Attachment #8.1
Return to Agenda

De-Carbonization / DER Report for NYSRC Executive Committee Meeting 6/10/2022

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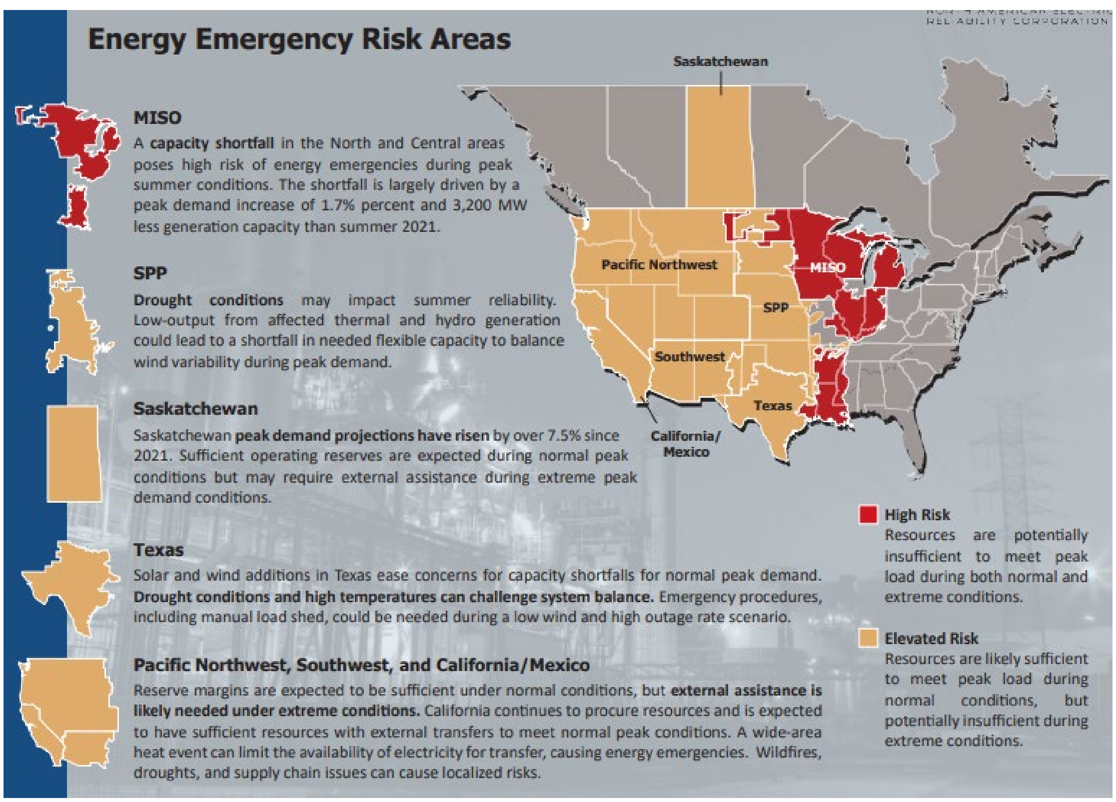
The June 2022 edition of the De-Carbonization / Distributed Energy Resources (DER) Report includes the following items:

- NERC May Newsletter: 2022 Summer Reliability Assessment
- Joint EPRI / NAGF / NATF / NERC Webinar – IEEE Standard 2800-2022
- Presentations from the NPCC Distributed Energy Resources / Variable Energy Resources (DER/VER) Forum
  - Evaluation of the Impacts of Electric Vehicles on the Transmission System (Hydro-Quebec)
  - Electrification of Transportation (Eversource)
  - Eversource and Electric Vehicles (Eversource)
  - Grid Infrastructure Planning for EV's (NationalGrid)
  - Transportation Electrification – impacts to the BPS (NERC)
- Resource Adequacy for a Decarbonized Future – Summary of Existing / Proposed Metrics
- US DOE 2020 Smart Grid System Report (Bi-annual Update for 2022)
- NYISO Blog: Grid Reliability Needs and How to Resolve Them, Keeping the Lights On (Video)
- Snapshot of the NYISO Interconnection Queue: Storage / Solar / Wind / Co-located Storage

Highlights from the May NERC Monthly Newsletter (Link)

NERC Summer 2022 Summer Reliability Assessment

NERC's 2022 Summer Reliability Assessment (Announcement / Report / Infographic) warns that several parts of North America are at Elevated or High risk of energy shortfalls this summer due to predicted above-normal temperatures and drought conditions over the western half of the United States and Canada. These above-average seasonal temperatures contribute to high peak demands as well as potential increases in forced outages for generation and some bulk power system equipment.



While NERC's risk scenario analysis shows adequate resources and energy for much of North America, the Western Interconnection, Texas, Southwest Power Pool (SPP), and Saskatchewan are at "Elevated risk" of energy emergencies during extreme conditions. Midcontinent ISO (MISO) is in the "High risk" category, facing capacity shortfalls in its north and central areas during both normal and extreme conditions due to generator retirements and increased demand. Additionally, at the start of the summer, MISO will be without a key transmission line connecting its northern and southern areas as restoration continues on a four-mile section of a 500 kV transmission line that was damaged by a tornado in December 2021.

Extended drought conditions present varied threats to capacity and energy across the country. In the Western Interconnection, the widespread drought and below-normal snowpack has the potential to lead to lower-than-average output from hydro generators, threatening the availability of electricity for transfers throughout the Interconnection. In Texas, wide-area heat events coupled with drought can lead to higher-than-expected peak electricity demand and tighter reserve conditions. Meanwhile, as drought conditions continue over the Missouri River Basin, output from thermal generators that use the Missouri River for cooling in SPP may be affected in summer months. Low water levels in the river can impact generators that use once-through cooling and lead to reduced output capacity

The assessment's other key findings include:

- Supply chain issues and commissioning challenges on new resource and transmission projects are a concern in areas where completion is needed for reliability during summer peak periods.
- The electricity and other critical infrastructure sectors face cyber security threats from Russia, in addition to ongoing cyber risks.
- Some coal-fired generator owners are facing challenges obtaining fuels as supply chains are stressed.
- Unexpected tripping of solar photovoltaic resources during grid disturbances continues as a reliability concern.
- Active late-summer wildfire season in Western United States and Canada is anticipated, posing some risk to bulk power system reliability.

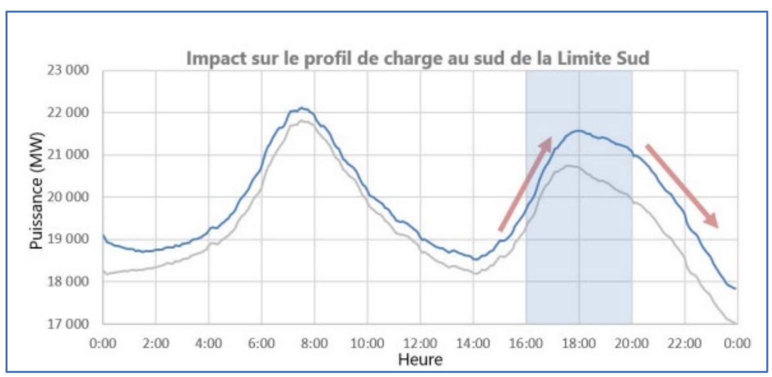
NPCC Distributed Energy Resources / Variable Energy Resources (DER/VER) Forum

Here are the links to the Forum's Agenda & Meeting Material & Webex Recording. Summaries from five key presentations are provided on the following pages.

DER/VER Forum: Evaluation of the Impacts of Electric Vehicles on the Transmission System (Hydro-Quebec)

Hydro-Quebec expects the number of electric vehicles in their service territory to increase to a level between one and 1.6 million by the year 2030. They have developed a new software application intended to simulate the impact of all DERs, including electric vehicles and solar, on the transmission system. The application performs a simulation covering up to 3 days of winter peaks or summer lows, each at 5-minute interval time steps.

The summary analysis, produced using the new software, showed a significant Impact on Load Ramps and reactive resource availability:



- The reference case shows average ramps of roughly 15 MW/min for the load south of the Southern Limit, with maximum ramps of roughly 40 MW/min.
- The morning ramps are essentially the same as for the benchmark system and are affected very little by EV preheating.
- Evening peak ramps are > 10% higher.
- Reactive resource availability decreases during peak periods. In the event of limited availability, system stability may be at risk.
- During the evening peak, reactive resource availability decreases by approximately 600 MVAR compared to the reference case.

DER/VER Forum: Electrification of Transportation (Eversource - Advanced Forecasting and Modelling Group)
Eversource's approach to Planning for significant transportation electrification uses state decarbonization goals to inform scenarios until 2050, which are used to build adoption propensity models. These models project EV sales by customer type and region. When the database is established, data analytics and driving patterns are evaluated over the course of a year using an hourly time series. The results will be utilized in capacity planning.

Key Observations with this method:

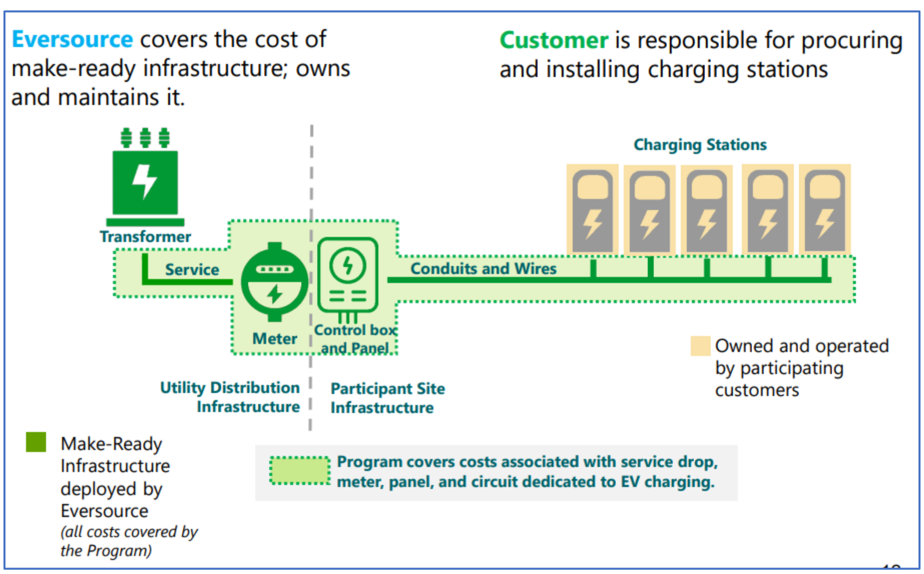
- Mobility of load leads to a factor "x" of installed charging capability across the system
- System planning must account for all charging stations, not vehicles
- Each vehicle can impact system resources severely above its own rated power
- Two peak scenarios, morning (C&I) and evening (residential)
- 26+ TWh of energy consumption through electric vehicles
- Will add, depending on system, between 10 – 30% of peak load
- Driving distance drives grid impact, not charging power

Considerations for Light Duty EV impact:

- Geographic distribution of charging (at work, at home, etc.) will blunt the impact on a specific system
- Temporal distribution of charging (after inbound commute, after outbound commute) will also blunt the impact of charging
- Commercial entities are likely to deploy charge management systems as they have demand charges to provide incentives, removing potential peaks
- Dense urban areas have high commuter, bike, and pedestrian commuter traffic which removes a lot of potential EV impacts
- With multiple charging opportunities the duration of each charging cycle drops, resulting in lower coincidence factors and lower overall grid impact
- Heavy duty EV charging requires detailed studies based on their proposed step loads

DER/VER Forum: Eversource and Electric Vehicles (Eversource - Energy Efficiency)
Eversource's approach to EV support uses separately metered services for EV stations allow for much more flexibility and future proofing of assets.

- Capacity built in: Each site has capability for 5 dual port level 2 stations, or multiple DCFC stations.
- Disaggregation of EV load from other loads. This will become increasingly important as EV load grows.
- Separately metered service can take advantage of EV tariffs and rates as they begin to surface.



DER/VER Forum: Eversource and Electric Vehicles (Continued)

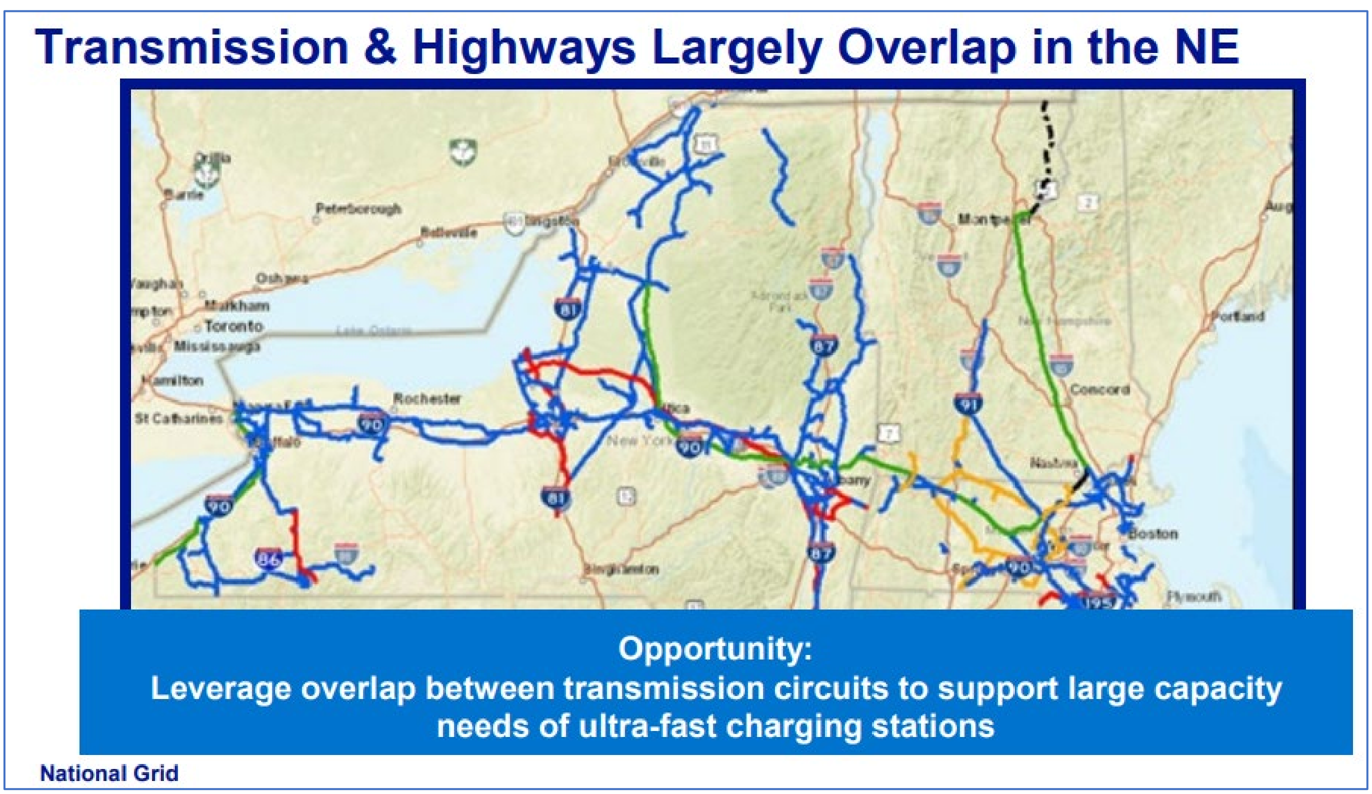
Next Phase considerations include:

- Continuation of Successful Make-Ready Infrastructure Program for Level 2 and DCFC (DC Fast Charging)
  Public Spaces (e.g., municipal lots, state facilities), Workplaces, Multi-Unit Dwellings, Destinations)
- EVSE (Electric Vehicle Supply Equipment) Incentives
  Rebates for a portion of EVSE equipment to incentivize more ports per site
- Incentives for Primary Metered (Campus) Customers
  Rebates for customer owned equipment that does not connect directly to Eversource distribution system
- Fleet Engagement Advisory
  Support for light, medium and heavy-duty fleet operators considering electrification
- Expansion of Residential Managed Charging
  Encourage highly efficient, smart, charging infrastructure to enable managed charging benefits
- Equity Pilot
  MUD (Multi-Unit Dwelling) Installations with Car Sharing component, Others

DER/VER Forum: Grid Infrastructure Planning for EV's (NationalGrid)

A major portion of this presentation focuses on the potential for EV Fleet Clustering can drive local grid requirements. Current studies indicate that system impacts can be substantial, yet can vary based on season and geography. Many fleets can be served via existing feeder capacity, but cluster locations require alternative solutions. In addition, warmer temperatures can drive higher efficiencies.

This presentation envisions the concept called "Electric Highways", in which charging stations can be located in cluster locations on highway sites that are in close proximity to existing transmission lines, which can be tapped to provide large amounts of clean energy. For Medium and Heavy-Duty Electric Vehicles (MHDV's), fast-charging and higher capacities will be required (on the order of 150 kW and up to one MW per charger).



DER/VER Forum: Grid Infrastructure Planning for EV's – National Grid (Continued)

Another area of focus was "Electric Fleets", in which For Fleet locations (such as industrial areas, airports or logistic hubs). It is anticipated that these cluster locations would require significant improvements in electric supply infrastructure and have corresponding notable impacts on the load peaks and profiles at the substation level.
The models in these studies showed residential and fleet charging more common during the night, while public usage showed higher levels in the daytime, and all sectors contributed to the evening peak load. It was noted that the utilization of a minimum charging or optimizing strategy helped to reduce peak loads to more manageable levels.

The figure below identifies the varies levels of charging energy vs. time to charge for a Tesla Model 3.

Minutes to Charge 100 Miles

	Level 1 (1.5 kW)	Level 2 (12 kW)	DCFC (50 kW)	DCFC (150 kW)	DCFC (350 kW)
Tesla Model 3	1,040	130	31	10	5

At the residential level, it was determined that management of charging through pricing alone risks the creation of secondary peaks. However, forms of active control can mitigate the issues and unlock additional grid and customer value. Concepts in managed charging include Demand response for weather events, Vehicle to Grid for extreme heat/cold and/or microgrid support, and customer whole home back-up in case of grid outages.

DER/VER Forum: Transportation Electrification – impacts to the BPS (NERC BPS Security and Grid Transformation)

This presentation considered the following major concerns driving consumer considerations:

- Travel Distance
- Charging Time
- Charging Infrastructure
- Price Point
- Vehicle Options
- Technology evolution and trust
- Technology in transition

A major new impact will be the Department of Energy's announcement of the first-ever collaboration to accelerate "Vehicle to Everything" technologies. The goals of this effort include:

- Accelerated focus on V2G, V2H, V2X concepts
- Value of increased grid flexibility
- Opportunities in Demand Response and DER aggregation
- Provision of essential reliability services
- Consumer-controlled optionality
- Integration with time of use rates and other tools

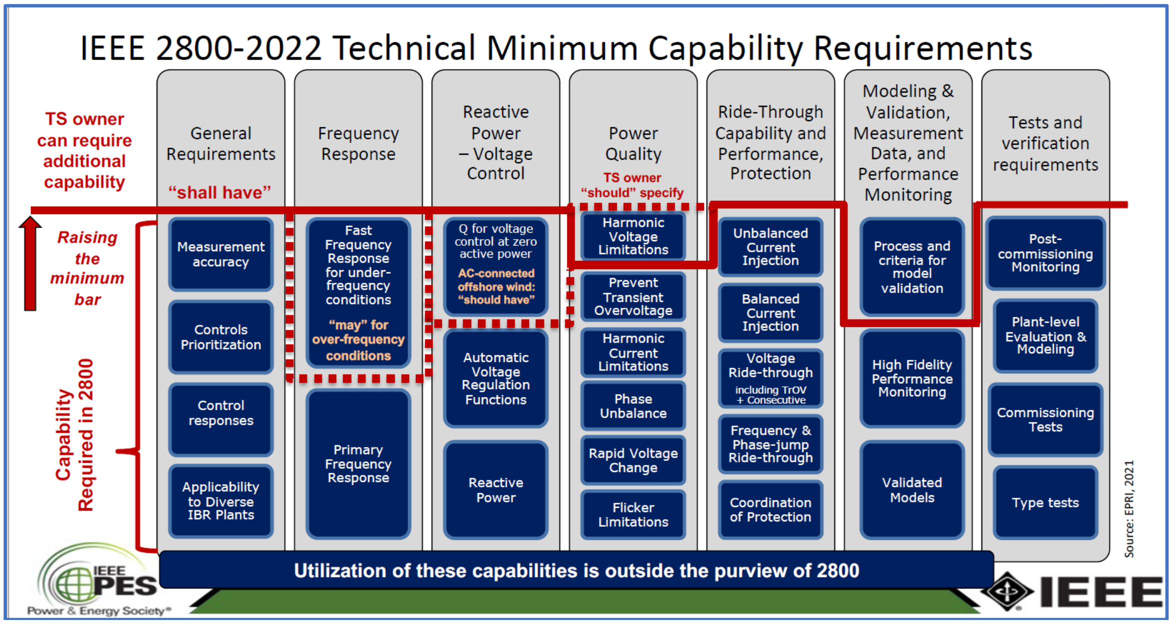
Potential negative impacts to the Bulk Power system include:

- Rapid or unexpected changes in load consumption, including concept of unplanned "Panic Charging"
- Ramping needs to manage critical charging hours, especially in anticipation of daily solar drop-off
- Constant Power load characteristics, leading to degradation of stability margins, wide-area oscillations, and Grid-unfriendly characteristics
- Fault Ride-Through behavior and recovery characteristics
- System restoration and Blackstart plans, including unexpected load steps during black start resulting in large swings of voltage and/or frequency
- Participation in DER aggregation, leading to displacement of BPS and other essential reliability services
- Other possible impacts such as power quality, harmonic and control interactions

Joint EPRI / NAGF / NATF / NERC Webinar – IEEE Standard 2800-2022

Supporting Links: [Presentation] [Joint Webinar] [NERC IRPS Webpage] [IEEE 2800 Download Webpage]

This jointly sponsored webinar was presented on May 3rd, The IEEE Standard 2800 successfully passed the IEEE SA ballot with 94% approval, and board approved on February 9th, The Standard establishes the required interconnection capability and performance criteria for inverter-based resources interconnected with transmission and sub-transmission systems. Included in this standard are performance requirements for reliable integration of inverter-based resources into the bulk power system, including, but not limited to voltage and frequency ride-through, active power control, reactive power control, dynamic active power support under abnormal frequency conditions, dynamic voltage support under abnormal voltage conditions, power quality, negative sequence current injection, and system protection. The figure below highlights these new requirements under their associated categories:



NERC has identified a variety of performance issues associated with Inverter-Based Resources, including:

- PLL Loss of Synchronism
- Inverter AC Under- or Overvoltage
- Inverter Under or Over-frequency
- Inverter DC Voltage [Ripple due to AC Voltage] Unbalance
- Slow Active Power Recovery
- Momentary Cessation
- Inverter AC Overcurrent
- Inverter UPS failure

Various requirements have been implemented in the Standard to mitigate these conditions, including:

Ride-Through Requirements

- Consecutive voltage dip
- Phase angle jump
- Rate of change of frequency
- Restore active power after voltage disturbance

Power Quality to mitigate:

- Voltage Fluctuations
- Harmonic Distortion
- Overvoltage by IBR Plant

IBR owner to provide models to Transmission Operators

- Power Flow / Short Circuit
- Stability dynamic model
- EMT
- Harmonics

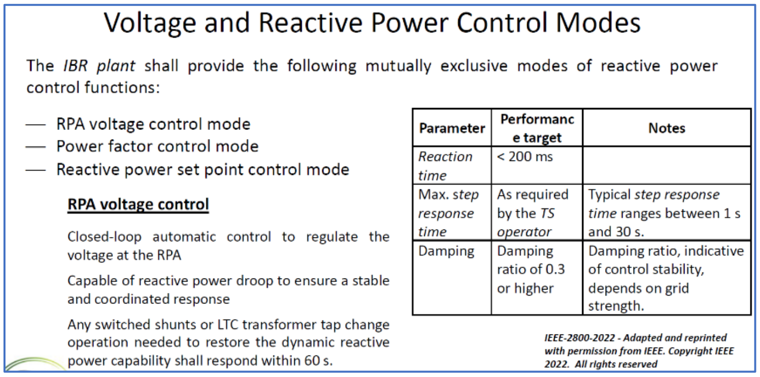
Protection Requirements

- Does not conflict with ride-through requirements
- Frequency, ROCOF, overvoltage, overcurrent
- Unintentional Islanding
- Interconnection System

Joint EPRI / NAGF / NATF / NERC Webinar – IEEE Standard 2800-2022 (Continued)

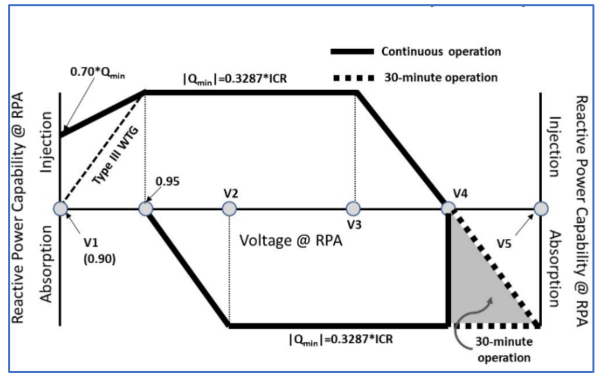
Examples of graphics from the Standard are shown below:

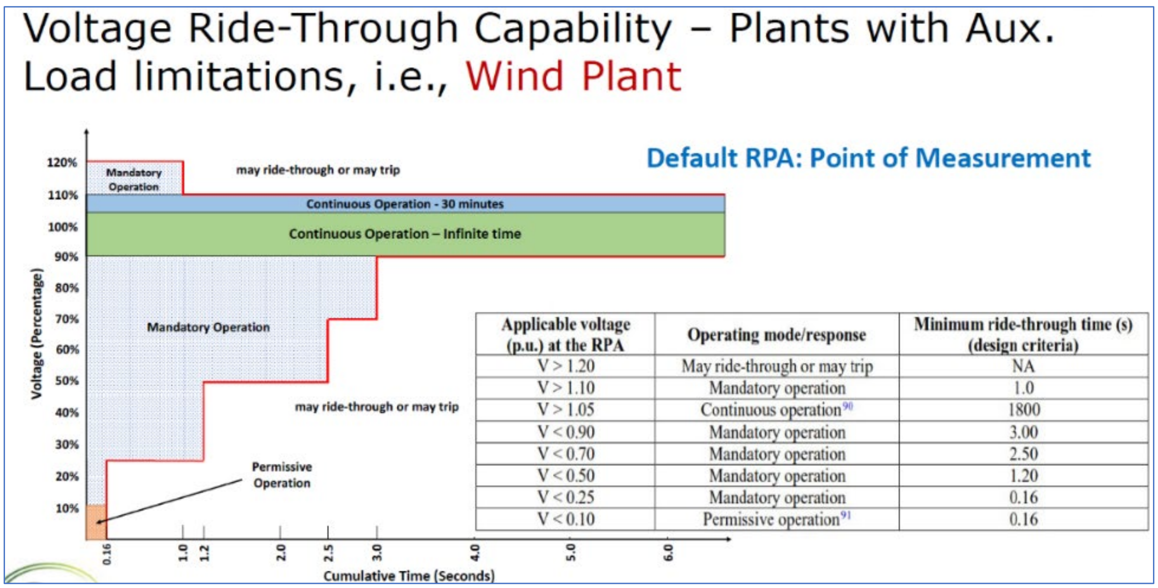
Three Control Modes for IBR Voltage / Reactive Power



Parameter	Performance target	Notes
Reaction time	< 200 ms	
Max. *step response time*	As required by the *TS operator*	Typical *step response time* ranges between 1 s and 30 s.
Damping	Damping ratio of 0.3 or higher	Damping ratio, indicative of control stability, depends on grid strength.

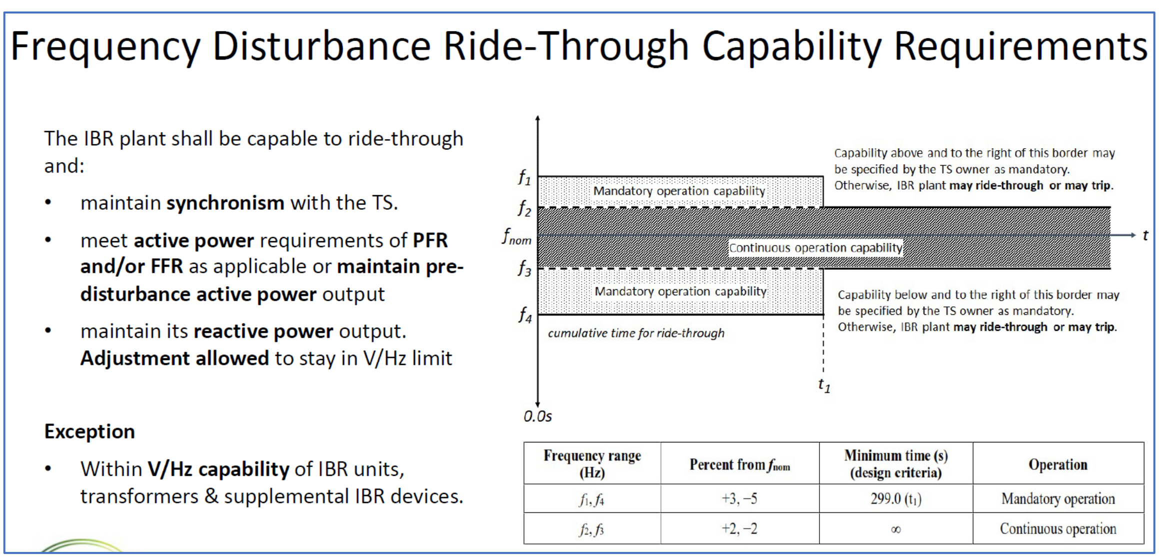
Minimum Reactive Power Capability at Reference Point of Applicability (RPA) vs. Voltage:





Applicable voltage (p.u.) at the RPA	Operating mode/response	Minimum ride-through time (s) (design criteria)
V > 1.20	May ride-through or may trip	NA
V > 1.10	Mandatory operation	1.0
V > 1.05	Continuous operation[90]	1800
V < 0.90	Mandatory operation	3.00
V < 0.70	Mandatory operation	2.50
V < 0.50	Mandatory operation	1.20
V < 0.25	Mandatory operation	0.16
V < 0.10	Permissive operation[91]	0.16

New EPRI



Frequency range (Hz)	Percent from f_{nom}	Minimum time (s) (design criteria)	Operation
f_1, f_4	+3, −5	299.0 (t_1)	Mandatory operation
f_2, f_3	+2, −2	∞	Continuous operation

Project: Resource Adequacy for a Decarbonized Future – Summary of Existing / Proposed Metrics

This publicly available paper (Download Link) serves as a primer for the variety of methods used to evaluate Resource Adequacy (RA). It summarizes existing and proposed metrics and discusses their historical context, current implementation, strengths, limitations, and appropriate use cases, and outlines planned work to be carried out in the near future. The planned work includes case studies to evaluate appropriate use of RA metrics to identify minimum criteria settings based on system characteristics and regulatory and market structures.

A key deliverable of this initiative will be the identification of appropriate adequacy assessment metrics and minimum criteria for low carbon systems in the face of changing climate. The goal of these metrics is to provide a comprehensive picture of system risk to planners, regulators, and policy makers, and to help establish minimum adequacy criteria that reflect both the costs and benefits of avoiding unserved energy. The report starts with a comprehensive review of both existing RA metrics and those under development, including:

- A review of RA's larger historical context as it relates to metrics choice.
- A discussion of the existing and proposed RA risk metrics, which can be either deterministic or probabilistic, to quantify the risk of firm load shedding.
- The metrics that measure resource contribution, which is essential both for accurate system adequacy planning, as well as for capacity accreditation purposes.
- A worldwide survey of RA risk metrics and criteria.
- EPRI planned methodology to evaluate the use of RA metrics and minimum criteria setting.

A RA assessment measures the risk of firm load shedding and ensures that it lies within acceptable reliability standards. To this end, a number of RA metrics exist, each capturing a particular adequacy risk. This report goes on to define existing and proposed RA metrics and discusses their strengths and limitations, appropriate use cases, and considerations for their implementation. Reliability Indices are divided into deterministic and probabilistic categories. A deterministic approach considers a single forecast, whereas a probabilistic approach considers a range of outcomes.

One of the most commonly used deterministic indices is the planning reserve margin (PRM), which is defined as the difference between the total installed generation capacity and the peak load, divided by the peak load. Deterministic metrics are simple to understand, require minimal computational time, and can be calculated based on limited system data. However, in its simplest form, the PRM over-simplifies the RA analysis by calculating the system risk only at peak load and failing to account for chronological issues such as storage state-of-charge management, demand response availability, and hourly variations in wind and solar resources.

The main advantage of using probabilistic metrics over deterministic metrics is that risk is evaluated based on a range of outcomes rather than a single outcome. The probabilistic approach remains the only way to perform a full adequacy assessment, evaluated across all hours or days of the year and not solely based on peak demand.

Future work will look to respond to the following questions:

- How are metrics correlated with one another, and when do the correlations break down?
- Which metrics can deliver a complete picture of a region's adequacy under future resource mixes and under different system modeling assumptions?
- Which metrics or modeling methods best capture high-impact, low-probability events?
- Which metrics or modeling methods best capture energy adequacy events when they are important?
- How does the cost of adequacy events vary across different capacity buildouts? The cost of adequacy is likely to be nonlinear, with appropriate impact on the levels and types of acceptable risks
- How sensitive is the system to unknown factors such as the probability of extreme events?
- What are the most appropriate mitigation options for different types of adequacy events?

US DOE 2020 Smart Grid System Report (Bi-annual Update for 2022)

The United States Department of Energy (DOE) announced this Report from the Department of Energy, This report is an ongoing biannual update to the original document published in 2018, and provides new information regarding smart grid deployments across the Nation, the capabilities they provide, and the challenges remaining as we move forward with the modernization of the electric grid.

Over the past five years, there has been an accelerated deployment in renewable energy resources and the emergence of a set of technologies, such as electric vehicles, grid-interactive buildings, and microgrids, which are becoming increasingly deployed at the grid edge. These technologies, which consumers and technology service providers often own and control, are introducing significant complexity and uncertainty to grid planners and operators. Due to the changing resource mix and industry composition, the electric grid must now evolve to a new operating structure with advanced functional capabilities; it will now need to manage variable power output, fluctuating and unpredictable load patterns, and bidirectional power flows, along with novel grid designs. It will also require effective, time-dependent coordination among all participants (utilities, market operators, and emerging players) to ensure the reliable operation of essential and evolving grid functions. The existing electric grid was not designed to handle these new demands and will require significant re-engineering involving advancements in both technology and institutional planning processes. Smart grid technology and strategies for deploying it are essential to address this new, evolving complexity.

As the grid evolves, there will be a need to build out a core cyber-physical, electric platform that will ensure an ability to serve multiple purposes (e.g., resilience, security, efficiency, affordability) while addressing uncertainty with regard to future technological options and changing customer preferences and policies. Plans must anticipate the convergence of the electricity infrastructure with other systems, such as the transportation, building, natural gas, telecommunications, and even social-networking infrastructures.

This report provides a look at both technological and institutional trends and related challenges associated with deploying the smart grid. Key findings and recommendations include:

- The proliferation of a variety of distributed energy resources (DERs), often not owned by the utility, shifts the operational paradigm from one of control to one of control and coordination. As DERs begin to influence how we generate and use electricity, we will need to institute processes that can effectively coordinate grid planning, operations, and market design/implementation not only among utility and nonutility participants but also across federal and state jurisdictions.

- Grid modernization is an essential component of an integrated planning process.
  Planning processes at the state level are evolving with regard to incorporating the application of smart grid technology and DERs into more holistic integrated plans; five states now mandate integrated distribution plans (IDPs), with others following suit. DOE has worked with state regulators and utilities over the past several years to institute consistent practices for determining grid modernization strategies that include examining functional and structural requirements needed over time to better inform technology implementation roadmaps.

- A whole-systems approach to resilience planning is needed to inform smart grid investments.
  Electric utilities typically improve the reliability and resilience of their systems through prudent asset management practices (e.g., assessing and replacing aged or damaged equipment) and protection schemes that can automatically isolate or reroute power flow to reduce equipment damage and minimize outages to customers. Strategic efforts are now required to address:
  a) Vulnerabilities related to interdependencies between the electric grid and other infrastructures
  b) The protection of critical civilian and defense functions
  c) Improvements in resilience from novel grid configurations, such as microgrids and mini grids

US DOE 2020 Smart Grid System Report: Bi-annual Update for 2022 (Continued)

- Research and development combined with technology demonstrations focused on system integration are required to enable the transition from legacy to more advanced grid infrastructures. Utilities must effectively integrate new systems with legacy infrastructure and perform to meet stringent requirements. R&D is needed in the following areas:
  - The advancement of solid-state materials and components to improve the performance of power electronics devices needed to control the flow and characteristics of electricity
  - The development of novel electrochemical approaches to improve the performance and reduce the cost of energy storage devices while minimizing reliance on scarce or critical materials.
  - The development and demonstration of low-cost, multiparametric sensors and supporting platforms that can provide observability of grid assets and the state of the system to support highly dynamic grid operations.
  - The implementation of methods to enable the exchange of data using standardized data formats across disparate systems combined with providing technical support to utilities to advance data analytics practices across the industry.
  - The advancement of communications networks that are scalable and support multiple functions (e.g., real-time control of DERs and automated feeder switching).
  - The demonstration of grid architectures that address operational control, coordination, and scalability issues as the electric grid begins to accommodate many more distributed assets and participants with potentially conflicting objectives.
  - The development of more powerful grid modeling and simulation tools that use stochastic methods to aid in planning and examining technological options under variable and uncertain circumstances.
  - The advancement of technology to prevent, detect, and mitigate the risk of cyber intrusion into electricity system operations.

- Managing cyber risks is key to enabling the smart grid. As grid operators increasingly rely on the data from digital devices and third-party systems to make real-time operating decisions, cyber risks are possible through the following pathways:
  - Digital devices connected to the enterprise network might have remote access capabilities and often are connected to corporate business networks. With interconnected systems, cyberattacks can migrate from these digital devices to corporate business networks and in the other direction, permitting remote access to intruders.
  - Grid-edge devices, such as customer-owned DER, are being integrated with utility and third-party systems. Although this integration is necessary to manage grid complexity, it marks an enormous expansion of the number of entry points for malicious actors.
  - Wide area monitoring and control equipment rely on global positioning system (GPS) clocks for extremely precise timing data. Malicious actors might manipulate GPS signals that could disrupt grid operations.
  - Supply chain risks can translate to cybersecurity risks for IT/OT technology due to the global nature of manufacturing. This broad-based sourcing increases the opportunity for malicious code to be introduced during the manufacturing process that could later impair grid operation.

- Achieving plug-and-play interoperability will remain a challenging and long-term task. Interoperability is the ability to exchange and use information among two or more devices and systems in a safe, secure, and effective manner. This means the myriad devices and systems on the grid to function in coordination under a wide variety of conditions.

NYISO: Announcements on the Blog Page of the NYISO Website:

Features from the Blog Page of the NYISO Website are as follows:

Press Release: **FERC approves NYISO plan to end "Buyer-side Mitigation" for clean energy resources.**
The Federal Energy Regulatory Commission on Tuesday approved the New York Independent System Operator's proposal to exempt clean energy resources from buyer-side mitigation, or BSM.

"We find that NYISO's proposal reduces the risk, present under the current BSM rules, of at least three significant harms: over-procurement of capacity, inflated capacity market prices, and inefficient price signals from the capacity market," FERC said in its decision.

FERC also approved NYISO's plan to create a marginal capacity accreditation design methodology to measure how much resources support reliability in peak periods. These issues are critical in New York, which requires that 70% of its power supply come from renewable energy resources by 2030 and be emissions-free by 2040.

Under NYISO's proposal, resources that meet New York's Climate Leadership and Community Protection Act goals won't face lower-end limits on their capacity bids. The proposal also establishes a marginal capacity accreditation framework that would assign a value to classes of resources based on their location on the grid. Resources that provide little additional reliability benefit to an area would have a lower value and receive less capacity revenue. The framework aims to steer resource development to areas where they are most needed.

Quarterly Grid Reliability Reports Address Rapid Rate of Change
This Short article expands on last month's Blog on Grid Reliability Needs and how to Resolve Them, and focuses on the Short-Term Assessment of Reliability (STAR) report, which has become increasingly important. STAR Q1 was recently released and focuses on identifying Reliability Needs up to five years in the future.

This STAR process helps to quickly evaluate changes to the system, such as:

- Generator deactivations
- Changes to the transmission system
- Changes in demand that could affect reliability

STAR reports look at both the adequacy of the energy resources and limitations of the transmission grid to determine whether the grid will be able to supply enough power to meet demand. During the process, if a "Short-Term Reliability Process Need" is identified, the NYISO will look for solutions to address that need.

While the identification of Reliability Needs is relatively rare, it may become more common due to the tightening of the reliability margins with the deactivation of fossil fuel-fired generators. The 2019 Peaker Rule adopted by New York State, which limits nitrogen oxide emissions from "peaker" plants, could result in the retiring of up to two dozen fossil fuel generators from 2023 to 2025. These facilities had the ability to provide up to 3,300 megawatts of power

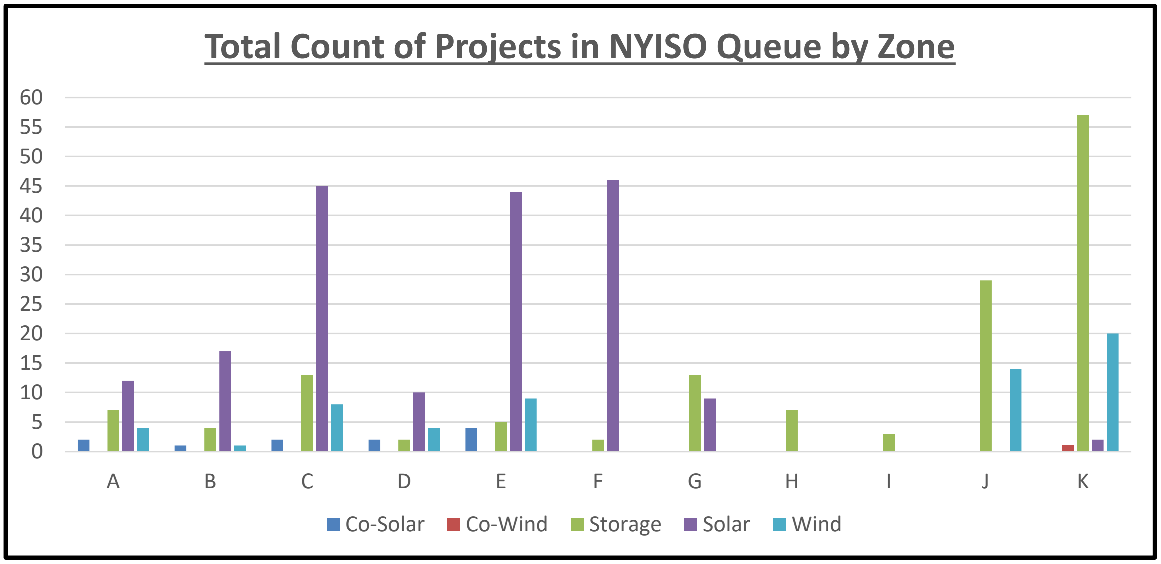
Interconnection Queue: Monthly Snapshot – Storage / Solar / Wind / CSRs (Co-located Storage)

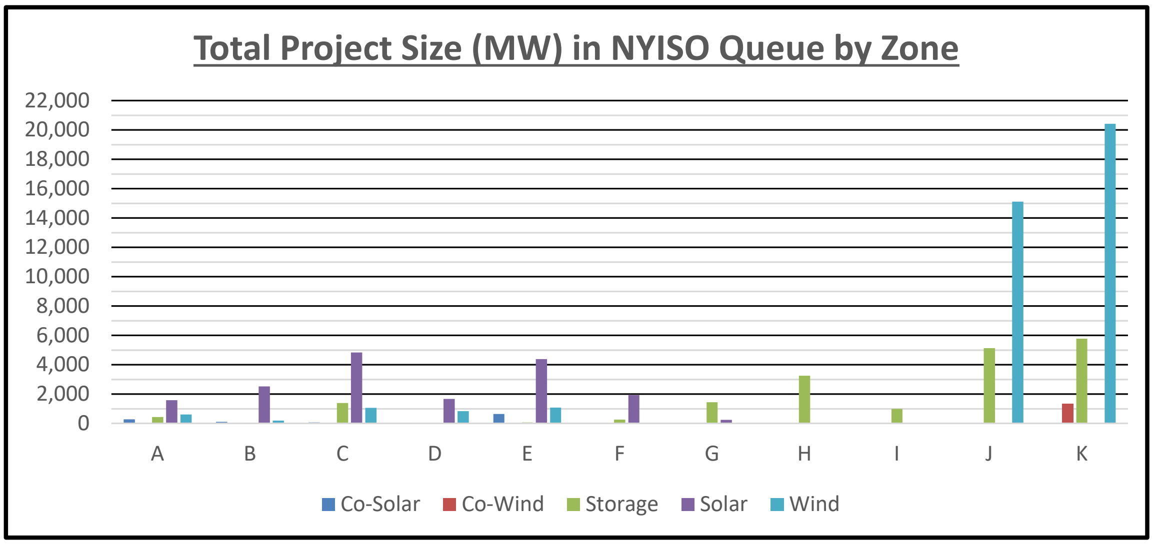
The intent is to track the growth of Energy Storage, Wind, Solar and Co-Located Storage (Solar and Wind now in separate categories) projects in the NYISO Interconnection Queue, looking to identify trends and patterns by zone and in total for the state. The information was obtained from the NYISO Interconnection Website, based on information published on May 21st, and representing the Queue as of April 30th. Note that 22 projects were added, and 5 were withdrawn during the month of March. Results are tabulated below and shown graphically on the next page.

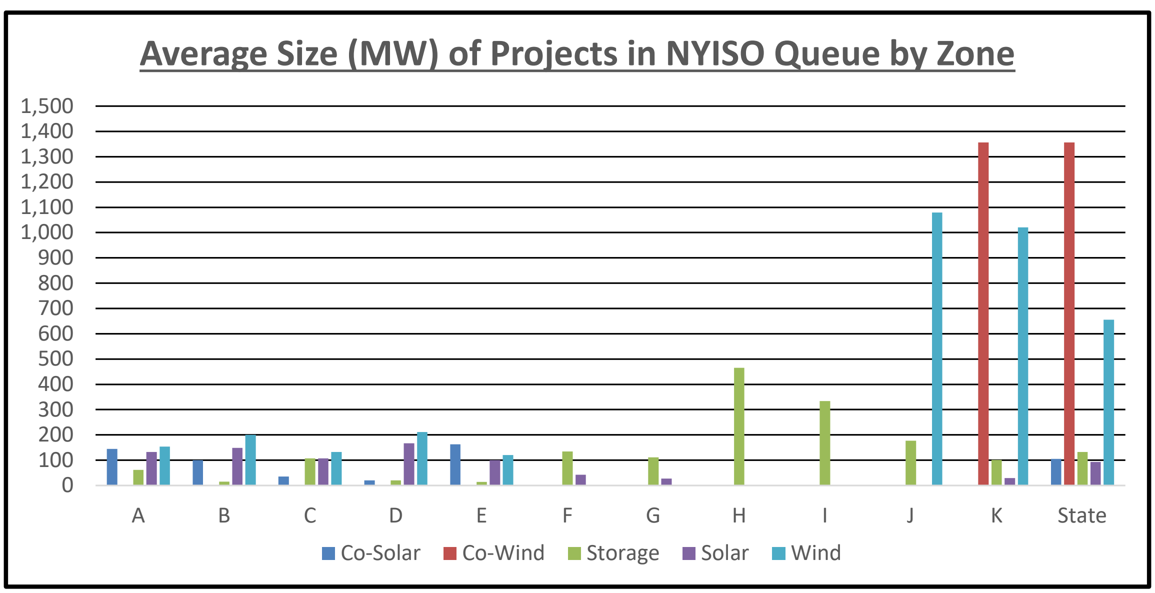
Total Count of Projects in NYISO Queue by Zone					
Zone	**Co-Solar**	**Co-Wind**	**Storage**	**Solar**	**Wind**
A	2		7	12	4
B	1		4	17	1
C	2		13	45	8
D	2		2	10	4
E	4		5	44	9
F			2	46	
G			13	9	
H			7		
I			3		
J			29		14
K		1	57	2	20
State	11	1	142	185	60

Total Project Size (MW) in NYISO Queue by Zone					
Zone	**Co-Solar**	**Co-Wind**	**Storage**	**Solar**	**Wind**
A	290		430	1,590	615
B	100		61	2,521	200
C	70		1,395	4,832	1,062
D	40		40	1,674	847
E	654		72	4,387	1,087
F			270	1,937	
G			1,441	250	
H			3,260		
I			1,000		
J			5,141		15,112
K		1,356	5,782	59	20,418
State	1,153	1,356	18,892	17,250	39,341

Average Size (MW) of Projects in NYISO Queue by Zone					
Zone	**Co-Solar**	**Co-Wind**	**Storage**	**Solar**	**Wind**
A	145		61	132	154
B	100		15	148	200
C	35		107	107	133
D	20		20	167	212
E	163		14	100	121
F			135	42	
G			111	28	
H			466		
I			333		
J			177		1,079
K		1,356	101	29	1,021
State	105	1,356	133	93	656


Total Count of Projects in NYISO Queue by Zone
60
55
50
45
40
35
30
25
20
15
10
5
0
A
B
C
D
E
F
G
H
I
J
K
Co-Solar
Co-Wind
Storage
Solar
Wind


Total Project Size (MW) in NYISO Queue by Zone
22,000
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
A
B
C
D
E
F
G
H
I
J
K
Co-Solar
Co-Wind
Storage
Solar
Wind


Average Size (MW) of Projects in NYISO Queue by Zone
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
A
B
C
D
E
F
G
H
I
J
K
State
Co-Solar
Co-Wind
Storage
Solar
Wind