September 2, 2016

Commissioner Travis Kavulla, President National Association of Regulatory Utility Commissioners 1101 Vermont Ave. NW #200 Washington, DC 20005

RE: IRC Comments on NARUC Distributed Energy Resource Compensation Manual (responses@naruc.org)

Dear President Kavulla:

The ISO/RTO Council (IRC)<sup>1</sup> welcomes the opportunity to comment on the draft Distributed Energy Resources (DER) Compensation Manual (Manual) developed by NARUC's Staff Subcommittee on Rate Design. We appreciate the reference in the Manual to the important role the ISO/RTOs play. We commend the Staff Subcommittee for detailing the challenges and opportunities before state regulators responsible for developing retail rate design and cost allocation methodologies, and for outlining various options for state regulators to consider when implementing DER policies.

The IRC is comprised of ISOs and RTOs across North America. Each ISO/RTO is responsible for ensuring the reliable operation of their respective region's transmission grid. We have varying levels of DER deployment in our respective regions. For most ISOs and RTOs, DER participation in the wholesale markets we administer is limited.<sup>2</sup> Most DERs act as load modifiers, operating behind the customer meter and outside the wholesale markets we administer. The lack of robust visibility to these resources makes forecasting demand and maintaining regional reliability more challenging as DERs grow into a larger share of the energy supply mix. Understanding the challenges and opportunities DERs present, our shared goal is to ensure DERs grow and mature into resources that help our regions maintain safe and reliable operations and promote efficient wholesale electricity markets.

The IRC welcomes dialogue with the states in our respective regions to better understand their DER policy objectives and any deployment plans under consideration by Electric Distribution Companies (EDCs) and customers so as to better integrate these resources into short-term grid operations and long-term regional planning to benefit regional reliability and wholesale market efficiency. We believe that working together with state regulators, additional value may be derived from the DER deployment. As an overarching policy matter, the IRC encourages NARUC to include a recommendation in the Manual that state regulators in ISO/RTO regions collaborate and coordinate with their ISO/RTO on DER policy development and deployment issues.

The IRC also offers NARUC a few recommendations for states in ISO/RTO regions to harness the value of DERs to wholesale power markets and regional grid operations, to ensure technology is leveraged to maintain reliability as DERs proliferate, and to leverage other potential wholesale market opportunities.

When DERs are small in number, the value of DERs accrues primarily to local distribution systems and the retail customers located on those systems. As DERs proliferate their aggregate impact will have broader regional implications. As such, the IRC recommends expanding the Manual's definition of DER to resources that can be used to "satisfy the energy and ancillary service needs of the distribution <u>and transmission grids</u>." This may further

<sup>&</sup>lt;sup>1</sup> The IRC consists of the following nine independent system operators ("ISOs") or regional transmission organizations ("RTOs"): AESO, CAISO, ERCOT, IESO, ISO-NE, MISO, NYISO, PJM, and SPP. IESO and AESO do not join these comments for jurisdictional reasons.

<sup>&</sup>lt;sup>2</sup> Participation in the wholesale markets is through the Electric Distribution Company or through an aggregator. Individual retail customers do not participate directly in the wholesale markets. NYISO and ISO-NE allows individual customers that can meet the minimum participation thresholds become market participants and represent themselves in ISO-administered demand response programs.

encourage state regulators to consider for utilities within ISO/RTO regions how best to facilitate capturing the value DER may bring to wholesale power markets and regional grid operations.

## Harnessing the Value of DER to Wholesale Power Markets and Regional Grid Operations

State renewable policies, technological developments, and consumer preferences are driving DER deployment. Today ISO/RTOs have limited visibility into the operation of certain DERs, generally only those DERs that participate in the wholesale markets we administer. DERs may be aggregated by the EDC, LSEs or other third parties to participate as generation or demand response resources in certain ISO/RTOs' energy, capacity or ancillary services markets.<sup>3</sup> Participation in such markets typically requires some degree of metering to measure and verify participation. ISO/RTOs also may be aware of certain DERs through registries that track production of energy from certain power sources, including distributed retail sources, to create renewable energy credits.<sup>4</sup>

ISO/RTOs economically dispatch wholesale market resources to reliably serve demand. DERs inject power onto the distribution grid or reduce the demand for power that, in aggregate, could impact regional grid operations and regional system planning. The proliferation of DERs, therefore, carries with it potential reliability and market impacts. Although the reliability impact of any one distributed energy resource is guite small, as deployment increases, it is incumbent on all of us to find ways to integrate these resources in a manner that enhances system reliability and market efficiency.

### Dispatchable and Nondispatchable Resources' Value to Wholesale Power Markets and Regional Grid Operations

There are reliability benefits to ensuring that dispatchable<sup>5</sup> and non-dispatchable DERs are visible to grid operators. Here the IRC is encouraged by the approach that parties in New York are taking with the NY ISO to improve coordination of DERs in planning and operation of the grid.<sup>6</sup> Experience is demonstrating the growing need for the EDC as well as the RTO to have sufficient information on where DERs are located and how they operate. For example, the events associated with the voltage disturbance in the Washington D.C. area on April 7, 2015,<sup>7</sup> underscore the enhanced need for visibility, communication and dispatchability of DERs. A fault occurred on a circuit that lasted approximately 58 seconds. The sustained fault resulted in the tripping of generators in the local area and prolonged voltage depression, leading to a total customer load loss of approximately 532 MW. During the event, much of that load was automatically transferred from grid power to behind the meter back up generation units. Unfortunately, the real-time operation of these back up generation units was largely invisible to PJM and Pepco at the very time both entities were trying to assess and prioritize system restoration.8

<sup>&</sup>lt;sup>3</sup> PJM, ISO-NE, ERCOT, NYISO, and CAISO have afforded the ability for DER participation in certain of their regional wholesale markets through EDCs, LSEs, or third party aggregators. As noted above, NY ISO and ISO-NE allow individual customers that can meet the minimum participation thresholds to become market participants and represent themselves in ISO-administered programs.

<sup>&</sup>lt;sup>4</sup> The Manual notes various regional renewable generation registries in footnote 72. Similar to the regions noted, PJM has awareness of the deployment of solar, including behind the meter retail solar, in its footprint through the Generator Attributes Tracking System for renewable energy credits.

<sup>&</sup>lt;sup>5</sup> Sources of electricity that can be dispatched at the request of power grid operators or of the plant owner; that is, generating

plants that can be turned on or off, or can adjust their power output accordingly to an instruction. <sup>6</sup> NY PSC Order Adopting Distributed System Implementation Plan Guidance, p. 42. "With respect to the roles, responsibilities, and interactions between utilities and the NY ISO, it is expected that the Supplemental DSIP will begin to define the obligations and actions that will be needed to ensure seamless and reliable operations of a dynamic transmission and distribution grid." http://documents.dsp.ny.gov/public/Common/ViewDoc.aspx?DocRefId={B1C7035C-B447-459A-8957-20BF3BDB6D0F}.

<sup>&</sup>lt;sup>7</sup> https://www.rfirst.org/Documents/Joint Report on D.C. Event.pdf

<sup>&</sup>lt;sup>8</sup> According to the Joint Report, the transferring of a building's load back to Pepco's electric distribution system required a manual process. Although manual transfers are not complicated, they are dependent on trained and authorized electricians or electrical service personnel being available to respond and perform the necessary switching operations on the customer equipment. The location and activity of customer facility electricians at the time of the disturbance affected the speed of manual

Another example underscores the benefits of visibility, communication and dispatchability. During the hot weather experienced during September 2013, for two days in a row, PJM was forced to shed a limited amount of load in the Pigeon River area in order to maintain system reliability within the zone. On the third day, although system conditions were the same, the operation of behind the meter generation, coordinated by the EDC, prevented a third day of local load shedding.<sup>9</sup> Knowing the location and quantity of available dispatchable distributed energy resources as well as having the ability to communicate (albeit through the EDC or other aggregator) likely could have prevented the need for load shedding on the prior days as well. Awareness and ability to coordinate the operation of dispatchable DERs likely will become more critical over time.

Also, there are market efficiency benefits to ensuring that dispatchable and non-dispatchable DERs are visible to grid operators. The ability to forecast the operation of both dispatchable and nondispatchable DERs, and to factor those dynamics into the day-ahead and real-time regional dispatch equations, will increase the accuracy and efficiency of a least-cost, regional dispatch solution.<sup>10</sup> Visibility would enable the grid operator to know the amount, timing, and location of generation injected into the grid and/or load reduced from the grid. This, in turn, will enhance regional grid operations and result in a least-cost regional dispatch solution for the regional wholesale market.

Additionally, increasing the transparency of DER locations and operations (and planned future deployment) would enhance RTO/ISOs ability to factor the operation of these resources into their long-term transmission planning processes, resulting in more efficient transmission expansion plans. Factoring the effect of the DERs into the long term load forecast would influence the transmission expansion requirements.<sup>11</sup>

The IRC, therefore, encourages state regulators to consider how the location and operation of both dispatchable and nondispatchable DERs may be made known to the regional grid operators to increase the reliability and efficiency of the regional dispatch, and to consider whether and how the regional grid operator may be able to call upon dispatchable DERs (through the EDC or other aggregator) if such resources could alleviate reliability issues on the wholesale grid.

Such coordination and communications among state regulators, EDCs, and bulk power grid operators has the potential to support system reliability as well as to harness DERs capability to increase grid resilience and wholesale market efficiency. By involving ISOs/RTOs in their discussions regarding DER with their utilities and other stakeholders, state regulators have an outstanding opportunity to consider how best to coordinate benefits to

restoration switching, which could have extended the outage for those customers while customer facility electricians responded. <u>https://www.rfirst.org/Documents/Joint</u> Report on D.C.Event.pdf

<sup>9</sup> <u>http://www.pjm.com/~/media/documents/reports/20130923-initial-analysis-of-operational-events-during-the-september-2013-</u> heat-wave.ashx

<sup>11</sup> Some ISO/RTOs, including PJM, MISO and ISO-NE have worked to incorporate the projected effect of DERs into the longterm load forecast that is used for regional transmission expansion and even for capacity market procurement. For example, ISO-NE and PJM recently enhanced their load forecasting methodologies to account for forecasted deployment of behind the meter solar generation in long-term load forecasting. This has implications on capacity procurements through the ISO-NE and PJM capacity markets as well as transmission planning. <u>http://www.pjm.com/~/media/planning/res-adeq/load-forecast/solarforecast-presentation.ashx.</u>; http://www.iso-ne.com/system-planning/system-forecasting/energy-efficiency-forecast; http://www.iso-ne.com/static-assets/documents/2016/05/2016\_pvforecast.pdf

<sup>&</sup>lt;sup>10</sup> Some ISO/RTOs allow DERs such as distributed generation backed demand response, solar and storage to present through EDCs or other aggregators directly into the wholesale markets. As such, these resources are already accounted for in the regional dispatch. Other dispatchable and nondispatchable DER, however, may not be factored into the dispatch if the ISO/RTO does not have situational awareness of its location and operation. The IRC notes that several of the ISO/RTOs have been working to improve forecasting of intermittent resources, such as wind and solar for more accurate day-ahead and real-time load forecasts to improve regional dispatch efficiency.

consumers and to foster learning about how the regulatory treatment of DER can be harmonized to meet the needs of both the distribution and transmission systems for reliable and efficient operations.

#### Increasing the Value of Dispatchable Resources to Wholesale Market Efficiency

The IRC has observed the benefit of appropriate price signals incenting operational performance of resources necessary to support regional grid reliability as well as to promote market efficiency. In similar fashion, the Manual notes various retail rate designs that seek to align retail pricing with wholesale market prices, such as the ComEd and Ameren real time pricing programs for residential electricity customers, to incent consumption behaviors to support grid needs indicated by pricing signals. The IRC applauds NARUC for observing that there may be ways for retail pricing, not limited to real time pricing, to incent consumption behavior that best supports reliability and market efficiency by aligning with the regional wholesale market pricing and operations. Similar to work that is already underway in New York,<sup>12</sup> the IRC encourages state regulators in ISO/RTO regions to consider how they may increase the reliability and market efficiency value of DER through retail pricing structures that may align with the wholesale market price signals.

# Additional Technology and Market Consideration for States in Organized Wholesale Market Regions

The IRC offers these additional comments to ensure technology is leveraged to maintain reliability as DER proliferates, and encourage states in organized wholesale market regions to leverage other potential wholesale market opportunities in their DER policies.

#### Smart Inverters

The IRC encourages states to follow the example of California, cited in the Manual. Some ISO/RTOs are in different stages of including smart inverter requirements for transmission grid interconnection of wholesale market participating resources.<sup>13</sup> Additionally, the Federal Energy Regulatory Commission (FERC) recently has issued two Final rules imposing new requirements impacting inverter-based technologies. On June 16, 2016, FERC issued Order No. 827, its Final Rule eliminating the existing exemptions for wind generators from the requirement to provide reactive power. The Order requires all Transmission Owners to revise pro forma Large/Small Generator Interconnection Agreements to remove the existing exemptions, and incorporate new provisions requiring all newly interconnecting non-synchronous generators to provide reactive power at the high-side of the generator substation as a condition of interconnection. Subsequently, on July 21, 2016, FERC issued Order No. 828 adopting requirements for frequency and voltage ride through capability for small generating facilities.

As DER proliferates at the distribution level, this technology will increase in its importance. Importantly, the concentration of DER in certain geographical areas may have implications for regional grid stability. Depending on circumstances, local overvoltage on the distribution system is possible at those locations where there is a significant amount of distributed generation on a feeder not otherwise designed to accommodate that generation. This, however, is not just a distribution system reliability issue. To the extent that voltage issues migrate "up the chain," these overvoltage issues can have reliability consequences at various substations and ultimately the transmission grid itself.

As DER proliferates, the need for dynamic behavior that supports grid stability increases. For inverter-based DER like solar and storage, this takes the form of standards for smart inverter functions. Some of these functions (such as local voltage support) are most relevant to distribution system reliability, while others (such as frequency support) are relevant to regional transmission system reliability. Most U.S. states use the IEEE 1547 standard for their distribution

<sup>&</sup>lt;sup>12</sup> See NYS DPS case "Value of DER".

http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-E0751&submit=Search+by+Case+Number

<sup>&</sup>lt;sup>13</sup> PJM and ISO-NE have established, with FERC approval, requirements for "enhanced inverter" capabilities for inverter-based interconnection customers coming through their interconnection queues to connect to the transmission grid.

interconnection requirements. Currently, as the Manual notes, IEEE is engaged in a process to update the 1547 standard such that advanced grid support functions should be provided by DERs. Coordination of these requirements and standards would be a valuable activity, especially across the various jurisdictions to which they would apply.

The IRC encourages the states to adopt smart inverter function requirements, even if they are only at an early stage of DER deployment, to be ahead of the need and to avoid future additional costs should system stability issues arise. The IRC, therefore, requests NARUC to go beyond the current recommendation in the Manual that suggests state regulators monitor the adoption rates of smart inverters and the standards development process to adopt requirements that will harmonize with the final IEEE smart inverter standards. Moreover, the IRC encourages state regulators to invite RTOs to work with them and EDCs on technical demonstrations to evaluate the appropriate configuration requirements for enabling enhanced inverter functionality including frequency and voltage support settings.

### Potential Organized Wholesale Market Participation

While the manual rightly focuses on the distribution benefits and implications for DERs, it may be valuable to consider whether there are opportunities in the region where the DER is located, for EDCs, LSEs or aggregators to present these resources to the wholesale market to provide the broadest scope of market opportunities to enhance the potential market (and reliability) value for the resources and consumers. In some instances, wholesale markets may be able to efficiently utilize these resources and pay them for their services. This would benefit the markets as well as the consumers. Thus, the IRC encourages NARUC to recommend that states in ISO/RTO regions consider how they may leverage the wholesale markets as they develop their DER policies.

## Conclusion

The IRC appreciates NARUC's references in the Manual to the important role the ISO/RTOs play in certain regions of the U.S. We thank you for your invitation to submit comments and appreciate your consideration of our recommendations.

Sincerely,

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