A14. Interconnection and Operating Guides for Inverter-Based Resources

A14.1 Power Factor

In accordance with FERC Order No. 827, all newly-interconnected generators (synchronous or non-synchronous) are required to provide dynamic reactive power support within the range of +/-0.95 power factor at the transmission voltage side of the generator step-up transformer at all dispatch levels. Static reactive power devices can only be used to make up for reactive losses that occur between the inverters and the transmission voltage side of the generator step-up transformer. Any additional reactive power must be supplied by a dynamic reactive power device.

The +/-0.95 power factor requirement corresponds to a triangle-shaped reactive power capability with proportional reduction in reactive power capability at lower active power (i.e. real power) output, as shown in Figure 1. However, reactive power capability outside the triangular-shaped requirement yet within the reactive power capability of the plant should be utilized to the greatest extent possible. Inverters shall not have artificial settings imposed to limit reactive power output to the triangular boundary.

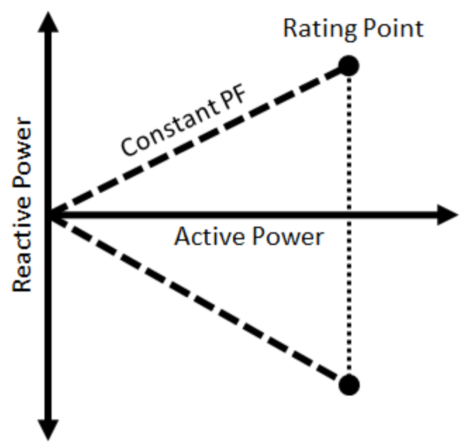

Figure 1. Inverter-based Resource Plant Reactive Power Capability

A14.2 Primary Frequency Response

In accordance with FERC Order No. 842, the Interconnection Customer shall ensure the primary frequency response capability of its Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The hardware and/or software that provides frequency responsive active power control shall be able to sense changes in system frequency and autonomously adjust the Generating Facility's real power output in accordance with the droop and deadband parameters provided by Entergy Transmission and to the extent the Generating Facility has operating capability in the direction needed to correct the frequency deviation. The Interconnection Customer is required to install a governor or equivalent controls with the capability of operating with a maximum 5% droop and a maximum ± 0.036 Hz deadband. This response must be timely and sustained rather than injected for a short period and then withdrawn. The primary frequency response requirements shall apply to all inverter-based generating resources including energy storage during both charging and discharging states.

The Generator Owner shall provide the status and settings of the governor or equivalent controls to Entergy Transmission upon request. If the Generator Owner needs to operate the Generating Facility with its governor or equivalent controls not in service, the Generator Owner shall immediately notify Entergy Transmission and make reasonable efforts to return its governor or equivalent controls to service as soon as practical.

A14.2.1 Dynamic Frequency Response Requirements for Inverter-Based Resources

For a step change in frequency at the Point of Interconnection (POI), inverter-based resources (IBR) shall have the capability to meet the dynamic characteristics shown in Table A14.1. The active power-frequency response shall be sustained by the resource until such time that the control signals (e.g., Balancing Authority automatic generation control (AGC)) return the generator to a new set point value.

Table A14.1: Dynamic Active Power-Frequency Performance

Parameter	Description	Performance Requirement
Reaction Time	Time between the step change in frequency and the time when the IBR's active power output begins responding to the change.	< 500 ms
Rise Time	Time in which the IBR has reached 90% of the new steady-state (target) active power output command.	< 4 s
Settling Time	Time in which the IBR has entered into, and remains within, the settling band of the new steady-state active power output command.	< 10 s
Overshoot	Percentage of rated active power output that the IBR can exceed while reaching the settling band.	< 5%
Settling Band	Percentage of rated active power output that the resource should settle to within the settling time.	< 2.5%

A14.3 Frequency and Voltage Ride Through

The frequency and voltage ride-through curves described in NERC Reliability Standard PRC-024-2 apply to the POI and not the inverter terminals themselves. The Interconnection Customer, in coordination with their inverter manufacturer, shall reflect the ride-through requirements at the POI to the inverter terminals to ensure that the inverters can ride through and continue current injection during disturbances.

The PRC-024-2 voltage and frequency ride-through curves specify a "No Trip Zone". Operations outside of the "No Trip Zone" shall not be interpreted as a "Must Trip Zone" but rather a "May Trip Zone".

A14.3.1 Frequency Measurements and Protection

Frequency shall be calculated over a period of time (no less than 6 cycles) and filtered to take control action on the fundamental frequency component of the calculated signal. Calculated frequency shall not be susceptible to spikes caused by phase jumps on the Bulk Electric System (BES).

Inverter-based resources shall also inhibit frequency tripping during and immediately after low voltage conditions. Inverter-based resources shall ensure that the frequency measurement and protection settings are set such that these resources are able to ride through and not trip for phase jumps or other grid disturbances where calculated frequency is affected but grid frequency is within the ride-through curves of PRC-024-2.

A14.3.2 Momentary Cessation

Inverter-based resources interconnected to the transmission system are expected to continue current injection inside the "No Trip" zone of the PRC-024-2 frequency and voltage ride through curves. Newly interconnecting inverter-based resources should eliminate the use of momentary cessation unless necessary in areas of the BES with low short circuit strength (SCR < 3).

A14.4 Voltage Control

BES-connected resources are required to operate in automatic voltage control mode as per NERC Reliability Standard VAR-002-4. All resources, including inverter-based resources, shall operate in a closed-loop, automatic voltage control mode to maintain voltage at the POI to within the specified voltage schedule tolerance band provided by the Transmission Operator as per NERC Reliability Standard VAR-002-4.

A14.4.1 Small Disturbance Reactive Power-Voltage Control Performance

Individual inverters shall operate in automatic voltage control at all times to support BES voltage schedules, post-contingency voltage recovery, and voltage stability. Each inverter shall continually respond to all changes in terminal voltage in a closed loop fashion to maintain the set point voltage level.

Inverter-based resources shall have the capability to meet the performance characteristics shown in Table A14.2. These characteristics are specified for the response of reactive power of the overall closed-loop response of the inverter-based resource plant.

Table A14.2: Dynamic Reactive Power-Voltage Performance for Small Disturbance

Parameter	Description	Performance Requirement
Reaction Time	Time between the step change in voltage and when the IBR's reactive power output begins responding to the change. Shall not include any intentional time delay.	< 500 ms

Rise Time	Time between a step change in control signal input (reference voltage) and when the reactive power output changes by 90% of its final value.	< 2-30 s
Overshoot	Percentage of rated reactive power output that the IBR can exceed while reaching the settling band.	< 5%

A14.4.2 Large Disturbance Reactive Power-Voltage Performance

The reactive power-voltage control shall be stable over all expected operating and grid conditions and be tuned to provide this stable response. The dynamic response of inverter-based resources shall be programmable by the Interconnection Customer (in coordination with the inverter manufacturer) to enable changes based on changing grid conditions once installed in the field.

Inverter response to fault events on the BES shall abide by the following principles:

- Fault Inception: During the inception of a fault, priority shall be given to delivering as much current to the system as quickly as possible to support protective relay systems to detect and clear the fault.
- On-Fault Current Injection: For the remaining on-fault period after the first couple cycles up to fault clearing, priority shall be given to accurately detecting and controlling the type of current needed based on terminal conditions, and providing a combination of active and reactive current as necessary.
- Post Fault Current Injection: Priority shall be given to ensuring sufficient local voltage support before attempting to maintain or return to pre-disturbance active current injection.
- Post-Fault Voltage Overshoot Mitigation: Inverter reactive current response shall not exacerbate transient overvoltage conditions on the BES.

Inverters shall be designed to have the capability to meet the performance specifications shown in Table A14.3.

Table A14.3: Dynamic Reactive Power-Voltage Performance for Large Disturbance

Parameter	Description	Performance Requirement
Reaction Time	Time between the step change in voltage and when the IBR's reactive power output begins responding to the change.	< 16 ms
Rise Time	Time between a step change in control signal input (reference voltage) and when the reactive power output changes by 90% of its final value.	< 100 ms

For unbalanced faults, in addition to increased positive sequence reactive current, the IBR unit shall inject negative sequence current:

- Dependent on IBR unit terminal (POI) negative sequence voltage and
- Leads the IBR unit terminal (POI) negative sequence voltage by an allowable range as specified below. The allowable range is provided in lieu of tolerance band specified in the definition of a settling time.
  - ➢ 90-100 degrees, for full converter based IBR units
  - ➢ 90-150 degrees, for type III WTGs

A14.5 Transmission System Studies

NERC Reliability Standard FAC-002-2 requires each Transmission Planner to assess the reliability impact of interconnecting new generation as well as any material modifications to existing interconnections of generation. Steady-state, dynamic, and short circuit studies are performed as part of the MISO Definitive Planning Phase (DPP) process. However, there are other considerations that may need to be assessed based on the interconnection location, IBR control functionality, and nearby resources (SVCs, series capacitors, synchronous generation, IBR generation, etc.).

A14.5.1 Controls Interactions and Controls Instability

Inter-plant coordination is increasingly important as the penetration of inverter-based resources continues to grow. When multiple resources attempt to control the same location on the BES (e.g., controlling voltage at the same POI or close proximity), their control systems need to be coordinated with one another in order to avoid reactive power output imbalance, circular reactive power flows, controls overshoot, voltage control hunting, and unstable oscillations. Coordination issues shall be evaluated prior to the resource connecting to the BES. Prior to performing this analysis, the consultant selected by the Interconnection Customer shall be approved by Entergy Transmission. This analysis shall be performed during the plant design phase prior to plant backfeed. The results of the analysis shall be provided to Entergy Transmission with the cost of the study borne by the Interconnection Customer.

A14.5.2 Weak Grid Analysis (SCR < 3)

The changing nature of the electric grid and the growing complexity of IBR control systems can impact the performance of inverter-based resources and shall be assessed to ensure reliable operation of the BES. One of these changes is the continued reduction of short circuit levels in areas of high penetration of inverter-based resources. For interconnections with a short circuit ratio < 3, an EMTP study is required to assess potential SSR/SSCI and the proposed control design. Prior to performing this analysis, the consultant selected by the Interconnection Customer shall be approved by Entergy Transmission. This analysis shall be performed during the plant design phase prior to plant backfeed. The results of the analysis shall be provided to Entergy Transmission with the cost of the study borne by the Interconnection Customer.

A14.5.3 Power Quality

Due to converter characteristics associated with IBR generation, there is increased possibility of generating harmonic currents; therefore, the Interconnection Customer shall make provisions to install power quality monitoring devices to ensure that the IEEE 519 and IEEE 1453 requirements are met at the POI with the IBR. The data retention period for the power quality meter shall be at least 30 days. If the power quality meter at the POI identifies harmonic currents (total demand distortion), harmonic voltages (total harmonic distortion), or other power quality issues in excess of the power quality criteria specified in IEEE 519 and IEEE 1453, and either complaints related to power quality are received from other customers on the system in the vicinity of the IBR plant, or Entergy experiences equipment performance issues that can be attributed to power quality then operating restrictions will be placed on the IBR plant by Entergy Transmission until it has been adequately demonstrated that the power quality issues have been resolved.

The Interconnection Customer shall provide harmonics modeling data for the inverters to be installed and modeling data for the IBR collector system in sufficient detail to perform a harmonics study of the IBR plant. In the event that a harmonics study is required due to power quality meter measurements at the POI in excess of the power quality criteria, the costs to conduct such studies will be the responsibility of the Interconnection Customer. Background measurements for harmonics, flicker, and voltage unbalance shall be supplied to Entergy Transmission prior to plant backfeed.

The IBR shall adhere to Entergy Standard AM3902 Transmission Power Quality Guide.

A14.5.4 Subsynchronous Resonance and Subsynchronous Torsional Interaction

Additional studies, such as subsynchronous resonance and subsynchronous torsional interaction, may be performed depending on the interconnection location. No poorly damped subsynchronous modes or interactions shall be permitted on the utility system.

Despite the results of the above-mentioned studies, if the IBR performance is found unsatisfactory after the commencement of commercial operation, such as problems associated with overvoltages, resonance, power quality, damping, or any adverse interactions impacting the reliability of the BES, the Interconnection Customer shall be responsible for mitigating the unsatisfactory performance.

A14.6 Modeling

The steady-state and dynamic models used to represent inverter-based resources shall accurately capture the small and large disturbance aspects of the resource. The following modeling information shall be provided to Entergy Transmission within 60 calendar days prior to plant backfeed.

- Steady state model including collector system equivalent as recommended by NREL, collector station transformer, padmount transformer, and transmission gen-tie line.

- Dynamic models using the 2nd Generation Renewable Energy Models [PSS/E Models REPC, REGC, and REEC].
- Frequency and voltage ride through characteristics and corresponding dynamic models [PSS/E VTGTPA, FRQTPA]. The low-voltage ride-through capability of the PV plant shall be demonstrated either through detailed modeling of the PV controls or by field/ factory tests.
- Inverter PQ curve.
- ASPEN short circuit model using a Voltage Controlled Current Source Model.
- EMTP-RV or PSCAD model of the IBR plant.
- Harmonic current spectrum information for modeling of the PV plant in harmonic scan studies.

Model verification shall be performed as per NERC Reliability Standards MOD-026-1 and MOD-027-1 and transmitted to the Transmission Planner within 365 calendar days after the commissioning date.

A14.7 Disturbance Monitoring

Various measurement and monitoring technologies are necessary to capture the performance of IBRs in response to small and large disturbances on the system. Sequence of events recording (SER) data provides information related to what occurred and when each action was taken. Digital fault recorder (DFR) and dynamic disturbance recorder (DDR) data captures the dynamic response of the resource at the POI and within the plant.

Measurements are taken throughout the inverter-based resource, from the individual inverters to the POI, using the technologies described above. The requirements relating to the types of data, resolution of that data, and retention of that data required of the Interconnection Customer is provided in Table A14.4. This table is not intended to be all-inclusive; rather, it provides an overview of the types of measurements and associated resolution and retention requirements.

All data within an inverter-based resource plant shall be time synchronized to a common reference time.

The data from the below-listed measuring devices shall be provided to Entergy Transmission within 30 calendar days of a request.

Table A14.4: Measurement Data and Retention Requirements

Data Type	Measurement/Data Points	Resolution	Retention
Sequence of Events Recording (SER) Data	SER devices shall be sized to capture and store thousands of event records and logs. SER events records can be triggered for many different reasons but include, at a high level, the following: • Event date/time stamp (synchronized to common reference) • Event type (status changes, synchronization status, configuration change, etc.) • Description of action • Sequence number (for potential overwriting)	≤ 1 millisecond	90 days
Digital Fault Recording (DFR) Data	This data shall be captured for at least the plant-level (e.g., at the POI) response to BES events. It is typically high resolution (kHz)	> 960 samples per second, triggered	90 days

	point-on-wave data, and triggered based on configured settings. Data points shall include: • Bus voltage phase quantities • Bus frequency (as measured/calculated by the recording device) • Current phase quantities • Calculated active and reactive power output • Dynamic reactive element voltage, frequency, current, and power output		
Dynamic Disturbance Recorder (DDR) Data	A DDR (e.g., a PMU or digital relay with this capability) shall capture the plant-level response during normal and disturbance events. This data shall be captured continuously at the POI and can be used for multiple purposes including event analysis and disturbance-based model verification. Data points shall include: • Bus voltage phasor (phase quantities and positive sequence) • Bus frequency • Current phasor (phase quantities and positive sequence) • Calculated active and reactive power output	> 30 samples per second, continuous	1 year