PJM Dynamic Model Development Guidelines for Interconnection Analysis

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PJM Interconnection

Revision 1.1

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Contents

1 Revision History

Revision	Date	Description
0	09/18/2023	Initial version
1	09/13/2024	Updated: Minor corrections throughout document PSS/E Version for Transition Cycle 2 (TC2) Added details to Section 4.2.2.2 Library Models Additional detail to Section 7 Testing requirements Deliverables Section 8, and moved Dynamic Model Checklist to Section 8.1 Clarifications: FAT report needed for As Built submissions only Reference to IEEE 1547 for lower kV submissions
1.1	10/8/2024	Added appendix 10.5 Example Dynamic Model Report Minor clerical updates

2   Introduction

This document provides a guideline to develop the dynamic model representation (in .idv & .dyr format) for New Service Request projects (including Surplus Service Requests, projects with an ISA/GIA requesting a Necessary Study or submitting As Built Data) to be used by PJM in dynamic transient stability studies. All electrical facilities must be designed, built and operated in accordance with applicable NERC, PJM and Interconnection Transmission Owner(s) standards and criteria. For New Service Requests, Surplus Service Requests and Necessary Study Requests, the model shall be parameterized as closely as possible to the intended design. The As Built Data model must reflect the settings after commissioning and include the Factory Acceptance Test (FAT) report for each main power transformer installed.

Projects not connecting to the bulk electric system (generally <100 kV) where NERC standards do not apply, the requirements of the entity with which the interconnection is made shall govern. Best practice for distribution connected inverter based resources is to follow the requirements in IEEE 1547[1].

This document is meant to serve as a guideline in the development of the dynamics model for your project. It is aimed at facilitating an efficient and timeous model submission and acceptance process. The short review of WECC Power Plant Models; typical values for Generator/Converter, Electrical Controls, and Plant Controller modules; and examples of .dyr files are intended to bring clarity and set a minimum standard of the expectation on dynamic model data submission. The checklist should also help promote good practice of model development by the Project Developers, facilitate consistent model reviews by the Transmission Planners and ensure the dynamic models meet applicable interconnection requirements. As the technology evolves, so will the modeling techniques.

This document may not cover every specific scenario. Any unique scenarios or settings that may be required for your project model shall be noted in the Dynamic Model Report and brought to the attention of PJM in the Queue Point Data Application form.

2.1   Expectation from Project Developer

The Project Developer (PD) shall use this guideline to develop a dynamic model for their project to be used by PJM in dynamic transient stability studies. The Project Developer will be required to meet the requirements outlined in Section 8 "Deliverables" in order for PJM to consider the submission as valid. In accordance with PJM Manual 14H section 2.1.2, failure to comply with the requirements of this document or cure deficiencies within the deficiency review period will result in the application being withdrawn.

The Dynamic Model Report and Dynamic Model Checklist submitted must include quality assurance sign offs from responsible parties, to ensure these guidelines were reviewed and followed. This document applies to the following types of submissions:

a. **New Service Request Projects** - To be submitted in Queue Point during the Application Phase of the Cycle.
   For any allowable changes made to the New Service Request project at Decision Point 1 or 2, the Project Developer must update the dynamic model for their project and resubmit the Dynamic Model Report and Checklist per the Section 8 "Deliverables" in the required timeframe.

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[1] https://www.pjm.com/-/media/planning/plan-standards/pjm-guideline-for-ride-through-performance.ashx

b. **Necessary Study Requests –** To be submitted in Queue Point along with the Necessary Study data submission.
c. **As Built Data Submissions -** To be submitted in Queue Point along with the As Built data submission. Factory Acceptance Test (FAT) report for each Main Power Transformer installed must be included.

3   Software Compatibility

The power flow (.idv) and dynamic models (.dyr) provided as representation of the New Service Request project must be usable by the software platform used to perform the simulation. PJM uses Siemens PTI PSS/E to perform transient stability analysis, and dynamic models and files provided must be compatible with the specific version listed for each queue/cycle, and also with any later version listed (for inclusion into future year base cases).

Table 1.   PSS/E Versions by Queue/Cycle

PJM Queue/Cycle	PSS/E Version
AC1	33.7.0
AC2	33.7.0
AD1	33.7.0
AD2	33.7.0
AE1	33.7.0
AE2	33.7.0
AF1	33.12.1
AF2	33.12.1
AG1	34.7
TC1[2]	34.7
TC2[3]	35.3.2

For Transition Cycle 2 (TC2) projects, Project Developers will be notified during TC2 Phase 2 if a PSCAD model is needed for their project. The Project Developer will be required to provide it at TC2 Decision Point 2 if this request is made.
During the Application Phase, if TC2 Project Developers want to submit a PSCAD model along with the required PSSE dynamic model, we will accept this. Note: the PSCAD model is optional unless requested by PJM, while the PSSE dynamic model is required for all projects.

4   Inverter Based Resources

4.1   General Modeling Requirements

The following modeling requirements, as provided in the WECC Solar Photovoltaic Power Plant Modeling and Validation Guideline[4], are adopted for all inverter-based power plants and provided below.

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[2] Transition Cycle 1
[3] Transition Cycle 2
[4] Solar Photovoltaic Power Plant Modeling and Validation Guideline

The power flow model for an inverter-based power plant includes:

- An explicit representation of the interconnection transmission line
- An explicit representation of all station transformers
- An equivalent representation of the collector systems for projects
- An equivalent representation of inverter pad-mounted transformers with a scaled MVA rating
- An equivalent representation of generators scaled to match the total capacity of the plant
- An explicit representation of all plant-level reactive compensation devices either as shunts (fixed or switchable) or as generators (FACTs devices), if applicable
- An explicit representation of any station and/or auxiliary loads

The figures below show examples of a Solar PV plant representation, which can be applied to other Inverter Based Resources (IBRs).

A typical inverter based plant is represented by the single machine equivalence, as depicted in Figure 1.

Figure 1.   Single-Generator Equivalent Power Flow Representation for a Solar PV Power Plant
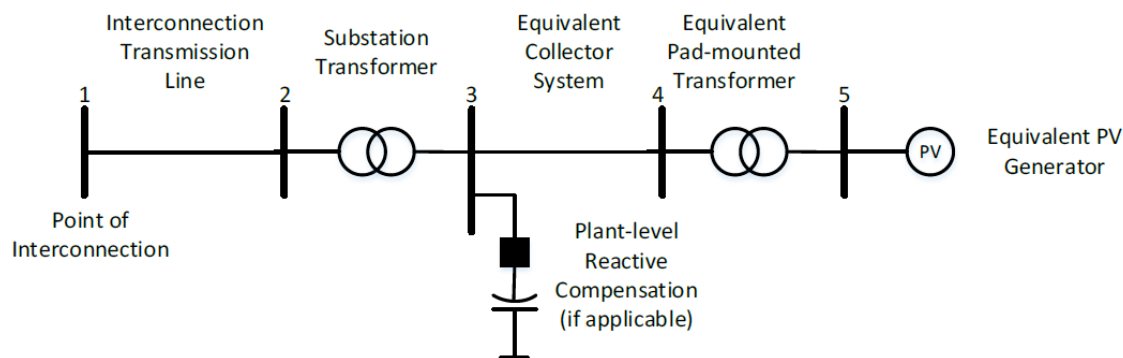
An inverter based plant that comprises of different inverter manufacturers having different reactive capability, control setup and protection setup would need to use a multi-generator representation as shown in Figure 2.

Figure 2.   Multiple-Generator Equivalent Power Flow Representation for a Solar PV Power Plant
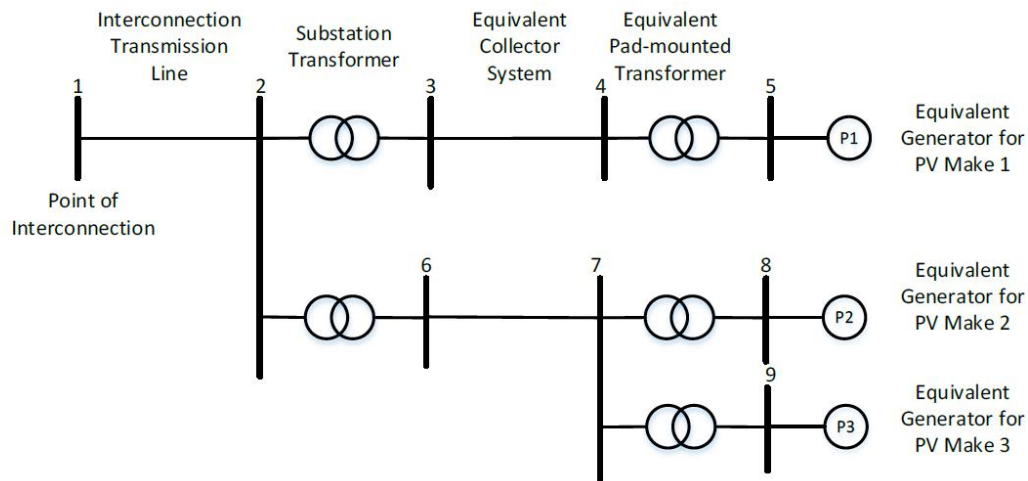
The dynamic model includes:

- A generator/converter module representing the typical inverter based resource in the plant, scaled-up to match the plant's aggregate nameplate rating
- A local electrical control module which translates real and reactive power references into current commands
- A plant-level control module which sends real and reactive power references to the local electrical controller, if the plant-level control is put in place
- Frequency and voltage protection modules, which show inverter protection settings under abnormal frequency and voltage conditions

PJM strongly encourages the use of PSSE library models. Dynamic models listed on the Unacceptable Models List, Appendix 10.2 of this document, are not allowed.

If a User Defined Model (UDM) is provided, the requirements in the Deliverables section of this document must be met. For UDMs, the developer will be responsible to update their project's dynamic model to support higher PSSE versions as these become available in the future (updated idv & dyr with version specific DLL files and supporting files as applicable). See Dynamic Data (.DYR) – User Defined Models section below for additional details.

4.2   PJM Dynamic Model Configuration

The Data Application form shall be completed and submitted in Queue Point. The data and information provided in the form shall match the data and parameters provided as the model for the project. Refer to the Appendix of this document for a sample format for the .idv and .dyr files submitted.

4.2.1   Project Specific Data

Generator Data:

a. The MW per inverter specified in the generator data section of the Data Application form will be the initial modeling point. If the MW net output of the plant at the Point of Interconnection (POI) is above or below the Maximum Facility Output (MFO), the MW per inverter shall be adjusted within the units MVA capability.
b. The inverter manufacturer and model shall match any additional documentation provided in the Data Application form.
c. Terminal voltage shall match the low side winding of the Inverter Step Up Transformer.

Maximum Facility Output (MFO):

a. The full facility model must be checked to ensure the gross active power output of the generator(s) can meet the MFO at the POI considering loads and losses for the facility.
b. The net active power output must be equal to the MFO requested.
c. If the MFO is not met at the POI, adjustments would need to be made to ensure the MFO requested can be achieved at the POI.
d. The analysis will be performed with the queue project meeting the MFO at the POI.

Reactive Power Capability Curve:

a. Must be provided with the Data Application form
b. The MVA capability must match the MVA base per inverter in the Data Application form
c. The PQ curve must match the inverter make and model name as provided in the Data Application form
d. A reasonable ambient temperature of 95F (35C) should be assumed. Justification along with supporting documentation must be included with your submission, for exceptions to this ambient temperature assumption.
e. The reactive power (Qmax/Qmin) modeled for power flow is determined using this curve based on the MW operating point required to meet the MFO.

4.2.2   Modeling Files

4.2.2.1   Power Flow (.IDV)

The facility shall be modeled in a response file (.idv) that uses RDCH to specify the data. The .idv provided must always include a full representation of the facility configuration, instead of updating just specific portions of the model.

For uprate projects, the idv shall remove and replace the existing plant modeling, rather than incrementally adding only the uprate portion.

The .idv model submitted to PJM for the queue project shall include the following configuration:

Generator:

a. Modeled at the terminal voltage specified in the Data Application form.

b. The Pgen and Pmax shall be set equal to each other to meet the MFO[5] at the POI.
c. The Qmin and Qmax limits shall be set based on the reactive capability curve for the active power operating point.
d. MVA base and active and reactive power limits should all be set as the equivalent of the aggregate number of inverters multiplied by the capability per inverter.
e. The generator source impedance should be selected such that the short circuit current contribution is negligible (i.e. a large value).
f. The control mode should be set to '1 Standard Qt, QB limits' if the model uses PSS/E library models.
g. Remote bus can be set to 0.

Inverter Step Up Transformer:

a. Inverter Step Up (ISU) Transformer should be included. Note: Inverters without the ISU Transformer explicitly being modeled shall include a note from the inverter manufacturer that the reactive capability curve and the dynamic model is prepared for a 34.5 kV terminal voltage.
b. Impedance I/O Code set to '2 Zpu (winding kV winding MVA)'. All other I/O codes can be left at the default PSS/E values.
c. Winding MVA shall be the equivalent of the aggregate number of ISU transformers multiplied by the capability per transformer. Include the winding configuration (per TO requirements)
d. Include load tap changer settings (Number of taps and voltage % per tap)

Collector System:

a. The equivalent collector system impedance shall be modeled for all projects
b. The total branch positive and negative sequence impedances (R, X and B) shall be provided in per unit on a 100MVA base

Additional Reactive Compensation:

a. If additional reactive compensation is needed, the specific size, step details, and control mode shall be modeled.
b. Modeled at the low side bus of the Main Station transformer

Main Station Transformer:

a. Impedance I/O Code set to '2 Zpu (winding kV winding MVA)' All other I/O codes can be left at the default PSS/E values.
b. Include the winding configuration (per TO requirements)
c. Include load tap changer settings (Number of taps and voltage % per tap)

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[5] FERC Order No. 827 requires that MFO be met while maintaining a power factor range between 0.95 lagging power factor to 0.95 leading power factor.

Loads:

    a.   Auxiliary Load shall be modeled using the ID "XA"

    b.   Station Service Load shall be modeled using ID "XS"

Attachment Line:

    a.   The attachment line impedance data and line length shall be included.

4.2.2.2 Dynamic Data (.DYR) – Library Models

The dynamic representation of large-scale IBRs requires the use of three renewable energy modules as listed below. Wind turbine models may also need additional modules such as WTDTAU1/WTDTA1, WTARAU1/WTARA1, WTPTAU1/WTPTA1 and WTTQAU1/WTTQA1. These modules shall be provided in .dyr format with suitable parameters to represent the project over the entire range of operating conditions.

1| REGC (REGC_*) module, used to represent the generator/converter (inverter) interface with the grid. It processes the real and reactive current command and outputs of real and reactive current injection into the grid model.

   Key points to note:

    a.   Acceleration Factor, Accel (CON(J+13)): This parameter may be adjusted, if needed, between >0 and <= 1. If adjustment of this value provided with the model is not recommended, indicate this with your model submission.

    b.   Momentary Cessation: must be eliminated to the extent possible. See sections 7.4 and 7.5.

        i.   If LVPLSW (ICON(M)) is 1, then set Brkpt = 0.01, Zerox = 0, and Lvpl1 = 1 if possible to eliminate momentary cessation and/or any unnecessary active-power curtailment. Otherwise, provide an explanation if these settings are not possible due to an equipment limitation.

        ii.   Set Lvpnt1 = 0.01 and Lvpnt0 = 0 if possible to eliminate momentary cessation and/or any unnecessary active-power curtailment. Otherwise, provide an explanation if these settings are not possible due to an equipment limitation.

2| REEC (REEC_*) module, used to represent the electrical controls of the inverters. It acts on the active and reactive power reference from the REPC module, with feedback of terminal voltage and generator power output, and gives real and reactive current commands to the REGC module.

   Key points to note:

    a.   The REECB model is not an acceptable model

    b.   REECA: To be used for PV projects and DC coupled hybrid (DC side charging only)

        i.   PFFlag (ICON(M+1)) should be set to 0 if a REPC model is provided.

        ii.   PQFlag (ICON(M+5)): Preference is Q priority but if P priority is selected provide a brief description of the reasoning

        iii.   Qmax (CON(J+13)) and Qmin (CON(J+14)): Shall match the maximum and minimum reactive power capability when active power is 0 from the reactive capability curve

      iv.   Pmax (CON(J+25)) and Pmin (CON(J+26)): Shall match the maximum and minimum active power capability when reactive power is 0 from the reactive capability curve.

      v.   Imax (CON(J+27)): Value is typically 1.0 p.u. but if greater than 1 review real and reactive current limits for model closely.

      vi.   Voltage Dependent Logic (VDL) Vq1 (CON(J+29)) to Ip4 (CON(J+44)): If current is reduced to zero check if this is a current reduction contributing to MC. Note the first Vq and Vp entries that are 0 signal the end of the V-I pairs in PSS/E.

  c. REECC: To be used for BESS projects and DC coupled hybrid (grid charging only)

      i.   PFFlag (ICON(M+1)) should be set to 0 if a REPC model is provided

      ii.   PQFlag (ICON(M+4): Preference is Q priority but if P priority is selected provide a brief description of the reasoning

      iii.   Qmax (CON(J+10)) and Qmin (CON(J+11)): Shall match the maximum and minimum reactive power capability when active power is 0 from the reactive capability curve

      iv.   Pmax (CON(J+21)) and Pmin (CON(J+22)): Shall match the maximum and minimum active power capability when reactive power is 0 from the reactive capability curve.

      v.   Imax (CON(J+23)): Value is typically 1.0 p.u. but if greater than 1 review real and reactive current limits for model closely

      vi.   Voltage Dependent Logic (VDL) Vq1 (CON(J+25)) to Ip4 (CON(J+40)): If current is reduced to zero check if this is a current reduction contributing to MC. Note the first Vq and Vp entries that are 0 signal the end of the V-I pairs in PSS/E

3| REPC (REPC_*) module, used to represent the plant controller. It processes voltage and reactive power output to emulate volt/VAr control at the plant level. It also processes frequency and active power output to emulate active power control. This module gives active reactive and power commands to the REEC module.
Key points to note:

  a. If (ICON (M+4)) VCFlag is set to 0 for voltage droop control, then the remote bus for voltage control (ICON (M)) should be set to the POI, ICON (M+1) to (M+3) should be set to the generator tie line branch with (ICON (M+2)) as the POI bus. When more than one generator equivalent shares an attachment line, then this should be set to an element (collector branch, generator step-up, etc.) uniquely specific to the generator equivalent.

  b. If (ICON (M+4)) is set to 1 for line drop compensation, then (ICON (M)) should be set to a bus representative of the voltage control point of the plant; ICON (M+1) through (M+3) should be chosen as the current measurement point for line drop compensation; and (CON (J+6)) and (CON (J+7)) should be set appropriately.

  c. RefFlag (ICON(M+5)): Should be set to 1 since POI voltage control is preferred

  d. Fflag (ICON(M+6)): Shall be set to 1 for frequency regulation for projects entering the queue/cycle after Oct 1, 2018.

  e. Qmax (CON(J+13)) and Qmin (CON(J+14)) shall be set to the limits modeled in the power flow case with +/-0.001 p.u. addition to prevent log messages about the model initializing at a limit.

  f. Deadband for Frequency Control (CON(J+18) to (J+19)): Frequency deadband cannot be greater than +/-0.0006 p.u. (+/-0.036 Hz).

g. Pmax (CON(J+22)) and Pmin (CON(J+23)) shall be set to the limits modeled in the power flow case with +/-0.001 p.u. addition to prevent log messages about the model initializing at a limit.

h. Droop for frequency control Ddn (CON(J+25)) and Dup (CON(J+26)): Maximum frequency droop of 5% is allowed, therefore Ddn and Dup value is typically not less than 20. It is possible that a setting lower than 20 will still result in a droop of 5%, if the Pmax is less than the MVA rating. In these cases, provide the calculations to support the less than 20 setting. Note PV and wind may provide 0 for Dup.

Note: When more than one generator is modeled within the plant, it is highly recommended that PLNTBU1 model be used as the plant controller. For different inverters or wind turbines, or if a single plant controller is being used for multiple inverter models, the PLNTBU1 plant controller may be utilized. This model has to be used with other models like REAX4BU1 (auxiliary signal model for Type 4 wind machines), REAX3BU1 (auxiliary signal model for Type 3 wind machines), SVCAXBU1 (auxiliary signal model for SVC), FCTAXBU1 (auxiliary signal model for FACTS device), or SYNAXBU1 (auxiliary signal model for synchronous condenser). The inputs to models REAX4BU1, REAX3BU1, SVCAXBU1 and SYNAXBU1 are the output from the PLNTBU1 model.

In addition to the above three modules, the **actual** inverter high and low Voltage and Frequency Protection settings shall also be included in the dyr file using the VTGTPAT/FRQTPAT or VTGDCAT/FRQDCAT models. Voltage and Frequency protection characteristics shall meet or exceed NERC PRC-024-3 requirements. **Limits provided shall reflect the intended settings for the facility**. Note that most inverters are capable of riding through voltage and frequency excursions beyond the minimum ride though characteristics defined in PRC-024-3. If the minimum ride though characteristics in PRC-024-3 are provided provide a brief description on the justification.

1| VTGTPAT/VTGDCAT Under/Over voltage generator trip relay:

    a. Low and high voltage settings not intended to be utilized shall be set to a value that prevents the unit from unintentionally tripping.

    b. Conflicting pickup times for the same voltage threshold shall be eliminated.

    c. No values shall be within the no trip zone of PRC-024-3.

2| FRQTPAT/FRQDCAT Under/Over frequency generator trip relay

    a. Low and high frequency settings not intended to be utilized shall be set to a value that prevents the unit from unintentionally tripping.

    b. Conflicting pickup times for the same frequency threshold shall be eliminated.

    c. No values shall be within the no trip zone of PRC-024-3.

    d. The Over/Under Frequency relay settings should be selected not to operate for numerical frequency deviations observed in PSSE during the disturbances. Instantaneous tripping shall not be allowed.

    e. Note PSS/E can result in erroneous frequency deviations following fault clearing of local faults that can be minimized by metering a point closer to the POI in the plant.

4.2.2.3 Dynamic Data (.DYR) – User Defined Models

A user defined model needs to meet the same requirements laid out above for the library model.

The user defined model and all modules shall be provided in .dyr format with suitable parameters to represent the project. Written documentation/user manual from the manufacturer must be supplied explaining the dynamic device parameters and performance characteristics. The model manual must show control block diagrams, design logic, descriptions of all model parameters, a list of which parameters are commonly tuned for site-specific settings, and a description of procedures for using the model in dynamic simulations.

Any benign warning messages that are generated by the model code at compilation time shall also be documented. Source code, .dll file, and Object file(s) shall be provided for the user defined model(s) in the applicable PSSE version. Any available higher versions of the user defined model shall also be provided. To support future basecase development, updated PSSE versions and supporting documentation for your user model must be provided when requested by PJM, within 30 days.

The **actual** inverter high and low Voltage and Frequency Protection settings shall also be included in the dyr file provided, using the appropriate PSSE models.

Details on Momentary Cessation, whether present or not, must be provided.

5   Synchronous Generators

5.1   General Modeling Requirements

The following modeling requirements are adopted for synchronous units.

The power flow model for synchronous generator facility includes:

- An explicit representation of the interconnection transmission line
- An explicit representation of all main power transformer(s)
- As explicit representation of any station service and/or auxiliary load(s)
- An explicit representation of synchronous generator(s)
- An explicit representation of all plant-level reactive compensation devices either as shunts (fixed or switchable), if applicable

The **Figure 3** shows an example of a single synchronous generator facility representation.

Figure 3.   One line representation of a single synchronous generator
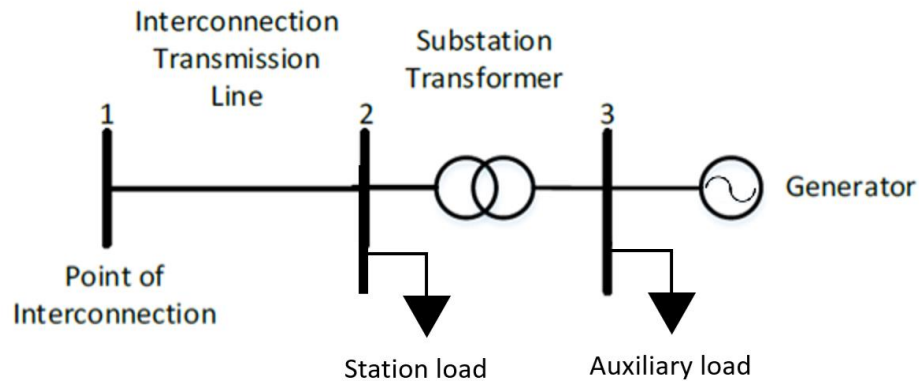
5.2   PJM Dynamic Model Configuration

The Data Application form shall be completed and submitted in Queue Point. The data and information provided in the form shall match the data and parameters provided as the model for the project. Refer to the Appendix of this document for a sample format for the .idv and .dyr files submitted.

5.2.1   Project Specific Data

Maximum Facility Output (MFO):

a. The full facility model must be checked to ensure the gross active power output of the generator(s) can meet the MFO at the POI considering loads and losses for the facility.
b. The net active power output must be equal to the MFO requested.
c. If the MFO is not met at the POI, adjustments would need to be made to ensure the MFO requested can be achieved at the POI.
d. The analysis will be performed with the queue project meeting the MFO at the POI.

e. For uprate requests, provide documentation of existing contractual MFO values prior to the uprate request.

Reactive Power Capability & Saturation Curve:

a. Must be provided with the Data Application form
b. Indicate the curve (based on ambient temperature, cooling water temperature, etc.) to be used for maximum Summer and/or Winter Gross MW operating values.
c. A reasonable ambient temperature of 95F (35C) should be assumed. Justification along with supporting documentation must be included with your submission, for exceptions to this ambient temperature assumption.
d. The reactive power (Qmax/Qmin) modeled for power flow is determined using the specified curve based on the Gross MW operating point for Summer and/or Winter
e. For uprate requests, provide documentation of the contractual power factor requirements prior to the uprate request.
f. Saturation curves must be provided.

5.2.2   Modeling Files

5.2.2.1   Power Flow (.IDV)

The facility shall be modeled in a response file (.idv) that uses RDCH to specify the data. The .idv provided must always include a full representation of the facility configuration, instead of updating just specific portions of the model.

For uprate projects, the idv shall remove and replace the existing plant modeling, rather than incrementally adding only the uprate portion.

The .idv model submitted to PJM for the queue project shall include the following configuration:

Generator:

    a.   Modeled at the terminal voltage specified in the Data Application data form.

    b.   The Pgen and Pmax shall be set equal to each other to meet the MFO at the POI with unity power factor.

    c.   The Qmin and Qmax limits shall be set based on the reactive capability curve for the active power operating point.

    d.   The generator source impedance (Zsource) shall be set equal to the unsaturated sub transient reactance value (X"d)

Main Station Transformer:

    a.   Impedance I/O Code set to '2 Zpu (winding kV winding MVA)' All other I/O codes can be left at the default PSS/E values.

    b.   Ensure correct transformer MVA base is provided per the cooling class designations specified

    c.   Include the winding configuration (per TO requirements)

    d.   Include load tap changer settings (Number of taps and voltage % per tap)

Loads:

    a.   Auxiliary Load shall be modeled using the ID "XA"

    b.   Station Service Load shall be modeled using ID "XS"

Attachment Line:

    a.   The attachment line impedance data and line length shall be included.

5.2.2.2   Dynamic Data (.DYR) – Library Models

    a.   Utilize the appropriate model(s) to represent your facility (i.e.: Hydro, Nuclear, etc.)

    b.   The dynamic model data must include, at a minimum, a generator model, a governor model, an exciter model, and if applicable, a power system stabilizer model and an excitation limiter model.

    c.   For Steam Turbines operating in sliding pressure mode, a governor model is not required. Provide an explanation for this.

    d.   Generator inertia constant H (kWs/kVA) must be the combined Turbine-Generator-Exciter Inertia

    e.   Unsaturated values for all reactance values must be entered for the generator model

f. All reactance and resistance values must be provided in per unit on the machine MVA base at machine terminal voltage.

5.2.2.3 Dynamic Data (.DYR) – User Defined Models

If a user defined model must be provided, it shall be in .dyr format with suitable parameters to represent the project. Written documentation/user manual from the manufacturer must be supplied explaining the dynamic parameters and performance characteristics. The model manual must show control block diagrams, design logic, descriptions of all model parameters, a list of which parameters are commonly tuned for site-specific settings, and a description of procedures for using the model in dynamic simulations.

Any benign warning messages that are generated by the model code at compilation time shall also be documented. Source code, .dll file, and Object file(s) shall be provided for the user defined model(s) in the applicable PSSE version. Any available higher versions of the user defined model shall also be provided. To support future basecase development, updated PSSE versions and supporting documentation for your user model must be provided when requested by PJM, within 30 days.

6 Other New Service Requests

For New Service Requests not covered in this guideline, such as but not limited to, HVDC requests, Offshore Wind requests, etc., a complete power flow model (.idv) and dynamic model (.dyr) for the project and the manufactures dynamic modeling guidelines describing parameter meanings and range of settings for the project, as planned to be installed, up to the Point of Interconnection must be provided.

The PJM Model Testing Requirements and Deliverables listed in the sections below must be met.

7 PJM Model Testing Requirements

Develop a .idv and .dyr file for the queue project model using a Single Machine Infinite Bus (SMIB) system in the appropriate PSS/E version, following the guidelines provided in the sections above. The SMIB shall connect to the POI using the equivalent Thevenin impedance with a SCR of 3 and X/R of 5. See Appendix 10.4 for guidance on this setup. The dynamic simulation for flat start and voltage ride through testing shall use a minimum time step of 0.004167 seconds and log and out files shall be plotted every time step.

Utilize your choice of bus numbers to develop the dynamic model for your project. **The project specific bus numbers will be applied by PJM.**

For Distributed Energy Resources (lower kV projects not connecting to the Transmission system), the requirements in IEEE 1547 (Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces) shall apply.
See sections in Appendix 10 to help with meeting the PJM Model Testing Requirements and Deliverables listed below for your dynamic model submission.

7.1 MFO Assessment

Verify that the MFO requested by the New Service Request project is achievable at the POI.

- The full facility model must be checked to ensure the gross active power output of the generator(s) can meet the MFO at the POI considering loads and losses for the facility.
- The net active power output must be equal to the MFO.
- If the MFO is not met at the POI, adjustments would need to be made to ensure the MFO requested can be achieved at the POI.

Table 2.   Sample MFO Assessment table

	Active Power (MW)
Requested MFO	650
Gross MW	662
Station Load + Auxiliary Load	8.15
Losses	3.85
MW at the POI	650
MW at the POI meets requested MFO	**Yes**

7.2 Power Factor Assessment

In accordance with Part IX, Subpart B, App. 2, Section 4.6.1 of the PJM Open Access Transmission Tariff[6], the following power factor requirements apply to New Service Request projects connecting to the PJM Transmission system:

- New and uprates to a non-synchronous generator shall provide 0.95 leading and 0.95 lagging power factor at the high-side of the main station transformer or the onshore station Transformer. The power factor range between 0.95 leading and 0.95 lagging shall be dynamic.
- New synchronous generators (> 20 MW) shall provide 0.95 leading and 0.90 lagging power factor at the generator terminals.
- New synchronous generators (≤ 20 MW) shall provide 0.95 leading and 0.90 lagging power factor at the point of interconnection.
- Uprates to synchronous generators (> 20 MW) shall provide 1.00 leading and 0.90 lagging power factor at the generator terminals.
- Uprates to synchronous generators (≤ 20 MW) shall provide 1.00 leading and 0.90 lagging power factor at the point of interconnection.

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[6] PJM OATT Part IX, Subpart B, App. 2, Section 4.6.1

- For uprates to prior queue projects or existing units the reactive power requirements in the Interconnection Service Agreement (ISA) is used for that respective MFO portion of the unit.

Projects not connecting to the bulk electric system (generally <100 kV) where NERC standards do not apply, the requirements of the entity with which the interconnection is made shall govern. Best practice for distribution connected inverter based resources is to follow the requirements in IEEE 1547[7]. Power factor specified in the applicable agreement for such projects shall be followed.

A power factor assessment shall be performed to determine if the facility can provide the reactive power necessary to meet the requirement at the specified measurement point, **while meeting the MFO requested, for both lagging and leading**. Project data shall not be submitted with reactive deficiencies; resolve reactive deficiencies prior to submitting data. The assessment considers the following:

Inverter Based Resources:

1| Reactive Capability of the Inverter:

  a. Use the PQ curve submitted for V=1.0pu from the inverter manufacturer. Determine the Qmax and Qmin available at the Gross MW output of the inverter. Multiply the results by the number of turbines/inverters by type, and sum.

  b. The inverters shall have a minimum dynamic reactive capability range of 0.95 leading to 0.95 lagging at the terminals.

2| Reactive Capability at the high side of main transformer:

  a. Use Single Machine Infinite Bus (SMIB) to set a swing generator modeled at the POI to control to the voltage schedule per
  Manual 03[8].

  b. Model the transmission attachment line, the main power transformer, the equivalent collector system, auxiliary and/or station service loads, the equivalent step up transformers and inverters.

  c. Set the inverter's active power dispatch to meet the MFO requested at the POI.

  d. Model any switched shunts and include any STATCOM or SVC devices if provided.

    i. **Lagging test:**
      - Ensure all reactive compensation devices (E.g.: Inverters, fixed shunts, SVC, STATCOMs) within the facility are at the maximum capacitive output allowing the steady-state solution to converge. Fixed shunt devices intended for compensation shall remain on.
      - Set the inverter to output its maximum reactive power capability, without exceeding 1.1 pu terminal voltage.
      - In cases where the inverter is not outputting the maximum capacitive reactive power capability with terminal voltage under 1.10 p.u., the transformer taps can be adjusted to ensure capacitive maximum reactive power output from the inverter. Document changes made.

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[7] https://www.pjm.com/-/media/planning/plan-standards/pjm-guideline-for-ride-through-performance.ashx
[8] PJM Manual 03

- Verify that the MFO is met. If it does not, adjust the inverter's active power to meet the MFO and determine the inverter's new maximum reactive power based on PQ curve.
- Calculate the reactive power losses.
- Calculate the Total Available Reactive Power at High Side of Main transformer
- Determine whether the project meets the reactive power requirements or not.

ii. **Leading test**

- Ensure all reactive compensation devices (E.g.: Inverters, SVC, STATCOM's) within the facility are at the maximum inductive output allowing the steady-state solution to converge. Fixed shunt devices intended for compensation shall remain on.
- Set the inverter to output its minimum reactive power capability, without exceeding 0.90 pu terminal voltage. Inverter capability de-rating due to terminal voltages off nominal shall be respected and represented in the reactive assessment.
- In cases where the inverter is not absorbing the maximum inductive reactive power capability with terminal voltage above 0.90 p.u., the transformer taps can be adjusted to ensure maximum inductive reactive power is absorbed from the inverter. Document changes made.
- Verify that the MFO is met. If it does not, adjust the inverter's active power to meet the MFO and determine the inverter's new minimum reactive power based on PQ curve.
- Calculate the reactive power losses.
- Calculate the Total Available Reactive Power at High Side of Main transformer
- Determine whether the project meets the reactive power requirements or not.

Table 3.   Sample Power Factor Assessment Table for IBRs

| Generator | MFO (MW) | Required Power Factor Range | | Maximum Lagging Qmax (Mvar) | Maximum Leading Qmin (Mvar) |
		Lagging	Leading		
AE1-xxx	120	0.95	0.95		
AF2-xxx (uprate)	7	0.95	0.95		
Total Reactive Power Required				41.74	-41.74
Reactive Power from Generators at Gross MW (obtained from D curve)				**Qmax**	**Qmin**
				79.5	-79.5
Reactive Power Losses (includes any planned compensation)				-22.63	-33.94
Station Load + Auxiliary Load				-0.18	-0.18
Total available reactive power at high side of main transformer				56.69	-113.62
Deficiency in Reactive Power				Meet	Meet

PD Planned Compensation, if any, included in assessment above = <u>X MVAR</u>
<u>(also indicate whether automatically controlled by the PPC or not)</u>

Project data shall not be submitted with reactive deficiencies; resolve reactive deficiencies prior to submitting data. Capacitor bank size cannot be greater than the reactive power losses. Switching fixed shunt devices on to meet the lagging power factor requirement and off to meet the leading power factor requirement and vice-versa is discouraged and will only be permitted if the plant controller is configured to automatically switch the capacitor bank. The project must demonstrate that a power factor range between 0.95 lagging to 0.95 leading is maintained with fixed shunt devices on. An updated power factor assessment table must be provided showing that the plant meets the power factor requirements.

See Appendix 10.3.2 for IBR dynamic model parameters settings to operate in automatic voltage control mode.

Synchronous Generators:

a. Power factor assessment shall be performed for each individual unit (eg: CT, ST) and not for the facility as a whole
b. For uprate requests, the breakdown or split of the requested uprate MW's among each of the units (eg: CT1, CT2 and ST) must be provided.
c. Typically performed for Winter energy values.
d. If the unit has ambient air cooling that can vary with ambient temperature, then a reactive assessment shall be performed for winter energy and summer energy values. Include another set of tables of similar format using the summer energy values.
e. Use the reactive capability curve provided by the generator manufacturer to obtain the Qmax and Qmin available at the Gross MW output of the unit.

Table 4. Sample Power Factor Assessment Table for Synchronous Generators (CT1, CT2, ST)

Generator (CT 1, 2)	Winter MFO (MW)	Required Power Factor Range		Maximum Lagging (Mvar)	Maximum Leading (Mvar)
		Lagging	Leading		
AA1-xxx	117	0.9	0.95	56	-38
AC2-xxx (uprate)	4.75	0.9	1	2	0
Total Reactive Power Required				58	-38
Total Available Reactive Power from Generators at Gross MW (121.75 MW)				**Qmax**	**Qmin**
				80	-45
Deficiency in Reactive Power				Meet	Meet

Generator (ST)	Winter MFO (MW)	Required Power Factor Range		Maximum Lagging (Mvar)	Maximum Leading (Mvar)
		Lagging	Leading		
AA1-xxx	135	0.9	0.95	62.47	-44.1
AC2-xxx (uprate)	0.5	0.9	1	0	0
Total Reactive Power Required				62.47	-44.1
Total Available Reactive Power from Generators at Gross MW (135.5 MW)				**Qmax**	**Qmin**
				62.47	-66.15
Deficiency in Reactive Power				Meet	Meet

Project data shall not be submitted with reactive deficiencies; resolve reactive deficiencies prior to submitting data.

7.3 Flat Start Test

The power flow and dynamic models for any type of generator must be usable by the Siemens PTI PSSE software platform to perform the simulation. The usability requirement includes three aspects:

1| All the models and associated parameters should be read by the simulation software correctly.

   a. The number of each power flow element including buses, lines, transformers, generators, shunts must match the number in the .sav file.

   b. Parameters read into the software must match the values in the .sav file.

   c. The number of dynamic models read into the software must match the number of dynamic models in the .dyr file.

   d. Parameters read into the software must match the values in the .dyr file.

2| There are no initialization errors for the dynamic models and the warning messages are reviewed with resolution or explanation.

3| The models must flat start (i.e.: produce flat lines) for a 20-second no-disturbance simulation. The PJM definition of flat start is variations of generator outputs Pgen and Qgen over 20 seconds no greater than 0.1 MW or 0.1 MVAR movement. The results of the flat start test shall show the unit(s) initializes without any DSTATE errors or suspect initial conditions in the log file and the real power, reactive power, voltage and frequency remain consistent thought out the simulation in the out file and the plots.

7.4   Voltage Ride Through (VRT) Test (for IBRs)

For inverter based resources a three-phase fault is applied at the POI for 9 cycles. The fault is cleared without the loss of any elements. The results of the VRT test shall show the unit(s) does not trip, the real and reactive power recovers to the prefault value. The response shall also be reviewed to see if the unit(s) entered Momentary Cessation if both the real and reactive current went to 0. Provide plots of real and reactive power, terminal voltage, terminal current and frequency. See Appendix 10.3.3 for details.

7.5   Momentary Cessation (for IBRs)

Momentary Cessation is when no current is injected into the grid by the inverter during low or high voltage conditions outside of the continuous operating range.
Reference: NERC Reliability Guideline "*BPS-Connected Inverter-Based Resources Performance", September 2018*
https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Inverter-Based_Resource_Performance_Guideline.pdf

The NERC recommendation is to eliminate Momentary Cessation (MC) to the extent possible. If Momentary Cessation cannot be eliminated due to equipment limitations, notify PJM when submitting the dynamic model for the project.

7.6   Primary Frequency Response

Verify the relevant dynamic model parameters are set to provide primary frequency response.

Part IX, Subpart B, App. 2, Section 4.6.2 of the PJM Open Access Transmission Tariff[9] includes the requirement that a "Generator Interconnection Customer shall ensure the primary frequency response capability of its Customer Facility by installing, maintaining, and operating a functioning governor or equivalent controls."

The ISA/GIA states the "Generator Interconnection Customer is required to install a governor or equivalent controls with the capability of operating: (1) with a maximum 5 percent droop and +/- 0.036 Hz deadband" and "the droop characteristic shall be: (1) based on the nameplate capacity of the Customer Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameters". See Appendix 10.3.4 for details.

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[9] PJM OATT Part IX, Subpart B, App. 2, Section 4.6.2

8   Deliverables

A **Dynamic Model Report** with the **Dynamic Model Checklist** in Section 8.1 below must be submitted along with quality assurance sign offs from responsible parties. Report shall include a summary of model development and testing per guidelines in this document. Deliverables shall include:

1| **Completed Queue Point Data Application form** along with all requested files to be submitted via the Queue Point portal.

2| **Dynamic Model Report** that includes a summary of the model development and testing per the guidelines in this document.

3| If a **Library model** is submitted, provide the .idv and .dyr files for the project developed using the guidelines in this document. See Appendix 10.1 for sample format.

4| If a **UDM** is submitted, provide a properly compiled PSSE version .sav case along with .idv, .dyr and .DLL files appropriately parameterized for the project using the guidelines in this document. Also include:

    a.   A **report on how the settings of the model were parameterized** along with the manufacturer's documentation, including user guide of the UDM

    b.   **Block diagram** for the model and sub modules, along with values, names and detailed explanation of all model parameters

5| Provide the **.raw, .sav case, .cnv, .snp and .sld file** for the project (case setup folder/files)

6| Verify that all testing requirements are met. Must provide:

    c.   MFO assessment table for the project

    d.   **Power Factor Assessment table** for the project along with PQ curve used, along with case setup for power factor assessment (lagging & leading scenarios)

    e.   Confirmation that the unit meets FERC Order No. 827 with regards to **automatic voltage regulation**, with appropriate model settings included in the Dynamic Model report

    f.   **Results for the flatstart test** including log, out and test plots showing Power, VARs, Eterm, Freq and Volt for each inverter(s)/generator(s)

    g.   **Results for the VRT test** including log, out and test plots showing Power, VARs, Eterm, Freq and Volt for each inverter(s). Provide confirmation that **Momentary Cessation is eliminated** (if not, provide reason)

    h.   Confirmation that Primary Frequency Response is enabled

7| For As Built submission only: A Factory Acceptance Test (FAT) report for each main power transformer installed must be included with your submission.

Place all files required per the Deliverables above, including the Dynamic Model Report and Dynamic Model Checklist in a folder, zip and attach/upload in Queue Point under the Generator Information Section > Stability Models. File upload size limit is 250 MB.

8.1 Dynamic Model Checklist

This checklist below must be completed by the Project Developer and included with the project submission in Queue Point to demonstrate that the Deliverables in Section 8 above have been met.

Item	Description	Comment	Check
1	Completed Queue Point Data Application form along with all requested files submitted via Queue Point portal		
2	Dynamic Model Report, summarizing model development and testing per guidelines in this document		
3	If a PSSE library model is submitted (preferred), .idv and .dyr files developed using the guidelines in this document are included		
4	If a UDM is submitted, a properly compiled PSSE version .sav case along with .idv, .dyr, and .dll files appropriately parameterized for the project using the guidelines in this document is included		
4a	For UDM: A report on how the settings of the model were parameterized along with the manufacturer's documentation, including a user guide of the UDM		
4b	For UDM: Block diagram for the model and sub modules, along with values, names and detailed explanation of all model parameters		
5	.raw, .sav case, .cnv, .snp, and .sld file for the project (case setup folder/files) are submitted		
6	Verify all testing requirements are met:		
6a	MFO assessment table is included in the Dynamic Model report		
6b	Power Factor Assessment table along with **PQ curve** used and case setup for power factor assessment (lagging and leading scenarios) is included in the Dynamic Model report		
6c	Confirm that the unit meets FERC Order No. 827 with regards to automatic voltage regulation, with appropriate model settings included in the Dynamic Model report		
6d	Results for the flatstart test including log, out and test plots showing Power, VARs, Eterm, Freq and Volt for each inverter/generator is included		
6e	Results for the VRT test including log, out and test plots showing Power, VARs, Eterm, Iterm, Freq and Volt for each inverter. Provide confirmation that Momentary Cessation is eliminated (if not, provide reason)		
6f	Confirm Primary Frequency Response is enabled		
7	For As Built submissions only: Factory Acceptance Test (FAT) report for each transformer installed		

9   References

1| Solar Photovoltaic Power Plant Modeling and Validation Guideline, MVWG, December 9, 2019
https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/Solar%20PV%20Plant%20Modeling%20and%20Validation%20Guidline.pdf&action=default&DefaultItemOpen=1

2| Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources, NERC IRPTF, September 2019

https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf

3| PJM Manual 14B

https://pjm.com/-/media/documents/manuals/m14b.ashx

4| PRC-024-3

https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-024-3.pdf

5| WECC Wind Power Plant Power Flow Modeling Guide
https://www.wecc.org/Reliability/WECCWindPlantPowerFlowModelingGuide.pdf

6| IEEE 1547 Standards
https://standards.ieee.org/ieee/1547/5915/

7| PJM Guideline for Ride Through Performance of Distribution-Connected Generators

https://www.pjm.com/-/media/planning/plan-standards/pjm-guideline-for-ride-through-performance.ashx

10 Appendix

10.1 Sample Format for .idv and .dyr files

The .idv and .dyr file provided for your project must include the following header at the top of the file, with the relevant information filled out.

```
/****************************************************
/*** Project Number:
/*** Project Name:
/*** POI location:
/*** TO Zone:
/*** MFO:
/*** Fuel Type:
/*** Inverter Details (Number x MW/inverter) OR Generators (CT, ST configuration):
/*** PSSE Version:
/*** Date:
/*** Description of Changes: (not required if this is the first file submission for the project)
/****************************************************
```

Start .idv/.dyr modeling information here

10.2 Unacceptable Models List

Model	Description
WT3G1, WT3G2	Doubly-Fed Induction Generator (Type 3)
WT4G1, WT4G2	Wind generator model with power converter (Type 4)
WT3E1	Electrical control for Type 3 wind generator
WT4E1, WT4E2	Electrical control models for Type 4 wind generator
WT3T1	Mechanical system model for Type 3 wind generator
WT3P1	Pitch control model for Type 3 wind generator
WT12A1	Pseudo-governor model for Type 1 and Type 2 wind generators
REECB1, REECBU1	Renewable Energy Electrical Control model (for large scale PV)
GENSAL	Salient pole generator model
GENCLS	Classical generator model
GENTRA	Transient Level Generator Model
SEXS	Simplified excitation system model
EX2000	EX2000 Excitation System
COMPCC	Voltage Regulator Current Compensating Model for Cross-Compound Units
URGS3T	WECC gas turbine governor model
GAST	Gas Turbine-Governor
GAST2A	Gas Turbine Model
GASTWD	Woodward Gas Turbine-Governor Model
IEEEG2	1981 IEEE type 2 turbine-governor model
WESGOV	Westinghouse digital governor for gas turbine
PVGU1	User written generator model to represent photo-voltaic (PV) systems
PVEU1	User written electrical control model for photo-voltaic(PV) systems

10.3 Dynamic Model Descriptions for IBRs

The WECC approved dynamic models required to represent inverter-based resources (IBRs) are shown in this section. Examples of typical values are given for different modules for Renewable Energy Resources (RES). Table 1 shows voltage and frequency protection modules applicable to all IBRs. Table 2 illustrates the different approved modules and their applicability.

Voltage and Frequency protection modules	
Model Name for Generator Protection	For All Facilities, Solar PV, Wind & Storage
Low/High Frequency Ride-Through	FRQTPAT, FRQDCAT
Low/High Voltage Ride-Through	VTGTPAT, VTGDCAT

Applicable WECC Approved IBR Dynamic Models		
Model Name	Model Name in Siemens PTI PSS®E	Applicability
Generator/Converter	REGCAU1(v 33); REGCA1 (v34 & v35)	All IBR
	REGCBU1 (v34 & v35)	All IBR, voltage source interface to grid for numerical robustness
Electrical Controls	REECAU1 (v33); REECA1 (v34 & v35)	Type 3 and 4 WTG Solar PV DC-coupled: BESS not charging from grid
	REECCU1 (v33 & v34); REEC1 (v35)	Stand-alone BESS DC-coupled: BESS charging from grid
	REECDU1 (v34 & v35)	All IBR, enhanced modeling capability from reecau1/reeca1 & reecbau1_
Plant Controller	REPCTAU1 & REPCAU1 (v33); REPCTA1 & REPCA1 (v34 & v35)	For single generator control (except for plant level PF control)
	PLNTBU1 (v33, v34 & v35)	For single and multiple generator control
Mechanical Models for Wind Turbines		
Two-mass model of the WTG drive-train	WTDTAU1 (v33); WTDTA1 (v34 v35)	Type 3 WTG Type 4 WTG if pflag = 1 in reecau1/reeca1
Aero-dynamic model for the type 3 WTG	WTARAU1 (v33); WTARA1 (v34 & v35)	Type 3 WTG
Model of the pitch control system	WTPTAU1 (v33); WTPTA1 (v34 & v35)	Type 3 WTG
Model of the torque control system	WTTQAU1 (v33); WTTQA1 (v34 & v35)	Type 3 WTG
New refined pitch-controller model	WTGPB	Type 3 WTG

The modules fall into four (4) categories:

1| **Renewable Energy Generator/Converter (REGC_*) models:** These modules are used to model the electrical generator and/or power converter interface between the generation unit and the grid. There are three (3) such modules:

   a. REGCAU1 (v33)/REGCA1 (v34 & v35) – this is the original model. It is a current-source model. It is adequate for modeling the generator dynamic behavior of the generator/converter interface. It is

not suitable for weak-grid connection points, where the short-circuit ratio (SCR) of the point of interconnection may be 3 or less.

b. REGCBU1 (v34 & v35) – this is a newly developed and approved voltage-source generator/converter interface model. It is better suited to weak-grid conditions, and if parameterized appropriately has been shown to be accurate numerically down to SCRs close to 1.

c. REGCCU1 – this is a new model yet to be fully implemented and approved by all the software vendors. It incorporates a generic representation of the phase-locked loop (PLL) and inner-current control loops, as well as being a voltage-source model.

Presently REGCAU1/REGCA1 and REGCBU1 are approved models and can be used for modeling the generator/converter interface of a RES. The choice of the model should be based on whether the IBR is connected at a weak point or strong point and the best data currently available for the plant being modeled. The point-of-interconnection of a plant may become weak over time as additional inverter-based resources interconnect in the vicinity of the plant. In such cases there may be a need to transition from a REGCAU1/REGCA1 model to a REGCBU1 model.

2| **Renewable Energy Electrical Controls (REEC_*) models**: These modules are used to model the electrical controls at the individual generating unit level, including individual wind turbine generators and individual PV inverters. There are three (3) such modules:

a. REECAU1/REECA1 – this is the original model developed and can be used, if appropriately parameterized for wind and PV generators.

b. REECCU1/REEC1 – this module was developed specifically for battery-energy storage systems (BESS) or can also be used to model hybrid PV-BESS systems, particularly when the BESS and PV are coupled on the dc-side of the inverter and share one common inverter.

c. REECDU1 – this is the latest electrical controls model developed which contains main new features, such as extended voltage-dependent current limit tables. As such, when modeling new facilities this model may offer greater flexibility and features. It can be used to model wind, PV and BESS. All three of the above REEC_* models are approved and can be used for modeling the electrical controls of the appropriate RES.

The REECBU1 model is **no longer approved** although still used in a number of ISOs/RTOs. The REECBU1 model does not have the "VDL" logic.

The REECAU1, REECCU1 and REECDU1 models have the "VDL" V-I characteristic curve parameters that define the momentary cessation characteristics. At VDL voltages V1 to V4 the corresponding limits for the active and reactive current commands Ip and Iq are defined. This enables the models to reduce or completely stop producing active and/or reactive power when low voltages are observed and then ramp back up once voltages increase. There are other parameters in the models that can impact this behavior. The REGCAU1 model includes an ICON for LVPL switch that enables the LVPL characteristic that can also define reduction in active power at low voltages, however, this characteristic is a single, linear-slope while the VDL logic is piece-wise linear.

3| **Renewable Energy Plant Controller (REPC_*) models**: These modules are used to model the plant level controls that monitor the point of common coupling (PCC), or point of interconnection (POI), of a plant and issues real and reactive power commands to all the individual generating units in the plant to control the real and reactive power at the PCC (or POI). There are three (3) such models:

a. REPCTAU1 & REPCAU1/REPCTA1 & REPCA1 – this is the original simple plant level controller. It allows for volt/var control and active power control. It does not include power factor control.

b. PLNTBU1 – this is a complex-plant controller to be used primarily for hybrid-plants which include multiple technologies, for example a combination of two different wind turbine technologies, or wind and PV, and other combinations. It does also allow for power factor control at the PCC (POI).

c. REPC_C – this model is not yet finalized and approved. It presents significant additional features and flexibility including, power factor control at the PCC (POI), ability to have coordinated and automatically switched shunt devices at the PCC (POI), and extra features for active power control.

Presently REPCTAU1 & REPCAU1/REPCTA1 & REPCA1 and PLNTBU1 are approved and can be used for modeling the appropriate plant controller.

4| **Mechanical Element Models for Wind Turbine Generators**: specifically for wind turbine generators (WTGs) there are a series of mechanical side models. Presently, for type 4 WTGs the only mechanical model used is an emulation of the drive-train dynamics. All the other models are used only for type 3 WTGs. The models are:

a. WTDTAU1/WTDTA1 – this is a two-mass model of the WTG drive-train.

b. WTARAU1/WTARA1 – this is a very simple aero-dynamic model for the type 3 WTG.

c. WTPTAU1/WTPTA1 – this is a simple model of the pitch control system.

d. WTTQAU1/WTTQA1 – this is a simple model of the torque control system.

e. WTGP_B – this is a new refined pitch-controller model, which provides added flexibility in the limits of the pitch controller.

WTDTAU1/WTDTA1, WTARAU1/WTARA1, WTPTAU1/WTPTA1 and WTTQAU1/WTTQA1 are all currently approved models and should be used when modeling a type 3 WTG. When modeling a type 4 WTG, due to the full-converter interface, for stability simulations it has been shown that none of these models are necessary.

10.3.1 IBR data submission and typical values

The dynamic model shall be submitted in a table and a Siemens PTI PSS®E version 34 dyr format. Examples dyr files and tables showing typical values for PV Solar, Wind, and Battery Storage modules are shown below.

10.3.1.1 PV Solar

The generator/converter REGCA1, electrical controls REECA1, and plant controls REPCA1 models with typical values for PV Solar are shown in the following three tables.

Lvplsw - Enable (=1) or disable (=0) Low Voltage Power Logic, LVPL

Generator/Converter Module		
REGCA1 (v34 & v35) / REGCAU1 (v33)		
Parameter	**Description**	**Typical Values**
Tg	Converter time constant (s)	0.02
Rrpwr	Low Voltage Power Logic (LVPL) ramp rate limit (pu/s)	10.0
Brkpt	LVPL characteristic voltage 2 (pu)	0.01
Zerox	LVPL characteristic voltage 1 (pu)	0.00
Lvpl1	LVPL gain (pu)	1.00
Volim	Voltage limit (pu) for high voltage reactive current management	1.2
Lvpnt1	High voltage point for low voltage active current management (pu)	0.8
Lvpnt0	Low voltage point for low voltage active current management (pu)	0.4
Iolim	Current limit for high voltage clamp logic (pu on mbase)	-1.0 to -1.5
Tfltr	Terminal voltage filter (for LVPL) time constant (s)	0.02
Khv	Overvoltage compensation gain used in high voltage reactive current management	0.7
Iqrmax	Maximum rate-of-change of reactive current (pu/s)	999.9
Iqrmin	Minimum rate-of-change of reactive current (pu/s)	-999.9
Accel	High voltage reactive current management acceleration factor, p.u.	0.7

Electrical Controls Module		
REECA1 (v34 & v35) / REECAU1 (v33)		
Parameter	**Description**	**Typical Values**
PFFLAG	1 if power factor control 0 if Q control, which can be controlled by an external signal	0
VFLAG	1 if Q control 0 if voltage control	1 or 0
QFLAG	1 if voltage or Q control 0 if constant pf or Q control	1 or 0
PFLAG	1 if active current command has speed dependency 0 for no dependency	1 or 0
PQFLAG	P/Q priority flag for current limit: 0 for Q priority 1 for P priority	0

REECA1 (v34 & v35) /REECAU1 (v33)		
Vdip	Low voltage threshold to activate reactive current injection logic	[0.00, 0.90]
Vup	Voltage above which reactive current injection logic is activated	[1.10, 1.30]
Trv	Voltage filter time constant.	[0.02, 0.05]
dbd1	Voltage error dead band lower threshold (≤ 0)	[-0.10, 0.00]
dbd2	Voltage error dead band upper threshold (≥ 0)	[0.00, 0.10]
Kqv	Reactive current injection gain during over and under voltage conditions	2.0
Iqh1	Upper limit on reactive current injection Iqinj	[0.00, 1.10]
Iql1	Lower limit on reactive current injection Iqinj.	[-1.10, 0.00]
Vref0	User defined reference (if 0, model initializes it to initial terminal voltage)	0.0
Iqfrz	Value at which Iqinj is held for Thld seconds following a voltage dip if Thld > 0	

Thld	Time for which Iqinj is held at Iqfrz after voltage dip returns to zero	0.0
Thld2	Time of holding the active current command after voltage dip returns to 0, sec.	0.0
Tp	Filter time constant for electrical power.	[0.02, 0.05]
Qmax	Maximum limit for reactive power regulator when vflag = 1, p.u.	[0.00, 0.43]
Qmin	Minimum reactive power when vflag = 1, p.u.	[-0.43, 0.00]
VMAX	Maximum limit for voltage control (pu)	[1.05, 1.15]
VMIN	Minimum limit for voltage control (pu)	[0.85, 0.95]
Kqp	Local Q regulator proportional gain, p.u.	
Kqi	Local Q regulator integral gain, p.u.	
Kvp	Local voltage regulator proportional gain, p.u	
Kvi	Local voltage regulator integral gain, p.u	
Vbias	Inner-loop voltage control reference, p.u., user-defined bias (normally 0)	0.0
Tiq	Reactive current regulator lag time constant, sec. Time constant on delay s4	[0.02, 0.05]
dPmax	Active power up-ramp limit, p.u./sec	999.00
dPmin	Active power down-ramp limit, p.u./sec	-999.00
PMAX	Maximum active power, p.u	1.00
PMIN	Minimum active power, p.u	0.00
Imax	Maximum limit on total converter current, Maximum apparent current, p.u.	[1.00, 1.70]
Tpord	Power filter time constant; Inverter power order lag time constant (s)	[0.02, 0.05]
Vq1	Reactive Power V-I pair, voltage (pu)	0
Iq1	Reactive Power V-I pair, current (pu)	1
Vq2	(Vq2>Vq1), Reactive Power V-I pair, voltage (pu)	2
Iq2	(Iq2>Iq1), Reactive Power V-I pair, current (pu)	1
Vq3	(Vq3>Vq2), Reactive Power V-I pair, voltage (pu)	0
Iq3	(Iq3>Iq2), Reactive Power V-I pair, current (pu)	0
Vq4	(Vq4>Vq3), Reactive Power V-I pair, voltage (pu)	0
Iq4	(Iq4>Iq3), Reactive Power V-I pair, current (pu)	0
Vp1	Real Power V-I pair, voltage (pu)	0
Ip1	Real Power V-I pair, current (pu)	0
Vp2	(Vp2>Vp1), Real Power V-I pair, voltage (pu)	0.7
Ip2	(Ip2>Ip1), Real Power V-I pair, current (pu)	0.8
Vp3	(Vp3>Vp2), Real Power V-I pair, voltage (pu)	0.9
Ip3	(Ip3>Ip2), Real Power V-I pair, current (pu)	0.98
Vp4	(Vp4>Vp3), Real Power V-I pair, voltage (pu)	1
Ip4	(Ip4>Ip3), Real Power V-I pair, current (pu)	1

Voltage-dependent active currents Ip1 to Ip4 and voltage-dependent reactive currents Iq1 to Iq4 are from the voltage-dependent current limits (VDL) tables (VDL1 and VDL2) and are used to model cessation of both active and reactive current respectively. The parameter Vdip in REECA1 must be equal or higher than the low voltage momentary cessation threshold vblkl and Vup must be equal or lower than the high voltage threshold vblkh to ensure inverter controls are frozen during the cessation period.

Low Voltage Power Logic Switch: It is best to set lvplsw in REGCA1 to 0 to prevent the generator/converter model from contradicting the VDL1 and VDL2 settings in the REECA1 model.

Plant Controls Module		
REPCA1 & REPCTA1 (v34 & v35)		
Parameter	**Description**	**Typical Value**
VCFlag	Droop flag: 0 – with droop if power factor control 1 – with line drop compensation	1 or 0
RefFlag	Flag for V or Q control 0 – Q control 1 – V control	1
Fflag	Flag to disable frequency control 1 – enable control 0 – disable control	1
REPCA1 & REPCTA1 (v34 & v35) /REPCAU1 & REPCTAU1 (v33)		
Tfltr	Voltage and reactive power filter time constant, sec.	[0.02, 0.05]
Kp	Volt/VAr /Reactive power PI control proportional gain (pu)	-
Ki	Volt/VAr /Reactive power PI control integral gain (pu)	-
Tft	Plant controller Q output lead time constant, sec	0.00
Tfv	Plant controller Q output lag time constant, sec.	[0.02, 0.15]
Vfrz	Voltage for freezing Volt/VAr regulator integrator, p.u	[0.00, 0.90]
Rc	Line drop compensation resistance, p.u.	≥ 0.0
Xc	Line drop compensation reactance, p.u	≥ 0.0
Kc	Reactive droop gain, p.u	
emax	Maximum Volt/VAr error, p.u; upper limit on deadband output (pu)	999.00
emin	Minimum Volt/VAr error, p.u.; lower limit on deadband output (pu)	-999.00
dbd1	Lower threshold for reactive power control deadband (<=0)	
dbd2	Upper threshold for reactive power control deadband (>=0)	
Qmax	Max plant reactive power command/Upper limit on output of V/Q control (pu)	[0.00, 0.43]
Qmin	Min plant reactive power command/Lower limit on output of V/Q control (pu)	[-0.43, 0.00]
Kpg	Real power control proportional gain, p.u	-
Kig	Real power control integral gain, p.u.	-
Tp	Real power measurement filter time constant (s)	[0.02, 0.05]
fdbd1	Frequency deadband downside, p.u.	-0.0006
fdbd2	Frequency deadband upside, p.u	0.0006
femax	Maximum power error in droop regulator/frequency error lower limit (pu)	999.00
femin	Minimum power error in droop regulator/frequency error lower limit (pu)	-999.00
Pmax	Upper limit on power reference/Maximum plant active power command, p.u.	1.00
Pmin	Lower limit on power reference/Minimum plant active power command, p.u	0.00
Tg	Plant controller P output lag time constant, sec.	[0.02, 0.15]
Ddn	Reciprocal of droop for over-frequency conditions (p.u.)	20
Dup	Reciprocal of droop for under-frequency conditions (pu)	20

For PV Solar, an example of a function call in the .dyr file is shown below.

```
4444, 'USRMDL', 1, 'REGCAU1', 101, 1, 1, 14, 3, 4
/ Lvplsw
      0
/ Tg        Rrpwr      Brkpt     Zerox    Lvpl1
0.020      10.0       0.01      0.00     1.00
/ Volim     Lvpnt1     Lvpnt0    Iolim    Tfltr
 1.10        0.9        0        -1.0     0.01
/ Khv       Iqrmax     Iqrmin    Accel
 0.0        99.0       -99.0     0.70


4444, 'USRMDL', 1, 'REECAU1', 102, 0, 6, 45, 6, 9
/ Bus#       PFflag      Vflag      Qflag      Pflag       PQflag
  0           0           1          1          0           0
/ Vdip       Vup        Trv        dbd1       dbd2
 0.90        1.10       0.01       -0.10       0.10
/ Kqv        Iqh1       Iql1       Vref0      Iqfrz
 2.0         1.0        -1.0       1.00       0.0
/ Thld       Thld2      Tp         QMax       QMin
 0.0         0.0        0.01       0.60       -0.60
/ Vmax       Vmin       Kqp        Kqi        Kvp
 1.10        0.9        1          5          1
/ Kvi        Vbias      Tiq        dPmax      dPmin
 3.0         0.0        0.016668   999        -999
/ Pmax       Pmin       Imax       Tpord      Vq1
 1           0          1.0        0.10       0.0
/ Iq1        Vq2        Iq2        Vq3        Iq3
 1.0         0.4        1.0        0.6        1.0
/ Vq4        Iq4        Vp1        Ip1        Vp2
 0.8         1.0        0.0        1.0        0.4
/ Ip2        Vp3        Ip3        Vp4        Ip4
 2.0         0.6        1.0        0.8        1.0


4444, 'USRMDL', 1, 'REPCAU1', 107, 0, 7, 27, 7, 9
/ Bus#     LDC_FromBus   LDC_ToBus    LDC_ID    VCFlag    Refflag    Fflag
 4444        4445          4446        '1'       0          1          1
/ Tfltr     Kp         Ki         Tft        Tfv
 0.05       0.5        3          0          0.05
/ Vfrz      Rc         Xc         Kc         emax
 0.9        0          0          0.1        0.05
/ emin      dbd1       dbd2       QMax       QMin
 -0.05      0          0          0.3669     -0.3669
/ Kpg       Kig        Tp         fdbd1      fdbd2
 0.5        0.25       0.25       -0.0006    0.0006
/ femax     femin      Pmax       Pmin       Tg
 999        -999       0.9304     0          0.7
/ Ddn       Dup
20.000     20.000


/ LOW VOLTAGE PROTECTION example
   1  'VTGDCAT'   4444   4444 '1 '
                    / Vlow       Vup        RlTm       BrTm
                      0.90      10.00      120.00      0.00
   2  'VTGDCAT'   4444   4444 '1 '
                    / Vlow       Vup        RlTm       BrTm
                      0.80      10.00      60.000      0.00
   3  'VTGDCAT'   4444   4444 '1 '
                    / Vlow       Vup        RlTm       BrTm
```

```
                 0.70       10.00      21.000     0.00
   4  'VTGDCAT'   4444   4444 '1 '
                 / Vlow      Vup        RITm       BrTm
                 0.50       10.00      10.000     0.00

/ HIGH VOLTAGE PROTECTION example
   5  'VTGDCAT'   4444   4444 '1 '
                 / Vlow      Vup        RITm       BrTm
                 0.00        1.10      120.00      0.00
   6  'VTGDCAT'   4444   4444 '1 '
                 / Vlow      Vup        RITm       BrTm
                 0.00        1.15      60.000      0.00
   7  'VTGDCAT'   4444   4444 '1 '
                 / Vlow      Vup        RITm       BrTm
                 0.00        1.20       2.000      0.00
   8  'VTGDCAT'   4444   4444 '1 '
                 / Vlow      Vup        RITm       BrTm
                 0.00        1.25       0.200      0.00

/ LOW FREQUENCY PROTECTION example
   9  'FRQDCAT'   4460   4444 '1 '
                 / Flow      Fup        RITm       BrTm
                 56.5       100.0       6.000      0.00

/ HIGH FREQUENCY PROTECTION example
  10  'FRQDCAT'   4460   4444 '1 '
                 / Flow      Fup        RITm       BrTm
                 00.0        63.5       6.000      0.00
```

10.3.1.2 Wind Power Plants

For wind power plants based on Type 3 and 4 WTGs, the required modules are listed below. The second-generation models for PSSE v34 have significantly improved with respect to the previous WECC generic model, in terms of structure and functionality.

- REGCAU1 (v33) module, used to represent the generator/converter processes the real and reactive current commands, and outputs real and reactive current injection into the grid model.
- REECAU1 (v33) module, used to represent the WTG electrical controls acts on the active and reactive power reference from the REPCAU1 module, with feedback of terminal voltage and generator power output, and provides real and reactive current commands to the REGCAU1 module.
- REPCAU1 (v33) modules, used to represent the plant controller processes voltage and reactive power output to emulate volt/var control at the plant level. It also processes frequency and active power output to emulate active power control. This module provides active reactive power command to the REECAU1 module.
- WTDTAU1 (v33) module, used to represent the turbine.
- WTARAU1 (v33) module, used to represent the aerodynamic conversion (Type 3 only).
- WTPTAU1 module, used to represent the pitch controller (Type 3 only).
- WTTQAU1 module, used to represent the torque controller (Type 3 only).

2nd Generation WECC Models in PSS/E v34 Format				
Model Name	**Wind Type 3**	**Wind Type 4**	**Solar Photovoltaic**	**Energy Storage**
Generator/Converter	REGCA1	REGCA1	REGCA1	REGCA1
Electrical Controller	REECA1	REECA1	REECDU1	REECCU1
Plant Controller	REPCTA1	REPCA1	REPCA1	REPCA1
Drive-Train	WTDTA1	WTDTA1 (optional)		
Pitch Control	WTPTA1			
Aerodynamic	WTARA1			
Torque Control	WTTQA1			

Lvplsw - Enable (1) or disable (0) low voltage power logic

REGCAU1 (v33) /REGCA1 (v34 & v35) Input Parameters		
Name	**Description**	**Typical Values**
Tg	Converter time constant (s)	0.02
Rrpwr	Active current up-ramp rate limit on voltage recovery (pu/s) (LVPL)	10.00
Brkpt	LVPL breakpoint (pu voltage)	0.01
Zerox	LVPL zero crossing (pu voltage)	0.00
Lvpl1	LVPL gain breakpoint (pu current on mbase / pu voltage)	1.00
Volim	Voltage limit for high voltage clamp logic (pu)	1.2
lvpnt1	High voltage point for low voltage active current management (pu)	0.8
lvpnt0	Low voltage point for low voltage active current management (pu)	0.4
lolim	Current limit (pu) for high voltage reactive current management	-1.0 to -1.5
Tfltr	Terminal voltage filter (for LVPL) time constant (s)	0.01 to 0.02
Khv	High voltage clamp logic acceleration factor	0.7
Iqrmax	Maximum rate-of-change of reactive current (pu/s)	999.9
Iqrmin	Minimum rate-of-change of reactive current (pu/s)	-999.9
Accel	acceleration factor (0 < Accel < 1)	0.7

REECAU1 (v33) /REECA1 (v34 & v35) Input Parameters		
Name	**Description**	**Typical Values**
PFflag	Constant Q (0) or PF (1) local control	0
Vflag	Voltage control (0) or Q control (1)	1 or 0
Qflag	Bypass (0) or engage (1) inner voltage regulator loop	1 or 0
Pqflag	Priority to reactive current (0) or active current (1)	0
Vdip	Low voltage condition trigger voltage (pu)	0.0 to 0.9
Vup	High voltage condition trigger voltage (pu)	1.1 to 1.3
Trv	Terminal bus voltage filter time constant (s)	0.01 to 0.02
dbd1	Overvoltage deadband for reactive current injection (pu)	-0.1 to 0.0
dbd2	Undervoltage deadband for reactive current injection (pu)	0.0 to 0.1
Kqv	Reactive current injection gain (pu/pu)	0.0 to 10.0

Iqhl	Maximum reactive current injection (pu on mbase)	1.0 to 1.1
Iqll	Minimum reactive current injection (pu on mbase)	-1.1 to -1.0
Vref0	Reference voltage for reactive current injection (pu)	0.95 to 1.05
Iqfrz	Value at which Iqinj is held for Thld seconds following a voltage dip if Thld > 0 (pu)	
Thld	Time for which Iqinj is held at Iqfrz after voltage dip returns to zero (sec)	
Thld2	(>=0), Time for which the active current limit (IPMAX) is held at the faulted value after voltage dip returns to zero (sec)	
Tp	Active power filter time constant (s)	0.01 to 0.02
Qmax	Maximum reactive power when Vflag = 1 (pu on mbase)	-
Qmin	Minimum reactive power when Vflag = 1 (pu on mbase)	-
Vmax	Maximum voltage at inverter terminal bus (pu)	1.05 to 1.15
Vmin	Minimum voltage at inverter terminal bus (pu)	0.85 to 0.95
Kqp	Local Q regulator proportional gain (pu/pu)	-
Kqi	Local Q regulator integral gain (pu/pu-s)	-
Kvp	Local voltage regulator proportional gain (pu/pu)	-
Kvi	Local voltage regulator integral gain (pu/pu-s)	-
Vbias	User-defined bias (normally 0)	0.00
Tiq	Reactive current regulator lag time constant (s)	0.01 to 0.02
dPmax	Power reference max. ramp rate (pu/s)	> 0
dPmin	Power reference min. ramp rate (pu/s)	< 0
Pmax	Maximum active power (pu on mbase)	1.0
Pmin	Minimum active power (pu on mbase)	0.0
Imax	Maximum apparent current (pu on mbase)	1.0 to 1.3
Tpord	Inverter power order lag time constant (s)	-
Vq1	Reactive Power V-I pair, voltage	0
Iq1	Reactive Power V-I pair, current	1
Vq2	(Vq2>Vq1), Reactive Power V-I pair, voltage	2
Iq2	(Iq2>Iq1), Reactive Power V-I pair, current	1
Vq3	(Vq3>Vq2), Reactive Power V-I pair, voltage	0
Iq3	(Iq3>Iq2), Reactive Power V-I pair, current	0
Vq4	(Vq4>Vq3), Reactive Power V-I pair, voltage	0
Iq4	(Iq4>Iq3), Reactive Power V-I pair, current	0
Vp1	Real Power V-I pair, voltage (pu)	0
Ip1	Real Power V-I pair, current (pu)	0
Vp2	(Vp2>Vp1), Real Power V-I pair, voltage (pu)	0.7
Ip2	(Ip2>Ip1), Real Power V-I pair, current (pu)	0.8
Vp3	(Vp3>Vp2), Real Power V-I pair, voltage (pu)	0.9
Ip3	(Ip3>Ip2), Real Power V-I pair, current (pu)	0.98
Vp4	(Vp4>Vp3), Real Power V-I pair, voltage (pu)	1
Ip4	(Ip4>Ip3), Real Power V-I pair, current (pu)	1

WTARAU1 (v33) /WTARA1 (v34 & v35) Input Parameters		
Name	**Description**	**Typical Values**
Ka	Aero-dynamic gain factor (pu/deg)	0.007
θ_0	Initial pitch angle (deg)	0.0

WTPTAU1 (v33) /(WTPTA1 v34 & v35) Input Parameters		
Name	**Description**	**Typical Values**
Kiw	Pitch control integral gain	25.0
Kpw	Pitch control proportional gain	150.0
Kic	Pitch compensation integral gain	30.0
Kpc	Pitch compensation proportional gain	3.0
Kcc	Proportional gain	0.0
Tpi	Pitch time constant (sec)	0.30
TetaMax	Maximum pitch angle (deg)	27.0 – 30.0
TetaMin	Minimum pitch angle (deg)	0.0
RTetaMax	Maximum pitch rate (deg/sec)	5.0 – 10.0
RTetaMin	Minimum pitch rate (deg/sec)	-10.0 – -5.0

WTTQAU1(v33) /WTTQA1 (v34 & v35) Input Parameters		
Name	**Description**	**Typical Values**
Kpp	Proportional gain	3,00
Kip	Integral gain	0.60
Tp	Power measurement lag time constant (sec)	0.05 to 0.1
Tωref	Speed reference time constant (sec)	30.0 to 60.0
Temax	Maximum torque (pu)	1.1 to 1.2
Temin	Minimum torque (pu)	0.00
p1	User-defined pair of points, function f(Pe)	0.15
spd1		0.85
p2		0.23
spd2		0.95
p3		0.35
spd3		1.10
p4		0.46
spd4		1.20
TRATE	Total turbine rating (MW)	*

* TRATE (CON J+14) needs to be set to limit modeled in the power flow case or set to 0 to use the Mbase.

REPCAU1 & REPCTAU1 (v33) / REPCA1 & REPCTA1 (v34 & v35) Input Parameters		
Name	Description	Typical Values
RefFlag	Plant level reactive power (0) or voltage control (1)	1
VCFlag	Droop flag 0: with droop if power factor control 1: with line drop compensation	1 or 0
Fflag	Flag to disable frequency control 1: Enable control 0: disable	1
Tfltr	Voltage and reactive power filter time constant (s)	0.01 to 0.02
Kp	Volt/VAR regulator proportional gain (pu/pu)m	
Ki	Volt/VAR regulator integral gain (pu/pu-s)	
Tft	Plant controller Q output lead time constant (s)	
Tfv	Plant controller Q output lag time constant (s)	0.15 to 5.0
Vfrz	Voltage for freezing Volt/VAR regulator integrator (pu)	0.0 to 0.9
Rc	Line drop compensation resistance (pu on mbase)	-
Xc	Line drop compensation reactance (pu on mbase) when VcompFlag = 1	-
Kc	Reactive droop (pu on mbase) when VcompFlag = 0	-
emax	Maximum Volt/VAR error (pu)	-
emin	Minimum Volt/VAR error (pu)	-
dbd1	lower threshold for reactive power control deadband	<=0
dbd2	upper threshold for reactive power control deadband	>=0
Qmax	Maximum plant reactive power command (pu on mbase)	-
Qmin	Minimum plant reactive power command (pu on mbase)	-
Kpg	Droop regulator proportional gain (pu/pu)	-
Kig	Droop regulator integral gain (pu/pu-s)	-
Tp	Active power filter time constant (s)	0.01 to 0.02
fdbd1	Deadband for frequency control, lower threshold (<=0)	-0.0006
fdbd2	Deadband for frequency control, upper threshold (>=0)	0.0006
femax	Maximum power error in droop regulator (pu on mbase)	-
femin	Minimum power error in droop regulator (pu on mbase)	-
Pmax	Maximum plant active power command (pu on mbase)	1.0
Pmin	Minimum plant active power command (pu on mbase)	0.0
Tg	Plant controller P output lag time constant (s)	0.15 to 5.0
Ddn	Reciprocal of droop for over-frequency conditions (pu)	20.0
Dup	Reciprocal droop for under-frequency conditions (pu)	20.0

For a wind power plant with Type 3 WTGs, the function call in the .dyr file would be as shown in the example below.

```
2222, 'USRMDL', 1, 'REGCAU1', 101, 1, 1, 14, 3, 4
  / Lvplsw
      0
   / Tg       Rrpwr     Brkpt     Zerox     Lvpl1
  0.02         3.0       0.01       0.0       1.00
   / Volim     Lvpnt1    Lvpnt0    Iolim     Tfltr
```

```
          1.2        0.1        0.01      -1.3       0.02
      / Khv       Iqrmax     Iqrmin     Accel
        0.2       999.0     -999.0       0.7


2222, 'USRMDL', 1, 'REECAU1', 102, 0, 6, 45, 6, 9
      / Bus#       PFflag      Vflag      Qflag      Pflag      PQflag
         0           0           1          1          0          0
      / Vdip       Vup         Trv        dbd1       dbd2
        0.9        1.1        0.02       -0.05       0.05
      / Kqv       Iqh1        Iql1       Vref0      Iqfrz
        0.0       1.0025     -1.0025      1.05       0.10
      / Thld      Thld2       Tp         QMax        QMin
        0.0        0.0        0.05       0.4421     -0.4421
      / Vmax      Vmin        Kqp        Kqi         Kvp
        1.1        0.9        0.0        0.41        1.0
      / Kvi       Vbias       Tiq        dPmax       dPmin
       60.0        0.0        0.02       99.0       -99.0
      / Pmax      Pmin        Imax       Tpord       Vq1
       0.8998       0         1.0025      0.02        0.0
      / Iq1       Vq2         Iq2        Vq3         Iq3
       0.99        0.9        0.54        1.1         0.54
      / Vq4       Iq4         Vp1        Ip1         Vp2
       1.25        1.26        0.0        0.0         0.5
      / Ip2       Vp3         Ip3        Vp4         Ip4
        0.0        0.9        1.23        1.0         1.107


2222, 'USRMDL', 1, 'WTDTAU1', 103, 0, 0, 5, 4, 3,
      / H          DAMP        Htfrac     Freq1      Dshaft
       3.22        0.0        0.01        1.88        1.5

2222, 'USRMDL', 1, 'WTPTAU1', 104, 0, 0, 10, 3, 1,
      / Kiw       Kpw         Kic        Kpc         Kcc
       50.0       200.0       0.0        0.0         0.0
      / Tp        TetaMax     TetaMin    RTetaMax    RTetaMin
        0.3        27.0        0.0        10.0        -10.0


2222, 'USRMDL', 1, 'WTARAU1', 105, 0, 0, 2, 0, 1,
      / Ka        Theta
       0.007       0.0


2222, 'USRMDL', 1, 'REPCTAU1', 107, 0, 7, 27, 7, 9,
      / Bus#       LDC_FromBus  LDC_ToBus   LDC_ID     VCFlag     Refflag     Fflag
       2223        2224        2225        '1'         0          1          1
      / Tfltr     Kp          Ki         Tft         Tfv
        0.5        2.0        1.0        0.02        0.25
      / Vfrz      Rc          Xc         Kc          emax
        0.7        0.0        0.0        0.0         0.1
      / emin      dbd1        dbd2       QMax        QMin
       -0.1         0           0         0.4421     -0.4421
      / Kpg       Kig         Tp         fdbd1       fdbd2
        1.2        0.14        0.1       -0.0006      0.0006
      / femax     femin       Pmax       Pmin        Tg
       999.0      -999.0       0.8211      0          0.25
      / Ddn       Dup
       20.0        20.0


2222, 'USRMDL', 1, 'WTTQAU1', 505, 0, 1, 15, 3, 3,
```

```
/ Tflag
    1
/ Kpp       KIP      Tp       Twref     Temax
  0.01      0.1      0.1      60.0      1.2
/ Temin     p1       spd1     p2        spd2
  0.04      0.2      0.69     0.4       0.78
/ p3        spd3     p4       spd4      TRATE
  0.6       0.98     0.74     1.2       0.0


/  OVER VOLTAGE PROTECTION example

 222201  'VTGTPAT'    2224   2234 '1'
 / Vlow      Vup         RlTm        BrTm
   -1.0000     1.2000      1.00            0.0000
 222202  'VTGTPAT'    2224   2234 '1'
 / Vlow      Vup         RlTm        BrTm
  -1.0000    1.175000     2.00            0.0000
 222203  'VTGTPAT'    2224   2234 '1'
 / Vlow      Vup         RlTm        BrTm
  -1.0000    1.1500      3.0000          0.0000
 222204  'VTGTPAT'    2224   2234 '1'
 / Vlow      Vup         RlTm        BrTm
   -1.0000    1.100      5.0000          0.0000


/ UNDER VOLTAGE PROTECTION example

 222205  'VTGTPAT'    2224   2234 '1'
  / Vlow      Vup         RlTm        BrTm
   0.45000    5.0000     1.0000           0.0000
 222206  'VTGTPAT'    2224   2234 '1'
  / Vlow      Vup         RlTm        BrTm
   0.650000    5.0000     5.0000          0.0000
 222207  'VTGTPAT'    2224   2234 '1'
 / Vlow       Vup        RlTm        BrTm
   0.75000    5.0000     10.000      0.0000
 222208  'VTGTPAT'    2224   2234 '1'
  / Vlow      Vup         RlTm        BrTm
   0.9000     5.0000     20.000      0.0000


/ OVER FREQUENCY PROTECTION example

 222209  'FRQTPAT'    2224   2234 '1'
  / Flow       Fup        RlTm        BrTm
   -100.00     61.800     10.000      0.0000
 222210  'FRQTPAT'    2224   2234 '1'
  / Flow       Fup        RlTm        BrTm
   -100.00     60.500     650.00      0.0000


/ UNDER FREQUENCY PROTECTION example

 222212  'FRQTPAT'    2224   2234 '1'
  / Flow       Fup        RlTm        BrTm
   57.800     100.00     10.000      0.0000
 222213  'FRQTPAT'    2224   2234 '1'
  / Flow       Fup        RlTm        BrTm
   59.500     100.00      1800.00     0.0000
```

10.3.1.3 Battery energy storage systems

Typical values for Battery Storage modules are shown below.

Generator/Converter Module		
REGCA1 (v34 & v35) / REGCAU1 (v33)		
Parameter	**Description**	**Typical Values**
Tg	Converter time constant (s)	0.02
Rrpwr	Low Voltage Power Logic (LVPL) ramp rate limit (pu/s)	1.00
Brkpt	LVPL characteristic voltage 2 (pu)	0.01
Zerox	LVPL characteristic voltage 1 (pu)	0.00
Lvpl1	LVPL gain breakpoint (pu current on mbase / pu voltage)	1.00
Volim	Voltage limit (pu) for high voltage reactive current management	2.00
Lvpnt1	Low voltage active current management breakpoint (pu)	0.10
Lvpnt0	Low voltage active current management breakpoint (pu)	0.00
Iolim	Current limit for high voltage clamp logic (pu on mbase)	-0.42486
Tfltr	Terminal voltage filter (for LVPL) time constant (s)	0.02
Khv	Overvoltage compensation gain used in high voltage reactive current management	0.00
Iqrmax	Maximum rate-of-change of reactive current (pu/s)	10.00
Iqrmin	Minimum rate-of-change of reactive current (pu/s)	-10.00
Accel	High voltage reactive current management acceleration factor, p.u.	0.7

Electrical Controls Module		
REECCU1 (v33 &v34) /REEC1 (v35)		
Vdip	Low voltage condition trigger voltage, p.u.	0.90
Vup	High voltage condition trigger voltage, p.u.	1.10
Trv	Terminal bus voltage filter time constant, sec.	0.02
dbd1	Overvoltage deadband for reactive current injection, p.u.	-0.10
dbd2	Undervoltage deadband for reactive current injection, p.u	0.10
Kqv	Reactive current injection gain, p.u	0.00
Iqh1	Maximum reactive current injection, p.u.	0.42486
Iql1	Minimum reactive current injection, p.u.	-0.42486
Vref0	Reference voltage for reactive current injection, p.u	1.00
Tp	Active power filter time constant, sec.	0.05
Qmax	Maximum reactive power when vflag = 1, p.u	0.42486
Qmin	Minimum reactive power when vflag = 1, p.u.	-0.42486
VMAX	Maximum voltage at inverter terminal bus, p.u	1.50
VMIN	Minimum voltage at inverter terminal bus, p.u	0.80
Kqp	Local Q regulator proportional gain, p.u.	0.5
Kqi	Local Q regulator integral gain, p.u.	5.0
Kvp	Local voltage regulator proportional gain, p.u	0.5
Kvi	Local voltage regulator integral gain, p.u	5.0
Tiq	Reactive current regulator lag time constant, sec.	0.02
dPmax	Active power up-ramp limit, p.u./sec	10.00

dPmin	Active power down-ramp limit, p.u./sec	-10.00
PMAX	Maximum active power, p.u	1.00
PMIN	Minimum active power, p.u	-1.00
Imax	Maximum apparent current, p.u.	1.00
Tpord	Inverter power order lag time constant (s)	0.02
Vq1	Reactive Power V-I pair, voltage (pu)	0.00
Iq1	Reactive Power V-I pair, current (pu)	1.00
Vq2	(Vq2>Vq1), Reactive Power V-I pair, voltage (pu)	0.00
Iq2	(Iq2>Iq1), Reactive Power V-I pair, current (pu)	0.00
Vq3	(Vq3>Vq2), Reactive Power V-I pair, voltage (pu)	0.00
Iq3	(Iq3>Iq2), Reactive Power V-I pair, current (pu)	0.00
Vq4	(Vq4>Vq3), Reactive Power V-I pair, voltage (pu)	0.00
Iq4	Reactive Power V-I pair, current (pu)	0.00
Vp1	Real Power V-I pair, voltage (pu)	0.00
Ip1	Real Power V-I pair, current (pu)	0.00
Vp2	(Vp2>Vp1), Real Power V-I pair, voltage (pu)	0.75
Ip2	(Ip2>Ip1), Real Power V-I pair, current (pu)	0.23
Vp3	(Vp3>Vp2), Real Power V-I pair, voltage (pu)	0.85
Ip3	(Ip3>Ip2), Real Power V-I pair, current	0.85
Vp4	(Vp4>Vp3), Real Power V-I pair, voltage	1.00
Ip4	(Ip4>Ip3), Real Power V-I pair, current	1.00
T	Battery discharge time (sec)	3600
SOCini	Initial state of charge (pu)	0.50
SOCmax	Maximum allowable state of charge (pu)	1.00
SOCmin	Minimum allowable state of charge (pu)	0.00

Plant Controls Module		
REPCA1 & REPCTA1 (v34 & v35) /REPCAU1 & REPCTAU1 (v33)		
Tfltr	Voltage and reactive power filter time constant, sec.	0.02
Kp	Volt/VAr regulator proportional gain, p.u.	5.0
Ki	Volt/VAr regulator integral gain, p.u.	50.00
Tft	Plant controller Q output lead time constant, sec	0.00
Tfv	Plant controller Q output lag time constant, sec.	0.10
Vfrz	Voltage for freezing Volt/VAr regulator integrator, p.u	0.80
Rc	Line drop compensation resistance, p.u.	0.00
Xc	Line drop compensation reactance, p.u	0.00
Kc	Reactive droop gain, p.u	0.1314
emax	Maximum Volt/VAr error, p.u	1.00
emin	Minimum Volt/VAr error, p.u.	-1.00
dbd1	Lower threshold for reactive power control deadband (<=0)	-0.001
dbd2	Upper threshold for reactive power control deadband (>=0)	0.001
Qmax	Maximum plant reactive power command, p.u	0.42486
Qmin	Minimum plant reactive power command, p.u.	-0.42486
Kpg	Real power control proportional gain, p.u	0.50
Kig	Real power control integral gain, p.u.	11.00
Tp	Active power filter time constant, sec.	0.02
fdbd1	Frequency deadband downside, p.u.	-0.0006
fdbd2	Frequency deadband upside, p.u	0.0006
femax	Maximum power error in droop regulator, p.u	999.00
femin	Minimum power error in droop regulator, p.u.	-999.00
Pmax	Maximum plant active power command, p.u.	1.00
Pmin	Minimum plant active power command, p.u	-1.00
Tg	Plant controller P output lag time constant, sec.	0.02
Ddn	Reciprocal of down regulation droop, p.u.	20.00
Dup	Reciprocal of up regulation droop, p.u	20.00

For a Battery Energy Storage System, the function call in the .dyr file would be as shown in the example below. This .dyr file example correlates with the examples of the Converter, Electrical Controls and Plant Controller modules above.

```
3333 'USRMDL'  1  'REGCAU1'  101  1  1  14  3  4  0
    0.0200     1.0000     0.01000    0.00000    1.00000
    2.0000     0.1000     0.00000   -0.42486    0.02000
    0.0000     10.000    -10.0000    0.70000
3333 'USRMDL' 1 'REECCU1'  102   0   5   45  7  6
    0 0 1 1 0
    0.9 1.1 0.02 -0.1 0.1
    0 0.42486 -0.42486 1 0.05
    0.42486 -0.42486 1.5 0.8 0.5
    5.0 0.5 5.0 0.02 10
    -10 1 -1 1 0.00
    2.0 1.0 0.0 0.0 0.0
    0.0 0.0 0.0 0.2 0 0.75
```

```
    0.23 0.85 0.85 1 1
    3600 0.5 1.0 0.0

3333 'USRMDL' 1 'REPCAU1' 107 0 7 27 7 9
    3334    3335    3336    '1'   1   1   1
    0.02      5.0     50.00     0.0        0.1
    0.8       0.0      0.0     0.1314     1.0
    -1.0     -0.001    0.001    0.42486    -0.42486
    0.5      11.0      0.02    -0.0006     0.0006
    999     -999       1.0     -1.0        0.02
    20       20

333801  'VTGTPAT'    938713    938714 '1' -1.0000     1.4000     0.1600     0.0000
333802  'VTGTPAT'    938713    938714 '1' -1.0000     1.2000     1.0000     0.0000
333803  'VTGTPAT'    938713    938714 '1' -1.0000     1.1800     2.0000     0.0000
333804  'VTGTPAT'    938713    938714 '1' -1.0000     1.1600     3.0000     0.0000
333805  'VTGTPAT'    938713    938714 '1' -1.0000     1.1200     5.0000     0.0000
333806  'VTGTPAT'    938713    938714 '1' 0.45000     5.0000     0.5000     0.0000
333807  'VTGTPAT'    938713    938714 '1' 0.60000     5.0000     5.0000     0.0000
333808  'VTGTPAT'    938713    938714 '1' 0.70000     5.0000    10.000     0.0000
333809  'VTGTPAT'    938713    938714 '1' 0.88000     5.0000    20.000     0.0000
333810  'FRQTPAT'    938713    938714 '1' -100.00    63.250     2.0000     0.0000
333811  'FRQTPAT'    938713    938714 '1' -100.00    61.800    10.000     0.0000
333812  'FRQTPAT'    938713    938714 '1' -100.00    60.600   650.00     0.0000
333813  'FRQTPAT'    938713    938714 '1'  57.00    100.00    10.000     0.0000
333814  'FRQTPAT'    938713    938714 '1'  59.000   100.00   600.00     0.0000
```

10.3.2   Automatic Voltage Regulation Requirement

IBRs that are subject to FERC Order 827 are required to operate in automatic voltage control mode to support voltage regulation and voltage stability. There are several valid control modes available to control voltage, using different combinations of pfflag, vflag and qflag in the REEC_* models and refflag in the REPC_* models. Table 4 lists all the compliant plant-level voltage control mode combinations.

Dynamic model parameter descriptions are as follows:

- Pfflag: Local power factor flag; voltage or reactive power control (0); power factor control (1)
- Vflag: Local voltage control flag; voltage control (0); reactive power control (1)
- Qflag: Local reactive power control flag; constant power factor or reactive power control (0); voltage control (1)
- Refflag: Plant-level reactive power control (0); plant-level voltage control (1); plant-level power factor control (2)

Plant-level Voltage Control Mode Combinations					
REEC_*			REPC_*	FERC Order 827 compliance	
pfflag	vflag	qflag	refflag	Mode	Compliant
0	N/A	0	0	Plant Q	No
0	1	1	0	Plant Q and Local Q/V	Yes
0	N/A	0	1	Plant V	Yes
0	0	1	1	Plant V and Local V	Yes
0	1	1	1	Plant V and Local Q/V	Yes
0	N/A	0	2	Plant PF	No
0	1	1	2	Plant PF and Local Q/V	Yes

Plant level volt/var control could be set to voltage control, reactive power control or power factor control. Automatic voltage regulation can be implemented directly at the plant level (Plant V control), or at the inverter level (Plant Q or PF and Local Q/V), or both (Plant V and Local Q/V). Some key parameters to coordinate plant level control with inverter control and provide automatic voltage regulation include [repc_*].vfrz, [reec_*].vdip, [reec_*].vdup, [reec_*].kqv, [reec_*].kvp, [reec_*].kvi.

Existing IBRs not subject to FERC Order 827 shall have the model reflect the field settings and the IBR operation.

10.3.3   Ride-Through Requirement

Momentary cessation (namely, ceasing to inject current during a fault without mechanical isolation) is prohibited unless transient high voltage conditions rise to 1.20 per unit or more. For transient low voltage conditions, the Asynchronous Generating Facility's units are required to inject reactive current. The level of this reactive current injection shall be directly proportional to the decrease in per unit voltage at the inverter AC terminals. The inverter shall produce full rating reactive current when the AC voltage at the inverter terminals drops to a level of 0.50 per unit. The Asynchronous Generating Facility must continue to operate and absorb reactive current for transient voltage conditions between 1.10 and 1.20 per unit. Upon the cessation of transient voltage conditions and the return of the grid to normal operating voltage (0.90 < V < 1.10 per unit), the Asynchronous Generating Facility's inverters automatically must transition to normal active (real power) current injection. The Asynchronous Generating Facility's inverters must ramp up to inject active (real power) current with a minimum ramping rate of at least 100% per second (from no output to full available output). The total time to complete the transition from reactive current injection or absorption to normal active (real power) current injection must be one second or less. The total time to return from momentary cessation, if used, during transient high voltage conditions over 1.20 per unit or more must be one second or less.

Momentary cessation, if used by the facility, should be modeled correctly in the reec_d model.

Transient Low Voltage

To meet the reactive injection requirement, the reactive current limit shall be non-zero under transient low voltage and at least 1.0 p.u. if the voltage is below 0.5. The effective reactive current limit is determined from the PQ priority (pqflag) and VDL1 and VDL2 parameters.

There are other ways to meet the requirement on the amount of reactive current injection. It depends on the setup of voltage dip logic and the control mode. Below are a couple of examples:

- Using voltage dip logic: vdip between 0 and 1.0 (typically 0.9) and kqv ≥ 2; or
- If voltage dip logic is disabled, the set qflag=1 and kvp ≥ 2

High Transient Voltage

The reactive current limit for voltage between 1.1 and 1.2 shall be non-zero and the control shall be in the right direction to lower voltage. A typical setup to meet the high transient voltage requirement is:

using voltage dip logic: vup at least 1.1 and non-zero kqv.

Return into Normal Operation

The inverters should return to normal active MW injection within 1 second once the voltage is normal. Therefore, [regc_*].rrpwr shall be no less than 1.0 p.u./sec. Active power reaching 95% of the pre-fault level is considered returning to normal.

10.3.4　Primary Frequency Response Requirement

IBRs are required to provide active power primary frequency response capability with a 5% droop for both under and over-frequency conditions, and a maximum deadband of ±36 mHz. The required control options to simulate the primary frequency response in dynamic simulations are shown below.

Active power primary frequency response is controlled by the plant-level controller (REPC_*) model. Dynamic model parameter descriptions are as follows:

- Frqflag: Governor response; disable (0) or enable (1)
- Ddn: Down regulation droop response to over-frequency condition (20 on the generator nameplate capacity base for 5% droop)
- Dup: Up regulation droop response to under-frequency condition (20 on the generator nameplate capacity base for 5% droop)
- Fdbd1: Over-frequency deadband for governor response (-0.0006 p.u./-36mHz)
- Fdbd2: Under-frequency deadband for governor response (0.0006 p.u./36mHz)

10.4 Guidance to setup Single Machine Infinite Bus

The dynamic models shall be tested with system conditions that represent a Thevenin equivalent with SCR of 3 and X/R of 5. Below are steps to prepare the swing generator to facilitate with this system condition.
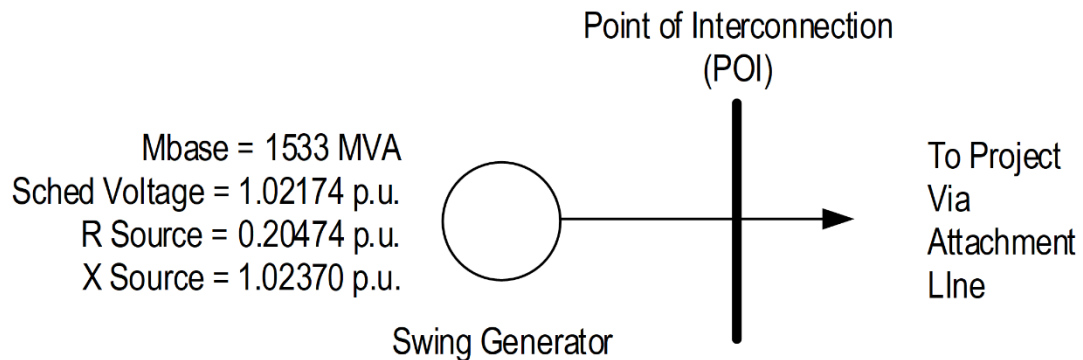
1. Model a swing generator at the POI.
2. Set the swing generator to control the POI voltage to the voltage schedule specified in PJM Manual 03.
3. Set the swing generator Mbase based on the following equation.
$$Mbase = 3 \times MFO \times Voltage\ Schedule\ (p.u.)$$
4. Set the swing generator machine impedance (R Source and X Source) to the values specified in Table 5.

Table 5. R Source and X Source values based on Sched Voltage

Voltage Level (kV)	765	500	345	230	161	138	115	69	66
R Source	0.19356	0.21622	0.20184	0.20474	0.20349	0.20040	0.20300	0.20184	0.20210
X Source	0.96780	1.08110	1.00920	1.02370	1.01745	1.00200	1.01500	1.00920	1.01050

Example: A 500 MW MFO project connecting to a 230 kV system will have the swing generator modeled at the POI with parameters shown in Figure 4 to produce an SCR of 3 and X/R of 5.

Mbase = 1533 MVA
Sched Voltage = 1.02174 p.u.
R Source = 0.20474 p.u.
X Source = 1.02370 p.u.

Point of Interconnection (POI)

To Project Via Attachment LIne

Swing Generator

Figure 4. Example SMIB

10.5 Example Dynamic Model Report

[Disclaimer: this example dynamic model report is being provided by PJM to aid developers in preparing a dynamic model report. It is the sole responsibility of the Project Developer (PD) to ensure their data submittal is complete and accurate. Errors and omissions in this example do not relieve PDs of the responsibility to provide a complete and accurate dynamic model package, including dynamic model report. Other dynamic model report formats are acceptable as long as all requirements of the PJM Dynamic Model Developer Guidelines are followed.]

Title Page

[Title page with name of project, developer name, and consultant (if applicable) is typically included. Omitted from this example to save space]

Revision History and Quality Assurance Sign Off

This report and modeling were developed by the XYZ consulting firm.

Revision	Note	Engineer	Approver	Date
0	Initial issue	*Responsible Engineer*	*Manager Approver*	1/1/2023
1	Corrected MPT	*Responsible Engineer*	*Manager Approver*	9/18/2024

Project Description

Pony Solar, PJM Queue ABC-123, is a 50 MW solar facility located in Henderson County Tennessee. The Point of Interconnection (POI) will be a direct connection to the existing Templeton 358 kV substation in the Electric Utility zone. Pony Solar will consist of 2 x 27 MVA BigWatts inverters with 2 x 32 MVA 777 volt to 33.3 kV step-up transformers, 33.3 kV collector system, and a 40 MVA Main Power Transformer stepping from 33.3 kV up to the 358 kV transmission voltage.

Model Development

The model for Pony Solar was developed following manufacturer recommended settings with consideration for site specific expected settings and in accordance with the PJM Dynamic Model Development Guidelines.

[Include a tabular parameterization of all provided dynamic models with explanations for source of parameter values. Section 10.3 contains examples of model parameter tables]

Checklist

Item	Description	Comment	Check
1	Completed Queue Point Data Application form along with all requested files submitted via Queue Point portal	Required Queue Point data submitted	RE
2	Dynamic Model Report, summarizing model development and testing per guidelines in this document	Dynamic Model Report provided	RE
3	If a PSSE library model is submitted (preferred), .idv and .dyr files developed using the guidelines in this document are included	PSSE library model submitted See "Pony_20240913.idv", "Pony_20240913.dyr" included in submitted package	RE
4	If a UDM is submitted, a properly compiled PSSE version .sav case along with .idv, .dyr, and .dll files appropriately parameterized for the project using the guidelines in this document is included	N/A	N/A
4a	For UDM: A report on how the settings of the model were parameterized along with the manufacturer's documentation, including a user guide of the UDM	N/A	N/A
4b	For UDM: Block diagram for the model and sub modules, along with values, names and detailed explanation of all model parameters	N/A	N/A
5	.raw, .sav case, .cnv, .snp, and .sld file for the project (case setup folder/files) are submitted	All required files provided. See "Pony_20240913.raw", "Pony_20240913.sav", "Pony_20240913.cnv", "Pony_20240913.snp", and "Pony_20240913.sld" included in submitted package	RE
6	Verify all testing requirements are met:		
6a	MFO assessment table is included in the Dynamic Model report	MFO Assessment Table provided	RE
6b	Power Factor Assessment table along with **PQ curve** used and case setup for power factor assessment (lagging and leading scenarios) is included in the Dynamic Model report	Power Factor Assessment Table provided PQ curve included in submission as "BigWatts_PQ.pdf". Case setups included "Pony_lagging_20240913.sav" and "Pony_leading_20240913.sav"	RE
6c	Confirm that the unit meets FERC Order No. 827 with regards to automatic voltage regulation, with appropriate model settings included in the Dynamic Model report	Unit meets automatic voltage regulation requirements of FERC Order No. 827	RE
6d	Results for the flatstart test including log, out and test plots showing Power, VARs, Eterm, Freq and Volt for each inverter/generator is included	Flatstart test results provided	RE
6e	Results for the VRT test including log, out and test plots showing Power, VARs, Eterm, Iterm, Freq and Volt for each inverter. Provide confirmation that Momentary Cessation is eliminated (if not, provide reason)	VRT test results provided Momentation Cessation is eliminated	RE
6f	Confirm Primary Frequency Response is enabled	Primary Frequency Response enabled	RE
7	For As Built submissions only: Factory Acceptance Test (FAT) report for each transformer installed	N/A	N/A

Testing Requirements
MFO Assessment

	Active Power (MW)
Requested MFO	50
Gross output	53
Station Load + Auxiliary Load	2
Losses	1
MW at POI	50
MW at POI meets requested MFO	Yes

Power Factor Assessment

Generator	MFO(MW)	Required Power Factor Range		Maximum Lagging Qmax (Mvar)	Maximum Leading Qmin (Mvar)
		Lagging	Leading		
ABC-123	50	0.95	0.95	16.434	-16.434
Total Reactive Power Required				16.434	-16.434
Reactive Power from Generators at Gross MW (obtained from D curve)				**Qmax**	**Qmin**
				22	-22
Reactive Power Losses (includes planned compensation of 2 MVAR capacitor bank automatically switched by PPC)				-5.25	-9.5
Station Load + Auxiliary Load				-0.25	-0.25
Total available reactive power at high side of main transformer				16.5	-31.75
Deficiency in Reactive Power				Meet	Meet

Automatic Voltage Regulation

Pony Solar is configured to automatically regulate the voltage at the POI substation.

Plant Level Voltage Control Model Settings					
REEC_*			REPC_*	AVR Compliance	
pfflag	vflag	qflag	refflag	Mode	Compliant
0	n/a	0	1	Plant V	Yes

Flat run

As shown in included "flat_run.log", "flat_run.out", and "flat_run_plots.pdf" the models for Pony Solar initialize without error and have no movement in a 20 second flat run. [Plots can be included in the model report or in a separate plot file. At a minimum, plots shall include channels for real and reactive power, terminal voltage, terminal current, and frequency.]

Voltage Ride Through and Momentary Cessation

To test Voltage Ride Through (VRT) compliance, a 9 cycle fault was applied at the POI. Plots are provided in "VRT_plots.pdf" and in "VRT_plots.out". As shown in the plots, Pony Solar was able to ride through the fault. The plots also show that Pony Solar did not enter Momentary Cessation because current is injected during and following the fault. [Plots can be included in the model report or in a separate plot file. At a minimum, plots shall include channels for real and reactive power, terminal voltage, terminal current, and frequency]

Primary Frequency Response

Primary Frequency Response is enabled for Pony Solar. Relevant model parameter settings shown in the table below:

REPC_* parameters				
Fflag (M+6)	Ddn (J+25)	Dup (J+26)	Fdbd1 (J+18)	Fdbd2 (J+19)
1	20	20	-0.0006	0.0006