rates and on a basis that is just and reasonable and not unduly discriminatory or preferential. See FERC.gov

Outage: The forced or scheduled removal of generating capacity or a transmission line from service.

Peak Demand: The maximum instantaneous power demand, measured in megawatts (MW), and known as peak load, is usually measured, and averaged over an hourly interval. The peak hour is the hour during which the coincident usage was the highest across the entire New York Control Area in a given time period.

Queue Position: The order, in the NYISO's Interconnection Queue, of a valid Interconnection Request, Study Request, or Transmission Interconnection Application relative to all other pending Requests.
See NYISO OATT

Rating: The operational limits of an electric system, facility, or element under a set of specified conditions. Rating categories include Normal Rating, Long-Term Emergency (LTE) Rating, and Short-Term Emergency (STE) Rating, as follows:

1. **Normal Rating:** The capacity rating of a transmission facility that may be carried through consecutive twenty- four (24) hour load cycles.
2. **Long-Time Emergency (LTE) Rating:** The capacity rating of a transmission facility that can be carried through infrequent, non- consecutive four (4) hour periods.
3. **Short-Time Emergency (STE) Rating:** The capacity rating of a transmission facility that may be carried during very infrequent contingencies of fifteen (15) minutes or less duration. (Source: NYSRC Reliability Rules). See NYSRC.org

Reasonably Available Control Technology for Major Facilities of Oxides of Nitrogen (NOx RACT): New York State Department of Environmental Conservation regulations for the control of emissions of nitrogen oxides (NOx) from fossil fuel-fired power plants. See DEC.ny.gov

Reactive Power: The portion of electric power that establishes and sustains the electric and magnetic fields of alternating-current equipment.

Reactive Power Resources: Facilities such as generators, high voltage transmission lines, synchronous condensers, capacitor banks, and static var compensators that provide reactive power.

Regional Greenhouse Gas Initiative (RGGI): A cooperative effort by a group of Northeast and Mid-Atlantic states to limit power sector greenhouse gas emissions using a market-based cap-and-trade approach. See RGGI.org

Reliability: The degree of performance of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired, which can be addressed by considering the adequacy and security of the electric system:

1. **Adequacy:** The ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Note: Adequacy encompasses both generation and transmission.
2. **Security:** The ability of the electric system to withstand disturbances such as electric short circuits or unanticipated loss of system elements. The ability of the power system to withstand the loss of one or more elements without involuntarily disconnecting firm load. See NYSRC.org

Reliability Criteria: The electric power system planning and operating policies, standards, criteria, guidelines, procedures, and rules promulgated by the North American Electric Reliability Corporation, Northeast Power Coordinating Council, and the New York State Reliability Council. See NYISO OATT Attachment Y

Reliability Need: A condition identified by the NYISO as a violation or potential violation of one or more Reliability Criteria. See NYISO OATT Attachment Y

Reliability Needs Assessment (RNA): A report that evaluates resource adequacy and transmission system security over years four through ten of a 10-year planning horizon and identifies future needs of the New York electricity grid. It is the first step in the NYISO's reliability planning process.
See NYISO OATT Attachment Y

Reliability Needs Assessment (RNA) Study Period: The seven-year time period encompassing years four through ten following the year in which the RNA is conducted, which is used in the RNA and the Comprehensive Reliability Plan. See NYISO OATT Attachment Y

Reliability Planning Process (RPP): The process by which the NYISO determines, in the Reliability Needs Assessment, whether any Reliability Need(s) on the New York State Bulk Power Transmission Facilities will arise in the Study Period and addresses any identified Reliability Need(s) in the Comprehensive Reliability Plan. See NYISO OATT Attachment Y

Reliability Solutions: Potential solutions to reliability needs include the following:

1. **Alternative Regulated Solutions (ARS):** Regulated solutions submitted by a Transmission Owner or other developer in response to a solicitation for solutions to a Reliability Need identified in a Reliability Needs Assessment.

2. **Gap Solution:** A solution to a Reliability Need that is designed to be temporary and to strive to be compatible with permanent market-based proposals. The NYISO may call for a Gap Solution to an imminent threat to reliability of the Bulk Power Transmission Facilities if no market-based solutions, regulated backstop solutions, or alternative regulated solutions can meet the Reliability Needs in a timely manner.

3. **Market-Based Solution:** Investor-proposed project driven by market needs to meet future reliability requirements of the bulk electricity grid as outlined in the Reliability Needs Assessment. These can include generation, transmission, and demand response Programs.

4. **Regulated Backstop Solution:** Proposals are required of certain Transmission Owners to meet Reliability Needs as outlined in the Reliability Needs Assessment.

Those solutions can include generation, transmission, or demand response. Non-Transmission Owner developers may also submit regulated solutions. See NYISO OATT Attachment Y

Resource Adequacy: The ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Note: Adequacy encompasses both generation and transmission. See definition of Reliability.

Responsible Transmission Owner (Responsible TO): The Transmission Owner(s) designated by the NYISO to prepare a proposal for a regulated backstop solution to a Reliability Need or to proceed with a regulated solution to a Reliability Need. The Responsible Transmission Owner will normally be the Transmission Owner in whose Transmission District the ISO identifies a Reliability Need and/or that owns a transmission facility on which a Reliability Need arises. See NYISO OATT Attachment Y

Short-Term Assessment of Reliability (STAR): The NYISO's quarterly assessment, in coordination with the Responsible Transmission Owner(s), of whether a Short-Term Reliability Process Need will result from a Generator becoming Retired, entering into a Mothball Outage, or being unavailable due to an Installed Capacity Ineligible Forced Outage, or from other changes to the availability of Resources or to the New York State Transmission System. See NYISO OATT Attachment FF

Short-Term Reliability Process: The process by which the NYISO evaluates and addresses the reliability impacts resulting from both: (1) Generator Deactivation Reliability Need(s), and/or (2) other Reliability Needs on or affecting the Bulk Power Transmission Facilities that are identified in a Short-Term Assessment of Reliability. The Short-Term Reliability Process evaluates reliability needs in years one through five of the ten-year Study Period, with a focus on needs in years one through three. See NYISO OATT Attachment FF

Short-Term Reliability Process Need: A Generator Deactivation Reliability Need or a condition identified by the NYISO in a Short-Term Assessment of Reliability as a violation or potential violation of one or more Reliability Criteria on the Bulk Power Transmission Facilities. See NYISO OATT Attachment FF

Short-Term Reliability Process Solution: A solution to address a Short-Term Reliability Process Need, which may include (1) an Initiating Generator, (2) a solution proposed pursuant to the NYISO Services Tariff, or (3) a Generator identified by the NYISO pursuant to the NYISO Services Tariff. See NYISO OATT and NYISO Services Tariff

Short-Term Assessment of Reliability (STAR) Start Date: The date on which the NYISO next commences a STAR after issuing a written notice to a Market Participant indicating that the Generator Deactivation Notice for its Generator is complete. See NYISO OATT Attachment FF

Special Case Resource ("SCR"): Demand Side Resources the Load of which is capable of being interrupted upon demand at the direction of the NYISO, and/or Demand Side Resources that have a Local Generator, which is not visible to the NYISO's Market Information System and is rated 100 kW or higher, that can be operated to reduce Load from the New York State Transmission System or the distribution system at the direction of the NYISO. See NYISO Services Tariff

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances. See NYSRC.org

System & Resource Outlook (formerly "CARIS"): Biennial report produced by the NYISO, through which it summarizes the current assessments, evaluations, and plans in the biennial Comprehensive System Planning Process, produces a twenty-year projection of congestion on the New York State Transmission System, identifies, ranks, and groups congested elements, and assesses the potential benefits of addressing the identified congestion.

System Benefits Charge (SBC): An amount of money, charged to ratepayers on their electric bills, which is administered and allocated by the New York State Energy Research and Development Authority towards energy-efficiency programs, research and development initiatives, low-income energy programs, and environmental disclosure activities.

Transfer Capability: The measure of the ability of interconnected electrical systems to reliably move or transfer power from one area to another over all transmission facilities (or paths) between those areas under specified system conditions.

Transmission Constraints: Limitations on the ability of a transmission system to transfer electricity during normal or emergency system conditions.

Transmission Owner (TO): A public utility or authority that owns transmission facilities and provides Transmission Service under the NYISO Tariffs.

Transmission Security: The ability of the electric system to withstand disturbances such as electric short circuits or unanticipated loss of system elements. The ability of the power system to withstand the loss of one or more elements without involuntarily disconnecting firm load. See definition of Reliability.

Unforced Capacity: The measure by which Installed Capacity Suppliers will be rated to quantify the extent of their contribution to satisfy the New York Control Area Installed Capacity Requirement.
See NYISO Services Tariff

Unforced Capacity Deliverability Rights (UDRs): Rights, as measured in MWs, associated with (1) new incremental controllable transmission projects, and (2) new projects to increase the capability of existing controllable transmission projects that have UDRs, that provide a transmission interface to a Locality. which, under certain conditions, allow such Unforced Capacity to be treated as if it were located in the Locality, thereby contributing to an LSE's Locational Minimum Installed Capacity Requirement. When combined with Unforced Capacity which is located in an External Control Area or non-constrained NYCA region either by contract or ownership, and which is deliverable to the NYCA interface in the Locality in which the UDR transmission facility is electrically located, UDRs allow such Unforced Capacity to be treated as if it were located in the Locality, thereby contributing to an LSE's Locational Minimum Installed Capacity Requirement. To the extent the NYCA interface is with an External Control Area the Unforced Capacity associated with UDRs must be deliverable to the Interconnection Point. See NYISO Services Tariff

Weather Normalized: Adjustments made to normalize the impact of weather when making energy and peak demand forecasts. Using historical weather data, energy analysts can account for the influence of extreme weather conditions and adjust actual energy use and peak demand to estimate what would have happened if the hottest day or the coldest day had been the typical, or "normal," weather conditions. "Normal" is usually calculated by taking the average of the previous 20 years of weather data.

Zone: One of the eleven regions in the New York Control Area connected to each other by identified transmission interfaces and designated as Load Zones A-K.

Appendix B - Planned Projects and Assumptions

The CRP conclusions are based on certain base case assumptions, which are summarized below.

Figure 1: Load and Capacity Data

	Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NYCA Baseline Demand Forecast											
	NYCA*	32,145	32,112	31,867	31,629	31,471	31,366	31,357	31,409	31,506	31,609
	Zone J*	11,211	11,378	11,342	11,292	11,270	11,271	11,326	11,399	11,484	11,573
	Zone K*	5,240	5,134	5,027	4,918	4,827	4,749	4,701	4,685	4,689	4,692
	Zone G-J*	15,364	15,518	15,447	15,368	15,329	15,322	15,377	15,454	15,550	15,652
Resources (MW)											
NYCA	Capacity**	37,334	37,902	37,155	37,155	36,551	36,551	36,551	36,551	36,551	36,551
	Net Purchases & Sales	1,812	1,816	1,794	1,954	1,954	1,954	1,954	1,954	1,954	1,954
	SCR	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282
	Total Resources	40,429	41,001	40,231	40,391	39,787	39,787	39,787	39,787	39,787	39,787
	Cap+NetPurch+SCR/Load Ratio	125.8%	127.7%	126.2%	127.7%	126.4%	126.8%	126.9%	126.7%	126.3%	125.9%
Zone J	Capacity**	9,568	9,568	8,795	8,795	8,190	8,190	8,190	8,190	8,190	8,190
	Full UDR Rights	315	315	315	315	315	315	315	315	315	315
	SCR	479	479	479	479	479	479	479	479	479	479
	Total Resources	10,362	10,362	9,589	9,589	8,984	8,984	8,984	8,984	8,984	8,984
	Cap+fullUDR+SCR/Load Ratio	92.4%	91.1%	84.5%	84.9%	79.7%	79.7%	79.3%	78.8%	78.2%	77.6%
Zone K	Capacity**	5,226	5,249	5,213	5,213	5,213	5,213	5,213	5,213	5,213	5,213
	Full UDR Rights	990	990	990	990	990	990	990	990	990	990
	SCR	48	48	48	48	48	48	48	48	48	48
	Total Resources	6,264	6,287	6,251	6,251	6,251	6,251	6,251	6,251	6,251	6,251
	Cap+fullUDR+SCR/Load Ratio	119.5%	122.5%	124.3%	127.1%	129.5%	131.6%	133.0%	133.4%	133.3%	133.2%
Zone G-J	Capacity**	14,320	14,320	13,509	13,509	12,904	12,904	12,904	12,904	12,904	12,904
	Full UDR Rights	315	315	315	315	315	315	315	315	315	315
	SCR	605	605	605	605	605	605	605	605	605	605
	Total Resources	15,240	15,240	14,429	14,429	13,824	13,824	13,824	13,824	13,824	13,824
	Cap+fullUDR+SCR/Load Ratio	99.2%	98.2%	93.4%	93.9%	90.2%	90.2%	89.9%	89.5%	88.9%	88.3%

Notes:

*NYCA load values represent baseline coincident summer peak demand. Zones J and K load values represent non-coincident summer peak demand. Aggregate Zones G-J values represent the G-J peak (Table I-5).

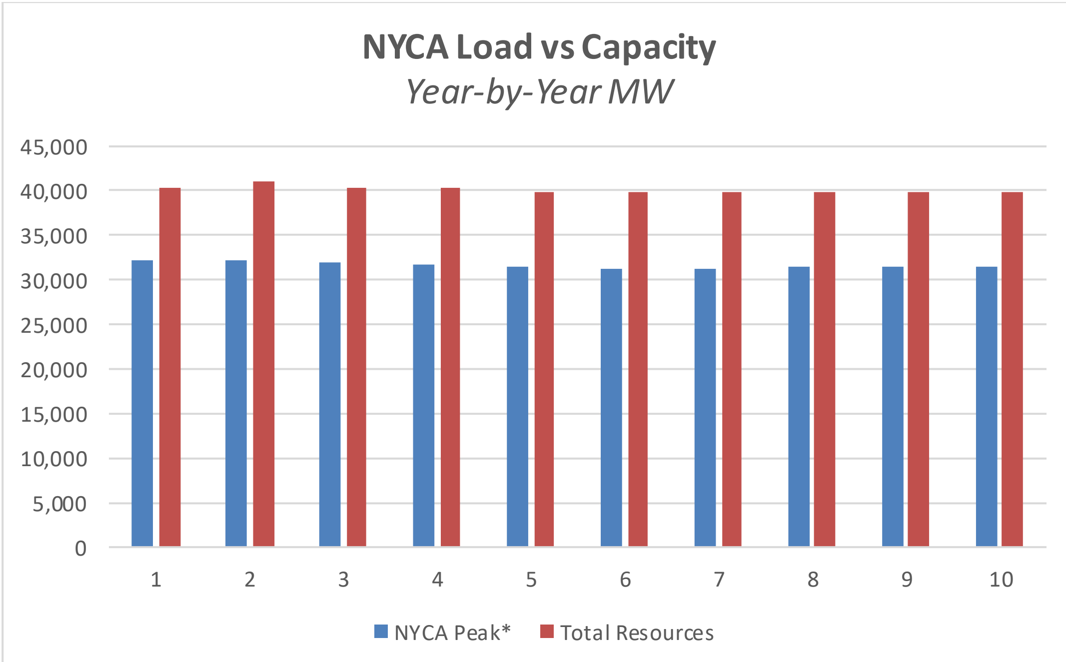
**NYCA Capacity values include resources electrically internal to NYCA, additions, re-ratings, and retirements (including proposed retirements and mothballs). Capacity values reflect the lesser of CRIS and DMNC values. NYCA resources include the net purchases and sales as per the Gold Book. Zonal totals include the full UDRs Rights for those capacity zones.

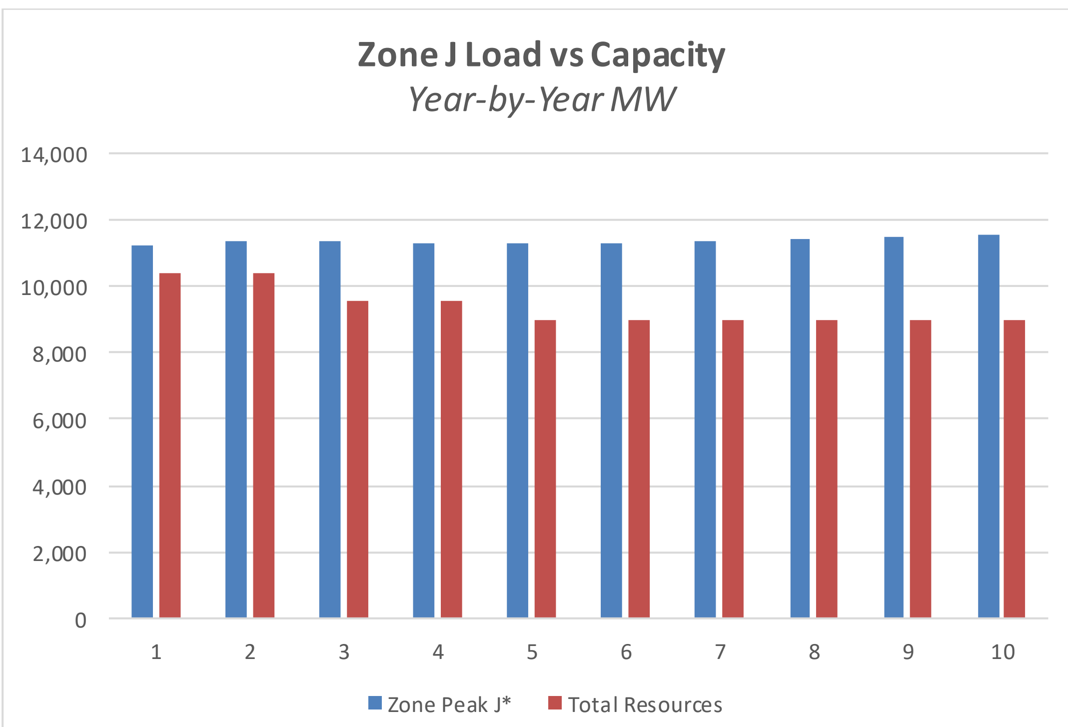
SCRs represent the forecasted MW ICAP value from 2020 Gold Book.

Wind, solar, run-of-river and landfill gas are counted as 100% of nameplate rating.

The following graphs show the load and total capacity information from the table above.

Figure 2: Load and Capacity Year-by-Year MW





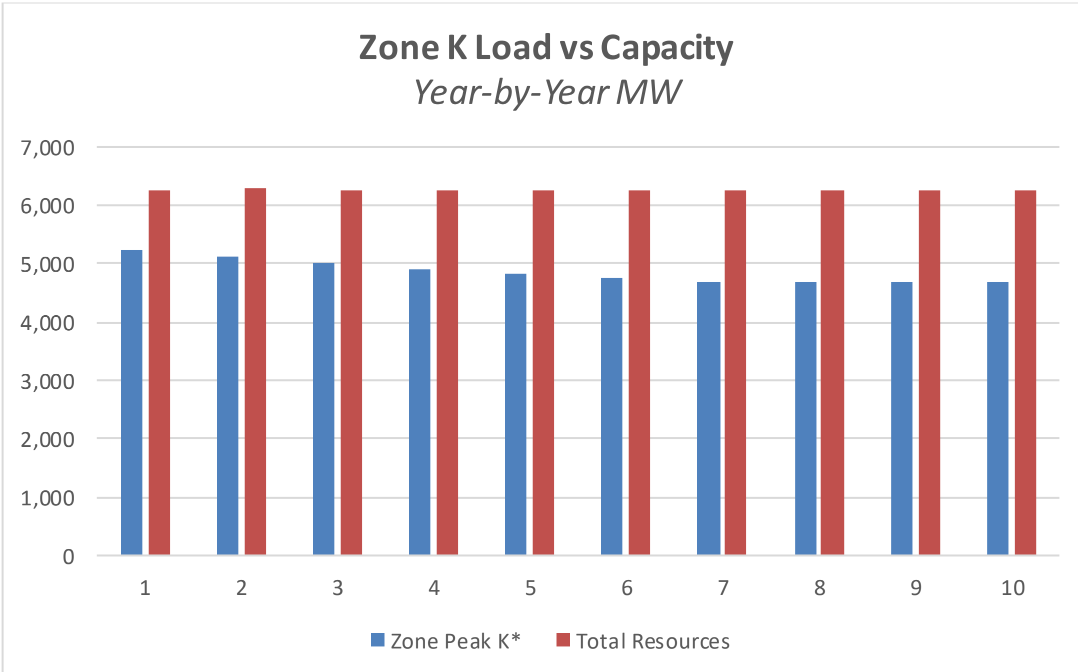


Figure 3: Baseline Peak Demand and Energy Forecasts

Baseline and Adjusted Baseline Energy Updated Forecasts

Annual GWh	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2020 End-Use Energy Forecast - Nov. update	154,860	157,664	159,328	160,833	162,153	163,545	164,704	165,717	166,535	167,116	167,475
-- Energy Efficiency and Codes & Standards	1,885	3,959	6,200	8,599	11,081	13,582	15,937	18,057	19,921	21,563	23,016
-- BTM Solar PV	2,631	3,274	3,899	4,563	5,193	5,738	6,205	6,591	6,893	7,130	7,289
-- BTM Non-Solar Distributed Generation	1,252	1,416	1,059	940	818	852	877	900	931	956	973
+ Storage Net Energy Consumption	19	43	67	99	130	160	189	221	254	281	309
+ Electric Vehicle Energy	199	345	538	781	1,085	1,456	1,889	2,407	3,031	3,765	4,506
+ Non-EV Electrification	190	457	815	1,289	1,884	2,591	3,337	4,163	5,055	5,997	6,988
November 2020 Baseline Forecast Update	149,500	149,860	149,590	148,900	148,160	147,580	147,100	146,960	147,130	147,510	148,000
+ BTM Solar PV	2,631	3,274	3,899	4,563	5,193	5,738	6,205	6,591	6,893	7,130	7,289
2020 RNA Base Case Updated Forecast[1]	152,131	153,134	153,489	153,463	153,353	153,318	153,305	153,551	154,023	154,640	155,289

Baseline and Adjusted Baseline Summer Updated Peak Forecasts

Annual MW	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2020 End-Use Peak Demand Forecast - Nov. update	33,319	33,615	33,962	34,169	34,346	34,621	34,904	35,208	35,501	35,749	35,941
-- Energy Efficiency and Codes & Standards	296	591	943	1,322	1,709	2,108	2,488	2,825	3,116	3,360	3,579
-- BTM Solar PV	555	707	841	986	1,102	1,204	1,287	1,351	1,392	1,411	1,411
-- BTM Non-Solar Distributed Generation	218	251	189	169	148	154	158	164	170	174	177
-- BTM Storage Peak Reductions	5	14	26	44	63	91	125	159	206	250	292
+ Electric Vehicle Peak Demand	40	68	103	147	201	261	333	418	513	625	748
+ Non-EV Electrification	11	25	46	72	104	146	187	230	279	327	379
November 2020 Baseline Forecast[2] Update	32,296	32,145	32,112	31,867	31,629	31,471	31,366	31,357	31,409	31,506	31,609
+ BTM Solar PV	555	707	841	986	1,102	1,204	1,287	1,351	1,392	1,411	1,411
2020 RNA Base Case Updated Forecast[1]	32,851	32,852	32,953	32,853	32,731	32,675	32,653	32,708	32,801	32,917	33,020

Notes:

For the resource adequacy study, the Gold Book baseline load forecast was modified by removing the behind-the-meter solar PV impacts in order to model the solar PV explicitly as a generation resource to account for the intermittent nature of its availability.

The transmission security power flow RNA base cases use this Gold Book baseline forecast.

Figure 4: Planned Additions

Queue #	Project Name	Zone	Point of Interconnection	Summer Peak (MW)	Commercial Operation Date
Proposed Transmission Additions, other than Local Transmission Owner Plans					
N/A*	Leeds-Hurley SDU	F,G	Leeds- Hurley SDU 345kV	n/a	summer 2021
430	Cedar Rapids Transmission Upgrade	D	Dennison - Alcoa 115kV	80	10/2021
Q545A*	Empire State Line	A	Dysinger - Stolle 345kV	n/a	6/2022
556	Segment A Double Circuit	E,F	Edic - New Scotland 345kV	n/a	12/2023
543	Segment B Knickerbocker-Pleasant Valley 345 kV	F,G	Greenbush - Pleasant Valley 345kV	n/a	12/2023
Proposed Generations Additions					
387*	Cassadaga Wind	A	Dunkirk - Moon Station 115 kV	126.5	12/2021
396	Baron Winds	C	Hillside - Meyer 230kV	238.4	12/2021
422	Eight Point Wind Energy Center	B	Bennett 115kV	101.8	12/2021
505	Ball Hill Wind	A	Dunkirk - Gardenville 230kV	100.0	12/2022
546	Roaring Brook Wind	E	Chases Lake Substation 230kV	79.7	12/2021
678	Calverton Solar Energy Center	K	Edwards Substation 138kV	22.9	12/2021
*also included in the 2019-2028 CRP Base Cases			Total MW generation	669	

Figure 5: Assumed Deactivations

2020 Gold Book Table	Owner/ Operator	Plant Name	Zone	CRIS	Assumed Date
Table IV-3: Deactivated Units with Unexpired CRIS Rights Not Listed in Existing Capacity Table III-2	International Paper Company	Ticonderoga (ICAP as SCR)	F	7.6	05/01/2017
	Helix Ravenswood, LLC	Ravenswood 09	J	21.7	11/01/2017
	Binghamton BOP, LLC	Binghamton	C	43.8	01/09/2018
	Helix Ravenswood, LLC	Ravenswood 2-1	J	40.4	04/01/2018
		Ravenswood 2-2	J	37.6	04/01/2018
		Ravenswood 2-3	J	39.2	04/01/2018
		Ravenswood 2-4	J	39.8	04/01/2018
		Ravenswood 3-1	J	40.5	04/01/2018
		Ravenswood 3-2	J	38.1	04/01/2018
		Ravenswood 3-4	J	35.8	04/01/2018
	Cayuga Operating Company, LLC	Cayuga 2	C	154.7	07/01/2018
	Lyonsdale Biomass, LLC	Lyonsdale	E	20.2	07/18/2019
Table IV-4: Deactivated Units Listed in Existing Capacity Table III-2	Exelon Generation Company LLC	Monroe Livingston	B	2.4	09/01/2019
	Innovative Energy Systems, Inc.	Steuben County LF	C	3.2	09/01/2019
	Consolidated Edison Co. of NY, Inc	Hudson Ave 4	J	13.9	09/10/2019
	New York State Elec. & Gas Corp.	Auburn - State St	C	5.8	10/01/2019
	Cayuga Operating Company, LLC	Cayuga 1	C	154.1	11/01/2019
	Consolidated Edison Co. of NY, Inc	Hudson Ave 3	J	16.0	11/01/2019
Table IV-5: Notices of Proposed Deactivations as of March 15, 2020	Albany Energy, LLC	Albany LFGE	F	4.5	09/18/2019
	Somerset Operating Company, LLC	Somerset	A	686.5	02/15/2020
	National Grid	West Babylon 4	K	49.0	12/11/2020
	Entergy Nuclear Power Marketing, LLC	Indian Point 2	H	1,026.5	04/30/2020
		Indian Point 3		1,040.4	04/30/2021

Figure 6: Assumed Generation Status Change due to the DEC's Peaker Rule

2020 Gold Book Table	Owner/ Operator	Plant Name	Zone	CRIS	Assumed Date
Table IV-6: Proposed Staus Change to Comply with DEC Peaker Rule**	Central Hudson Gas & Elec. Corp.	Coxsackie GT	G	19.9	05/01/2023
		South Cairo	G	19.8	05/01/2023
	Consolidated Edison Co. of NY, Inc.	74 St. GT 1 & 2	J	39.1	05/01/2023
		Hudson Ave 5		15.1	05/01/2023
		59 St. GT 1		15.4	05/01/2025
	Helix Ravenswood, LLC	Ravenswood 01	J	8.8	05/01/2023
		Ravenswood 10		21.2	05/01/2023
		Ravenswood 11		20.2	05/01/2023
	National Grid	Glenwood GT 1	K	14.6	05/01/2023
		Northport GT		13.8	05/01/2023
		Port Jefferson GT 01		14.1	05/01/2023
	NRG Power Marketing, LLC	Astoria GT 2-1, 2-2, 2-3, 2-4	J	165.8	05/01/2023
		Astoria GT 3-1, 3-2, 3-3, 3-4		170.7	05/01/2023
		Astoria GT 4-1, 4-2, 4-3, 4-4		167.9	05/01/2023
		Arthur Kill GT1		16.5	05/01/2025
	Astoria Generating Company, L.P.	Gowanus 1-1 through 1-8**	J	138.7	05/01/2023
		Gowanus 4-1 through 4-8**		140.1	05/01/2023
		Astoria GT 01**		15.7	05/01/2025
		Gowanus 2-1 through 2-8**		152.8	05/01/2025
		Gowanus 3-1 through 3-8**		146.8	05/01/2025
		Narrows 1-1 through 2-8**		309.1	05/01/2025
			Total**	1,626	

*Consistent with deactivation dates

** Some of the units will be out of service in the ozone season only

In addition to the projects that met the base case inclusion rules, a number of other projects are progressing through the NYISO's interconnection process. Some of these additional generation resources either have accepted their cost allocation as part of a prior Class Year Facilities Study process, or are included in the Class Year 2021 Facilities Study, or are candidates for future interconnection facilities studies. The most recent list of these projects resides in the 2021 Gold Book.

Figure 7: Firm Transmission Plans included in 2020 RNA Base Case

Transmission Owner	Terminals		Line Length in Miles	In-Service Date/Yr		Nominal Voltage in kV		# of ckts	Thermal Ratings (4)		Project Description / Conductor Size
				Prior to (2)	Year	Operating	Design		Summer	Winter	
2020 Gold Book - Firm Plans (5) (included in FERC 715 Base Case)											
ConEd	Jamaica	Jamaica	Reconfiguration	In-Service	2019	138	138		N/A	N/A	Reconfiguration
ConEd	East 13th Street	East 13th Street	xfmr	In-Service	2019	345	345		N/A	N/A	Replacing xfmr 10 and xfmr 11
ConEd	Gowanus	Gowanus	xfmr	In-Service	2019	345	345		N/A	N/A	Replacing xfmr T2
ConEd	East 13th Street	East 13th Street	Reconfiguration	In-Service	2019	345	345		N/A	N/A	Reconfiguration (xfmr 10 -xfmr 11)
ConEd	Rainey	Corona	xfmr/Phase shifter	In-Service	2019	345/138	345/138	1	268 MVA	320 MVA	xfmr/Phase shifter
LIPA	Far Rockaway	Far Rockaway	Reconfiguration	In-Service	2019	34.5	34.5		N/A	N/A	Reconfigure 34.5 kV switchgear
LIPA	Elwood	Elwood	Breaker	In-Service	2019	138	138		N/A	N/A	Install double bus tie - Operate Normally Open
LIPA	Canal	Southampton	5.20	In-Service	2019	69	69	1	1107	1169	2500 kcmil XLPE CU
LIPA	Deer Park	Deer Park	-	In-Service	2019	69	69	1	N/A	N/A	Install 27 MVAR Cap Bank
LIPA	MacArthur	MacArthur	-	In-Service	2019	69	69	1	N/A	N/A	Install 27 MVAR Cap Bank
LIPA	West Hempstead	East Garden City	-2.92	In-Service	2019	69	69	1	1158	1245	477 ACSS
LIPA	West Hempstead	Hempstead	0.97	In-Service	2019	69	69	1	1158	1245	477 ACSS
LIPA	Hempstead	East Garden City	1.95	In-Service	2019	69	69	1	1158	1245	477 ACSS
LIPA	Pilgrim	West Bus	-11.86	In-Service	2019	138	138	1	2087	2565	2493 ACAR
LIPA	West Bus	Kings	8.25	In-Service	2019	138	138	1	2087	2565	2493 ACAR
LIPA	Pilgrim	Kings	4.81	In-Service	2019	138	138	1	2087	2565	2493 ACAR
NGRID	Golah	Golah	Cap Bank	In-Service	2019	115	115	1	18MVAR	18MVAR	Capacitor Bank
NGRID	Falls Park	Schodack(NG)	17.33	In-Service	2019	115	115	1	186 MVA	227 MVA	Loop for NYSEG Sub Will Reconfigure NG Line #14 Into Two New Lines
NGRID	Falls Park	Churchtown	9.41	In-Service	2019	115	115	1	175 MVA	206 MVA	Loop for NYSEG Sub Will Reconfigure NG Line #14 Into Two New Lines

Transmission Owner	Terminals		Line Length in Miles	In-Service Date/Yr		Nominal Voltage in kV		# of ckts	Thermal Ratings (4)		Project Description / Conductor Size
				Prior to (2)	Year	Operating	Design		Summer	Winter	
2020 Gold Book - Firm Plans (5) (included in FERC 715 Base Case)											
NGRID	Batavia	Batavia	Cap Bank	In-Service	2019	115	115	1	30MVAR	30MVAR	Second Capacitor Bank
NGRID	Battenkill	Eastover Road	-22.72	In-Service	2019	115	115	1	937	1141	New Schaghticoke Switching Station
NGRID	Battenkill	Schaghticoke (New Station)	14.31	In-Service	2019	115	115	1	937	1141	New Schaghticoke Switching Station
NGRID	Schaghticoke (New Station)	Eastover Road	8.41	In-Service	2019	115	115	1	937	1141	New Schaghticoke Switching Station
NGRID	Mohican	Luther Forest	-34.47	In-Service	2019	115	115	1	937	1141	New Schaghticoke Switching Station
NGRID	Mohican	Schaghticoke (New Station)	28.13	In-Service	2019	115	115	1	937	1141	New Schaghticoke Switching Station
NGRID	Ohio St	Ohio St		In-Service	2019	115	115		N/A	N/A	New Distribution Station at Ohio Street
NGRID	Albany Steam	Greenbush	6.14	In-Service	2019	115	115	2	1190	1527	Reconductor Albany - Greenbush 115kV lines 1 & 2
NGRID	Schodack	Churchtown	-26.74	In-Service	2019	115	115	1	937	1141	Line removal tapped by Falls Park Project
NGRID	Sodeman Rd	Sodeman Rd		In-Service	2019	115	115		N/A	N/A	New Distribution Station at Sodeman Road
NGRID	Dewitt	Dewitt		In-Service	2019	115	115		N/A	N/A	New Distribution Station at Dewitt
NGRID	Luther Forest	Schaghticoke (New Station)	6.34	In-Service	2019	115	115	1	1280	1563	New Schaghticoke Switching Station
NGRID	Seneca	Seneca	-	In-Service	2019	115/22	115/22	-	50MVA	50MVA	Damage/Failure on TR2
NGRID	Mortimer	Mortimer	Reconfiguration	In-Service	2019	115	115	1	N/A	N/A	Reconfiguration of Station
NGRID	Mohican	Butler	3.50	S	2019	115	115	1	TBD	TBD	Replace 3.5 miles of conductor w/min 336.4 ACSR
NYSEG	Wood Street	Carmel	1.34	In-Service	2019	115	115	1	261 MVA	261 MVA	477 ACSR
NYSEG	Flat Street	Flat Street	xfmr	In-Service	2019	115/34.5	115/34.5	2	40MVA	45.2MVA	Transformer #2
NYSEG	Falls Park 115/34.5kV Substation			In-Service	2019	115/34.5	115/34.5				Tap to interconnect NG Line #14
NYSEG	Falls Park	Falls Park	xfmr	In-Service	2019	115/34.5	115/34.5	1	62 MVA	70 MVA	Transformer #1

Transmission Owner	Terminals		Line Length in Miles	In-Service Date/Yr		Nominal Voltage in kV		# of ckts	Thermal Ratings (4)		Project Description / Conductor Size
				Prior to (2)	Year	Operating	Design		Summer	Winter	
2020 Gold Book - Firm Plans (5) (included in FERC 715 Base Case)											
RGE	Station 42	Station 23	Phase Shifter	In-Service	2019	115	115	1	253 MVA	253 MVA	Phase Shifter
RGE	Station 23	Station 23	xfmr	In-Service	2019	115/11.5/11.5	115/11.5/11.5	2	75 MVA	84 MVA	Transformer
RGE	Station 23	Station 23	xfmr	W	2019	115/34.5	115/34.5	2	75 MVA	84 MVA	Transformer
CHGE	North Chelsea	North Chelsea	xfmr	S	2020	115/69	115/69	1	564	728	Replace Transformer 1
CHGE	Fishkill Plains	East Fishkill	2.05	S	2020	115	115	1	995	1218	1-1033.5 ACSR
CHGE	North Catskill	North Catskill	xfmr	W	2020	115/69	115/69	2	560	726	Replace Transformer 4 & 5
ConEd	Buchanan North	Buchanan North	Reconfiguration	S	2020	345	345		N/A	N/A	Reconfiguration (bus work related to decommissioning of Indain Point 2)
LIPA	Meadowbrook	East Garden City	-3.11	S	2020	69	69	1	458	601	4/0 CU
LIPA	East Garden City	Lindbergh	2.50	S	2020	69	69	1	575	601	750 kcmil CU
LIPA	Lindbergh	Meadowbrook	2.11	S	2020	69	69	1	458	601	4/0 CU
LIPA	Elmont	Floral Park	-1.59	S	2020	34.5	34.5	1	644	816	477 AL
LIPA	Elmont	Belmont	1.82	S	2020	34.5	34.5	1	342	457	2/0 CU
LIPA	Belmont	Floral Park	2.04	S	2020	34.5	34.5	1	644	816	477 AL
NGRID	Rosa Rd	Rosa Rd	-	S	2020	115	115		N/A	N/A	Install 35.2MVAR Cap Bank at Rosa Rd
NGRID	Rotterdam	Curry Rd	7	S	2020	115	115	1	808	856	Replace 7.0 miles of mainly 4/0 Cu conductor with 795kcmil ACSR 26/7
NGRID	Elm St	Elm St	xfmr	S	2020	230/23	230/23	1	118MVA	133MVA	Add a fourth 230/23kV transformer
NGRID	West Ashville	West Ashville		S	2020	115	115		N/A	N/A	New Distribution Station at West Ashville
NGRID	Spier	Rotterdam (#2)	-32.74	S	2020	115	115	1	1168	1416	New Lasher Rd Switching Station
NGRID	Spier	Lasher Rd (New Station) (#2)	21.69	S	2020	115	115	1	1168	1416	New Lasher Rd Switching Station

Transmission Owner	Terminals		Line Length in Miles	In-Service Date/Yr		Nominal Voltage in kV		# of ckts	Thermal Ratings (4)		Project Description / Conductor Size
				Prior to (2)	Year	Operating	Design		Summer	Winter	
2020 Gold Book - Firm Plans (5) (included in FERC 715 Base Case)											
NGRID	Lasher Rd (New Station)	Rotterdam	11.05	S	2020	115	115	1	2080	2392	New Lasher Rd Switching Station
NGRID	Spier	Luther Forest (#302)	-34.21	S	2020	115	115	1	916	1070	New Lasher Rd Switching Station
NGRID	Spier	Lasher Rd (New Station) (#302)	21.72	S	2020	115	115	1	916	1118	New Lasher Rd Switching Station
NGRID	Lasher Rd (New Station)	Luther Forest	12.49	S	2020	115	115	1	990	1070	New Lasher Rd Switching Station
NGRID	Rotterdam	Rotterdam	-	S	2020	115	115	2	N/A	N/A	Install Series Reactors at Rotterdam Station on lines 17 & 19
NGRID	Huntley	Lockport	6.9	S	2020	115	115	2	1303	1380	Replace 6.9 miles of 36 and 37 lines
NGRID	Two Mile Creek	Two Mile Creek		S	2020	115	115		N/A	N/A	New Distribution Station at Two Mile Creek
NGRID	Maple Ave	Maple Ave		S	2020	115	115		N/A	N/A	New Distribution Station at Maple Ave
NGRID	Randall Rd	Randall Rd		S	2020	115	115		N/A	N/A	New Distribution Station at Randall Road
NGRID	GE	Geres Lock	7.14	S	2020	115	115	1	785	955	Reconductoring 4/0CU & 336 ACSR to 477 ACCR (Line #8)
NGRID	Gardenville 115kV	Gardenville 115kV	-	S	2020	-	-	-	-	-	Rebuild of Gardenville 115kV Station to full breaker and a half
NGRID	Rotterdam	Woodlawn	7	S	2020	115	115	1			Replace 7.0 miles of mainly 4/0 Cu conductor with 795kcmil ACSR 26/7
NGRID	Gardenville 230kV	Gardenville 115kV	xfmr	S	2020	230/115	230/115	-	347 MVA	422 MVA	Replacement of 230/115kV TB#4 stepdown with larger unit
NGRID	Oswego	Oswego	-	W	2020	115	115		N/A	N/A	Rebuild of Oswego 115kV Station
NYPA	Fraser Annex	Fraser Annex	SSR Detection	S	2020	345	345	1	1793 MVA	1793 MVA	MSSC SSR Detection Project
NYPA	Niagara	Rochester	-70.20	W	2020	345	345	1	2177	2662	2-795 ACSR
NYPA	Somerset	Rochester	-44.00	W	2020	345	345	1	2177	2662	2-795 ACSR
NYPA	Niagara	Station 255 (New Station)	66.40	W	2020	345	345	1	2177	2662	2-795 ACSR
NYPA	Somerset	Station 255 (New Station)	40.20	W	2020	345	345	1	2177	2662	2-795 ACSR
NYPA	Station 255 (New Station)	Rochester	3.80	W	2020	345	345	2	2177	2662	2-795 ACSR

Transmission Owner	Terminals		Line Length in Miles	In-Service Date/Yr		Nominal Voltage in kV		# of ckts	Thermal Ratings (4)		Project Description / Conductor Size
				Prior to (2)	Year	Operating	Design		Summer	Winter	
2020 Gold Book - Firm Plans (5) (included in FERC 715 Base Case)											
NYPA	Niagara 230 kV	Niagara 230 kV	Breaker	W	2020	230	230	1	N/A	N/A	Add a new breaker
NYPA	Niagara 230 kV	Niagara 115 kV	Autotransformer	S	2020	230	115	1	240 MVA	240 MVA	Replace Niagara AT #1
NYPA	Astoria 138 kV	Astoria 13.8 kV	Astoria CC GSU Refurbishment	W	2020	138	18	1	234	234	Astoria CC GSU Refurbishment
NYSEG	Watercure Road	Watercure Road	xfmr	W	2020	345/230	345/230	1	426 MVA	494 MVA	Transformer #2 and Station Reconfiguration
NYSEG	Willet	Willet	xfmr	W	2020	115/34.5	115/34.5	1	39 MVA	44 MVA	Transformer #2
NYSEG	Coddington	E. Ithaca (to Coddington)	8.07	W	2020	115	115	1	307 MVA	307 MVA	665 ACCR
O & R	West Nyack	West Nyack	Cap Bank	S	2020	138	138	1	-	-	Capacitor Bank
O & R	Harings Corner (RECO)	Closter (RECO)	3.20	S	2020	69	69	1	1098	1312	UG Cable
O & R	Ramapo	Ramapo	xfmr	S	2020	345/138	345/138	1	731	731	-
RGE	Station 122-Pannell-PC1	Station 122-Pannell-PC1 and PC2		S	2020	345	345	1	1314 MVA-LTE	1314 MVA-LTE	Relay Replacement
RGE	Station 262	Station 23	1.46	W	2020	115	115	1	2008	2008	Underground Cable
RGE	Station 33	Station 262	2.97	W	2020	115	115	1	2008	2008	Underground Cable
RGE	Station 262	Station 262	xfmr	W	2020	115/34.5	115/34.5	1	58.8MVA	58.8MVA	Transformer
RGE	Station 255 (New Station)	Rochester	3.80	W	2020	345	345	1	2177	2662	2-795 ACSR
RGE	Station 255 (New Station)	Station 255 (New Station)	xfmr	W	2020	345/115	345/115	1	400 MVA	450 MVA	Transformer
RGE	Station 255 (New Station)	Station 255 (New Station)	xfmr	W	2020	345/115	345/115	2	400 MVA	450 MVA	Transformer
RGE	Station 255 (New Station)	Station 418	9.60	W	2020	115	115	1	1506	1807	New 115kV Line
RGE	Station 255 (New Station)	Station 23	11.10	W	2020	115	115	1	1506	1807	New 115kV Line
CHGE	Hurley Avenue	Leeds	Static synchronous series compensator	S	2021	345	345	1	2336	2866	21% Compensation
LIPA	Valley Stream	East Garden City	7.36	S	2021	138	138	1	1171	1171	2000 SQMM XLPE

Transmission Owner	Terminals		Line Length in Miles	In-Service Date/Yr		Nominal Voltage in kV		# of ckts	Thermal Ratings (4)		Project Description / Conductor Size
				Prior to (2)	Year	Operating	Design		Summer	Winter	
2020 Gold Book - Firm Plans (5) (included in FERC 715 Base Case)											
LIPA	Amagansett	Montauk	-13.00	S	2021	23	23	1	577	657	750 kcmil CU
LIPA	Amagansett	Navy Road	12.74	S	2021	23	23	1	577	657	750 kcmil CU
LIPA	Navy Road	Montauk	0.26	S	2021	23	23	1	577	657	750 kcmil CU
LIPA	Riverhead	Wildwood	10.63	S	2021	138	138	1	1399	1709	1192ACSR
LIPA	Riverhead	Canal	16.49	S	2021	138	138	1	1000	1110	2368 KCMIL (1200 mm^2) Copper XLPE
NGRID	Clay	Dewitt	10.24	S	2021	115	115	1	220MVA	268MVA	Reconductor 4/0 CU to 795ACSR
NGRID	Clay	Teall	12.75	S	2021	115	115	1	220 MVA	268MVA	Reconductor 4/0 CU to 795ACSR
NGRID	Gardenville 230kV	Gardenville 115kV	xfmr	S	2021	230/115	230/115	-	347 MVA	422 MVA	Replacement of 230/115kV TB#3 stepdown with larger unit
NGRID	Huntley 115kV	Huntley 115kV	-	S	2021	230	230	-	N/A	N/A	Rebuild of Huntley 115kV Station
NGRID	Mortimer	Mortimer	xfmr	S	2021	115	115		50MVA	50MVA	Replace Mortimer 115/69kV Transformer
NGRID	Mortimer	Mortimer	-	S	2021	115	115		N/A	N/A	Second 115kV Bus Tie Breaker at Mortimer Station
NGRID	New Bethlehem	New Bethlehem	-	S	2021	115	115		N/A	N/A	New Bethlehem 115/13.2kV station
NGRID	New Cicero	New Cicero		S	2021	115	115		N/A	N/A	New Distribution Station at New Cicero
NGRID	Mountain	Lockport	0.08	S	2021	115	115	2	174MVA	199MVA	Mountain-Lockport 103/104 Bypass
NGRID	Royal Ave	Royal Ave	-	S	2021	115/13.2	115/13.2	-	-	-	Install new 115-13.2 kV distribution substation in Niagara Falls (Royal Ave)
NGRID	Niagara	Packard	3.4	W	2021	115	115	1	344MVA	449MVA	Replace 3.4 miles of 192 line
NYPA	Moses 230 kV	Adirondack 230 kV	Series Compensation	S	2021	230	230	-	±13.2kV	±13.2kV	Voltage Source Series Compensation
NYPA	St. Lawrence 230kV	St. Lawrence 115kV	xfmr	S	2021	230/115	230/115	1	TBD	TBD	Replacement of St. Lawrence AutoTransformer #2
NYPA	Plattsburg 230 kV	Plattsburg 115 kV	xfmr	W	2021	230/115	230/115	1	249	288	Refurbishment of Plattsburgh Auto Transformer #1

Transmission Owner	Terminals		Line Length in Miles	In-Service Date/Yr		Nominal Voltage in kV		# of ckts	Thermal Ratings (4)		Project Description / Conductor Size
				Prior to (2)	Year	Operating	Design		Summer	Winter	
2020 Gold Book - Firm Plans (5) (included in FERC 715 Base Case)											
NYPA	Astoria Annex	Astoria Annex	Shunt Reactor	W	2021	345	345	2	TBD	TBD	
O & R	Lovett 345 kV Station (New Station)	Lovett	xfmr	S	2021	345/138	345/138	1	562 MVA	562 MVA	Transformer
O & R	Little Tor	-	Cap Bank	S	2021	138	138	1	32 MVAR	32 MVAR	Capacitor bank
O & R	Deerpak	Port Jervis	2	S	2021	69	69	1		1604	
O & R	Westtown	Port Jervis	7	S	2021	69	69	1		1604	
O & R/ConEd	Ladentown	Buchanan	-9.5	S	2021	345	345	1	3000	3211	2-2493 ACAR
O & R/ConEd	Ladentown	Lovett 345 kV Station (New Station)	5.5	S	2021	345	345	1	3000	3211	2-2493 ACAR
O & R/ConEd	Lovett 345 kV Station (New Station)	Buchanan	4	S	2021	345	345	1	3000	3211	2-2493 ACAR
CHGE	St. Pool	High Falls	5.61	W	2022	115	115	1	1010	1245	1-795 ACSR
CHGE	High Falls	Kerhonkson	10.03	W	2022	115	115	1	1010	1245	1-795 ACSR
CHGE	Modena	Galeville	4.62	W	2022	115	115	1	1010	1245	1-795 ACSR
CHGE	Galeville	Kerhonkson	8.96	W	2022	115	115	1	1010	1245	1-795 ACSR
CHGE	Hurley Ave	Saugerties	11.40	W	2022	69	115	1	1114	1359	1-795 ACSR
CHGE	Kerhonkson	Kerhonkson	xfmr	W	2022	115/69	115/69	1	564	728	Add Transformer 3
CHGE	Kerhonkson	Kerhonkson	xfmr	W	2022	115/69	115/69	1	564	728	Add Transformer 4
CHGE	Rock Tavern	Sugarloaf	12.10	W	2022	115	115	1	N/A	N/A	Retire SL Line
CHGE	Sugarloaf	NY/NJ State Line	10.30	W	2022	115	115	2	N/A	N/A	Retire SD/SJ Lines
NGRID	South Oswego	Indeck (#6)	-	S	2022	115	115	1	-	-	Install High Speed Clearing on Line #6
NGRID	Porter	Porter	-	S	2022	230	230		N/A	N/A	Porter 230kV upgrades
NGRID	Watertown	Watertown		S	2022	115	115		N/A	N/A	New Distribution Station at Watertown

Transmission Owner	Terminals		Line Length in Miles	In-Service Date/Yr		Nominal Voltage in kV		# of ckts	Thermal Ratings (4)		Project Description / Conductor Size
				Prior to (2)	Year	Operating	Design		Summer	Winter	
2020 Gold Book - Firm Plans (5) (included in FERC 715 Base Case)											
NGRID	Golah	Golah	xfmr	S	2022	69	69		50MVA	50MVA	Replace Golah 69/34.5kV Transformer
NGRID	Niagara	Packard	3.7	S	2022	115	115	1	344MVA	449MVA	Replace 3.7 miles of 191 line
NGRID	Lockport	Mortimer	56.5	S	2022	115	115	3	-	-	Replace Cables Lockport-Mortimer #111, 113, 114
NGRID	Niagara	Packard	3.7	W	2022	115	115	2	344MVA	449MVA	Replace 3.7 miles of 193 and 194 lines
NGRID	Gardenville	Big Tree	6.3	W	2022	115	115	1	221MVA	221MVA	Gardenville-Arcade #151 Loop-in-and-out of NYSEG Big Tree
NGRID	Big Tree	Arcade	28.6	W	2022	115	115	1	129MVA	156MVA	Gardenville-Arcade #151 Loop-in-and-out of NYSEG Big Tree
NGRID	Coffeen	Coffeen	-	S	2022	115	115	-	TBD	TBD	Terminal equipment replacements
NGRID	Browns Falls	Browns Falls	-	S	2022	115	115	-	TBD	TBD	Terminal equipment replacements
NGRID	Taylorville	Taylorville	-	S	2022	115	115	-	TBD	TBD	Terminal equipment replacements
NYPA	Niagara 345 kV	Niagara 230 kV	xfmr	W	2022	345/230	345/230	1	TBD	TBD	Replacement of Niagara AutoTransformer #3
NYSEG	South Perry	South Perry	xfmr	W	2022	115/34.5	115/34.5	1	59 MVA	67 MVA	Transformer #3
NYSEG	South Perry	South Perry	xfmr	W	2022	230/115	230/115	1	246 MVA	291 MVA	Transformer
NYSEG	Fraser	Fraser	xfmr	W	2022	345/115	345/115	1	305 MVA	364 MVA	Transformer #2 and Station Reconfiguration
NYSEG	Fraser 115	Fraser 115	Rebuild	W	2022	115	115		N/A	N/A	Station Rebuild to 4 bay BAAH
NYSEG	Delhi	Delhi	Removal	W	2022	115	115		N/A	N/A	Remove 115 substation and terminate existing lines to Fraser 115 (short distance)
NYSEG	Erie Street Rebuild	Erie Street Rebuild	Rebuild	W	2022	115	115				Station Rebuild
NYSEG	Big Tree Road	Big Tree Road	Rebuild	W	2022	115	115				Station Rebuild
NYSEG	Meyer	Meyer	xfmr	W	2022	115/34.5	115/34.5	2	59.2MVA	66.9MVA	Transformer #2
O & R	Ramapo (NY)	South Mahwah (RECO)	5.50	W	2022	138	138	2	1980	2120	1272 ACSS
RGE	Station 168	Mortimer (NG Trunk #2)	26.4	W	2022	115	115	1	145 MVA	176 MVA	Station 168 Reinforcement Project

Transmission Owner	Terminals		Line Length in Miles	In-Service Date/Yr		Nominal Voltage in kV		# of ckts	Thermal Ratings (4)		Project Description / Conductor Size
				Prior to (2)	Year	Operating	Design		Summer	Winter	
2020 Gold Book - Firm Plans (5) (included in FERC 715 Base Case)											
RGE	Station 168	Elbridge (NG Trunk # 6)	45.5	W	2022	115	115	1	145 MVA	176 MVA	Station 168 Reinforcement Project
RGE	Station 127	Station 127	xfmr	W	2022	115/34.5	115/34.5	1	75MVA	75MVA	Transformer #2
CHGE	Saugerties	North Catskill	12.46	W	2023	69	115	1	1114	1359	1-795 ACSR
NGRID	Cortland	Clarks Corners	0.2	S	2023	115	115	1	147MVA	170MVA	Replace 0.2 miles of 1(716) line and series equipment
NGRID	Maplewood	Menands	3	S	2023	115	115	1	220 MVA	239 MVA	Reconductor approx 3 miles of 115kV Maplewood – Menands #19
NGRID	Maplewood	Reynolds	3	S	2023	115	115	1	217 MVA	265 MVA	Reconductor approx 3 miles of 115kV Maplewood – Reynolds Road #31
NGRID	Elm St	Elm St	-	S	2023	230/23	230/23	-	118MVA	133MVA	Replace TR2 as failure
NGRID	Packard	Huntley	9.1	W	2023	115	115	1	262MVA	275MVA	Walck-Huntley #133, Packard-Huntley #130 Reconductor
NGRID	Walck	Huntley	9.1	W	2023	115	115	1	262MVA	275MVA	Walck-Huntley #133, Packard-Huntley #130 Reconductor
NGRID	Kensington Terminal	Kensington Terminal	-	W	2023	115/23	115/23	-	50MVA	50MVA	Replace TR4 and TR5
NGRID	Malone	Malone	-	S	2023	115	115	-	TBD	TBD	Station Rebuild
NGRID	Taylorville	Boonville	-	S	2023	115	115	-	TBD	TBD	Install series reactors on the 5 and 6 lines. Size TBD
NYPA	Moses	Adirondack	78	S	2023	230	345	2	1088	1329	Replace 78 miles of both Moses-Adirondack 1&2
NYPA	Niagara 345 kV	Niagara 230 kV	xfmr	W	2023	345/230	345/230	1	TBD	TBD	Replacement of Niagara AutoTransformer #5
NYSEG	Gardenville	Gardenville	xfmr	W	2023	230/115	230/115	1	316 MVA	370 MVA	NYSEG Transformer #3 and Station Reconfiguration
NYSEG	Wood Street	Wood Street	xfmr	W	2023	345/115	345/115	1	327 MVA	378 MVA	Transformer #3
O & R	Burns	West Nyack	5.00	S	2023	138	138	1	940	940	UG Cable
O & R	Shoemaker	Pocatello	2.00	W	2023	69	69	1	1604	1723	795 ACSS
O & R	Sugarloaf	Shoemaker	12.00	W	2023	69	138	2	1062	1141	397 ACSS
ConEd	Hudson Ave East	New Vinegar Hill Distribution Switching Station	xfmrs/PARs/Feeders	S	2024	138/27	138/27		N/A	N/A	New Hudson Ave Distribution Switching Station

Transmission Owner	Terminals		Line Length in Miles	In-Service Date/Yr		Nominal Voltage in kV		# of ckts	Thermal Ratings (4)		Project Description / Conductor Size
				Prior to (2)	Year	Operating	Design		Summer	Winter	
2020 Gold Book - Firm Plans (5) (included in FERC 715 Base Case)											
ConEd	Farragut	Farragut	Reconfiguration	S	2024	138	138		N/A	N/A	Install PASS Breaker
NGRID	Dunkirk	Laona	-	S	2024	115	115	2	N/A	N/A	Remove series reactors from New Road Switch Station and install new to Moons Switch Station
NGRID	Laona	Moons	-	S	2024	115	115	2	N/A	N/A	Remove series reactors from New Road Switch Station and install new to Moons Switch Station
NGRID	Golah	Golah	Reconfiguration	S	2024	115	115		-	-	Add a Golah 115kV bus tie breaker
NGRID	Dunkirk	Dunkirk	-	S	2024	115	115		N/A	N/A	Rebuild of Dunkirk 115kV Station
NGRID	Gardenville	Dunkirk	20.5	S	2024	115	115	2	1105	1346	Replace 20.5 miles of 141 and 142 lines
NGRID	Homer Hill	Homer Hill	-	S	2024	115	115	-	116MVA	141MVA	Homer Hill Replace five OCB
NGRID	Inghams	Saint Johnsville	2.94	W	2024	115	115	1	1114	1359	Reconductor 2.94mi of 2/0 + 4/0 Cu (of 7.11mi total) to 795 ACSR
NGRID	Inghams 115kV	Inghams 115kV	Breaker	W	2024	115	115	-	2000	2000	Add series breaker to Inghams R15 (Inghams - Meco #15 115kV)
NGRID	Schenectady International	Rotterdam	0.93	W	2024	69	115	1	1114	1359	Reconductor 0.93mi of 4/0 Cu + 336.4 ACSR (of 21.08mi total) to 795 ACSR
NGRID	Rotterdam	Schoharie	0.93	W	2024	69	115	1	1114	1359	Reconductor 0.93mi of 4/0 Cu (of 21.08mi total) to 795 ACSR
NYSEG	Westover 115	Westover	Removal	W	2024	115	115		N/A	N/A	Remove 115 substation and terminate existing lines to Oakdale 115 (short distance)
O & R	Montvale (RECO)	-	Cap Bank	S	2024	69	69	1	32 MVAR	32 MVAR	Capacitor bank
O & R	Ramapo	Sugarloaf	17.00	W	2024	138	138	1	1980	2120	1272 ACSS
O & R	Burns	Corporate Drive	5.00	W	2024	138	138	1	1980	2120	1272 ACSS
RGE	Station 418	Station 48	7.6	W	2024	115	115	1	175 MVA	225 MVA	New 115kV Line
RGE	Station 82	Station 251 (Upgrade Line #902)		W	2024	115	115	1	400MVA	400MVA	Line Upgrade
RGE	Mortimer	Station 251 (Upgrade Line #901)	1.00	W	2024	115	115	1	400MVA	400MVA	Line Upgrade
NGRID	Stoner	Rotterdam	9.81	W	2025	115	115	1	1398	1708	Reconductor 9.81mi of 4/0 Cu + 336.4 ACSR (of 23.12mi total) to 1192.5 ACSR

Transmission Owner	Terminals		Line Length in Miles	In-Service Date/Yr		Nominal Voltage in kV		# of ckts	Thermal Ratings (4)		Project Description / Conductor Size
				Prior to (2)	Year	Operating	Design		Summer	Winter	
2020 Gold Book - Firm Plans (5) (included in FERC 715 Base Case)											
NGRID	Meco	Rotterdam	9.81	W	2025	115	115	1	1398	1708	Reconductor 9.96mi of 4/0 Cu + 336.4 ACSR (of 30.79mi total) to 1192.5 ACSR
NGRID	Niagara	Gardenville	26.3	S	2026	115	115	1	275MVA	350MVA	Packard-Erie / Niagara-Garenville Reconfiguration
NGRID	Packard	Gardenville	28.2	S	2026	115	115	2	168MVA	211 MVA	Packard-Gardenville Reactors, Packard-Erie / Niagara-Garenville Reconfiguration
NGRID	Mortimer	Pannell	15.7	S	2026	115	115	2	221MVA	270MVA	
NGRID/NYSEG	Erie St	Gardenville	5.5	S	2026	115	115	1	139MVA	179MVA	Packard-Erie / Niagara-Garenville Reconfiguration, Gardenville add breakers
O & R	West Nyack	West Nyack	-	S	2026	138	138	1			Station Reconfiguration
O & R	West Nyack (NY)	Harings Corner (RECO)	7.00	W	2026	69	138	1	1604	1723	795 ACSS

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Appendix C – Resource Adequacy Models and Analysis

Modeling Background

The NYISO conducts its resource adequacy analysis using the GE-MARS software package, which performs probabilistic simulations of outages of capacity and select transmission resources. The program employs a sequential Monte Carlo simulation method and calculates expected values of reliability indices such as LOLE (days/year) and includes load, generation, and transmission representation. Additional modeling details and links to various stakeholders' presentations are in the assumption's matrix, below. In determining the reliability of a system, there are several types of randomly occurring events that are taken into consideration. Among these are the forced outages of generation and transmission, and deviations from the forecasted loads.

Generation Model

The NYISO models the generation system in GE-MARS using several types of units. Thermal units considerations include: random forced outages as determined by Generator Availability Data System (GADS) — calculated EFORd and the Monte Carlo draw, scheduled and unplanned maintenance, and thermal derates. Renewable resource units (*i.e.,* solar PV, wind, run-of-river hydro, and landfill gas) are modeled using five years of historical production data. Co-generation units are also modeled using a capacity and load profile for each unit.

Load Model

The load model in the NYISO GE-MARS model consists of historical load shapes and load forecast uncertainty (LFU). The NYISO uses three historical load shapes in the GE-MARS model (2002, 2006 and 2007) in seven different load levels using a normal distribution. LFU is applied to every hour of these historical shapes and each of the seven load levels are run through the GE-MARS model.

External Areas Model

The NYISO models the four external Control Areas interconnected to the NYCA: (ISO-New England, PJM, Ontario, and Quebec). The transfer limits between the NYCA and the external areas are set in collaboration with the NPCC CP-8 Working Group and are shown in the MARS Topology **Figure 20**. Additionally, the probabilistic model used in the 2020 RNA to assess resource adequacy employs a number of methods aimed at preventing overreliance on support from the external systems. These include imposing a limit of 3,500 MW to the total emergency assistance from all neighbors, modeling simultaneous peak days, and modeling the long-term purchases and sales with neighboring control areas.

MARS Topology

The NYISO models the amount of power that could be transferred across the system in GE-MARS using interface transfer limits applied to the connections between the GE-MARS areas[3] ("bubble-and-pipe" model).

Impacts of the Post-RNA (CRP) Changes

The impacts of the changes from the final RNA MARS base case to the CRP MARS base case are described below:

- An updated load forecast was modeled in the MARS Base Cases. This change decreased the NYCA LOLE, mainly due to the decrease in the load forecast in Zone J.

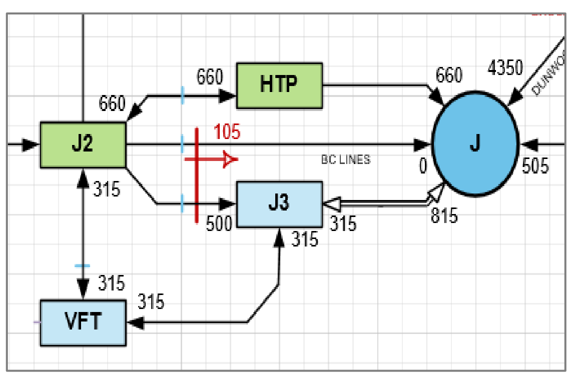
Below are the updated end-use energy and peak demand forecasts (along with the resulting final baseline forecasts). There were no updates to any other forecast components.

- The Con Edison series reactors status change impacts on the MARS topology are described below. The impacts are throughout the entire RNA Study Period (2024-2030):
    - Zone G to H (UPNY-Con Ed interface) limit decreased by 750 MW (to 6,625 MW)
    - Zone I to J (Dunwoodie South interface, and its grouping) limit increased by 50 MW (to 4,400 MW)
- Con Edison's proposed Goethals — Fox Hills 138 kV feeder unbottles Staten Island capacity and is reflected in the MARS topology as an increase in the corresponding dynamic limits table, as well as below.

Figure 8: Staten Island Dynamic Limits Changes

Final RNA: Staten Island Import Limits, Arthur Kill and Linden CoGen Units

Unit Availability				J_to_J3	
AK02	AK03	LINCOG1	LINCOG2	Fwd	Rev
A	A	A	A	315	**200**
U	A	A	A	315	**500**
A	U	A	A	315	**700**
A	A	U	A	315	**500**
A	A	A	U	315	**500**
Otherwise				315	815



[3] No generation pockets in Zone J and Zone K are modeled in detail in MARS.

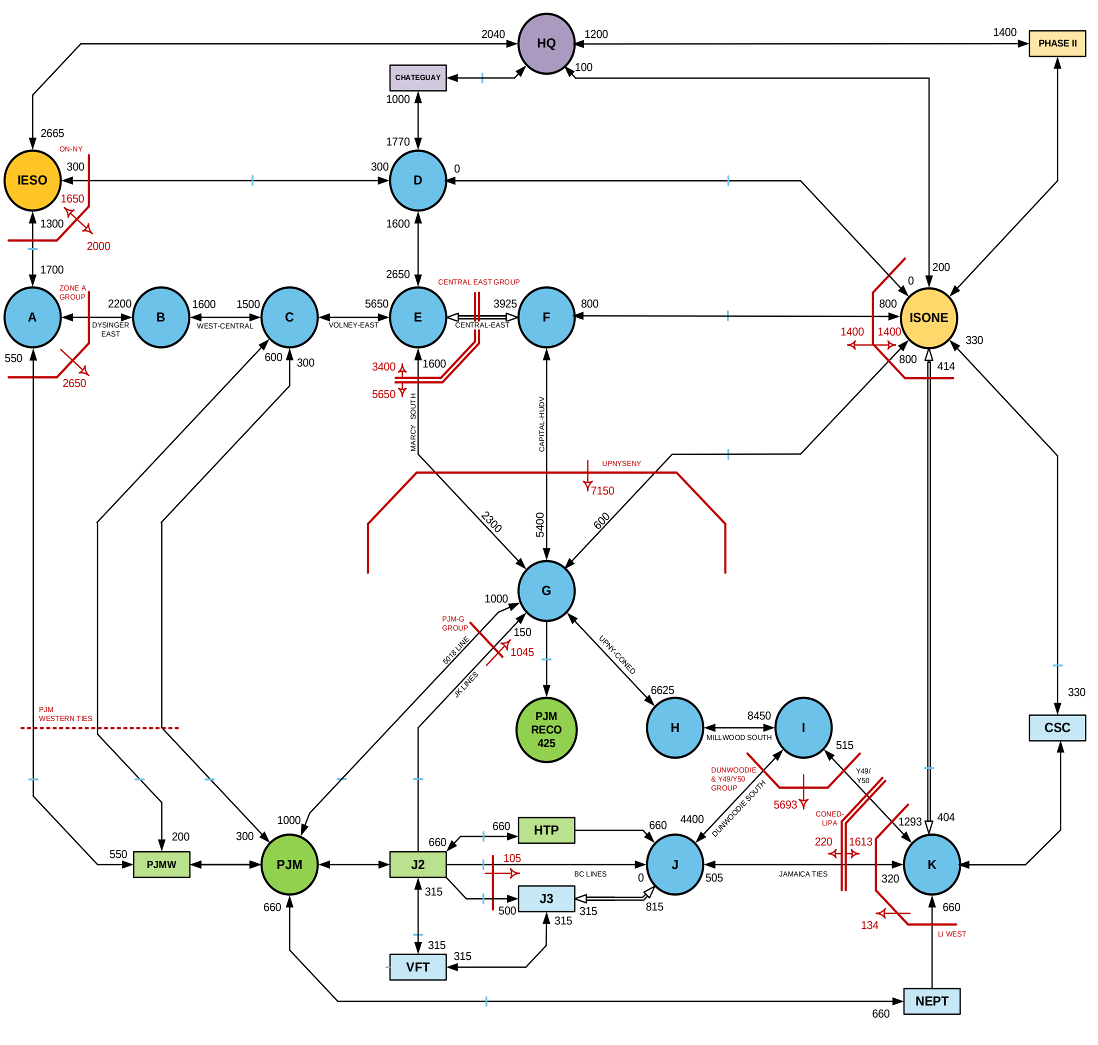
CRP updates, 2025 through 2030					

Staten Island Import Limits, Arthur Kill and Linden CoGen Units

				J_to_J3	
AK02	AK03	LINCOG1	LINCOG2	Fwd	Rev
A	A	A	A	315	**425**
U	A	A	A	315	**700**
A	A	U	A	315	**750**
A	A	A	U	315	**750**
Otherwise				315	815

The updated CRP MARS topology is below.

CRP MARS Topology Study Years 4-10 (2024-2030)



Notes

1. PJM to NY emergency assistance (EA) assumption for calculating the PJM-NY Western ties, PJM-G Group, and ABC Line Group flow distribution limit: 1500MW
2. NYCA EA simultaneous import limit: 3,500 MW
3. External areas representation based upon information received from the NPCC CP-8 WG

Legend

- Interface
- Unidirectional Interface
- Interface w/ Dynamic Ratings
- Interface Group
- Interface Group w/ Dynamic Ratings
- Monitoring Interface Group
- NYCA EA Interface Group Marker
- XX "Dummy Bubble" i.e. no load

NOTE: An interface is considered to not have a MW limitation if no number is specified

Topology for CRP Base Case with 'Post-2020 RNA' updates: Study Years 2024-2030
Dynamic Limits and Groupings Information

Interface Group	Limit	Flow Equation
LI_WEST	134	(K to I&J) - 0.13*(K_NEPT)

Central East Voltage Limits, Oswego Complex Units

Depends On:	9MILP1, 9MILP2, FPNUC1, STHIND, OS05, OS06			
Units	E_to_F		E_to_FG	
Available	Fwd	Rev	Fwd	Rev
6	3925	1999	5650	3400
5	3875	1999	5575	3400
4	3815	1999	5490	3400
3	3710	1999	5335	3400
2	3595	1999	5160	3400
Otherwise	3470	1999	4960	3400

Staten Island Import Limits, AK and Linden CoGen Units

Unit Availability				J_to_J3	
AK02	AK03	LINCOG1	LINCOG2	Fwd	Rev
A	A	A	A	315	425
U	A	A	A	315	700
A	A	U	A	315	750
A	A	A	U	315	750
Otherwise				315	815

Notes:
AK03 outage in 2025 table is captured in "Otherwise"
J to J3 Rev reflects impacts from A new 345/138 kV PAR controlled Goethals – Fox Hills feeder (summer 2025):

Depends On:	NPRTS1-4	
Units	LI_NE	
Available	Norwalk to K	K to Norwalk
4	260	414
Otherwise	404	414

Depends On:	Barrett1 and 2	
Units	ConEd-LIPA	
Available	IJ to K	K to IJ
2	1613	220
1	1613	200
0	1613	130

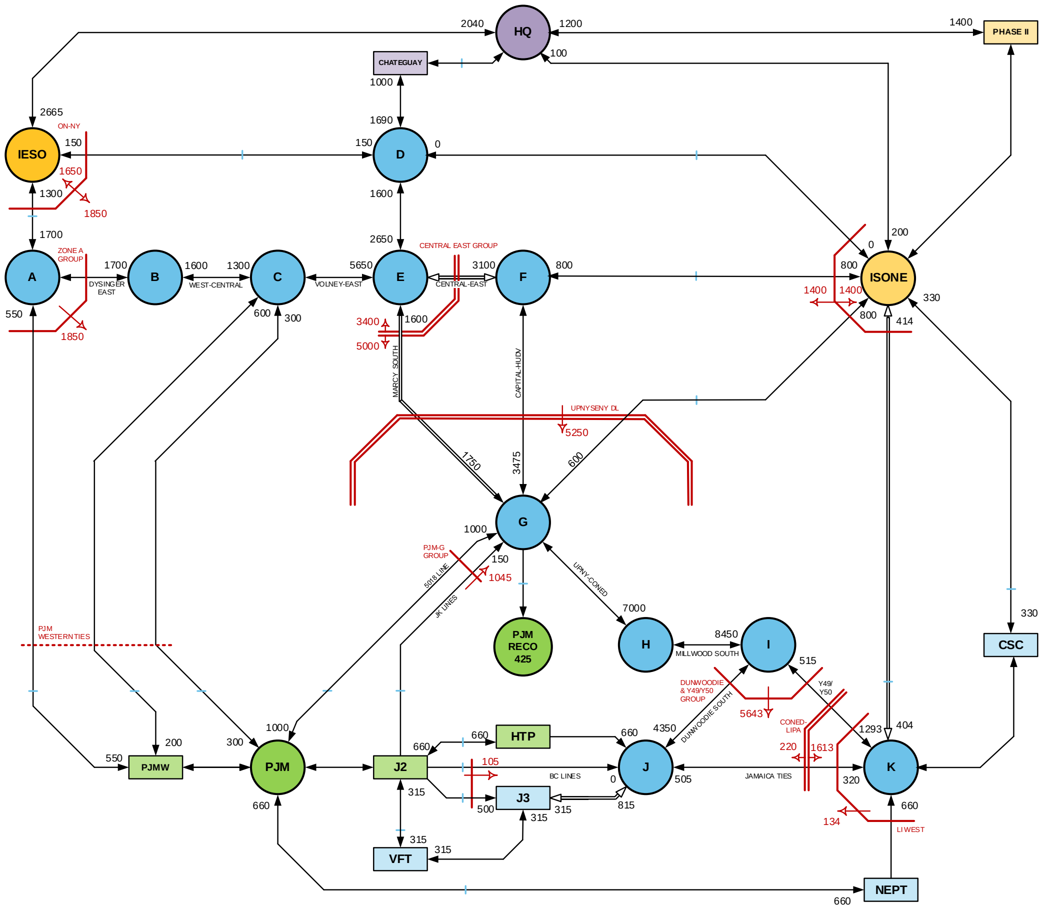
Voltage Limited Interfaces
Central East MARS
Central East Group
UPNY-ConEd

PJM-NY JOA Flow Distribution (Jan 31, 2017 filing)	RECO Load Deliveries	PJM-NY Emergency Assistance
PJM-NY Western Ties	20%	46%
5018 Line	80%	32%
JK Lines	0%	15%
A Line	0%	7%
BC Lines	0%	0%

Additionally, MARS topologies for study year 2021 through 2024 are below:

MARS Topology Study Years 4-10 (2021-2024)

Topology for 2020 RNA Base Case: Study Year 2021



Notes

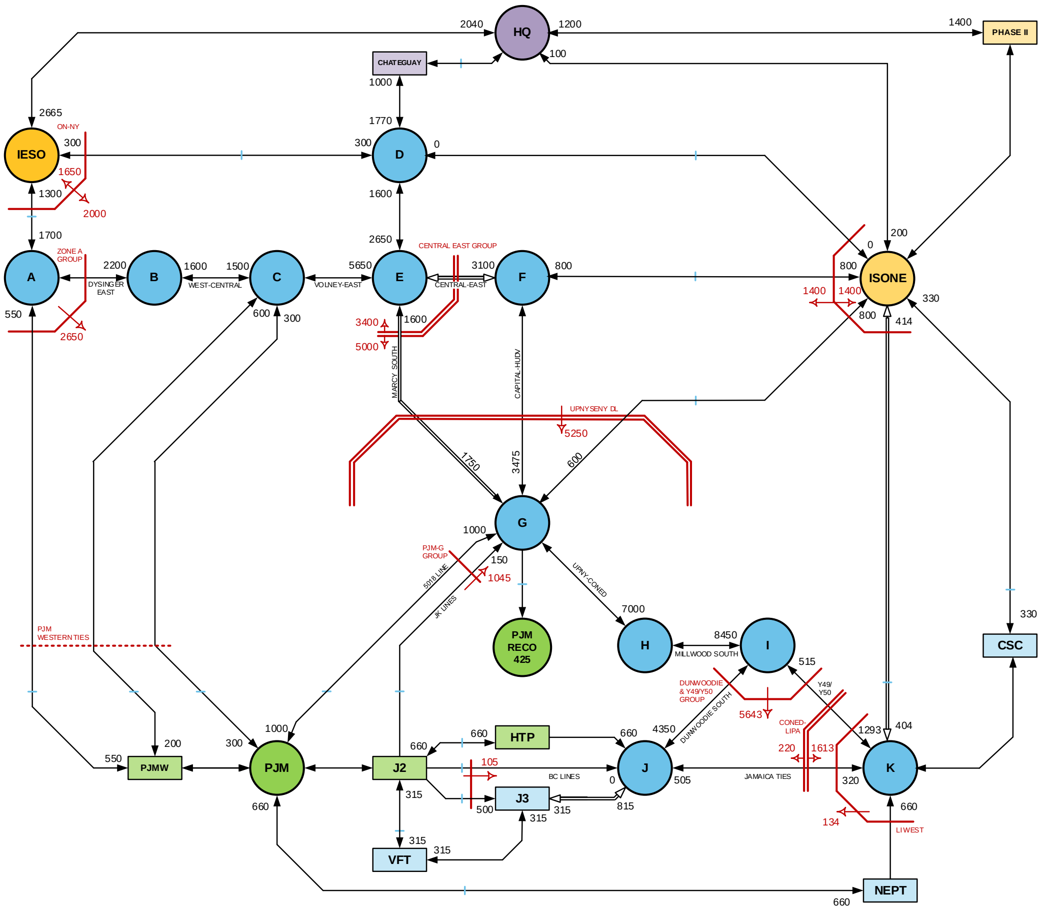
1. PJM to NY emergency assistance (EA) assumption for calculating the PJM-NY Western ties, PJM-G Group, and ABC Line Group flow distribution limit: 1500MW
2. NYCA EA simultaneous import limit: 3,500 MW
3. External areas representation based upon information received from the NPCC CP-8 WG

Legend

- Interface
- Unidirectional Interface
- Interface w/ Dynamic Ratings
- Interface Group
- Interface Group w/ Dynamic Ratings
- Monitoring Interface Group
- NYCA EA Interface Group Marker
- XX "Dummy Bubble" i.e. no load

NOTE: An interface is considered to not have a MW limitation if no number is specified

Topology for 2020 RNA Base Case: Study Year 2022



Notes

1. PJM to NY emergency assistance (EA) assumption for calculating the PJM-NY Western ties, PJM-G Group, and ABC Line Group flow distribution limit: 1500MW

2. NYCA EA simultaneous import limit: 3,500 MW

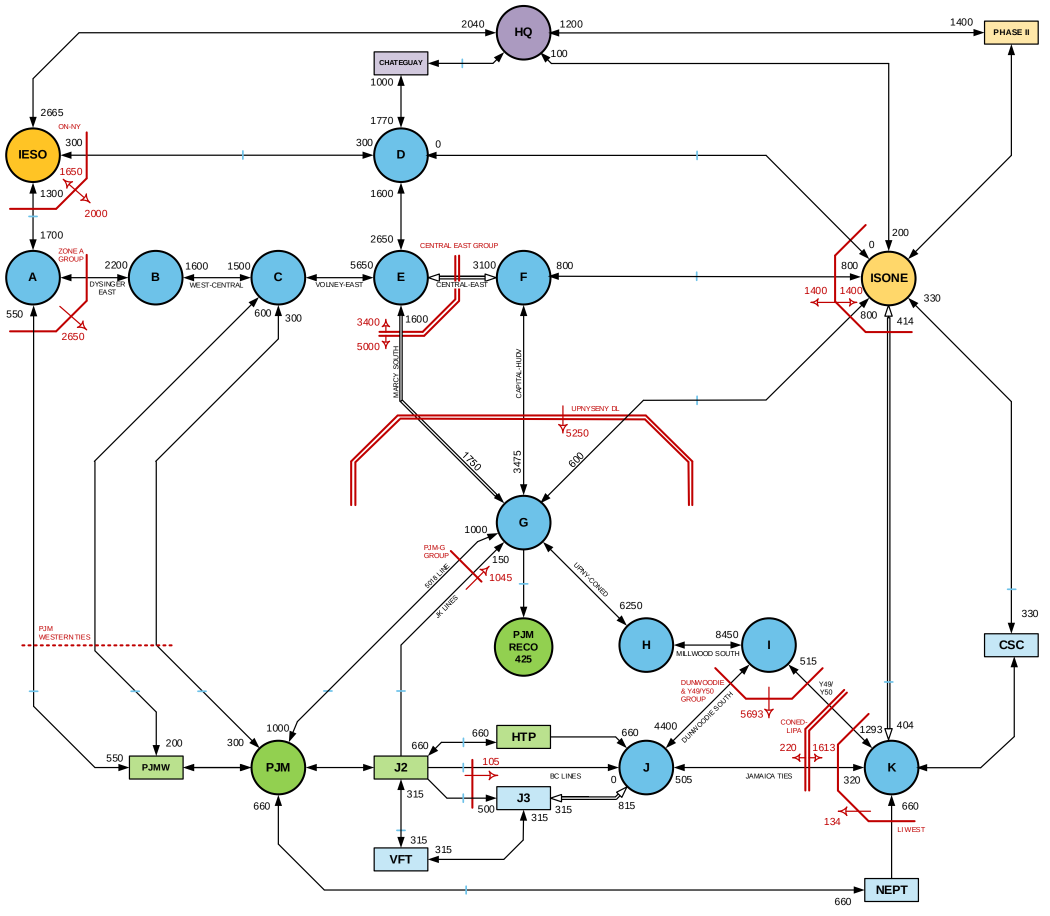
3. External areas representation based upon information received from the NPCC CP-8 WG

Legend

- Interface
- Unidirectional Interface
- Interface w/ Dynamic Ratings
- Interface Group
- Interface Group w/ Dynamic Ratings
- Monitoring Interface Group
- NYCA EA Interface Group Marker
- XX "Dummy Bubble" i.e. no load

NOTE: An interface is considered to not have a MW limitation if no number is specified

Topology for CRP Base Case with ‘Post-2020 RNA’ updates: Study Year 2023



Notes

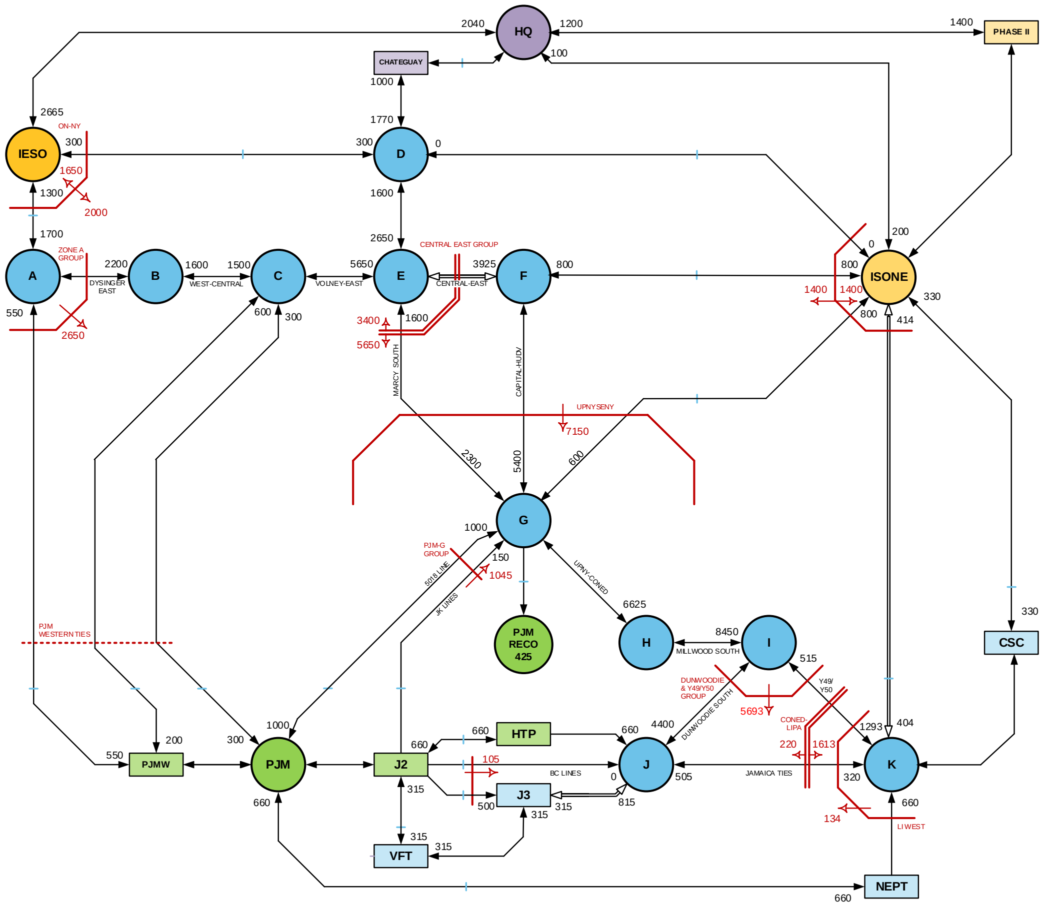
1. PJM to NY emergency assistance (EA) assumption for calculating the PJM-NY Western ties, PJM-G Group, and ABC Line Group flow distribution limit: 1500MW
2. NYCA EA simultaneous import limit: 3,500 MW
3. External areas representation based upon information received from the NPCC CP-8 WG

Legend

- Interface
- Unidirectional Interface
- Interface w/ Dynamic Ratings
- Interface Group
- Interface Group w/ Dynamic Ratings
- Monitoring Interface Group
- NYCA EA Interface Group Marker
- XX “Dummy Bubble” i.e. no load

NOTE: An interface is considered to not have a MW limitation if no number is specified

Topology for CRP Base Case with ‘Post-2020 RNA’ updates: Study Years 2024-2030



Notes

1. PJM to NY emergency assistance (EA) assumption for calculating the PJM-NY Western ties, PJM-G Group, and ABC Line Group flow distribution limit: 1500MW
2. NYCA EA simultaneous import limit: 3,500 MW
3. External areas representation based upon information received from the NPCC CP-8 WG

Legend

- Interface
- Unidirectional Interface
- Interface w/ Dynamic Ratings
- Interface Group
- Interface Group w/ Dynamic Ratings
- Monitoring Interface Group
- NYCA EA Interface Group Marker
- XX — “Dummy Bubble” i.e. no load

NOTE: An interface is considered to not have a MW limitation if no number is specified

Topology for 2020 RNA Base Case: Study Years 2021-2023
Dynamic Limits and Groupings Information

Interface Group	Limit	Flow Equation
LI_WEST	134	(K to I&J) - 0.13*(K_NEPT)

Central East Voltage Limits, Oswego Complex Units

Depends On:	9MILP1, 9MILP2, FPNUC1, STHIND, OS05, OS06			
Units	E_to_F		E_to_FG	
Available	Fwd	Rev	Fwd	Rev
6	3100	1999	5000	3400
5	3050	1999	4925	3400
4	2990	1999	4840	3400
3	2885	1999	4685	3400
2	2770	1999	4510	3400
Otherwise	2645	1999	4310	3400

Staten Island Import Limits, AK and Linden CoGen Units

Unit Availability				J_to_J3	
AK02	AK03	LINCOG1	LINCOG2	Fwd	Rev
A	A	A	A	315	200
U	A	A	A	315	500
A	U	A	A	315	700
A	A	U	A	315	500
A	A	A	U	315	500
Otherwise				315	815

Depends On:	NPRTS1-4	
Units	LI_NE	
Available	Norwalk to K	K to Norwalk
4	260	414
Otherwise	404	414

Depends On:	Barrett1 and 2	
Units	ConEd-LIPA	
Available	IJ to K	K to IJ
2	1613	220
1	1613	200
0	1613	130

Voltage Limited Interfaces
Central East MARS
Central East Group
UPNY-ConEd

PJM-NY JOA Flow Distribution (Jan 31, 2017 filing)	425MW RECO Load Deliveries	1500MW PJM-NY Emergency Assistance
PJM-NY Western Ties	20%	46%
5018 Line	80%	32%
JK Lines	0%	15%
A Line	0%	7%
BC Lines	0%	0%

US DL Limit	Units Available		
(MW)	CPV	Cricket	Athens
5250	2	3	3
5100	2	3	2
5350	1	3	3
5200	2	2	3
5150	2	1	3
5250	1	1	3
5100	2	0	3
5350	All Other Conditions		

E_TO_G DL Limit (MW)	Units Available CPV
1750	2
2000	1
2250	0

Draft Topology for 2020 RNA Base Case: Study Years 2024
Dynamic Limits and Groupings Information

Interface Group	Limit	Flow Equation
LI_WEST	134	(K to I&J) - 0.13*(K_NEPT)

Central East Voltage Limits, Oswego Complex Units

Depends On:	9MILP1, 9MILP2, FPNUC1, STHIND, OS05, OS06			
Units	E_to_F		E_to_FG	
Available	Fwd	Rev	Fwd	Rev
6	3925	1999	5650	3400
5	3875	1999	5575	3400
4	3815	1999	5490	3400
3	3710	1999	5335	3400
2	3595	1999	5160	3400
Otherwise	3470	1999	4960	3400

Above table reflects ACPPTPP target COD of 2024

Staten Island Import Limits, AK and Linden CoGen Units

Unit Availability				J_to_J3	
AK02	AK03	LINCOG1	LINCOG2	Fwd	Rev
A	A	A	A	315	200
U	A	A	A	315	500
A	U	A	A	315	700
A	A	U	A	315	500
A	A	A	U	315	500
Otherwise				315	815

Depends On:	NPRTS1-4	
Units	LI_NE	
Available	Norwalk to K	K to Norwalk
4	260	414
Otherwise	404	414

Depends On:	Barrett1 and 2	
Units	ConEd-LIPA	
Available	IJ to K	K to IJ
2	1613	220
1	1613	200
0	1613	130

Voltage Limited Interfaces
Central East MARS
Central East Group
UPNY-ConEd

PJM-NY JOA Flow Distribution (Jan 31, 2017 filing)	RECO Load Deliveries	PJM-NY Emergency Assistance
PJM-NY Western Ties	20%	46%
5018 Line	80%	32%
JK Lines	0%	15%
A Line	0%	7%
BC Lines	0%	0%

CRP Base Case Event Analysis

Loss of Load Expectation (LOLE, in days/year) is generally defined as the expected (weighted average) number of days in a given time period (*e.g.,* one study year) when at least one hour from that day, the hourly demand (for each of the seven load bins and per replication) is projected to exceed the zonal resources capacity (event day) in any of the seven load bins. Within a day, if the zonal demand exceeds the resources in at least one hour of that day (could be anywhere from hour 1 to 24, consecutive or not), this will be counted as **one event day** for the respective load bin and replication. The NYISO currently simulates 2,000 replications per study year and load level (seven load bins), for a total of 14,000 replications per study year. Weighted average is based on load bin probability, total bin event days, and total number of replications. NYSRC and NPCC's LOLE criterion is that the NYCA LOLE not exceed one day in 10 years, or LOLE < 0.1 days/year.

For each study year and in a single MARS replication, the zonal MW hourly margins (MW surplus or deficit) are calculated for each bin using load forecast uncertainty (LFU) applied load, forced outage calculations, hourly shape values (*i.e.,* wind, solar, run-of-river hydro, landfill gas), contracts and interface flows. In instances where there is a deficit in any area, emergency operating procedures (EOPs) steps are completed until either the deficits are gone, or there are no more EOP steps to call. Once all of this is completed MARS calculates the reliability indices (LOLE, LOLH, LOEE) for the replication. This occurs concurrently across all load levels simultaneously: MARS lumps them all together in a weighted sum to get a single value for each replication.

NYCA LOLE (days/ year) = $\frac{1}{N}\sum_{i=1}^{7} D_i \, P_i$

NYCA LOLH (hour/ year) = $\frac{1}{N}\sum_{i=1}^{7} H_i \, P_i$

NYCA EUE (MWh) = $\frac{1}{N}\sum_{i=1}^{7} E_i \, P_i$

where, $\boldsymbol{D_i}$ is the **event days** for bin i for the study year
$\mathbf{H_i}$ **is** the **event hours** for bin i
Ei is the MW deficit for bin i
$\mathbf{P_i}$ is the **probability of occurring of bin i** which is the LFU probability data
N is the total number of **replications** e.g. 2000

The below figures provide additional insight into how the LOLE bin and month distribution for the CRP Base Case, study year 2030. Additional details on load forecast uncertainty (LFU) and MARS load bins is under the April 13, 2020 Load Forecast Task Force presentation [link]

Key observation

- The MARS events for the CRP Base Case study year 2030 are distributed in June, July, and August, in the afternoon hours, and in load bins 1 and 2.

Figure 9: CRP Base Case, Study Year 2030, Bin and Month LOLE Distributions

LOLE (dy/yr)

Month	1	2	3	4	5	6	7	Total
Jan								
Feb								
Mar								
Apr								
May								
Jun	0.0000	0.0002	0.0002	0.0002				0.0006
Jul	0.0138	0.0145	0.0002					0.0286
Aug	0.0036	0.0289	0.0024	0.0002				0.0351
Sep								
Oct								
Nov	0.0000							0.0000
Dec								
Annual	0.0174	0.0437	0.0029	0.0004				0.0644

Load Level

Figure 10: CRP Base Case, Study Year 2030, Event Summary

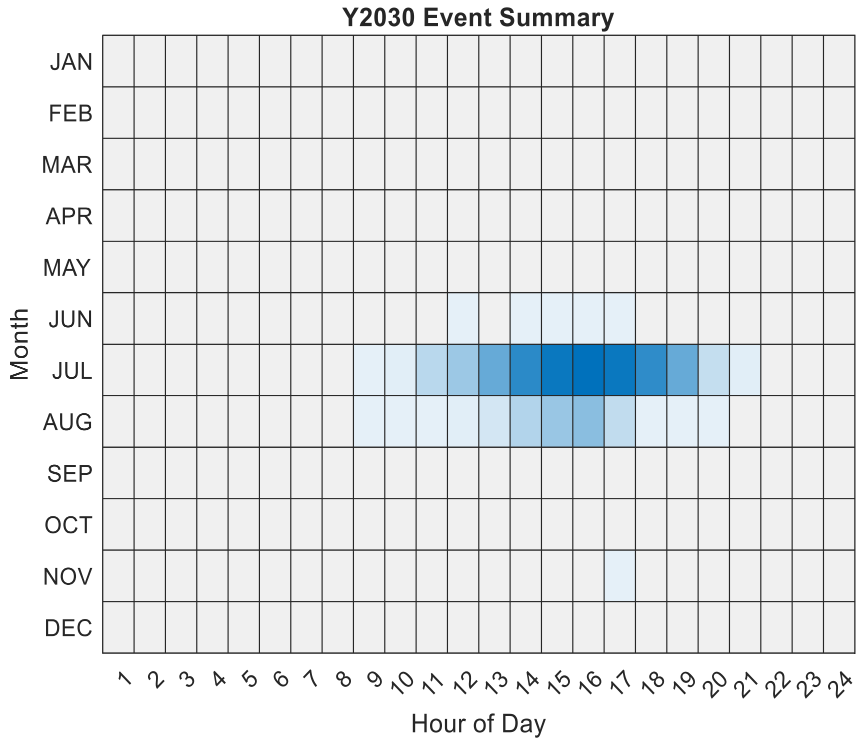
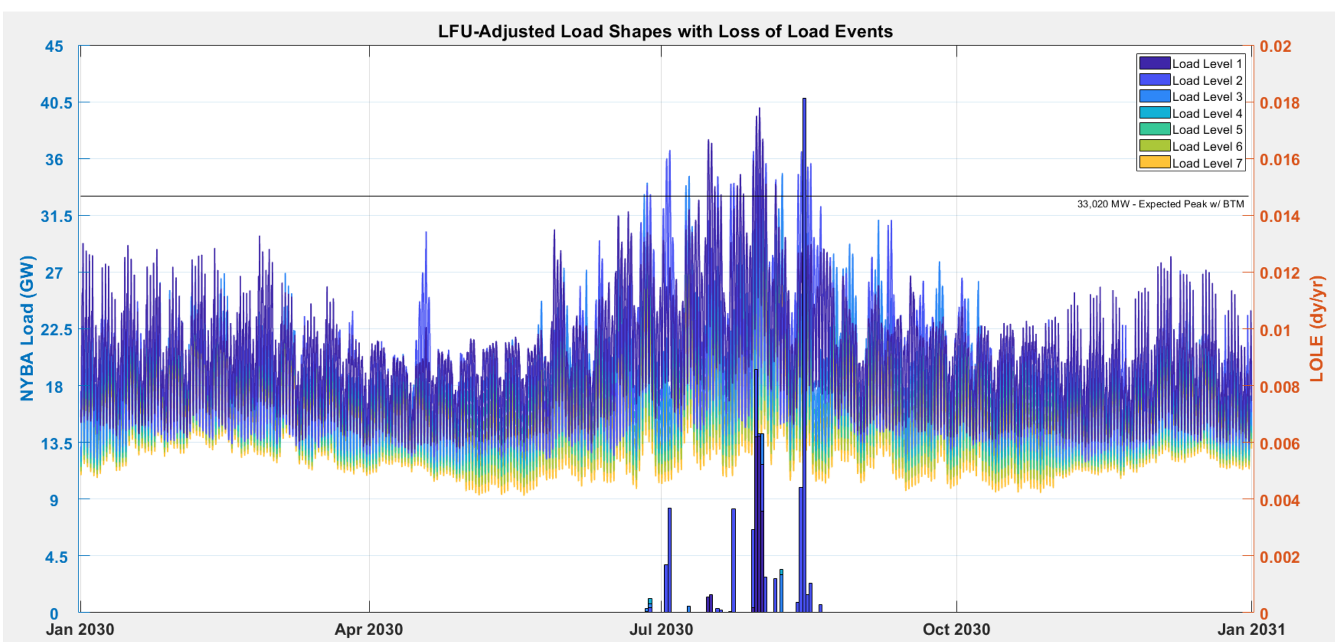


Figure 11: CRP Base Case, Study Year 2030, LFU-Adjusted Load Shapes vs Load Events



Resource Adequacy Assumptions Matrix

#	Parameter	2018 RNA/CRP (2018 GB) Study Period: 2019 -2028	2020 RNA (2020 GB) Study Period: 2024(y4) -2030 (y10)	2021 CRP **2020 GB with updates:** Study Period: 2024(y4) -2030 (y10)
Load Parameters				
1	**Peak** Load Forecast	Adjusted 2018 Gold Book NYCA baseline peak load forecast. The GB 2018 baseline peak load forecast includes the impact (reduction) of behind-the-meter (BTM) solar at the time of NYCA peak. For the Resource Adequacy load model, the deducted BTM solar MW was added back to the NYCA zonal loads, which then allows for a discrete modeling of the BTM solar resources.	Similar method	Similar method **Updated** long term energy and peak forecasts: Nov 19, 2020, ESPWG/LFTF/TPAS/ICAP presentation
2	Load **Shapes** (Multiple Load Shapes)	Used Multiple Load Shape MARS Feature 8,760 hour historical load shapes were used as base shapes for LFU bins: Bin 1: 2006 Bin 2: 2002 Bins 3-7: 2007 Peak adjustments on a seasonal basis. For the BTM Solar adjustment, the BTM shape is added back to account for the impact of the BTM generation on both on-peak and off-peak hours.	Similar method	No change from 2020 RNA
3	Load Forecast Uncertainty (**LFU**)	Used updated summer LFU values for the 11 NYCA zones.	Updated via Load Forecast Task Force (LFTF) process Reference: April 13 2020, LFTF presentation: https://www.nyiso.com/documents/20142/11883362/LFU_Summary.pdf	No change from 2020 RNA
Generation Parameters				
1	**Existing** Generating Unit Capacities	2018 Gold Book values. Use summer min (DMNC vs. CRIS). Use winter min (DMNC vs. CRIS). Adjusted for RNA inclusion rules.	Similar method	No change from 2020 RNA

2	**Proposed New Units Inclusion** Determination	GB2018 with Inclusion Rules Applied	Similar method	No change from 2020 RNA
3	Retirement, Mothballed Units, IIFO	GB2018 with Inclusion Rules Applied	Similar method	No change from 2020 RNA
4	Forced and Partial Outage Rates	Five-year (2013-2017) GADS data for each unit represented. Those units with less than five years – use representative data. Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period For new units or units that are in service for less than three years, NERC 5-year class average EFORd data are used.	Similar method	No change from 2020 RNA
5	Planned Outages	Based on schedules received by the NYISO and adjusted for history	Similar method	No change from 2020 RNA
6	Summer Maintenance	Nominal 50 MW (25 in J and 25 in K)	None	No change from 2020 RNA
7	Combustion Turbine Derates	Derate based on temperature correction curves For new units: used data for a unit of same type in same zone, or neighboring zone data.	Similar method	No change from 2020 RNA
8	Existing Landfill Gas Plants	**New method:** Actual hourly plant output over the period 2013-2017. Program randomly selects a LFG shape of hourly production over the 2013-2017 for each model replication. Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected in the Monte Carlo process.	Similar method	No change from 2020 RNA
9	Existing **Wind** Units (>5 years of data)	Actual hourly plant output over the period 2013-2017. Probabilistic model is incorporated based on five years of input shapes with one shape per replication being randomly selected in Monte Carlo process	Similar method	No change from 2020 RNA

10	Existing **Wind** Units (<5 years of data)	For existing data, the actual hourly plant output over the period 2013-2017 is used. For missing data, the nameplate normalized average of units in the same load zone is scaled by the unit's nameplate rating.	Similar method	No change from 2020 RNA
11a	Proposed **Land based Wind** Units	Inclusion Rules Applied to determine the generator status. The nameplate normalized average of units in the same load zone is scaled by the unit's nameplate rating.	Similar method	No change from 2020 RNA
11b	Proposed **Offshore Wind** Units	N/A	N/A	N/A
12a	Existing **Utility-scale Solar Resources**	The 31.5 MW Upton metered solar capacity: probabilistic model chooses from 5 years of production data output shapes covering the period 2013-2017 (one shape per replication is randomly selected in Monte Carlo process.)	Similar method	No change from 2020 RNA
12b	Proposed **Utility-scale Solar Resources**	Inclusion Rules Applied to determine the generator status. The nameplate normalized average of units in the same load zone is scaled by the unit's nameplate rating.	Similar method	No change from 2020 RNA
13	Projected **BTM Solar Resources**	The large projection of increasing retail (BTM) solar installations over the 10- year period require a discrete model with detailed hourly performance. **New method:** An 8,760 hourly shape was created by using NREL's PV Watt[4] tool. MARS will randomly select a daily shape from the current month for each day of each month of each replication.	**New Method:** Will use 5-year of inverter production data. Probabilistic model is incorporated based on five years of input shapes with one shape per replication being randomly selected in Monte Carlo process **Reference**: April 6, 2020 TPAS/ESPWG meeting materials	No change from 2020 RNA

[4] NREL's PVWatts Calculator, credit of the U.S. Department of Energy (DOE)/NREL/Alliance (Alliance for Sustainable Energy, LLC).

14	Existing **BTM-NG Program**	**New category:** These are former load modifiers to sell capacity into the ICAP market. Modeled as cogen type 2 unit in MARS. Unit capacity set to CRIS value; load modeled with weekly pattern that can change monthly.	Similar method	No change from 2020 RNA
15	Existing **Small Hydro** Resources	**New method:** Actual hourly plant output over the period 2013-2017. Program randomly selects a hydro shape of hourly production over the 5-year window for each model replication. The randomly selected shape is multiplied by their current nameplate rating.	Similar method	No change from 2020 RNA
16	Existing **Large Hydro**	Probabilistic Model based on 5 years of GADS data. Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period (2013-2017). Methodology consistent with thermal unit transition rates.	Similar method	No change from 2020 RNA
17	Proposed **Energy Storage**	N/A	N/A	N/A
Transaction - Imports / Exports				
1	Capacity Purchases	Grandfathered Rights and other awarded long-term rights Modeled using MARS explicit contracts feature.	Similar method	No change from 2020 RNA
2	Capacity Sales	These are long-term contracts filed with FERC. Modeled using MARS explicit contracts feature. Contracts sold from ROS (Zones: A-F). ROS ties to external pool are derated by sales MW amount	Similar method	No change from 2020 RNA

3	FCM Sales	Model sales for known years Modeled using MARS explicit contracts feature. Contracts sold from ROS (Zones: A-F). ROS ties to external pool are derated by sales MW amount	Similar method	No change from 2020 RNA
4	UDRs	Updated with most recent elections/awards information (VFT, HTP, Neptune, CSC)	Similar method	No change from 2020 RNA
5	EDRs	N/A	**New category:** Cedars Uprate 80 MW. Increased the HQ to D by 80 MW. Note: the Cedar bubble has been removed and its corresponding MW was reflected in HQ to D limit. References: 1. March 16, 2020 ESPWG/TPAS 2. April 6, 2020 TPAS/ESPWG	No change from 2020 RNA
6	Wheel-Through Contract	n/a	**New category:** 300 MW HQ through NYISO to ISO-NE. Modeled as firm contract. Reduced the transfer limit from HQ to NYISO by 300 MW and increased the transfer limit from NYISO to ISO-NE by 300 MW.	No change from 2020 RNA
MARS Topology: a simplified bubble-and-pipe representation of the transmission system				
0			**Summary of major topology changes** (as compared with the 2018-2019 RPP): Link1)-7); Link8)-9); Link10) 1) Marion-Farragut 345kV cables (B and C) assumed out of service 2) 71, 72, M51, M52 series reactors assumed by-passed after deactivation of Indian Point 3) Moses – St. Lawrence (L33P) tie line assumed out of service	**Summary of major topology changes** as compared with the 2020 RNA [link]: **1.** The ConEd series reactors status change impacts, throughout the entire RNA Study Period (2024-2030): • G to H (UPNY-ConEd interface) limit decrease by 750 MW (to 6625 MW) • I to J (Dunwoodie South interface) group

			4) Rainey – Corona transmission project in service impacting J to K limits 5) UPNY-SENY simplification 2021-2023 before the addition of AC PPTPP projects 6) AC PPTPs Segment A and B Projects Added starting 2024 7) Removal of Cedars bubble/tie to Zone D model; adding the MW from the bubble to the tie HQ to D tie limit. 8) Removal of PJM-SENY Group Interface 9) Updates to Zone K Imports/Exports 10) Somerset retirement impacts 11) The external areas model for PJM and ISO-NE were simplified by consolidating the 5 PJM areas (bubbles) into one, and the 8 ISO-NE areas into one.	limit increase by 50 MW (to 4400 MW) **2.** The ConEd LTPs unbottles Staten Island capacity, reflected in the MARS topology as increase in the corresponding dynamic limit table
1	Interface Limits	Developed by review of previous studies and specific analysis during the RNA study process	Similar method	No change from 2020 RNA
2	New Transmission	Based on TO- provided firm plans (via Gold Book 2018 process) and proposed merchant transmission; inclusion rules applied	Similar method	No change from 2020 RNA
3	AC Cable Forced Outage Rates	All existing cable transition rates updated with data received from ConEd and PSEG-LIPA to reflect most recent five-year history	Similar method	No change from 2020 RNA
4	UDR unavailability	Five-year history of forced outages	Similar method	No change from 2020 RNA
Emergency Operating Procedures				
1	Special Case Resources	SCRs sold for the program discounted to historic availability ("effective capacity"). Summer values calculated from the latest available July registrations, held constant for all years of study. 5 calls/month	Similar method but with 15 calls/year Note: also, combined the two SCR steps (generation and load zonal MW)	No change from 2020 RNA

2	EDRP Resources	2018 Gold Book with effective capacity modeled. Resources sold for the program and discounted to historic availability. Summer values calculated from July 2018 registrations and forecast growth. Values held constant for all years of study.	Not modeled: the values are less than 2 MW.	No change from 2020 RNA
3	Other EOPs	Based on TO information, measured data, and NYISO forecasts	Similar method	No change from 2020 RNA
External Control Areas				
1	PJM	As per RNA Procedure External model (load, capacity, topology) provided by PJM/NPCC CP-8 WG. PJM is a 5-zone model. LOLE of pool adjusted to be between 0.10 and 0.15 days per year by adjusting capacity pro-rata in all areas.	**New model:** Simplified model: The 5 PJM MARS areas (bubbles) were consolidated into one	No change from 2020 RNA
2	ISONE	As per RNA Procedure External model (load, capacity, topology) provided by PJM/NPCC CP-8 WG. LOLE of pool adjusted to be between 0.10 and 0.15 days per year by adjusting capacity pro-rata in all areas.	**New model:** Simplified model: The 8 ISO-NE MARS areas (bubbles) were consolidated into one	No change from 2020 RNA
3	HQ	As per RNA Procedure External model (load, capacity, topology) provided by PJM/NPCC CP-8 WG. LOLE of pool adjusted to be between 0.10 and 0.15 days per year by adjusting capacity pro-rata in all areas.	Similar method	No change from 2020 RNA
4	IESO	As per RNA Procedure External model (load, capacity, topology) provided by PJM/NPCC CP-8 WG. LOLE of pool adjusted to be between 0.10 and 0.15 days per year by adjusting capacity pro-rata in all areas.	Similar method	No change from 2020 RNA
5	Reserve Sharing	All NPCC Control Areas indicate that they will share reserves **equally** among all members before sharing with PJM.	Similar method	No change from 2020 RNA
6	NYCA Emergency Assistance Limit	Implemented a statewide limit of 3,500 MW	Similar method	No change from 2020 RNA
Miscellaneous				
1	MARS Model Version	Version 3.22.6	3.29.1499	3.29.1499 (also run on new MARS rev with no significant change in results)

Appendix D – Transmission Security Margins (Tipping Points)

The purpose of this assessment is to identify plausible changes in conditions or assumptions that might adversely impact the reliability of the Bulk Power Transmission Facilities (BPTF) or "tip" the system into violation of a transmission security criterion. This assessment is performed using a deterministic approach through a spreadsheet-based methods based on input from the 2021 Load and Capacity Data Report (Gold Book) and CRP base case updates. For this assessment, "tipping points" are evaluated for the NYCA as well as Zone G-J, J, and K localities. For this evaluation the system tips when the transmission security margin is less than 0 or when a condition could change that is larger than the security margin.

New York Control Area (NYCA) Tipping Points

The tipping points for the NYCA are evaluated under summer peak conditions. A tipping point occurs when the transmission security margin is a negative value. The transmission security margin is the ability to meet load plus losses and system reserve (*i.e.,* total capacity requirement) against the NYCA generation, interchanges, and temperature-based generation de-rates (total resources). The NYCA generation (from line-item A) is comprised of the existing generation plus additions of future generation resources that meet the reliability planning process base case inclusion rules as well as the removals of deactivating generation and peaker units. Consistent with transmission planning practices for transmission security, (1) wind generation is assumed at a 0 MW output, (2) run-of-river hydro is reduced consistent with its average capacity factor, and (3) is solar dispatched based on the ratio of its nameplate capacity and solar PV peak reductions stated in the 2021 Gold Book. Additionally, the NYCA generation includes the Oswego export limit for all lines in-service. **Figure 11** provides a summary of the NYCA transmission security margin. Under current applicable reliability rules and procedures, a violation would be identified when the transmission security margin is negative for the base case assumptions (e.g., baseline load forecast, no pre-contingency unscheduled forced outages, etc.)

As shown in **Figure 11,** under baseline load conditions the statewide system margin (line-item H) ranges between 2,303 MW in 2022 to 1,318 MW in 2031. The annual fluctuations are driven by the decreases in NYCA generation (line-item A) and in the load forecast (line-item E). In consideration of the transmission security margin (line-item H), the values show that it is feasible to not tip into the largest source of 1,310 MW (loss of Nine Mile Unit 2).[5] However, in 2031 this combination of conditions results in a transmission security margin of 8 MW.[6]

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[5] https://www.nyiso.com/documents/20142/3691300/Summer-2020-Operating-Study-Draft-Final-OC-Approved.pdf/

[6] This value is calculated as 1,318 MW – 1,310 MW = 8 MW.

It is feasible for other combinations of events to tip the system over its margin, such as increased load or a combination of reductions in total resources and load. An additional evaluation shown in **Figure 11** is the impact of the historical forced outage rate of NYCA thermal generation on the transmission security margin. Also, while SCRs are not included for transmission security analysis under normal conditions, they are used for this forced outage rate evaluation. The adjusted statewide system margin (line-item K) shows that sufficient margin exists under this condition.

Figure 12 shows the statewide system margin for the 1-in-10-year load conditions (also known as 90/10 or 90^{th} percentile load) under the assumption that the system is in an emergency condition. Although the system is not designed under Transmission Security for the 90th percentile forecast, **Figure 12** shows the margin that would exist (Line-item I). As shown in **Figure 12**, under the 90^{th} percentile load conditions the inclusion of the historical forced outage rate of thermal generation (line-item J) shows that the system tips in 2022 (line-item K) and remains below the transmission security margin through 2031.

Under transmission security for the 1 in 100-year forecast, **Figure 13** shows that there is insufficient statewide system margin as early as 2022 (line-item I). This deficiency is exacerbated with the inclusion of forced outages (line-item K). The adjusted statewide system margin is deficient beyond the point of meeting the total capability requirement without reserves. For example, changing the operating reserve requirement to 0 MW, the adjusted transmission security margin ranges from 175 MW deficient in 2022 to 724 MW deficient in 2031.

Figure 14 provides a summary of the statewide system margins under each load level.

Figure 12: Statewide System Margin (Summer Baseline Peak Forecast - Normal)

Line	Item	Peak Load Forecast									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
A	NYCA Generation (1)	35,257	34,307	34,297	33,684	33,679	33,679	33,674	33,669	33,664	33,659
B	External Area Interchanges (2)	1,844	1,844	1,844	1,844	1,844	1,844	1,844	1,844	1,844	1,844
C	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
D	**Total Resources (A+B+C) (3)**	37,101	36,151	36,141	35,528	35,523	35,523	35,518	35,513	35,508	35,503
E	Load Forecast	(32,178)	(31,910)	(31,641)	(31,470)	(31,326)	(31,278)	(31,284)	(31,348)	(31,453)	(31,565)
F	Operating Reserve Requirement	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)
G	**Total Capability Requirement (E+F)**	(34,798)	(34,530)	(34,261)	(34,090)	(33,946)	(33,898)	(33,904)	(33,968)	(34,073)	(34,185)
H	**Statewide System Margin (D+G)**	2,303	1,621	1,880	1,438	1,577	1,625	1,614	1,545	1,435	1,318
I	SCRs (4), (5)	822	822	822	822	822	822	822	822	822	822
J	Forced Outages (3)	(2,164)	(1,952)	(1,952)	(1,867)	(1,867)	(1,867)	(1,867)	(1,867)	(1,867)	(1,867)
K	**Adjusted Statewide System Margin (H+I+J) (4)**	961	491	750	393	532	580	569	500	390	273

Notes:

1. Reflects the 2021 Gold Book existing summer capacity plus projected additions, deactivations, and de-rates. For this evaluation wind generation is assumed to have 0 MW output, solar generation is based on the ratio of solar PV nameplate capacity (2021 Gold Book Table I-9a) and solar PV peak reductions (2021 Gold Book Table I-9c). De-rates for run-of-river hydro are included as well as the Oswego Export limit for all lines in-service.
2. Interchanges are based on ERAG MMWG values.
3. Includes de-rates for thermal resources.
4. Special Case Resources (SCRs) are not applied for transmission security analysis of normal operations.
5. Includes a de-rate of 373 MW for SCRs.

Figure 13: Statewide System Margin (1-in-10 (90/10) Peak Forecast - Emergency)

Line	Item	90th Percentile Forecast									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
A	NYCA Generation (1)	35,257	34,307	34,297	33,684	33,679	33,679	33,674	33,669	33,664	33,659
B	External Area Interchanges (2)	1,844	1,844	1,844	1,844	1,844	1,844	1,844	1,844	1,844	1,844
C	SCRs (4), (5)	822	822	822	822	822	822	822	822	822	822
D	Temperature Based Generation Derates	(208)	(195)	(195)	(185)	(185)	(185)	(185)	(185)	(185)	(185)
E	**Total Resources (A+B+C+D)**	37,715	36,778	36,768	36,164	36,159	36,159	36,154	36,149	36,144	36,139
F	Load Forecast	(34,158)	(33,871)	(33,582)	(33,399)	(33,246)	(33,191)	(33,195)	(33,262)	(33,373)	(33,490)
G	Operating Reserve Requirement	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)
H	**Total Capability Requirement (F+G)**	(36,778)	(36,491)	(36,202)	(36,019)	(35,866)	(35,811)	(35,815)	(35,882)	(35,993)	(36,110)
I	**Statewide System Margin (E+H)**	937	287	566	145	293	348	339	267	151	29
J	Forced Outages (3)	(2,164)	(1,952)	(1,952)	(1,867)	(1,867)	(1,867)	(1,867)	(1,867)	(1,867)	(1,867)
K	**Adjusted Statewide System Margin (I+J)**	(1,227)	(1,665)	(1,386)	(1,722)	(1,574)	(1,519)	(1,528)	(1,600)	(1,716)	(1,838)

Notes:

1. Reflects the 2021 Gold Book existing summer capacity plus projected additions, deactivations, and de-rates. For this evaluation wind generation is assumed to have 0 MW output, solar generation is based on the ratio of solar PV nameplate capacity (2021 Gold Book Table I-9a) and solar PV peak reductions (2021 Gold Book Table I-9c). De-rates for run-of-river hydro are included as well as the Oswego Export limit for all lines in-service.
2. Interchanges are based on ERAG MMWG values.
3. Includes de-rates for thermal resources.
4. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
5. Includes a de-rate of 373 MW for SCRs.

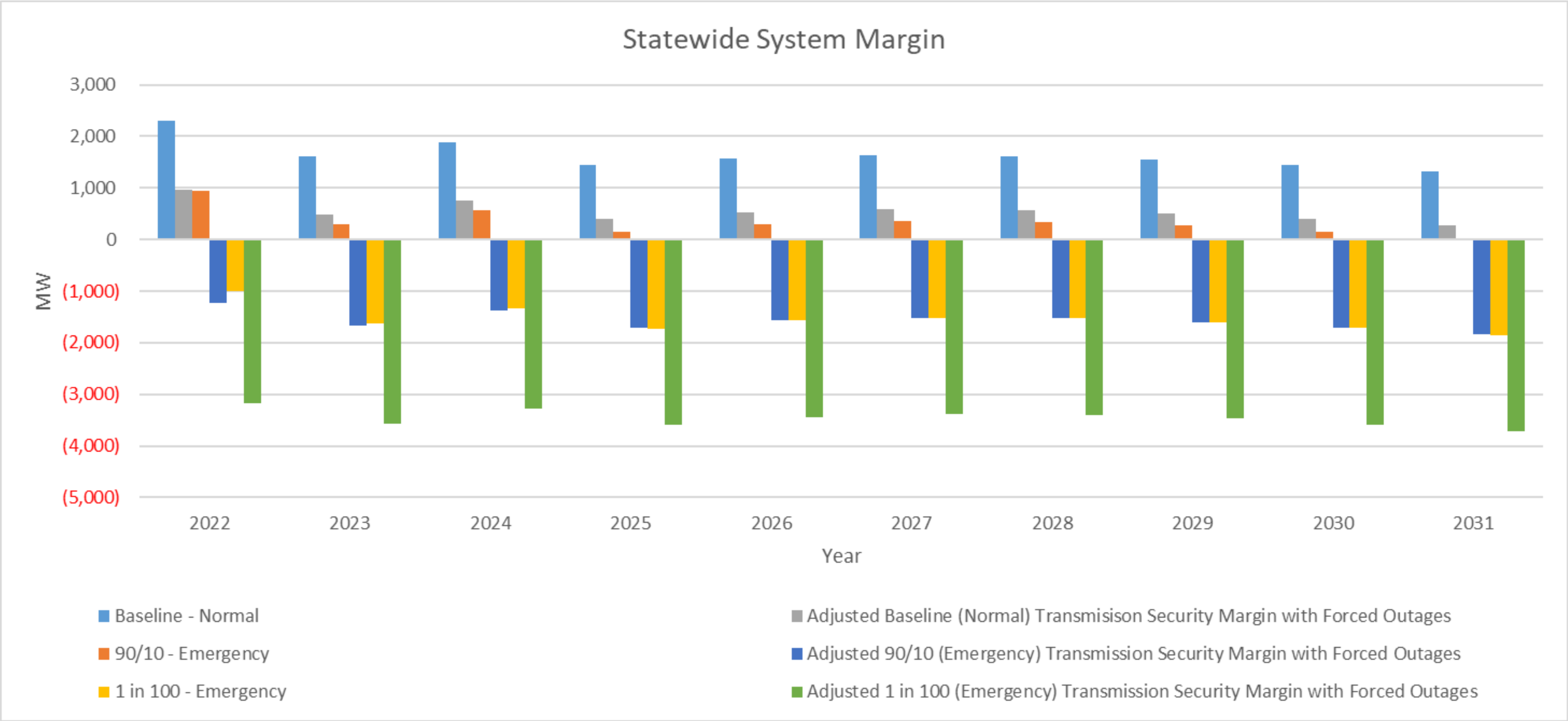
Figure 14: Statewide System Margin (Summer 1-in-100 Peak Forecast - Emergency)

Line	Item	1 in 100 Forecast									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
A	NYCA Generation (1)	35,257	34,307	34,297	33,684	33,679	33,679	33,674	33,669	33,664	33,659
B	External Area Interchanges (2)	1,844	1,844	1,844	1,844	1,844	1,844	1,844	1,844	1,844	1,844
C	SCRs (4), (5)	822	822	822	822	822	822	822	822	822	822
D	Temperature Based Generation Derates	(437)	(410)	(410)	(390)	(390)	(390)	(390)	(390)	(390)	(390)
E	**Total Resources (A+B+C+D)**	37,486	36,563	36,553	35,959	35,954	35,954	35,949	35,944	35,939	35,934
F	Load Forecast	(35,870)	(35,569)	(35,264)	(35,073)	(34,909)	(34,852)	(34,856)	(34,924)	(35,039)	(35,164)
G	Operating Reserve Requirement	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)
H	**Total Capability Requirement (F+G)**	(38,490)	(38,189)	(37,884)	(37,693)	(37,529)	(37,472)	(37,476)	(37,544)	(37,659)	(37,784)
I	**Statewide System Margin (E+H)**	(1,004)	(1,626)	(1,331)	(1,734)	(1,575)	(1,518)	(1,527)	(1,600)	(1,720)	(1,850)
J	Forced Outages (3)	(2,164)	(1,952)	(1,952)	(1,867)	(1,867)	(1,867)	(1,867)	(1,867)	(1,867)	(1,867)
K	**Adjusted Statewide System Margin (I+J)**	(3,168)	(3,578)	(3,283)	(3,601)	(3,442)	(3,385)	(3,394)	(3,467)	(3,587)	(3,717)

Notes:

1. Reflects the 2021 Gold Book existing summer capacity plus projected additions, deactivations, and de-rates. For this evaluation wind generation is assumed to have 0 MW output, solar generation is based on the ratio of solar PV nameplate capacity (2021 Gold Book Table I-9a) and solar PV peak reductions (2021 Gold Book Table I-9c). De-rates for run-of-river hydro are included as well as the Oswego Export limit for all lines in-service.
2. Interchanges are based on ERAG MMWG values.
3. Includes de-rates for thermal resources.
4. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
5. Includes a de-rate of 373 MW for SCRs.

Figure 15: Summary of Statewide System Margin



Lower Hudson Valley (Zones G-J) Tipping Points

The Lower Hudson Valley, or southeastern New York (SENY) region, is comprised of Zones G-J and includes the electrical connections to the RECO load in PJM. To determine the tipping point for this area, the most limiting combination of two non-simultaneous contingency events (N-1-1) to the transmission security margin was determined. Design criteria N-1-1 combinations include various combinations of losses of generation and transmission. As the system changes the limiting contingency combination may also change. **Figure 15** shows how the transmissions security margin changes through time in consideration of the most limiting contingency combination for the year being evaluated. In years 2022 and 2023 (prior to the completion of the Segment B public policy project) the most limiting contingency combination to the transmission security margin under peak load conditions is the loss of Leeds-Pleasant Valley (92) 345 kV followed by the loss of Dolson — Rock Tavern (DART44) 345 kV and Coopers Corners – Rock Tavern (CCRT34). For the remainder of the years the contingency combination changes to the loss of Ravenswood 3 followed by the loss of Pleasant Valley-Wood St. 345 kV (F30/F31).

Figure 16: Lower Hudson Valley Transmission Security Margin (Summer Baseline Peak Forecast - Normal)

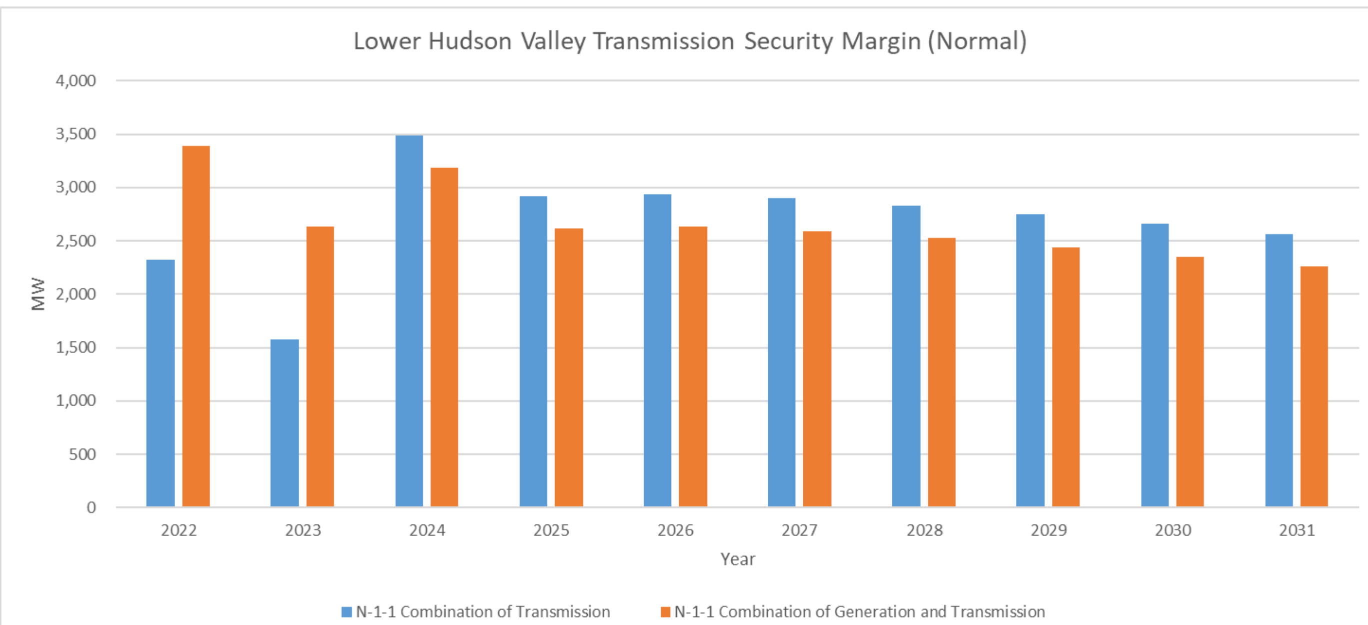


Figure 16 shows the calculation of the lower Hudson Valley transmission security margin for summer baseline peak load (normal) conditions. The transmission security margin ranges from 2,325 MW (2022) to 2,260 MW (2031). Considering the baseline peak load transmission security margin, multiple outages the lower Hudson Valley would be required to tip the system over its security margin.

An additional evaluation shown in **Figure 16** is the impact of the historical forced outage rate of thermal generation on the transmission security margin. Also, while SCRs are not included for an evaluation of transmission security under normal transfer criteria, the impact of SCRs is accounted for in this adjusted transmission security margin. The adjusted transmission security margin (line-item S) shows that generation outages consistent with the historical forced outage rates would not result in "tipping" beyond transmission security limits, with a margin of 1,274 MW in 2022 growing to 1,450 MW in 2031.

Figure 17 and **Figure 18** show the transmission security margin for the 1-in-10-year load conditions (also known as 90/10 or 90th percentile load) and 1-in-100-year load conditions (respectively) under the assumption that the system is in an emergency condition. An additional evaluation shown in each figure is the impact of the historical forced outage rate of thermal generation on the transmission security margin. Under 1-in-10-year load conditions the adjusted transmission security margin (line-item S) shows that generation outages consistent with the historical forced outage rates would not result in "tipping" beyond transmission security limits, with a margin of 1,228 MW in 2022 growing to 1,402 MW in 2031. Under 1-in-100 load conditions the historical forced outage rate does "tip" the system in 2023. However, the remaining years of the study period is sufficient primarily due to the additional transmission capability of the Segment B public policy project.

Figure 19 provides a summary of the transmission security margins under each load level.

Figure 17: Lower Hudson Valley Transmission Security Margin (Summer Baseline Peak Forecast - Normal)

		Peak Load Forecast									
Line	**Item**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
A	G-J Load Forecast	(15,311)	(15,231)	(15,163)	(15,120)	(15,100)	(15,142)	(15,210)	(15,294)	(15,381)	(15,474)
B	RECO Load	(397)	(397)	(397)	(397)	(397)	(397)	(397)	(397)	(397)	(397)
C	**Total Load (A+B)**	(15,708)	(15,628)	(15,560)	(15,517)	(15,497)	(15,539)	(15,607)	(15,691)	(15,778)	(15,871)
D	UPNY-SENY Limit (5)	3,200	3,200	5,725	5,725	5,725	5,725	5,725	5,725	5,725	5,725
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	95	95	95	95	95	95	95	95	95	95
G	**Total SENY AC Import (D+E+F)**	3,284	3,284	5,809	5,809	5,809	5,809	5,809	5,809	5,809	5,809
H	Loss of Source Contingency	0	0	(980)	(980)	(980)	(980)	(980)	(980)	(980)	(980)
I	**Resource Need (C+G+H)**	(12,424)	(12,344)	(10,731)	(10,688)	(10,668)	(10,710)	(10,778)	(10,862)	(10,949)	(11,042)
J	*Resources needed after N-1-1 (C+G)*	(12,424)	(12,344)	(9,751)	(9,708)	(9,688)	(9,730)	(9,798)	(9,882)	(9,969)	(10,062)
K	G-J Generation (1)	14,434	13,603	13,602	12,988	12,988	12,988	12,988	12,988	12,987	12,987
L	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports	315	315	315	315	315	315	315	315	315	315
N	**Total Resources Available (K+L+M)**	14,749	13,918	13,917	13,303	13,303	13,303	13,303	13,303	13,302	13,302
O	*Resources available after N-1-1 (H+N)*	14,749	13,918	12,937	12,323	12,323	12,323	12,323	12,323	12,322	12,322
P	**Transmission Security Margin (I+N)**	2,325	1,574	3,186	2,615	2,635	2,593	2,525	2,441	2,353	2,260
Q	SCRs (3), (4)	288	288	288	288	288	288	288	288	288	288
R	Forced Outages (2)	(1,339)	(1,182)	(1,182)	(1,098)	(1,098)	(1,098)	(1,098)	(1,098)	(1,098)	(1,098)
S	**Adjusted Transmission Security Margin (P+Q+R) (3)**	1,274	680	2,292	1,805	1,825	1,783	1,715	1,631	1,543	1,450

Notes:

1. Reflects the 2021 Gold Book existing summer capacity plus projected additions, deactivations, and de-rates. For this evaluation wind generation is assumed to have 0 MW output, solar generation is based on the ratio of solar PV nameplate capacity (2021 Gold Book Table I-9a) and solar PV peak reductions (2021 Gold Book Table I-9c). De-rates for run-of-river hydro is included as well as the Oswego Export limit for all lines in-service.
2. Includes de-rates for thermal resources.
3. Special Case Resources (SCRs) are not applied for transmission security analysis of normal operations.
4. Includes a de-rate of 242 MW for SCRs.
5. Limits in 2022 and 2023 are based on limits from the summer peak 2023 representations. Limits for 2024 through 2031 are based on the summer peak 2025 representations.

Figure 18: Lower Hudson Valley Transmission Security Margin (Summer 1-in-10 (90/10) Peak Forecast - Emergency)

		90th Percentile Load Forecast									
Line	**Item**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
A	G-J Load Forecast	(16,046)	(15,961)	(15,888)	(15,843)	(15,822)	(15,865)	(15,935)	(16,023)	(16,115)	(16,212)
B	RECO Load	(397)	(397)	(397)	(397)	(397)	(397)	(397)	(397)	(397)	(397)
C	**Total Load (A+B)**	(16,443)	(16,358)	(16,285)	(16,240)	(16,219)	(16,262)	(16,332)	(16,420)	(16,512)	(16,609)
D	UPNY-SENY Limit (5)	3,925	3,925	5,450	5,450	5,450	5,450	5,450	5,450	5,450	5,450
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	155	155	155	155	155	155	155	155	155	155
G	**Total SENY AC Import (D+E+F)**	4,069	4,069	5,594	5,594	5,594	5,594	5,594	5,594	5,594	5,594
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(12,374)	(12,289)	(10,691)	(10,646)	(10,625)	(10,668)	(10,738)	(10,826)	(10,918)	(11,015)
J	*Resources needed after N-1-1 (C+G)*	(12,374)	(12,289)	(10,691)	(10,646)	(10,625)	(10,668)	(10,738)	(10,826)	(10,918)	(11,015)
K	G-J Generation (1)	14,434	13,603	13,602	12,988	12,988	12,988	12,988	12,988	12,987	12,987
L	Temperature Based Generation Derates	(96)	(85)	(85)	(75)	(75)	(75)	(75)	(75)	(75)	(75)
M	Net ICAP External Imports	315	315	315	315	315	315	315	315	315	315
N	SCRs (3), (4)	288	288	288	288	288	288	288	288	288	288
O	**Total Resources Available (K+L+M+N)**	14,941	14,121	14,120	13,516	13,516	13,516	13,516	13,515	13,515	13,515
P	*Resources available after N-1-1 (H+O)*	14,941	14,121	14,120	12,225	12,225	12,225	12,224	12,224	12,224	12,224
Q	**Transmission Security Margin (I+O)**	2,567	1,832	3,429	2,870	2,891	2,848	2,778	2,689	2,597	2,500
R	Forced Outages (2)	(1,339)	(1,182)	(1,181)	(1,098)	(1,098)	(1,098)	(1,098)	(1,098)	(1,098)	(1,098)
S	**Adjusted Transmission Security Margin (Q+R)**	1,228	650	2,248	1,772	1,793	1,750	1,680	1,591	1,499	1,402

Notes:

1. Reflects the 2021 Gold Book existing summer capacity plus projected additions, deactivations, and de-rates. For this evaluation wind generation is assumed to have 0 MW output, solar generation is based on the ratio of solar PV nameplate capacity (2021 Gold Book Table I-9a) and solar PV peak reductions (2021 Gold Book Table I-9c). De-rates for run-of-river hydro is included as well as the Oswego Export limit for all lines in-service.
2. Includes de-rates for thermal resources.
3. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
4. Includes a de-rate of 242 MW for SCRs.
5. Limits in 2022 and 2023 are based on limits from the summer peak 2023 representations. Limits for 2024 through 2031 are based on the summer peak 2025 representations.

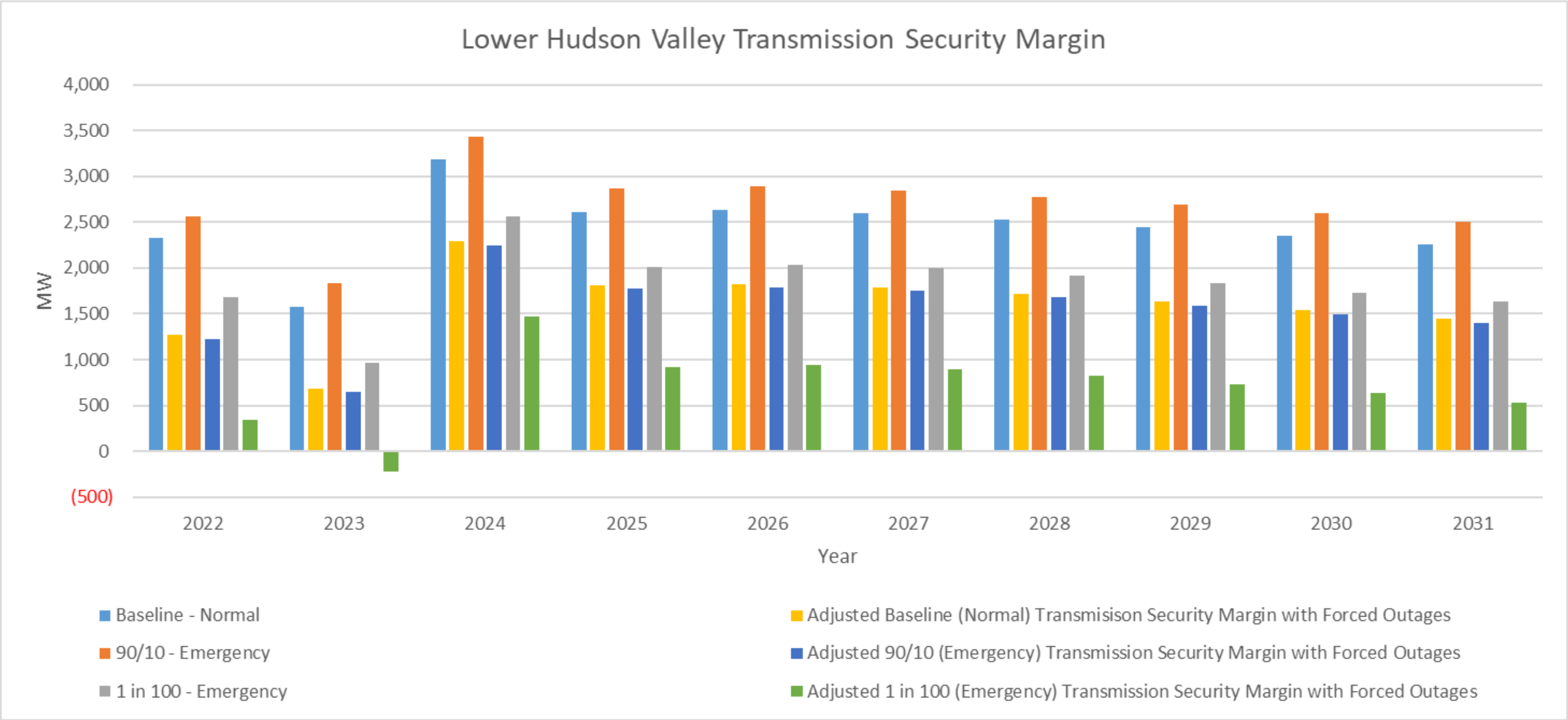
Figure 19: Lower Hudson Valley Transmission Security Margin (Summer 1-in-100 Peak Forecast - Emergency)

		1 in 100 Forecast									
Line	**Item**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
A	G-J Load Forecast	(16,778)	(16,690)	(16,614)	(16,568)	(16,545)	(16,590)	(16,663)	(16,754)	(16,849)	(16,951)
B	RECO Load	(443)	(443)	(443)	(443)	(443)	(443)	(443)	(443)	(443)	(443)
C	**Total Load (A+B)**	(17,221)	(17,133)	(17,057)	(17,011)	(16,988)	(17,033)	(17,106)	(17,197)	(17,292)	(17,394)
D	UPNY-SENY Limit (5)	3,925	3,925	5,450	5,450	5,450	5,450	5,450	5,450	5,450	5,450
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	155	155	155	155	155	155	155	155	155	155
G	**Total SENY AC Import (D+E+F)**	4,069	4,069	5,594	5,594	5,594	5,594	5,594	5,594	5,594	5,594
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(13,152)	(13,064)	(11,463)	(11,417)	(11,394)	(11,439)	(11,512)	(11,603)	(11,698)	(11,800)
J	*Resources needed after N-1-1 (C+G)*	(13,152)	(13,064)	(11,463)	(11,417)	(11,394)	(11,439)	(11,512)	(11,603)	(11,698)	(11,800)
K	G-J Generation (1)	14,434	13,603	13,602	12,988	12,988	12,988	12,988	12,988	12,987	12,987
L	Temperature Based Generation Derates	(201)	(179)	(179)	(159)	(159)	(159)	(159)	(159)	(159)	(159)
M	Net ICAP External Imports	315	315	315	315	315	315	315	315	315	315
N	SCRs (3), (4)	288	288	288	288	288	288	288	288	288	288
O	**Total Resources Available (K+L+M+N)**	14,836	14,027	14,026	13,432	13,432	13,432	13,432	13,431	13,431	13,431
P	*Resources available after N-1-1 (H+O)*	14,836	14,027	14,026	13,432	13,432	13,432	13,432	13,431	13,431	13,431
Q	**Transmission Security Margin (I+O)**	1,685	963	2,564	2,016	2,038	1,993	1,920	1,829	1,733	1,631
R	Forced Outages (2)	(1,339)	(1,182)	(1,098)	(1,098)	(1,098)	(1,098)	(1,098)	(1,098)	(1,098)	(1,098)
S	**Adjusted Transmission Security Margin (Q+R)**	346	(219)	1,466	918	940	895	822	731	635	533

Notes:

1. Reflects the 2021 Gold Book existing summer capacity plus projected additions, deactivations, and de-rates. For this evaluation wind generation is assumed to have 0 MW output, solar generation is based on the ratio of solar PV nameplate capacity (2021 Gold Book Table I-9a) and solar PV peak reductions (2021 Gold Book Table I-9c). De-rates for run-of-river hydro is included as well as the Oswego Export limit for all lines in-service.
2. Includes de-rates for thermal resources.
3. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
4. Includes a de-rate of 242 MW for SCRs.
5. Limits in 2022 and 2023 are based on limits from the summer peak 2023 representations. Limits for 2024 through 2031 are based on the summer peak 2025 representations.

Figure 20: Summary of Lower Hudson Valley Summer Transmission Security Margin



New York City (Zone J) Tipping Points

Within the Con Edison service territory, the 345 kV transmission system along with specific portions of the 138 kV transmission system are designed for the occurrence of two non-simultaneous contingencies and a return to normal.[7] The analysis for this is noted as N-1-1-0, and the CRP notes a transmission security margin of 50 MW in Zone J.[8] Figure 22 provides a summary of the zone J transmission security margin.

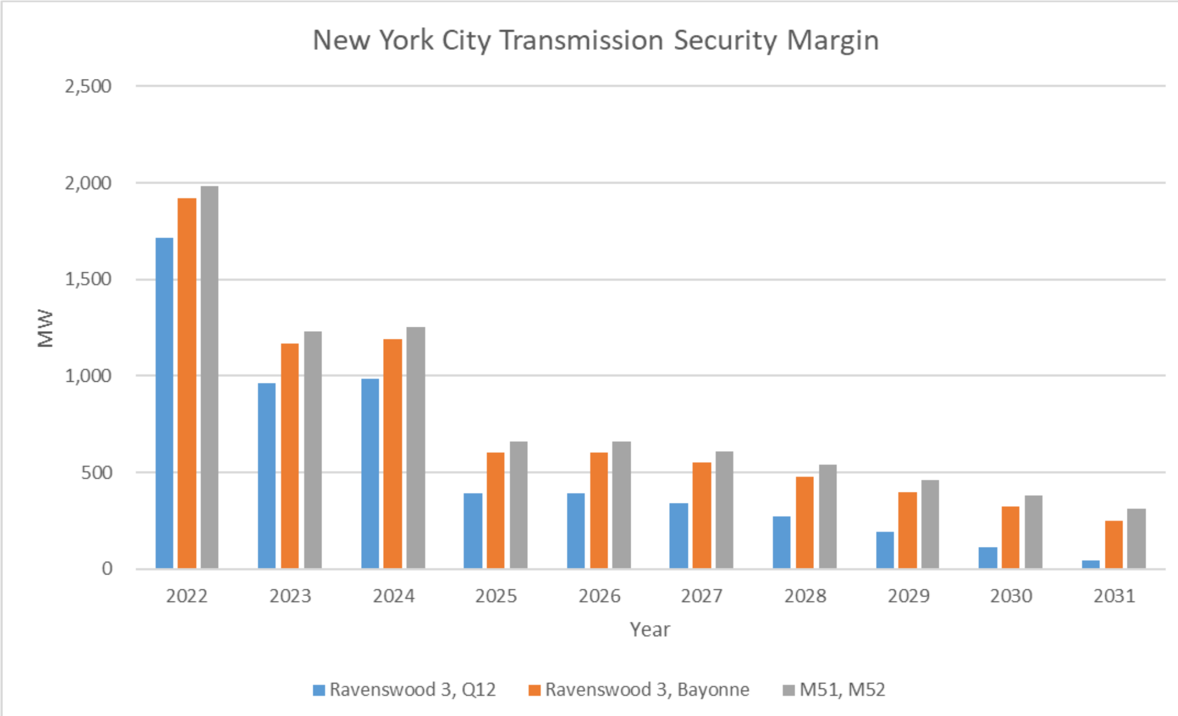
The tipping points for Zone J are evaluated under the most limiting N-1-1-0 contingency combination to the transmission security margin, which is loss of Ravenswood 3 followed by the loss of Mott Haven – Rainey 345 kV (Q12). Figure 22 shows the transmission security margin under baseline load conditions with this contingency combination, which ranges from 1,174 MW in 2022 to 42 MW in 2031). The most limiting contingency combination to transmission security margin in Zone J is the loss of Ravenswood 3 and Mott Haven – Rainey (Q12) 345 kV. The power flowing into J from other NYCA zones is shown in line-item B. Other contingency combinations result in changing the power flowing into J from other NYCA zones. For example, in considering the possible combinations of N-1-1-0 events these can include a mix of generation and transmission, two transmission events, or two generation events. Figure 21 shows the transmission security margin for the contingency combinations of: Ravenswood 3 and Mott Haven – Rainey (Q12) 345 kV, Ravenswood 3 and Bayonne Energy Center, and Sprain Brook-W. 49th St. 345 kV (M51 and M52). For Ravenswood 3 and Bayonne Energy Center the power flowing into J from other NYCA zones is 4,717 MW. For Sprain Brook-W. 49th St. 345 kV (M51 and M52) the power flowing into J from other NYCA zones is 3,191 MW. As seen in Figure 21, the selecting an interface flow with the lowest value (3,191 MW for the loss of M51/M52) does not result in the smallest transmission security margin. In this specific example, all year's show the loss of M51/M52 with the largest transmission security margin.

Considering the baseline peak load transmission security margin (42 MW observed in 2031), many different losses of generation or load increases will exceed the transmission security margin.

[7] Con Edison, TP-7100-18 Transmission Planning Criteria, dated August 2019.

[8] https://www.nyiso.com/documents/20142/19415353/07 2020-2021RPP_PostRNABaseCaseUpdates.pdf/

Figure 21: Impact of Contingency Combination on Zone J Transmission Security Margin



An additional evaluation shown in **Figure 21** is the impact of the historical forced outage rate of thermal generation on the transmission security margin. Also, while SCRs are not included for an evaluation of transmission security under normal transfer criteria, the impact of SCRs is accounted for in this adjusted transmission security margin. The adjusted transmission security margin (line-item P) shows that generation outages consistent with the historical forced outage rates of thermal generation would "tip" beyond the transmission security limits in 2028 with a 20 MW deficiency which grows to a deficiency of 250 MW by 2031.

Figure 22 shows the transmission security margin for the 1-in-10-year load conditions under the assumption that the system is in an emergency condition. Insufficient transmission security margin is observed in 2028 (Line-item N). As shown in **Figure 22**, under the 90th percentile load conditions the inclusion of the historical forced outage rate of thermal generation (line-item O) shows that the system tips in 2025 (line-item P) and remains deficient through the study period.

Under transmission security for the 1 in 100-year forecast, Figure 23 shows that there is insufficient transmission security margin (line-item N) starting in 2025. The adjusted transmission security margin (line-item P), which includes the historical forced outage rate of thermal generation, exacerbates the insufficiency of the transmission security margin and the system tips as early as 2023.

Figure 24 provides a summary of the transmission security margins under each load level.

Figure 22: New York City Transmission Security Margin (Summer Baseline Peak Forecast - Normal)

		Peak Load Forecast									
Line	**Item**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
A	**Zone J Load Forecast**	(11,116)	(11,075)	(11,052)	(11,029)	(11,031)	(11,082)	(11,151)	(11,232)	(11,308)	(11,381)
B	I+K to J (5)	3,904	3,904	3,904	3,904	3,904	3,904	3,904	3,904	3,904	3,904
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	3,893	3,893	3,893	3,893	3,893	3,893	3,893	3,893	3,893	3,893
E	Loss of Source Contingency	(980)	(980)	(980)	(980)	(980)	(980)	(980)	(980)	(980)	(980)
F	**Resource Need (A+D+E)**	(8,203)	(8,162)	(8,139)	(8,116)	(8,118)	(8,169)	(8,238)	(8,319)	(8,395)	(8,468)
G	*Resources needed after N-1-1 (A+D)*	(7,223)	(7,182)	(7,159)	(7,136)	(7,138)	(7,189)	(7,258)	(7,339)	(7,415)	(7,488)
H	J Generation (1)	9,602	8,809	8,809	8,195	8,195	8,195	8,195	8,195	8,195	8,195
I	Temperature Based Generation Derates (2)	0	0	0	0	0	0	0	0	0	0
J	Net ICAP External Imports	315	315	315	315	315	315	315	315	315	315
K	**Total Resources Available (H+I+J)**	9,917	9,124	9,124	8,510	8,510	8,510	8,510	8,510	8,510	8,510
L	*Resources available after N-1-1 (E+K)*	8,937	8,144	8,144	7,530	7,530	7,530	7,530	7,530	7,530	7,530
M	**Transmission Security Margin (F+K)**	1,714	962	985	394	392	341	272	191	115	42
N	SCRs (3), (4)	223	223	223	223	223	223	223	223	223	223
O	Forced Outages (2)	(744)	(599)	(599)	(515)	(515)	(515)	(515)	(515)	(515)	(515)
P	**Adjusted Transmission Security Margin (M+N+O) (3)**	1,193	586	609	102	100	49	(20)	(101)	(177)	(250)

Notes:

1. Reflects the 2021 Gold Book existing summer capacity plus projected additions, deactivations, and de-rates. For this evaluation wind generation is assumed to have 0 MW output, solar generation is based on the ratio of solar PV nameplate capacity (2021 Gold Book Table I-9a) and solar PV peak reductions (2021 Gold Book Table I-9c). De-rates for run-of-river hydro is included as well as the Oswego Export limit for all lines in-service.
2. Includes de-rates for thermal resources.
3. Special Case Resources (SCRs) are not applied for transmission security analysis of normal operations.
4. Includes a de-rate of 205 MW for SCRs.
5. The I+K to J flows are based on N-1-1-0 analysis in the post-RNA updates utilizing the models representing summer peak 2030.

Figure 23: New York City Transmission Security Margin (Summer 1-in-10 (90/10) Peak Forecast - Emergency)

90th Percentile Load Forecast											
Line	Item	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
A	**Zone J Load Forecast**	(11,577)	(11,534)	(11,510)	(11,486)	(11,488)	(11,541)	(11,613)	(11,697)	(11,777)	(11,853)
B	I+K to J (5)	3,904	3,904	3,904	3,904	3,904	3,904	3,904	3,904	3,904	3,904
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	3,893	3,893	3,893	3,893	3,893	3,893	3,893	3,893	3,893	3,893
E	Loss of Source Contingency	(980)	(980)	(980)	(980)	(980)	(980)	(980)	(980)	(980)	(980)
F	**Resource Need (A+D+E)**	(8,664)	(8,621)	(8,597)	(8,573)	(8,575)	(8,628)	(8,700)	(8,784)	(8,864)	(8,940)
G	*Resources needed after N-1-1 (A+D)*	(7,684)	(7,641)	(7,617)	(7,593)	(7,595)	(7,648)	(7,720)	(7,804)	(7,884)	(7,960)
H	J Generation (1)	9,602	8,809	8,809	8,195	8,195	8,195	8,195	8,195	8,195	8,195
I	Temperature Based Generation Derates	(72)	(61)	(61)	(52)	(52)	(52)	(52)	(52)	(52)	(52)
J	Net ICAP External Imports	315	315	315	315	315	315	315	315	315	315
K	SCRs (3), (4)	223	223	223	223	223	223	223	223	223	223
L	**Total Resources Available (H+I+J+K)**	10,069	9,285	9,285	8,681	8,681	8,681	8,681	8,681	8,681	8,681
M	*Resources available after N-1-1 (E+L)*	9,089	8,305	8,305	7,701	7,701	7,701	7,701	7,701	7,701	7,701
N	**Transmission Security Margin (F+L)**	1,405	664	688	108	106	53	(19)	(103)	(183)	(259)
O	Forced Outages (2)	(744)	(599)	(599)	(515)	(515)	(515)	(515)	(515)	(515)	(515)
P	**Adjusted Transmission Security Margin (N+O)**	661	65	89	(407)	(409)	(462)	(534)	(618)	(698)	(774)

Notes:

1. Reflects the 2021 Gold Book existing summer capacity plus projected additions, deactivations, and de-rates. For this evaluation wind generation is assumed to have 0 MW output, solar generation is based on the ratio of solar PV nameplate capacity (2021 Gold Book Table I-9a) and solar PV peak reductions (2021 Gold Book Table I-9c). De-rates for run-of-river hydro is included as well as the Oswego Export limit for all lines in-service.
2. Includes de-rates for thermal resources.
3. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
4. Includes a de-rate of 205 MW for SCRs.
5. The I+K to J flows are based on N-1-1-0 analysis in the post-RNA updates utilizing the models representing summer peak 2030.

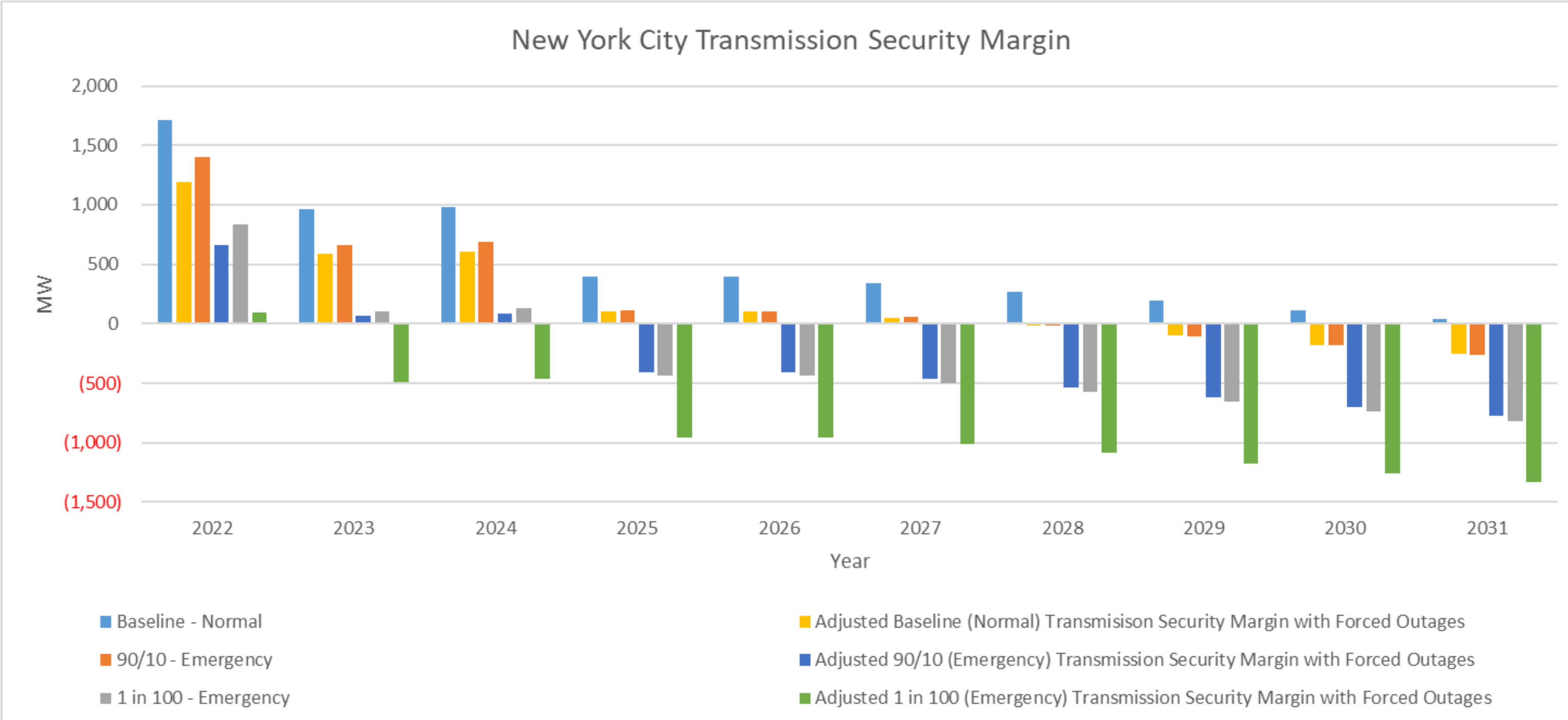
Figure 24: New York City Transmission Security Margin (Summer 1-in-100 Peak Forecast - Emergency)

		1 in 100 Forecast									
Line	**Item**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
A	**Zone J Load Forecast**	(12,068)	(12,023)	(11,998)	(11,974)	(11,976)	(12,031)	(12,106)	(12,194)	(12,276)	(12,356)
B	I+K to J (5)	3,904	3,904	3,904	3,904	3,904	3,904	3,904	3,904	3,904	3,904
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	3,893	3,893	3,893	3,893	3,893	3,893	3,893	3,893	3,893	3,893
E	Loss of Source Contingency	(980)	(980)	(980)	(980)	(980)	(980)	(980)	(980)	(980)	(980)
F	**Resource Need (A+D+E)**	(9,155)	(9,110)	(9,085)	(9,061)	(9,063)	(9,118)	(9,193)	(9,281)	(9,363)	(9,443)
G	*Resources needed after N-1-1 (A+D)*	(8,175)	(8,130)	(8,105)	(8,081)	(8,083)	(8,138)	(8,213)	(8,301)	(8,383)	(8,463)
H	J Generation (1)	9,602	8,809	8,809	8,195	8,195	8,195	8,195	8,195	8,195	8,195
I	Temperature Based Generation Derates	(151)	(130)	(130)	(110)	(110)	(110)	(110)	(110)	(110)	(110)
J	Net ICAP External Imports	315	315	315	315	315	315	315	315	315	315
K	SCRs (3)	223	223	223	223	223	223	223	223	223	223
L	**Total Resources Available (H+I+J+K)**	9,989	9,217	9,217	8,623	8,623	8,623	8,623	8,623	8,623	8,623
M	*Resources available after N-1-1 (E+L)*	9,009	8,237	8,237	7,643	7,643	7,643	7,643	7,643	7,643	7,643
N	**Transmission Security Margin (F+L)**	834	107	132	(438)	(440)	(495)	(570)	(658)	(740)	(820)
O	Forced Outages (2)	(744)	(599)	(599)	(515)	(515)	(515)	(515)	(515)	(515)	(515)
P	**Adjusted Transmission Security Margin (N+O)**	90	(492)	(467)	(953)	(955)	(1,010)	(1,085)	(1,173)	(1,255)	(1,335)

Notes:

1. Reflects the 2021 Gold Book existing summer capacity plus projected additions, deactivations, and de-rates. For this evaluation wind generation is assumed to have 0 MW output, solar generation is based on the ratio of solar PV nameplate capacity (2021 Gold Book Table I-9a) and solar PV peak reductions (2021 Gold Book Table I-9c). De-rates for run-of-river hydro is included as well as the Oswego Export limit for all lines in-service.
2. Includes de-rates for thermal resources.
3. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
4. Includes a de-rate of 205 MW for SCRs.
5. The I+K to J flows are based on N-1-1-0 analysis in the post-RNA updates utilizing the models representing summer peak 2030.

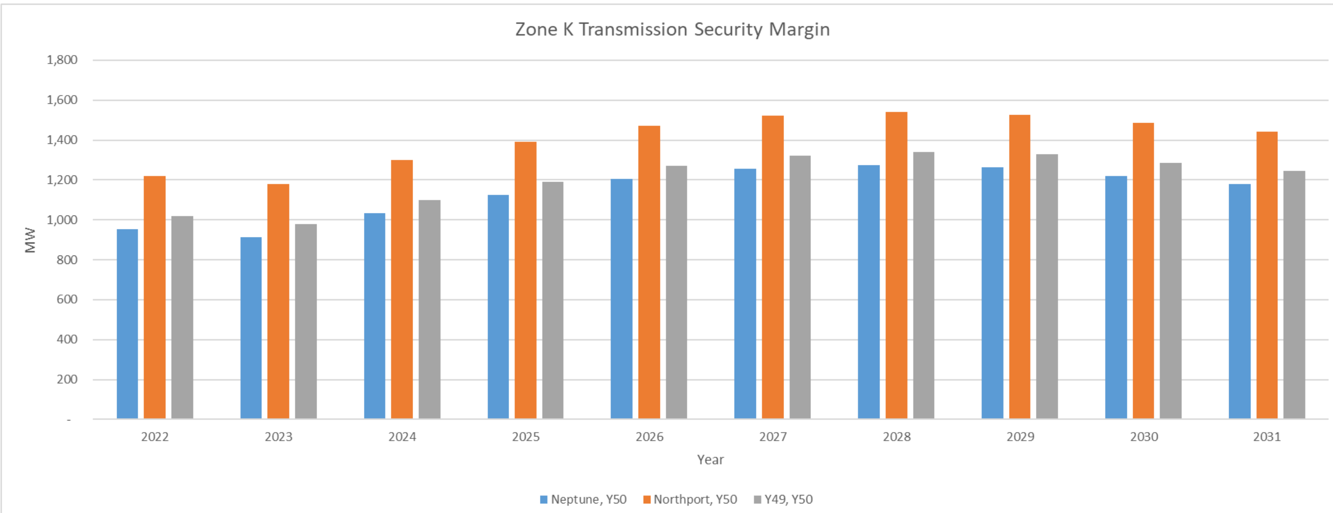
Figure 25: Summary of New York City Transmission Security Margin



Long Island (Zone K) Tipping Points

Within the PSEG Long Island service territory, the BPTF system (primarily comprised of 138 kV transmission) is designed for N-1-1. As shown in **Figure 25,** the most limiting N-1-1 combination for the transmission security margin under normal conditions is the outage of Neptune HVDc (660 MW) followed by securing for the loss of Dunwoodie — Shore Road 345 kV (Y50) for all evaluated years.

Figure 26: Impact of Contingency Combination on Zone K Transmission Security Margin



As seen in **Figure 26** the transmission security margin (line-item M) in Zone K under baseline conditions ranges from 964 MW in 2022 growing to 1,179 MW in 2031 due to a forecasted decrease in peak demand through time. Considering the baseline peak load transmission security margin, multiple outages in Zone K would be required to tip the system over its security margin, beyond the outage of Neptune.

An additional evaluation included in **Figure 26** is the impact of the historical forced outage rate of thermal generation on the transmission security margin. Also, while SCRs are not included for an evaluation of transmission security under normal transfer criteria, the impact of SCRs is accounted for in this adjusted transmission security margin. The adjusted transmission security margin (line-item P) shows that generation outages consistent with the historical forced outage rates would not result in "tipping" beyond transmission security limits, with a margin of 549 MW in 2022 growing to 829 MW in 2031. This assumes no transmission outages beyond the outage of Neptune.

Figure 27 shows the transmission security margin for the 1-in-10-year load conditions (90/10) under the assumption that the system is in an emergency condition (line-item N). Under emergency conditions, higher line ratings are allowed to be utilized, fewer contingency events are secured for, and SCRs are accounted for as available resources. The limiting contingency combination under emergency conditions is the outage of Sprain Brook — East Garden City 345 kV (Y49) followed by securing for the loss of Dunwoodie — Shore Road 345 kV (Y50). An additional evaluation shown in this figure is the impact of the historical forced outage rate of Zone K thermal generation on the transmission security margin (line-item P). Under both conditions there is sufficient transmission security margin.

For the 1-in-100-year forecast shown in Figure 28 sufficient transmission security margin is observed for all years assuming that the system is in an emergency condition. An additional evaluation shown in this figure is the impact of the historical forced outage rate of Zone K generation on the transmission security margin (line-item P). Under both conditions there is sufficient transmission security margin. However, if a large facility such as Neptune is also lost in addition to the generator outages, there would be insufficient transmission security margin (line-item P) in years 2022 through 2025.

Figure 29 provides a summary of the transmission security margins under each load level.

Figure 27: Long Island Transmission Security Margin (Summer Baseline Peak Forecast - Normal)

		Peak Load Forecast									
Line	**Item**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
A	**Zone K Load Forecast**	(5,136)	(5,039)	(4,919)	(4,826)	(4,746)	(4,695)	(4,676)	(4,689)	(4,729)	(4,771)
B	I+J to K	929	929	929	929	929	929	929	929	929	929
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	929	929	929	929	929	929	929	929	929	929
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)
F	**Resource Need (A+D+E)**	(4,867)	(4,770)	(4,650)	(4,557)	(4,477)	(4,426)	(4,407)	(4,420)	(4,460)	(4,502)
G	*Resources needed after N-1-1 (A+D)*	(4,207)	(4,110)	(3,990)	(3,897)	(3,817)	(3,766)	(3,747)	(3,760)	(3,800)	(3,842)
H	K Generation (1)	5,161	5,024	5,023	5,023	5,023	5,023	5,022	5,022	5,021	5,021
I	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
J	Net ICAP External Imports	660	660	660	660	660	660	660	660	660	660
K	**Total Resources Available (H+I+J)**	5,821	5,684	5,683	5,683	5,683	5,683	5,682	5,682	5,681	5,681
L	*Resources available after N-1-1 (E+K)*	5,161	5,024	5,023	5,023	5,023	5,023	5,022	5,022	5,021	5,021
M	**Transmission Security Margin (F+K)**	954	914	1,033	1,126	1,206	1,257	1,275	1,262	1,221	1,179
N	SCRs (3), (4)	25	25	25	25	25	25	25	25	25	25
O	Forced Outages (2)	(430)	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)
P	**Adjusted Transmission Security Margin (M+N+O) (3)**	549	564	683	776	856	907	925	912	871	829

Notes:

1. Reflects the 2021 Gold Book existing summer capacity plus projected additions, deactivations, and de-rates. For this evaluation wind generation is assumed to have 0 MW output, solar generation is based on the ratio of solar PV nameplate capacity (2021 Gold Book Table I-9a) and solar PV peak reductions (2021 Gold Book Table I-9c). De-rates for run-of-river hydro is included as well as the Oswego Export limit for all lines in-service.
2. Includes de-rates for thermal resources.
3. Special Case Resources (SCRs) are not applied for transmission security analysis of normal operations.
4. Includes a de-rate of 18 MW for SCRs.

Figure 28: Long Island Transmission Security Margin (Summer 1-in-10 (90/10) Peak Forecast - Emergency)

		90th Percentile Load Forecast									
Line	**Item**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
A	**Zone K Load Forecast**	(5,530)	(5,425)	(5,296)	(5,196)	(5,110)	(5,055)	(5,035)	(5,049)	(5,092)	(5,137)
B	I+J to K	887	887	887	887	887	887	887	887	887	887
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	887	887	887	887	887	887	887	887	887	887
E	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
F	**Resource Need (A+D+E)**	(4,643)	(4,538)	(4,409)	(4,309)	(4,223)	(4,168)	(4,148)	(4,162)	(4,205)	(4,250)
G	*Resources needed after N-1-1 (A+D)*	(4,643)	(4,538)	(4,409)	(4,309)	(4,223)	(4,168)	(4,148)	(4,162)	(4,205)	(4,250)
H	K Generation (1)	5,161	5,024	5,023	5,023	5,023	5,023	5,022	5,022	5,021	5,021
I	Temperature Based Generation Derates	(38)	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)
J	Net ICAP External Imports	660	660	660	660	660	660	660	660	660	660
K	SCRs (3), (4)	25	25	25	25	25	25	25	25	25	25
L	**Total Resources Available (H+I+J+K)**	5,808	5,674	5,672	5,672	5,672	5,672	5,671	5,671	5,670	5,670
M	*Resources available after N-1-1 (E+L)*	5,808	5,674	5,672	5,672	5,672	5,672	5,671	5,671	5,670	5,670
N	**Transmission Security Margin (F+L)**	1,165	1,136	1,263	1,363	1,449	1,504	1,523	1,509	1,465	1,420
O	Forced Outages (2)	(430)	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)
P	**Adjusted Transmission Security Margin (N+O)**	735	761	888	988	1,074	1,129	1,148	1,134	1,090	1,045

Notes:

1. Reflects the 2021 Gold Book existing summer capacity plus projected additions, deactivations, and de-rates. For this evaluation wind generation is assumed to have 0 MW output, solar generation is based on the ratio of solar PV nameplate capacity (2021 Gold Book Table I-9a) and solar PV peak reductions (2021 Gold Book Table I-9c). De-rates for run-of-river hydro is included as well as the Oswego Export limit for all lines in-service.
2. Includes de-rates for thermal resources.
3. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
4. Includes a de-rate of 18 MW for SCRs.

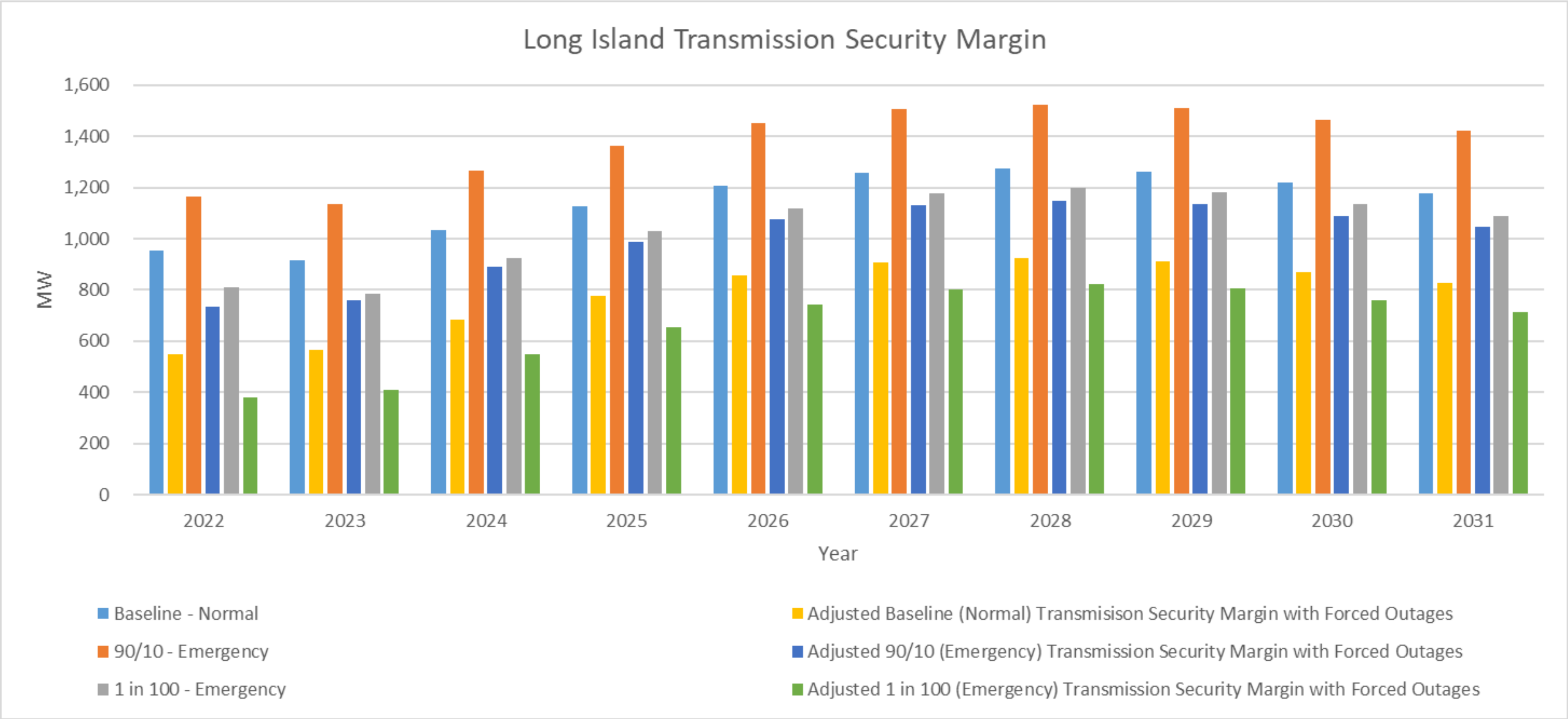
Figure 29: Long Island Transmission Security Margin (Summer 1-in-100 Peak Forecast - Emergency)

		1 in 100 Forecast									
Line	**Item**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
A	**Zone K Load Forecast**	(5,843)	(5,733)	(5,596)	(5,490)	(5,399)	(5,341)	(5,320)	(5,334)	(5,380)	(5,428)
B	I+J to K	887	887	887	887	887	887	887	887	887	887
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	887	887	887	887	887	887	887	887	887	887
E	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
F	**Resource Need (A+D+E)**	(4,956)	(4,846)	(4,709)	(4,603)	(4,512)	(4,454)	(4,433)	(4,447)	(4,493)	(4,541)
G	*Resources needed after N-1-1 (A+D)*	(4,956)	(4,846)	(4,709)	(4,603)	(4,512)	(4,454)	(4,433)	(4,447)	(4,493)	(4,541)
H	K Generation (1)	5,161	5,024	5,023	5,023	5,023	5,023	5,022	5,022	5,021	5,021
I	Temperature Based Generation Derates	(82)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)	(77)
J	Net ICAP External Imports	660	660	660	660	660	660	660	660	660	660
K	SCRs (3), (4)	25	25	25	25	25	25	25	25	25	25
L	**Total Resources Available (H+I+J+K)**	5,764	5,632	5,631	5,631	5,631	5,631	5,630	5,630	5,629	5,629
M	*Resources available after N-1-1 (E+L)*	5,764	5,632	5,631	5,631	5,631	5,631	5,630	5,630	5,629	5,629
N	**Transmission Security Margin (F+L)**	808	786	922	1,028	1,119	1,177	1,197	1,183	1,136	1,088
O	Forced Outages (2)	(430)	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)
P	**Adjusted Transmission Security Margin (N+O)**	378	411	547	653	744	802	822	808	761	713

Notes:

1. Reflects the 2021 Gold Book existing summer capacity plus projected additions, deactivations, and de-rates. For this evaluation wind generation is assumed to have 0 MW output, solar generation is based on the ratio of solar PV nameplate capacity (2021 Gold Book Table I-9a) and solar PV peak reductions (2021 Gold Book Table I-9c). De-rates for run-of-river hydro is included as well as the Oswego Export limit for all lines in-service.
2. Includes de-rates for thermal resources.
3. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
4. Includes a de-rate of 18 MW for SCRs.

Figure 30: Summary of Long Island Transmission Security Margin



Appendix E – 70 x 30 Scenario – Extended Wind Lull

One of the objectives of the Reliability Planning Process is to identify, through the development of appropriate scenarios, factors and issues that might adversely impact the reliability of the Bulk Power Transmission Facilities (BPTF). The scenarios in this CRP are focused on potential reliability issues as the New York electric system transitions to significant quantities of renewable resources that provide intermittent output to the power system.

Weather variability, which impacts the output from wind and solar resources, presents a fundamental challenge to relying exclusively on those resources to meet electricity demand, particularly during extended wind lull events. Even outside of multi-day wind lulls assessed in the study, the Climate Study's results suggest that reductions in wind output create significant reliance on dispatchable emissions free resources (DEFRs) to avoid potential loss of load events.

To continue the study efforts on this subject, the NYISO conducted additional 'wind lull' scenarios in its Reliability Planning Process. In this CRP, the NYISO conducted scenarios under which there is no wind generation output for an extended period of time, such as one week. These scenarios add to the scenarios performed under the 2020 RNA (*e.g.,* high load, 70 x 30, status quo).

Summary of the 2020 RNA 70 x 30 Scenario Major Assumptions

The 2020 RNA evaluated several scenarios, including a 70 x 30 analysis. The 2020 RNA 70 x 30 Scenario modeled the same zonal renewable resource distribution as modeled in the 2019 Congestion Assessment and Resource Integration Study (CARIS) 70 x 30 Scenario. The CARIS output was used to establish dispatch profiles accounting for generation curtailments. The nameplate capacity of the renewable resource mix is provided in **Figure 31** below.

Figure 31: Renewable Mix Assumptions for each Load Level

70x30 Base Load' Case (Nameplate MW)					
Zone/Type	OSW	LBW	UPV	BTM-PV	Total
A		2,286	4,432	995	**7,713**
B		314	505	298	**1,117**
C		2,411	2,765	836	**6,012**
D		1,762		76	**1,838**
E		2,000	1,747	901	**4,648**
F			3,592	1,131	**4,723**
G			2,032	961	**2,993**
H				89	**89**
I				130	**130**
J	4,320			950	**5,270**
K	1,778		77	1,176	**3,031**
Total	**6,098**	**8,772**	**15,150**	**7,542**	**37,562**

70x30 'Scenario Load' Case (Nameplate MW)					
Zone/Type	OSW	LBW	UPV	BTM-PV	Total
A		1,640	3,162	995	**5,797**
B		207	361	298	**866**
C		1,765	1,972	836	**4,573**
D		1,383		76	**1,459**
E		1,482	1,247	901	**3,630**
F			2,563	1,131	**3,694**
G			1,450	961	**2,411**
H				89	**89**
I				130	**130**
J	4,320			950	**5,270**
K	1,778		77	1,176	**3,031**
Total	**6,098**	**6,477**	**10,832**	**7,542**	**30,949**

Two load models from the 2019 CARIS 70 x 30 Scenario were used for the 2020 RNA 70 x 30 Scenario, both developed from the 2020 RNA 2030 Base Case, with major modifications as highlighted below:

1. **'Base Load'** represents a higher energy shape (153 TWh) and a higher peak forecast (31,303 MW): The 2002 load shape (8,760 hours) was scaled up to 2028 energy forecast from the 2019 Gold Book. The same load shape was used for all MARS load levels; and

2. **'Scenario Load'** represents a lower energy shape (136 TWh) and a lower peak forecast (25,312 MW): The CARIS-developed load shape was scaled to match CARIS 70 x 30 'Scenario Load' energy and peak demand forecast. The same load shape was used for all MARS load levels.

Figure 32: Summer Energy and Peak Demand Forecast Zonal Distribution

70x30 Base Load	A	B	C	D	E	F	G	H	I	J	K	NYCA
Net Load Energy (GWh)	14,590	9,695	15,394	5,337	7,095	11,312	9,544	2,807	5,881	51,749	19,608	153,012
Net Load Peak (MW)*	2,537	1,937	2,653	718	1,264	2,197	2,174	637	1,405	11,589	4,730	31,303
+ BtM-PV at Zonal Peak (MW)	368	60	556	13	518	584	246	35	35	352	102	2,757
Total Load Peak (MW)	2,905	1,997	3,209	731	1,782	2,781	2,420	672	1,440	11,941	4,832	34,060

70x30 Scenario Load	A	B	C	D	E	F	G	H	I	J	K	NYCA
Net Load Energy (GWh)	13,034	7,757	12,626	5,101	5,694	9,654	7,911	2,848	5,952	46,354	19,026	135,958
Summer Net Load Peak (MW)*	2,112	1,417	2,171	651	1,052	1,988	1,912	625	1,385	9,129	3,914	25,312
+ BtM-PV at Summer Zonal Peak (MW)	77	16	0	0	0	0	22	2	5	64	24	269
Total Summer Load Peak (MW)	2,189	1,433	2,171	651	1,052	1,988	1,934	627	1,390	9,193	3,938	25,581
Winter Net Load Peak (MW)*	2,234	1,310	2,264	740	1,246	1,934	1,607	636	1,065	7,344	3,841	23,779
+ BtM-PV at Winter Zonal Peak (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Total Winter Load Peak (MW)	2,234	1,310	2,264	740	1,246	1,934	1,607	636	1,065	7,344	3,841	23,779

Note: *Non-coincident zonal peak

Additional modeling details employed in the 2020 RNA 70 x 30 scenarios, by type:

- **Land-based wind (LBW):** Hourly dispatch profiles (MWh shapes) are applied from the CARIS simulation output, including curtailments observed in the production simulation, for each of the two load shapes. CARIS used the 2009 National Renewable Energy Laboratory (NREL) hourly data as input.
- **Offshore wind (OSW):** Hourly dispatch profiles (MWh shapes) are applied from the CARIS simulation output, including curtailments observed in the production simulation, for each of the two load shapes. CARIS used the 2009 National Renewable Energy Laboratory (NREL) hourly data as input.
- **Utility-scale Photovoltaic (UPV):** Hourly dispatch profiles (MWh shapes) are applied from the CARIS simulation output, including curtailments observed in the production simulation, for each of the two load shapes. CARIS used the 2017 production data for existing plants and the 2006 NREL hourly data for new plants as input.
- **Behind-the-Meter PV (BTM PV):** Hourly dispatch profile (MWh shapes) are applied from the CARIS simulation output, for each of the two load shapes. The CARIS behind-the-meter solar profiles are based on hourly shapes created using the NREL's PV Watt tool.
- **External areas:** added a 1,310 MW Hydro Quebec to Zone J HVDC tie, consistent with the CARIS modeling.
- **Peakers:** All peaker units affected by DEC's Peaker Rule[9] were removed in 2023 and 2025 to further align with the 2019 CARIS assumptions.

Wind Lull Scenarios Assumptions

Using the 70 x 30 models developed during the 2020 RNA, and as described below, additional weekly 'wind lull' scenarios were simulated using GE MARS.

Resource adequacy impacts of these events are measured in terms of three reliability metrics: Loss of Load Expectation (LOLE in days/year), Loss of Load Hours (LOLH in hours/year) and Expected Unserved Energy (EUE in MWh). The assessment also determined the compensatory MW ('perfect capacity') needed for returning the system back to its initial (pre-wind lull) LOLE, under each scenario assessed. "Perfect capacity" is capacity that is not derated (*e.g.,* due to ambient temperature or unit unavailability), not subject to energy durations limitations (*i.e.,* available for every hour of the year), and not tested for transmission

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[9] In 2020, the New York State Department of Environmental Conservation adopted a regulation to limit nitrogen oxides (NOx) emissions from simple-cycle combustion turbines ("Peaking Units") (referred to as the "Peaker Rule"). 6 NYCRR Part 227-3. See https://govt.westlaw.com/nycrr/Browse/Home/NewYork/NewYorkCodesRulesandRegulations?guid=I9e8759705fd311eaa71dc9fbe3ec8164&originationContext=documenttoc&transitionType=Default&contextData=(sc.Default)&bhcp=1 The Peaker Rule required all impacted plant owners to file compliance plans by March 2, 2020.

security or interface impacts.

The following MARS models were used. Their assumptions reside in the 2020 RNA November Report [link]. Major assumptions are also reiterated below.

Model #1: The 70 x 30 'Base Load' "at criterion" (case "67*" in the table below) cases used for the 2020 RNA scenario evaluations. These cases are brought to approximately 0.1 days/year LOLE by employing an age-based fossil removal method.

Figure 33: "70 x 30 Base Load" Case at-Criterion: Age-based Fossil Removal

	Total Thermal Capacity (MW)				Cumulative Capacity Removed (MW)				
Cases (Age >=)	Zone J	Zone K	Other Zones	Total	Zone J	Zone K	Other Zones	Total	NYCA LOLE
Total	8,190	3,962	15,012	27,165	0	0	0	0	0.00
70	6,978	3,564	14,616	25,160	1,212	398	396	2,005	0.02
68	6,601	3,371	14,616	24,590	1,589	591	396	2,575	0.05
67*	6,386	3,360	14,616	24,364	1,804	602	396	2,801	0.11
67	6,236	3,360	14,616	24,214	1,954	602	396	2,951	0.15

Figure 34: “70 x 30 Base Load” Case: ICAP vs UCAP

NYCA Totals	70x30 "CARIS Base Load" (ICAP)	70x30 "CARIS Base Load" (UCAP)[1]
Load (net of BtM Solar)	**31,303**	**31,303**
CARIS Renewable Additions *(offshore&land wind, utility solar)*	30,020	7,861
Total capacity in the 70x30 model before age-based removal[2]	62,837	38,322
Total thermal capacity in the 70x30 model before age-based removal	27,165	25,444
Total fossil units in the 70x30 model before age-based capacity removal	23,822	22,175
Total nukes in the 70x30 model before age-based capacity removal	3,343	3,269
Age-based fossils removed to get to 0.1 LOLE ("model at criterion")[3]	2,801	2,629
Total capacity ("model at criterion")	**60,036**	**35,693**
Capacity/ Load Ratio	**191.8%**	**114.0%**

NY_J Totals		
Load (net of BtM Solar)	**11,589**	**11,589**
Total capacity in 70x30 Case	12,510	8,761
Total fossil units in 70x30 model before age-based fossil removal	8,190	7,602
Age-based fossils removed to get to 0.1 LOLE ("model at criterion")**	1,804	1,701
Total capacity ("model at criterion")	**10,706**	**7,060**
Capacity/Load Ratio	**92.4%**	**60.9%**

NY_K Totals		
Load (net of BtM Solar)	**4,730**	**4,730**
Total capacity in 70x30 Case	5,782	4,400
Total fossil units in 70x30 model before fossil removal	3,962	3,745
Age-based fossils removed to get to 0.1 LOLE ("model at criterion")**	602	579
Total capacity ("model at criterion")	**5,180**	**3,821**
Capacity/Load Ratio	**109.5%**	**80.8%**

Notes:

1. UCAP calculation:

For thermal units, MARS EFORd data is used.

For renewables, UCAP is calculated based on the average output during 4 peak hours.

2. Reflects additional peakers removal in Zone K.

3. Calculated based on case “67*”.

Model #2: The 70 x 30 ‘Scenario Load’ “at criterion” cases (case “38” in the table below) used for the 2020 RNA scenario evaluations. These cases are brought to approximately 0.1 days/year LOLE by employing an age-based fossil removal method.

Model #3: 70 x 30 ‘Scenario Load’ model at low LOLE: a Scenario Case with age-based removal at 0.03 LOLE, which is case “50” in the table above.

Figure 35: “7070 x 30 Scenario Load” Case at-Criterion: Age-based Fossil Removal

	Total Thermal Capacity (MW)				Cumulative Capacity Removed (MW)				
Cases (Age >=)	**Zone J**	**Zone K**	**Other Zones**	**Total**	**Zone J**	**Zone K**	**Other Zones**	**Total**	**NYCA LOLE**
Total	8,190	3,962	15,012	27,165	0	0	0	0	0
50	4,354	1,541	11,228	17,124	3,836	2421	3784	10,041	0.03
40	4,354	1,393	10,247	15,995	3,836	2569	4765	11,170	0.07
39	4,354	1,349	10,197	15,901	3,836	2613	4815	11,264	0.09
38	3,563	1,325	9,935	14,824	4,627	2637	5077	12,341	0.11

Figure 36: "70 x 30 Scenario Load" Case at-Criterion: ICAP vs UCAP

NYCA Totals	70x30 "CARIS Scenario Load" (ICAP)	70x30 "CARIS Scenario Load"[1] (UCAP)
Load (net of BtM Solar)	**25,312**	**25,312**
CARIS Renewable Additions (*offshore&land wind, utility solar)*	23,407	6,082
Total capacity in the 70x30 model before age-based fossil removal[2]	56,224	36,543
Total thermal capacity in the 70x30 model before age-based removal	27,165	25,444
Total fossil units in the 70x30 model before age-based capacity removal	23,822	22,174
Total nukes in the 70x30 model before age-based capacity removal	3,343	3,269
Age-based fossils removed to get to 0.1 LOLE ("model at criterion")[3]	12,341	10,295
Total capacity ("model at criterion")	**43,883**	**26,246**
Capacity/ Load Ratio	**173.4%**	**103.7%**

NY_J Totals		
Load (net of BtM Solar)	**9,129**	**9,129**
Total capacity in 70x30 Case	13,460	8,759
Total fossil units in 70x30 model before age-based fossil removal	8,190	7,602
Age-based fossils removed to get to 0.1 LOLE ("model at criterion")[3]	4,627	4,152
Total capacity ("model at criterion")	**8,833**	**4,607**
Capacity/Load Ratio	**96.8%**	**50.5%**

NY_K Totals		
Load (net of BtM Solar)	**3,914**	**3,914**
Total capacity in 70x30 Case	5,782	4,391
Total fossil units in 70x30 model before fossil removal	3,962	3,745
Age-based fossils removed to get to 0.1 LOLE ("model at criterion")[3]	2,637	2,502
Total capacity ("model at criterion")	**3,145**	**1,889**
Capacity/Load Ratio	**80.3%**	**48.3%**

Notes:
1. UCAP calculation:
For thermal units, MARS EFORd data is used.
For renewables, UCAP is calculated based on the average output during peak hours.
2. Reflects additional peakers removal in Zone K.
3. Calculated based on case "38".

Wind Lull Scenario Scope

The following types of analysis and events were simulated using each of the three MARS models described above. For each, zonal compensatory MW to bring NYCA LOLE close to the initial case was identified. The wind lull weeks assume that all land-based or offshore wind (not both) are completely out for the whole week (*i.e.,* seven consecutive days) and then recover for the following week.

1. Top two weeks with highest % of NYCA LOLE events:
    a. On the top two weeks (one week at the time) with highest % of LOLE events, simulate total loss of all NYCA wind (either land-based or offshore at 0 MW for all NYCA zones)

for that entire week and calculate NYCA LOLE, LOLH, and EUE.

b. Compute compensatory MW to bring LOLE close to the initial case.

2. Top two weeks with highest land-based wind capacity factor:

    a. On the top two weeks (one week at the time) with highest land-based wind capacity factors simulate total loss of NYCA land-based wind (0 MW) for that entire week and calculate NYCA LOLE, LOLH, and EUE.

    b. Compute compensatory MW to bring LOLE close to the initial case.

3. Top two weeks with highest offshore wind capacity factor:

    a. On the top two weeks (one week at the time) with highest offshore wind capacity factors simulate total loss of NYCA offshore wind (0 MW) for that entire week and calculate NYCA LOLE, LOLH, and EUE.

    b. Compute compensatory MW to bring LOLE close to the initial case.

It is important to be noted that the MARS simulations do not take into consideration potential reliability impacts due to:

- Unit commitment and dispatch, ramp rate constraints, and other production cost modeling techniques; or
- Intra-zonal constraints on the transmission system.

Wind Lull Scenario Results

The NYCA reliability indices (LOLE, LOLH, and EUE) and compensatory MW results for the loss of wind scenarios are summarized below.

LOLE is generally defined as the expected (weighted average) number of days in a given period (*e.g.,* one study year) when at least one hour from that day, the hourly demand is projected to exceed the zonal resources (event day). Within a day, if the zonal demand exceeds the resources in at least one hour of that day, this will be counted as one event day. The criterion is that the LOLE not exceed one day in 10 years, or LOLE < 0.1 days/year.

LOLH is generally defined[10] as the expected number of hours per period (*e.g.,* one study year) when a system's hourly demand is projected to exceed the zonal resources (event hour). Within an hour, if the

[10] NYSRC's "Resource Adequacy Metrics and their Application": https://www.nysrc.org/PDF/Reports/Resource%20Adequacy%20Metric%20Report%20Final%204-20-2020[6431].pdf

zonal demand exceeds the resources, this will be counted as one event hour.

EUE, also referred to as loss of energy expectation (LOEE), is generally defined[11] as the expected energy (MWh) per period (*e.g.,* one study year) when the summation of the system's hourly demand is projected to exceed the zonal resources. Within an hour, if the zonal demand exceeds the resources, this deficit will be counted toward the system's EUE.

LOLE is generally defined as the expected (weighted average) number of days in a given time period (*e.g.,* one study year) when at least one hour from that day, the hourly demand (for each of the seven load bins and per replication[12]) is projected to exceed the zonal resources (event day) in any of the seven load bins. Within a day, if the zonal demand exceeds the resources in at least one hour of that day, this will be counted as one event day for the respective load bin. NYSRC and NPCC's LOLE criterion is that the NYCA LOLE not exceed one day in 10 years, or LOLE < 0.1 days/year.

LOLE does not account for the magnitude (MW) or duration (hours) of the deficit; it accounts for the number of event days in each load bin for each replication and study year. In a single MARS replication, the zonal MW hourly margins (MW surplus or deficit) are calculated for each bin using load forecast uncertainty (LFU) applied load, forced outage calculations, hourly shape values (*i.e.*, wind, solar, run-of-river, landfill gas units), contracts and interface flows. In instances where there is a deficit in any area, EOP steps are completed until either the deficits are gone, or there are no more emergency operating procedure (EOP) steps to call. Once all of this is completed MARS calculates the reliability indices (LOLE, LOLH, LOEE) for the replication. This occurs across all load levels simultaneously: MARS lumps them all together in a weighted sum to get a single value for each replication.

LOLH is generally defined[13] as the expected number of hours per period (*e.g.,* one study year) when a system's hourly demand is projected to exceed the zonal resources (event hour) for any load bin. Within an hour, if the zonal demand exceeds the resources, this will be counted as one event hour. This metric is calculated using each hourly bin load in the given period. This occurs across all load levels simultaneously: MARS lumps them all together in a weighted sum to get a single value for each replication.

EUE, also referred to as loss of energy expectation (LOEE), is generally defined[14] as the expected

[11] NYSRC's "Resource Adequacy Metrics and their Application": https://www.nysrc.org/PDF/Reports/Resource%20Adequacy%20Metric%20Report%20Final%204-20-2020[6431].pdf

[12] We currently simulate 2000 replications per study year and load level (7 load bins), for a total of 14,000 replications per study year. Weighted average is based on load bin probability, total bin event days, and total number of replications.

[13] NYSRC's "Resource Adequacy Metrics and their Application": https://www.nysrc.org/PDF/Reports/Resource%20Adequacy%20Metric%20Report%20Final%204-20-2020[6431].pdf

[14] NYSRC's "Resource Adequacy Metrics and their Application": https://www.nysrc.org/PDF/Reports/Resource%20Adequacy%20Metric%20Report%20Final%204-20-2020[6431].pdf

energy (MWh) per period (*e.g.,* one study year) when the summation of the system's hourly demand is projected to exceed the zonal resources capacity for any load bin. Within an hour, if the zonal demand exceeds the resources, this deficit will be counted toward the system's EUE. This occurs across all load levels simultaneously: MARS lumps them all together in a weighted sum to get a single value for each replication.

Loss of Land-Based Wind (LBW)

Figure 37: NYCA LOLE (days/year) for Loss of LBW during the Week with Highest LOLE Events

No LBW during the 1st Highest NYCA Event % Week					Compensatory MW		
Model	Event %	Initial LOLE	Resultant LOLE	Delta LOLE	Zones A-I	Zone J	Zone K
70x30 'Base Load' at-criterion	34%	0.11	0.11	**0.00**	<25	<25	<25
70x30 'Scenario Load' at-criterion	23%	0.11	0.11	**0.00**	<25	<25	<25
70x30 'Scenario Load' at-low-LOLE	24%	0.03	0.03	**0.00**	<25	<25	<25
No Land-Based Wind during the 2nd Highest NYCA Event % Week					**Compensatory MW**		
Model	**Event %**	**Initial LOLE**	**Resultant LOLE**	**Delta LOLE**	**Zones A-I**	**Zone J**	**Zone K**
70x30 'Base Load' at-criterion	19%	0.11	0.11	**0.00**	<25	<25	<25
70x30 'Scenario Load' at-criterion	18%	0.11	0.11	**0.00**	<25	<25	<25
70x30 'Scenario Load' at-low-LOLE	18%	0.03	0.03	**0.00**	<25	<25	<25

Figure 38: NYCA LOLE (days/year) for Loss of LBW during the Week with Highest LBW Capacity Factor

No LBW during the 1st Highest LBW Capacity Factor (CF) Week					Compensatory MW		
Model	LBW CF	Initial LOLE	Resultant LOLE	Delta LOLE	Zones A-I	Zone J	Zone K
70x30 'Base Load' at-criterion	23%	0.11	0.11	**0.00**	<25	<25	<25
70x30 'Scenario Load' at-criterion	23%	0.11	0.11	**0.00**	<25	<25	<25
70x30 'Scenario Load' at-low-LOLE	23%	0.03	0.03	**0.00**	<25	<25	<25
No LBW during the 2nd Highest LBW Capacity Factor Week					**Compensatory MW**		
Model	**LBW CF**	**Initial LOLE**	**Resultant LOLE**	**Delta LOLE**	**Zones A-I**	**Zone J**	**Zone K**
70x30 'Base Load' at-criterion	20%	0.11	0.11	**0.00**	<25	<25	<25
70x30 'Scenario Load' at-criterion	20%	0.11	0.11	**0.00**	<25	<25	<25
70x30 'Scenario Load' at-low-LOLE	20%	0.03	0.03	**0.00**	<25	<25	<25

While the resource adequacy reliability criterion of 0.1 days/year established by the NYSRC and th e NPCC is compared with the loss of load expectation (LOLE in days/year) calculation, currently there is no criteria for determining a reliable system based on the LOLH and EUE reliability indices.

Figure 39: NYCA LOLE (days/year), LOLH (hours/year) and EUE (MWh/year) for Loss of LBW during the Week with Highest LOLE Events

No LBW during the 1st Highest NYCA Event % Week						
Model	**Initial LOLE**	**Resultant LOLE**	**Initial LOLH**	**Resultant LOLH**	**Initial EUE**	**Resultant EUE**
70x30 'Base Load' at-criterion	0.11	0.11	0.291	0.291	85.7	85.7
70x30 'Scenario Load' at-criterion	0.11	0.11	0.269	0.269	40.9	41.0
70x30 'Scenario Load' at-low-LOLE	0.03	0.03	0.067	0.067	8.5	8.5
No Land-Based Wind during the 2nd Highest NYCA Event % Week						
Model	**Initial LOLE**	**Resultant LOLE**	**Initial LOLH**	**Resultant LOLH**	**Initial EUE**	**Resultant EUE**
70x30 'Base Load' at-criterion	0.11	0.11	0.291	0.291	85.7	85.7
70x30 'Scenario Load' at-criterion	0.11	0.11	0.269	0.272	40.9	41.8
70x30 'Scenario Load' at-low-LOLE	0.03	0.03	0.067	0.069	8.5	8.9

Figure 40: NYCA LOLE (days/year), LOLH (hours/year) and EUE (MWh/year) for Loss of LBW during the Week with Highest LBW Capacity Factor

No LBW during the 1st Highest LBW Capacity Factor Week						
Model	**Initial LOLE**	**Resultant LOLE**	**Initial LOLH**	**Resultant LOLH**	**Initial EUE**	**Resultant EUE**
70x30 'Base Load' at-criterion	0.11	0.11	0.291	0.291	85.7	85.7
70x30 'Scenario Load' at-criterion	0.11	0.11	0.269	0.272	40.9	41.7
70x30 'Scenario Load' at-low-LOLE	0.03	0.03	0.067	0.067	8.5	8.5
No LBW during the 2nd Highest LBW Capacity Factor Week						
Model	**Initial LOLE**	**Resultant LOLE**	**Iinitial LOLH**	**Resultant LOLH**	**Initial EUE**	**Resultant EUE**
70x30 'Base Load' at-criterion	0.11	0.11	0.291	0.291	85.7	85.7
70x30 'Scenario Load' at-criterion	0.11	0.11	0.269	0.269	40.9	41.0
70x30 'Scenario Load' at-low-LOLE	0.03	0.03	0.067	0.067	8.5	8.5

Loss of Land-Based Wind Observations:

Removal of all LBW generation during the studied weeks has a low to no impact on NYCA LOLE. This is largely due to the majority of the NYCA LOLE events being concentrated in the Zones J and K, whereas LBW is assumed located in the rest-of-state zones. Also, the significant amount of fossil plants in the state would likely be available during the weeklong wind lull. No impact on the NYCA LOLE also means that there was no need to identify compensatory MW to bring the NYCA LOLE back to the criterion level in the cases with the wind in service.

Loss of Offshore Wind (OSW)

Figure 41: NYCA LOLE (days/year) for Loss of OSW during the Week with Highest LOLE Events

No OSW during the 1st Highest NYCA Event % Week				Compensatory MW		
Model	**Initial LOLE**	**Resultant LOLE**	**Delta LOLE**	**Zones A-I**	**Zone J**	**Zone K**
70x30 'Base Load' at-criterion	0.11	0.18	**0.07**	∞	200	∞
70x30 'Scenario Load' at-criterion	0.11	0.22	**0.11**	∞	∞	150
70x30 'Scenario Load' at-low-LOLE	0.03	0.06	**0.03**	∞	∞	150
No OSW during the 2nd Highest NYCA Event % Week				**Compensatory MW**		
Model	**Initial LOLE**	**Resultant LOLE**	**Delta LOLE**	**Zones A-I**	**Zone J**	**Zone K**
70x30 'Base Load' at-criterion	0.11	0.11	**0.01**	∞	150	∞
70x30 'Scenario Load' at-criterion	0.11	0.13	**0.02**	∞	∞	50
70x30 'Scenario Load' at-low-LOLE	0.03	0.03	**0.00**	∞	∞	25

∞ - Either a large, or no amount of capacity added in the zone can bring NYCA LOLE back to the target LOLE

Figure 42: NYCA LOLE (days/year) for Loss of OSW during the Week with Highest OSW Wind Capacity Factor

No OSW during the 1st Highest OSW Capacity Factor Week					Compensatory MW		
Model	**OSW CF**	**Initial LOLE**	**Resultant LOLE**	**Delta LOLE**	**Zones A-I**	**Zone J**	**Zone K**
70x30 'Base Load' at-criterion	41%	0.11	0.26	**0.16**	∞	350	∞
70x30 'Scenario Load' at-criterion	41%	0.11	0.22	**0.11**	∞	∞	150
70x30 'Scenario Load' at-low-LOLE	41%	0.03	0.06	**0.03**	∞	∞	150
No OSW during the 2nd Highest OSW Capacity Factor Week					**Compensatory MW**		
Model	**OSW CF**	**Initial LOLE**	**Resultant LOLE**	**Delta LOLE**	**Zones A-I**	**Zone J**	**Zone K**
70x30 'Base Load' at-criterion	32%	0.11	0.14	**0.04**	∞	100	∞
70x30 'Scenario Load' at-criterion	32%	0.11	0.47	**0.36**	∞	∞	400
70x30 'Scenario Load' at-low-LOLE	32%	0.03	0.16	**0.13**	∞	∞	350

∞ - Either a large, or no amount of capacity added in the zone can bring NYCA LOLE back to the target LOLE

The graphics below depict how much hourly MW of OSW is lost during the wind lull simulation weeks. This is based on the 2002 NREL zonal hourly data for OSW, as developed for the 2019 CARIS studies. For instance, the loss of 417,340 MWh of wind is simulated as lost for the wind lull simulations at highest capacity factor. The assumed nameplate capacity is 6,098 MW (in Zones J and K), and the wind is at 5,602 MW maximum output during that simulation week.

Figure 43: OSW MW Output during the Week with Highest OSW Capacity Factor

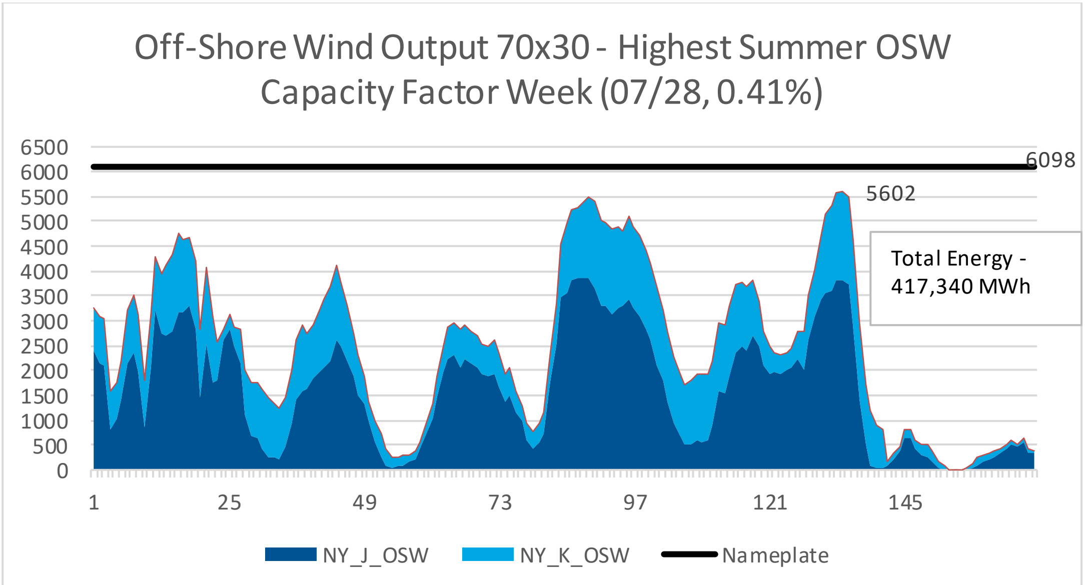


Figure 44: OSW MW Output during the Week with Highest % Events for the 70 x 30 'Base Load' Cases

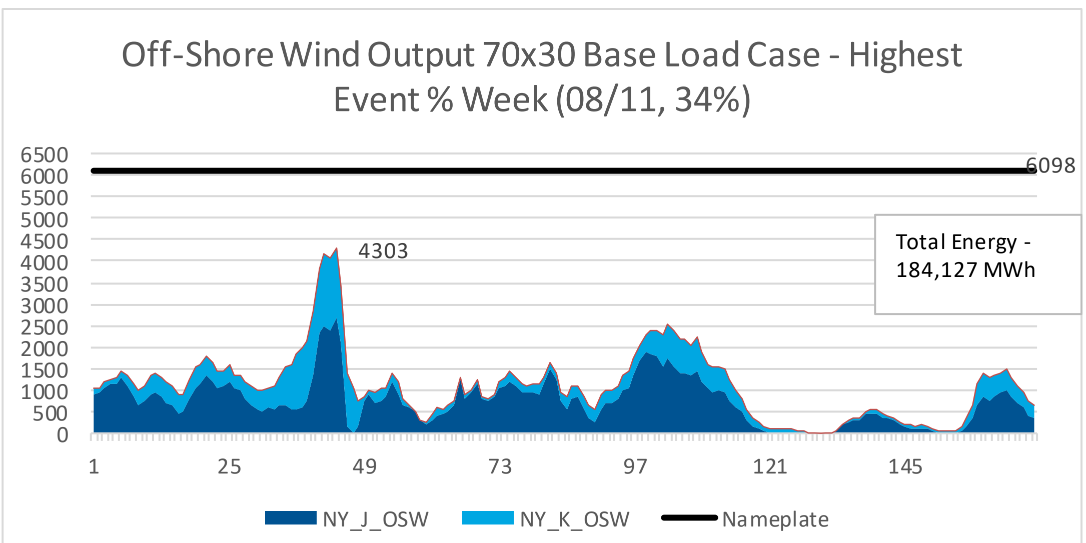
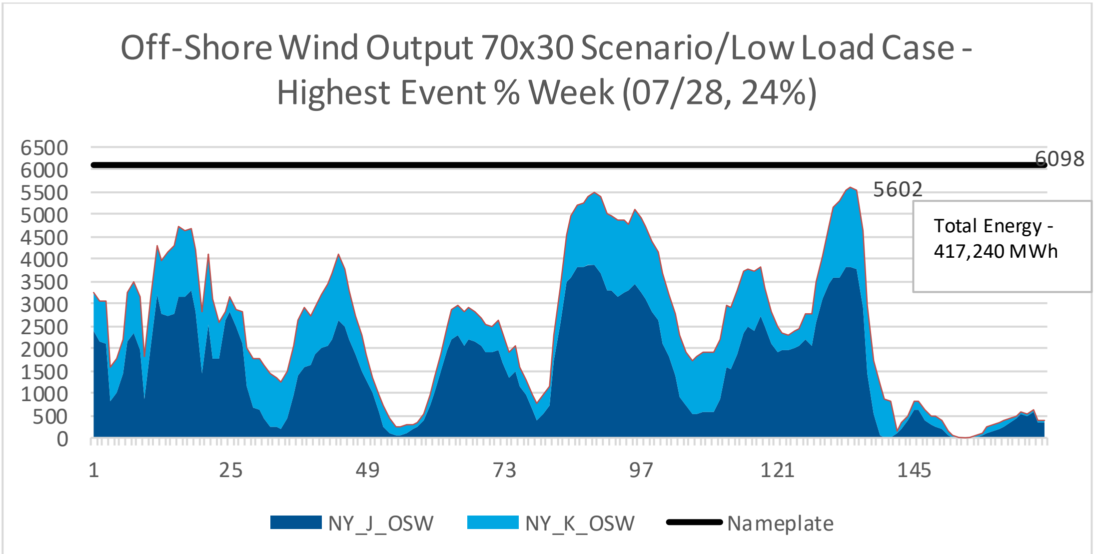


Figure 45: OSW MW Output during the Week with Highest % Events – 70 x 30 'Scenario Load' and 'Low LOLE' Cases



Additionally, for information purposes, the LOLH (hours/year) and EUE (MWh/year) reliability indices for each of the models and loss of wind events simulated are in the below tables.

Figure 46: NYCA LOLE (days/year), LOLH (hours/year) and EUE (MWh/year) for Loss of OSW during the Week with Highest LOLE Events

No OSW during the 1st Highest NYCA Event % Week						
Model	**Initial LOLE**	**Resultant LOLE**	**Initial LOLH**	**Resultant LOLH**	**Initial EUE**	**Resultant EUE**
70x30 'Base Load' at-criterion	0.11	0.18	0.291	0.547	85.7	182.8
70x30 'Scenario Load' at-criterion	0.11	0.22	0.269	0.542	40.9	125.8
70x30 'Scenario Load' at-low-LOLE	0.03	0.06	0.067	0.143	8.5	23.9
No OSW during the 2nd Highest NYCA Event % Week						
Model	**Initial LOLE**	**Resultant LOLE**	**Initial LOLH**	**Resultant LOLH**	**Initial EUE**	**Resultant EUE**
70x30 'Base Load' at-criterion	0.11	0.11	0.291	0.318	85.7	94.2
70x30 'Scenario Load' at-criterion	0.11	0.13	0.269	0.310	40.9	46.7
70x30 'Scenario Load' at-low-LOLE	0.03	0.03	0.067	0.074	8.5	9.3

Figure 47: NYCA LOLE (days/year), LOLH (hours/year) and EUE (MWh/year) for Loss of OSW during the Week with Highest OSW Wind Capacity Factor

No OSW during the 1st Highest OSW Capacity Factor Week						
Model	**Initial LOLE**	**Resultant LOLE**	**Initial LOLH**	**Resultant LOLH**	**Initial EUE**	**Resultant EUE**
70x30 'Base Load' at-criterion	0.11	0.26	0.291	0.849	85.7	289.9
70x30 'Scenario Load' at-criterion	0.11	0.22	0.269	0.542	40.9	125.8
70x30 'Scenario Load' at-low-LOLE	0.03	0.06	0.067	0.143	8.5	23.9
No OSW during the 2nd Highest OSW Capacity Factor Week						
Model	**Initial LOLE**	**Resultant LOLE**	**Initial LOLH**	**Resultant LOLH**	**Initial EUE**	**Resultant EUE**
70x30 'Base Load' at-criterion	0.11	0.14	0.291	0.414	85.7	123.6
70x30 'Scenario Load' at-criterion	0.11	0.47	0.269	1.409	40.9	341.3
70x30 'Scenario Load' at-low-LOLE	0.03	0.16	0.067	0.470	8.5	87.1

Loss of Offshore Wind Observations:

1. Removal of all offshore wind generation for the studied week has a substantial impact on NYCA LOLE. This is largely due to the location of the offshore wind in the J and K Zones, where the majority of the NYCA LOLE events occur.
2. There is a higher impact in the NYCA LOLE for the “Scenario Load” case (*i.e.,* a lower energy case), which had a higher level of MW of fossil-fueled generation removed (*i.e.,* around 12,340 MW fossil generation removed, as identified in the 2020 RNA Report) in order to bring it from a very low LOLE to the 0.1 day/year criterion (“at criterion”).
3. Annual compensatory MW values are reducing LOLE in other times of the year, not just during the week affected by the wind lull. Hence, the “perfect capacity” values are significantly less than the amount of hourly wind lost during the week of wind lull.
4. Using yearly compensatory MW (*i.e.,* “perfect capacity MW” available every hour of the study year) to bring the NYCA LOLE back to the levels found in the original cases reduces resultant LOLH but increases EUE. This is because smaller events are mitigated by the compensatory MW, but the large events that are created by the wind lull create a larger energy deficit during that week.
5. The assumption for loss of wind in these simulations was 100% loss throughout the whole week. The wind is modeled as one 8,760 hourly shape based on NREL data and 2019 CARIS output. However, the regular planning models usually contain five 8,760 hourly shapes for each wind plant modeled, with the MW data from the actual historical production. In that case, it is possible to assume a different weight for wind lull, such as 20% occurrence (instead of

100%) for one shape, with MARS randomly picking one shape for each study year replication. Applying a percentage value to the LOLE delta could be a good equivalent to simulating the random application of the same percentage chance of a wind lull occurring. For example, a 20% chance of wind lull occurring would lead to roughly an expected new LOLE equal to 20% of the change to the LOLE provided in the above tables.

Wind Lull Conclusions

With high penetration of renewable intermittent resources, the system will need dispatchable, long-duration resources to balance intermittent supply with demand especially during extended periods where the intermittent resources are not available. These types of resources will need to be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs.

Appendix F – 70 x 30 Scenario – Dynamic Stability, Short-Circuit Ratio, and Voltage Flicker

Dynamic Stability

The steady state transmission security assessment under 70 x 30 conditions was evaluated in the 2020 Reliability Needs Assessment.[15] The transmission security assessment for 70 x 30 models six different output levels of intermittent renewable resources and load levels. The basis for the load and renewable resource mix is the 70 x 30 'Base Load' case from the 2019 CARIS 70 x 30 renewable resource mix and associated load forecasts.[16] The 2019 CARIS assumptions were based on the 2019 Gold Book, and used GE MAPS for production cost simulations, and its findings are intended to provide insight of the extent to which transmission constraints may prevent the delivery of renewable energy to New York consumers. The 70 x 30 scenarios evaluated in the RNA, as well as this report, are intended to supplement the 2019 CARIS 70 x 30 analysis of congestion and resource curtailment by providing insights on potential reliability impacts.

Figure 47 shows the load level for each case along with the assumption for land-based wind, offshore wind, and solar evaluated in the transmission security assessments. **Figure 48** provides the total zonal MW capability for offshore wind (OSW), land-based wind (LBW), utility scale solar (UPV), and behind-the-meter solar (BTM-PV). For the solar dispatch, both the behind-the-meter and in front of the meter solar are dispatched to the same percentage. The pairings of similar load levels (*e.g.,* Cases 1 & 2, Cases 3 & 4, and Cases 5 & 6) with different levels of renewable resource penetration shows that a balance in load and generation is achievable (*i.e.,* the case was able to match load plus losses with available generation under N-0). While transmission security analysis for this assessment does not consider an 8,760-hourly type of load and generation variety, the six cases consider, within reasonable bounds, load levels that can be seen for many hours. For all cases (except Case 2), the renewable generation mix shown in **Figure 47** was selected based on observations from the CARIS 70 x 30 'Base Load' results for similar load levels. Case 2 reflects the potential for an evening peak load assuming no MW output from wind and solar resources. The evening peak load reflects approximately 93% of the peak load observed during the day peak with no output from behind-the-meter solar. For this assessment, after peak generation removals and age-based generation removals, both 10-minute and 30-minute operating reserve levels were maintained by utilizing the remaining synchronous generation. The amount of dispatchable resources included in the transmission security base case is approximately 24,700 MW (after age-based removals and peaker removals). The age-

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15 https://www.nyiso.com/documents/20142/2248793/2020-RNAReport-Nov2020.pdf/

16 https://www.nyiso.com/documents/20142/2226108/2019-CARIS-Phase1-Report-Final.pdf/

based fossil removals for the Base Load resource adequacy scenario in the RNA, with no energy storage resources (ESR), are also modeled in this assessment, including the removal of units that were in-service prior to January 1, 1963. This removal amounts to a total of 2,586 MW summer capability. The 2,586 MW removal is utilized in the transmission security analysis, as it is the last point of generation removal prior to observing resource adequacy LOLE violations.

Figure 48: 70 x 30 Scenario Transmission Security Case Assumptions ('Base Load' Case)

Case #	Case Load (Net load including BtM solar reductions, MW)	Land Based Wind (% of Pmax)	Off-Shore Wind (% of Pmax)	Solar (% of Pmax)
1	Day Peak Load (30,000)	10	20	45
2	Evening Peak Load (31,100)	0	0	0
3	Light Load (12,500)	15	45	0
4	Light Load (12,500)	0	0	0
5	Shoulder Load (21,500)	0	0	40
6	Shoulder Load (21,500)	15	45	40

Figure 49: Capabilities (MW) of Renewable Mix Assumptions for Base Load

Zone/Type	OSW	LBW	UPV	BTM-PV
A	-	2,286	4,432	995
B	-	314	505	298
C	-	2,411	2,765	836
D	-	1,762	-	76
E	-	2,000	1,747	901
F	-	-	3,592	1,131
G	-	-	2,032	961
H	-	-	-	89
I	-	-	-	130
J	4,320	-	-	950
K	1,778	-	77	1,176
Total	**6,098**	**8,772**	**15,150**	**7,542**

Summary of 2020 RNA Steady State Analysis Results from the 2020 RNA

The 2020 RNA documents the steady state transmission security issues focusing on the steady state thermal loading of the BPTF for N-1 and N-1-1 conditions. The thermal loading issues indicate transmission constraints that may occur with high renewable output, as well as under peak load conditions without these resources. These issues are observed in the Orange and Rockland, Con Edison, and PSEG-Long Island service territories. The thermal loading issues indicate transmission constraints that may occur with high renewable output, as well under peak load conditions without these resources. To secure the transmission system, additional dispatchable resources would be needed. To maintain system transmission security, approximately 750 MW of dispatchable resources would be needed in addition to the 24,700 MW of dispatchable resources remaining in the model *(i.e.* after age-based removals and peakers). This assessment did not consider the potential duration of the deficiencies or the sudden loss of all offshore wind. Rather, contingency events for renewable resources only considered loss of resources due to electrical faults. For all cases, the NYISO locational reserves requirements were achieved by utilizing dispatchable generation.

70 x 30 Dynamic Stability Transmission Security Methodology and Results

The purpose of this assessment is to identify reliability risks focusing on the system stability of the New York transmission system for N-1 and N-1-1 conditions. To capture the potential dynamics impact of renewable generators added to the model to meet the 70 x 30 goals, this assessment utilizes generic renewable models (REGCA1 and REECA1)[17] and model parameters.

For a stability simulation to be deemed stable, oscillations in angle and voltage must exhibit positive damping within ten seconds after the initiation of the disturbance. The system is unstable, if following a disturbance, the stability analysis indicates increasing angular displacement between various groups of machines or if oscillatory instability is observed.[18] For this study, the analysis considered all dynamics criteria with the exception of transient voltage response due to dynamic modeling assumptions for the renewable generators added to the model to meet the 70 x 30 goals. Transient voltage response is primarily a local area issue and is sensitive to the dynamic load model as well as the dynamic characteristics of generators.

Consistent with the reliability compliance criteria, the stability analysis evaluates NERC, NPCC Directory #1, and NYSRC Reliability Rules planning design criteria stability contingencies that are expected to produce a more severe system impact on the BPTF. These contingencies include the most severe loss of reactive capability and increased impedance on the BPTF. The contingencies are modeled to simulate the removal of all elements that the protection system or other automatic controls would disconnect without operator intervention. The stability performance contingencies include the impact of successful high speed (less than one second) reclosing and unsuccessful high-speed reclosing into a fault, where high-speed reclosing is utilized. Design criteria stability N-1-1 analysis evaluates the ability of the system to meet design criteria following the occurrence of a single event and allowable system adjustments. Allowable

[17] REGCA1 is a renewable energy generator/converter model and REECA1 is a generic renewable electrical control model. As generators connect to the NYCA they are required to provide all relevant modeling data (such as dynamics modeling data) as documented in the NYISO Reliability Analysis Data Manual.

[18] New York Independent System Operator, Transmission Expansion, and Interconnection Manual Guideline 3-1, dated December 2020

system adjustments between the first (N-1-0) and second contingency (N-1-1) include: generator redispatch, PAR adjustments, switched shunt adjustments, transformer tap adjustments, and HVDC adjustments.

N-1 Analysis

N-1 stability analysis was performed for all six cases. Under these system conditions no N-1 dynamics criteria violations were observed.

N-1-1 Analysis

N-1-1 stability analysis was performed for Cases 1, 3, and 6 as these cases have a higher penetration of renewable resources. These cases were selected for N-1-1 analysis based on engineering judgement due to the lower amount of online system inertia inherent with higher penetrations of renewable resources.

Figure 50 below lists first event outages for the N-1-1 analysis included in this assessment. For the first event outages, the loss of key elements that may be impactful to increased penetrations of renewable resources were selected for evaluation based on engineering judgement. These events include the loss of key transmission paths (such as elements impactful to the Central East interface), the loss of large synchronous generators, and the loss of HVDC.

Figure 50: First Level Outage Cases for N-1-1 Analysis

Outage #	Outage Description
1	Oakdale-Fraser 345 kV (32)
2	Fraser – Gilboa 345 kV (GF5-35)
3	Edic-Gordon Road 345 kV (14A)
4	Marcy-New Scotland 345 kV (18)
5	Loss of CPV Generation
6	Loss of Ravenswood 3
7	Loss of Chateauguay HVDC Import
8	Loss of Rainey HVDC Import

Figure 50 below lists the second level outages for the N-1-1 analysis. These events in combination with the first level comprise the most severe event combinations.

Figure 51: N-1-1 Second Level Contingencies

Event Name	Event Description
CE01_AC-SegA	Fault at Edic 345 kV with L/O Edic – Princetown (14) 345 kV
CE02	Fault at Marcy 345 kV with L/O Marcy – New Scotland (UNS-18) 345 kV with reclosing
CE06	Fault at Marcy 345 kV with L/O Edic – Marcy (UE1-7) 345 kV
CE07	Faults at Edic 345 kV and Marcy 345 kV with L/O Marcy-Coopers Corners (UCC2-41) 345 kV and Edic-Fraser (EF24-40) 345 kV
CE08	Fault at Coopers Corners 345 kV with L/O Fraser-Coopers Corners (FCC33) 345 kV and Marcy-Coopers Corners (UCC2-41) 345 kV
CE11	Fault at Fraser 345 kV with L/O Fraser – Gilboa (GF-5) 345 kV and Fraser 345 kV SVC
CE12_AC-SegA	Fault at Princetown 345 kV with L/O Edic – Princetown (14) 345 kV with reclosing
CE15	Fault at Marcy 345 kV with L/O Volney – Marcy (VU-19) 345 kV and Edic – Marcy (UE1-7) 345 kV
CE21OAK	Fault at Fraser 345 kV with L/O Fraser – Coopers Corners (33) 345 kV and Oakdale – Fraser (32) 345 kV
CE22	Fault at Edic 345 kV with L/O Edic – Fraser (EF24-40) 345 kV
CE22_DCT	Fault at Edic 345 kV with L/O tower Edic – Fraser (EF24-40) 345 kV and Edic-Princetown (352) 345 kV
CE26_DCT	Fault at Coopers Corners 345 kV with L/O tower Marcy-Coopers Corners (UCC2-41) and Edic-Princetown (352) 345 kV
CE36	Fault at Scriba 345 kV with L/O Scriba – Fitzpatrick (FS-10) 345 kV and Scriba 345/115 kV transformer T2
CE99	Fault at Scriba 345 kV with L/O Scriba – Volney (21) 345 kV and Scriba – Fitzpatrick (FS-10) 345 kV
ConEd08	Fault at E. 13th St. 138 kV with stuck breaker 4E
ConEd12	Fault at Fresh Kills 138 kV with L/O Arthur Kill 2
ConEd15	Fault at Greenwood 138 kV with stuck breaker 7S
NE04	Fault at Millstone 345 kV with L/O Millstone – Haddam (348) 345 kV and Millstone 3
NE08	Fault at Sandy Pond 345 kV with L/O Sandy Pond – Sandy Pond HVDC1 (3512) 345 kV
SA11_DCT	Fault at Edic 345 kV with L/O tower Edic-Princetown (351) 345 kV and Edic-Princetown (352) 345 kV
SA17_DCT	Fault at Princetown 345 kV with L/O tower Princetown-New Scotland (361) 345 kV and Princetown-New Scotland (362) 345 kV
ST09-VE05	Fault at Oakdale 345 kV with L/O Oakdale – Fraser (32) 345 kV
ST10	Fault at Oakdale 345 kV with L/O Oakdale – Fraser (32) 345 kV and Oakdale – Clarks Corners (36) 345 kV
TE03-UC03	Fault at Sprainbrook 345 kV and L/O Sprainbrook – Millwood (W64/W99, W79/W93) 345 kV
TE20_UC20	Fault at Dunwoodie 345 kV and L/O Dunwoodie – Pleasantville (W89 & W90) 345 kV
TE32	Fault at New Scotland 345 kV with L/O New Scotland 77 345 kV bus
TE33	Fault at New Scotland 345 kV with L/O New Scotland 99 345 kV bus
UC11	Fault at Sprainbrook 345 kV and L/O Sprainbrook – Tremont (X28) 345 kV and Buchanan – Sprainbrook (W93/W79) 345 kV
UC25A	Fault at Ravenswood 3 345 kV and L/O Ravenswood 3
UC25B	Fault at Rainey 345 kV and L/O 60L 345 kV circuit
VE02	Fault at Clay 345 kV with L/O Clay – Pannell (PC-2) 345 kV and Clay – Edic (2-15) 345 kV
VE07	Fault at Clay 345 kV with L/O Clay – Volney (6) 345 kV

For the evaluated cases and contingency combinations, the N-1-1 stability analysis indicated no stability issues for any of the simulations.

Sudden Loss of Offshore Wind

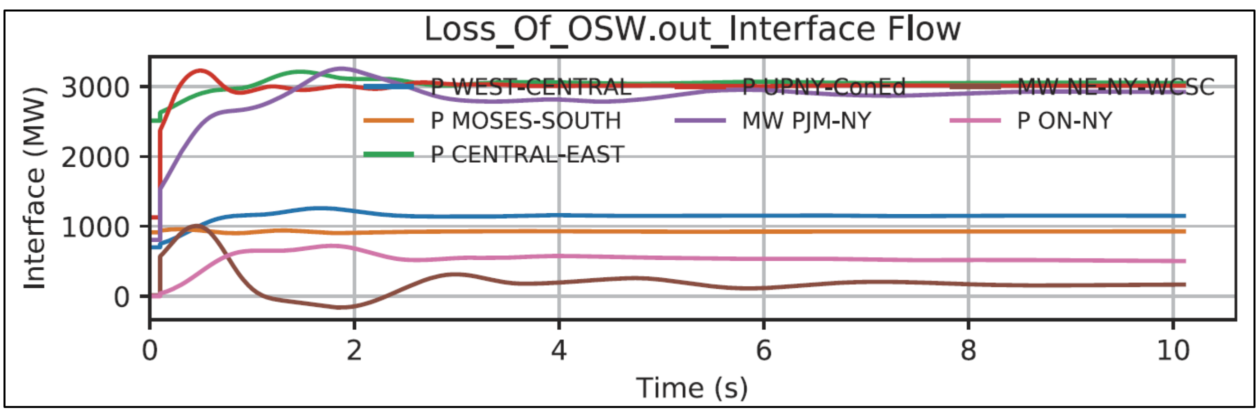
The purpose of this assessment is to evaluate the dynamic system response for the sudden loss of OSW. As shown in **Figure 51** for the 70 x 30 analysis, a total amount of OSW of 6,098 MW was interconnected to the NYCA system and was split between New York City (4,320 MW in Zone J) and Long Island (1,778 MW in Zone K). The evaluation of the sudden loss of offshore wind is not predicated on an electrical fault. Rather this condition is more plausible under weather related conditions.

In order to evaluate the impact of the sudden loss of all OSW, three scenarios were considered for the analysis: Peak Load (Case 1), Light Load (Case 3) and Shoulder Load (Case 6). The percentage of dispatch of OSW for each case is shown in **Figure 47** For each case, the dynamic response of the system was evaluated under N-1 conditions and N-1-1, with the first level contingency being the loss of Sprain Brook – East Garden City 345 kV (Y49), and the second level contingency being the loss of OSW.

N-1 & N-1-1 Analysis

Under the conditions shown in **Figure 51** (Cases 1, 3, and 6), in all cases the sudden loss of OSW shows a stable system response under N-1 and N-1-1. As can be seen in **Figure 51** (which provides an example of the changing interface flows under light load conditions in response to the event), to account for the loss of OSW the generators from the Eastern Interconnection provide MW output in respond to the event.

Figure 52: Light Load Interface Flows for the Loss of Offshore Wind (Base Output)

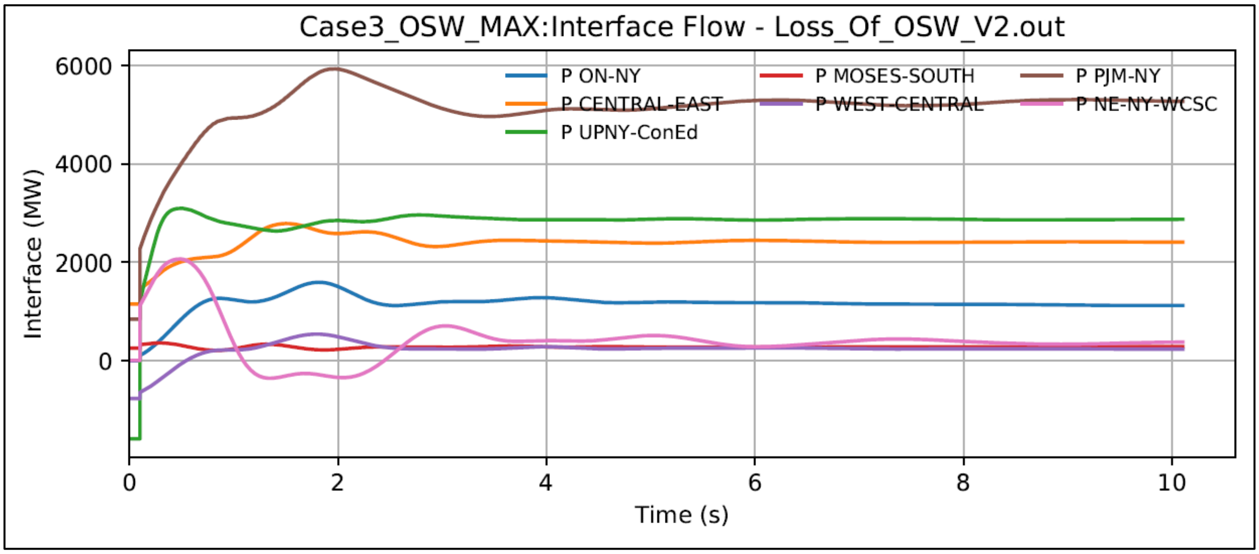


N-1 & N-1-1 Analysis (Offshore Wind at Maximum Output)

As depicted in **Figure 53**, the N-1 and N-1-1 analyses under base OSW output conditions showed a stable system response. Therefore, further investigation was performed to evaluate the dynamic response of the system with OSW at maximum output. To create the condition of full OSW output, the output of fossil-based generation in New York City and Long Island was reduced. These dispatch adjustments result in N-0 thermal violations and PARs hitting angle limits. For this analysis these issues were ignored.

With OSW at full output, in all cases the sudden loss of OSW also shows a stable system response. However, as shown in **Figure 52** the amount of MW flows across the NYCA interfaces has significantly increased as compared to the OSW base output conditions. There is also a noticeable degradation in the frequency response of the system when comparing the conditions shown in **Figure 52** as compared to the condition with OSW at maximum capability.

Figure 53: Light Load interface Flows for the Loss of Offshore Wind (Maximum Output)



System Frequency Response for the Sudden Loss of Offshore Windz

Background on Frequency Response

Maintaining system frequency within appropriate bounds is an essential measure to the reliable operation of the system.[19] At the most basic level, frequency is maintained at 60 Hz when load and generation on the system is perfectly balanced. For normal state operation, the frequency of the system is not less than 59.95 Hz or greater than 60.05 Hz.[20] Additionally, it is critical to keep the frequency response above the Under-Frequency Load Shedding (UFLS) thresholds[21] so that load is not tripped.[22]

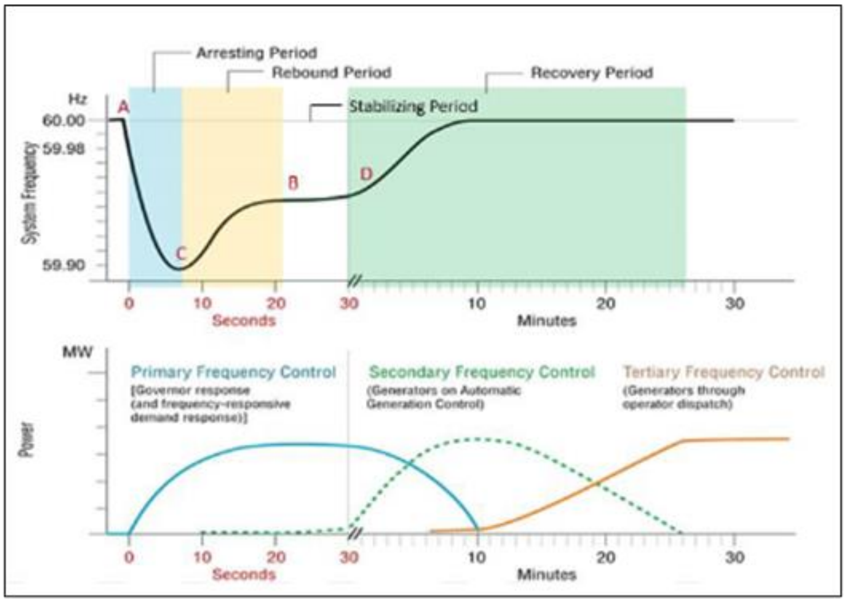
[19] North American Electric Reliability Corporation, Essential Reliability Services Whitepaper on Sufficiency Guidelines, dated December 2016.

[20] New York Independent System Operator, Transmission and Dispatch Operations Manual (Manual 12), dated March 2021.

[21] Under-Frequency Load Shedding is an extreme action taken to arrest declining frequency, assist recovery of frequency following under-frequency events and provide last resort system preservation measures. See NERC Standards PRC-006 and PRC-006-NPCC.

[22] For New York this is 59.5 Hz. See North American Electric Reliability Corporation Reliability Standard PRC-006-NPCC-2.

Figure 54: Frequency Response Characteristics[23]



Upon loss of a large generation facility, the frequency response on the system will immediately fall, requiring a fast response to slow the rate of frequency decline and restore the system back to normal conditions. A visual description of the characteristics of frequency response is provided in **Figure 53.** Point "A" in **Figure 53** is the pre-disturbance frequency (at 60 Hz). The period between the time of the disturbance and the lowest frequency at point "C" (or frequency nadir) is called the arresting period (shown in blue). The nadir point shown in **Figure 53** is 59.9 Hz. As rotating machines slow down (shown as a frequency decline) the generator governors' sense this change in speed and act to increase the speed of the generator.[24] In order to arrest the frequency decline the governor response must offset the power deficit and replace the balancing power that had extracted inertial energy from the rotating machines of the interconnection. When the balance of power is re-established (called the "nadir"), primary response resources continue to provide additional power to the system.

Primary frequency control (or primary frequency response) is the response of generation and load to arrest local changes in frequency. This state of frequency response is automatic and begins moments after an event, such as loss of generation, occurs on the system. The initial rate at which the frequency declines depend on the amount of inertial response of the system at the time of the event. The inertial response depends on the available kinetic energy provided by rotating machines, such as synchronous generation

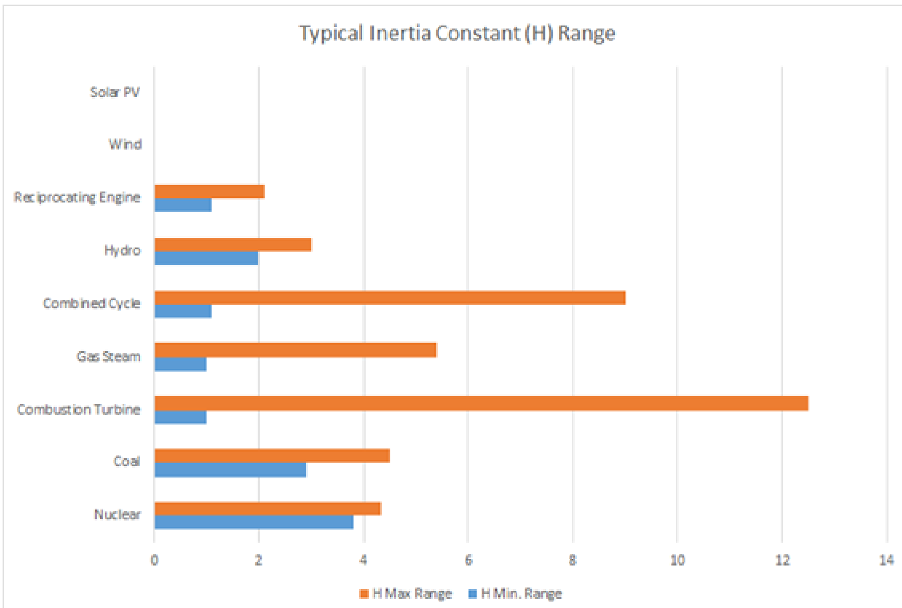
[23] North American Electric Reliability Corporation, Primary Frequency Control Reliability Guideline, dated May 2019.

[24] North American Electric Reliability Corporation, The Reliability Role of Frequency Response, dated October 30, 2012.

and load, as well as governor response.[25] Inertia constants (H) are provided for individual machines but can also be calculated for an equivalent system-wide H (or Heq). As shown in the equation below, the equivalent system inertia is ratio of Total Inertia of the System (sum of the product of Base MVA and Inertia Constant for each generator) to Total MVA Base of the System (sum of the Base MVA for each generator). Typical inertia constants for different types of generators are shown in **Figure 54**.[26]

$$H_{eq} = \frac{\sum_i^n H_{i^*} MBASE_i}{\sum_i^n MBASE_i}$$

Figure 55: Typical Inertia Constant (H) Range



The behavior of the frequency through the rebound, stabilizing, and recovery periods depends on the behavior of primary and secondary frequency control action as well as other system characteristics, such as the behavior of load, and bus voltages. The frequency behavior shown in **Figure 53** between points "C" and "B" is the rebound period. The frequency during the rebound period is primarily driven by the governor response of generators. Governor response is primarily driven by its droop settings and deadband. The droop setting of a generator is defined by the frequency change that is necessary to cause the generator to operate from no output to full output. For example, a three percent droop characteristic means that a three

[25] A machine's inertia constant H is defined as the kinetic energy divided by the machine's rating capacity. The H constant is the time in units of seconds that it would take to deliver all of its stored kinetic energy to the power grid assuming that it is producing at rated power and speed.

[26] ERCOT, Inertia: Basic Concepts and Impacts on the ERCOT Grid, dated 2018. http://www.ercot.com/content/wcm/key_documents_lists/141324/Inertia_Basic_Concepts_Impacts_On_ERCOT_v0.pdf

percent change in frequency causes a generator to move from full output to no output and vice versa. Deadband is the amount of frequency change that a generator must see before the governor will respond. NERC recommends deadband settings should not exceed ±36 mHz and droop settings of no more than five percent.

The overall responsiveness of a generator during the rebound period also depends on other plant control factors. For example, the early withdrawal of primary frequency response by generators returning to their original basepoints (i.e., generators that have a squelched governor response) will slow the frequency recovery. According to Eastern Interconnection Reliability Assessment Group's (ERAG) Multi-Regional Modeling Working Group (MMWG) Procedure Manual, a generators governor response is assigned one of the three classifications:

Full Responsive: The generator is sensitive to system frequency and will response according to the change in system frequency based on the model settings.

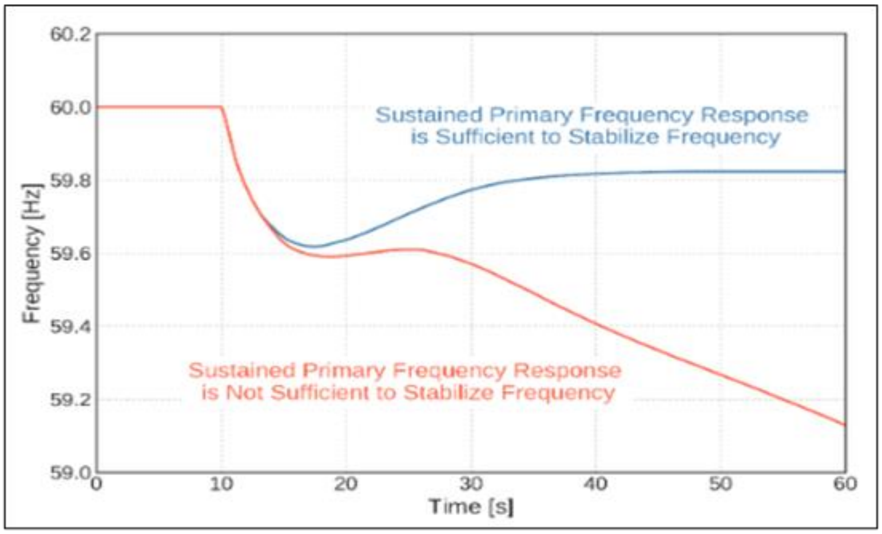
Squelched: The generator will respond to the change in system frequency but will return to its initialized value after 10-20 seconds due to load controller action.

Non-Responsive: The generator power output changes minimally for change in system frequency.

The importance of primary frequency response (PFR) is shown in **Figure 55**. If sufficient sustained PFR is not available (i.e., a large portion of the system has a squelched or non-responsive governor response), although the frequency begins to recover, ultimately the frequency will collapse due to insufficient resources. FERC Order No. 842 requires all "newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing PFR as a condition of interconnection."[27]

[27] https://www.ferc.gov/sites/default/files/2020-06/Order-842.pdf; https://www.ferc.gov/sites/default/files/2020-06/Order-842.pdf

Figure 56: Effect of Primary Frequency Response on System Frequency[28]



As shown in **Figure 53** the stabilizing period is between points "B" and "D". Frequency is stabilized at a value lower than the original scheduled frequency due to droop control characteristics. Finally, the frequency is restored back to 60 Hz during the recovery period by means of automatic generation control and other manual actions directed by system operators.

As the penetration of renewable generation increases and to the extent that these resources replace the synchronous generation across the system, the system inertia will reduce and the Rate of Change of Frequency (ROCOF) will increase.[29] Some key system characteristics that affect the ROCOF include; (1) the overall system inertia from synchronous machines and loads, (2) speed and magnitude of energy injection response, (3) speed and magnitude of load tripping due to frequency change, and (4) magnitude of the contingency, including loss of source or load and its corresponding impact in system losses.

In general, as ROCOF increases, fast frequency response to arrest the ROCOF and deeper frequency nadir may be needed to avoid triggering of UFLS.[30] Fast frequency response (FFR)[30] is power injected into or absorbed from the grid in response to change in the frequency during the arresting phase to improve frequency nadir and initial ROCOF. FFR can be provided by synchronous machine inertial response, governor response of synchronous machines, additional power from rotating wind turbines, and fast responding batteries and solar PV.

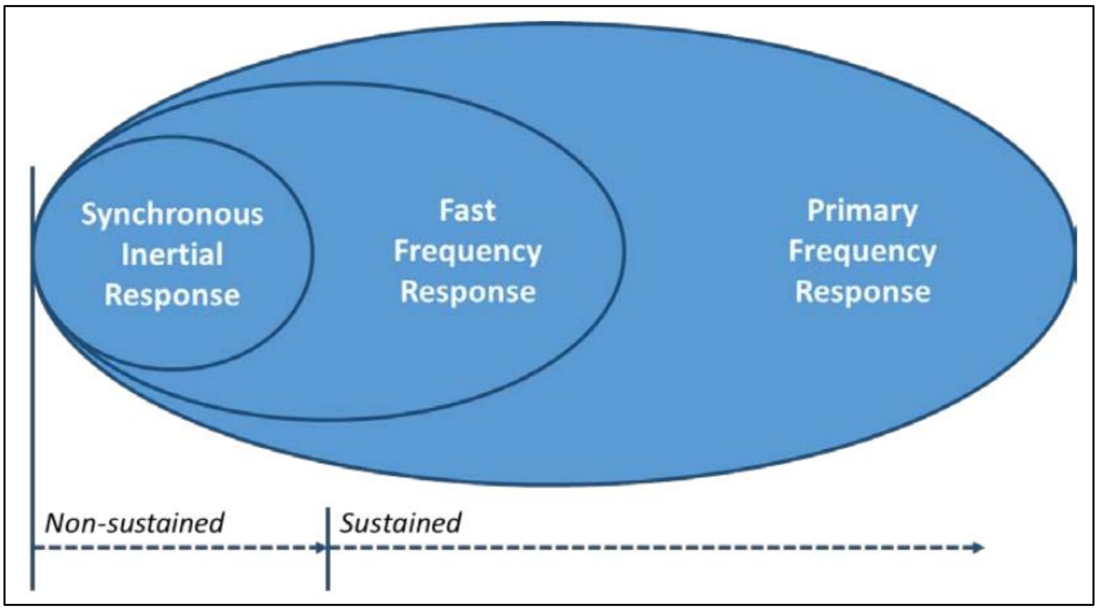
[28] North American Electric Reliability Corporation, Primary Frequency Control Reliability Guideline, dated May 2019

[29] ROCOF is a measure of how quickly the frequency changes following sudden imbalance between generation and load.

[30] North American Electric Reliability Corporation, Fast Frequency Response Concepts and BPS Reliability Needs, dated March 2020.

The FFR will be part of primary frequency response of the system and can be coordinated with the synchronous inertial response and PFR to sustain the overall frequency response of the system. As shown in **Figure 56** immediately after an event such as loss of large source of generation, the system indicates a non-sustained frequency response (arresting period) as the synchronous inertial response of the system along with FFR and PFR arrest the decline in the frequency. Once the nadir is established, the system indicates a sustained frequency response (rebound period) as FFR and PFR maintain change in power injection into the system until new balance of generation, load and frequency is achieved. Once the stable frequency response is achieved, the secondary frequency controls will return the system to the nominal frequency.

Figure 57: Simultaneous Contributions of Inertia Response, FFR, and PFR[30]

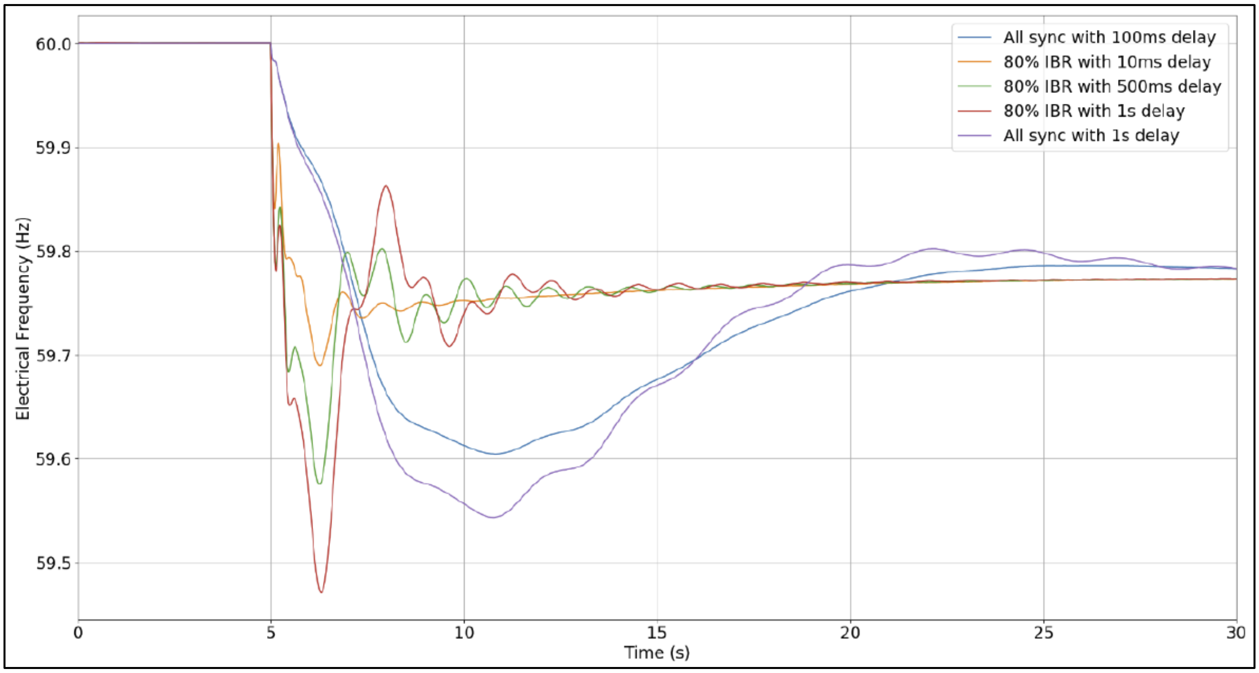


The FFR from different technologies can be available under non-sustained and sustained frequency response phases. For the system with large synchronous inertia will have low ROCOF and a separate FFR than the PFR may not be needed. However, as the system inertia reduces, synchronous inertial response can reach a threshold at which the non-sustained frequency response can trigger UFLS actions. Thus, in order to compensate for the reduced synchronous inertial response in the system FFR can be introduced as a part of the PFR to improve the overall frequency response of the system.

As new interconnecting renewable facilities will be capable of providing frequency response, FFR from these inverter-based resources (IBR) can be an option to improve the ROCOF and frequency nadir. As shown by NERC in **Figure 57** IBR can provide FFR under different frequency control delay settings to improve the frequency response. The blue and purple curves are frequency response of a system with all synchronous generation with a standard delay of 100 milliseconds and a delay of 1 second respectively.

The red, green and orange curves are frequency responses of the same system with 80% of the synchronous generators replaced by same sized renewable generators under different delay settings.

Figure 58: FFR Response from Inverter Based Resources[30]



NYCA Frequency Response for the Loss of Offshore Wind

To evaluate the frequency response of the system, the sudden loss of OSW generation is simulated under the conditions shown in **Figure 47.** This simulation includes the loss of OSW as an N-1 event as well as a second level contingency under N-1-1 conditions, with the first contingency as loss of the Y49 cable.

Figure 58 shows the system frequency response and NYCA generation response in Case 1 (peak) conditions for the loss of OSW event. **Figure 60** provides a summary of several important characteristics of the system frequency response. For this report all frequency response plots are from the Farragut 345 kV bus. The generation MW amounts are the total NYCA generation dispatch through the simulation.

Figure 59: System Frequency Response and NYCA Generation Response for the Loss of Offshore Wind - Case 1

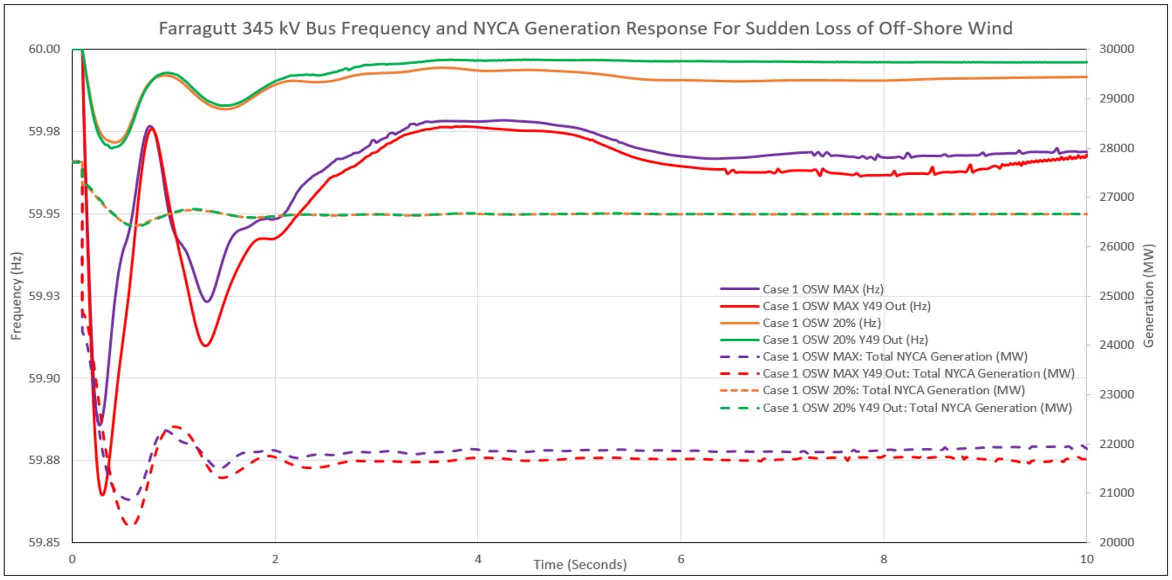


Figure 60: Summary of System Frequency Response Characteristics - Case 1

Description	Nadir Point (Hz)	Rate of Change of Frequency (Hz/Sec)	Settling Frequency (Hz) (10 Seconds)	Equivalent NYCA System Inertia (Heq)	NYCA Inertia Online (MVA-s)
N-1 OSW Max	59.89	-1.03	59.97	1.47	83,770
N-1-1 OSW Max	59.86	-1.1	59.97	1.52	88,607
N-1 OSW 20%	59.97	-0.19	59.99	1.67	105,099
N-1-1 OSW 20%	59.97	-0.2	59.99	1.67	105,099

Figure 60 and **Figure 62** show that with higher equivalent system inertia, lower ROCOF is observed. This is due to more synchronous generation in-service in the model with OSW dispatched at 20% output as compared to having less synchronous generation in-service in the model with OSW dispatched at maximum output.

As observed in **Figure 58** the loss of OSW event results in damped electrical power swing across the system. The total electrical power loss shown in **Figure 58** shows that the loss of generation from the OSW but also includes the impacts of electrical power swings which in total impact the system frequency response of the system. For example, there are multiple rises and dips in frequency shown in **Figure 58** which correspond with the rises and dips in electrical power output. The role of generator governors is to respond to these rises and dips in electric power output to ultimately settle the system response.

Figure 60 and **Figure 61** provide the system frequency response details under light load conditions. **Figure 62** and **Figure 63** provides the system frequency response details under shoulder load conditions. For all cases the system frequency response passes criteria. Additionally, no UFLS is triggered.

Figure 61: System Frequency Response and NYCA Generation Response for the Loss of Off-Shire Wind - Case 3

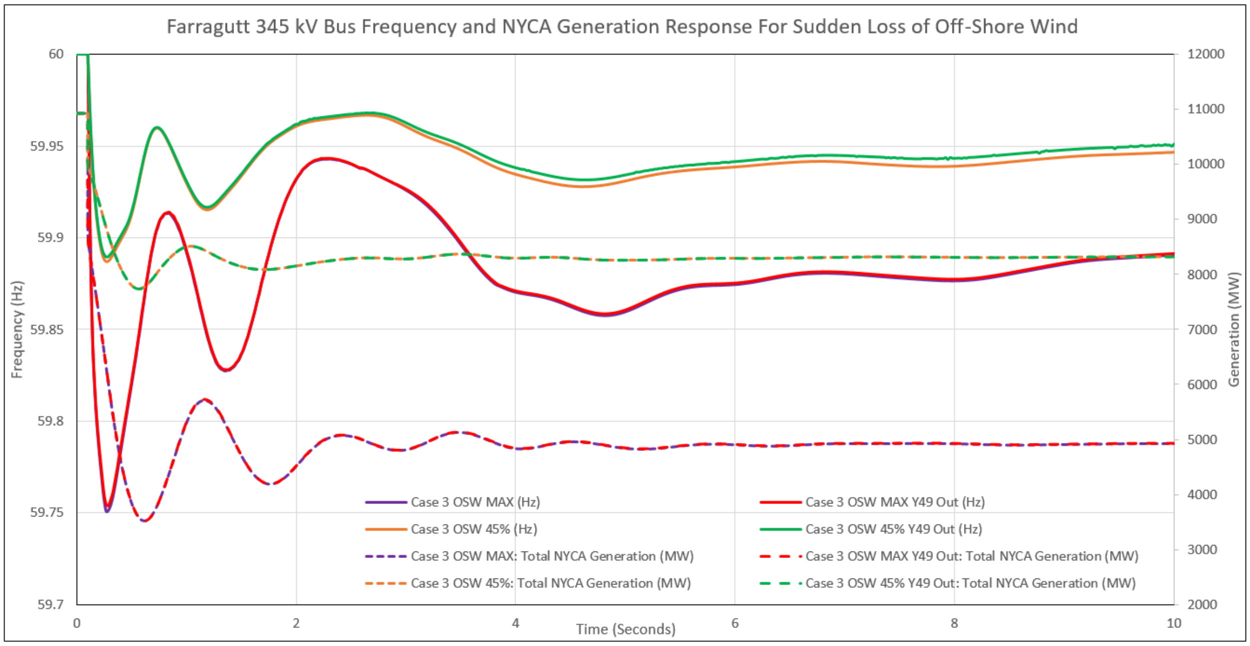


Figure 62: Summary of System Frequency Response Characteristics - Case 3

Description	Nadir Point (Hz)	Rate of Change of Frequency (Hz/Sec)	Settling Frequency (Hz) (10 Seconds)	Equivalent NYCA System Inertia (Heq)	NYCA Inertia Online (MVA-s)
N-1 OSW Max	59.75	-2.91	59.89	1.7	56,451
N-1-1 OSW Max	59.75	-2.87	59.89	1.7	56,451
N-1 OSW 45%	59.89	-1.24	59.95	1.79	63,129
N-1-1 OSW 45%	59.89	-1.22	59.95	1.79	63,129

Figure 63: System Frequency Response and NYCA Generation Response for the Loss of Offshore Wind - Case 6

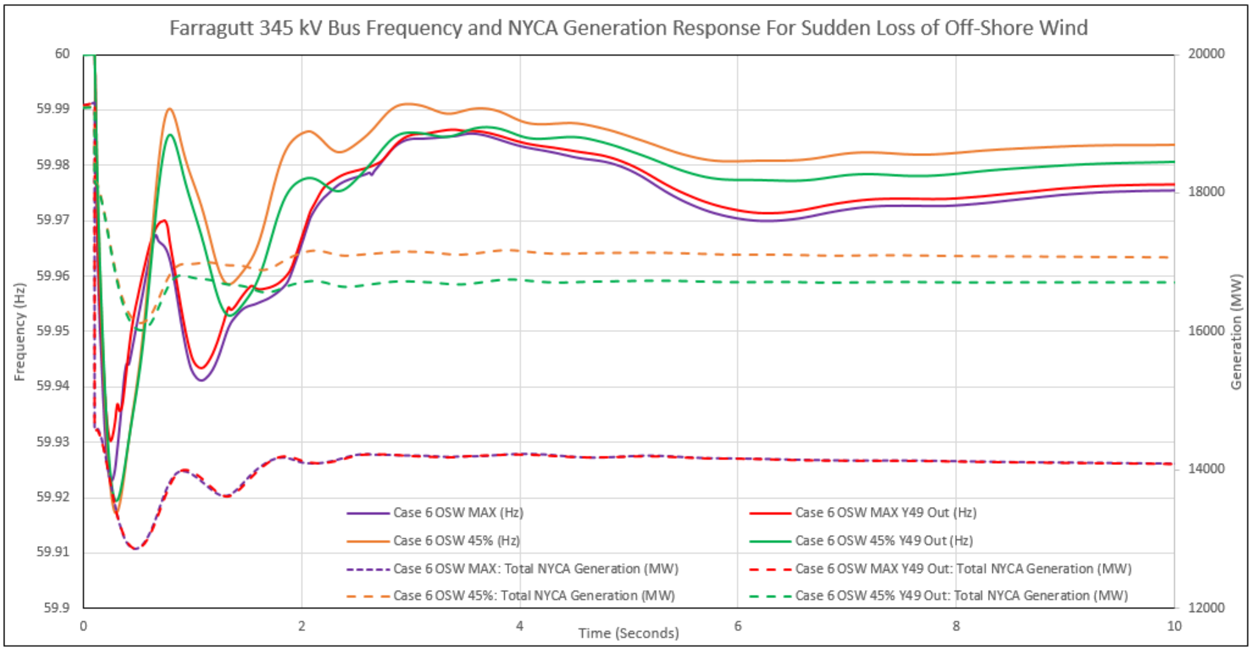


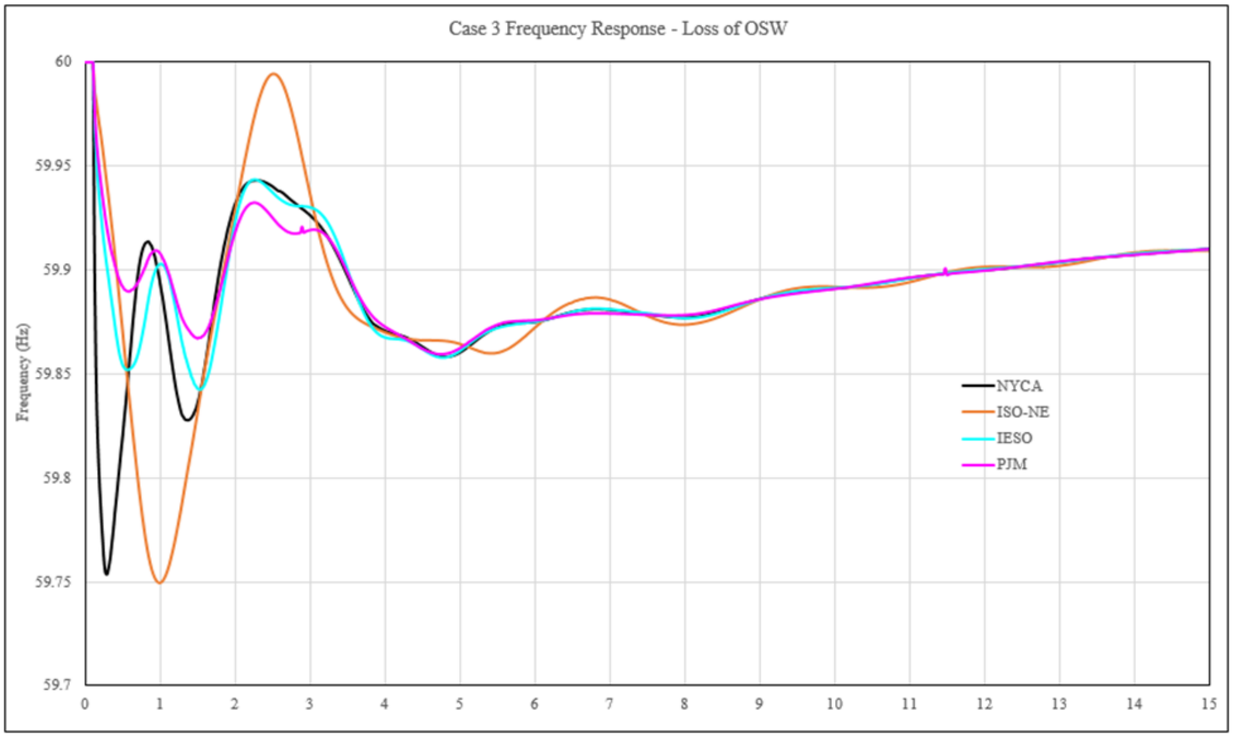
Figure 64: Summary of Frequency Response Characteristics - Case 6

Description	Nadir Point (Hz)	Rate of Change of Frequency (Hz/Sec)	Settling Frequency (Hz) (10 Seconds)	Equivalent NYCA System Inertia (Heq)	NYCA Inertia Online (MVA-s)
N-1 OSW Max	59.92	-0.91	59.98	1.22	47,326
N-1-1 OSW Max	59.93	-0.83	59.98	1.22	47,326
N-1 OSW 45%	59.92	-0.76	59.98	1.42	51,640
N-1-1 OSW 45%	59.92	-0.73	59.98	1.42	51,640

Impact of System Inertia & Governor Response on System Frequency

Although all cases show a stable system response, the loss of OSW event under light load conditions has a noticeably poorer system response in terms of the point at which the system frequency response is arrested (or "nadir" point) as well as primary frequency response characteristics. In general, a light load case has less synchronous generation operating on the system which results in less inertia compared to instances of higher load. Figure 17, see page 34 of the report, shows the system frequency response, under Case 3 conditions with OSW at its maximum and the Y49 cable out of service, as seen across some of the buses located in NYCA and in the adjacent areas. Figure 17, also demonstrates that, although the primary system frequency response after the loss of OSW across these buses is different, the frequency recovery across these buses is similar.

Figure 65: Case 3 (Light Load) System Frequency Response (Including External Areas) with Y49 Out-Of Service



As renewable generation interconnects to the system and synchronous generation retires, an overall decrease in the average system inertia is expected. Since the future renewable models interconnecting in the other areas are not available for this assessment, the impact of external area inertia on maintaining system stability was investigated by reducing the inertia constant of the synchronous generators in the other areas. Thus, in order to model and study penetration of renewable resources across the other portion of the Eastern Interconnection, as a proxy, the inertia constant (H) of all the synchronous generator models was reduced, which in turn will reduce the overall inertia of the system. For this study, the inertia constant across the Eastern Interconnection, except for the NYCA generators, was reduced by approximately 50% (NYCA generators were not reduced as we included age-based generation removals and the 70 x 30 renewable dispatch in the development of the cases).

As seen in **Figure 65** the frequency response observed with inertia constant (H) reduced by approximately 50% are slightly inferior to the system frequency response with 100% of the inertia constant. However, the simulation indicated an overall stable response. The summary of the system frequency response characteristics for the Eastern Interconnection is provided in **Figure 66.** As seen in **Figure 66,** the nadir point for the frequency in New York is reduced along with an increased ROCOF. As there was no change in this simulation to the governor response, the primary frequency response through 15 seconds is insignificantly changed.

Figure 66: System Frequency Response with External Area Inertia Constant (H) Reduced by Approx. 50%

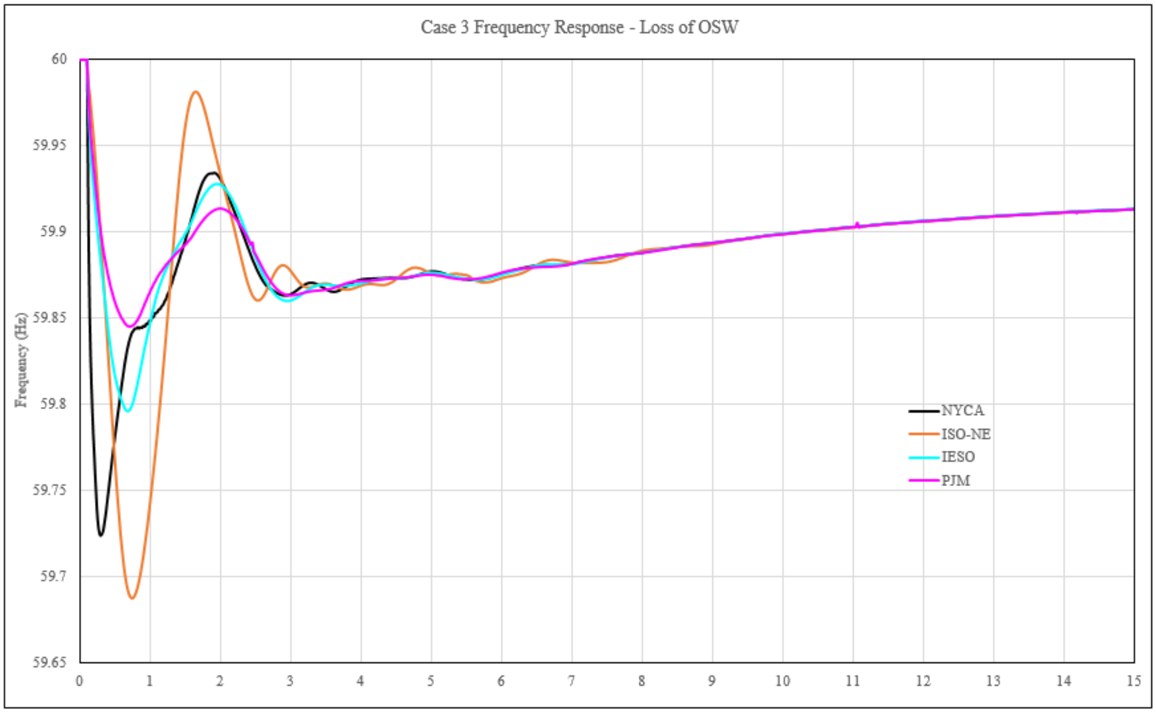


Figure 67: Summary of System Frequency Response Characteristics – With H Reduced by Approx. 50% in External Areas

Description	Nadir Point (Hz)	Rate of Change of Frequency (Hz/Sec)	Settling Frequency (Hz) (10 Seconds)	Equivalent Eastern Interconnection System Inertia (Heq)	Eastern Interconnection Inertia Online (MVA-s)
Case 3 N-1-1 OSW Max	59.75	-2.87	59.89	3.38	1,657,602
Case 3 N-1-1 OSW Max with 50% Inertia Constant	59.72	-2.99	59.9	1.75	857,026

In addition to the expectation for reduced system inertia with increased renewable resource penetration it is also anticipated that the governor responsiveness may be increasingly squelched. To account for this expectation an additional evaluation was performed, in addition to the reduction in inertia by 50%, by squelching the governor response characteristics of generators in the eastern interconnection that have more than 200 MVA in capacity and that are classified as full responsive.[31]

[31] See ERAG MMWG Manual for the process on changing a governor response to squelched.

The system frequency response and response characteristics seen for this condition for the loss of OSW are shown in **Figure 67.** The frequency response characteristics for this condition are the same as shown in **Figure 66** with 50% inertia constant. As observed from comparing **Figure 65** to **Figure 67** and **Figure 66** to **Figure 69**, the change in nadir point in each area is not impacted by squelching the governor response as the nadir point is primarily impacted by system inertia. However, the frequency recovery response is different. In the case with system inertia reduced by 50%, the bus frequency recovers to 59.9 Hz in 10-seconds with increased frequency improvement seen through 15-seconds, whereas in the case with system inertia reduced by 50% and generators squelched, the frequency does not recovery to 59.9 Hz by 15-seconds. Thus, it is seen from this analysis that reduction in system inertia can degrade the frequency nadir and ROCOF, while the reduction in the governor response capabilities impacts the stabilizing and recovery characteristics of the system frequency response.

Figure 68: System Frequency Response Characteristic with External Area Inertia Constant (H) Reduced by 50% and Increased Governor Squelching

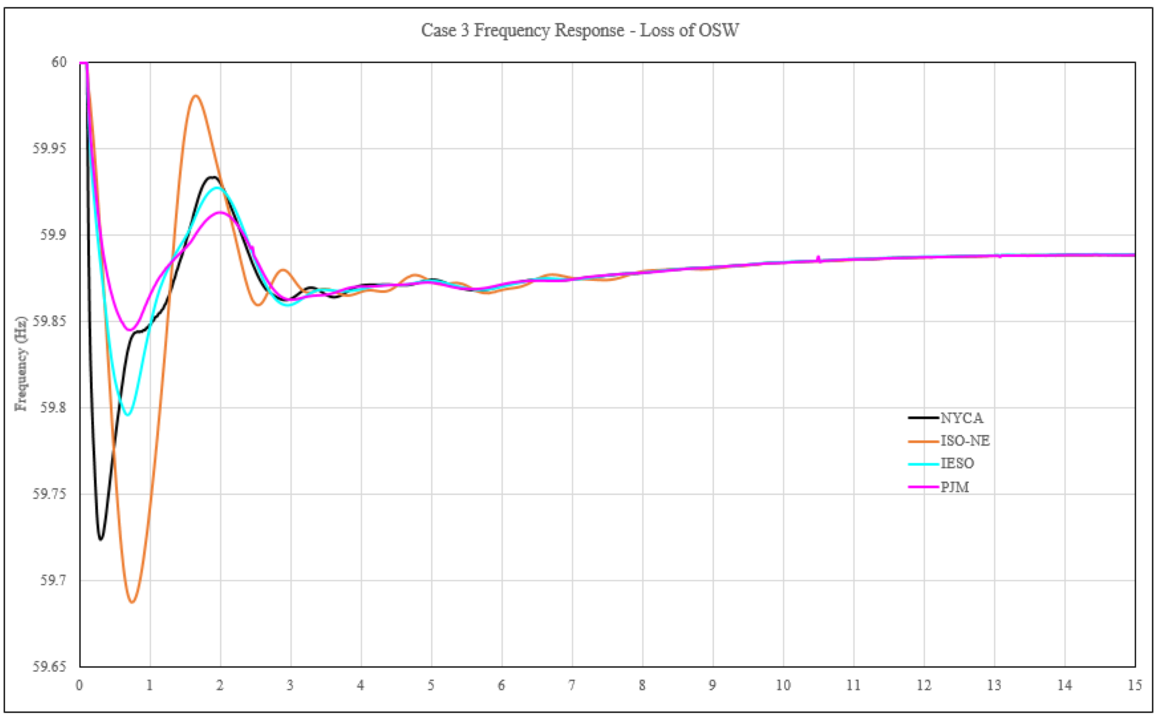


Figure 69: Summary of Frequency Response Characteristics - With H Reduced by Approx. 50% and Increased Governor Squelching

Description	Nadir Point (Hz)	Rate of Change of Frequency (Hz/Sec)	Settling Frequency (Hz) (10 Seconds)	Equivalent Eastern Interconnection System Inertia (Heq)	Eastern Interconnection Inertia Online (MVA-s)
Case 3 N-1-1 OSW Max with 50% Inertia Constant and Governor Squelched	59.72	-2.99	59.88	1.75	857,026

Short-Circuit Ratio

Background on Short-Circuit Ratio

With the planned increased to renewable energy resources on the system, there are several important considerations to evaluate in addition to traditional steady state and dynamics analysis. It is expected that many renewable generators will connect to the grid asynchronously through power electronic devices (*i.e.,* inverter-based resources). The ability of inverter-based resources to function properly often depends on the strength of the grid at or near the interconnection of the resources. Grid strength is a commonly used term to describe how the system responds to system changes (*e.g.,* changes in load, and equipment switching). In a "strong" system, the voltage and angle are relatively insensitive to changes in current injection from the inverter-based resource. Inverter-based resources connecting to a portion of the system rich in synchronous generation that is electrically close or relatively large is likely connecting to a strong system. Inverter-based resources connected to a "weak" portion of the grid may be subject to instability, adverse control interactions, and other issues.[32]

As documented by NERC, inverter-based resources are particularly susceptible to weak grid conditions for several reasons. First, they have little or no inertia in their mechanical systems to provide the synchronizing power inherent in more traditional generation forms. Their ability to provide expected real and reactive power is dependent on the electronic controls which separate the power source from the grid. These controls depend on a stable voltage reference from the grid. As the system is weakened, the voltage reference becomes less stable thereby leading to unstable controls behavior.

[32] North American Electric Reliability Corporation, Integrating Inverter-Based Resources into Low Short Circuit Strength Systems Reliability Guideline, dated December 2017.

The prevailing measure of system strength is the short-circuit ratio calculation. Short-circuit ratio is defined as the ratio of short-circuit apparent power (SCMVA) at the point of interconnection (POI) from a 3-phase fault at the POI to the power rating of the resource.

$$Short\ Circuit\ Ratio_{POI} = \frac{SCMVA_{POI}}{MW}$$

For example, a 300 MW inverter-based resource with a SCMVA of 717 MVA equates to a short-circuit ratio of 2.39. This method of calculating short-circuit ratio is most appropriate when the inverter-based resource is not in close proximity to other inverter-based resources. The weighted short-circuit ratio is a more appropriate methodology for determining the short-circuit ratio amongst closely connected inverter-based resources where SCMVAi is the short-circuit capacity at bus i without current contribution from non-synchronous generation and PRMWi is the MW rating of non-synchronous generation to be connected at bus i. N is the number of inverter-based resource plants fully interacting with each other and i is the plant index.

$$Weighted\ Short - Circuit\ Ratio = \frac{\sum_{I}^{N} SCMVA_i \times P_{RMW\,i}}{\left(\sum_{i}^{N} P_{RMW\,i}\right)^2}$$

Short-circuit ratio or weighted short-circuit ratio calculations should be used as a guideline to identify potential areas of concern. These calculations are a guideline to show areas where additional studies may need to be performed when connecting inverter-based resources. Once weak areas are identified, other analysis may need to be performed, such as sub-synchronous control interaction studies or electromagnetic transient. A typical threshold for identifying low short-circuit ratio is 3.0.[33]

NYCA Short-Circuit Ratio

The NYISO evaluated short-circuit ratio and weighted short-circuit ratio under the 70 x 30 scenario transmission security base case assumptions. Short-circuit ratio and weighted short-circuit ratio are calculated for all the new and existing wind and solar plants.

Figure 69 shows a summary of the buses in the NYCA that have a short-circuit ratio of less than 3.0. Appendix A provides a summary of all evaluated buses short-circuit ratio. **Figure 70** shows where these buses are located within New York where intensity inversely proportional to short-circuit ratio to emphasize weak locations.

[33] North American Electric Reliability Corporation, Short-Circuit Modeling and System Strength, dated February 2018

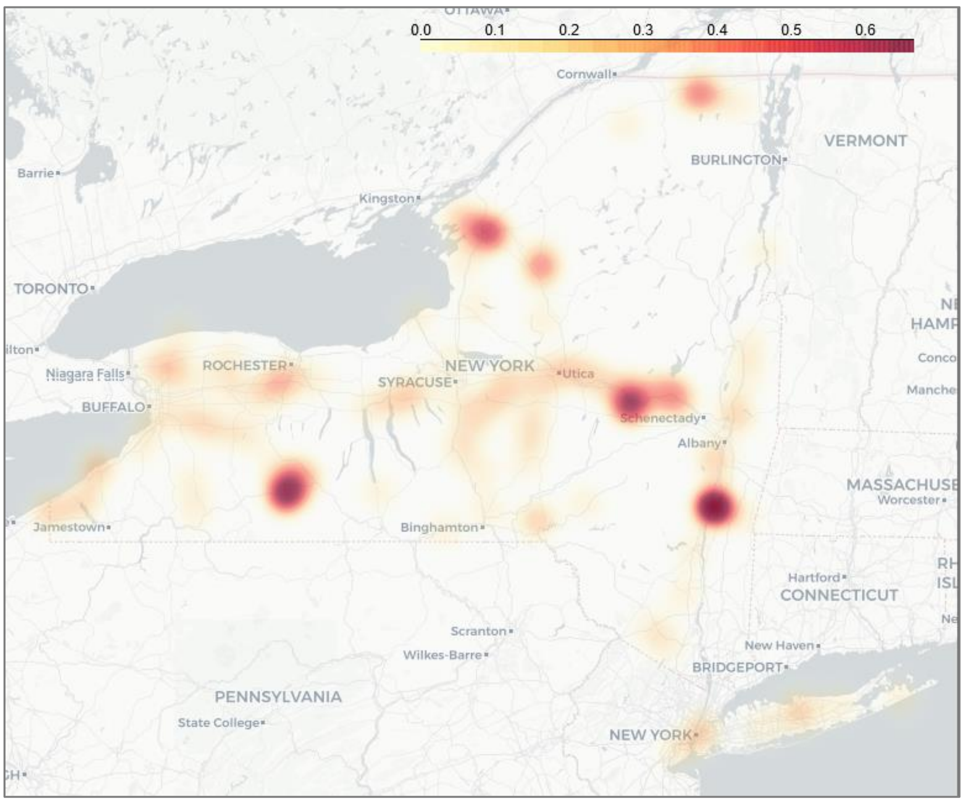
Figure 70: NYCA Buses with Short-Circuit Ratio Less than 3.0

Bus Name	Bus Voltage (kV)	Lowest Short-Circuit Ratio (1)
North Catskill	115	1.4
Bennett	115	1.5
Black River	115	1.7
Marshville 115	115	2.2
Patnode	230	2.7

Notes:

(1) The reported value is the lowest short-circuit ratio in consideration of all six 70x30 cases. For most buses the short-circuit ratio is similar across all six cases.

Figure 71: Case 1 Short-Circuit Ratio Locations



In performing the weighted short-circuit ratio calculations the evaluations included groups of inverter-based generators in a 22-kilometer radius. The 22-kilometer distance is selected because this corresponds to approximately a 0.2° in either longitude or latitude. **Figure 71** provides a summary of the buses in NYCA that have a weighted short-circuit ratio of less than 3.0. **Figure 72** provides the geographical representation of the short-circuit ratio values across the NYCA system.

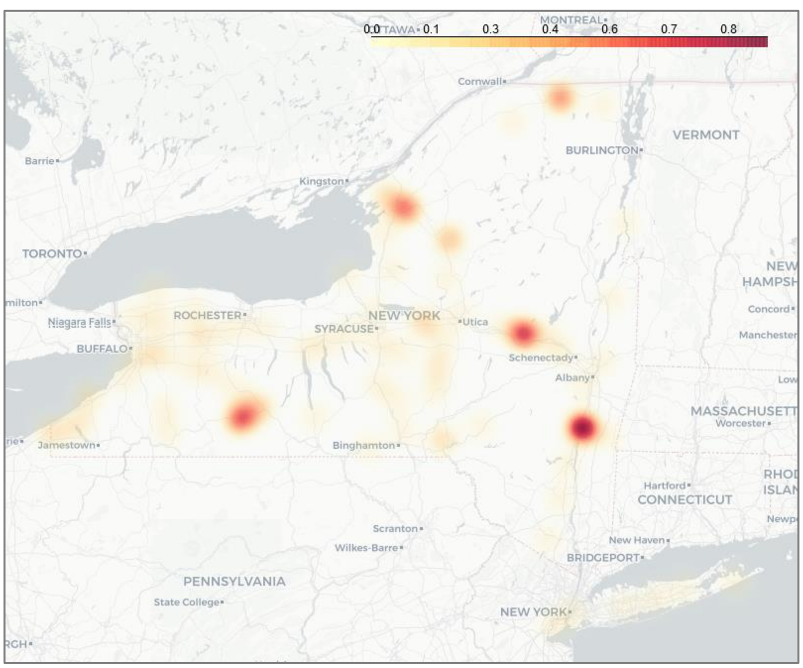
Figure 72: NYCA Buses with Weighted Short-Circuit Ratio Less than 3.0

Bus Name	Bus Voltage (kV)	Lowest Weighted Short-Circuit Ratio (1)
North Catskill & Indep C	115	1.1
Meco 115 & Marshville 115 & Clinton	115	1.3
Black River & Coffeen Street	115	1.4
Bennett & Q# 422 Eight Point Wind Energy Center	115	1.4
Willis E & Ryan & Patnode & Jericho Rise Wind Transformer 1	230 & 230 & 230 & 115	1.6
Chases L & Rector & Bremen & Lowville-Maple Avenue	230 & 230 & 115 & 115	2.1
Avoca & Canadaigua Wind Tap & Howard Wind 115	230 & 230 & 115	2.3
Whitman & Fenner Wind Farm	115	2.7
Lyme Tap & Lyme	115	2.8
Stilesville	115	3

Notes:

(1) The reported value is the lowest short-circuit ratio in consideration of all six 70x30 cases. For most buses the short-circuit ratio is similar across all six cases.

Figure 73: Case 1 Weighted Short-Circuit Ratio Locations



Voltage Flicker

As the transmission system changes, another important consideration is light flicker caused by the connection of large reactive devices, such as a shunt reactive device or a load. Some New York Transmission Owners have flicker (or Delta-V) criteria. For example, Avangrid criteria for voltage flicker is a change of 3% in bus voltage.[34]

The solution methodology for this analysis is the same as used for switching studies (triangularized Y matrix network solution activity or TYSL). The TYSL solution methodology is designed for situations where the internal flux linkages of generators are assumed to remain unchanged as load or other devices are switched into the system. While this solution methodology does provide an instantaneous change to the bus voltage due to a switching event, other fast electromagnetic transient variations are not captured. The effects of voltage change of newly added load is influenced by the statuses of generations near that load. If all available generation near the load is in-service, and as these generators would control their "internal" voltage, the observed voltage drop would then be less in magnitude than the instances with some or all nearby generators out-of-service. The flicker calculation also assumes that wind or solar farms are stable in controlling their POI and terminal voltages.

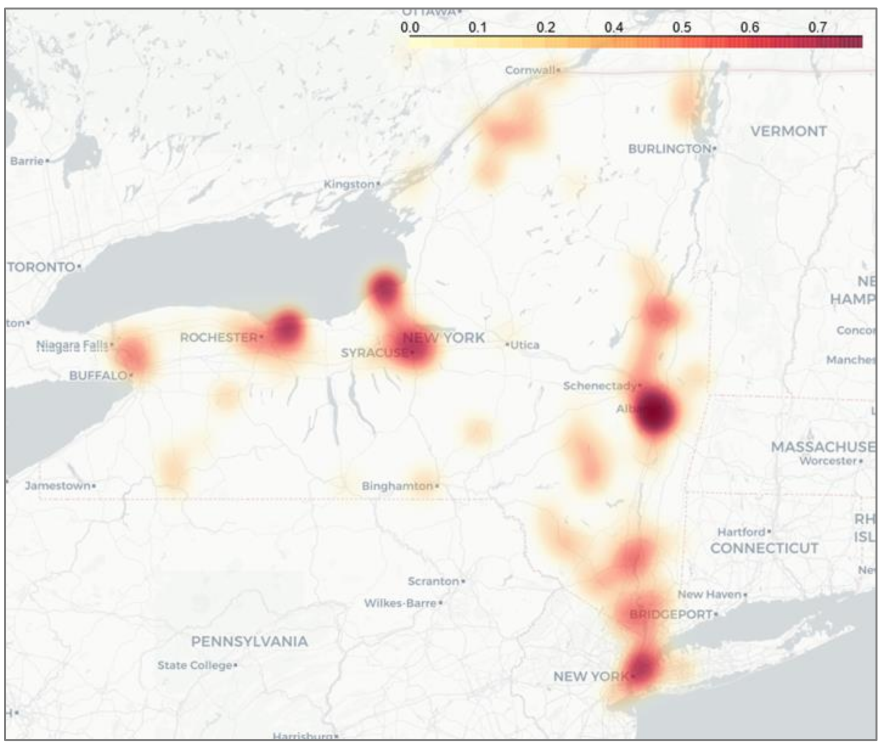
The first step in this analysis is to determine the size of reactive device at a given NYCA BES bus using the low renewable generation (*i.e.,* Case 2, Case 4, and Case 5) that results in a 3% change in bus voltage. Once the size of the reactive device is known, the second step is to simulate the change in bus voltage under high renewable generation conditions (*i.e.,* Case 1, Case 3, and Case 6). **Figure 73** provides a summary the largest change in bus voltage observed between peak load, shoulder load, and light load conditions. The Delta-V column in **Figure 73** shows the additional voltage drop (*i.e.,* beyond 3%). For example, in Case 2 a reactive load was placed at the Nine Mile Point 345 kV bus that resulted in a 3% change in bus voltage. When this reactive load was placed in Case 1 the resulting change in voltage was a 5.43% decline. The difference in bus voltages is 2.43% which is reported in **Figure 73. Figure 74, Figure 75,** and **Figure 76** provide a visual representation of the flicker between the peak, light load, and shoulder load cases, respectively. As shown on these figures the flicker results are influenced by the statuses of generations near the test load.

[34] Avangrid Electric Transmission Planning Manual, Technical Manual TM 1.2.00, dated June 29, 2019.

Figure 74: Summary of NYCA Flicker

Bus Name	Bus Voltage (kV)	Delta-V	Peak/Light Load/Shoulder Load
Bayonne	138	-3.39%	Shoulder Load
Nine Mile Point 1	345	-2.43%	Peak Load
Station 13a, Bus #1 & Bus #2	115	-1.86%	Peak Load
Marshville 115	115	-1.80%	Shoulder Load
Scriba	345	-1.67%	Peak Load
Oswego	345	-1.67%	Peak Load
Fitzpatrick	345	-1.67%	Peak Load
Independence	345	-1.66%	Peak Load
Albany Steam	115	-1.54%	Light Load
Clinton Avenue	115	-1.52%	Shoulder Load

Figure 75: Peak Load Flicker[35]



[35] In the plot scale, a 0 represents no change in per-unit voltage and a 1 represents at 0.03 per-unit voltage decline.

Figure 76: Light Load Flicker

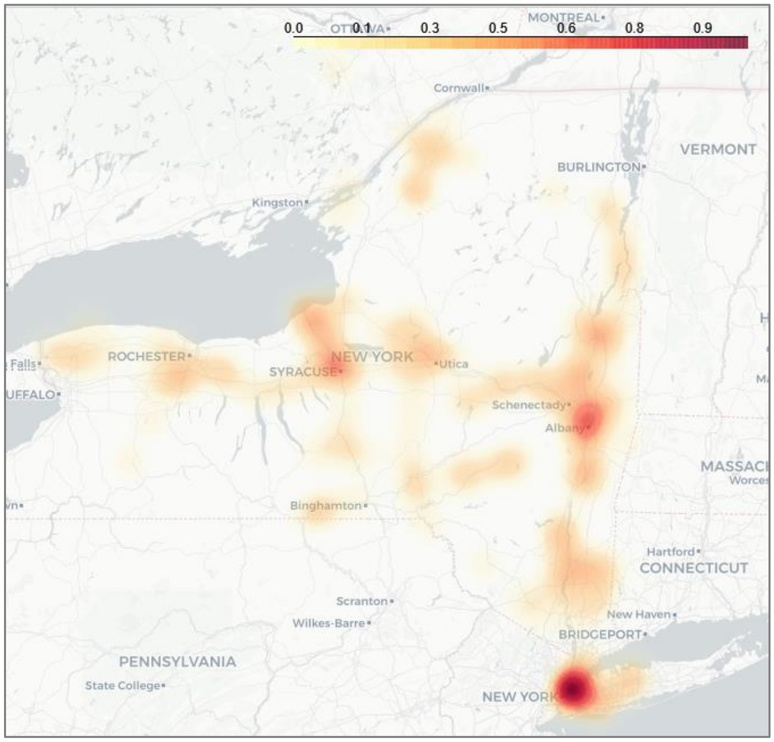
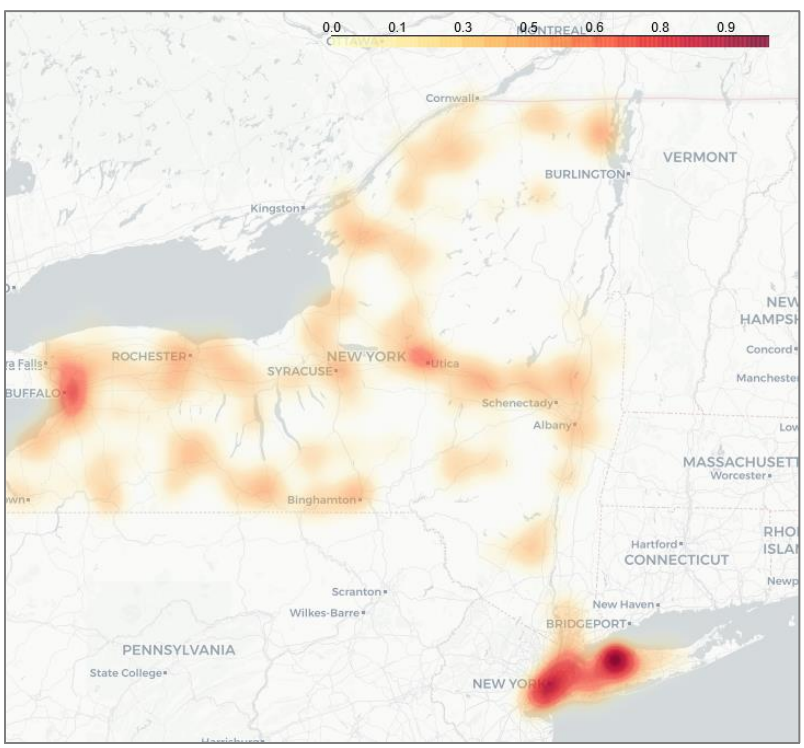


Figure 77: Shoulder Load Flicker



Appendix G – Reliability Planning Process

This appendix presents an overview of the NYISO's Reliability Planning Process. A detailed discussion of the Reliability Planning Process, including applicable Reliability Criteria, is contained in NYISO Manual entitled: *Reliability Planning Process Manual*, which is posted on the NYISO's website[36].

The NYISO Reliability Planning Process is an integral part of the NYISO's overall Comprehensive System Planning Process (CSPP).

The CSPP is comprised of four components:

1. Local Transmission Planning Process (LTPP),
2. Reliability Planning Process (RPP), along with the Short-Term Reliability Process (STRP),
3. Economic Planning Process, and
4. Public Policy Transmission Planning Process.

Under the LTPP, the local Transmission Owners (TOs) perform transmission studies for their transmission areas according to all applicable criteria. This process produces the Local Transmission Owner Plan (LTP), which feeds into the NYISO's determination of system needs through the CSPP. Links to the Local Transmission Owner Plans (LTPs) can be found on the NYISO's website[37].

The second component in the CSPP cycle is the RPP, covering year 4 through year 10 following the year of starting the study, in conjunction with the STRP, covering year 1 through year 5 following the STAR Start Date of the study. The RPP and STRP requirements are described in detail in the RPP Manual and Attachments Y and FF to the OATT, respectively. Under the biennial process for conducting the RPP, the reliability of the New York Bulk Power Transmission Facilities (BPTF) is assessed, any Reliability Needs are identified, solutions to identified needs are proposed and evaluated for their viability and sufficiency to satisfy the identified needs, and the more efficient or cost-effective transmission solution to the identified needs is selected by the NYISO.

During the Reliability Planning Process, the NYISO conducts the Reliability Needs Assessment (RNA) and Comprehensive Reliability Plan (CRP). The RNA evaluates the adequacy and security of the BPTFs over the RNA Study Period (i.e., years 4 through 10 following the year in which the RNA is conducted). In

[36] Link to RPP Manual: https://www.nyiso.com/documents/20142/2924447/rpp_mnl.pdf/85b28e6b-16b0-0ce7-60f3-c2291733acea

[37] Link to LTPP: https://www.nyiso.com/documents/20142/3632262/Local-Transmission-Owner-Planning-Process-LTPP.pdf/025b47f1-d90a-94e3-8eba-c21e7a6131aa

identifying resource adequacy needs, the NYISO identifies the amount of resources in megawatts (MW, known as "compensatory MW") and the locations in which they are needed to meet those needs.

Following approval of the RNA by its Board of Directors and before NYISO issues a solicitation for regulated backstop, market-based, and alternative regulated solutions, the NYISO will request updated LTPs, NYPA transmission plans, and other status updates relevant to reducing, or eliminating, the Reliability Needs, as timely received from Market Participants, Developers, TOs, and other parties. Any such update must meet, in NYISO's determination, the RNA Base Case inclusion rules, as defined in Section 3 of the RPP Manual. If there are remaining Reliability Needs after these updates, the NYISO will request solutions for the remaining Reliability Needs. These solutions will be then undergoing the Viability and Sufficiency Assessments under the CRP, and if needed and as applicable, Transmission Evaluation and Selection. The CRP documents the solutions determined to be viable and sufficient to meet the identified Reliability Needs. The NYISO ranks any regulated transmission solutions submitted for the Board to consider for selection of the more efficient or cost-effective transmission project. If built, the selected transmission project would be eligible for cost allocation and recovery under the NYISO's tariff.

There are two different aspects to analyzing the BPTF's reliability in the RNA: adequacy and security. Adequacy is a planning and probabilistic concept. A system is adequate if the probability of having sufficient transmission and generation to meet expected demand is equal to or less than the system's standard, which is expressed as a loss of load expectation (LOLE). The New York State bulk power system is planned[38] to meet an LOLE that, at any given point in time, is less than or equal to an involuntary load disconnection that is not more frequent than once in every 10 years, or 0.1 days per year. This requirement also forms the basis of New York's installed reserve margin (IRM) resource adequacy requirement.

Security is an operating and deterministic concept. This means that possible events are identified as having significant adverse reliability consequences. The system is planned and operated so that the system can continue to serve load even if these events occur. Security requirements are sometimes referred to as N-1 or N-1-1. N is the number of system components. An N-1 requirement means that the system can withstand single disturbance events (*e.g.*, generator, bus section, transmission circuit, breaker failure, double-circuit tower) without violating thermal, voltage and stability limits or before resulting in unplanned loss of service to consumers. An N-1-1 requirement means that the Reliability Criteria apply

[38] NYSRC Reliability Rules: "The loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. LOLE evaluations shall make do allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring control areas, NYS Transmission System emergency transfer capability, and capacity and/or load relief from available operating procedures."

after any critical element such as a generator, a transmission circuit, a transformer, series or shunt compensating device, or a high voltage direct current (HVDC) pole has already been lost. Generation and power flows can be adjusted by the use of 10-minute operating reserve, phase angle regulator control, and HVDC control. Following such adjustments, a second single disturbance is analyzed.

The Reliability Planning Process is anchored in the market-based philosophy of the NYISO and its Market Participants, which posits that market solutions should be the preferred choice to meet the identified Reliability Needs reported in the RNA. In the CRP, the reliability of the BPTFs is assessed and solutions to Reliability Needs evaluated in accordance with existing Reliability Criteria of the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council, Inc. (NPCC), and the New York State Reliability Council (NYSRC) as they may change from time to time. These criteria and a description of the nature of long-term bulk power system planning are described in detail in the Reliability Planning Process Manual, and are briefly summarized below.

In the event that market-based solutions do not materialize to meet a Reliability Need in a timely manner, the NYISO designates the Responsible TO or Responsible TOs or developer of an alternative regulated solution to proceed with a regulated solution in order to maintain system reliability. Under the Reliability Planning Process, the NYISO also has an affirmative obligation to report historic congestion across the transmission system. In addition, the draft RNA is provided to the Market Monitoring Unit (MMU) for review and consideration of whether market rules changes are necessary to address an identified failure, if any, in one of the NYISO's competitive markets. If a market failure is identified as the reason for the lack of market-based solutions to a Reliability Need, the NYISO will explore appropriate changes in its market rules with its stakeholders and the MMU. The Reliability Planning Process does not substitute for the planning that each TO conducts to maintain the reliability of its own bulk and non-bulk power systems.

The NYISO does not license or construct projects to respond to identified Reliability Needs reported in the RNA. The ultimate approval of those projects lies with regulatory agencies such as the Federal Energy Regulatory Commission (FERC), the New York State Public Service Commission (NYPSC), environmental permitting agencies, and local governments. The NYISO monitors the progress and continued viability of proposed market and regulated projects to meet identified Reliability Needs and reports its findings to the Board.

The Short-Term Reliability Process (STRP) uses quarterly Short-Term Assessment of Reliability (STAR) studies to assess the reliability impacts of generator deactivations on both Bulk Power Transmission Facilities (BPTF) and non-BPTF (local) transmission facilities, in coordination with the Responsible

Transmission Owner(s). The STAR is also used by the NYISO, in coordination with the Responsible Transmission Owner(s), to assess the reliability impacts on the BPTF of system changes that are not related to a Generator deactivation. These changes may include adjustments to load forecasts, delays in completion of planned upgrades, long duration transmission facility outages and other system topology changes. Section 38 of the NYISO OATT describes the process by which the NYISO, Transmission Owners, Market Participants, Generator Owners, Developers, and other interested parties follow to plan to meet Generator Deactivation Reliability Needs affecting the New York State Transmission System and other Reliability Needs affecting the BPTF (collectively, Short-Term Reliability Needs).

Each STAR will assess a five-year period, with a particular focus on Short-Term Reliability Process Needs ("needs") that are expected to arise in the first three years of the study period. The STRP is the sole venue for addressing Generator Deactivation Reliability Needs on the non-BPTF, and for BPTF needs that arise in the first three years of the assessment period. With one exception,[39] needs that arise in years four or five of the assessment period may be addressed in either the STRP or longer-term Reliability Planning Process (RPP).

Each STAR looks out five years from its STAR Start Date. The STRP concludes if a STAR does not identify a need or if the NYISO determines that all identified needs will be addressed in the RPP. Should a STAR identify a need to be addressed in the STRP, the NYISO would request the submission of market-based solutions to satisfy the need along with a Responsible Transmission Owner STRP solution. The NYISO evaluates the viability and sufficiency of the proposed solutions to satisfy the identified needs and selects a solution to address the need. The NYISO reviews the results of the solution or combination of solutions (including an explanation regarding the solution that is selected) with stakeholders and posts a Short-Term Reliability Process Report detailing the determination with stakeholders.

The third component of the CSPP is the Economic Planning Process, which is the process by which the ISO: (1) develops the System & Resource Outlook and identifies current and future congestion on the New York State Transmission System; (2) evaluates in an Economic Transmission Project Evaluation any Regulated Economic Transmission Project proposals to address any constraint(s) on the BPTFs identified in the Economic Planning Process, which transmission projects are eligible for cost allocation and cost recovery under the ISO OATT if approved by a vote of the project's Load Serving Entity beneficiaries; and (3) conducts any Requested Economic Planning Studies. In conducting the process, the ISO will analyze a base case and scenarios that are developed in consultation with stakeholders.

[39] Generator Deactivation Reliability Needs that arise on local facilities, not on the BPTF, must always be addressed in the STRP.

The fourth component of the CSPP is the Public Policy Transmission Planning Process. Under this process interested entities propose, and the New York State Public Service Commission (NYPSC) identifies, transmission needs on the BPTF driven by Public Policy Requirements. The NYISO then requests that interested entities submit proposed solutions to the identified Public Policy Transmission Need. The NYISO evaluates the viability and sufficiency of the proposed solutions to satisfy the identified Public Policy Transmission Need. The NYISO then evaluates and may select the more efficient or cost-effective transmission solution to the identified need. The NYISO develops the Public Policy Transmission Planning Report that sets forth its findings regarding the proposed solutions. This report is reviewed by NYISO stakeholders and approved by the Board of Directors.

In concert with these four components, interregional planning is conducted with NYISO's neighboring control areas in the United States and Canada under the Northeastern ISO/RTO Planning Coordination Protocol. The NYISO participates in interregional planning and may consider Interregional Transmission Projects in its regional planning processes.

Figure 78: NYISO's Comprehensive System Planning Process (CSPP)

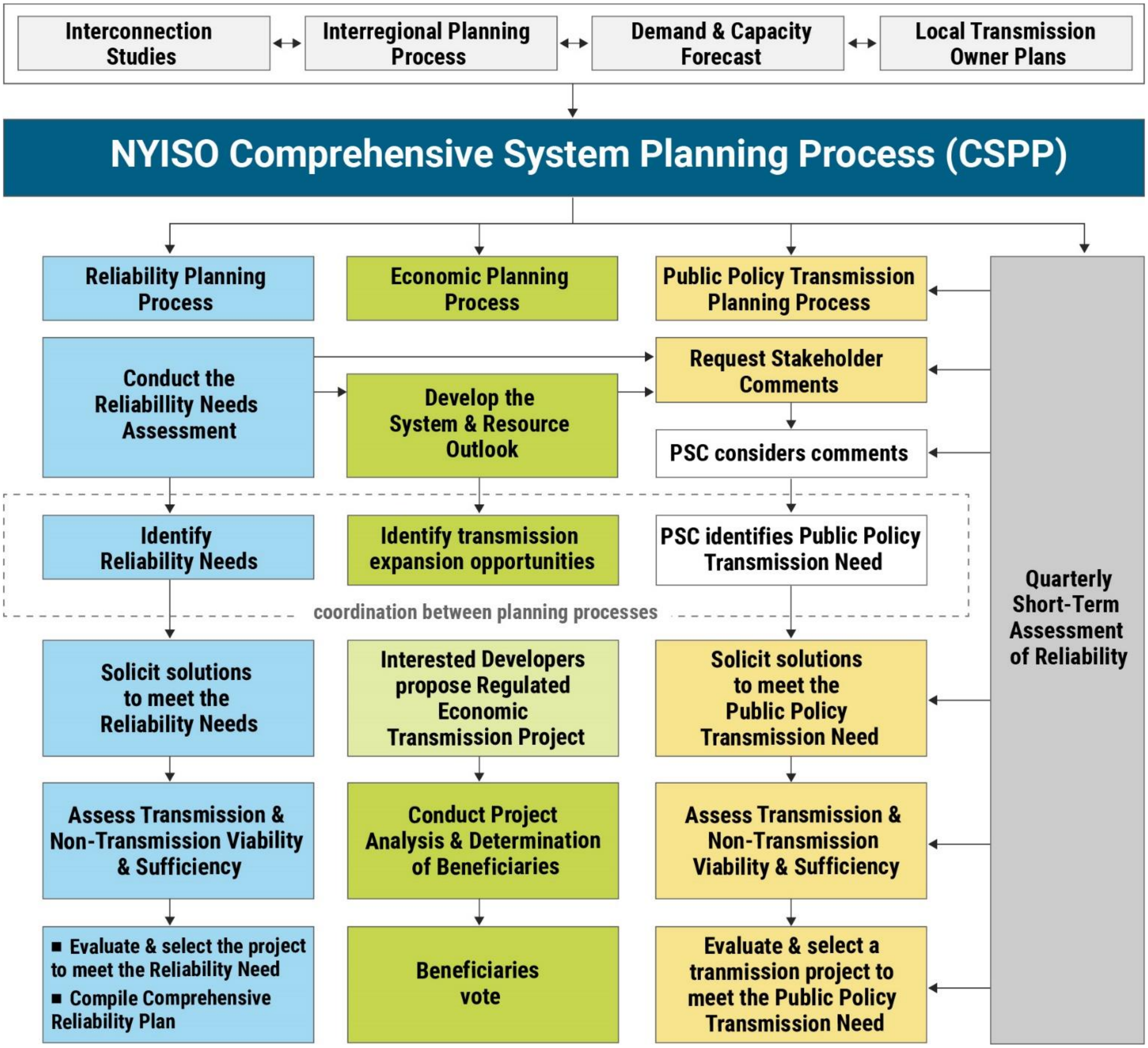
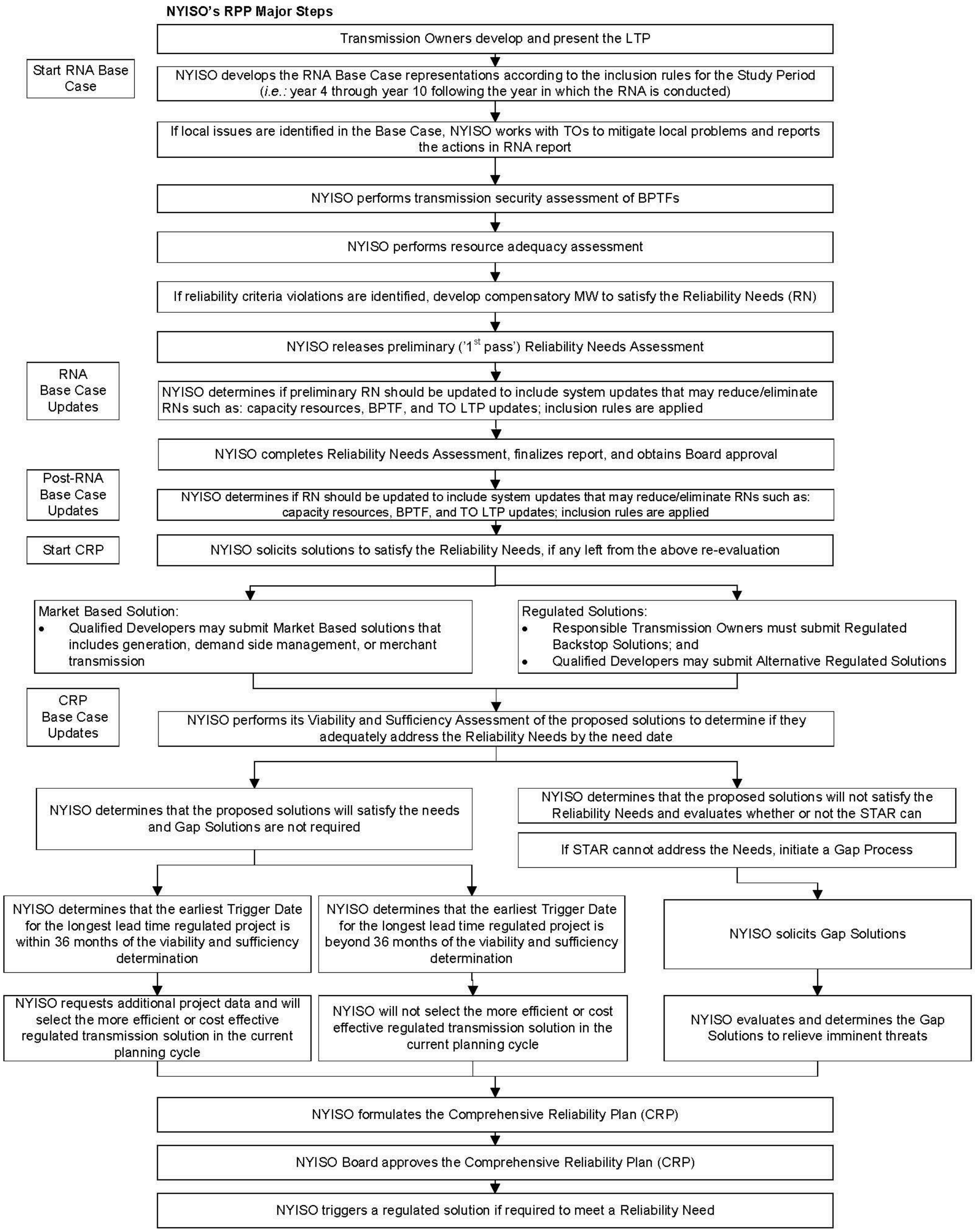


Figure 79: NYISO Reliability Planning Process



Notes:
* If an immediate threat to the reliability of the power system is identified, a Gap Solution outside of the normal RPP cycle may be requested by the NYISO Board.

Appendix H - Reliability Compliance Obligations and Activities

The Reliability Needs Assessment and the CRP are not the only NYISO work product or activity related to reliability planning. The purpose of this section is to discuss the NERC Planning Coordinator and Transmission Planner obligations fulfilled by the NYISO as well as the other NPCC and NYSRC planning compliance obligations. The NYISO has various compliance obligations under NERC, NPCC, and the NYSRC. The periodicity of these requirements varies amongst the standards and requirements. While achieving compliance with all NERC, NPCC, and NYSRC obligations is critical to ensuring the continued reliability of the transmission system, this section primarily discusses in some detail the planning compliance requirements that closely align with this Reliability Needs Assessment. The full details of the compliance obligations are found within the reliability standards and requirements themselves. Publicly available results for the compliance activities listed below are found on the NYISO website under Planning – Reliability Compliance[40].

The purpose of the NERC Reliability Standards is to "define the reliability requirements for planning and operating the North American bulk power system and are developed using a results-based approach that focuses on performance, risk management, and entity capabilities." The objective of NPCC Directory #1 and the NYSRC Reliability Rules and Compliance Manual are to provide a "design-based approach" to design and operate the bulk power system to a level of reliability that will not result in the loss or unintentional separation of a major portion of the system from any of the planning and operations contingencies with the intent of avoiding instability, voltage collapse and widespread cascading outages. Figure 80 shows the various NERC Standards with requirements applicable to the NYISO as a NERC registered Planning Coordinator and/or Transmission Planner. The NPCC planning compliance obligations are primarily located in NPCC Regional Reliability Reference Directory #1 Design and Operation of the Bulk Power System. The NYSRC planning compliance obligations are located in the Reliability Rules and Compliance Manual.

Fundamental to any reliability study is the accuracy modeling data provided by the entities responsible for providing the data. The data requirements for the development of the steady state, dynamics, and short circuit models are provided in the NYISO Reliability Analysis Data Manual (RAD Manual).[41] This data primarily comes from compliance with NERC MOD standards. Much of this data is collected through the annual database update process outlined in the RAD Manual and the annual FERC Form 715 filing to which the transmitting utilities certify, to the best of their knowledge, the accuracy of the

[40] https://www.nyiso.com/planning-reliability-compliance

[41] https://www.nyiso.com/documents/20142/2924447/rel-anl-data-mnl.pdf

data. Additional compliance obligations provide for the accuracy of the modeling data through comparison to actual system events (*e.g.,* MOD-026, MOD-026, and MOD-033).

Following the completion of the annual database update, these databases are used for study work such as the Reliability Planning Process, and for many other compliance obligations such as those listed in Figure 80. Planning studies similar to the Reliability Planning Process include the NPCC/NYSRC Area Transmission Reviews (ATRs) and the NERC TPL-001 assessments.

Figure 80: List of NERC Standards for Planning Coordinators and Transmission Planners

Standard Name	Title	Purpose
FAC-002	Facility Interconnection Studies	To study the impact of interconnecting new or materially modified Facilities to the Bulk Electric System.
FAC-010	System Operating Limits Methodology for the Planning Horizon	To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
FAC-013	Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon	To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.
FAC-014	Establish and Communicate System Operating Limits	To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
IRO-017	Outage Coordination	To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.
MOD-020	Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators	To ensure that assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition to assist a proper real-time operating, load information related to controllable Demand-Side Management programs is needed.
MOD-026	Verification of Models and Data for Generator Excitation Control System or Plant Volt/VAR Control Functions	To verify that the generator excitation control system or plant volt/var control function model (including the power system stabilizer model and the impedance compensator model) and the model parameters used in dynamic simulations accurately represent the generator excitation control system or plant volt/var control function behavior when assessing Bulk Electric System (BES) reliability.
MOD-027	Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions	To verify that the turbine/governor and load control or active power/frequency control model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, accurately represent generator unit real power response to system frequency variations.

Standard Name	Title	Purpose
MOD-031	Demand and Energy Data	To provide authority for applicable entities to collect Data, energy and related data to support reliability studies and assessments to enumerate the responsibilities and obligations of requestors and respondents of that data.
MOD-032	Data for Power System Modeling and Analysis	To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.
MOD-033	Steady State and Dynamic System Model Validation	To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.
PRC-002	Disturbance Monitoring and Reporting Requirements	To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances
PRC-006	Automatic Underfrequency Load Shedding	To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.
PRC-006-NPCC	Automatic Underfrequency Load Shedding	The NPCC Automatic Underfrequency Load Shedding (UFLS) regional Reliability Standard establishes more stringent and specific NPCC UFLS program requirements than the NERC continent-wide PRC-006 standard. The program is designed such that declining frequency is arrested and recovered in accordance with established NPCC performance requirements stipulated in this document.
PRC-010	Undervoltage Load Shedding	To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).
PRC-023	Transmission Relay Loadability	Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
PRC-026	Relay Performance During Stable Power Swings	To ensure that load-responsible protective relays are expected to not trip in response to stable power swings during non-Fault conditions.
TPL-001	Transmission System Planning Performance Requirements	Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.
TPL-007	Transmission System Planned Performance for Geomagnetic Disturbance Events	Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.

NPCC/NYSRC Area Transmission Reviews

The NPCC/NYSRC Area Transmission Reviews (ATRs) are performed on an annual basis to demonstrate that conformance with the performance criteria specified in NPCC Directory #1 and the NYSRC Reliability Rules. The ATR is prepared in accordance with NPCC and NYSRC procedures that require the assessment to be performed annually, with a Comprehensive Area Transmission Review performed at least every five years. Either an Interim or an Intermediate review can be conducted between Comprehensive reviews, as appropriate. In an Interim review, the planning coordinator summarizes the changes in planned facilities and forecasted system conditions since the last Comprehensive review and assesses the impact of those changes. No new analysis are requir ed for an Interim review. An Intermediate review covers all the elements of a Comprehensive review, but the analysis may be limited to addressing only significant issues, considering the extent of the system changes. In the ATRs, the NYISO assesses the BPTF for a period four to six years in the future (the NYISO evaluates year five of the Study Period). The most recent ATR completed by the NYISO is the 2020 Comprehensive ATR completed June 2021.[42] This ATR included the post-RNA base case updates and found that the system conforms to the applicable NPCC Directory #1 and NYSRC Reliability Rules.

Seven assessments are required as part of each ATR.

The first assessment evaluates the steady state and dynamics transmission security. For instances where the transmission security assessments results indicate that the planned system does not meet the specified criteria, a corrective action plan is incorporated to achieve conformance. As part of the ATRs, and for compliance with NERC FAC-013, thermal, voltage, and stability transfer limits are performed to identify the limiting constraints for power transfers. The most resent ATR found no steady state or dynamics transmission security criteria violations.

For the second assessment, steady state and dynamics analysis are conducted to evaluate the performance of the system for low probability extreme contingencies. The purpose of the extreme contingency analysis is to examine the post contingency steady state conditions, as well as stability, overload, cascading outages, and voltage collapse, to obtain an indication of system robustness and to determine the extent of any potential widespread system disturbance. In instances where the extreme contingency assessment concludes there are serious consequences, the NYISO evaluates implementing a change to design or operating practices to address the issues.

The extreme contingency analysis included in the most recent ATR concludes that the system remained stable during most events and showed no thermal overloads over short-term emergency (STE) ratings or significant voltage violations on the BPTF. For the events that did show voltage, thermal, or dynamics issues, these events were local in nature (loss of local load or reduction of location generation) and did not result in a widespread system disturbance.

[42] https://www.nyiso.com/documents/20142/1397660/2020-Comprehensive-Area-Transmission-Review.pdf/

The third assessment evaluates extreme system conditions that have a low probability of occurrence such as high peak load conditions (*e.g.*, 90th percentile load) resulting from extreme weather or the loss of fuel supply from a given resource (*e.g.,* loss of all gas units under winter peak load). The extreme system conditions evaluate various design criteria contingencies to evaluate the post contingency steady state conditions, as well as stability, overload, cascading outages, and voltage collapse. The evaluation of extreme contingencies indicates system robustness and determine the extent of any potential widespread system disturbance. In instances where the extreme contingency assessment concludes that there are serious consequences, the NYISO evaluates implementing a change to design or operating practices to address the issues. For both the high peak load and loss of gas supply conditions evaluated in the most recent ATR, the steady state analysis results indicate that these system conditions do not cause thermal or voltage violations on the BPTF. For the loss of gas case, the stability analysis results show that most contingencies are stable and damped. However, the evaluation concluded that about 400 MVAR of dynamic reactive capability near the Oswego Complex would be needed to meet dynamics reliability criteria.

The fourth assessment evaluates the breaker fault duty at BPTF buses. The most recent ATR found no over-dutied breakers on BPTF buses.

The fifth assessment evaluates other requirements specific to the NYSRC Reliability Rules including an evaluation of the impacts of planned system expansion or configuration facilities on the NYCA System Restoration Plan and Local Area Operation Rules for New York City Operations, loss of gas supply — New York City, and loss of gas supply — Long Island.

The sixth assessment is a review of Special Protection Systems (SPSs). This review evaluates the designed operation and possible consequences of failure to operate or mis-operation of the SPS within the NYCA.

The seventh assessment is a review of requested exclusions to the NPCC Directory #1 criteria.

NERC Planning Assessments (TPL-001)

The NERC TPL-001 assessment (Planning Assessment) is performed annually. The purpose of the Planning Assessment is to demonstrate conformance with the applicable NERC transmission system planning performance requirements for the NYCA Bulk Electric System (BES). The Planning Assessment is a coordinated study between the NYISO and New York Transmission Owners.

The required system conditions to evaluate for this assessment include planned system representations over a 10-year study period for a variety of system conditions. **Figure 81** below, provides a description of the steady state, dynamics, and short circuit cases required to be evaluated in the Planning

Assessment.

Figure 81: Description of NERC TPL-001 Planning Assessment Study Cases

Case Description	Steady State	Dynamics	Short Circuit
System Peak Load (Year 1 or 2)	x		
System Peak Load (Year 5)	x	x	x
System Peak Load (Year 10)	x	x[1]	
System Off-Peak Load (One of the 5 years)	x	x	
System Peak Load (Year 1 or 2) Sensitivity	x		
System Peak Load (Year 5) Sensitivity	x	x	
System Off-Peak Load (One of the 5 years) Sensitivity	x	x	

Notes:
Only required to be assessed to address the impact of proposed material generation additions or changes in that timeframe.

The steady state and dynamics transmission security analyses evaluate the New York State BES to meet the applicable criteria. As part of this assessment, the unavailability of major transmission equipment with a lead time of more than a year is also assessed. The fault duty at BES buses are evaluated in the short-circuit representation. When the steady state, dynamics, or short circuit analysis indicates an inability of the system to meet the performance requirements in the standard, a corrective action plan is developed addressing how the performance requirements will be met. Corrective action plans are reviewed in subsequent Planning Assessments for continued validity and implementation status.

For each steady state and dynamics case, the Planning Assessment evaluates the system response to extreme contingencies. Similar to the ATR, when the Planning Assessment extreme contingency analysis concludes, there is cascading caused by an extreme contingency, the NYISO evaluates possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts.

The most recent NERC Planning Assessment for compliance with TPL-001 was completed in June 2021. As this study contains Critical Energy Infrastructure Information (CEII), it is not posted on the NYISO website. Generally, the results of this study are consistent with the ATR studies. The study scope of this assessment is different from the ATR because the ATR evaluates the Bulk Power Transmission Facilities (BPTF), while the TPL evaluates the Bulk Electric System (BES). Accordingly, criteria violations were observed on the BES. The corrective action plans for criteria violations are generally addressed in the affected Transmission Owner's Local Transmission Plan (LTP) and/or the proposed transmission facilities listed in Section 7 of the Load and Capacity Data Report.

Resource Adequacy Compliance Efforts

NPCC's Directory 1 defines a compliance obligation for the NYISO, as Resource Planner and Planning Coordinator, to perform a resource adequacy study evaluating a five-year planning horizon. The NYISO delivers a report every year under this study process to verify the system against the one-day-in-ten-years loss of load expectation (LOLE) criterion, usually based on the latest available RNA/CRP results and assumptions. The New York Area Review of Resource Adequacy completed reports are available here.

NYSRC Reliability Rules have recently added a requirement[43] that the NYISO deliver a Long Term Resource Adequacy Assessment report every RNA year, and an annual update in the non-RNA years. The NYISO first implemented this requirement after finalizing the 2020 RNA.

The NYISO is also actively involved in other activities such as the NERC's annual Long Term Reliability Assessment (LTRA), along with its biennial Probabilistic Assessment (ProbA), performed by NERC with the input from all the NERC Regions and Areas, as well as NPCC's Long Range Adequacy Overview (LROA).

[43] NYSRC Reliability Rule A.3, R.3.

Appendix I - Bulk Power Transmission Facilities

Existing New York State Bulk Power Transmission Facilities

Facility Identifier	Terminal A	Nominal Voltage	Terminal B	Nominal Voltage
MSC-7040	Chateauguay (HQ)	765	Massena	765
BK 1	Marcy	765	Marcy	345
BK 2	Marcy	765	Marcy	345
BK 1	Massena	765	Massena (MMS1)	230
BK 2	Massena	765	Massena (MMS2)	230
MSU1	Massena	765	Marcy	765
5018	Branchburg	500	Ramapo	500
BK 1500	Ramapo	500	Ramapo	345
M29	Academy	345	Sprain Brook	345
2	Alps	345	New Scotland	345
393	Alps	345	Berkshire (ISO-NE)	345
1-AR	Alps	345	Reynolds Road	345
Q35L	Astoria	345	E. 13th St C	345
Q35M	Astoria	345	E. 13th St D	345
G13	Astoria Annex	345	Astoria Energy	345
PAR-1	Astoria Annex	345	Astoria Annex	345
TR-1	Astoria Annex	345	Astoria Annex	138
91	Athens	345	Pleasant Valley	345
95	Athens	345	Leeds	345
CC1	Athens	345	Athens CC/ST #1	18
CC2	Athens	345	Athens CC/ST #2	18
CC3	Athens	345	Athens CC/ST #3	18
G27	Bayonne	345	Gowanus	345
PA301	Beck (IESO) A	345	Niagara	345
PA302	Beck (IESO) B	345	Niagara	345
68	Bowline	345	Ladentown	345
1	Bowline Point	345	Bowline Point #1	20
2	Bowline Point	345	Bowline Point #2	20
67-1	Bowline Point	345	W. Haverstraw	345
BK TA5	Buchanan N.	345	Buchanan TA5	138
W93	Buchanan N.	345	Eastview 2N	345
W95	Buchanan N.	345	Indian Point #2	22
W95	Buchanan N.	345	Indian Point #2	345
Y94	Buchanan N.	345	Ramapo	345
W96	Buchanan S.	345	Indian Point #3	22
W96	Buchanan S.	345	Indian Point #3	345
W97	Buchanan S.	345	Millwood	345

Facility Identifier	Terminal A	Nominal Voltage	Terminal B	Nominal Voltage
W98	Buchanan S.	345	Millwood	345
Y88	Buchanan S.	345	Ladentown	345
36	Clarks Corners	345	Oakdale	345
16893	Clarks Corners	345	Lafayette	345
BK 1	Clarks Corners	345	Clarks Corners	115
BK 2	Clarks Corners	345	Clarks Corners	115
6	Clay	345	Volney	345
8	Clay	345	Nine Mile Point #1	345
13	Clay	345	Dewitt	345
26	Clay	345	Independence	345
1-16	Clay	345	Edic	345
2-15	Clay	345	Edic	345
BK 1	Clay	345	Clay	115
BK 2	Clay	345	Clay	115
PC1	Clay	345	Pannell Rd	345
PC2	Clay	345	Pannell Rd	345
33	Coopers Corners	345	Fraser	345
BK 2	Coopers Corners	345	Coopers Corners	115
BK 3	Coopers Corners	345	Coopers Corners	115
CCDA42	Coopers Corners	345	Dolson Ave	345
CCRT-34	Coopers Corners	345	Rock Tavern/Middletown	345
UCC2-41	Coopers Corners	345	Marcy	345
F83	Cricket Valley	345	Pleasant Valley	345
F84	Cricket Valley	345	Pleasant Valley	345
398	Cricket Valley	345	Long Mountain (NE)	345
MSUT-1	Cricket Valley	345	Cricket Valley	18
MSUT-2	Cricket Valley	345	Cricket Valley	18
MSUT-3	Cricket Valley	345	Cricket Valley	18
22	Dewitt	345	Lafayette	345
BK 2	Dewitt	345	Dewitt	115
DART44	Dolson Ave	345	Rock Tavern	345
501	Duffy Ave	345	Newbridge Road	345
71	Dunwoodie	345	Mott Haven	345
72	Dunwoodie	345	Mott Haven	345
W73/BK S1	Dunwoodie	345	Dunwoodie South	138
W74/BK N1	Dunwoodie	345	Dunwoodie North	138
W75	Dunwoodie	345	Sprain Brook	345
W89	Dunwoodie	345	Pleasantville	345
W90	Dunwoodie	345	Pleasantville	345
Y50	Dunwoodie	345	Shore Road	345

Facility Identifier	Terminal A	Nominal Voltage	Terminal B	Nominal Voltage
BK 17	E. 13th St	345	E. 13th St	69
45	E. 13th St A	345	Farragut	345
BK 14	E. 13th St A	345	E. 13th St	138
BK 15	E. 13th St A	345	E. 13th St	138
M54	E. 13th St A	345	W. 49th St.	345
46	E. 13th St B	345	Farragut	345
BK 12	E. 13th St B	345	E. 13th St	138
BK 13	E. 13th St B	345	E. 13th St	138
M55	E. 13th St B	345	W. 49th St.	345
B47	E. 13th St C	345	Farragut	345
BK 16	E. 13th St C	345	E. 13th St	138
48	E. 13th St D	345	Farragut	345
BK 10	E. 13th St D	345	E. 13th St	138
BK 11	E. 13th St D	345	E. 13th St	138
305	E. Fishkill	345	Roseton	345
BK 1	E. Fishkill	345	E. Fishkill	115
BK 2	E. Fishkill	345	E. Fishkill	115
F36	E. Fishkill	345	Pleasant Valley	345
F37	E. Fishkill	345	Pleasant Valley	345
F38/Y86	E. Fishkill	345	Wood St/Pleasantville	345
F39/Y87	E. Fishkill	345	Wood St/Pleasantville	345
BK 1	E. Garden City	345	E. Garden City	138
BK 2	E. Garden City	345	E. Garden City	138
PAR1	E. Garden City	345	E. Garden City	345
PAR2	E. Garden City	345	E. Garden City	345
Y49	E. Garden City	345	Sprain Brook	345
1N*	Eastview	345	Eastview	138
1S*	Eastview	345	Eastview	138
2N*	Eastview	345	Eastview	138
2S*	Eastview	345	Eastview	138
W64	Eastview 1N	345	Sprain Brook	345
W99	Eastview 1N	345	Millwood	345
W78	Eastview 1S	345	Sprain Brook	345
W85	Eastview 1S	345	Millwood	345
W79	Eastview 2N	345	Sprain Brook	345
W65	Eastview 2S	345	Sprain Brook	345
W82	Eastview 2S	345	Millwood	345
14	Edic	345	New Scotland	345
17/BK 2	Edic	345	Porter	230
BK 3	Edic	345	Porter	115

Facility Identifier	Terminal A	Nominal Voltage	Terminal B	Nominal Voltage
BK 4	Edic	345	Porter	115
BK 5	Edic	345	Edic	115
BK 6	Edic	345	Edic	115
EF24-40	Edic	345	Fraser	345
FE-1	Edic	345	Fitzpatrick	345
UE1-7	Edic	345	Marcy	345
17-EO	Elbridge	345	Oswego	345
17-LE	Elbridge	345	Lafayette	345
BK 1	Elbridge	345	Elbridge	115
41	Farragut	345	Gowanus	345
42	Farragut	345	Gowanus	345
61	Farragut	345	Rainey	345
62	Farragut	345	Rainey	345
63	Farragut	345	Rainey	345
B3402	Farragut	345	Hudson A	345
BK 1*	Farragut	345	Farragut	138
BK 10	Farragut	345	Farragut	138
BK 2*	Farragut	345	Farragut	138
BK 3*	Farragut	345	Farragut	138
BK 4*	Farragut	345	Farragut	138
BK 5*	Farragut	345	Farragut	138
BK 6*	Farragut	345	Farragut	138
BK 7*	Farragut	345	Farragut	138
BK 8	Farragut	345	Farragut	138
BK 9	Farragut	345	Farragut	138
C3403	Farragut	345	Hudson B	345
TR11	Farragut	345	Farragut PAR (B3402)	345
TR12	Farragut	345	Farragut PAR (C3403)	345
1	Fitzpatrick	345	Fitzpatrick	24
FS-10	Fitzpatrick	345	Scriba	345
BK1	Five Mile Rd	345	Five Mile Rd	115
29	Five Mile Road	345	Stolle Road	345
37	Five Mile Road	345	Piercebrook	345
32	Fraser	345	Oakdale	345
BK 2	Fraser	345	Fraser	115
GF5-35	Fraser	345	Gilboa	345
20	Arthur Kill #3	345	Fresh Kills	345
20/TR3	Fresh Kills	345	Arthur Kill #3	22
21	Fresh Kills	345	Goethals	345
22	Fresh Kills	345	Goethals	345

Facility Identifier	Terminal A	Nominal Voltage	Terminal B	Nominal Voltage
TA 1	Fresh Kills	345	Fresh Kills R	138
TB 1	Fresh Kills	345	Fresh Kills R	138
1	Gilboa	345	Gilboa #1	17
2	Gilboa	345	Gilboa #2	17
3	Gilboa	345	Gilboa #3	17
4	Gilboa	345	Gilboa #4	17
GL3	Gilboa	345	Leeds	345
GNS-1	Gilboa	345	New Scotland	345
BK 1	Goethals	345	Goethals	230/13
BK 1N	Goethals	345	Goethals	345
G23L	Goethals	345	Linden Cogen	345
G23M	Goethals	345	Linden Cogen	345
25	Goethals	345	Gowanus	345
BK 2	Gowanus	345	Gowanus	138
26	Goethals	345	Gowanus	345
BK 14	Gowanus	345	Gowanus	138
37	Homer City	345	Stolle Rd	345
47	Homer City	345	Mainesburg	345
48	Homer City	345	Piercebrook	345
Y56	Hudson HVdc	345	W. 49th St	345
HR1	Henrietta (S. 255)	345	Rochester Station #80	345
HR2	Henrietta (S. 255)	345	Rochester Station #80	345
40	Henrietta (S. 255)	345	Rochester Station #80	345
BK1	Henrietta (S. 255)	345	Henrietta (S. 255)	115
BK2	Henrietta (S. 255)	345	Henrietta (S. 255)	115
SHI-39	Henrietta (S. 255)	345	Kintigh (Somerset)	345
301	Hurley Ave	345	Leeds	345
303	Hurley Ave	345	Roseton	345
BK 1	Hurley Ave	345	Hurley Ave	115
25	Independence	345	Scriba	345
27	Independence	345	Sithe Independence #1	18
28	Independence	345	Sithe Independence #2	18
NS1-38	Kintigh (Somerset)	345	Niagara	345
67	Ladentown	345	W. Haverstraw	345
W72	Ladentown	345	Ramapo	345
92	Leeds	345	Pleasant Valley	345
93	Leeds	345	New Scotland	345
94	Leeds	345	New Scotland	345
398	Long Mtn. (ISO-NE)	345	Pleasant Valley	345
30	Mainesburg	345	Watercure	345

Facility Identifier	Terminal A	Nominal Voltage	Terminal B	Nominal Voltage
18	Marcy	345	New Scotland	345
19	Marcy	345	Volney	345
TA 1	Millwood	345	Millwood	138
TA 2	Millwood	345	Millwood	138
F30/W80	Millwood	345	Wood St/Pleasant Valley	345
F31/W81	Millwood	345	Wood St/Pleasant Valley	345
BK 6*	Mott Haven	345	Mott Haven	138
BK 7*	Mott Haven	345	Mott Haven	138
BK 8*	Mott Haven	345	Mott Haven	138
BK 9*	Mott Haven	345	Mott Haven	138
Q11	Mott Haven	345	Rainey	345
Q12	Mott Haven	345	Rainey	345
BK 1	New Scotland	345	New Scotland	115
BK 2	New Scotland	345	New Scotland	115
BUS TIE	New Scotland	345	New Scotland	345
BK 3	Niagara	345	Niagara	230
BK 4	Niagara	345	Niagara	230
BK 5	Niagara	345	Niagara	230
NH2	Niagara	345	Henrietta (S. 255)	345
2	Nine Mile Point	345	Nine Mile Point #1	23
9	Nine Mile Point	345	Scriba	345
23	Nine Mile Point #2	345	Scriba	345
31	Oakdale	345	Watercure	345
BK 2	Oakdale	345	Oakdale	115/34.5
BK 3	Oakdale	345	Oakdale	115
5	Oswego	345	Oswego #5	22
6	Oswego	345	Oswego #6	22
11	Oswego	345	Volney	345
12	Oswego	345	Volney	345
BK 7	Oswego	345	Oswego	115
BK 1	Pannell Road	345	Pannell Road	115
BK 2	Pannell Road	345	Pannell Road	115
BK 3	Pannell Road	345	Pannell Road	115
RP1	Pannell Road	345	Rochester Station #80	345
RP2	Pannell Road	345	Rochester Station #80	345
BK S1	Pleasant Valley	345	Pleasant Valley	115
F30	Pleasant Valley	345	Wood St.	345
F31	Pleasant Valley	345	Wood St.	345
BK 1	Pleasantville	345	Pleasantville	13
BK 2	Pleasantville	345	Pleasantville	13

Facility Identifier	Terminal A	Nominal Voltage	Terminal B	Nominal Voltage
Y86	Pleasantville	345	Wood St.	345
Y87	Pleasantville	345	Wood St.	345
TR5E/PAR5	Rainey	345	Corona	138
30	Rainey	345	Ravenswood #3	22
60L	Rainey	345	Ravenswood	345
60M	Rainey	345	Ravenswood	345
BK 2E*	Rainey	345	Rainey	138
BK 3W*	Rainey	345	Rainey	138
BK 7E*	Rainey	345	Rainey	138
BK 7W*	Rainey	345	Rainey	138
BK 8E	Rainey	345	Rainey	138
BK 8W*	Rainey	345	Rainey	138
BK 9E*	Rainey	345	Rainey	138
69	Ramapo	345	S. Mahwah A	345
70	Ramapo	345	S. Mahwah B	345
76	Ramapo	345	Sugarloaf/Rock Tavern	345
77	Ramapo	345	Rock Tavern	345
PAR3500	Ramapo	345	Ramapo	345
PAR4500	Ramapo	345	Ramapo	345
BK 2	Reynolds Road	345	Reynolds Road	115
BK 1	Rochester Station #80	345	Rochester Station #80	115
BK 2	Rochester Station #80	345	Rochester Station #80	115
BK 3	Rochester Station #80	345	Rochester Station #80	115
BK 5	Rochester Station #80	345	Rochester Station #80	115
311	Rock Tavern	345	Roseton	345
BK TR1	Rock Tavern	345	Rock Tavern	115
BK TR3	Rock Tavern	345	Rock Tavern	115
1	Roseton	345	Roseton #1	20
2	Roseton	345	Roseton #2	20
BK 258	S. Mahwah	345	S. Mahwah	138
J3410	S. Mahwah A	345	Waldwick	345
K3411	S. Mahwah B	345	Waldwick	345
20	Scriba	345	Volney	345
21	Scriba	345	Volney	345
BK 1	Scriba	345	Scriba	115
BK 2	Scriba	345	Scriba	115
1	Kintigh (Somerset)	345	Somerset	24
BK 1	Shore Road	345	Shore Road	138
BK 2	Shore Road	345	Shore Road	138
BK N7	Sprain Brook	345	Sprain Brook	138

Facility Identifier	Terminal A	Nominal Voltage	Terminal B	Nominal Voltage
BK S6	Sprain Brook	345	Sprain Brook	138
M51	Sprain Brook	345	W. 49th St	345
M52	Sprain Brook	345	W. 49th St	345
X28	Sprain Brook	345	Tremont	345
BK 3	Stolle Road	345	Stolle Road	115
BK 4	Stolle Road	345	Stolle Road	115
11	Tremont	345	Tremont	138
12	Tremont	345	Tremont	138
BK 1	W. 49th St	345	W. 49th St	138
BK 2*	W. 49th St	345	W. 49th St	138
BK 3*	W. 49th St	345	W. 49th St	138
BK 4*	W. 49th St	345	W. 49th St	138
BK 5*	W. 49th St	345	W. 49th St	138
Y56	W. 49th St	345	Hudson HVdc	345
BK 194	West Haverstraw	345	West Haverstraw	138
BK 1	Watercure	345	Watercure	230
BK 2	Watercure	345	Watercure	230
BK 1	Wood Street	345	Wood Street	115
BK 2	Wood Street	345	Wood Street	115
13	Adirondack	230	Chases Lake	230
12-AP	Adirondack	230	Porter	230
MA1	Adirondack	230	Moses	230
MA2	Adirondack	230	Moses	230
E205W	Bear Swamp (NE)	230	Eastover Rd.	230
BP76	Beck (IESO)	230	Packard	230
PA27	Beck (IESO)	230	Niagara	230
60	Canandaigua	230	Meyer	230
68	Canandaigua	230	Stoney Ridge	230
11	Chases Lake	230	Porter	230
DP1	Duley	230	Plattsburgh	230
PND-1	Duley	230	Patnode	230
68	Dunkirk	230	S. Ripley	230
73	Dunkirk	230	Gardenville	230
74	Dunkirk	230	Gardenville	230
70	E.Towanda	230	Hillside	230
38	Eastover Rd.	230	Rotterdam	230
TB 1	Eastover Rd.	230	Eastover Rd.	115
TB 2	Eastover Rd.	230	Eastover Rd.	115
17	Edic	230	Porter	230
70	Elm St	230	Huntley	230

Facility Identifier	Terminal A	Nominal Voltage	Terminal B	Nominal Voltage
71	Elm St	230	Gardenville	230
72	Elm St	230	Gardenville	230
69	Erie East (PJM)	230	S. Ripley	230
66	Gardenville	230	Stolle Rd	230
79	Gardenville	230	Huntley	230
80	Gardenville	230	Huntley	230
BK 2	Gardenville	230	Gardenville	115
BK 3	Gardenville	230	Gardenville	115
BK 4	Gardenville	230	Gardenville	115
BK 6	Gardenville	230	Gardenville	115/34.5
BK 7	Gardenville	230	Gardenville	115/34.5
T8-12	Gardenville (NGrid)	230	Gardenville (NYSEG)	230
A2253	Goethals	230	Linden (PJM)	230
67	High Sheldon	230	Stolle Rd	230
81	High Sheldon	230	Stoney Creek	230
69	Hillside	230	Watercure	230
72	Hillside	230	Stoney Ridge	230
BK 3	Hillside	230	Hillside	115/34.5
BK 4	Hillside	230	Hillside	115/34.5
77	Huntley	230	Packard	230
BK 670	Huntley	230	Huntley #67	13
BK 680	Huntley	230	Huntley #68	13
78	Huntley	230	Packard	230
MMS1	Massena	230	Moses	230
MMS2	Massena	230	Moses	230
85/87	Meyer	230	Wethersfield	230
BK 4	Meyer	230	Meyer	115/34.5
BK 1	Moses	230	Moses	115
BK 2	Moses	230	Moses	115
BK 3	Moses	230	Moses	115
BK 4	Moses	230	Moses	115
L33P	Moses	230	St. Lawrence (IESO)	230
L34P	Moses	230	St. Lawrence (IESO)	230
MW1	Moses	230	Willis	230
MW2	Moses	230	Willis	230
61	Niagara	230	Packard	230
62	Niagara	230	Packard	230
64	Niagara	230	Robinson Rd	230
2332	Niagara	230	Niagara	230
2342	Niagara	230	Niagara	230

Facility Identifier	Terminal A	Nominal Voltage	Terminal B	Nominal Voltage
BK T1	Niagara	230	Niagara	115
BK T2	Niagara	230	Niagara	115
N Bus Tie	Niagara	230	Niagara	230
S Bus Tie	Niagara	230	Niagara	230
71	Oakdale	230	Watercure	230
BK 1	Oakdale	230	Oakdale	115
3	Packard	230	Packard	115
4	Packard	230	Packard	115
WPN1	Patnode	230	Willis	230
BK 1	Plattsburgh	230	Plattsburgh	115
BK 4	Plattsburgh	230	Plattsburgh	115
RYP-2	Plattsburgh	230	Ryan	230
30	Porter	230	Rotterdam	230
31	Porter	230	Rotterdam	230
BK 1	Porter	230	Porter	115
BK 2	Porter	230	Porter	115
65	Robinson Road	230	Stolle Road	230
BK 1	Robinson Road	230	Robinson Road	115/34.5
WRY-2	Ryan	230	Willis	230
83	Stony Creek	230	Wethersfield	230
BK 1	Academy 1	138	Academy 1	138
BK 8	Academy 8	138	Academy 8	138
34124L&M	Astoria E	138	Astoria #4	138
34125L&M	Astoria E	138	Astoria #5	138
24121	Astoria W	138	Astoria #3	138
24122	Astoria W	138	Astoria #3	138
24124L&M	Astoria W	138	Astoria #4	138
24125L&M	Astoria W	138	Astoria #5	138
563	Bagatelle Rd.	138	Newbridge Road	138
564	Bagatelle Rd.	138	Pilgrim	138
291	Barrett	138	Valley Stream	138
292	Barrett	138	Valley Stream	138
459	Barrett	138	Freeport	138
PAR	Barrett	138	Barrett PAR	138
861	Brookhaven	138	Wildwood	138
864	Brookhaven	138	Edward Ave	138
874	Brookhaven	138	Sills Road	138
887	Brookhaven	138	Sills Road	138
95891	Buchanan GT	138	Buchanan TA5	138
361	Carle Place	138	E. Garden City	138

Facility Identifier	Terminal A	Nominal Voltage	Terminal B	Nominal Voltage
363	Carle Place	138	Glenwood	138
883	Central Islip	138	Ronkonkoma	138
889	Central Islip	138	Hauppauge	138
BK N1	Dunwoodie	138	Dunwoodie	138
BK N2	Dunwoodie	138	Dunwoodie	138
BK S1	Dunwoodie	138	Dunwoodie	138
BK S2	Dunwoodie	138	Dunwoodie	138
262	E. Garden City	138	Valley Stream	138
261	E. Garden City	138	Valley Stream	138
362	E. Garden City	138	Roslyn	138
462	E. Garden City	138	Newbridge Road	138
463	E. Garden City	138	Newbridge Road	138
465	E. Garden City	138	Newbridge Road	138
467	E. Garden City	138	Newbridge Road	138
893	Edward Ave	138	Riverhead	138
673	Elwood	138	Greenlawn	138
674	Elwood	138	Oakwood	138
678	Elwood	138	Northport	138
681	Elwood	138	Northport	138
461	Freeport	138	Newbridge Road	138
PAR1	Fresh Kills (AK)	138	Fresh Kills PAR	138
PAR2	Fresh Kills (AK)	138	Fresh Kills PAR	138
365	Glenwood	138	Shore Road	138
366-1	Glenwood	138	Shore Road	138
366-2	Glenwood	138	Glenwood GT	138
364	Glenwood GT	138	Roslyn	138
676	Greenlawn	138	Syosset	138
871	Hauppauge	138	Pilgrim	138
872	Holbrook	138	Sills Road	138
884	Holbrook	138	North Shore Beach	138
885	Holbrook	138	Miller Place	138
888	Holbrook	138	West Bus	138
862	Holbrook	138	Port Jefferson	138
875	Holbrook	138	Ronkonkoma	138
882	Holbrook	138	Ruland Road	138
886	Holbrook	138	Port Jefferson	138
818	Holtsville	138	Union Ave	138
876	Holtsville	138	West Bus	138
877	Holtsville	138	West Bus	138
903	Jamaica	138	Lake Success	138

Facility Identifier	Terminal A	Nominal Voltage	Terminal B	Nominal Voltage
901 L&M	Jamaica	138	Valley Stream	138
367	Lake Success	138	Shore Road	138
368	Lake Success	138	Shore Road	138
PAR	Lake Success	138	Lake Success PAR	138
558	Locust Grove	138	Newbridge	138
559	Locust Grove	138	Syosset	138
879	Miller Place	138	Shoreham	138
561	Newbridge Road	138	Ruland Road	138
562	Newbridge Road	138	Ruland Road	138
567	Newbridge Road	138	Ruland Road	138
878	North Shore Beach	138	Wading River	138
1	Northport	138	Northport #1	22
2	Northport	138	Northport #2	22
3	Northport	138	Northport #3	22
4	Northport	138	Northport #4	22
672	Northport	138	Pilgrim	138
677	Northport	138	Pilgrim	138
679	Northport	138	Pilgrim	138
1385 (601, 602, 603)	Northport	138	Norwalk Harbor	138
PAR 1	Northport	138	Northport	138
PS2	Northport	138	Northport	138
675	Oakwood	138	Syosset	138
661	Pilgrim	138	Ruland Road	138
662	Pilgrim	138	Ruland Road	138
881	Pilgrim	138	West Bus	138
PAR	Pilgrim	138	Pilgrim PAR	138
36311	Rainey	138	Vernon	138
36312	Rainey	138	Vernon	138
890	Riverhead	138	Wildwood	138
863	Shoreham	138	Wildwood	138
867	Shoreham	138	Wildwood	138
891	Shoreham	138	Wading River	138
873	Sills Road	138	West Bus	138
PAR11	Tremont	138	Tremont PAR 11	138
PAR12	Tremont	138	Tremont PAR 12	138
PAR	Valley Stream	138	Valley Stream	138
10	Vernon	138	Ravenswood #1	20
20	Vernon	138	Ravenswood #2	20
1-BP	Boonville	115	Porter	115
2-BP	Boonville	115	Porter	115

Facility Identifier	Terminal A	Nominal Voltage	Terminal B	Nominal Voltage
3	Clay	115	Dewitt	115
4	Clay	115	South Oswego	115
5	Clay	115	Dewitt	115
10	Clay	115	Teall Ave.	115
11	Clay	115	Teall Ave.	115
14	Clay	115	Lockheed (GE)	115
17	Clay	115	Woodard	115
7-CL	Clay	115	Lighthouse Hill	115
8	Deerfield	115	Porter	115
9	Deerfield	115	Porter	115
20	Edic	115	Porter	115
1	Ginna	115	Ginna	16
912	Ginna	115	Pannell Rd.	115
908-1	Ginna	115	Pannell Rd.	115
7X8272	Mortimer	115	Sta#82	115
7	Oneida	115	Porter	115
PAR3	Plattsburgh	115	Plattsburgh	115
PV20	Plattsburgh	115	South Hero	115
3	Porter	115	Yahnundasis	115
4	Porter	115	Valley	115
5	Porter	115	Watkins Rd.	115
6	Porter	115	Terminal	115
13	Porter	115	Schuyler	115
10	Edic	115	Porter	115

New York Control Area Proposed Bulk Power Transmission Facilities List

Transmission Owner	Terminals		Expected In-Service		Nominal Voltage in kV		# of Circuits	Thermal Ratings	
	From	To	Prior To	Year	Operating	Design		Summer	Winter
ConEd	Rainey	Corona	S	2023	345/138	345/138		N/A	N/A
ConEd	Cricket Valley	Dover (New Station)	W	2023	345	345	1	2220	2700
ConEd	Dover (New Station)	CT State Line	W	2023	345	345	1	2220	2700
ConEd	Gowanus	Greenwood	S	2025	345/138	345/138		N/A	N/A
ConEd	Goethals	Fox Hills	S	2025	345/138	345/138		N/A	N/A
LIPA	Riverhead	Wildwood	S	2021	138	138	1	1399	1709
LSP	Gordon Rd (New Station)	Rotterdam	S	2022	345/230	345/230	2	478 MVA	478 MVA
LSP	Gordon Rd (New Station)	Princetown (New Station)	S	2023	345	345	1	3410	3709
LSP	Princetown (New Station)	New Scotland	S	2023	345	345	2	3410	3709
LSP	Gordon Rd (New Station)	Gordon Rd (New Station)	S	2029	345/230	345/230	1	478 MVA	478 MVA
LSP	Gordon Rd (New Station)	Rotterdam	S	2029	345/115	345/115	2	650 MVA	650 MVA
LSP/NGRID	Edic	Gordon Rd (New Station)	S	2022	345	345	1	2228	2718
LSP/NGRID	Gordon Rd (New Station)	New Scotland	S	2022	345	345	1	2228	2718
LSP/NGRID	Princetown (New Station)	New Scotland	S	2023	345	345	1	2228	2718
LSP/NYPA/NGRID	Edic	Princetown (New Station)	W	2023	345	345	2	3410	3709
New York Transco	Knickerbocker (New Station)	Pleasant Valley	W	2023	345	345	1	3862	4103
New York Transco/Con Ed	Van Wagner (New Station)	Pleasant Valley	W	2023	345	345	1	3126	3704
New York Transco/Con Ed	Van Wagner (New Station)	Pleasant Valley	W	2023	345	345	1	3126	3704
NextEra Energy Transmission NY	Dysinger (New Station)	East Stolle (New Station)	S	2022	345	345	1	1356 MVA	1612 MVA
NextEra Energy Transmission NY	Dysinger (New Station)	Dysinger (New Station)	S	2022	345	345	1	700 MVA	700 MVA
NGRID	Knickerbocker (New Station)	New Scotland	W	2023	345	345	1	2381	3099
NGRID	Knickerbocker (New Station)	Alps	W	2023	345	345	1	2552	3134
NGRID	Athens	Van Wagner (New Station)	W	2023	345	345	1	2228	2718
NGRID	Leeds	Van Wagner (New Station)	W	2023	345	345	1	2228	2718
NGRID	Gordon Rd (New Station)	Eastover Rd	S	2029	230	230	1	1114	1284
NYSEG	Wood Street	Wood Street	W	2022	345/115	345/115	1	327 MVA	378 MVA
NYSEG	Fraser	Fraser	S	2024	345/115	345/115	1	305 MVA	364 MVA
NYSEG	Gardenville	Gardenville	S	2026	230/115	230/115	1	316 MVA	370 MVA

Transmission Owner	Terminals		Expected In-Service		Nominal Voltage in kV		# of Circuits	Thermal Ratings	
	From	To	Prior To	Year	Operating	Design		Summer	Winter
NYSEG	South Perry	South Perry	S	2027	230/115	230/115	1	246 MVA	291 MVA
NYSEG	Oakdale 345	Oakdale 115	S	2027	345/115	345/115/34.5	1	494MVA	527 MVA
NYSEG	Coopers Corners	Coopers Corners	S	2031	345/115	345/115	1	232 MVA	270 MVA
O & R	Lovett 345 kV Station (New Station)	Lovett	S	2023	345/138	345/138	1	562 MVA	562 MVA
O & R/ConEd	Ladentown	Lovett 345 kV Station (New Station)	S	2023	345	345	1	3000	3211
O & R/ConEd	Lovett 345 kV Station (New Station)	Buchanan	S	2023	345	345	1	3000	3211