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Managing the New Grid

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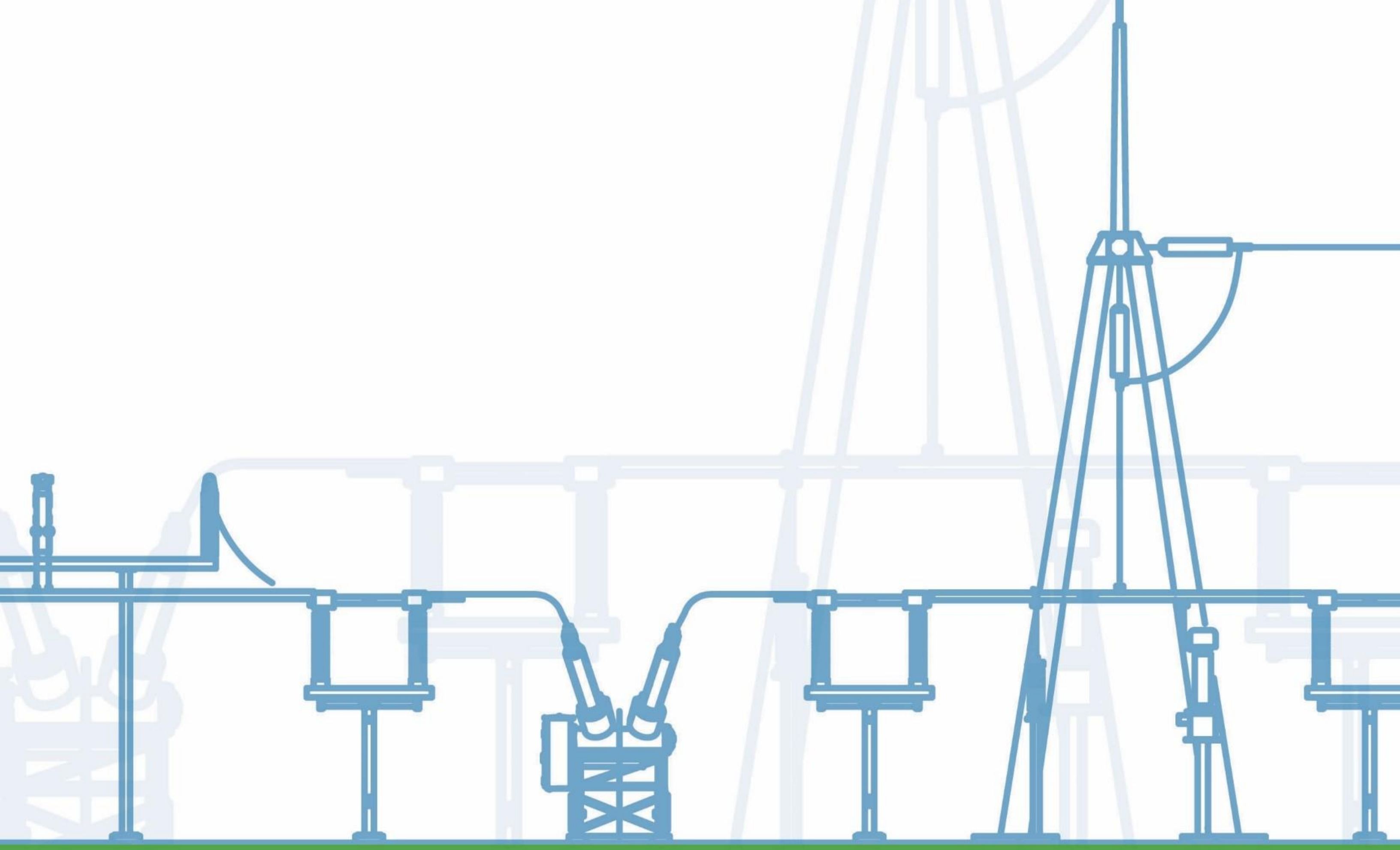

IEEE PES INDUSTRY TECHNICAL SUPPORT TASK FORCE

Prepared for
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FERC 2018 Reliability Technical Conference
Docket No. AD18-11-000

MANAGING THE NEW GRID

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Introduction

The Institute of Electrical and Electronics Engineers (IEEE) is the world's largest professional organization dedicated to advancing technology for the benefit of humanity. IEEE and its members inspire a global community to innovate for a better tomorrow through its more than 420,000 members in over 160 countries, and its highly cited publications, conferences, technology standards, and professional and educational activities. IEEE is the trusted “voice” for engineering, computing, and technology information around the globe.

The purpose of this brief written testimony is to provide an IEEE viewpoint in response to the FERC 2018 Reliability Technical Conference (Docket No. AD18-11-000). IEEE representative, Damir Novosel, will be on the Panel III, Managing the New Grid. This panel will explore Power System Planning and Operations challenges and opportunities as a result of the changes in the generating resource mix, taking into account steps NERC, the Regional Entities, industry, and the Commission have taken. These steps include assessing the impacts of power plant retirements and the increasing dependence of the grid on natural gas, solar, and wind power.

With timeliness as the main goal, these remarks have been put together using contributions by the IEEE Power & Energy Society Industry Technical Support Task Force members. The diversity of the IEEE membership across private and public sectors provides a balanced, unbiased and independent viewpoint.

a. **Discuss the trends in Essential Reliability Services (ERS) – frequency response, ramping and voltage support – in each of the three U.S. interconnections. Discuss observed trends and likely future challenges to ensuring the availability of ERS moving forward. Are ERS adequately quantified to augment existing measures of reliability such as reserve margin? Is there an opportunity to further refine ERS so they can be used to develop and deploy solutions to the specific challenges facing the grid?**

- Generation trends:
  - Eastern-Interconnection: “Gas is dominant”. Increase in gas generation (retirement of coal and nuclear); slowly increasing renewables.
  - ERCOT: “Wind is dominant”. Highly localized in Panhandle. Challenges caused by lack of “system strength”.
  - California: “Solar is dominant” – The net generation and power demand seen by utilities typically resembles that of duck body profile during the day and hence the nickname “the duck curve” by CAISO. The duck curve shows steep ramping needs for utilities when sun sets and potential overproduction risk during the day when the sun shines.
  - So far, all the interconnections have seen imminent risks associated with these trends, primarily due to the oversupply situation in most states.
- ERS is supplement to a reserve margin requirement for grid reliability. It has been provided by conventional generation technologies when the grid has adequate resource supplies. With the transition in technology, ERS are used-and-useful, but there are opportunities to explicit recognize their attributes (especially to account for resilience).
- Integrating resilience into planning process is an emerging challenge, while the industry stakeholders and academia are working toward technical definition and resilience measurement matrices. Resilience consideration is largely ignored in the planning process. The FERC Order 1000 Competitive framework should identify resiliency considerations and identify resiliency requirements to implement mitigation measures.
- The 2018 version of the IEEE 1547 defines the frequency response, ramping and voltage support capabilities for the DERs connected to the distribution system
  - While the DER is a source of the needs for ERS, proper controls and inverter technology of the DERs will be able to support ERS in BPS with mandated frequency response and ramp rate capability and performance under corresponding categories.
  - Voltage support capability of DER capability is mandated by IEEE1547-2018 but performance parameters and enabling this function will be at Utility’s discretion.
- There is recognition that the Grid needs to be modernized to address the challenges: automation, monitoring, protection, and control HW and SW tools and systems; telecommunication infrastructure; power electronics; storage; new materials; etc., to support the needs of ERS while the conventional generation is phasing out. There still exists significant opportunities to continue to invest in modernizing the electric grid to keep up with the new and changing dynamic nature of the DER and the resulting changes in resource mix. Having a consistent regulatory framework that support these investments at both the Federal and local state level is an important policy step to support these changes.

b. What actions could be taken to ensure that sufficient ERS are available as the resource mix continues to evolve? Are there specific benefits or risks posed by variable energy resources and distributed energy resources? What potential roles can customers play? Is there a need to better quantify ERS so they can be provided through a market mechanism rather than a Reliability Standard?

- The rapid renewable penetration driven by public policies (e.g. California) and increased reliance on presently less expensive natural gas (e.g. Eastern Interconnection) provide significant opportunities, but also risks. Extreme care must be taken so that the adoption of new type of generation does not undermine the reliability and resilience of the electric grid.
- Natural gas generation is negatively impacted by delivery challenges during high demand caused by inadequate infrastructure and contractual agreements that prioritize residential customers (i.e. winter heating needs) over electric generators.
  - Only short term market mechanisms have been explored in the marketplace
  - A long-term solution need to be investigated to address the fuel delivery vulnerability
- For a foreseeable future, large scale introduction of intermittent renewable resources and DERs requires conventional fuel secure resources and market mechanism to incentivize storage to provide the ERS.
- The risk of fuel unavailability, interruption, and disruption is not recognized in the assessment for transmission security and the ERS for the grid. This assessment does not differentiate between fuel-secure (security?) and just-in-time fuel supplies and fuel unavailability during extreme events is not addressed. In December 2017, New England continued to operate only because oil fired generation facilities existed and could be ramped up from their typical less than 1% of generation to more than 40% of generation in the region. When they are removed, this option will not exist and a new set of options will have to be developed.
- Much like a diversified stock portfolio, a diverse generating mix can help protect against price spikes and volatility associated with an overreliance on any individual fuel source at any given time. A diversified energy mix includes all generating sources – natural gas, clean coal, nuclear, hydro, and renewable resources, as well as storage.
- There is the critical link between energy security, energy independence, grid resilience, and ultimately, national security. As malicious man-made attacks designed to inflict maximum disruption to electric grid operations become a growing concern, a diverse electricity generating mix is better able to absorb, withstand, and recover from an attack on a single fuel supply.
- In conclusion, adequate mix of fuel secure and fuel independent technologies is key to maintain sufficient ERS to withstand primary fuel (water, solar, wind, natural gas, etc.) disruptions, price volatility, and nature and man-made disturbances on the electric grid. For that reason, conventional generating resources are expected to remain critical for system reliability for the foreseeable future.
- Quantifying the value ERS in a technology neutral manner (not only for conventional generation but for Inverter Based Resources (IBR)) would be beneficial to improve reliability and resilience. For example, IBR can provide reserve margins if the ERS is properly addressed and recognized in by the system operators and in the marketplace. Market mechanisms would require proper reliability standards to price the ERS services provided by all technologies.

- Demand response to alter electric load shapes has been in broad use for decades and its strengths and weaknesses are well known. The best candidates for demand response are commercial/industrial customers. Numerous residential demand response programs are in operation as well, but are more difficult to implement to contribute to ERS. While the impacts of load shifting programs are fairly predictable, multi-day forecasts for interruptible/curtailable programs may be more difficult to provide with adequate certainty. With advances in communications and control technology such forecasts will become simpler to accomplish. The aggregators could then be asked for a forecast, or at least a model forecast, of what demand response resources would be available at any given time. In the meantime, ERS applications of demand response should focus on commercial/industrial loads.
- With potential gas interruptions, one of the ERS options to consider is an analogous program aimed at natural gas loads - natural gas demand response. In fact, many natural gas distribution/retail companies already offer interruptible service for business customers and, in some cases, also multi-family residential customers.[1] Gas demand response could be at least an interim option until the requisite gas pipelines and storage are built.

c. What lessons can be drawn and what measures should the Commission and NERC take from the August 2016 Blue Cut Fire and October 2017 Canyon Fire events regarding the risks of inverter-connected and non-synchronous technologies for both reliability and resilience? Are there potential benefits of such technologies that can be applied to improve system performance?

- Suboptimal Inverter Based Resources (IBR) integration can trigger hidden costs and operational risks, as shown during the mentioned 2016 and 2017 events
  - A significant lesson learned is that these issues can arise from inverter setting and/or how the inverter calculates voltages (e.g. RMS vs. Peak) and frequency. Inverters from some manufacturers are unable to accurately calculate instantaneous frequency during power system disturbances.
  - Some inverter protection settings of large PV plants were set to meet the current IEEE 1547 ride through performance requirements. The standard at the time of the installation was meant for plants less than 10 MVA.
  - A momentary overvoltage occurred during one disturbance and caused the loss of generation from an entire plant instead of just one cluster of PV arrays.
  - Many inverters appear to be set to temporarily shut down if voltage exceeds the normal operating range of 0.90 to 1.10 per unit. These inverters remain offline until voltage returns within the normal operating range.

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[1] Examples include Southern Connecticut Gas Company (https://www.soconngas.com/wps/portal/scg/home/search/!ut/p/z1/dz/d5/L2dBISEvZ0FBIS9nQSEh/?sourceContentNode=Z6_31MEH4C0NOI250AFENPLM90KI0&search_query=Interruptible%20Service&y=8&x=5); Washington Gas (https://www.washingtongas.com/my-account/account-services-support/current-rates/virginia-tariff-info, as well as other states they serve); Excel Energy (https://www.xcelenergy.com/staticfiles/xe-responsive/Programs%20and%20Rebates/Business/MN-WI-Interruptible-Gas-Info-Sheet.pdf); Colorado Springs Utilities (https://www.csu.org/CSUDocuments/tariffgas.pdf); Puget Sound Energy (https://pse.com/aboutpse/Rates/Documents/gas_sch_086.pdf); and many others.

- The Inverter-based resources have very different response characteristics than the traditional rotating machinery and these new response characteristics should be incorporated into the ride-through capabilities.
- NERC PRC-024-2 standard currently allows inverters to instantaneously trip if the system conditions are outside of a defined set of boundaries. This is an area that should be reevaluated as the existing PRC-024-2 standard was created in the context of the traditional rotating machinery. One simple fix is to consider a 6 cycle delay (100 ms) rather than an instantaneous trip.
- To protect the inverters, a "momentary cessation" mode is used during system disturbances. In this mode, solar plants are technically still connected to the system and have not tripped (as required by NERC reliability standards) but they do not inject amps into the system during and immediately after the fault to support frequency, voltage or short circuit duty.
- The new IEEE 1547 ride through and mandatory operation requirements should be sufficient to avoid tripping large amount of DERs trip due to disturbances like the Blue Cut Fire and Canyon Fire events. This assumes that the voltage and frequency measurements are done properly.
- It is recommended that NERC mandates the IEEE 1547 ride through requirements to the bulk system DER interconnections as well.
- Integrating IBRs will improve system reliability/performance designed and managed properly from the system perspective. One example is reserving active power headroom for operating reserve margin. This is essentially more a market mechanism challenge, rather than a technical obstacle.
- In summary, Inverter Based Resources (IBRs) bring in new features and operational challenges in power grid's planning, operation and control. Three technical domains would have immediate reliability impact on Bulk Power Systems (BPS), including Voltage/Reactive Power support, frequency response and control, and power system protection coordination with low fault current. IEEE report to NERC identifies solutions to these potential conditions such that when they are encountered by the electric utility industry in the future, utility engineers will have the tools and capabilities to address these issues reliably. [2]

[2] "Impact of Inverter Based Generation on Bulk Power System Dynamics and Short-Circuit Performance," IEEE PES Task Force Report, July 2018: http://resourcecenter.ieee-pes.org/pes/product/technical-publications/PES_TR_7-18_0068.

d. How is industry preparing for the changing demands on the Bulk-Power System in light of the growth of distributed energy resources (DER) and storage? How can these, and other supporting, technologies be deployed to improve reliability and resilience? Are changes to the NERC Reliability Standards necessary to continue to protect the reliability of the Bulk Power System?

- Despite the increase of DER, the transmission and energy storage systems (ESS) will play a critical role as part of the overall delivery system because these DERs are not located near the load centers.
- There is a need to better understand and model the dynamic behaviors of the inverter based resources. Current interconnection or reliability studies do not show this behavior.
- Per the recent NERC alert, solar plant owners that dropped out during the southern California events are required to provide the transmission operator with dynamic model updates by end of July. This will allow the benchmark of the models against actual events to validate accuracy, and then to test the transmission system with more severe disturbances to determine if the grid is stable today. As the industry continue to take on greater DERs, this dynamic system performance analysis will need to a part of the review and interconnection process in the future.
- There should be a new NERC standard to clarify and expand current reliability requirements for inverter based resources to support the grid during system disturbances. As emphasized before, those standards are required to price the ERS services provided.
- Given the advanced in new technology such as ESS and the associated control systems and advances in the inverter-based control technology, there is a great opportunity to increase the application of energy storage as part of the overall portfolio of solutions to: mitigate renewable DER variability and power quality issues, address the transmission congestion and other issues, and improve T&D utilization and economics.
  - Technical, regulatory and economic barriers still impede its adoption even in states with aggressive programs for deployment. It is widely understood that "shared applications" - multiple use of the same energy storage device - is a key to realizing the best economic potential from the technology. Regulatory paradigms should enable rapid adoption of these technologies and their most effective uses. Energy storage fits into the generation, transmission, distribution or customer "buckets" and should not be forced to follow rules established for just one asset class. Energy storage is in many viewpoints a new asset class of its own.
  - As energy storage is becoming more cost effective and a viable non-wire solutions, it is becoming more and more important to develop procedures and tools to optimize siting and sizing of BESS, as well as perform accurate benefit cost analysis, including storage lifecycle economics and market participation benefits. Time-series power flow simulations are required for accurate evaluation.
- Electric transportation holds significant promise for reducing dependence on oil and carbon footprint. Furthermore, electrical systems can help improve the livability, workability and sustainability of "Smart Cities", including electrical transportation.

e. As non-traditional sources of generation are added to the Bulk-Power System and the distribution system, what real-time data and EMS applications, or changes to Reliability Standards, would promote better grid operations, and improve reliability and resilience? What operating and planning adaptations can be considered best practices?

- Energy Management Systems (EMS) and their corresponding Supervisory Control and Data Acquisition (SCADA) that are used on the U.S. Bulk Power System (BPS) must have standards to comply with laws, regulations and operating practices that are in place. A fundamental underpinning is that an EMS/SCADA has monitoring and control of key electric system components so that the operating states of transmission lines, substations and generation can be directly known and managed. Rules are in place for the monitoring and control that must be implemented for any type of generation attached to the BPS, including Wind and Solar. Thus a well-managed EMS/SCADA operating on the BPS is largely a deterministic system with a low and manageable level of randomness. It is critical that existing rules be maintained, and enhanced where needed, for generation that is attached to the BPS.
- The situation is very different for the non-BPS electric grid. There is continued growth in the quantity and aggregate capacity of individual Wind and Solar devices attached to utility distribution systems. Local laws and guidelines generally do not require that the utility be provided with monitoring and control for each device. Many utilities have SCADA implemented on the distribution system that can provide deterministic results; however, the inability to monitor and control individual generating devices (solar and wind) is resulting in distribution operations that are increasingly probabilistic in areas with high penetration of these devices. Development of new, probability-based tools will be required through close work and partnerships with the utility industry, vendors, R&D organizations and government.
- With high penetration DERs, the traditional EMS applications at control center will require adequate observability/visibility for generation resources which are normally not directly presented in today's operation model or behind the equivalent load zones. Under the interoperability requirement, EMS shall be able to monitor DERs, which are in the categories with reliability impact as they do today for traditional generations, through/from DER aggregator/DER facilities. Furthermore, EMS application will also need to examine power system model to include applicable distribution network, which the DERs interconnects, a task which could require extensive model and SCADA infrastructure enhancement.
- In addition to the above, T&D systems are experiencing faster dynamic changes. Deploying GPS-based synchrophasor technology[3] enables improved visibility as it records voltage and current at high rates of 30 to 120 times per second (much faster than existing SCADA systems) and can very accurately compute and time-synchronize parameters such as phase angle and frequency across the grid, as well as power quality parameters. Tools using synchronized measurements have been implemented globally to improve the reliability, performance, and security of power systems. In addition to wide-area monitoring, protection and control, their use is expanding to distribution system applications, such as state estimation with DERs, intentional islanding, and emergency response during natural disasters.[4]

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[3] D. Novosel, V. Madani, B. Bhargava, K. Vu, and J. Cole, "Dawn of the Grid Synchronization," IEEE Power and Energy Magazine, Vol. 6, pp. 49-60, January/February 2008.

[4] www.naspi.org/sites/default/files/reference_documents/naspi_distt_synchrophasor_monitoring_distribution_20180109.pdf.

- BPS Planning and Ops processes will be able to identify DER's reliability impact from its interconnection request, through implementation and commissioning, and into normal operation. It is foreseeable that DERs' reliability impact could be locational-based and operational condition based. The intermittency nature of renewable DERs will also centered in this reliability matrix. For example, PJM and CAISO have integrated distributed solar into the long term load forecast. PJM also has a real-time wind and solar forecast, and DR/DER have been integrated into Post Contingency Local Load Relief Warning (PCLLRW) procedures.
- To better address resource adequacy and performance, it is recommended[5] to expand the use of probabilistic approaches to develop resource adequacy measures that reflect variability and overall reliability characteristics of the resources and composite loads, including non-peak system conditions, and improve load forecasting that takes into account behind-the-meter resources, generator modeling, and coordination between BPS and distribution system planners and operators by analyzing data requirements necessary to ensure there is sufficient detail on the capability and performance of the BPS as it is impacted by DER.
- Distribution Management System (DMS) and DER Management System (DERMS) will address operation and dispatch control issues where DER interconnects, and provide reliability operation data support to BPS' EMS. DMS will not only need model and monitor DER facilities, but also need to assess distribution load models near the DERs to ensure adequate local power flow and voltage profiles. Smart Grid technologies, including smart meters, could help improve metering and operational observability in distribution networks with DERs. Emerging technologies and applications, such as micro-grid and electric vehicle, will bring in both challenge and opportunities to future DMS.
- Today DER integration studies are performed on a local (feeder) basis. There is not as yet a vehicle or a tool set for performing integrated transmission and distribution interconnection studies where the aggregate amount of DER on an interface point basis is considered.
    - There are strong incentives to integrate DER into wholesale market operations, but there are no definitive studies of the impact of wholesale market participation especially in ancillaries such as regulation on the distribution system. A 1 MW battery selling regulation services from a distribution circuit could introduce as much flicker and other power quality issues as PV beyond the hosting capacity of the system.
    - Achieving DER visibility and control cost effectively will depend upon use of the public internet or existing utility communications systems – posing regulatory and security challenges.
- The U.S. is seeing a period of rapid change with increasing levels of solar and wind being implemented along with the retirement (or planned retirement) of nuclear and coal. Although reliability standards have changed over the years, they have not changed as quickly as the generation fuel security is changing. NERC (N-1) planning and operation criteria are difficult to satisfy without a reliable generation to re-dispatch and mitigate criteria violations. For example, there are no systematic reliability criteria for the planning and operation of natural gas deliverability systems.
- The new IEEE 1547 mandates interoperability capabilities for DERs regardless of the size and type. These requirements enable utilities to monitor and control DERs at the utilities' discretion. The new IEEE 1547

[5] NERC ERO Reliability risk Priorities – February 2018. https://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO-Reliability-_Risk_Priorities-Report_Board_Accepted_February_2018.pdf

standard also mandates DERs to comply with one of the three "local" communication protocols: IEEE Std P2030.5 (SEP2), IEEE Std 1815 (DNP3), or SunSpec Modbus. These protocols enable utilities to integrate DERs to their Distribution Management Systems (DMS) or Distributed Energy Resources Management Systems (DERMS). Other communication protocols i.e. IEC 61850 are also allowed as long as the DER complies with one of the three above-mentioned protocols.

- Interoperability will play a key role in the future power system, which is a hybrid energy system mixed with traditional synchronous generations, high penetration DERs, storage, and smart grid technology enabled distribution networks with conventional and smart energy efficient loads.
  - IEEE P2030 Smart Grid Interoperability Guide has provided philosophical reference (data map) on interoperability data source and communication.
  - IEEE 1547-2018 has defined interoperability requirements for DERs. IEEE 1547.1 will provide guidance on implementation and commissioning of interoperability from DER to Local EPS and BPS.

f. Other nations have experience in addressing the introduction of significant DER and renewable resources on their electric systems. What policies are currently in place in markets outside of the United States, including Europe and Japan, to accommodate changes to the electricity system from a traditional centralized, oneway electrical grid to one where DER is rapidly being adopted?

- EU has very ambitious targets for reducing greenhouse gases (GHGs). A large contribution to this goal is expected to come from renewables, particularly generation, heating and cooling (incl. heat pumps), and transportation. In 2016, renewable energy represented 17% of energy consumed in the EU.[6] Renewable energy sources in EU are defined rather broadly. They include wind, solar (thermal, photovoltaic and concentrated), hydro, tidal power, geothermal energy, biofuels and the renewable part of waste. Hydro is the most important source, followed closely by wind. In 2016, electricity generation from renewable sources contributed 29.6% to total EU-28 gross electricity consumption. Shares of wind and solar in the total quantity of electricity generated from renewable energy sources rose to 31.8% and 11.6% in 2016, respectively.
- The current EU policies are closely tied to the politics of the individual member states. Transmission grids are operated on a sub-national or national level. Transmission networks are run by transmission-system operators (TSO).[7, 8] At European level, these are organized in the European Network of Transmission System Operators (ENTSO-E), which draws up 10-year network development plans and participates in the development of network codes (rules for operating the network)[9]. Distribution networks are managed by distribution-system operators (DSO), who connect consumers, install electricity meters and communicate

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[6] Eurostat, June 2018; http://ec.europa.eu/eurostat/statistics-explained/index.php/Renewable_energy_statistics

[7] Understanding EU electricity markets, European Parliamentary Research Service Nov 2016; http://www.europarl.europa.eu/RegData/etudes/BRIE/2016/593519/EPRS_BRI(2016)593519_EN.pdf

[8] EU Legislation in Progress: Common rules for the internal electricity market, European Parliamentary Research Service May 2018; http://www.europarl.europa.eu/RegData/etudes/BRIE/2017/595924/EPRS_BRI(2017)595924_EN.pdf

[9] See e.g., Reliability Guideline: BPS-Connected Inverter-Based Resource Performance, International Grid Codes and References, NERC May 2018

the consumption to the energy suppliers. Electricity from smaller renewable sources, such as solar and wind, is generally fed into the distribution network.

- The rules for the operation of electricity markets are set by independent national regulators. At EU level, the Agency for the Cooperation of Energy Regulators (ACER) defines the guidelines for transnational electricity networks and markets, the so-called network codes. ACER is mainly responsible for promoting cooperation between national regulatory authorities, monitoring progress in the implementation of the 10-year network development plans and monitoring the internal markets in electricity and gas.
- Some of the consequences of the current approach are outlined in ACER's most recent Market Monitoring Report[10]. The issues listed in the report include:
  - "The use of the available cross-border capacity in the day ahead timeframe is close to optimal. However, for the intraday and balancing market timeframes it could be significantly improved."
  - "Cross-zonal exchanges are discriminated against internal (intra-zonal) ones, limiting the cross-border capacity available for trade. In 2016 the average proportion of capacity made available for cross-zonal trade in internal-to-bidding zone lines in the Core (CWE, Central West Europe) region was only 12% of their maximum capacity, whereas the remaining 88% was 'consumed' by flows resulting from internal exchanges. "
  - "Fragmented national adequacy assessments underestimates the contribution of interconnectors to security of supply. One third of the national adequacy assessments, where a decision was taken on whether to implement a capacity mechanism (CM)11, ignore the contribution of interconnectors to adequacy."
- While continuing to pursue GHG goals, EU is also proposing to radically restructure the power system. The objective would be to create an Energy Union, an integrated energy market, which would assure smooth interconnections, mandate regional planning, and eliminate subsidies for coal, nuclear, and renewable generation. The market would be streamlined by including consumers, prosumers, and aggregators in the markets for energy and ancillary services. Negotiations of specific elements of this plan are continuing. A recent article12 discusses the major concerns of the industry and the states with the proposed approach. Some of the examples include:
  - "One of the most contentious parts of the legislation relates to the conditions under which member states should be allowed to set up capacity mechanisms or strategic reserves. Through these schemes they pay generators or suppliers to keep backup capacity available to be used in case of shortages or emergencies. Many critics feel the schemes are used to subsidize incumbent generators and do not

[10] ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Gas Markets in 2016, October 2017; https://acer.europa.eu/en/Electricity/Market%20monitoring/Pages/Current-edition.aspx

[11] A mechanism that rewards market participants for available capacity, on top of revenues generated by selling electricity in the wholesale market. These payments are meant to ensure security of supply by incentivizing sufficient investment in new capacity or preventing the retirement of existing capacity. CMs take many forms and are sometimes referred to as capacity remuneration mechanisms (CRMs).
Source: Laurie van der Burg and Shelagh Whitley, Rethinking power markets: Capacity Mechanisms and Decarbonisation, Overseas Development Institute May 2016; https://www.odi.org/sites/odi.org.uk/files/resource-documents/10569.pdf

[12] New EU electricity market design: More market or more state?, Energy Post March 2018; http://energypost.eu/the-new-eu-electricity-market-design-more-market-or-more-state/

provide enough incentives for alternative, market-based solutions, such as "demand response" schemes."

  - "Virtually everyone in the energy industry is critical of the proposal in the market design legislation to include a 550 g CO2/kWh emission standard limit for capacity mechanisms. This is intended to exclude coal plants from public support, but the industry experts feel that capacity mechanisms should not be used to carry out climate policy."
  - "Another point of discussion in the market design debate is how renewables should be treated in the energy system. In some countries, they get priority in the system ("priority dispatch"). They also generally do not have balancing responsibilities. The proposals aim to abolish these advantages, though the European Parliament wants to maintain priority dispatch for small-scale and existing installations. Again, most industry experts agree that any kind of special treatment should be phased out."
- Clearly, EU has set out to pursue very ambitious goals, which will require significant financial resources and an unprecedented amount of cooperation between Member States.

Closing Statement

As we continue to embark on this new grid brought about the rapidly advancing technologies between the information and operational domain, we must pay attention to adequately prioritize and address those challenges and associated risks. Summary of the risks to be addressed are:

- Extreme Natural Events, such as earthquakes, hurricanes, floods, fires, Geo-Magnetic Disturbances (GMD)
- Cyber and Physical Security Vulnerability, including Electromagnetic Pulse (EMP)
- Asset management and Maintenance
- Changing Resource Mix
- Bulk Power System Planning, Adequacy and Performance
- Human Performance and Skilled Workforce

All those risks should not be treated as an isolated concern - rather it should be viewed in the holistic context. While addressing those risks, the industry will need to continue to be diligent in prioritizing mitigation investments to achieve reliability and resilience targets in the most effective way. For example, while putting efforts to address threats of GMD and EMP, investments priorities may be on preventing and managing challenges from sustained natural disastrous events (e.g. fire risks in California) and fuel unavailability.

In general, despite these risks, the future, nevertheless, presents an exciting opportunity as we continue to work together on advancing the grid that has become inextricably linked with our well-being.