De-Carbonization / DER Report for NYSRC Executive Committee Meeting 2/11/2022

Contact: Matt Koenig (koenigm@coned.com)

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

- NERC ERATF Workshop
- EPRI Reports (Publicly Available)
  - Strategies and Actions for Achieving a 50% Reduction in U.S. Greenhouse Gas Emissions by 2030
  - Enhancing Grid Reliability and Resiliency in a Net-Zero Economy
  - Maximizing Distributed Energy Resource Value Through Grid Modernization
  - Leveraging Existing Energy Infrastructure to Help Meet 2030 Greenhouse Gas Reduction Goal
- NYISO Blog: Reforming Buyer Side Mitigation with Comprehensive Mitigation Review Proposal
- Snapshot of the NYISO Interconnection Queue: Storage / Solar / Wind / Co-located Storage

Upcoming Event: NERC ERATF Workshop

NERC is hosting an industry workshop to discuss the key findings and recommendations from a technical paper written by the Energy Reliability Assessment Task Force (ERATF). Panelists will discuss energy assurance issues in the operations, operational planning and planning time horizons. In addition, the task force will gather industry comments for development of a final Standard Authorization Request (see attachment) for Reliability and Security Technical Committee (RSTC) consideration.

Use this Link to register for the Workshop

Supporting Information for the workshop can be found in these attachments:

- Standard Authorization Request: Fuel Assurance with Energy-Constrained Resources (January 5, 2022)
- ERATF DRAFT: Technical Justification (November 30, 2021)

The Energy Reliability Assessment Task Force serves the NERC Reliability and Security Technical Committee in providing a formal process to analyze and collaborate with stakeholders to address the issues identified in the whitepaper entitled *Ensuring Energy Adequacy with Energy-Constrained Resources* (published in December 2020). This whitepaper identified energy availability concerns related to operations, operations planning, and mid- to long-term planning horizons. Background information can be found in the NERC ERATF Work Plan 2020-2022 (published February 19, 2021)

Observations within the Technical Justification document noted that the existing Reliability Standards do not explicitly require energy assessments. In a new or revised standard, the following attributes should be considered:

- Add requirement(s) for extreme weather or environmental3 events.
- Determine how much time is required to recover and prepare for the next stress event.
- Create an approach to support assessments of the impact of decarbonization goals.
- Consider the risk to natural gas supply disruption, such as natural gas being unavailable due to high demand.
- Ensure that there is adequate coordination between the operations and planning teams.
- When writing transmission planning studies, consider including other transmission equipment along with transformers.
- Studies need to account for additional characteristics (e.g., ramp rate, start/stop of units).
- Consideration is needed for dynamic load model studies.

Latest EPRI Reports on Decarbonization

The EPRI website has a trove of publicly available material that on their Thought Leadership Landing Page. Areas of interest include Strategic Insights, Low Carbon Resources Initiative (LCRI), and Efficient Electrification. Several reports found within these categories are summarized on the following pages

Strategies and Actions for Achieving a 50% Reduction in U.S. Greenhouse Gas Emissions by 2030 Download Link
This White Paper explores strategies to achieve the U.S. greenhouse gas (GHG) economy-wide emissions target of about 50% reduction from 2005 levels by 2030, identifying least-cost emission reduction actions across the electric sector, transport, buildings, and industry.

The analysis focuses on three core scenarios:

- Reference. Assumes on-the-books federal and state policies and incentives
- 50x30. Achieves a 50% reduction in 2030 GHG emissions relative to 2005, assuming electrification economics and technology improvements consistent with earlier EPRI studies
- 50x30 E+. Assumes additional technology and policy drivers that accelerate electrification by lowering the cost of electricity-using technologies, reducing customers' reticence to shift technologies, and accelerating the turnover of end use equipment

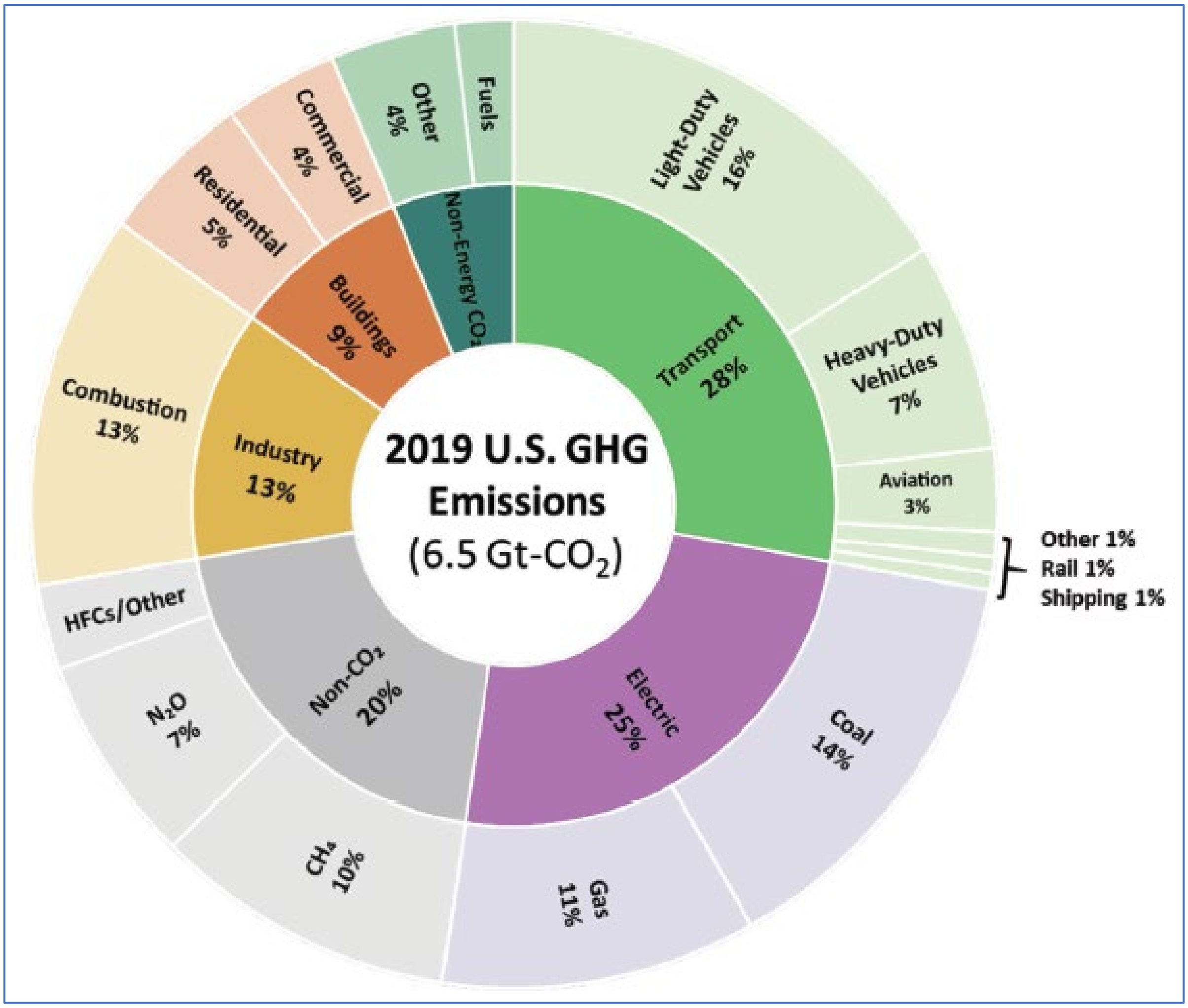
In general, the results highlight that energy efficiency, cleaner electricity, and rapid electrification are the central strategies to achieve the 2030 target. Emerging technologies (carbon capture-utilization-storage, advanced nuclear and clean hydrogen) are important for driving future reductions. However, they are unlikely to provide large reductions this decade given the stringency of the target and lead times for deploying these technologies at scale.

Instead, the challenges in driving 2030 reductions are primarily in execution, with a 50% reduction requiring large changes in how energy is produced, delivered, used, and governed while maintaining reliability and affordability every step of the way. In parallel, technological advances and deployment incentives will be needed to facilitate more stringent 2035 and mid-century emission goals.

Key Findings include:

1. Halving GHG emissions by 2030 will involve significant efforts beyond business-as-usual trends
    - Reductions triple their historic pace, enabled by accelerated electrification
    - Achieving the 2030 interim emission goal will depend on strong policies
    - Emission reductions bring near and long-term costs and benefits
- Reaching decarbonization targets for the power sector involves accelerated and sustained change
    - Projected capacity additions in the 2020s total around half the capacity of the current U.S. grid
    - Coal assets retire with attendant community, jobs, and financial impacts
    - Firm capacity is a key asset for system balancing
    - New carbon capture equipped capacity can provide low-carbon firm capacity
    - Electric sector technology pathways are sensitive to assumed costs and policies
- Electrification and efficiency gains drive GHG reductions in transport, industry and buildings
    - Electricity's share of end-use energy increases
    - Transport leads the way, but electrification is a critical reduction strategy for all sectors
    - Energy efficiency gains temper the growth in electricity and energy demand
    - Rapid end-use changes mean quickly changing supply chains and buying habits for tens of millions of households

The figure below shows U.S. historical energy CO2 emissions by sector and 2030 scenarios. Historical emissions are based on U.S. EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks



The Report anticipates these interrelated trends and activities:

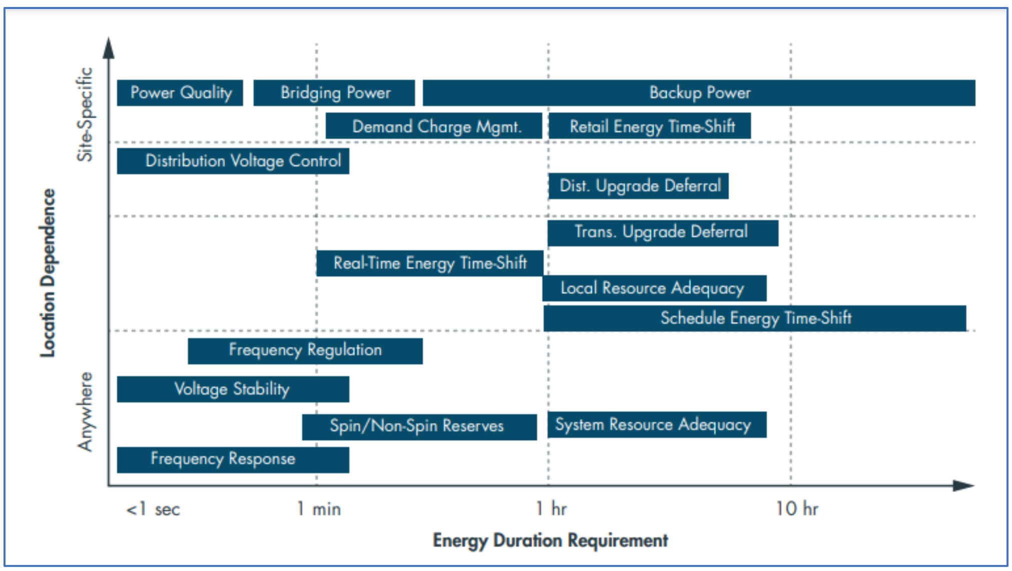
- Rapid expansion of wind and solar generation
- Operational and market issues will have to be addressed with renewables penetration, which are projected to exceed current thresholds for nonsynchronous resources for large fractions of annual hours in many regions and scenarios.
- New grid operational control and protection capabilities will likely be needed for day-today operation
- Electricity market reforms will be needed to support generation investment and grid flexibility
- Grid modernization will be essential to efficiently integrate distributed resources and expand demand response.

Enhancing Grid Reliability and Resiliency in a Net-Zero Economy

While emerging clean resources have the potential to provide capabilities on a par with synchronous generation, they may not provide as broad a set of reliability services and their provision of grid services often is not as widely understood and tested. As the grid transitions, the resources comprising the grid must provide the required services at every step in the transition. This Report provides a more detailed evaluation of these components to support both reliability and resiliency in the areas of:

- Resource Adequacy: Sufficiency of resource availability and deliverability to meet energy demand across all hours under extreme conditions and equipment failures.
- Transmission Infrastructure: Sufficiency of transmission system capacity to enable interregional economic energy flows and intra-regional delivery to load centers.
- Distribution Infrastructure: Sufficient distribution system infrastructure to enable distributed generation, serve increased demand from electrification, and support flexible load for providing grid services, all while maintaining distribution reliability standards.
- Operational Reliability – Balancing and Flexibility: Instantaneously balance supply and demand through all operating conditions.
- Operational Reliability – Grid Stability: Ability of the grid to maintain desired system performance during credible operating conditions and disturbances and to prevent cascading outages and ensure reasonable restoration for disturbances that are beyond planning criteria.

The figure below characterizes different Energy Storage functions based on duration, location and service type:



The report concludes with these recommendations for prioritizing the Decarbonization pathway:

- Reliability and resiliency planning. Development and application of detailed reliability and resiliency planning processes and models on a regional and national level across transmission and distribution to maximize the impact of available investment capital.
- Power system operational capabilities. Development and deployment of new grid control and protection capabilities and clean supply and demand balancing resources for reliably and efficiently operating a much more dynamic, decentralized, and inverter-based renewable resource grid.
- Markets and financial systems. Design and implementation of market, financial, and regulatory processes that incentivize investment in significant new supply, demand flexibility, and transmission and distribution infrastructure, and compensate all resources for essential grid services provided.

Maximizing Distributed Energy Resource Value Through Grid Modernization

This comprehensive Report discusses how leveraging DER effectively across a modernized grid requires the improvement of grid operator visibility and control, in addition to the support of emerging energy services. The report identifies the latest planning and operational challenges facing DER growth. Major factors that are accelerating DER adoption include government policies, customer expectations, climate related impacts, and grid modernization activities. However, existing issues remain, and new challenges are appearing. Secure, cost-effective integration of DER is growing more complex for many reasons:

- Because of growing variable renewable energy generation, transmission grid operators may need to adjust the operations of DER frequently to help balance energy supply and demand, with control intervals as brief as a few seconds.
- DER come in many types such as rooftop solar, battery storage, EVs, and controllable loads, each with their own power characteristics and capabilities.
- DER are deployed in many sizes, from small residential to large commercial and utility scales, potentially requiring different control approaches.
- In more and more regions, DER are being deployed in large numbers, and adoption is accelerating.
- DER are connected in diverse locations with varying energy demand and supply.
- DER are owned and controlled by a range of entities, each with its own objectives and priorities, which may at times conflict with the goals of a grid operator. For example, the highest priority of customers with behind-the-meter storage may be to reduce their bills, whereas the grid operator is most concerned about grid reliability.
- Different types of DER may be co-located but controlled by different entities. For instance, a single home may have a solar array, an energy storage system, a plug-in EV, and a smart thermostat, each communicating with and controlled by a different entity, each managed according to different goals, and each unaware of the operations of the others.

Potential grid services from DER include:

- Load leveling: Smoothing load by absorbing energy from or injecting energy into the grid.
- Peak demand reduction: Providing power to the grid to limit the peak load on grid assets.
- Ramping support: Providing supplemental power when solar or wind generation output fluctuates.
- Energy arbitrage: Shifting energy production from lowvalue to high-value periods.
- Distribution capacity: Injecting power (rooftop solar, EVs, and storage) or reducing consumption (EVs, appliances, and other controllable loads) to reduce net load on specific distribution infrastructure.
- Firm capacity: Guaranteeing availability of backup capacity to compensate for dips in renewable energy production.
- Reserves: Grid-connected reserve power ready for instantaneous delivery as well as reserves not connected to the grid but able to delivery power within minutes.
- Black start: Bringing a generation plant from shutdown to a specified power level within a specified time, without support from transmission lines.
- Frequency regulation: Providing short-term power adjustments to help maintain grid frequency within required levels.
- Voltage support: Producing or absorbing reactive power to maintain grid voltage within required levels or to correct voltage excursions.
- Back-tie: Supplying power or decreasing consumption to reduce loading of grid infrastructure when operators
- reconfigure distribution feeders during an outage recovery.
- Renewable self-consumption: Using a behind-the-meter energy storage system to absorb power from a rooftop solar system to avoid curtailment of excess generation

Leveraging Existing Energy Infrastructure to Help Meet 2030 Greenhouse Gas Reduction Goals
This White Paper explores the potential for expanding the capacity and operational capabilities of existing hydropower, nuclear, and transmission assets which offer realistic opportunities for comparatively low-cost carbon reduction. Nuclear and hydropower upgrades increase the amount of firm, flexible, carbon-free capacity to support the rapid expansion of solar and wind, while partially offsetting essential grid reliability services lost with coal plant retirements. Transmission upgrades can help maintain reliability while integrating more distant, variable generation.

Enhance Nuclear Operational Flexibility and Plant Capacity
U.S. nuclear power fleet operating licenses can be extended to 80 and potentially 100 years to increase the generation from existing units by 106%. There is also potential to add flexibility and capacity. Key plant capability enhancements include:

- Enable operational flexibility for power decreases from 100% of maximum output to 25% through enhanced maintenance strategies and new technologies
- Add up to 11 GW of nuclear generation capacity by uprating existing nuclear power plants

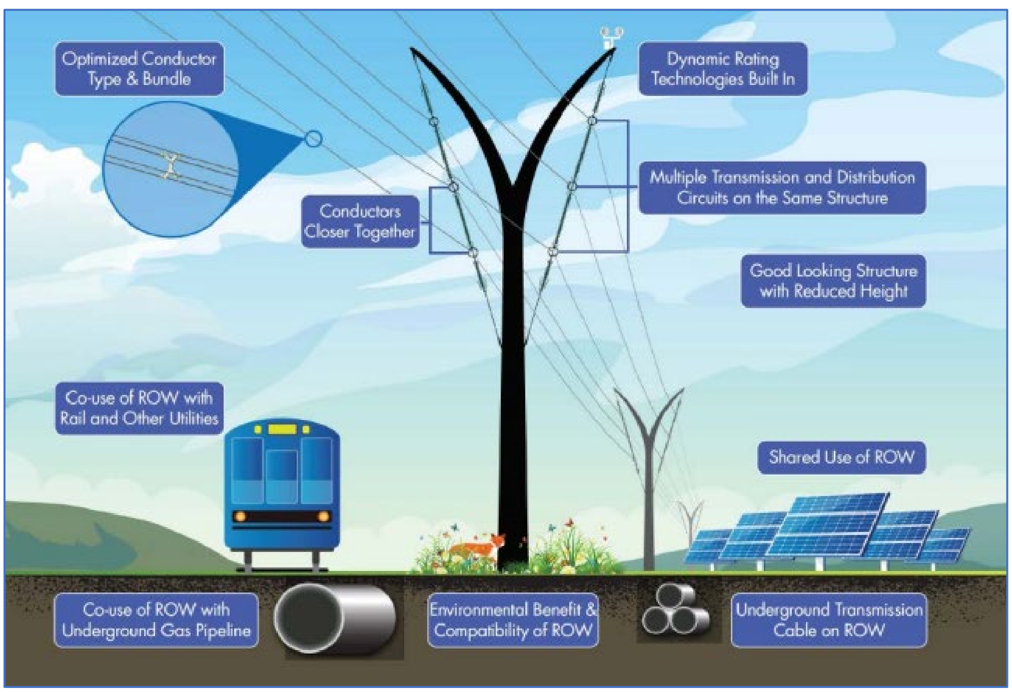
Increase Output of Hydropower Generation
The U.S. hydropower fleet output could increase by 8-10% through equipment and plant uprates at existing facilities and even more by powering non-powered dams. Key options include:

- Improve installed hydraulic turbine efficiency and increase plant discharge and gross head
- Evaluate the 91,000 unpowered dams in the U.S. for up to 12 GW in techno-economic potential

Leverage Existing Transmission Lines and Rights-of-Way
Key options for increasing the capacity of existing transmission lines and Rights-of-Way (ROW) include:

- Uprate lines and install underground cables and highcapacity overhead lines in existing/new ROW
- Double the line capacity by increasing voltage, or 250% by conversion from AC to HVDC lines

The figure below provides examples for increasing power flow and utilization in a transmission Right-Of -Way



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

This month's features from the [Blog Page] of the [NYISO Website] includes a press release, FAQ, and interview with Rana Mukerji, the NYISO Senior Vice president of Market Structures. All three articles cover various aspects of the recent NYISO proposal "Comprehensive Mitigation Review" which has been approved by the stakeholders and submitted to FERC. The proposal looks to reform capacity market rules for Buyer-Side Mitigation (BSM) and capacity market accreditation. The links are provided below, followed by a general summary of the initiative.

FAQ: Reforming Buyer-Side Mitigation
PRESS RELEASE: NYISO Acts to Remove Significant Barrier to Renewable Development in New York State
Q&A with Rana Mukerji: Evolving Energy Markets for the Grid of the Future

BSM rules were initially developed to ensure sure capacity market prices stay competitive. The rules guard against market participants' potential to drive capacity prices lower than what the competitive market should bear. Many of the new resources entering the markets in response to environmental policies receive out-of-market payments (such as state or federal incentives) for their clean-energy attributes, creating an imbalance with other resources that may not qualify for such subsidies. To compensate, the NYISO is proposing these changes to the capacity market:

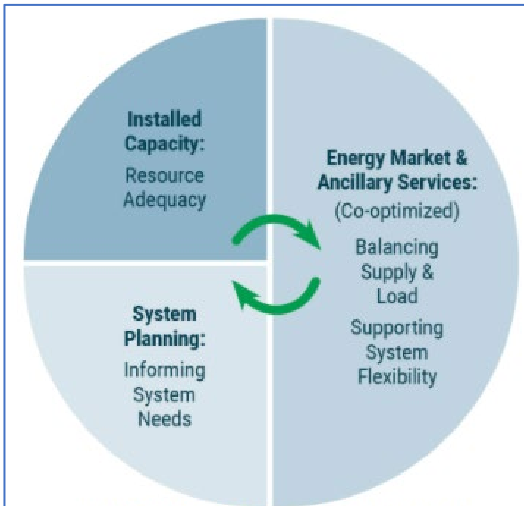
- Create an exclusion from the BSM rules for resource types that align with New York State's CLCPA mandates, including wind, solar, energy storage, and demand response resources that are entering the market in response to the CLCPA. This will allow for the growth of CLCPA-driven investment while still protecting the markets. It will also allow the market to continue to produce just and reasonable prices needed to meet resource adequacy needs while avoiding conflict with CLCPA mandates.
- Reform capacity accreditation rules to align capacity market compensation with the reliability contribution of specific technologies. The NYISO is modifying the process for determining how much capacity resources are eligible to offer into our competitive markets to reflect the reliability value that all energy resources bring to the energy grid as a whole. In order to maintain reliability as the resource mix quickly evolves, it is essential to align a resource's reliability contribution with its capacity value.

The NYISO, with significant stakeholder input, performed a consumer impact analysis, which found that if the market rules are accepted by the FERC as proposed, consumers could expect annual savings of nearly $500 million.

Key forward-looking comment by Rana Mukerji:

"…the intermittent nature of the renewable units puts a premium on response, which is provided by ancillary services. What we are seeing is that ancillary services are almost becoming the main event or will become the main event.

The energy market is becoming secondary as a source of revenues. The ancillary services market is going to drive the behavior that is needed. One of the things we have to look at is to make our ancillary services market more impactful to drive the kind of system response that we need to balance the power system."



SOURCE: *Power Trends 2021* - Introduction: System Planning & Competitive Markets Support Public Policy

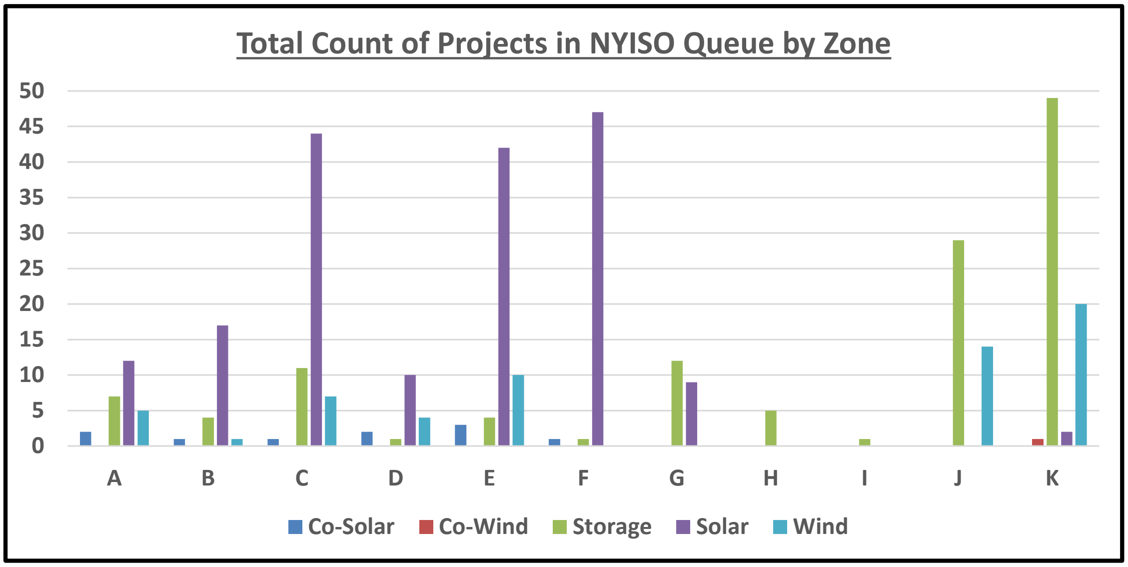
Interconnection Queue: Monthly Snapshot – Storage / Solar / Wind / CSRs (Co-located Storage)

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 January 21st, and representing the Queue as of December 31st. Note that 15 projects were added, and 8 were withdrawn during the month of December. Annual totals for 2021 are 197 projects added and 98 withdrawn. Results are tabulated below and shown graphically on the next page.

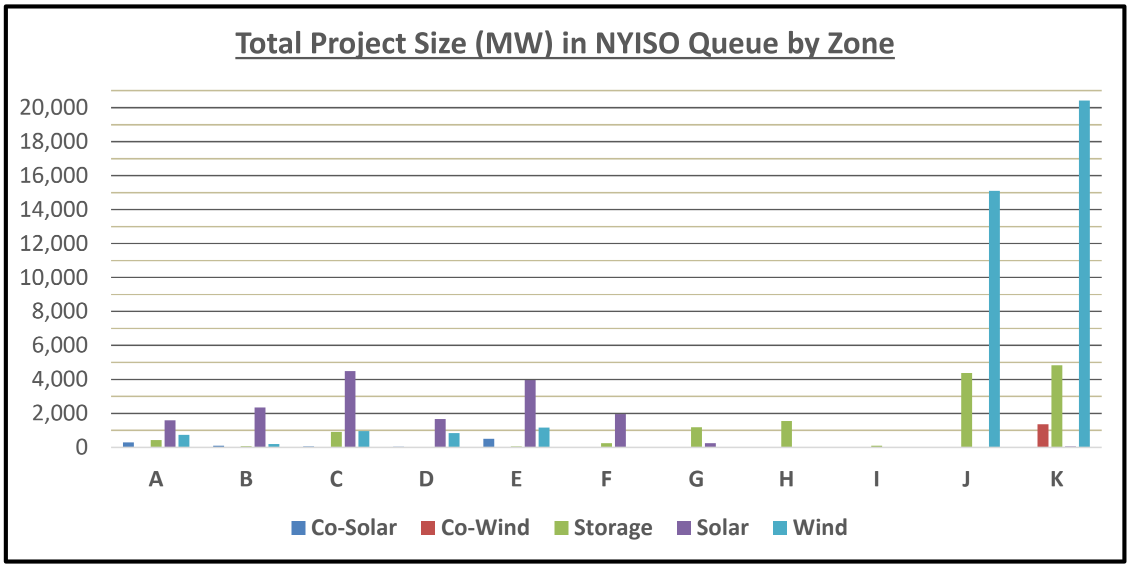
Total Count of Projects in NYISO Queue by Zone					
Zone	Co-Solar	Co-Wind	Storage	Solar	Wind
A	2		7	12	5
B	1		4	17	1
C	1		11	44	7
D	2		1	10	4
E	3		4	42	10
F	1		1	47	
G			12	9	
H			5		
I			1		
J			29		14
K		1	49	2	20
State	10	1	124	183	61

Total Project Size (MW) in NYISO Queue by Zone					
Zone	Co-Solar	Co-Wind	Storage	Solar	Wind
A	290		430	1,590	741
B	100		61	2,345	200
C	50		908	4,495	960
D	40		20	1,674	847
E	513		50	3,949	1,165
F	20		250	1,957	
G			1,173	250	
H			1,560		
I			100		
J			4,393		15,112
K		1,356	4,821	59	20,418
State	1,013	1,356	13,766	16,318	39,444

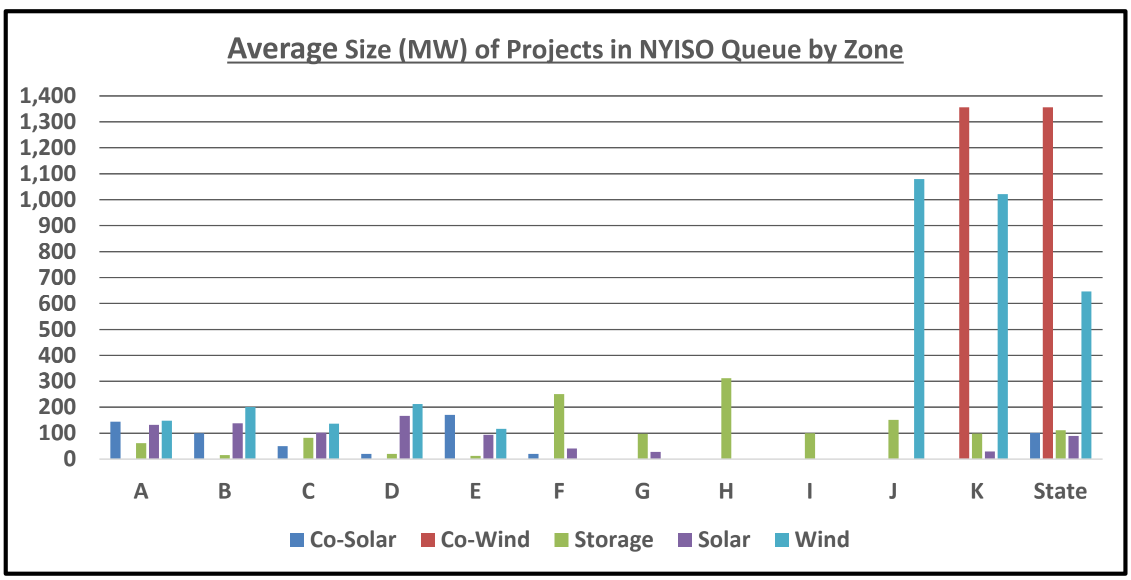
Average Size (MW) of Projects in NYISO Queue by Zone					
Zone	Co-Solar	Co-Wind	Storage	Solar	Wind
A	145		61	132	148
B	100		15	138	200
C	50		83	102	137
D	20		20	167	212
E	171		13	94	117
F	20		250	42	
G			98	28	
H			312		
I			100		
J			151		1,079
K		1,356	98	29	1,021
State	101	1,356	111	89	647



Total Count of Projects in NYISO Queue by Zone
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
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
1,400
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

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Fuel Assurance with Energy-Constrained Resources		
Date Submitted:	4/1/2022		
SAR Requester			
Name:	Chair Peter Brandien on behalf of the		
Organization:	Energy Reliability Assessment Task Force (ERATF) of the Reliability and Security Technical Committee (RSTC)		
Telephone:	(413) 535-4022	Email:	pbrandien@iso-ne.com
SAR Type (Check as many as apply)			
☒ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
Unassured deliverability of fuel supplies, coincident with the timing and inconsistent output from variable renewable energy resources and volatility in forecasted load, can result in insufficient amounts of capacity and/or energy on the bulk electric system (BES) needed to serve electrical demand and ensure the Reliable Operation of the BES throughout each hour of the time period being evaluated[1]. Historically, analysis of the energy assessments of the bulk power system focused on capacity over peak time periods. Assessments focused on capacity reserve levels compared to peak demand because resources were generally dispatchable and, except for unit outages and de-rates, were available when needed. Reserve margins were planned so that deficiency in capacity to meet daily peak demand (Loss of Load Expectation (LOLE) or Loss-of-Load Probability (LOLP)) occurred no more than one day-in-ten-			

[1] The industry need is described in the *Ensuring Energy Adequacy with Energy-Constrained Resources* white paper, presented to the RSTC, December 2020.

Requested information
years. Reserve margins are calculated from probabilistic analysis using generating unit forced outage rates based on random equipment failures derived from their historic performance. The targeted level has typically been one event every ten years, based on daily peaks most often driven by summer and/or winter peaks (rather than hourly energy obligations). Additional insights were traditionally gained by also calculating Loss-of-Load-Hours (LOLH) and expected unserved energy (EUE) based on the mean-time-to-repair (MTTR) during unit averages. A key assumption in this analysis has been that fuel is available when capacity is required to provide the requisite energy (along with essential reliability services). This is not surprising since fuel availability was assured with either long-term fuel contracts (commodity plus transportation capacity), on-site storage (e.g. oil, coal, and reservoir-based hydro), or with required periodic and predictable fuel replacement (e.g. nuclear). With diverse, dispatchable resource technologies, capacity from other technologies could mitigate impacts when fuel for one resource type became unavailable. Today, this framework is changing. Transitioning from coal and nuclear resources to wind, solar, gas that is dual fueled, and hybrid (with bulk energy storage systems) resources creates a more complex scenario, hence fuel assurance and forward energy supply planning becomes increasingly important. Importantly, generating capacity alone is not sufficient to ensure the Reliable Operation of the bulk power system. Policy efforts to increase the contribution of renewable energy has resulted in a higher emphasis on the ‘on call’ availability of capacity to supply energy to serve net demand. Production flexibility from these balancing resources has already become important and will become critical in the future. Operational uncertainty is increasing due to the types of, and conditions under which, energy, and by implication, fuel, is available or acquired. Examples of these uncertainties are resources solely dependent on the availability of wind and solar, which are similar to run-of-river hydro plants in that they have no energy storage capabilities and are completely dependent on real-time weather or environmental conditions. These also include distribution connected resources and flexible load programs which may introduce additional volatility into energy forecasts. Layered into this uncertainty, natural gas fueled resources may, depending on the type of contract for fuel acquisition, be subject to fuel curtailment or interruption during peak fuel demands. Additionally, gas pipeline design and how gas generators interconnect with the pipeline can vary, which can result in significantly different impacts to the generator and the Bulk Electric System (BES) under gas pipeline disruption scenarios. This same gas system is, in itself, dependent on the Reliable Operation of the bulk electric system as well as weather conditions. This interdependency creates even more uncertainty in the availability of fuel when it is required the most, creating energy limited scenarios. In some areas, variable energy resources require that there are sufficient flexible energy resources available to quickly respond to off-set ramping requirements. The impacts can be mitigated with the supply and geographical diversity from renewable and smaller distributed resources, though wide-spread common weather and environmental conditions may result in scarcity from neighboring energy supplies. These uncertainties are already causing many system operators to consider scheduling, optimization, and commitment of resources over a multi-day timeframe. Replacing the existing

Requested information
generation fleet with energy limited resources requires industry to consider both capacity requirements and energy, and by extension fuel, availability. Even if sufficient capacity is available, a level of certainty in the delivery of fuel is required to ensure that energy is available to support demand. <u>Standard Requirement</u>: One common underlying risk is the increased use of just-in-time delivery of fuel. More specifically, challenges are mounting from the single points of failure caused by the penetration of wind, solar, and natural gas with increased uncertainties due to unexpected interruptions of fuel delivery. This could be a result of the sun not shining or the sun being blocked by smoke, snow, and ice, the wind not blowing, or blowing too much, extreme cold or heat, and natural gas becoming unavailable (due to the contract type, or equipment failure, or pipeline maintenance, or pipeline failure). Energy security, and by extension fuel security, risks are increasingly becoming more apparent as extreme weather has resulted in deficits in energy (rather than capacity). During the past 10 years, there were four events that jeopardized the Reliable Operation of the BES. In February 2011[2], there was an arctic cold front in the southwest and resulted in generation outages and natural gas facility outages. In January 2014[3], there was a Polar Vortex that affected central and eastern U.S. and Texas. Again, the 2014 event triggered generation outages and natural gas availability issues. In January 2018[4], the south-central U.S. experienced many generation outages resulting in emergency measures. The February 2021[5] event is the fourth event, and an arctic cold air mass impacted Mississippi, Louisiana, Arkansas, Oklahoma and Texas. In fact, these events are coming with more regularity, and may not be “extreme” anymore, but rather expected. High impact points of failure require study by the industry towards understanding effects and putting in place plans to address them. Either enhancements to existing NERC Reliability Standards or creating new Standards is needed to mitigate issues that were documented during the January 2019 and February 2021 events. For example, study of the loss of a large natural gas pipeline is already called for as an extreme event(s) in the transmission planning Reliability Standard TPL-001-4, but more scenarios for planning and extreme events are needed to represent common modes of failure, such as the loss of solar, wind, water, and natural gas. This would be demonstrated by entities performing energy assessments ensuring that they understand the risks. Furthermore, corrective action plans should be in place to mitigate impacts from agreed upon planned event design basis and an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts from agreed upon extreme event(s). The scenarios belonging in planned events versus extreme events require the development of an agreed upon design basis identifying what risks/impacts are acceptable and which are not, and require mitigation. The resulting Reliability Standard should provide certainty of risk mitigation and expected

[2] Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011 - FERC and NERC
[3] Polar_Vortex_Review
[4] 2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018
[5] February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations - FERC, NERC and Regional Entity Joint Staff Inquiry

Requested information
reliability performance across the industry when the system is planned. Rather than a burden, these enhancements would provide certainty of risk mitigation between organizations and throughout the interconnections, thereby, ensuring that an Adequate Level of Reliability for the BES is maintained.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This project will enhance reliability by requiring industry to analyze their energy-related issues and the impact of currently unstudied constraints on the reliability of the BES. The focus of an energy reliability assessment is to analyze two parameters: fuel assurance and flexibility based on the evolving resource mix, and gas delivery security. These two parameters need to be analyzed in three time horizons: Operations, Near-Term Transmission Planning and Long-Term Transmission Planning. Regarding fuel assurance and flexibility, as the mix of resources trends toward more renewable energy, primarily with variable and intermittent supplies of fuel (e.g. sunshine, wind, and water), maintaining a balanced power system will require a more flexible approach to energy and capacity adequacy in order to maintain operational awareness. Traditionally, peak-hour capacity can be solved in an isolated case that ignores all other hours, but in a limited energy situation, the use of system resources affects the availability during peak hours. In addition, generator flexibility is gaining importance as load ramps begin to stress the existing infrastructure. Regarding gas delivery security, maintaining system balance in cooperation with a limited energy set of resources will require some level of controllability with the remaining fleet, which will most likely be gas fired generation. In addition, the variability of the renewable resources will likely change how gas is used, requiring a higher precision of understanding to determine if the existing system is capable of serving the changing needs (e.g. larger swings of gas demand due to higher overall gas generation ramp rates and shorter periods of online time). This issue is further complicated since stakeholders external to power system operators may influence gas delivery security, such as policies and procedure developments from FERC, NAESB, natural gas pipeline companies, or other entities.
Project Scope (Define the parameters of the proposed project):
The project scope is to create new or modify the existing NERC Reliability Standards to address the following: ▪ Define terms e.g. energy reliability assessment, fuel, fuel assurance, etc. ▪ For energy reliability assessments, metrics and observations should be compared to targets or predefined criteria. Results should be in terms of the impact to the Bulk Power System. ▪ Energy reliability assessments should be required to include the appropriate assumptions and scenarios that account for, but not limited to: time-coupled restrictions on the availability of fuel, the impact of energy storage and other flexible resources, the logistical constraints of the associated fuel delivery supply chains, common mode outages not connected to fuel supply, coincident outages of multiple independent resources, outage duration based on failure modes, and variable resources need to account to be included to account for their unique characteristics.

Requested information
▪ Energy reliability assessments must be coordinated between areas to harmonize interchange assumptions. ▪ Wide-spread, long term, extreme event analysis needs to be defined and included in the assessments. ▪ Requirements for energy reliability assessment should include a clearly defined periodic basis and performed in each of the NERC defined planning time horizons, as well as the operations time horizon. Periodicity should include clauses for their re-performance and/or update of existing assessment when changes to assumptions and input data invalidates an existing assessment.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[6] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The Energy Reliability Assessment Task Force (ERATF) was formed to assess risks associated with unassured energy supplies. The task force was created to provide a formal process to analyze and collaborate with stakeholders addressing the issues identified in the Ensuring Energy Adequacy with Energy-Constrained Resources whitepaper. This whitepaper identified energy sufficiency concerns related to operations, operations planning, and mid to long-term planning time frames. Based on the eleven questions formulated in the whitepaper, the task force created a survey questionnaire. The survey was distributed it to sub-groups of the Reliability and Security Technical Committee (RSTC) and ISO/RTOs to gather feedback on energy assurance for three focus areas: Energy Adequacy and Flexibility for Evolving Resource Mix, Natural Gas Delivery Assurance, and Metrics, Procedures & Analysis. The goal of the survey was to understand how stakeholders are evaluating their energy constraint issues and, by extension, fuel availability issues. The original 11 questions from the whitepaper were modified slightly for the purpose of survey in order to seek out answers to more specific, tactical questions which would inform the ERATF's recommendations. For example, sub-questions were added to understand how specific assessment input assumptions were developed and how the impact of varying those assumptions was assessed. The survey questionnaire had 18 core questions and 12 responses were received from NERC stakeholder groups, Independent System Operators, and individual utilities. These responses provided a tremendous volume of information (over 500 answers) to help evaluate the energy constraint issues. <u>NERC ERATF Energy Assessment Survey</u> The NERC ERATF formed a sub-group of volunteers to review all the survey responses and identify recommendations. The rigor and thoroughness of the responses was excellent and it is clear entities

[6] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
"put a lot of work" into their responses. On October 18, this sub-group presented high-level summaries of the responses to the eighteen questions and higher-level, generalized responses as described below:

- Across many of the responses, it was not always clear if entities were addressing current practices for "capacity" assessments or "energy" assessments. Many entities responded that they modify capacity assessments with higher forced outage rates and extreme scenarios to develop to assess evaluate a range of operating conditions. But based on the responses energy assessments are not well defined and not being perform consistently across industry.
- The survey demonstrated differences in how energy assessments are performed in the three time frames (operations, operational planning, mid/long term planning).
- Unclear what operating entities do with low likelihood, high impact energy assessment results. Some provide the results publically to stakeholders for awareness, yet most do not. For predicted energy deficiencies in the operational planning timeframe of 1-3 days, almost all entities do schedule additional capacity. Most do not provide energy assessments reflective of low likelihood, high impact events in seasonal assessments. Some respondents mentioned review of extreme contingencies in the longer-term planning timeframe yet it is unclear if any planning actions are taken:
    - Most of the responses were focused on extreme weather scenarios. Very few comments on the evaluation criteria included other potential failure modes, including cyber-attacks or other disruptions that could impact energy assurance, specifically cyber-attacks impacting the fuel supply chain.
    - Many entities use history looking back 30 years to develop planning forecasts. Yet others responded that "…the world climate and social policies (heating & transportation electrification) are changing fast…" and entities should focus and forecast the future based predicted future events more so than history, including worse case extreme weather.
- Many responded that developing forecasts and assumptions for the mid- and long-term assessments is very difficult and it is challenging to assign levels of confidence in those forecasted assumptions. As an example, it is hard to forecast fuel replenishment or renewable production in the 6-12 month timeframe and more challenging in the long-term planning timeframe.
- Some entities responded that, in the future, the worst conditions could be in the fall or spring seasons with low renewable generation rather than heat wave peak conditions, if those peak conditions also included high renewable generation.
- Some entities responded that there are regional differences that may result or define different energy assessment reliability issues. More specifically, some operating entities have wider ranges in peak loads for extreme temperatures, some have significant fuel risks, some have extreme storm risks, some have significant forest fire risks, and some have drought risks. The reliability implications can vary regionally and therefore risks can vary regionally. Yet most responded it is commonly important across all of NERC industry to "…develop common and consistent energy assessment methods…"

Requested information
▪ A few responded on the need to assess sufficient energy flexibility including dispatch energy, reserves, and regulation. ▪ Some offered transitioning from capacity adequacy to energy assurance can initially be performed by considering more conservative assumptions with fuel, wind, and solar, modeling higher probabilities of derates and extreme weather but more sophisticated techniques need to be developed. ▪ Some entities offered that based on the February 2021 extreme cold weather events it is clear that extreme peaks can be coincident with loss of fuel. ▪ Many respondents indicated that energy reliability assessments should be performed throughout the year, not just during peak conditions, to capture the risk for fuel unavailability. ▪ Classic forced outage rate measurements such as Effective Force Outage Rates – Demand (EFORD) metrics and Unforced Capacity (UCAP) constructs are not great for assessing renewable energy assurance, as they assume a randomness to failures, rather than a coincidence. Many existing capacity valuation constructs, especially for longer term resource adequacy does not value capacity that might support energy deficits resulting from multi-day loss of resources such as loss of fuel for over a week; especially for common mode loss of regional fuel. ▪ Some entities offered a significant issue in the planning horizon is assumptions regarding retirements of legacy fossil flexible resources with flexibility. ▪ Developing mid- to long-term assumptions is very important. For example, “what to assume for non-ICAP imports” or “what to assume for fuel replenishment” in seasonal timeframes. ▪ Some use 90-10 for extreme scenario assessments, others do something different. <u>NERC Reliability Standards Review</u> A set of sub teams of the ERATF were formed to review of the existing NERC Reliability Standards from the viewpoint of energy (required to make electricity) assurance and identify any gaps. The perspective of this review was addressing the assumption Reliability Standards may have that energy is always available. This assumption is now under review with the new resource mix, and may not be always true without having performed an energy reliability assessment and without monitoring the resources ability to deliver. One team reviewed the operations planning time frame, and a second team assessed at the mid- and long-term planning time frame. The comments from the operations planning sub team were the following observations: 1. The existing Reliability Standards do not explicitly define or require energy reliability assessments. 2. A number of the Standards depend on resources to deliver energy to adhere to the requirements, such as operating within system operating limits (SOL) and interconnection reliability operating limits (IROLs), contingency reserves to regulate the system, and energy characteristics such as large ramps that may constrict or be limited by available energy. The timing of deploying energy resources to meet the demand is crucial.

Requested information
3. There is little understanding of critical infrastructure interdependencies and the potential impacts on power generation. 4. Currently, there are insufficient tools to model and forecast wind, solar, etc. for energy reliability assessments. Also mentioned was to consider power system modeling to create more accurate predictive tools, and include dynamic modeling of the gas system. 5. As the majority of fuel infrastructure exists beyond a single area, there is a need to understand and model the fuel infrastructure on a larger basis (e.g. affects from events outside of a specific area that can have impact on that area), so the impacts can be understood. 6. Considering that NERC Standards that require the use of generation assume that fuel is available, situational awareness was mentioned. The Emergency Operations (EOP) and Transmission Operations (TOP) Reliability Standards, and transmission operational requirements should require energy reliability assessments. With the current Reliability Standards, an adequate analysis of the transmission system has been conducted and while still not meeting the energy requirements needed for the Reliable Operation of the bulk power system. Are the standards assuming that there is adequate situational awareness, and can maintain the energy supply? There is an 'energy' aspect of situational awareness that is missing from the current set of Reliability Standards. 7. Consider moving some elements of the NERC Reliability and Security guidelines into NERC's Reliability Standards. The comments and recommendations from the mid/long term planning sub team include the following observations: 1. The existing Reliability Standards do not explicitly require energy reliability assessments. In a new or revised standard consider the following attributes: a. Add requirement(s) for extreme weather or environmental events, including those that are widespread and long duration. b. Determine how much time is required to recover and prepare for the next stress event. c. Create an approach to support assessments of the impact of decarbonization goals. d. Consider the risk to gas supply disruption, such as natural gas being unavailable due to high demand. e. Ensure that there is adequate coordination between the operations and planning teams. f. When writing transmission planning studies, consider including other transmission equipment along with transformers. g. Studies need to account for additional characteristics, e.g. ramp rate, start/stop of units. h. Consideration is needed for 'dynamic load model' studies. 2. It was noted that the TPL standards are potentially the most appropriate location to add an energy assurance requirement, or create new class of Reliability Standards.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):

Requested information
It is not the intention of the ERATF to require solutions to the energy related issues being addressed. This SAR is intended to require study of energy related issues to clearly convey the risks related to operating the BES under conditions of the concurrent limited fuel supply and variable output resources.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
The BES facilities impacted by this proposed project will all have unique characteristics including fuel type, delivery, location (ability to access additional fuel, i.e. are road networks sufficient, rail line contingencies, barges for waterway-based plants, etc.), design, construction, time of year (season) and operational characteristics, etc. These unique characteristics need to be addressed during drafting to achieve the intended enhancements to reliability.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Planning Coordinator, Reliability Coordinator, Balancing Authority, Transmission Operator, and Generation Operator.
Do you know of any consensus building activities[7] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
On February X, 2022, the ERATF is sponsoring a workshop that outlines the challenges and works towards solutions in the Operational Planning and Operational time horizons.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
SAR 2021 10 06 Extreme Cold Weather Grid Operations, Preparedness, and Coordination; consider the impact to the TPL, EOP and TOP standards.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
There have been three Reliability Guidelines, however, in the past 10 years, there have been four cold weather events during the months of February 2011, January 2014, January 2018, and February 2021. The numerous events illustrate that the guidelines are not as widely adopted as necessary to prevent reoccurrence. Reliability and Security Guidelines (nerc.com) ▪ Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis ▪ Reliability Guideline: Generating Unit Winter Weather Readiness ▪ Reliability Guideline: Gas and Electrical Operational Coordination Considerations

[7] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☒	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g., NPCC	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Technical Justification

Updated November 30, 2021

Introduction

The Energy Reliability Assessment Task Force (ERATF) was formed to assess risks associated with unassured energy supplies. The task force was created to provide a formal process to analyze and collaborate with stakeholders to address the issues identified in the *Ensuring Energy Adequacy with Energy-Constrained Resources*[1] whitepaper. This whitepaper identified energy sufficiency concerns related to operations, operations planning, and mid- to long-term planning time frames.

Based on the eleven questions formulated in the whitepaper, the task force created a survey questionnaire. The survey was distributed it to subgroups of the Reliability and Security Technical Committee (RSTC) and independent system operators (ISO)/regional transmission organizations to gather feedback on energy assurance for three focus areas: Energy adequacy and flexibility for evolving resource mix, natural gas delivery assurance as well as metrics, procedures, and analysis. The goal of the survey was to better understand how stakeholders are evaluating their energy constraint issues and fuel availability issues by extension. The original 11 questions from the whitepaper were modified slightly to seek out answers to more specific questions that would inform the ERATF's recommendations. For example, sub questions were added to understand how specific assessment input assumptions were developed and how the impact of varying those assumptions was assessed.

The survey questionnaire had 18 core questions, and 12 responses were received from NERC stakeholder groups, ISOs, and individual utilities. These responses provided a large amount of information (over 500 answers) to help evaluate the energy constraint issues (Appendix A of the whitepaper).

NERC ERATF Energy Assessment Survey

In September 2021, the NERC ERATF formed a subgroup of volunteers to review all the survey responses and identify recommendations. The rigor and thoroughness of the responses was excellent, and it is clear that entities put a lot of work into their responses. On October 18, this subgroup presented high-level summaries of the responses to the 18 core questions and higher-level, generalized responses as described in the following:

- Across many of the responses, it was not always clear if entities were addressing current practices for capacity assessments or energy assessments. Many entities responded that they modify capacity assessments with higher forced outage rates and extreme scenarios to develop to assess evaluate a range of operating conditions, but these are not well defined and perform inconsistently across industry based on the responses energy assessments.
- The survey demonstrated differences in how energy assessments are performed in the three time frames (operations, operational planning, and mid/long term planning).

[1] Energy Assurance White Paper (nerc.com)

- It was unclear what operating entities do with low likelihood, high impact energy assessment results. Some provide the results publically to stakeholders for awareness, yet most do not. For predicted energy deficiencies in the operational planning time frame of one to three days, almost all entities do schedule additional capacity. Most do not provide energy assessments reflective of low likelihood, high impact events in seasonal assessments. Some respondents mentioned review of extreme contingencies in the longer-term planning time frame, yet it is unclear if any planning actions are taken:
  - Most of the responses were focused on extreme weather scenarios. Very few comments on the evaluation criteria included other potential failure modes, including cyber attacks or other disruptions that could impact energy assurance, specifically cyber attacks that impact the fuel supply chain.
  - Many entities use 30 years of history to develop planning forecasts, but others responded that *"…the world climate and social policies (heating & transportation electrification) are changing fast…"* and that entities should focus and forecast the future based predicted future events more so than history, including worse case extreme weather.
- Many responded that developing forecasts and assumptions for the mid- and long-term assessments is very difficult, and it is challenging to assign levels of confidence in those forecasted assumptions. As an example, it is hard to forecast fuel replenishment or renewable production in the 6–12 month time frame and more challenging in the long-term planning time frame.
- Some entities responded that the worst conditions could be in the fall or spring seasons in the future with low renewable generation rather than heat wave peak conditions if those peak conditions also included high renewable generation.
- Some entities responded that there are regional differences that may result or define different energy assessment reliability issues. More specifically, some operating entities have wider ranges in peak loads for extreme temperatures, some have significant fuel risks, some have extreme storm risks, some have significant forest fire risks, and some have drought risks. The reliability implications can vary regionally, so risks can vary regionally. Most responded that it is important across all of the bulk electric system industry to *"…develop common and consistent energy assessment methods…"*
- A few responded on the need to assess sufficient energy flexibility, including dispatch energy, reserves, and regulation.
- Some offered that transitioning from capacity adequacy to energy assurance can initially be performed by considering more conservative assumptions with fuel, wind, and solar, modeling higher probabilities of derates and extreme weather, but more sophisticated techniques need to be developed.
- Some entities offered that, based on the February 2021 extreme cold weather events, it is clear that extreme peaks can be coincident with loss of fuel.
- Many respondents indicated that energy assessments should be performed throughout the year, not just during peak conditions, to capture the risk for fuel unavailability.

- Classic forced outage rate measurements, such as effective force outage rates demand metrics and unforced capacity constructs, are not great for assessing renewable energy assurance as they assume randomness for failures rather than coincidences. Many existing capacity valuation constructs, especially for longer term resource adequacy, do not value capacity that might support energy deficits that result from multiday loss of resources, such as loss of fuel for over a week, especially for common mode loss of regional fuel.
- Some entities offered that a significant issue in the planning horizon is assumptions regarding retirements of legacy fossil fuel resources with flexibility.
- Developing mid- to long-term assumptions is very important. For example, *"what to assume for non-ICAP imports"* or *"what to assume for fuel replenishment"* in seasonal time frames.
- Some use 90–10 for extreme scenario assessments; others do not.

NERC Reliability Standards Review

A set of sub-teams of the ERATF were formed to review the existing NERC Reliability Standards from the viewpoint of energy (required to make electricity) assurance and identify any gaps. The perspective of this review was addressing the assumption Reliability Standards may have that energy is always available. This assumption is now under review with the new resource mix and may not be always true without having performed an energy assessment and without monitoring the resources ability to deliver. One team reviewed the operations planning time frame, and a second team assessed at the mid- and long-term planning time frame.

The comments from the operations planning sub-team were the following observations:

- The existing Reliability Standards do not explicitly define or require energy assessments.
- A number of the Reliability Standards depend on resources to deliver energy to adhere to the requirements, such as operating within system operating limits and interconnection reliability operating limits, contingency reserves to regulate the system, and energy characteristics—like large ramps that may constrict or be limited by available energy. The timing of deploying energy resources to meet the demand is crucial.
- There is little understanding of critical infrastructure interdependencies and their potential impacts on power generation.
- Currently, there are insufficient tools to model and forecast wind, solar, etc., for energy assessments. Also mentioned was to consider power system modeling to create more accurate predictive tools and include dynamic modeling of the natural gas system.
- As the majority of fuel infrastructure exists beyond a single area, there is a need to understand and model the fuel infrastructure on a larger basis (i.e., effects from events outside of a specific area that can have impact on that area), so the impacts can be understood.
- Considering that NERC Reliability Standards that require the use of generation assume that fuel is available, situational awareness was mentioned. The emergency operations and transmission operations Reliability Standards and transmission operational requirements should require energy

assessments. With the current Reliability Standards, it can an adequate analysis of the transmission system has been conducted while still not meeting the energy requirements needed for the reliable operations of the bulk power system. Are the standards assuming that there is adequate situational awareness, and can maintain the energy supply? There is an energy aspect of situational awareness that is missing from the current set of Reliability Standards.

- Consider moving some elements of the NERC reliability and security guidelines[2] into NERC's Reliability Standards.

The comments and recommendations from the mid- to long-term planning sub-team include the following observations:

- The existing Reliability Standards do not explicitly require energy assessments. In a new or revised standard, consider the following attributes:
  - Add requirement(s) for extreme weather or environmental[3] events.
  - Determine how much time is required to recover and prepare for the next stress event.
  - Create an approach to support assessments of the impact of decarbonization goals.
  - Consider the risk to natural gas supply disruption, such as natural gas being unavailable due to high demand.
  - Ensure that there is adequate coordination between the operations and planning teams.
  - When writing transmission planning studies, consider including other transmission equipment along with transformers.
  - Studies need to account for additional characteristics (e.g., ramp rate, start/stop of units).
  - Consideration is needed for dynamic load model studies.
- It was noted that the Transmission Planning (TPL) Reliability Standards are potentially the most appropriate location to add an energy assurance requirement, or a new class of standards would need to be created.

Recommendations

Based on the review of the questionnaire and the NERC Reliability Standards gap review, sub-teams #1 and #2 are recommending that a standards authorization request be submitted. Energy assessments must be required within the NERC Reliability Standards that consider the following:

- Define terms e.g. energy reliability assessment, fuel, fuel assurance, etc.
- For energy reliability assessments, metrics and observations should be compared to targets or predefined criteria. Results should be in terms of the impact to the Bulk Power System.

[2] https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx
[3] Extreme environmental events includes long-duration environments, such as cloud cover, smoke, no wind, etc.

- Energy reliability assessments should be required to include the appropriate assumptions and scenarios that account for, but not limited to: time-coupled restrictions on the availability of fuel, the impact of energy storage and other flexible resources, the logistical constraints of the associated fuel delivery supply chains, common mode outages not connected to fuel supply, coincident outages of multiple independent resources, outage duration based on failure modes, and variable resources need to account to be included to account for their unique characteristics.
- Energy reliability assessments must be coordinated between areas to harmonize interchange assumptions.
- Wide-spread, long term, extreme event analysis needs to be defined and included in the assessments.
- Requirements for energy reliability assessment should include a clearly defined periodic basis and performed in each of the NERC defined planning time horizons, as well as the operations time horizon. Periodicity should include clauses for their re-performance and/or update of existing assessment when changes to assumptions and input data invalidates an existing assessment.

Appendix A
Questionnaire

Question 1: Stakeholders were asked if their definitions of time frames differ from the ones provided in the white paper, and the survey feedback several categories that are similar, but not identical to the three horizons described.

There are a variety of industry definitions and they are similar to the white paper definitions. Most stakeholders responded with the operations timeframe of 0 days to 3-7 days, many described rigorous energy adequacy assessments for the following 7 days, and most stakeholders responded with planning timeframes that are longer than 5 years. In addition, there are a large number of scenarios being evaluate in the mid-term assessments. There were no observed reliability gap as the result of the timeframe definitions.

The NERC glossary of terms defines the time frames. The NERC glossary definition of "Operational Planning Analysis" refers to the next day's operation and has been active since 4/1/2021. The NERC glossary definition of "Near-Term Transmission Planning Horizon" covers year 1 through 5 and has been active since 4/13/2013. The NERC glossary definition of "Long Term transmission Planning Horizon" covers six through ten or beyond years, and has been an active definition since 1/1/2015.

Question 2: Stakeholders were asked if their organization performs energy assessments that include requirements considered to be within the existing NERC Standards or any other requirements such as regional entity criteria (allocating contingency reserves, TPL & FAC criteria contingencies, etc.). In addition, stakeholders were asked about the frequency that these energy assessments are performed, such as annual, seasonal, monthly, weekly, and/or daily. Stakeholders were also asked if they performed energy assessments that exceed NERC Standard requirements, such as fuel supply chain disruption analysis. They were also asked about the precise additional contingencies considered in the energy assessments.

A variety of responses were reviewed, and not many of the responses were a complete energy analysis. Some stakeholders did describe some elements of an energy analysis, and the words "energy analysis" were used, however, there is no consistent definition of the term and no consistency between the studies. Some stakeholders consider that a series of capacity analyses is the same as an energy analysis. We can consider defining the term 'energy analysis' and contrast it with a 'capacity analysis'. There is a need include the changing resource mix in planning for the future and having a formal process on conducting energy assessments.

Question 3: Stakeholders were asked detailed questions on the parameters that are incorporated into the energy assessments. If they are not currently performing energy assessments, then the questions covered how the parameters should be incorporated within an energy assessment, and if additional parameters and data should be or are being considered. The parameters that were covered were as follows: load, distributed energy resources, demand response, storage (batteries and pump hydro), hybrid power plants (e.g. batteries and solar, batteries and CTs), gas availability (e.g. fuel contracts, storage availability), fuel storage and replenishment limitations, transfer capability, generator (resource) outages, flexibility of resources (ability to cycle), ramping requirements to balance intermittent resources and load uncertainty, performance of resources (such as higher forced outage rates due to increased ramping and cycling, trading off flexibility for performance), intermittency or variability of resources, emissions constraints (machine specific and/or pooled allowances), common failure modes leading to multiple resource losses, correlated risk of failures or limited operation of resources and load uncertainty, duration of energy scarcity events (e.g., sufficient energy from storage, DR, stored fuels, hydro reservoir capacity).

A detailed list of 17 parameters described the depth of the analysis that is needed to highlight the complexities of understanding the plethora of scenarios that planners are facing. The technical descriptions for each for different timeframes indicate that transmission operators have given this a lot of thought. Most of these variables are well understood and considered in energy adequacy assessments. In addition, acknowledgement is made where improvements are currently needed for eventually needed. Evaluations of techniques for considering variables: for some variables, incorporate reflecting upon historic performance; for peak loads, provide 90-10 for awareness (but not necessarily scheduled additional capacity); program terms; for some like storage & hybrid forecasts assume optimization; gas availability, fuel storage, flexibly, and ramping are incorporated but fuel replenishment is very difficult to predict; many state more work is needed to incorporate common mode failure in energy assessments; emissions usually are not well known by transmission operators especially beyond 2-3 days. The comments also noted that variables behind-the-meter are less understood, and most are not forecasting or assessing flexibility in mid and long term time horizons.

Question 4: For the items above (in question #3a-q), stakeholders were asked is they noticed any variations or uncertainty when studying each individual item and related items in combination, such as extreme natural events: cold weather, hot weather, wildfires, hurricanes, wind/solar droughts, etc.

The responds included a variety of comments: some indicated "risk scenarios only for hours with greatest risks. In 1-3 day time horizon, many are primarily focused on load & wind uncertainty and other variables are only assed based on forecast conditions especially extreme weather. For some, extreme scenarios not considered in seasonal assessments. In the operations timeframe, extreme cold and heat only assessed based on weather forecasts; and cold weather assessments includes gas availability for some operators. Some seasonal assessments look at extreme cold weather, high winter peaks, reduced fuel, and increased generator outages. For others with large wind portfolios, evaluate loss cold weather wind. For longer term planning, probabilities are used in LOLE Resource Adequacy and extreme scenarios, multiple load forecasts, drought conditions. For mid-range planning, most utilize 50-50 and 90-10 peak loads for assessments. In the immediate term, assessments become more certain (yet more important).

Question 5: Stakeholders were asked if extreme natural event scenarios are included in their energy assessments. They were asked about how the scenarios are developed and what data is utilized (such as historic weather data, probabilistic analysis based on modeling of future weather events). For the energy adequacy assessments, they were also asked about how the interdependencies of the extreme events are taken into account based on the various resource types (wind, solar, natural gas, etc.).

Answers included discussing using known prior events and using weather data to model future events. Extreme event interdependencies are not evaluated. Cold weather, heat waves, wind/solar droughts, are considered in the assessments. For the planning answers, some looked at range of third quartile to 97th percentile for load for solar, wind, hydro, and base load generation. Some look at 99% for load in the seasonal range. Some "waterfall" charts are combined with the effects of extreme demand. Multiple low resources are used to provide deterministic "bookend" without proxy resource additions. Some with large hydro portfolios utilize deterministic extreme drought assumptions in the planning horizon. Many in planning have probabilities for extreme loads associated with extreme weather, both hot and cold. Some under TPL-001 extreme weather scenarios' include increased contingencies within several miles of ocean shore. Some use rolling forward five year capacity assessments. Some look at historical fuel performance from the past extreme weather events. For seasonal resource adequacy assessments, some consider 90/95/95+ and max thermal outages from the worse 10 yr. history. Some do not consider wild fires, droughts, or hurricanes; some stated will begin considering extreme natural events going forward. Some stated using historical data captures interdependencies if time sequenced. Some incorporate extreme natural events after they occur using historic outages for evaluating future events. For midterm planning, some develop an extreme scenario assuming worse case extreme peak load with worse case wind, solar, significant reduced hydro, and thermal unit ambient derates. For the operations timeframe, many input forecasted extreme conditions in day ahead operating plan, and this may require additional out-market commitments. Unfortunately, midterm assessments are more difficult because the number of possible extreme scenarios evaluated increases resulting in reporting of energy deficiencies.

Question 6: Stakeholders were asked about the key metrics that are used from the energy analyses that are being done, and if they are using a pass/fail criteria that requires action as a result?

Regarding the key metrics, most offered "meeting operating reserve requirement", some offered "communicate with stakeholders if deficient energy metric for extreme scenarios", a few operators mentioned flexibility and ramping as key metric. The planning key metric is LOLE 1 day in ten years and incorporated in minimum installed reserve margins (year ahead and long term planning). But a few offered classic LOLE is still a capacity planning metric, not an energy adequacy metric. For fuel consumption assessments some evaluate "fuel depleted" metrics along with reserve and energy metrics. This is a concern on the renewable integration and how it impacts key metrics, renewables studies over range of historic conditions. For many planning deliverability is considered a pass-fail metric. Some in the planning timeframe monitor fuel metric by running LOLE with worse increased generator outage, and some consider that for the operations timeframe, all output from secure day ahead commitment are key metrics (reserves, energy, transmission, ramp). In addition, negative seasonal margins result in changes to scheduled generator outages, and some commitment generations with long lead times (+48 hours) if 3-day metrics indicate reserve shortages.

Question 7: Stakeholders were asked if the metrics that are being used in energy analyses are adequate to quantify the risks caused by inadequate energy, and if any additional metrics or modifications to existing metrics should be considered as part of an energy analysis. They were also asked if there needs to be common practices for how resource margins are determined for the metrics to be comparable.

Some responded “yes” and some responded “no”. One “no” indicated that their current capacity constructs completely ignores limited capacity in longer term assessments. Risks causing inadequate energy resulting in economic loss is not quantified by operators, and many offered additional metrics under discussion like capacity accreditation, ELCC, (long list). Some greatly support the work of the PAWG activities to consider a much wider range of planning resource adequacy metrics reflective of energy assurance. Some offered understanding risk levels and certainty of assumptions is bigger challenging than metric definition, and some offered opportunities to improve compensation commensurate for service of reliability services offered. There is a possible opportunity to enhance the evaluation of winter & summer load assessments reflective of actual winter and summer generation performance (enhance winter and summer UCAP & EFORd constructs)

Question 8: Stakeholders were asked about the current tools that are used to assess energy adequacy, and if these tools are commercially available, developed internally, or developed in collaboration with research or commercial entities.

Several tools were described for all 3 timeframes, such as Gridview, PSS/E, PROMOD, and GE MARs. There are a lot of internal tools.

Question 9: Stakeholders were asked about the limitations of current tools in assessing energy adequacy?

Limitations were numerous, such as the following list: adaptability to changing conditions, changing resource technologies, and capabilities; tool limitation less challenging than confidence in long term assumptions and valuing risks. For planning, the tools are limited by granularity and interdependency modeling going forward. For some, in the operation and mid timeframes the tools assume limited fixed dispatch assumptions and limited in modeling all constraints. Some offered despite LOLE assessments being highly sophisticated, there are still limitations in the energy adequacy aspect of LOLE. It is difficult to standardize tools for all areas based on regional differences in the challenges, and a limitation is properly characterizing probability of outlier (high impact, low probability event). Beyond 24 hours, tools scheduling energy limited resources usually not optimized. There are a wide range of modeling attributes: AC vs DC, hourly vs multi-year, deterministic vs probability, full line-on-line transmission vs bubble models, generator operational constraints, fuel-wind-solar-storage variances between models. It is important to increase subject matter staffing.

Question 10: Stakeholders were asked if all energy resources' or combination of resource's contributions and constraints to supporting energy adequacy are accurately included in current tools and assessment methods. In addition, they were asked about which resources need better representation of their impacts on energy adequacy.

No, all energy resources’ or combination of resource’s are not included. Some stated lacking adaptability and granularity; many offered there are still opportunities to use actual historical data to enhance models especially energy storage modeling and physical characteristics. What is missing are the new technologies: DG, DER integrated in wholesale markets, DR, micro grids, advanced nuclear, hydrogen turbines, and there are opportunities to enhanced fuel procurement. There are opportunity to enhance common mode loss of energy like coincident loss of wind and solar. Also loss of wind at extreme cold temperatures. A lot of work still needed to better model real wind and solar profiles. Off shore wind will be very “new”. Behavior and characteristics of all behind meter resources is not modeled, and for some, enhanced import modeling will be needed (mid & planning). There appears to be a battle of highest marginal price.

Question 11: Stakeholders were asked if any additional types of tools are needed to better evaluate energy adequacy.

Most of the responses indicated that, in general, commercially available tools are sufficient. Some indicated that more sophisticated tools are needed, tools that are robust in solving models, versatile in the use of constraints, and simple enough to use. The main issue is the complexity and work load associated with developing the data sets. Streamlining the overall process would be helpful.

Question 12: Stakeholders were asked about the work that is currently outlined in the work plan for their working group/task force to address/evaluate the topics in this questionnaire.

Several efforts are outlined, including company specific, regional and NERC committees, sub-committees and working groups.

Question 13: Stakeholders were asked if the current limitations of assessment tools are fixed, are there any energy adequacy risks that are not understood sufficiently to evaluate and require more research accurately evaluate and set metrics.

Yes, other areas not understood are that market implications is challenging, understanding customer choice is challenging, the challenge remains with certainty on longer term assumptions and balance of costs to mitigate low probability, high impact risks. Most responded, “no” and “very little” to the question. The real limitation is “…challenge is the unknown factors and risks associated with the unknown…” As all assessment tool limitations are fixed, with future experience undoubtable new assessment tool limitations will be identified and hopefully the tools will be continuously be enhanced.

Question 14: Stakeholders were asked if there any other relevant considerations from their subgroups work which haven't been mentioned in this questionnaire.

Many answered “No” to this question and indicated that Q1-Q13 cover the significant issues. NERC EGWG contributed significant to the white paper questions Q1-Q13. Some expect there will be in the future as the electric system evolves. One entity offered, “…supply deliverability of inverter-based resources should/is being considered for investigation as part of resource adequacy analysis…”

Question 15: Stakeholders were asked about how emergency procedures should be revised to reflect current (generating resource) fleet structure and operating needs?

Emergency procedures typically reflect upon lessons learned. For predicted limited energy situations, procedures should act to conserve total energy prior to expected deficiency. Some reported no need to enhance current emergency procedures. Current operating procedures have a lot of authority and latitude. The biggest thing is additional commitment of capacity, more energy, and flexibility. Those authorities currently exist in emergency procedures. At least one offered opportunities to enhance communications going into extremely tight conditions and during load shedding.

Question 16: Stakeholders were asked if their emergency procedures or remedial actions during energy adequacy events should be revised to ensure service or minimize risk to loads critical to electric system operation (e.g., gas pipeline compressors, DER locations) and end-user safety (e.g. hospitals, water pumps)?

Exact load shed “switches” in many cases are not operated by transmission owners, there are opportunities for review and improvement. Some recommended surveys of manual, automatic, and critical loads. One stated during testing of emergency procedures, there is a review of load characteristics as part of load shed test. It is crucial that transmission owners and distribution owners are aware of critical loads essential for gas infrastructure operations along with awareness of such in demand response programs.

Question 17: Stakeholders were asked if there needs to be common planning practices for how forced outages are incorporated into resource adequacy analysis.

Some stakeholders said ‘yes’, some said ‘no’, and some said ‘it depends’. A set of recommended approaches for representing forced outages in resource adequacy analysis would be helpful. The team can get together to see if there is a useful statistical model for forecasting forced outage levels based on weather inputs.

Question 18: Stakeholders were asked if strategically overbuilding a similar technology (i.e. solar) augmented by either storage or some portion of the firm capacity fleet (albeit operating at low capacity factors only when needed) could provide for a resilient and reliable transition.

Most stakeholders said that overbuilding is a good idea, however, it needs to be balanced with affordability. Some said that further analysis is required.

Question IRP - 1: Stakeholders were asked about the key attributes of inverter-based resources which should be considered in planning for energy adequacy.

Different technologies (wind, solar, storage) have different operating performance characteristics, and are impacted by weather and location, ‘fuel availability’ is a main consideration.

Question IRP - 2: Stakeholders were asked about work that has been done/is planned to assess the uncertainty around those different attributes which could be used in assessing energy adequacy. An example would include development of extreme scenarios.

Assessment are being conducted by some stakeholders, and several did not answer the question.

Question EGWG - 1: Stakeholders were asked how additional long-range contracts would or provisions for locally stored fuel change the outcome of an energy analysis.

Some stakeholders said that long range contracts are considered by many, but have been determined to not be something that generators would be willing to invest in with no return on that investment. Some stakeholders said it would not impact their analysis.

Question EGWG - 2: Stakeholders were asked about the level of detail that energy analyses are performed in regards to modeling of gas pipeline disruptions; and how precise are the gas outages reflected in generator outages; and what tools and data are currently used to include gas system risk and constraints in electric energy assessment.

Minimal or zero level of detail on modeling gas pipeline disruptions in energy analysis, most stakeholders do not have a way to evaluate gas pipeline disruptions.

Question EGWG - 3: Stakeholders were asked about the limitations of the current tools and data that include gas system risk and constraints in electric energy assessment.

Almost no information about the gas system is used, as far as limitations (other than assumptions) there is not a simple way to consider ideas like the deliverability of gas for assessments. If there is information, it is delivered without sufficient notice.

Question EGWG - 4: Stakeholders were asked if they can think of additional types of tools that are needed to better evaluate the gas system's impacts and constraints on energy adequacy.

Further coordination/integration of gas system and electric system market models, or using probabilistic evaluations' of gas disruptions.

Question EGWG - 5: Stakeholders were about the data or attributes of the gas system that should be included in energy assessment models; and if electric energy risk assessments in planning and operations require dynamic gas system models (e.g. gas flows and pipeline pressure) and data monitoring in electric co-simulation.

Locations of Compressor stations, pumping stations, storage facilities; status of contractual arrangements for pipeline transportation and supply (how firm is the gas?); historic outage and planned maintenance information, including laterals that feed generators data could be helpful.