Joint Utility Anti-Islanding Position

Interconnection Technical Working Group

October 26, 2016

I. Introduction

The accelerating rate of Distributed Generation ("DG") deployment in New York State requires a careful consideration of unintentional islanding from DG connections penetrating the electric power system ("EPS"). Balancing the need to keep systems safe and secure while not imposing undue costs on interconnection customers continues to be a central concern. A prolonged unintentional island can have significant impacts on both public safety and utility/customer equipment integrity. Even shorter duration unintentional island conditions can have significant impact on customer service and system power quality. Consequently, increasing integration of DG requires a careful consideration of unintentional islanding risk and the identification of appropriate mitigation measures. As new approaches for addressing unintentional islanding become available that have the ability to reduce the costs imposed on customers, they should be evaluated to facilitate their effective implementation where they are able to sufficiently address the risk of an unintentional island.

Pursuant to the September 27, 2016 meeting of the Interconnection Technical Working Group ("ITWG"), the Joint Utilities of New York ("Joint Utilities") developed a common position on anti-islanding schemes for DG, particularly solar photovoltaic ("PV") systems. As requested by the Department of Public Service Staff ("Staff"), this position addressed the following four areas:

1. Updated Anti-Islanding Criteria with a list of concerns with Inverter Performance
2. Common Joint Utility position on Sandia Criteria Analysis (Flow Chart)
3. Common Joint Utility position on Risk of Islanding (ROI) Studies
4. Common Joint Utility position on Recloser Blocking Schemes

Direct transfer trip ("DTT") is a well-recognized measure for anti-islanding protection. However, the application of DTT represents an incremental cost for the interconnection of a project and limits operational flexibility for the utility. The Joint Utilities are committed to identifying lower cost alternatives to DTT where risk to public safety and service reliability is adequately mitigated, and reducing the cost of

DTT implementation where it is still necessary. In the development of this common position document, the Joint Utilities undertook a significant benchmarking and research effort, analyzing and adapting the information learned to New York State's unique characteristics.

II. Background

Islanding refers to a condition where DG continues to energize an electric power system ("EPS") area through the point of common coupling ("PCC") after a loss of service to the area from the electric utility as a result of an unplanned outage or routine maintenance. Unintentional islanding is of concern due to the following reasons:

- The impacts of unintentional islanding on power quality could result in damage to customer equipment. Because utilities lack control of the islanded system, maintaining power quality may become an issue during islanded conditions. The DG may be unable to maintain the local voltage within the ANSI C84.1 range or the frequency within parameters established by the Northeast Power Coordinating Council (PR6, PRC 12 and NPCC directory 12). Customers connected to the island could experience equipment damage as a result of these excursions.
- Islanding can impact utility asset integrity. For example, these conditions can interfere with manual or automatic reclosing, or loop feed automatic switching on the radial distribution system. Utility assets incorporated into or reconnecting to an island with abnormal voltage or frequency conditions may result in extensive equipment damage, for example, a line recloser damaged by reclosing out of phase or lightning arrestor damaged due to abnormally high voltages.
- Public safety risk may increase on delta connected systems. For example, a downed wire can remain energized after a device opens to isolate a fault. Depending on the location of the DG installation and the impedance of the downed wire, there may not be sufficient fault current or voltage deviation to trip a generator offline resulting in power being provided to the downed wire.

Anti-islanding protection detects the island and causes the DG to cease power production and must operate quickly to mitigate the negative impacts of an islanding condition.

III. Current Inverter Capabilities and Limitations

A. Scope

While anti-islanding protection is a requirement for all DG, the recent work by the Joint Utilities and its position in this document is focused on anti-islanding protection in the context of solar PV inverters. Solar PV inverters are the current scope of the ITWG and present the greatest opportunity to impact DG interconnection costs.

B. Island Detection

When the electric grid experiences an outage, the anti-islanding feature of a grid tied PV inverter will detect a sudden change or actively disrupt system frequency, voltage, or real or reactive power output. This will cause the inverter to trip offline. According to IEEE 1547-2003 Standard, the UL 1741 certified PV inverter is required to trip offline within two seconds of detecting an islanding condition.

Although many solar PV inverters are UL 1741 certified and trip offline within the two second time requirement, these inverters are only certified on an individual basis and not in multiple inverter scenarios, or when non-inverter based generation is included in the island. The anti-islanding mechanisms implemented within PV inverters may differ between solar PV inverter manufacturers and models. Inverter algorithms are not publicly disclosed and can only sometimes be obtained through non-disclosure agreements (NDA) between manufacturers and the utility or consultant completing a study that prevent meaningful and timely dynamic or transient analysis of islanding behavior. Although today's inverters generally use active anti-islanding measures, existing inverters present on the distribution system may contain antiquated passive anti-islanding algorithms. Additionally, although active anti-islanding, positive feedback with frequency shift or voltage shift algorithms are more effective than the passive type, as addressed in Sandia's *Evaluation of Islanding Detection Methods for Utility-Interactive Inverters in Photovoltaic Systems* report, all inverters contain a window of ineffectiveness known as the non-detection zone (NDZ)[1]. The combination of unknown and varying inverter algorithms, along with increased scenarios of PV output matching the islanded real and reactive load as solar PV penetration increases, exasperates the potential for operation in non-detection zones. In islanded conditions with many inverter types, each individual inverter's efforts to detect an island may be interfered with by the other inverters in the island[2].

It is also described in Sandia's Suggested Guidelines for Anti-Islanding Screening that some studies have shown the mixing different types of inverters with the same type of detection and prevention scheme but different implementations, leads to a degradation of islanding detection effectiveness in the case of multiple inverters[1]. While the Joint Utilities agree that an island is highly unlikely to be sustained indefinitely, the equipment damage due to voltage and frequency shift can occur quickly; hence the current IEEE 1547 Standard requirement to trip inverters within 2 seconds upon formation of an island.

C. Power Quality

Multiple inverters connected to the utility with minimal impedance between the distributed sources raises concerns about power quality, interoperability and loss of utility detection in particular when the inverters are from different manufacturers utilizing different anti-islanding methods[3]. National Renewable Energy Labs ("NREL") tested various multi-inverter scenarios in the distribution system to detect the maximum run-on-time for islanding. In all multi-inverter scenario test cases the maximum island run-on-time remained below 640 milliseconds, which is below the 2 second requirement specified in the IEEE 1547 Standard. Even though the run-on-time is below the value specified in the IEEE 1547 Standard, NREL admits that it is difficult to predict the extent at which their results will apply to islands with larger numbers of inverters, or to inverters using different islanding detection philosophies than

[1]Ropp, Mike. Sandia National Laboratory, (2012) *Suggested Guidelines for Anti-Islanding Screening. http://prod.sandia.gov/techlib/access-control.cgi/2012/121365.pdf*

[2] Bell, Frances. National Renewable Energy Laboratory (NREL) (2016) *Experimental Evaluation of PV Inverter Anti-Islanding with Grid Support Functions in Multi-Inverter Island Scenarios. http://www.nrel.gov/docs/fy16osti/66732.pdf*

[3] Ropp, Mike. Gonzalez, S. Sandia National Laboratories and Northern Plains Power Technology. *MULTI-PV INVERTER UTILITY INTERCONNECTION EVALUATIONS. http://energy.sandia.gov/wp-content/gallery/uploads/MULTI-PV-INVERTER-UTILITY-INTERCONNECTION-EVALUATIONSSAND2011-3898C1.pdf*

those explored in NREL's testing[2]. Only four different, single-phase inverters were tested for the NREL study that supporting documentation is absent to apply to the larger three phase inverter systems being experienced in NY.

General Electric ("GE") conducted a study for the California Public Utilities Commission and Pacific Gas & Electric ("PG&E") to quantify the risk of unintended islanding[4]. GE attempted to understand the combined behavior of PV inverters and connected loads in the interval of time from occurrence of islanding to the time when the island disconnects from the PV and ceases to exist. GE agreed that the tests they conducted are performed on synthetic resistance, inductance, and capacitive ("RLC") type circuits and as a result, they are unable to predict possible interactions of multiple inverters on the same circuit (i.e. possible interaction of anti-islanding schemes from different inverter manufacturers). They also mention that the active anti-islanding algorithms used by the various inverter vendors are held proprietary, which prevented GE from conducting meaningful studies of islanding behavior using dynamic or transient simulations.

Active methods for detecting the island introduce deliberate changes or disturbances in voltage and frequency to the connected feeder, and then monitor the response against the utility grid's stable frequency, voltage and impedance to determine if the utility grid is still connected. If the small disturbance is able to affect the parameters of the load connection at the PCC within prescribed requirements, the active circuit causes the inverter to cease power production and delivery to the load. Although active island detection methods are more accurate in detecting islanding conditions, they introduce a system disturbance. This system disturbance often degrades power quality and if significant enough, may degrade the system stability even when connected to the grid[5].

The Joint Utilities also note that instantaneous reclosing schemes that mitigate power quality issues associated with avoiding a permanent service interruption for transient faults may require adjustment with the integration of DG, to prevent reclosing into an island. Typical instantaneous reclose times (<0.25

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[4] General Electric (GE) (2016) *Quantification of Risk of Unintended Islanding and Re-Assessment of Interconnection Requirements in High Penetration of Customer Sited PV Generation.* Prepared for CA PUC and PG&E

[5] Chandrakar, Chandra Shekhar et. al. (2012) *An Assessment of Distributed Generation Islanding Detection Methods, International Journal of Advances in Engineering and Technology.*

seconds) are faster than anti-islanding detection and operation times for inverters. Therefore, reclose times may need to be extended, creating a power quality issue for all customers located on the load side of the recloser.

IV. Benchmarking and Outreach

The Joint Utilities pursued significant benchmarking efforts over the past month, reviewing laboratory testing reports and meeting with utilities in other jurisdictions. The following is a summary of outreach and results:

Outreach	Report Reviewed	Findings
Northern Plains Power Technologies ("NPPT") (Mike Ropp)	New York State Standardized Interconnection Requirements ("NYSSIR") and Sandia screens	The Joint Utilities require DTT if a project fails the Sandia screens and subsequent risk of islanding study. The Sandia screens do not go far enough for systems as large as 2 MW directly connected to the distribution system to ensure anti-islanding. The Sandia screen for VAR matching is complicated for the dynamic distribution EPS behavior and it is suggested that how much reactive power is a concern would be a practical application.
PG&E	CA Rule 21 and GE Anti-Islanding report	PG&E requires DTT if non-inverter based generation makes up 25% of the aggregate generation on a line section. As an alternative to DTT, PG&E relies on the inverter's UL 1741 certification and will install a recloser at the PCC with line reclose blocking when necessary. The typical project size is less than 1 MW and often connected behind the meter or to the bulk power system. There is currently no active Community Solar Program in PG&E's service territory.
Arizona Public Service ("APS")	APS Interconnection Request	APS relies on the inverter's UL 1741 certification. They do not require DTT for most inverter based projects on shared distribution feeders and install a SCADA connected RTU at the PCC when necessary. Larger projects applying for interconnection are typically less than 1 MW nameplate rating and behind the meter in more urban load centers. APS also applies a limit on system size for project subsidies to not exceed 125% of the customer's total connected load. There is currently no active Community Solar Program in APS's service territory.
NREL	Various Presentations and reports from NREL	The Joint Utilities reviewed various publications and presentations from NREL regarding anti-islanding protection, including DTT. Even though NREL recommends eliminating DTT, they agreed that there might be concerns with multiple inverters from different manufacturers in an islanded scenario (described earlier in this document).
National Grid, NPPT, Pterra, Staff, PG&E	Sandia report, NYSSIR, California Rule 21	National Grid facilitated a workshop on October 14, 2016 with Staff, Pterra, PG&E, NYSERDA, NPPT as well as internal staff at the executive level, from their relevant engineering departments, and their DG Ombudsman to attempt to come up with viable alternatives to requiring DTT for large projects. During their presentations and discussion, National Grid evaluated UL 1741 certified inverters' ability to trip offline within two seconds upon detecting a loss of utility service. In an effort to come to a position on anti-islanding, National Grid concluded that UL 1741 certified inverters' anti-islanding mechanisms can be relied on for inverter only line sections. National Grid will continue to review projects under the Sandia screens and will offer a risk of islanding study upon the developer's request should the project fail the Sandia screens.

Electric Power Research Institute ("EPRI")	List of Various Inverters	The Joint Utilities reached out to EPRI for a list of various inverters that have capability to detect islanding by Active Islanding Methods. EPRI is currently researching the request and will provide the Joint Utilities with a list of inverters, if feasible.
Xcel Energy - Minnesota	Minnesota Electric Rate Book	Xcel Energy - Minnesota ("Xcel") relies on certified inverters (UL 1741 and IEEE 1547.1a) with necessary protection already installed to prevent unintentional islanding. For inverter based generation, per the requirements, supplemental anti-islanding protection shall be implemented when the applicable minimum load is less than 125% of aggregate inverter AC nameplate capacities. Xcel may also require transfer trip depending on the size of the generation system vs the capacity and the minimum loading on the feeder. The Xcel Energy interconnection study will identify the specific requirements for installing DTT.

A common finding across all benchmarking efforts was that while there are many utilities outside of New York who are experiencing high penetration of PV, the queued penetration of 2MW Community and Remote Net Metered Solar PV connected without substantial load offsetting the generation is unique to New York. Moreover, these interconnection applications are often in rural areas with available land. In other jurisdictions such as California and Arizona, public policy decisions on net metering and installation subsidy caps drive system sizes much lower. Therefore, the development and evolution of an anti-islanding protection position in New York State is unique.

V. Application of Sandia Screens

The Joint Utilities currently apply the Sandia screens for solar PV applications with nameplate ratings greater than 50 kW. As described in the subsequent Anti-Islanding Protection section, the Joint Utilities recommend that this limit be raised in many cases. When utilized, the Sandia screens are applied as depicted on Slide 7 of the *Solar Industry Perspectives on Anti-islanding and the Rationale for Removing DTT* Requirements presentation at the September 27, 2016 ITWG meeting. EPRI is also working with NREL and Sandia to update the screens by the end of 2016. The Joint Utilities anticipate this may drive a reduction in the need for DTT, and also note that JU positions may need to adapt as a result of the new screening criteria.

VI. Risk of Islanding (ROI) Studies

The Joint Utilities agree to offer Risk of Islanding ("ROI") studies to developers when a project fails the Sandia screening criteria. National Grid has experience with offering ROI studies, contracting the work to

NPPT. All of the other individual utilities have recently begun offering the studies. After gathering all the relevant data, NPPT builds and validates both the circuit model and inverter model. NPPT obtains NDAs with inverter manufacturers for the inverter models being evaluated. NPPT identifies the individual use cases to be studied and then runs a parametric sweep calculating the run-on-time as a function of real and reactive loading level on the circuit. NPPT then repeats the parametric sweep process for relevant:

- Switching devices
- Capacitor states
- Circuit configurations
- Load distributions
- Load types (Z vs ZIP-motor vs aggregate)
- Inverter Types

The typical time frame to conduct a study is approximately 4-6 weeks. This time frame is dependent on receiving data and appropriate system information and schematics in a timely fashion. Additional factors such as database errors, and the use of inverters that have not been previously studied, may increase the time to study a particular project.

Following the completion of the Coordinated Electric System Interconnection Review ("CESIR"), the Joint Utilities will offer ROI studies as a next step option for any projects that fail the Sandia screens. This ROI study will commence following the CESIR study, since some of the outputs from the CESIR study are used as inputs for the ROI study. Full payment will be required from the developer prior to beginning the ROI study. Failure of an ROI study may result in a requirement for reclose blocking schemes or DTT, as described in the next section.

VII. Anti-Islanding Protection Requirements

Obviating the need for DTT will require close collaboration and active participation among all parties represented in the ITWG. The Joint Utilities recommend the following framework that eliminates the need for DTT in many cases. Falling outside of this scope may result in application of Sandia screens and subsequent ROI studies resulting in DTT or reclose blocking; however, each utility at its discretion may implement more relaxed requirements. In addition, there may be situations that require deviation from the typical requirements to ensure safety and reliability of the utility system.

A. Requirements

The initial priority of the Joint Utilities is to evaluate the risk of islanding and determine when DTT can be eliminated and/or supplemented with alternatives, such as reclose blocking schemes. This effort will facilitate the reduction in the application of DTT. Subject to the requirements outlined in the remainder of this document, the Joint Utilities propose to eliminate the requirement for DTT where the following conditions are met:

1. Proposed interconnection is for a solar PV system with up to 2 MW nameplate rating.
2. Aggregate DG on the feeder that is not UL 1741 certified, inverter-based generation shall be less than 50 kW.
3. Interconnection is to the distribution system, at voltage levels 15kV and below, on shared (non-dedicated) distribution feeders.
4. Individual interconnection applications on sub-divided or adjacent parcels are evaluated based upon total aggregate nameplate ratings.
5. Distribution systems are radial without automated loop schemes.

Within the five parameters identified above, the following are the anti-islanding protection requirements for line section aggregated DG:

1. 50 kW – 1 MW

- 5kV class voltage – a recloser with communications through SCADA or other methods at the PCC for monitoring, protection, and control is required above 300 kW.
- Minimum load on a feeder (less than 1 MW) may trigger the need for Sandia Screening, ROI Studies, and reclose blocking schemes along with PCC reclosers.[6]

[6] Orange & Rockland is evaluating this position and will finalize its decision by December 31, 2016.

2. 1 MW – 2MW

- A recloser with communications through SCADA or other methods at the PCC for monitoring, protection, and control is required.
- Reclose blocking schemes are required if aggregate DER is greater than 50% of line section minimum load. In lieu of this requirement, some utilities may apply the Sandia screens for each line section:
    - Upon passing the Sandia screens, there will be no additional requirements.
    - Upon failure of the Sandia screens, an ROI study will be offered.
        - If the developer declines the ROI study, reclose blocking schemes may be required on the impacted line section(s).
        - If the developer completes the ROI study, reclose blocking schemes may be required in the event of failure.[7]

B. Reclose Blocking Scheme Implementation

Where reclose blocking is applied, feeder head relays and mid-line reclosers will need to be set with a load side voltage check function. This will prevent the recloser from closing back into a downstream islanding condition to avoid out of phase reclosing, causing voltage disturbances on the EPS. The PCC recloser would trip and then reclose back in after 5 minutes of source side power restoration.

Aside from using voltage check function, fast frequency shift option can also be explored to implement reclose blocking as permitted within the NPCC reliability criteria for underfrequency limits. If the PCC recloser relay detects a frequency shift in a set time frame (# of cycles) it will trip the recloser and wait 5 minutes of stable utility power before reclosing back in. The 5 minute timeframe will allow source side protective devices to go through all of their reclosing cycles and reset.

Depending on the particular feeder configuration and existing protective devices, voltage check function or frequency shift function may require installation of potential transformers, device setting changes,

[7] Orange & Rockland is evaluating this position and will finalize its decision by December 31, 2016.

and/or protective device replacement at the affected utility feeder breaker and/or mid-line recloser(s). Some utilities are exploring the ability to implement reclose blocking through the PCC recloser; however, there are device coordination challenges with identifying all possible scenarios of upstream power interruptions and reclose times. In addition, anytime reclose blocking is required, an electronic recloser is required at the PCC with communications through SCADA or other methods to enable remote tripping in the case that an island is established.

C. Legal and Regulatory Requirements

As a result of these proposed changes, the NYSSIR will need to be updated to require proof of insurance and liability from the developer or customer for equipment and public damage in the event an island is formed. In addition, the utility shall be able to reserve the right to require DTT at the developer's expense, should problems arise or non-inverter based generation be added to the feeder. The Joint Utilities will initiate development of the necessary standardized contract language during the first quarter of 2017. However, prior to standardized contract modification, this element must be incorporated. Each utility shall also be protected from the negative implications to electric reliability performance metrics in the event that the application of the reclose blocking functionality to protect from islanding conditions negatively impacts utility reliability.

VIII. Joint Utility Projects to Mitigate Cost Impacts of DTT

While the Joint Utility position described in this document has eliminated the need for DTT in many cases, the Joint Utilities have taken steps to mitigate the cost impact associated with DTT and will continue on that path. Traditionally, the Joint Utilities have relied upon audio-tone signals as a communication medium for DTT. The Joint Utilities are actively exploring alternate methods to mitigate DTT costs such as power line carrier communication (PLCC) and Radio Communication.

A. Power Line Carrier Communication (PLCC):

Power line carrier communication ("PLCC") relies on the use of the utility power line as the of primary communication channel. . The PLCC transmitter (installed on the utility side of the PCC) transmits a low-energy signal (voltage or frequency) to a receiver installed on the PV side of the PCC. When an islanding condition occurs, this communication signal is disrupted causing the DG facility's PLCC receiver to trip the PV inverter system offline. PLCC technology for DTT applications at the distribution level is currently being evaluated. To date, the PLCC technology has proven to be reliable; however the transmitter installation cost renders PLCC less cost effective than audio-tone DTT for single/low numbers of PV installations on specific feeders. However, because a transmitter can service all the DG systems on a feeder, PLCC becomes increasingly cost effective with multiple DG requiring DTT on a specific feeder. Central Hudson is responding to the first applications requiring DTT in its service territory in over 20 years and therefore PLCC is being evaluated through a research and development project. National Grid has performed a pilot voltage pulse PLCC project completed in early 2014 as a trial for R&D purposes. National Grid presently is installing a pilot frequency pulse PLCC project on a 23kV subtransmission system and on a 13.2kV distribution system in the same geographic operating area. National Grid has confidence the frequency pulse PLCC method will have better results toward a DTT alternative in its tool kit.

B. Radio Communication:

Radio signal communication relies on signal strength and line-of-sight radio path from the transmitter to the receiver. When an islanding condition occurs, a radio communication signal is sent to the DG facility's radio receiver relay to trip the PV inverter DG system offline. Although this method is less costly than audio-tone communications, its reliability and overall cost is dependent on the propagation path and thus, may not be economically feasible in all situations. Due to the dependence on line-of-sight, Central Hudson is testing this technology for DTT applications in its mountainous, tree covered service territory. As the Central Hudson Network Communication Strategy is rolled out over the next 5 years, it is anticipated that installations across 90% of the service territory will be able to implement DTT using a radio communications scheme. National Grid has also installed this technology in limited situations where conditions warrant, such as the ability to have sufficient signal strength without causing nuisance tripping due to a signal latency condition.

IX. Future Considerations

As previously stated, this Joint Utility position addresses cases of radial distribution feeders with inverter based generation only, and the specific cases described. The update of the Sandia screens will further inform the Joint Utility position in that area, as well as in cases of non-UL 1741 certified inverters and/or non-inverter based generation mixed with inverter based generation. In addition, the Joint Utilities will continue to collaborate on this topic and evolve requirements.

A. On-going Research

Con Edison is exploring a new phase comparison scheme, consisting of a synchro-phasor over a radio/cell link, to serve as an alternative to DTT for non-inverter based generation, and generation with nameplate ratings greater than 2 MW. The scheme essentially compares the phase angle of the system at a reliable and nearby "reference" node, with that of the generator output. When the phase angle is within a certain criteria, there are no issues and the generator is permitted to operate. When there is a significant phase angle difference the generator is tripped. In the event of loss of communication with the reference signal, the local relay at the generator implements very "tight" under/over frequency controls.

Applications utilizing this scheme have not been commissioned yet but depending on overall project schedules, one scheme is planned to be in-service before the end of 2016 and another during 2017. Both schemes involve large (~10MW) synchronous generation connected to Con Edison's underground network system. The cost of implementing the phase comparison scheme depends on each installation but is presently estimated at less than a tenth of the original DTT scheme for Con Edison. This is because it does not require hard wired connections to the supplying substation's circuit breakers as well as communications.

The Joint Utilities expect to learn from Con Edison's research in this area.

B. Testing

The specific implementation of protection schemes in lieu of DTT will require testing and learning in New York State. Upon implementation of legal requirements and within the boundaries described, the Joint Utilities recommend bypassing a pilot phase and moving to wide scale implementation. Developers will then need to consider the risk where new trial installations may not have the expected results necessitating changes. In conjunction with that expectation, it must be recognized by DPS Staff and the developer community that this complex technical implementation of reclose blocking application may require adjustment along the way as the developers and utilities learn through application on their unique systems and standardize implementations within the individual utilities. Power quality and distribution automation impacts are of particular concern.

C. Document Updates

As previously described, the New York State Standardized Interconnection Requirements will require updates to the contract language. In addition, updates to protect each utility from electric outage frequency requirements in the event that reclose blocking applications negatively impact reliability, will be required.

X. Summary of Utility Position

The Joint Utility position on anti-islanding represents significant benchmarking efforts, as well as collaboration and analysis specific to the complexities of remote net metering and community distributed generation in New York State. When necessary, the Joint Utilities will uniformly apply the Sandia screens and offer subsequent ROI studies when the screens fail. DTT will be eliminated in many cases, and where still necessary, the utilities will continue to take steps to mitigate cost impacts.

The Joint Utilities look forward to next steps including:

- Discussion at the November 8, 2016 Interconnection Technical Working Group meeting.
- Evolution of Sandia screens as they are updated and resulting impact on the Joint Utility position.
- Evolution of IEEE 1547 and its revision issue and resulting impact on the Joint Utility position.
- Development of items identified in the *Legal Requirements* section and updating of the NYSSIR contract required to fully implement this recommendation.
- Continued development of Joint Utility positions, such as for voltage classes > 15kV.
- Collaboration with developers as the technical implementation of reclose blocking occurs.
- Continued Joint Utility collaboration, including lessons learned regarding implementation of reclose blocking schemes, as well as additional opportunities to evolve joint positions.
- Developer pursuit of an industry standard inverter model for inverters commonly connected to the EPS.
- In cases where DTT is still required, on-going efforts to implement more cost effective alternatives to audio-tone communications.

- Development of methodology to track and measure the reliability and power quality impacts of shifting away from DTT requirements.
- Evaluation of the impact of shifting away from DTT on further automation of the distribution system.
- Finalizing this draft New York Joint Utility anti-islanding position document.