2025

JEA’s Distributed Energy Resource (DER) Technical Interconnection and Interoperability Requirements

1. INTRODUCTION

1.1. Scope and Applicability

It is the mission of JEA to improve lives and build community. This includes supporting programs that enhance the quality of life, protect the environment, provide significant value to the City of Jacksonville and the communities we serve. This document will establish clearly defined technical and safety standards necessary for a customer's generating and/or storage facility interconnecting to JEA's electric distribution system, referred to here as a Distributed Energy Resource (DER). All interconnections are to comply with the applicable statutes, ordinances, codes, rules, and regulations of all governmental units, bodies, and agencies.

This **Technical Interconnection and Interoperability Requirements** (TIIR) document specifies technical requirements for the interconnection of DER on JEA's electric distribution system. DER's include inverter-based and rotating machine generation as well as energy storage facilities that operate in parallel with the distribution grid of JEA. The purpose of these requirements is to maintain safety, reliability, power quality of the distribution grid and service, and to protect both utility and customer assets. The requirements apply to all DER interconnections unless an exception has been granted by JEA to the customer. This document succeeds JEA's Parallel Operations & Interconnection of DER Facilities on the Distribution System version 7.0.

The utility distribution includes AC medium voltages of 26.4kV, 13.2kV, 4.16kV and AC low voltages of 120/240V, 120/208V, 277/480V.

The document also addresses the responsibilities of the customer as they relate to a DER's grid integration, point of connection, and general system performance. It provides guidance on DER interconnection requirements relevant to operational performance, power quality, protection, monitoring, control, and telemetry. Interoperability with other grid equipment, as well as, metering, commissioning test and verification requirements are also addressed. The document covers specific operating requirements and any special protection that may be required for connections on radial or network locations in the distribution grid. Further, it enumerates DER interconnection technical review criteria.

1.2. Adoption of IEEE 1547-2018

JEA has fully adopted IEEE Std 1547-2018[1], as corrected by IEEE Std 1547-2018[2] and as amended by IEEE Std 1547a-2020[3], (hereafter: IEEE 1547-2018) for all DERs interconnected to its distribution system. All DERs interconnecting under these TIIRs shall meet requirements as specified in IEEE 1547-2018 and be tested, verified, or certified according to applicable standards. IEEE Std 1547-2018 clauses that are pertinent to sections in this document are identified throughout.

Requirements that are beyond the scope of IEEE 1547-2018 are also stipulated in this document.

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[1] https://standards.ieee.org/standard/1547-2018.html

[2] https://standards.ieee.org/content/dam/ieee-standards/standards/web/documents/erratas/1547-2018_errata.pdf

[3] https://standards.ieee.org/standard/1547a-2020.html

1.3. Effective Date and Grandfathering Clause

The requirements specified in this document shall apply to all DER interconnection applications received on and after **April 1st, 2025.** Any DER interconnections that are either already in operation or that have submitted their full applications prior to the above specified date may continue to meet requirements as defined at that time. Meanwhile, existing DER interconnections that are upgraded or modified shall be submitted to JEA and may have to comply with the requirements specified in this document based on project and/or system conditions and circumstances.

1.4. Responsibilities

1.4.1. JEA Technical Interconnection and Interoperability Requirements (this document)

The Chief Electric Systems Officer through his/her designee, the Director of Electric System Planning, is responsible for the maintenance of these requirements.

1.4.2. Customer-Owned Generating Equipment

The customer is responsible for designing, installing, operating, and maintaining their own equipment in accordance with interconnection agreements and applicable standards. The interconnection shall comply with the requirements set forth in this document and IEEE 1547-2018. Other applicable standards include, but are not limited to the National Electrical Code, JEA Distributed Generation policy, JEA Electric Service Rules and Regulations, and all applicable laws, statutes, guidelines, regulations, and local codes. This includes installing, setting, and maintaining all protective devices necessary for safe grid integration and to protect the customer, utility personnel and facilities.

Inverters and synchronous machines shall be certified to UL 1741 SB, or equivalent standards, qualified as “Grid Support Interactive” or “Grid Support Utility Interactive,” and installed or commissioned with IEEE 1547-2018-specified performance capabilities.

Non-certified DER will need to be evaluated and tested to meet IEEE 1547-2018 specified performance capabilities and any additional JEA performance requirements specified for interconnection.

1.4.3. Utility Managed and Operated Distribution System

Requirements specified in these DER requirements are also intended to complement utility efforts and responsibilities to maintain distribution grid safety, power quality, and reliability. Continuity and quality of service to all customers is a key responsibility of the utility.

1.4.4. Requirements Related to Ongoing Utility Upgrades

The utility system is constantly changing due to shifts in loading, service restoration, and the addition or removal of generation. The possibility exists that a change or multiple changes in the utility system may require additional protection or other requirements at a DER interconnection. The customer’s responsibility is to maintain compliance with the requirements set forth in this document and all requirements detailed in the interconnection agreement.

2. DEFINITIONS AND ACRONYMNS

2.1. Definitions

Terminology used in this document is intended to follow definitions and usage in IEEE Standard 1547-2018 and other related IEEE, IEC, and ANSI standards. In some cases, terms related to the FERC-SGIP and NFPA related codes such as the US National Electric Code, NFPA-70 are used.

Selected definitions are provided here in alphabetical order. Where appropriate, sources are noted in the text.

- **ABNORMAL:** Term characterizing an event that results in electrical parameters deviating from normal steady state conditions causing undesirable conditions. The main electric characteristics are Voltage, Current, and Frequency but may include other parameters such as harmonics as required.
- **AREA ELECTRIC POWER SYSTEM (AREA EPS):** The utility electric network which includes public rights-of-way and extends across property boundaries.
- **CONTROL CENTER:** The JEA office that monitors and has direct control over the operation of the utility's Power Delivery System.
- **CUSTOMER:** Any adult person, partnership, association, corporation, or other entity whose name on a service account is listed. A customer includes anyone taking delivery service or combined electric supply and delivery service from the Company under one service classification for one account. A customer is responsible for any DER connected to the electric system at the account.
- **DER NAMEPLATE RATING:** The sum of total maximum rated power output of all a DER's constituent generating units as identified on the manufacturer nameplate, regardless of whether it is limited by any approved means.
- **DISTRIBUTED ENERGY RESOURCE (DER):** DER's are electric power generation, storage, energy efficiency and flexible load technology solutions connected to the distribution system, including EVs. *Additional context: A source of electric power that is not directly connected to the bulk power system. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device necessary for compliance with IEEE Std 1547 is part of a DER.*
- **ENERGY STORAGE SYSTEM (ESS):** A system that has the mechanical, electrical, or electrochemical means to store and release electrical energy, and its associated interconnection and control equipment. An ESS is considered a DER that can operates in parallel with the distribution system.
- **EXPORT CAPACITY:** The amount of power that can be transferred from the DER to the Distribution System across the Point of Common Coupling (PCC).
- **FACILITY (OR FACILITIES):** The customer-owned DER equipment and all associated or ancillary equipment, including interconnection equipment, on the customer's side of the Point of Common Coupling.
- **GRID:** The interconnected arrangement of lines, transformers, and generators that comprise the electric power system. In this document, grid refers to the medium and low voltage portions of the grid.
- **HOSTING CAPACITY:** Hosting Capacity is the amount of DER and/or load that can be accommodated on the distribution system without adversely impacting Power Quality (PQ) and reliability under existing control and infrastructure configurations.

- **INADVERTENT EXPORT:** Unscheduled export of active power from an export-limited DER which exceeds a specified magnitude for a limited duration generally due to fluctuations in load-following behavior.
- **INTEGRATION MARGIN:** Limits defined and used to protect the grid by providing a safety margin added to DER integration limits—for example limits to prevent reverse power on a substation power transformer.
- **INTERCONNECTION AGREEMENT(S):** Any contract between JEA and one or more parties that outlines and governs the interconnection requirements of a generation facility.
- **INTERCONNECTION APPLICATION:** The request made by a customer proposing to interconnect DER to the utility's electric distribution system.
- **INTERCONNECTION EQUIPMENT:** The equipment necessary to safely interconnect the Facility to the utility's power delivery system, including all relaying, interrupting devices, metering or communication equipment needed to protect the facility and the utility power delivery system and to control and safely operate the facility in parallel with the utility power delivery system.
- **INTERCONNECTION:** The mutual physical connection between JEA's electric system and another or multiple entities.
- **INTEROPERABILITY:** the capability of two or more networks, systems, devices, applications, or components to externally exchange and readily use information securely and effectively.
- **LIMITED EXPORT:** Exporting capability of a DER whose generating capacity is limited by the use of any configuration or operating mode described in section 11.
- **LOCAL DER COMMUNICATION INTERFACE:** A local interface capable of communicating to support the information exchange requirements specified in IEEE Std 1547-2018 for all applicable functions that are supported in the DER.
- **LOCAL ELECTRIC POWER SYSTEM (LOCAL EPS):** The electrical facilities including load and generation within a single premise on the customer side of the point of common coupling.
- **MICROGRID INTERCONNECT DEVICE (MID):** A device that enables a microgrid (intentional island) system to separate from and reconnect to operate in parallel with the area EPS.
- **NET-METERING:** A metering and billing methodology whereby customer-owned renewable generation is allowed to offset the customer's electricity consumption on site.
- **NON-EXPORT OR NON-EXPORTING:** DER sized, designed, and operated using any of the methods in section 11, such that the output can be used to serve the local EPS and no electrical energy (except inadvertent export) is transferred from the DER to the area EPS.
- **NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION (NERC):** The agency assigned to ensure the adequacy, reliability, and security of the bulk electric supply systems through coordinated operations and planning of generation and transmission facilities.
- **OPERATING PROFILE:** The way the DER is designed to be operated, based on the generating prime mover, Operating Schedule, and the managed variation in output power or charging behavior. The Operating Profile includes any limitations set on power imported or exported at the Point of Common Coupling and the resource characteristics (e.g., solar output profile or ESS operation).
- **OPERATING SCHEDULE:** The time of year, time of month, or hours of the day designated in the Interconnection Application for a DER's power import or export.
- **PARALLEL OPERATION:** Any electrical connection between the utility power delivery system and the customer's generation source.

- **PERMISSION TO OPERATE (PTO):** Formal notice and authorization from the utility the interconnection is approved for operation in accordance with all interconnection requirements and agreement by all impacted parties.
- **POINT OF COMMON COUPLING (PCC):** Point where the customer system interconnects with the utility grid. It is the demarcation point between customer owned equipment and utility owned equipment (Adapted from IEEE Std 154-2018).
- **POINT OF DER CONNECTION (POC):** The point where DER is electrically connected within a premise or electric network. Sometimes this point is also the PCC.
- **POWER CONTROL SYSTEM (PCS):** Systems or devices which electronically limit or control steady state currents to a programmable limit.
- **POWER CONTROL SYSTEM (PCS):** Systems or devices which electronically limit or control steady state currents to a programmable limit.
- **REFERENCE POINT OF APPLICABILITY (RPA):** The electrical location used to determine satisfactory DER performance. Reference point of applicability for any requirement varies and can be at the Point of Connection (PoC) or Point of Common Coupling (PCC), or either. DER Requirements of this document apply to the RPA. (IEEE Std 1547-2018; the location concept is defined in Clause 4.2.)
- **REVENUE METERING:** The meter or meters used for billing purposes and the instrument transformers, communications equipment, and wiring between these devices.
- **RTU (REMOTE TERMINAL UNIT):** The remote unit of a supervisory control system used to telemeter operating data, provide device status/alarms, and provide remote control of equipment at a substation or generator site. The unit communicates with a master unit at the JEA Control Center.
- **SYSTEM EMERGENCY:** An imminent or occurring condition on the utility power delivery system, the ISO/RTO System, the system of a neighboring utility, or in the facility that is likely to impair system reliability, quality of service, or result in significant disruption of service, or damage, to any of the foregoing, or is likely to endanger life, property or the environment.
- **SYSTEM IMPACT STUDY:** Engineering effort to identify and detail electric system impacts that would result if the proposed DER were interconnected without project modifications or electric system modification.
- **TELEMETRY:** The automated process collecting, measuring, and transmitting data from remote or inaccessible sources to a receiving system for monitoring, analysis, and decision-making guidance that uses sensors or instruments to measure various parameters and conditions that include but are not limited to Voltage, Current, Power, and other performance metrics.

2.2. Acronyms

- **ACR**: Automatic Circuit Recloser
- **DA**: Distribution Automation
- **DER**: Distributed Energy Resource
- **EMI**: Electromagnetic Interference
- **EPS**: Electric Power System
- **ESS**: Energy Storage System
- **PCC**: Point of Common Coupling
- **PoC**: Point of Connection
- **RPA**: Reference Point of Applicability
- **TIIR**: Technical Interconnection and Interoperability Requirements

3. INTERCONNECTION TECHNICAL REVIEW

3.1. General Criteria for DER Interconnection

Any DER interconnection to the JEA electric power system must meet basic technical requirements and related standards. All interconnections will be evaluated for the following:

- Safety of the public and of JEA personnel,
- Risk of degradation to services for customers due to interruptions or power quality events,
- Compromise of security or reliability of JEA electrical systems,
- Cost responsibility associated with customer-owned DER,
- Implementation and Terms of Service,
- DER performance standards such as IEEE 1547-2018.

If an installation fails to meet any requirements either during the application process or during its operation, JEA may either 1) refuse to connect, 2) disconnect the installation, or 3) disconnect the customer from the JEA grid. JEA reserves the right to alter the requirements specified by special agreement if conditions change and a subsequent technical study indicates that the safe and acceptable operation of the JEA EPS and service to other customers may be compromised.

A customer shall not operate their DER in parallel with JEA's EPS without the prior written consent of JEA and without full compliance with this procedure.

Qualified projects will undergo DER design evaluation and screening; however, a Detailed Study may be required prior to the interconnection of the DER which may include, but is not limited to the following:

- Distribution System Impact Study
- Site Visit, Commissioning and Witness Testing
- Customers proposing interconnection of large (e.g. > 1 MW) projects should contact JEA and schedule a scoping meeting to discuss project specifics.
- DER connecting the electric system at or greater than 69kV must follow a different interconnection process and requirements not covered in this document. For those requests, refer to JEA's OASIS page and the JEA Agreement for Generator Interconnection to Transmission System.

Developers and owners of approved DER interconnections are required to be responsive to JEA's direction and instructions during emergency conditions. This may require removing the DER from service when JEA is performing line maintenance or other work on the circuit to which the DER is connected.

3.2. Technical Review Requirements

3.2.1. Interconnection Application Process

Guidelines for processing applications to interconnect DER in JEA's service area, and the associated technical reviews are specified in this section. Details of required technical review depend on the size and complexity of the DER plant to be connected. A tiered evaluation approach, illustrated in Figure 1, provides the possibility of expedited approval, as well as of conducting progressively more involved interconnection reviews initial review screening, supplemental review, and detailed study respectively.

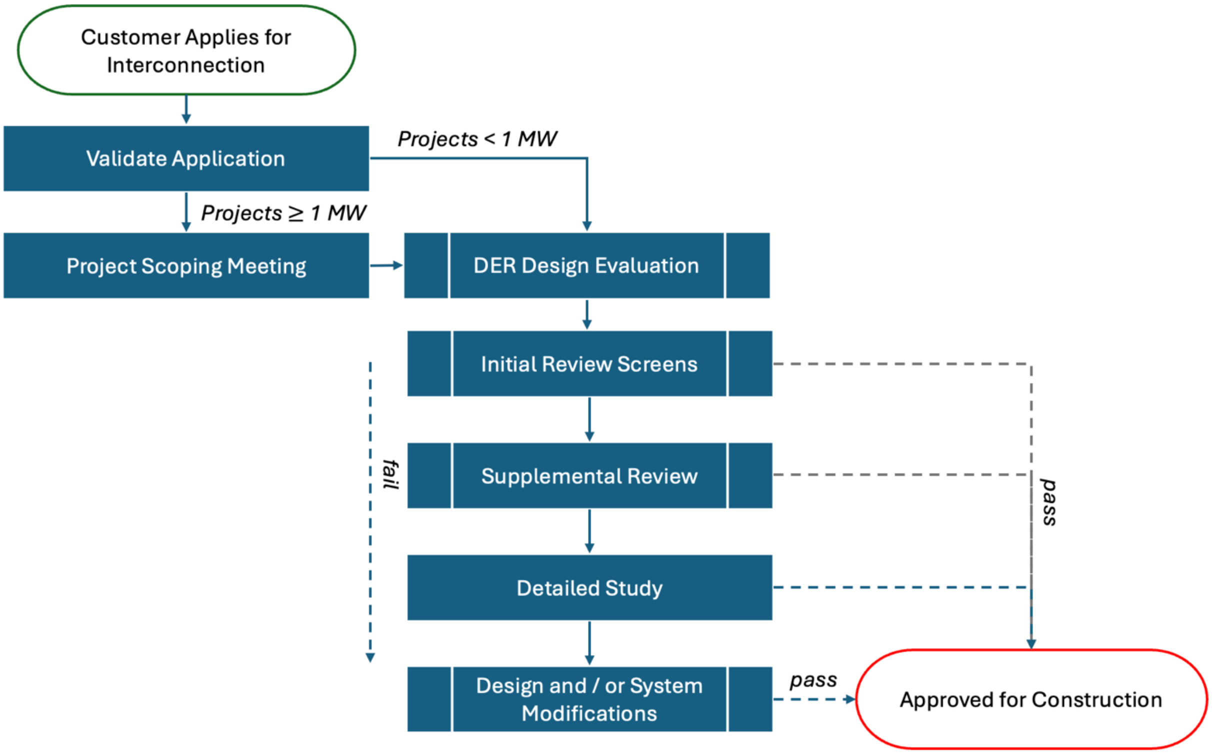

Figure 1. Overview of Interconnection Technical Review Process Flow

Technical requirements are defined for each level of review. They depend on timely submission of DER plans and other project details needed to complete each review level. The primary technical areas to be covered include voltage regulation, protection, power quality and thermal limits. Other requirements include service requirements and metering; telemetry, and at higher power levels, bulk system stability and reactive power balance studies. In some cases, analytical tools and feeder data are required to complete a review or study. Areas with high relative penetration of DER are more likely to require additional review and detailed studies.

3.2.2. Expected Technical Review Outcomes and Approvals

The expected outcome when applications are approved via technical review is a formal written notice provided to the customer with an 'Approval to Install' or 'Permission to Construct' letter.

The expected outcomes in case of conditionally approved applications are to provide the applicant with written notification with the specific conditions and requirements for interconnection—including the estimated cost to customer, when applicable. The following are examples of conditional approvals:

- Conditional with agreed-to changes in the proposed DER system design.
- Conditional with changes to DER operation, such as limited operating modes, and including utility control and/or curtailment of the DER under certain contingency circumstances.
- Conditional requiring utility system enhancement to resolve an issue identified in the technical review and paid for by the applicant.

- Applications held up for planned upgrades[4] may have the opportunity to contribute to the cost if is feasible to move forward with the work.
- If determined through mutual agreement between Utility and Applicant, another option is to identify DER operating requirements and/or limitations that contribute to overcoming the infrastructure deficiency.

Upon the completion of customer and/or JEA work, the applicant must have received a written authorization or permission to operate (PTO) prior to energization of the DER. JEA in many cases, will require commissioning and witness tests be performed prior to PTO issue. Commissioning and inspection testing is covered in Chapter 10. JEA reserves the right to inspect any DER at the time of installation or any time thereafter.

3.3. Technical Review Process

Every project will be required to undergo technical review and design assessment, including consideration for installed DER capacity, in-queue DER capacity, and distribution network specifics. Large capacity projects, and projects interconnecting in congested network locations may fail initial review screening and supplemental review, escalating to a detailed study. See Figure 1.

3.3.1. Initial Review

The screens described below assess impacts of both individual and aggregate DER in the vicinity of the interconnection. An application must pass all the screens to be eligible for approval for interconnection without further review. JEA will notify the customer of the results if the proposed interconnection fails any screen.

DER Design Evaluation:

The site plan, electrical layout (one-line diagram), and equipment data sheets will be reviewed for compatibility with the requirements outlined within this document and JEA electrical service standards, as applicable.

Initial Review Screens:

1. The proposed DER's Point of Common Coupling must be in the JEA service territory.
2. For interconnection of a proposed DER to a radial distribution circuit, the aggregated Export Capacity generation, including the proposed DER on the circuit shall not exceed 15% of the line section annual peak load as most recently measured at the substation. A line section is that portion of JEA's distribution connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. For solar JEA may consider 100% of applicable loading (i.e. daytime minimum load for solar), if available, instead of 15% of line section peak load.

[4] JEA scheduled upgrades or system modifications that were not triggered by the project proposing interconnection.

3. For interconnection of a proposed DER approved for export limiting and that can introduce Inadvertent Export, where the Nameplate Rating minus the Export Capacity is greater than 250 kW, the following Inadvertent Export screen is required. With a power change equal to the Nameplate Rating minus the Export Capacity, the change in voltage at the point on the medium voltage (primary) level nearest the Point of Interconnection does not exceed 3%. Voltage change will be estimated applying the following formula:

Formula	$\frac{(\boldsymbol{R_{Source}} \times \Delta\boldsymbol{P}) - (\boldsymbol{X_{Source}} \times \Delta\boldsymbol{Q})}{\boldsymbol{V^2}}$
Where: $\Delta\boldsymbol{P}$ = (DER apparent power Nameplate Rating – Export Capacity) × PF, $\Delta\boldsymbol{Q} =$ (DER apparent power Nameplate Rating – Export Capacity) × $\sqrt{(\boldsymbol{1 - PF^2})}$, R_{Source} is the grid resistance, X_{Source} is the grid reactance, V is the grid voltage and PF is the power factor	

4. Is interconnection of a proposed DER on the load side of spot network or area network protectors? If yes, fail screen – project will require more detailed review and potentially reverse power flow protection. If the answer to screen 4 is no, the screen passes.
5. The fault current of the proposed DER, in aggregation with the fault current of other DER on the distribution circuit, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the MV (primary) level nearest the proposed point of interconnection.
6. The fault current of the proposed DER, in aggregate with fault current of other DER on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or customer interconnection equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.
7. If the proposed DER is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed DER, shall not exceed 20 kW or 65% of the transformer nameplate rating.
8. If the DER PCC is behind a line voltage regulator[5], the DER's Nameplate Rating shall be less than 500 kW.
9. The proposed DER configuration confirms with Primary Distribution Line Type according to Table 1.

[5] This screen does not include substation voltage regulators.

Table 1. Acceptable DER Configuration per Primary Distribution Line Type

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result/Criteria
Three-phase, three-wire	If ungrounded on primary or any type on secondary	Pass screen
Three-phase, four-wire	Single-phase line-to-neutral	Pass screen
Three-phase, four-wire (for any line that has sections or mixed three-wire and four-wire)	All others	Pass screen for inverter-based generation if aggregate generation rating is ≤ 100% feeder* minimum load, or ≤ 30% feeder* peak load (if minimum load data isn't available) Pass screen for rotating generation if aggregate generation rating ≤ 33% of feeder* minimum load, or ≤ 10% of feeder* peak load (if minimum load data isn't available) * - or line section

If the proposed interconnection passes the screening and requires construction of any facilities, JEA will notify the customer of such requirement when it provides the Initial Review results. This normally includes related analysis and data underlying the determination. If the construction requirement is clear then JEA may provide a good faith cost estimate; if it is not clear then the requirement for a supplemental review or a system impact study will be indicated.

If the proposed interconnection fails initial screening and requires additional review, then a decision to proceed with the additional review will be required in writing from the customer.

Within 5 business days, the customer shall inform JEA if they intend to proceed with either required construction, further technical review or to withdraw the application.

3.3.2. Customer Options Meeting

If JEA is informed of a desire to proceed, then JEA and the customer shall schedule a customer options meeting to review 1) possible facility modifications, 2) screen analysis, and/or 3) related results to determine what further steps are needed to permit the DER to be connected safely and reliably. At the time of notification of JEA's determination, or at the customer options meeting, JEA shall:

- Offer to perform a supplemental review in accordance with section 3.3.4 and provide a non-binding good faith estimate of the costs of such review; or
- Obtain the customer's consent to continue evaluating the Interconnection Application via the Study Process and provide a non-binding good faith estimate of the costs of such review.

3.3.3. Supplemental Review Process

To accept the offer of a supplemental review, the customer shall agree in writing and submit a deposit for the estimated costs of the supplemental review in the amount of JEA's good faith estimate of the costs, both within 15 Business Days of the offer.

The customer shall be responsible for JEA's actual costs for conducting the supplemental review. The customer shall pay any review costs that exceed the deposit within 20 Business Days of receipt of the invoice or resolution of any dispute.

Following receipt of the deposit for a supplemental review JEA shall: 1) provide an estimated schedule and perform a supplemental review using the screens set forth below; 2) notify in writing the customer of the results; and 3) include with the notification copies of the analysis and data underlying JEA's determinations under the screens. JEA shall notify the customer following failure of any supplemental review.

Supplemental Review:

1. ***Minimum Load Screen:*** Where 12 months of line section minimum load data (including onsite load but not station service load served by the proposed DER) are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate DER capacity on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed DER.
   a) The type of generation used by the proposed DER will be considered when calculating, estimating, or determining circuit or line section minimum load relevant for this application. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (i.e., 8 a.m. to 6 p.m. for fixed panel systems and 7 a.m. to 7 p.m. for PV systems utilizing tracking systems), while all other generation uses absolute minimum load.
   b) When this screen is being applied to a DER that serves some station service load, only the net injection into JEA's electric system will be considered as part of the aggregate generation. JEA will not consider as part of the aggregate generation for purposes of this screen DER capacity known to be already reflected in the minimum load data.
2. ***Voltage and Power Quality Screen:*** In aggregate with existing generation on the line section: (1) the voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions; (2) the voltage fluctuation is within acceptable limits as defined by IEEE Standard 1453, or utility practice similar to IEEE Standard 1453; and (3) the harmonic levels meet IEEE Standard 519 limits.
3. ***Safety and Reliability Screen:*** The location of the proposed DER and the aggregate generation capacity on the line section do not create impacts to safety or reliability that cannot be adequately addressed without application of the Study Process. JEA shall give due consideration to the following and other factors in determining potential impacts to safety and reliability in applying this screen.
   a) Whether the line section has significant minimum loading levels dominated by a small number of customers (e.g., several large commercial customers).
   b) Whether the loading along the line section is uniform or even.
   c) Whether the proposed DER is near the substation (i.e., less than 2.5 electrical circuit miles), and whether the line section from the substation to the Point of Common Coupling is a Main line rated for normal and emergency ampacity.
   d) Whether the proposed DER incorporates a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time.

e) Whether operational flexibility is reduced by the proposed DER, such that transfer of the line section(s) of the DER to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

f) Whether the proposed DER employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, islanding, reverse power flow, or voltage quality.

4. ***Grounding Compatibility Screen:*** Determine if supplemental grounding is required to maintain effective grounding. If Supplemental grounding is required, provide the option to modify the DER system to include the necessary grounding equipment without proceeding to full study before the interconnection agreement is provided.

If the application fails supplemental review or if it is determined that the proposed interconnection requires construction of any facilities, JEA shall provide the customer with the option of proceeding to the Detailed Impact Study stage. If the customer wishes to proceed it shall notify JEA within 15 Business Days to retain its queue position.

3.3.4. Detailed Study

To accept the offer of a detailed study, the customer shall agree in writing and submit a deposit for the estimated costs of required studies in the amount of JEA's good faith estimate of the costs, both within 15 Business Days of the offer.

The necessary studies will be determined by JEA and may be informed by either initial screening and/or the supplemental technical review. Typical areas included in technical review studies are described in this section and summarized in **Table 2**. These studies are conducted based upon a review of the specific DER, location, and utility engineering practices. The estimated cost of any study must be paid by the customer. Upon completion the study actual costs will determine additional cost or refund.

3.3.4.1. System Impact Study (SIS)

A system impact study shall identify and detail the electric system impacts that would result if the proposed DER were interconnected without project modifications or electric system modifications. The SIS focuses on the adverse system impacts including but not limited to those identified in a scoping meeting. A SIS shall evaluate the impact of the proposed interconnection on the reliability of the electric system.

The system impact study must consider the proposed DER's design and operating characteristics, including but not limited to the applicant's proposed Operating Profile (where verifiable), and study the project according to how the project is proposed to be operated. If the DER limits export pursuant to Section 11, the system impact study must use Export Capacity instead of the Nameplate Rating, except when assessing fault current contribution. To assess fault current contribution, the system impact study must use the rated fault current; for example, the Customer may provide manufacturer test data (pursuant the fault current test described in IEEE 1547.1-2020 clause 5.18) showing that the fault current is independent of the Nameplate Rating.

Table 2. Comprehensive System Impact Study

Study Component	Criteria Evaluated
Load Flow	Steady State voltage, voltage unbalance, regulator tap movements
Power Quality	Voltage Fluctuations (e.g., TOV, flicker or RVC, inadvertent export events)
Thermal	Component current and energy limits, cycle times
Protection	Short circuit current, coordination, interrupt rating, breaker reach
System Grounding	Risk of Islanding, TOV
Stability (EMT)	Dynamic response and transient behavior

4. GENERAL TECHNICAL REQUIREMENTS

The DER interconnection shall be in compliance with IEEE 1547™-2018 and IEEE 1547.1™-2020. Inverters and synchronous machines, whenever possible, shall be UL 1741 SB certified and installed or commissioned with the IEEE 1547-2018 specified performance capabilities.

In addition, the customer is responsible for compliance with other codes such as: the National Electrical Code, local safety codes, and any applicable regulations imposed by the local authority having jurisdiction. This includes installing, setting, and maintaining all devices necessary for safe grid integration, operation, and to protect the customer's facilities.

4.1. Reference Points of Applicability (RPA)

The characteristics of the Local EPS and DER shall determine the RPA. The RPA for all performance requirements shall be the PCC except as stated in IEEE 1547-2018 clause 4.2. The RPA may be an alternate location for situations which include the power output rating of the DER, power output rating of the DER relative to other load levels on the Local EPS, power export capability of the Local EPS and zero sequence continuity between the PCC and PoC.

4.2. Applicable Voltages

The applicable voltages for proposed DER interconnections are as follows:

Medium Voltage Interconnections: Primary connected at 26.4kV, 13.2kV, 4.16kV as determined by the nominal operating voltage at the Point of Common Coupling (PCC).

Low Voltage Interconnections: Single-phase or three-phase line-side or load-side connected at single phase 120V/240V, three phase 120V/208V, 277V/480V and subject to the limitations of the service transformer and conductor serving the PCC.

4.3. TIR Isolation Requirements

4.3.1. DER Technology Application

4.3.1.1. Standby Generation

This system requires a disconnect switch either inside or outside the facility that is customer owned. A sign is required at the meter and at the utility isolation point (disconnect switch location) provided by the customer and as designed by JEA. Meter Socket Type Automatic/Manual Transfer Switching Devices are allowed that have been approved by JEA. JEA will not be responsible and held harmless of any damage that is caused by the malfunctioning of this device in any situation including when this device must be operated or removed by JEA.

The following requirements apply for approval of these installations:

- Application Form required (JEA.com)
- Residential 200A and below non-CT services do not require a disconnect switch (JEA meter is used as isolation device)
- Sign required at the meter and at the isolation point as designated by JEA (exception if isolation point is next to meter or residential 200A & below then only one sign is required)

- Electrical one line diagram required for review on residential services above 200A and all commercial services
- Disconnects must be at the facility/building voltage and can either be located inside or outside the facility
- Utility isolation point may be a switch or breaker that is located on the switchboard/switchgear or ATS/MTS
- Closed transition systems require JEA to review and approve the relaying and protection schema
- For closed transition systems, contractor must provide proof of meeting IEEE 1547 requirements (<100ms)
- For closed transition systems, JEA requires opportunity to witness test and copy of the commissioning report
- For approved closed transition systems on the JEA downtown network system, precautions must be taken by the customer to prevent inadvertent tripping of network protectors that can affect the availability of power to other downtown customers

4.3.1.2. Cogeneration:

This system requires an external disconnect type by the meter that is customer owned. A sign is required at the disconnect, near the meter, that is provided by the customer.

A disconnect switch or rapid shutdown device (RSD) shall be required to provide a separation point between the customer's cogeneration system and JEA's electrical system. This switch will be furnished and installed by the customer, in a visible location accessible to JEA personnel at all times. The switch will be installed as close to the meter as practical and be capable of being locked in the open position with a JEA padlock. The switch shall meet all applicable local and national electrical codes for the installed cogeneration system. The disconnect switch shall be permanently labeled clearly stating "*Cogenerator - JEA Disconnect Switch*" with the sign meeting the requirements below. If the disconnect switch is mounted out of sight of the meter, additional permanent signage must be posted at the revenue meter clearly stating the location of the JEA accessible disconnect switch. Signs shall be at a minimum, six inches by six inches with 3/8" white letters on a bright red background and comprised of metal, hard plastic, or weatherproof vinyl. The description on the sign may be text or a visual depiction and the switch will still need to meet the other JEA requirements.

The customer shall be responsible for coordination and synchronization of the customer's equipment with JEA's electrical system and assumes all responsibilities for damages that may occur on the JEA system from improper coordination or synchronization of the cogenerator with JEA's system. The customer must have JEA approval of the proposed design and protection schema before parallel operation is permitted.

The customer shall provide approved utility grade protective equipment necessary to immediately, completely, and automatically disconnect the cogeneration system from JEA's system in the event of a fault on JEA's system, a fault on the customer's system, or loss of source on JEA's system. The cogeneration system shall incorporate a protection schema that will cease to parallel with the utility line and shall not have the capability to back feed into the utility distribution system until continuous normal voltage and frequency have been maintained by the utility, at which time the customer is allowed to parallel the cogeneration system back onto the utility. This protection schema will be sanctioned by JEA before final approval is given to operate customer's cogeneration system in parallel with JEA. JEA reserves the right to require a commissioning test report demonstrating the design operates as expected.

4.3.1.3. DER Interconnection at Primary Distribution Voltage:

This system requires an external and accessible JEA approved customer owned isolation device that is lockable with a JEA padlock outside the facility and operable by JEA. A JEA provided DER sign must also be permanently mounted at this disconnect. JEA reserves the right to install a separate disconnecting device depending on the complexity of the interconnection that may require remote switching, telemetry, and protection capabilities.

JEA must be aware of the location of the isolation device. A sign at the JEA revenue meter must either visually or in text clearly depict the location of the isolation device. The sign must be red, approximately 6"x6", 3/8" white lettering made of metal, hard plastic or weatherproof vinyl.

4.3.1.4. DER Interconnection at Secondary Distribution Voltage and/or Behind the Meter (BTM):

For residential and commercial customers, these systems require a utility disconnect. If the system includes a permanently mounted battery or multiple batteries, a separate battery load disconnect is also required. This also includes all stand-alone battery systems capable of V2H (vehicle to home), V2G (vehicle to grid), and systems capable of islanding. These disconnects must be external to the home or facility. A sign is required at both the utility and battery load disconnect locations. If the disconnect(s) are located more than 10 feet away or not visible from the meter, a separate sign is required at the JEA meter that either visually or clearly depicts in text the location of the disconnect(s). V2H systems will follow the standby generator utility disconnect and signage requirements in section 4.3.1.1. and as noted in 4.3.1.4.

The following requirements also apply for the BTM DER interconnection applications:

The utility and battery load disconnect switches can be in the same enclosure; however, JEA encourages the use of separate enclosures for additional clarity of independent function with the customers system. All isolation devices must be external, accessible, lockable with a JEA padlock (5/16" shank) and near the meter. If the disconnect switch(es) cannot be located visibly or reasonably near the meter, ensure there is a sign (provided by the contractor) at the meter (red, approximately 6"x6", 3/8" white lettering made of metal, hard plastic or weatherproof vinyl) indicating where the disconnect switch is located. The disconnect location must be external and accessible on the house or facility. The description on the sign may be text or a visual depiction and the switch will still need to meet the other above stated requirements. In addition, battery load disconnect switches may consist of either an AC or DC disconnect. A rapid shutdown device (RSD) is an acceptable battery load disconnect. All other utility disconnects must be AC and at the facility voltage.

- PowerClerk application required on JEA.com
- All commercial systems require a scheduled safety inspection in PowerClerk
- Any residential systems with a battery, including V2H systems, require a scheduled safety inspection in PowerClerk (PV only inspections do not require scheduling with the customer/contractor)
    - V2H systems require the customer to be present for safety inspection
- During the scheduled inspection, contractor must successfully demonstrate the functionality of disconnect switches and transfer of power to critical loads panel with battery systems

- Impact study will be required on commercial systems that are 2MW or above even if initial screens pass
- $1000 fee required for systems that are 100kW and above
- Customer required to pay CIAC charge if combined DER systems (customer and neighbors) exceed 120% of JEA transformer rating
- This type of system is not normally allowed on downtown network systems due to their effects on network protectors

4.4. Transformer and Grounding Compatibility

4.4.1. Service Transformer Connections

The physical location of all low and medium voltage DER interconnections must comply with JEA's rules and regulations for electric service, reviewed and approved by JEA. Three phase service may be required for larger single phase DER interconnection requests.

4.4.1.1. Transformer Configuration Requirement

The following transformer winding configuration requirements shall apply. The utility side transformer connection is determined by the Area EPS configuration. The DER side transformer connection will be dictated by the plant design.

Table 3. Transformer winding configuration requirements

Utility System	Primary Winding (Utility Side)	Secondary Winding (DER Side)	Comments
26.4kV, 13.2kV, and 4.160kV (4 wire)	Wye - Grd	Wye – Grd	Preferred
	Wye - Grd	Wye	Must be approved by JEA
	Wye – Grd	Delta	Must be approved by JEA

4.4.2. Effective Grounding

Requirements for effective grounding are specified in IEEE 1547-2018 clause 4.12 - Integration with Area EPS Grounding.

The DER interconnection inclusive of DER associated equipment and interconnecting transformer must be compatible with the feeder grounding practice at the point of interconnection. With some exceptions, installations should meet the requirements for "effectively grounded" as described in IEEE/ANSI C62.92.2 for synchronous machines and IEEE/ANSI C62.92.6 for inverters. Any exceptions must be approved by JEA. In addition, where applicable, grounding requirements identified in the National Electrical Code and local electrical codes shall be met.

4.5. Additional General Technical Requirements of DER

In alignment with IEEE 1547-2018, the following performance requirements should be satisfied by proposed DER interconnections and should conform with the following performance requirements.

Requirement	IEEE 1547-2018 Clause
Measurement Accuracy	*Clause 4.4 includes steady state and transient measurement windows, accuracy, and range across parameters governing DER capability.*
Cease to Energize	*Clause 4.5 describes cease to energize such that DER may maintain auxiliary self-power to continue to assess grid conditions and perform service re-entry routine.*
Control Capability	*DER shall be capable, per clause 4.6, of receiving an external signal that disables service re-entry, to limit active power, or by changing active modes or parameters.*
Prioritization of DER Response	*Prioritization in this context is not based on grid need or operational discretion. 1547 lays out the hierarchy of functions such as trip, frequency droop, ride-through, and power mode. Certified DER must follow this prioritization as part of their active response to system conditions.*

4.6. Inadvertent Energization of Area EPS

The DER shall not energize the Area EPS when the Area EPS is de-energized. Exceptions may be given for intentional Area EPS islands and at the discretion of JEA.

4.7. Enter Service

The voltage and frequency settings to be used for entering service shall be the default values for voltage and frequency ranges as displayed in Table 4 in IEEE 1547-2018 Clause 4.10.2 – Enter Service Criteria, unless specified otherwise by JEA. The default values for delays and ramp rate shall be used as identified in IEEE 1547-2018 Clause 4.10.3 – Performance during entering service.

4.7.1. IEEE 1547-2018 Section 4.10 Enter Service Settings

DER configuration regarding Enter Service Criteria is specified in Appendix A of this document. They include Permit Service, Enter Service Voltage, Enter Service Frequency, and Soft-Start Ramp Rate.

4.7.2. Synchronization

Requirements for synchronization are specified in IEEE 1547-2018 clause 4.10.4 - Synchronization. DER shall not exceed limits to frequency, voltage, or phase angle while paralleling with the area EPS.

4.8. DER Interconnect Integrity

Requirements for DER interconnection integrity are specified in IEEE 1547-2018 clause 4.11, and include immunity from electromagnetic interference, surge withstand and 2 times over voltage capability for paralleling equipment.

4.8.1. Basic Insulation Levels (BIL)

The BIL rating of any new transformer, circuit breakers, reclosers, and any other electrical equipment connected to the utility power system must coordinate with the requirements of the utility system at the PCC.

5. DER SUPPORT OF GRID VOLTAGE

5.1. Reactive Power Capability

All DER installations will be required to have reactive power support capability. Requirements for reactive power capability are specified in IEEE 1547-2018 – Clause 5.2 – Reactive Power Capability of the DER. Unless otherwise specified by JEA, Category A for rotating machines and Category B for inverters shall be used to determine the appropriate values identified in IEEE 1547-2018.

Table 4. **Assignment of IEEE 1547-2018 normal performance categories to various types of DERs**

Power Conversion	Prime Mover (Energy Source)	Reactive Power Support
Inverter	Solar PV, Battery Energy Storage, Wind, Fuel Cell	Category B
Synchronous and Induction	Bio-/Landfill Gas, Fossil Fuel, Hydro, Combined Heat & Power	Category A

JEA DER configuration requirements for reactive power control mode and active power control modes are provided in Appendix A.

6. DER RESPONSE TO ABNORMAL CONDITIONS

Requirements for DER response to abnormal conditions are specified in IEEE 1547-2018 clause 6 – Response to Area EPS abnormal conditions. DER ride-through and trip settings are also provided in Appendix A.

Unless otherwise specified by JEA, the DER shall meet abnormal operating performance category according to Table 5, and specified in Clause 6 of IEEE 1547-2018.

Table 5. Assignment of IEEE 1547-2018 abnormal performance categories to various types of DERs

Power Conversion	Prime Mover/Energy Source	Category
Inverter	Solar PV, Battery Energy Storage, Fuel Cell, Wind	Category II or III
Synchronous and Induction	Bio-/Landfill Gas, Fossil Fuel, Hydro, Combined Heat & Power	Category I

<u>JEA's Protection Coordination Clearing Times for Category II DG Projects</u>

IEEE 1547-2018: Category II Interconnection System Response to Abnormal Voltages and Frequencies

	Pickup	Inverter Clearing Time (cycles/seconds)	DER's DG Clearing Time (cycles/seconds)	JEA's DG Clearing Time (cycles/seconds)
UV Step 2	**V < 45%**	9.6~ / 0.16 s	25~ / 0.42 s	40~ / 0.67 s
UV Step 1	**45% ≤ V < 70%**	600~ / 10 s	615~ / 10.25 s	630~ / 10.5 s
OV Step 1	**110% < V < 120%**	120~ / 2 s	135~ / 2.25s	150~ / 2.5 s
OV Step 2	**V ≥ 120%**	9.6~ / 0.16 s	25~ / 0.42 s	40~ / 0.67 s
UF Step 2	***F < 56.5 Hz**	9.6~ / 0.16 s	25~ / 0.42 s	40~ / 0.67 s
UF Step 1	***F < 58.5 Hz**	18,000~ / 300 s	18,015~ / 300.25 s	18,030~ / 300.5 s
OF Step 1	***F > 61.2 Hz**	*18,000~ / 300 s	*18,015~ / 300.25 s	*18,030~ / 300.5 s
OF Step 2	***F > 62 Hz**	9.6~ / 0.16 s	25~ / 0.42 s	40~ / 0.67 s

* Default values. This time shall be chosen to coordinate with typical regional underfrequency load shedding programs and expected frequency restoration time.

6.1. Area EPS Faults

Requirements for area EPS faults are specified in IEEE 1547-2018 clause 6.2.1 -Area EPS Faults. For short-circuit faults on the Area EPS medium voltage the DER shall cease to energize and trip unless specified otherwise by the Area EPS operator. This requirement is not applicable to faults that cannot be detected.

6.2. Open-Phase Conditions

Requirements for open-phase conditions are specified in IEEE 1547-2018 clause 6.2.2 – Open Phase Conditions. Three phase DER shall detect, cease to energize, and trip within 2.0 s for any open phase condition occurring directly at the reference point of applicability.

6.3. Area EPS Reclosing Coordination

Requirements for area EPS reclosing coordination are specified in IEEE 1547-2018 clause 6.3 - Area EPS Reclosing Coordination. Appropriate means to ensure that the DER does not expose the utility to unacceptable stresses or disturbances may include, but are not limited to properly operating DER islanding detection, reclosing blocking on energized circuit, transfer trip, or other schemes required by JEA.

6.4. Voltage Ride-through Capability Requirements and Trip Settings

Requirements for voltage trip and ride-through requirements are specified in IEEE 1547-2018 clause 6.4 – Voltage.

DER except for synchronous and induction generating machines shall meet abnormal operating performance Category II or Category III identified in IEEE 1547-2018. Synchronous and induction machines shall meet abnormal operating performance Category I.

The DER shall trip for default values for under and over voltage and clearing times as identified in IEEE 1547-2018 Tables 11, 12, and 13.

6.5. Frequency Ride-through Capability Requirements and Trip Settings

Requirements for frequency trip and ride-through are specified in IEEE 1547-2018, clause 6.5 - Frequency.

The DER shall trip for default values for abnormal over and under frequency and clearing times as identified in IEEE 1547-2018 Table 18 – "DER response (shall trip) to abnormal frequencies for DER of abnormal operating performance Category I, Category II, and Category III."

The parameters of frequency droop operation shall be to their default values as identified in IEEE 1547-2018 Table 24.

Frequency tripping and clearing times from IEEE 1547-2018 Clause 6.5 shall be as specified in Table 6-3.

7. POWER QUALITY PERFORMANCE

Traditional power quality standards define expected voltage quality in the electric grid. DER operating in parallel with the grid should not degrade voltage quality under any operating or malfunction condition. Requirements for DER output power are intended to be more stringent than the requirements for customer load. This follows the principle that generation operating in the grid should be better behaved than load.

Given these expectations the IEEE Std 1547™-2018, section 7, addresses power quality requirements for DER certification. Note these are limits for DER in normal operation and do not apply to inadvertent mis-operation or failure modes. When installed, DER should not impact the delivered voltage quality of other customers on the grid.

Certification tests cover dc injection, synchronization, harmonic current distortion, and load rejection overvoltage. There are also power quality requirements regarding DER caused voltage fluctuations, flicker, rapid voltage change and ground fault overvoltage. These depend on the relative strength of the grid and the PCC. Determining compliance comes from either circuit analysis or by measurement either during commissioning or in response to a voltage complaint.

The following additional requirements address potential voltage impacts of DER when interconnected and operating in parallel with the grid.

7.1. Limitation on DC Injection

The DER should not inject dc current into the ac power system under any condition. IEEE 1547 specifies a limit of 0.5% of rated current and certified DER are assumed to meet this limit.

7.2. Limits on DER-caused Voltage Fluctuations

Voltage fluctuation limits depend on both the DER relative size and the strength of the grid (short-circuit MVA) at the PCC. The main concerns are DER-caused fluctuations on the medium voltage power system. Requirements address rapid voltage change (RVC) as caused by switching large real or reactive power components, repeating power fluctuation causing flicker, and power changes that cause excessive voltage regulator operations. RVC and flicker limits are specified in IEEE Std 1547™-2018 clause 7.2 - Limitation of Voltage Fluctuations Induced by the DER.

7.2.1. Rapid Voltage Change (RVC) Limits

In normal operation the DER shall not cause RVC changes that exceed 3% ΔV at medium voltage and 5% ΔV when the PCC is at low voltage. Excluded are rare events such as transformer energization during a plant start-up or circuit restoration.

7.2.2. Flicker Limits

In normal operation the DER shall not cause repetitive changes of power output leading to voltage fluctuations that may can light flicker or other load impacts. To determine compliance an allocation of the grid's flicker capacity at the PCC is provided to the DER. The allocation is $P_{st} \leq 0.35$, based on a 10-minute assessment of DER-caused voltage fluctuations. Photovoltaic DER that is suspect of creating flicker violations should be subject to a flicker assessment as part of a supplemental review.

7.3. Limitation of Current Distortion

The DER should not cause an increase in voltage distortion at the PCC. If increased voltage distortion is observed then additional monitoring, investigation and mitigation may be required. This is not expected from certified DER; however, unexpected interactions can occur. For example, harmonic resonance or unpredictable interactions with customer loads.

7.4. Limitation of Overvoltage Contribution

The DER should not cause overvoltage that exceed limits defined in IEEE 1547-2018. Overvoltage contribution refers to a single cycle overvoltage level of 138% for effective grounding limits and a cumulative instantaneous limit which is often used to alleviate load rejection overvoltage (LROV) concerns.

7.5. Limits on Unbalance

Three-phase DER installations shall not create current unbalance during normal conditions. The limit of periodic current unbalance is not to exceed 25% or any level that causes phase voltage in service to other users to violate limits for three-phase balance. Three-phase voltage unbalance in power service is typically limited to 2-3%, defined by:

$$Percent\ Voltage\ Unbalance\ = 100 \times \frac{Maximum\ Deviation\ from\ V_{ave}}{V_{ave}}$$

The largest capacity single phase DER operating in parallel with the grid is typically ≤ 50kW. Above that size, a balanced 3 phase system is normally required. In case of two-phase service, the 3-phase DER limit will be determined by analysis of the available service and the DER. When 3-phase service is available, a balanced 3-phase connection shall be used.

8. ISLANDING

Requirements for DER islanding response are specified in IEEE 1547-2018 clause 8 – Islanding.

8.1. Unintentional islanding

Within 2 seconds of the formation of an island the DER shall detect the island and cease to energize the Area EPS.

8.2. Intentional islanding

Intentional islands can be one of two types: (1) an Intentional Area EPS Island which includes any portion of the Area EPS (i.e., multiple utility customers) and shall be designed and operated in coordination with the Area EPS operator when islanded; and (2) an Intentional Local EPS Island, or Facility Island, which is totally within the bounds of the local EPS (i.e., a single utility customer electrically connected at a single PCC) during the intentional island condition. The requirements outlined within this section pertain to the second type, a customer or third-party owned and operated Intentional Local EPS Island.

The customer shall bear all responsibility for energy management, service, safety, power quality, and plant operation during any operation while DER is isolated from the JEA Area EPS.

DER configured to support intentional islands shall disconnect from the JEA system by a microgrid interconnect device (MID)[6] in accordance with NEC Article 700.

Any DER interconnecting with the aim of operating as an intentional island shall be equipped with a multi-mode system consisting of stand-alone capable DER and MID. In cases where the DER is a simple, single unit, the DER and MID shall be tested together and certified to UL 1741 SB including UL 1741 CRD for multi-mode. In accordance with UL 1741 CRD for multi-mode, such systems may employ open or closed transfer when switching between sources. The following are some technical requirements for DER proposing to interconnect with intentional island capabilities.

- Closed transition, also known as make-before-break designs shall be limited to 100 ms of parallel connection.
- Combinations of DER and MID shall conform to anti-islanding provisions of IEEE 1547-2018.
- Systems where the RPA is PCC or Composite DER Systems[7] shall be subject to additional commissioning and witness testing to demonstrate isolation during island mode and return to service.

[6] A Microgrid Interconnect Device (MID) is a device that enables a microgrid (intentional island) system to separate from and reconnect to operate in parallel with the area EPS.

[7] Composite DER: Systems which meet IEEE 1547-2018 compliance through various supplemental DER devices such as micro grid or plant controllers, relays, and reactors.

8.2.1. Conditions for transitions to intentional island

The conditions under which an intentional island may disconnect from the Area EPS and transition the DER to intentional island mode are covered in P1547 Clause 8.2.2

8.2.2. Reconnection of an intentional island to the Area EPS

The return to service conditions in Section 4.7 shall be met prior to an intentional island reconnecting to the Area EPS.

8.2.3. Adjustment to DER settings

Control and protection settings may have to be adjusted when operating as an intentional island. DER shall demonstrate the capability to revert to the settings issued by JEA for parallel operation.

8.2.4. Commissioning and Witness Testing

DER configured for and applying with intentional island capability may be subject to additional commissioning and witness tests to demonstrate the applicable additional capabilities.

9. DER INTEROPERABILITY AND CYBER SECURITY

9.1. General Requirements

All DER shall meet the requirements for interoperability as specified in IEEE 1547-2018 Clause 10 – Interoperability, Information Exchange, Information Models, and Protocols.

This section defines specific requirements for JEA and clarifies which systems must be connected to telecommunications networks for monitoring and control purposes.

9.2. DER Local Communication Interface

9.2.1. DER Requirements

All DER shall have a local DER communication interface meeting the interoperability requirements specified in IEEE 1547-2018 clause 10 – Interoperability, Information Exchange, Information Models, and Protocols.

9.2.2. Communication Interface Onsite Physical Presence

The DER local communication interface shall be a wired interface as specified in IEEE 1547-2018 Table 41. This wired interface shall be physically present at the DER site, having no dependencies on internet or other network connectivity and no dependencies on cloud or other offsite systems.

9.2.3. Single Communication Interface for a DER

In accordance with the IEEE 1547-2018, JEA requires a single communication interface for each DER. It shall not be acceptable for separate communication interfaces to be provided for parts of a DER, for example at each inverter in a multi-inverter DER plant.

Monitoring and nameplate information read through the single communication interface shall be representative of the plant as a whole, not a part or portion thereof.

Control settings and functions shall be relevant to the DER as a whole and the associated single reference point of applicability (RPA) such as the point of common coupling (PCC) or electrical point of connection (PoC). For example, with a multi-inverter DER plant, the control settings for the volt-var function shall apply to the voltage and reactive power at a single point, the RPA, and not to multiple points of measurement at each inverter within the DER.

9.2.4. Local Communication Interface Labeling

JEA requires that the standard local communication interface be labeled at each DER site such that it is readily locatable and identifiable. The label shall state "IEEE 1547-2018 Local Communication Interface" and shall name the standard protocol by which the DER was certified.

For interconnection applications that involve a site plan, the physical location of the local communication interface shall be identified on the plan.

9.2.5. Communication Interface Availability

The DER local communication interface shall be present and available for DER when deployed and shall remain in place for the life of the DER. All hardware required shall be present and no additional equipment shall be needed to make the local interface operational.

No DER equipment changes shall be needed to access or activate the local communication interface such as jumpers, switches, wire-splicing, or mechanical modifications.

9.2.6. Communication Interface Operability

JEA requires that the standard local communication interface not be locked, disabled, or otherwise unresponsive to communication as specified by the standard communication protocol for which the DER is certified. Vendor-proprietary setup, configuration, password mechanisms, remote procedures and customer actions shall not be utilized to make the communication interface operational and responsive.

As specified in IEEE 1547-2018, Table 42, “The local DER communication interface shall be active and responsive whenever the DER is operating and in a continuous operation region or mandatory operation region.

Where communication interface is utilized the DER customer shall include provision in design for power to communication equipment.

9.3. Right to Utilize DER Communications

JEA reserves the right to make use of the DER communication capabilities for monitoring and control purposes.

9.3.1. Utilization Onsite or Remote

The communication may be performed onsite during commissioning or subsequent visits to check or adjust plant settings. This may be performed using JEA’s software tools connecting to the DER’s standard local communication interface.

The communication may be performed remotely. This may be performed using fixed networks that are deployed by JEA connecting to the DERs local communication interface.

9.3.2. Utilization Upon Interconnection or Thereafter

JEA’s utilization of the standard local communication interface may be immediate, during or upon interconnection or subsequently at any time over the lifecycle of the DER.

9.4. DER Local Interface Protocol

IEEE 1547-2018 clause 10.7 – Communication protocol requirements recognizes that JEA may specify the required protocols at local DER communication interfaces from among the three standards identified in Table 41.

JEA specifies the required protocols on the local communication interface based on criteria identified in Table 6:

Table 6. Assignment of IEEE 1547-2018 local DER communication interface protocols to various types of DERs

Criteria 1: DER Size	Criteria 2: Power Conversion	Examples	Required Protocol
Small scale	Inverter	Residential and small commercial Solar PV, Battery Energy Storage or EVSE with V2G capability	SunSpec Modbus
	Synchronous generator	Small industrial and independent power producer bio-/landfill gas, fossil fuel, hydro, combined heat & power	IEEE 1815 (DNP3):AN2018-001
Large scale	Inverter	Utility-scale Solar PV, Battery Energy Storage	IEEE 1815 (DNP3):AN2018-001
	Synchronous generator	Industrial and independent power producer bio-/landfill gas, fossil fuel, hydro, combined heat & power	IEEE 1815 (DNP3):AN2018-001

9.5. Communication Network Connectivity

All DER interconnections will be reviewed for the need of communication connectivity before permission to operate is approved. JEA reserves the right to activate the communication connectivity for any DER not initially activated in commissioning at a future date.

9.6. JEA DER Network Adapter (DER Gateway)

For DER interconnections that require a communication network connection to JEA, JEA will provide and install, at customer cost, a DER gateway that connects to the DER's standard local communication interface.

9.6.1. Gateway Inspection and Maintenance

JEA reserves the right to access the DER gateway for inspection, reconfiguration, and maintenance purposes. JEA reserves the right to replace the DER gateway, at JEA's cost, as needed over the life of the DER.

9.7. DER Cyber Security

9.7.1. Secondary Communication Interfaces

DER greater than 1 MW may be prohibited from having additional remotely accessible communication connections to plant controllers, inverters, protective devices or other equipment capable of affecting the power behavior of the DER. Communication connections to metering devices for remote monitoring purposes are permitted. JEA will evaluate the communication interfaces for greater than 1 MW DER on an individual basis.

9.7.2. DER Firmware/Software Updates

DER 1 MW or below may be firmware/software updated by the DER vendor, owner or operator, either onsite or remotely, as required.

DER greater than 1 MW are required to inform JEA and receive approval prior to any firmware/software updates.

For all DER sizes, DER configuration and settings must be retained or restored when any firmware/software update takes place.

10. COMMISSIONING AND VERIFICATION REQUIREMENTS

10.1. General Requirements

Verification requirements (design evaluation, as-built submittals, configuration settings, and commissioning tests) are specified in IEEE 1547-2018 clause 11 – Test and Verification Requirements and in Annex F, Discussion on Testing and Verification.

This section provides steps supporting verification that the plant interconnection demonstrates capabilities described in IEEE 1547-2018 and JEA grid compatibility requirements. This process includes configuration of the DER's functional and protection settings DER As-Built Evaluation, commissioning, and witness testing. DER size, class, and relative impact will be used by JEA to determine configuration and test requirements.

Specific requirements for each project will be communicated to the customer. These requirements will be a subset of the items found in this section.

10.2. DER Commissioning Process

Commissioning and verification requirements are specified in IEEE 1547-2018 clause 11 – Test and Verification Requirements.

1. Customer shall notify JEA upon completion of construction and submit as-built documentation.
2. JEA will conduct an Installation Evaluation, confirming that installation as-built matched the approved design and a review of DER settings.
3. Projects will be identified by JEA which require a pre-commissioning test plan. This plan will be provided by the customer, approved by JEA, and will be conducted within an agreed upon timeframe.
4. Upon completion of pre-commissioning tests, customer shall notify JEA and provide test results. If determined to be satisfactory by JEA, the JEA commissioning / witness test will be scheduled by mutual agreement.

10.2.1. Verification of the DER Settings

Prior to commissioning tests, the customer shall configure the DER facility's settings by means of one of the following options:

1. Using local or remote vendor configuration tools.
2. Use of a configuration and validation toolkit that uses the *local DER communication interface*.[7]

10.2.2. Installation Evaluation

Prior to the performance of commissioning tests by qualified personnel, JEA will evaluate the as-built documentation to confirm that it is consistent with the application and other required project documentation. This installation evaluation is intended to determine whether commissioning can

[7] Common File Format for Distributed Energy Resources Settings Exchange and Storage. EPRI. Palo Alto, CA: December 2022. 3002025445. [Online] https://www.epri.com/research/products/000000003002020201

proceed and the level of commissioning that is required. Certain commissioning tests may need to be completed by the customer before Witness Testing can take place.

10.2.2.1. Review to Confirm As-Builts

The as-installed DER equipment information is required before witness testing for confirmation of consistency with previously provided documentation. This information shall be supplied for the installed DER system and for all DER equipment. Any system not installed per approved design is in violation of JEA requirements and shall be deemed not compliant for parallel operation.

10.2.2.2. Documentation and Reporting of DER Functional Settings

The customer shall provide verification that the plant has been programmed according to the settings profile requirements issued by JEA. This may be done by providing a serialized, time stamped EPRI common file format read from the DER.

10.3. DER Commissioning Tests

The DER facility commissioning process shall be planned and carried out at the expense of the customer by a qualified third-party contractor after construction is completed, installation as-built evaluation is satisfactory, and the site is ready for JEA Witness Testing. The commissioning process shall verify that the facility does not create adverse system impacts to the electric grid and to other customers served by the grid. JEA staff and / or approved JEA inspector(s) will be on site for the testing process.

10.3.1. Facility Commissioning Tests

Commissioning requirements are dependent on the size of the DER, DER certification, and whether the RPA is at the PCC or PoC as identified in IEEE 1547-2018. The following summarizes detailed and basic commissioning tests for various classes of DER.

Example commissioning test by category:

Commissioning Test	Basic Commissioning	Detailed Commissioning
As-built Verification	X	X
Protection Relay / DTT		X
SCADA / Metering	X	X
Cease to Energize / Loss of Grid	X	X
Permit Service Signal	X	X
Enter Service Ramp		X
Open Phase Detection / Open Phase Overvoltage Test		X
Power limit function (as applicable)	X	X

Commissioning tests shall be performed by qualified personnel. For DER systems with plant controllers, commissioning tests shall include the plant controller. The results of the commissioning tests will be evaluated by JEA before Witness Testing can take place.

In addition to the commissioning test requirements identified in IEEE 1547-2018 DER settings shall be verified, and protective relaying shall be tested as identified in Section 13.4.2.- Protective Relay Tests. Commissioning is also required for telemetry systems depending on DER size and application. Witness testing for spot or area network connected DER shall include a JEA System Protection/Telecom point-to-point testing of any protection scheme.

10.4. Protective Relay Tests

Qualified testing personnel must perform tests on the customer's protective relaying prior to energizing from the JEA system. Testing requirements will be evaluated and determined on a case-by-case basis by JEA, dependent upon the configuration of the proposed generating facility. Portions of the customer's equipment may be energized when the associated testing for that portion has been completed and verified.

Table 7. Example testing requirement for relay equipment

Relay Equipment Testing Requirement	Type of Testing
Protection Device Function	Variable – Determined by Relay Type
Acceptance Testing	Test Document Review
Setting Calibration	Witness/Functionality
Tripping Check	Witness/Functionality
Sensing Devices	Test Document Review
Primary Current/Voltage	Witness/Functionality
Telemetry for Protection Scheme	Witness/Functionality

The configuration of settings for the protection systems shall be the settings previously provided by the customer to JEA and approved by JEA. These settings shall not be altered during commissioning without the authorization of JEA.

10.5. Witness Testing

Before parallel operation with the Utility System, and after completion of commissioning tests, additional witness testing may be required and inspected by JEA and/or approved JEA inspector(s). The customer is responsible for providing qualified personnel who will complete all required tests. Witness testing is generally required for larger DER. JEA reserves the right to require witness testing in all DER interconnected scenarios. Witness tests that must be performed in accordance with requirements described above include, but are not limited to:

- Cease-to-energize and trip test
- Anti-islanding
- Reconnection test
- Load Rejection Overvoltage test
- Power Limit functions test (if applicable)
- Radio Frequency Interference test

- Current harmonics test
- Telemetry/SCADA (If applicable)
- Primary Metering
- DC Injection
- Direct Transfer Trip (If applicable)
- Reverse power relay (If applicable)}

Witness testing for spot or area network connected DER shall include a JEA System Protection/Telecom point-to-point testing of any protection scheme.

10.6. Recommissioning

Recommissioning is required, under certain circumstances, after the original commissioning and witness testing is completed. The extent of recommissioning is dependent on the reason for the commissioning and the effect on the DER interconnection.

Circumstances that may lead to event based DER recommissioning include:

- Change in version of software, software or parameter modifications that change rated values.
- Replacement of major components or modules with a new version.
- Required changes in the facility telemetry, or changes in major equipment (e.g. transformers, circuit breakers, etc.). Change in operating mode that was not previously commissioned.

Recommissioning may be scheduled, triggered based on notification of facility change requirements, and may occur due to automated notices of operation outside of expected parameters. These notices may include mis-operation of the DER, mis-operation of protective systems, or excess harmonics detected at the PCC. JEA will determine whether recommissioning may require the full set of tests required of a new facility or a subset of these tests will be sufficient. The level of testing is dependent on the reason for the recommissioning.

10.7. Periodic Testing

Periodic testing may be required as part of the regular testing of basic functionalities of protective and control functions. These tests are expected and may need to occur in time frames typically ranging from every year to every 10 years depending on manufacturers recommendations and JEA's experience with similar equipment.

Additional requirements for periodic testing are specified in IEEE 1547-2018 clause 11.2.6 - Periodic Tests and Verifications. These requirements include changes in functional software or firmware changes, changes in hardware components of the DER, and changes in protection functions or settings.

10.8. Periodic Testing Requirements

The customer must provide JEA with calibration and functional test data for the associated equipment upon request. Minimum intervals are indicated below:

Table 8. Periodic testing requirements

Device	Frequency
Relays	Annually
Communication Channels	Annually
Circuit breakers	Every 3 Years
Batteries[8]	Per IEEE 450-2020 Standard

The customer must include the identities and qualifications of the personnel who performed the tests. Utility personnel may need to periodically witness the testing.

[8] Vented lead-acid batteries for stationary applications that are used in DER design.

11. DISTRIBUTION SYSTEM COMPATIBILITY

11.1. DER Integration Compatibility with the Grid

This section provides protection guidelines, equipment rating evaluation and requirements for both radial connected and network connected DER. JEA will provide the bus and line configurations and the protection requirements that are necessary to connect the proposed DER. Protection requirements for a specific facility may be greater than those listed, based on system conditions, interconnection location, DER type and/or for large DER.

Settings of utility-operated protection systems located at the RPA and proposed upstream between the DER and the substation of the bulk power system, must be submitted to, and approved, by JEA. Settings require review for coordination of DER performance under abnormal conditions (e.g., ride-through) as specified in IEEE 1547-2018.

Typical protection requirements for all sites are covered in this section. This provides basic information on the types of protection schemes necessary for parallel operation of generators.

11.2. Grid Integration for Radial-Connected DER

Integration requirements for radial-connected DER address the compatibility of the DER facility at the PCC and along the distribution feeder. Feeder voltage regulation, protective relaying, short circuit coordination, reverse power requirements are among compatibility considerations. Requirements depend on the DER type, location, existing conditions, normal and abnormal boundaries, and feeder capacity.

The objective of requirements is to maintain service voltage within limits for all customers. This includes operating equipment within equipment power limits, managing reverse power, coordinating protection and addressing contingencies requiring feeder reconfigurations. In this section, possible modifications to the distribution system are addressed which can mitigate DER impacts to the system.

11.2.1. Thermal Operating Limits

An interconnection shall not thermally overload any electrical equipment based on ratings and industry practices for determining limits. Thermal limits shall be based on both individual and aggregate DER system ratings, as well as the feeder loading. DER plant level export limiting systems may be used to mitigate overloads. Managing active power may be required to assure that thermal limits are not exceeded.

11.2.1.1. Conductor Thermal Limits

JEA will evaluate interconnecting DERs at the export limit capacity while considering feeder loading according to minimum load data (daytime for PV power systems) to ensure feeder conductors do not exceed current ratings. Aggregate DER capacity less minimum loading cannot exceed conductor ampacity at any point along a feeder.

11.2.1.2. Substation Power Transformers Thermal Limits

The aggregate DER rating capacity can be limited to between 50% to 100% of the substation transformer normal rating. In the case of parallel substation transformers, aggregate DER capacity shall be limited to the value of the substation transformer normal rating of the smallest transformer.

11.2.1.3. Distribution Service Transformer Thermal Limits

The DER interconnection requires a change in the service transformer if the aggregate DER output is greater than 120% of the transformer nameplate rating. Also, secondary conductors may require upgrade to avoid thermal limit or excessive voltage drop issues.

11.2.2. Short Circuit Limits and Coordination

The short circuit limit of all protective devices (e.g., breakers, reclosers, and fuses) across the JEA distribution system will typically be evaluated at 90% of their interrupting rating.

In addition, all DER interconnection requests that increase the effective three-phase or single-phase to ground short circuit current of the system, at any location, by 10% or more will require a review of the protection coordination by JEA SPC in the Area EPS to ensure that proper coordination can be maintained.

11.2.3. Voltage Limits

11.2.3.1. Steady State Voltage Limits

A load flow simulation is performed by JEA to evaluate if voltage on the circuit will remain within the ANSI C84.1 Range A limits. The feeder or section with DER is simulated for peak and minimum loads for normal operating conditions. Abnormal conditions such as during an overload or fault condition are not addressed in the load flow, but abnormal boundaries can be.

11.2.3.2. Voltage Fluctuation Limits

This metric is used to represent the DER generation impact on distribution feeder voltage. It quantifies the difference in feeder voltage between the DER system at full output compared to sudden loss of generation. A DER caused change in feeder voltage should not exceed 3%. The primary determining factor is relative size of the DER compared to the feeder short circuit MVA at the chosen PCC. Voltage impact is greatly influenced by distance from a substation. If the 3% criterion cannot be met with power factor mitigation, an impact study, line reconductoring or reduction in DER size may be required. This is to ensure that voltage can be maintained within applicable standards (Also discussed in power quality requirements).

11.2.4. Reverse Power Flow Limits

Reverse power flows are not allowed through any electric system components not designed to accommodate it. Distribution components that may not be designed to accommodate reverse power flow can include transformers, LTC equipment, voltage regulators, network protectors, protective relaying, and substation metering. Some JEA devices may require reconfiguration, control scheme re-evaluation, or upgrade/replacement. Where transmission or distribution has constraints, DER reverse flow potential shall be evaluated. Limiting DER export capacity may be required.

11.2.5. Substation Ground-Fault Overvoltage (GFOV)

Area EPS with delta-wye substation transformers and a high generation to load ratio can result in transmission system overvoltage’s during a transmission ground fault. Due to the transformer winding configuration, the distribution system cannot contribute zero sequence ground fault current for this fault. This results in phase to ground over voltages after the utility transmission line breakers are opened which can exceed insulation levels of the substation and transmission line equipment.

DER capacity typically beyond 50% to 80% of the minimum load on the station may require substation modifications such as to install a 3V0 protection scheme. A 3V0 protection scheme consists of voltage potential sensing on the transmission system and trips the low side substation breakers to isolate the distribution system and DER from the fault.

11.2.6. Plant Relay Protection (or built-in protection functions)

The protective relaying requirements are dependent on the DER type and the characteristics of both the site and feeder. The relay functionality is determined based on which can provide protection for faults internal to the DER site and for Area EPS faults.

DER protection systems shall include overcurrent protection for internal faults on the DER equipment, including any customer owned interconnection transformers. This protection shall be coordinated with JEA-owned upstream protection devices.

Protective relaying will trip and disable reclosing for faults internal to the DER plant.

11.2.7. Utility Owned Recloser at PCC

JEA owned reclosers are normally required on all medium voltage interconnected DER that are 1MW or greater. JEA reserves the right to install protective devices such as these on smaller interconnections, if needed to maintain system reliability.

11.2.8. Compatibility with Distribution Automation ("DA") Schemes

The DER shall not interfere with Distribution Automation (DA) schemes. Where DERs may interfere with existing DA schemes the following design requirements shall apply:

- DERs applying within Distribution Automation zones shall not interfere with the proper operation of the scheme. The range of load and DER output levels must be maintained to ensure proper operation under all conditions. Mitigation techniques may be necessary to meet this requirement.
- DERs proposed within existing protection and automation schemes must be integrated and interoperable to maintain existing levels of reliability.

11.2.9. Special Case – Direct Transfer Trip Protection

Direct Transfer Trip (DTT) protection may be required for synchronous and induction generators and for larger inverter-connected DER installations. Considerations for synchronous generators are different than inverter based.

11.2.10. Special Case - Dual Utility Service (normally open)

For customer locations where switchgear is equipped with alternate feeds, and employs automatic-transfer capability, protection shall be provided to block the transfer while DERs are paralleled to the system to prevent an out-of-phase condition. In addition, if required protection is not installed on the customer alternate source, the DER will be tripped before the customer is transferred to the alternative source.

11.2.11. Special Case - Restricted Capacity Circuits

Any distribution circuit will have an upper limit to the amount of distributed generation that can be accommodated. When the installed generation on a circuit has reached its maximum, (generally just before the point of thermal or voltage violations), no further interconnection applications can be accepted for DER's, regardless of size, unless the customer is willing to pay for the needed upgrades.

Potential DER owners may request, at their expense, to pay for upgrades that would allow them to install their system. In many cases, the required upgrade costs may make an installation cost prohibitive. An alternative to upgrades may be DER export control or export limiting based on timing or another agreed criterion.

11.2.12. Special Case - Buffer Zone Capacity Limits

Buffer zones may be set around specific DER integration requirements such as current levels, individual or aggregate DER capacity, and reverse power kVA limits. Buffer zones indicate nearing, or exceeding, a limit and provide a margin of safety. They indicate when mitigation alternatives need to be considered for interconnection, for example, at a substation, feeder, or PCC hosting capacity limit.

11.3. Grid Integration for LV Network-connected DER

Requirements for grid integration for network connected DER are specified in IEEE 1547-2018 clause 9 - DER on distribution secondary grid/area/street (grid) networks and spot networks.

IEEE 1547-2018 clause 9.1 addresses several specific issues related to DER integration into networks.

11.3.1. Area (Secondary) Networks

Requirements for area networks are specified in IEEE 1547-2018 clause 9.2 - Distribution Secondary Grid Networks.

Area networks, such as in downtown locations, are typically 120/208V and are served by multiple transformer banks and meshed on secondaries. In area networks DERs must be limited to avoid reverse power that causes network protectors to open resulting in an outage. In addition, the DER must not cause network protector cycling.

DER systems less than or equal to 25kW can be approved if the DER maximum generation is ≤ 5% of the area network peak load and the generation never exceeds minimum load. JEA has the right to revise the maximum export level in case of changed conditions or future negative impacts. Customer owned export limiting controls will be required to prevent any inadvertent operation of network protectors. Export limiting controls will be tested and verified. In some cases, customers can export excess generation to the network if export can be accomplished without causing reverse power to any of the network protectors at any time. In some cases, customers will be required to maintain a minimum import limit.

11.3.2. Spot Networks

Requirements for spot networks are specified in IEEE 1547-2018 clause 9.3, Distribution Secondary Spot Networks

DER can be approved on spot networks if aggregate DER generation is ≤ 5% of the spot network peak load and generation never exceeds minimum load. Export of generation into the spot network transformer(s) for any duration will not be allowed. JEA has the right to revise operating limits in case of changed conditions or future negative impacts.

The facility must maintain a minimum power import of at least 20% of the facility minimum. If DER is PV, facility minimum includes minimum daytime load. JEA will have the right to revise the allowed injection level in case of future negative impact.

Customer owned export limiting controls may be required to prevent any inadvertent operation of network protectors.

11.3.3. Special Review and Evaluation of Network Protection

Witness testing for network connected DER includes a JEA System Protection/Telecom point-to-point testing of any protection scheme. This test is in addition to any other commissioning and witness testing required in Section 13 – "Commissioning and Verification Requirements" of this document.

11.3.4. Special Control Requirements for Network Service

Telemetry is required for all DERs larger than 150 kW and installed with network service. DER interconnections smaller than 150 kW on any network service will be reviewed on a case-by-case basis for telemetry requirements. Requirements are to monitor three-phase voltage, three-phase power, three-phase current, total MW, total MVAR, the power crossing at the interchange of the facility, and any solar output. Remote trip capability may also be required. The monitored values shall be brought back into an Energy Management System (EMS), Distribution Management Systems (DMS), DER Management Systems (DERMS), or other management system and stored into a JEA database. Interoperability requirements described in Chapter 9 apply.

11.4. Control Requirements for Export Limiting

JEA may require an approved method of export limiting to avoid reverse power impacts, and required upgrades, on the grid. If using an approved method, then the DER application will be evaluated using the export limit capacity rather than the name plate of the DER. JEA will also consider if the full name plate capacity is compatible with the selected PCC during abnormal conditions such as system faults or plant tripping, a screen for inadvertent export is described in section 3.

When proposing to limit or prevent export from the DER facility with one of the approved methods, JEA will need to review the methods and the operation of the control device. The following information will be required from the applicant at the time of submission.

- Manufacturer and model of the device or power control system, or the components that make up the system (See approved methods 11.4.1. and 11.4.2.).
- The technical specifications of the devices or power control systems.
- A description of the operating modes, services, and any specific settings that are enabled, and how the hardware/software present in the design is used to accomplish the goals of the mode being used.

11.4.1. Approved Methods for Non-Exporting DER

- **Reverse Power Protection (ANSI Device 32R):** To limit export of power across the point of interconnection, a reverse power protective function is implemented using a utility grade protective relay. The default setting for this protective function is typically 0.1% (export) of the service transformer's nominal base nameplate power rating, with a maximum typically ranging from 2-30 second time delay to limit inadvertent export.

- **Minimum Power Protection (ANSI Device 32F):** To limit export of power across the point of interconnection, a minimum import protective function is implemented utilizing a utility grade protective relay. The default setting for this protective function is typically 5% (import) of the small generator facility's total nameplate rating, with a maximum delay time typically ranging from 2-30 seconds to limit inadvertent export.
- **Relative distributed energy resource rating:** This option requires the small generator facility's nameplate rating to be so small in comparison to its host facility's minimum load that the use of additional protective functions is not required to ensure that power will not be exported to the electric distribution system. This option requires the small generator facility's nameplate rating to be no greater than typically 50% of the customer's verifiable minimum host load during relevant hours over the past 12 months. This option may not be available for interconnections to area networks or spot networks.

11.4.2. Approved Methods for Limited Export DER

- **Directional Power Protection (Device 32):** To limit export of power across the point of interconnection, a directional power protective function is implemented using a utility grade protective relay. The default setting for this protective function is to be the export capacity value, with a maximum delay time typically ranging from 2-30 seconds to limit inadvertent export.
- **Configured Power Rating:** A reduced output power rating utilizing the power rating configuration setting may be used to ensure the small generator facility does not generate power beyond a certain value lower than the nameplate rating. The configuration setting corresponds to the active or apparent power ratings in Table 28 of IEEE 1547-2018, as described in subclause 10.4. A local small generator facility communication interface is not required to utilize the configuration setting as long as it can be set by other means. The reduced power rating may be indicated by means of a nameplate rating replacement, a supplemental adhesive nameplate rating tag to indicate the reduced nameplate rating, or a signed attestation from the customer confirming the reduced capacity.

11.4.3. Approved Methods for Limited Export or Non-Exporting DER

- **Certified Power Control Systems:** Small generator facility may use certified power control systems to limit export. Small generator facility utilizing this option must use a power control system and inverter certified per UL 1741 by a nationally recognized testing laboratory (NRTL) with a maximum open loop response time of no more than 30 seconds to limit inadvertent export. NRTL testing to the UL Power Control System Certification Requirement Decision must be accepted until similar test procedures for power control systems are included in a standard. This option may not be available for interconnections to area networks or spot networks as the open loop response time may be too long to prevent network protectors from operating.
- **Agreed-upon Means:** Small generator facility may be designed with other control systems and/or protective functions to limit export and inadvertent export if mutual agreement is reached with JEA. The limits may be based on technical limitations of the customer's equipment or the electric distribution system equipment. To ensure inadvertent export remains within mutually agreed-upon limits, the customer may use an uncertified power control system, an internal transfer relay, energy management system, or other customer facility hardware or software if approved by JEA.

12. FACILITY REVENUE METERING

12.1. Primary Interconnected DER

DER interconnecting to distribution primary which serves no local load excluding DER plant auxiliary loads will be separately metered. DER design should include provisions for JEA to provide a revenue grade meter at the PCC.

Meter equipment installation for measuring gross output of DER may include production and PQ meters and may not be located at the PCC.

Design shall include provisions for a meter socket/enclosure shall be installed where which the following apply:

1. Compliant with JEA electrical service standards and JEA Rules and Regulations for Electric Service.
2. Located at the PCC.
3. Observes applicable NEC and JEA clearances.

12.2. Secondary Interconnected DER

DER interconnecting on the low voltage side of a service transformer where Net Metering is implemented, non-bi-directional meters shall be upgraded with revenue metering capable of accurately recording two-way power flows. The premise may be subject to a brief maintenance outage to allow meter upgrade, programming, or installation.

The basic configuration of revenue metering consists of a bi-directional revenue grade meter (import and export) at each point of common coupling with the JEA system. A separate production revenue meter for measuring the gross output of the generation may be required, depending on the generation capacity, applicable contractual provisions, voltage class, and associated tariffs.

A DER SETTINGS TABLES

The tables below show the setting configuration for DERs under Cat-B and Cat-III normal and abnormal performance categories respectively. Each table includes the standard label used in the EPRI Common File Format[9]. **Utility-Required Settings** should be adjusted if they deviate from Category B, Category III Default. Adjustable ranges are provided in General Technical Requirements, DER Support of Grid Voltage, and DER Response to Abnormal Conditions. Refer to IEEE 1547-2018 or EPRI Common File Format for Category A, Category I, and Category II parameter ranges.

ENTER SERVICE CRITERIA		EPRI Common File Format	UNITS	Utility-Required Settings
Permit Service		ES_PERMIT_SERVICE-SS	Mode	Enabled
Enter Service Voltage	ES Voltage Low Setting	ES_V_LOW-SS	V p.u.	0.917
	ES Voltage High Setting	ES_V_HIGH-SS	V p.u.	1.05
Enter Service Frequency	ES Frequency Low Setting	ES_F_LOW-SS	Hz	59.5
	ES Frequency High Setting	ES_F_HIGH-SS	Hz	60.1
Soft-Start Ramp	ES Randomized Delay	ES_RANDOMIZED_DELAY-SS	s	300
	ES Delay Setting	ES_DELAY-SS	s	300
	ES Ramp Rate Setting	ES_RAMP_RATE-SS	s	300

DER SUPPORT OF GRID VOLTAGE[10]	EPRI Common File Format	UNITS	Utility-Required Setting
Constant Power Factor Mode	CONST_PF_MODE_ENABLE-SS	Mode	Enabled
Constant Power Factor Excitation	CONST_PF_EXCITATION-SS	Mode	INJ
Constant Power Factor setting	CONST_PF-SS	PF	1.00
Voltage-Reactive Power Mode	QV_MODE_ENABLE-SS	Mode	Disabled
Active Power Reactive Power Mode	QP_MODE_ENABLE-SS	Mode	Disabled
Constant Reactive Power Mode Enable	CONST_Q_MODE_ENABLE-SS	Mode	Disabled
Voltage-Active Power Mode Enable	PV_MODE_ENABLE-SS	Mode	Disabled

[9] EPRI has published the *Common File Format for Distributed Energy Resources Settings Exchange and Storage*, a document developed in collaboration with industry stakeholders (manufacturers, nationally recognized testing laboratories, certification entities, planning and operations engineers, etc.) that facilitates the DER settings file exchange. More details at https://www.epri.com/research/products/000000003002020201 (open to public).

[10] Constant Power Factor Mode is enabled in this example as a commonly implemented *default* mode, this simplified table includes the parameters associated with Constant Power Factor Mode (shown in grey below) and lists other DER Support of Grid Voltage modes as disabled. If utility DER management includes DER mode switching capability, parameters for all modes utilized will need to be specified.

A.1 Category II DER Response to Abnormal Voltages and Frequencies

Mandatory Voltage Tripping Characteristics		EPRI Common File Format	UNITS	Utility Required Settings
OV2	HV Trip Curve Point OV2 Setting	OV2_TRIP_V-SS	V p.u.	1.20
	HV Trip Curve Point OV2 Setting	OV2_TRIP_T-SS	s	0.16
OV1	HV Trip Curve Point OV1 Setting	OV1_TRIP_V-SS	V p.u.	1.10
	HV Trip Curve Point OV1 Setting	OV1_TRIP_T-SS	s	2.00
UV1	LV Curve Trip Point UV1 Setting	UV1_TRIP_V-SS	V p.u.	0.70
	LV Curve Trip Point UV1 Setting	UV1_TRIP_T-SS	s	10.0
UV2	LV Curve Trip Point UV2 Setting	UV2_TRIP_V-SS	V p.u.	0.45
	LV Curve Trip Point UV2 Setting	UV2_TRIP_T-SS	s	0.16

Mandatory Frequency Tripping Characteristics		EPRI Common File Format	UNITS	Utility Required Settings
OF2	OF Curve Trip Point OF2 Setting	OF2_TRIP_F-SS	Hz	62.00
	OF Curve Trip Point OF2 Setting	OF2_TRIP_T-SS	s	0.16
OF1	OF Curve Trip Point OF1 Setting	OF1_TRIP_F-SS	Hz	61.20
	OF Curve Trip Point OF1 Setting	OF1_TRIP_T-SS	s	300.00
UF1	UF Curve Trip Point UF1 Setting	UF1_TRIP_F-SS	Hz	58.50
	UF Curve Trip Point UF1 Setting	UF1_TRIP_T-SS	s	300.00
UF2	UF Curve Trip Point UF2 Setting	UF2_TRIP_F-SS	Hz	56.50
	UF Curve Trip Point UF2 Setting	UF2_TRIP_T-SS	s	0.16