DYNAMIC MODEL REVIEW GUIDELINE FOR INVERTER BASED INTERCONNECTION REQUESTS

White Paper by

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1. Introduction

The guideline is developed from WECC Solar Photovoltaic Power Plant Modeling and Validation Guideline[1] and incorporated the CAISO interconnect requirements for inverter-based generators. The purpose of guideline is to promote good practice of model development by the interconnection customers, facilitate consistent model reviews by the transmission planners and ensure the inverter-based generators meet various interconnection requirements. As the technology evolves, so does the modeling technique. It is important to understand the concepts and principles in this guideline and adapt to any particular configuration of an inverter-based power plant.

2. Model Usability Requirement

First of all, the power flow and dynamic models for any type of generators must be usable by the software platform to perform the simulation. The usability requirement includes three aspects:

1) All the models and associated parameters are read by the simulation software[1] correctly.
    a. The number of each power flow element, such as buses, lines, transformers, generators, shunts and etc., matches the number in the epc file.
    b. Parameters read into the software match the values in the epc file.
    c. The number of dynamic models read into the software matches the number of dynamic models in the dyd file.
    d. Parameters read into the software match the values in the dyd file.[2]
2) There is no initialization errors for the dynamic models and the warning messages are reviewed with resolution or explanation.
3) The models produce flat lines for a 20-second no-disturbance simulation. The CAISO definition of flat lines is variations of generator outputs Pgen and Qgen over 20 seconds are less than 1MW and 1Mvar respectively, or 1%.

3. General Modeling Requirements

The modeling requirements in WECC Solar Photovoltaic Power Plant Modeling and Validation Guideline are adopted for all inverter-based power plants and provided below.

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;
- 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; and

[1] The CAISO and Participating TO's use GE PSLF platform to perform the dynamic simulation. The models should be provided in GE PSLF format, i.e. epc for power flow and dyd for dynamic model.
[2] GE PSLF reads dynamic model parameters by the sequence in the dyd entry. The parameter names in the dyd file are for readability, not an identifier. It is a common mistake that the parameters are not provided in the sequence specified in the GE PSLF manual.

- An explicit representation of all plant-level reactive compensation devices either as shunts (fixed or switchable) or as generators (FACTs devices), if applicable.

For integrated inverters and pad-mounted transformers, the manufacturer's test and data are provided at the terminal of the integrated unit of inverter and pad-mounted transformer. Inverter control inputs are also taken from the terminal of the integrated unit. In such case, the pad-mounted transformers are not explicitly modeled in the power flow model. Instead, the integrated units are modeled by the equivalent generator.

The dynamic model includes:

- A generator/converter module representing the typical solar PV inverter 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; and
- Frequency and voltage protection modules, which show inverter protection settings under abnormal frequency and voltage conditions.

4. Generator Equivalencing

The determination of single or multiple generator equivalence should take into account the number of the main substation transformers, the collector system behind each main substation transformer, the placement of different makes of inverters behind the main substation transformers, the setting difference among inverters, and the mix of different inverters.

- Each substation transformer is explicitly represented in the power flow model.
- If the same inverters are installed behind the substation transformer, represent the inverters with one equivalent collector circuit, one equivalent pad-mounted transformer, and one equivalent generator.
- If different inverters with the same control and protection setting are installed behind one substation transformer, represent all inverters by one equivalent collector circuit, one equivalent pad-mounted transformer, and one equivalent generator.
- If inverters with different settings are installed behind the same substation transformer, model each type of inverter that has at least 10 MVA installed capacity using one equivalent generator with its own equivalent pad-mounted transformer. Any inverters with less than 10 MVA installed capacity may be aggregated with another type of inverter in one equivalent generator.

Generator Equivalencing for Hybrid Power Plants

There are two types of electrical configuration of hybrid plants – ac coupled or dc coupled. If different fuel type each has its own set of inverters, i.e. ac coupled, each fuel type should be modeled explicitly by separate equivalent generators, equivalent pad-mounted transformers and equivalent collectors. The reactive capability requirement applies to the entirety of the hybrid plant. Each fuel type individually may not have capability to meet the requirement alone.

If different fuel types are behind the same inverters, i.e. dc-coupled, the equivalent generator represents the inverters as looking from the ac side and become a hybrid generator. A negative Pmin of the equivalent generator represents the maximum charging power if the battery storage charges from the grid.

Figure 1: Single-Generator Equivalent Power Flow Representation for a Solar PV Power Plant

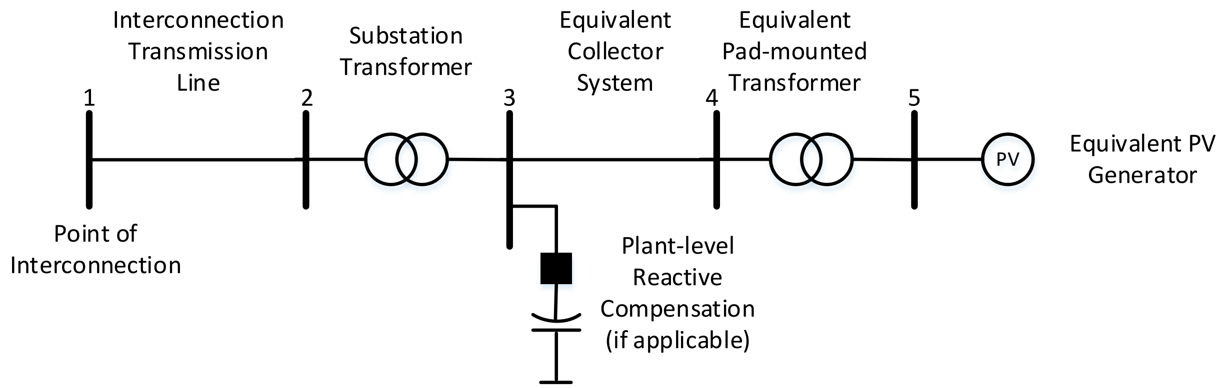
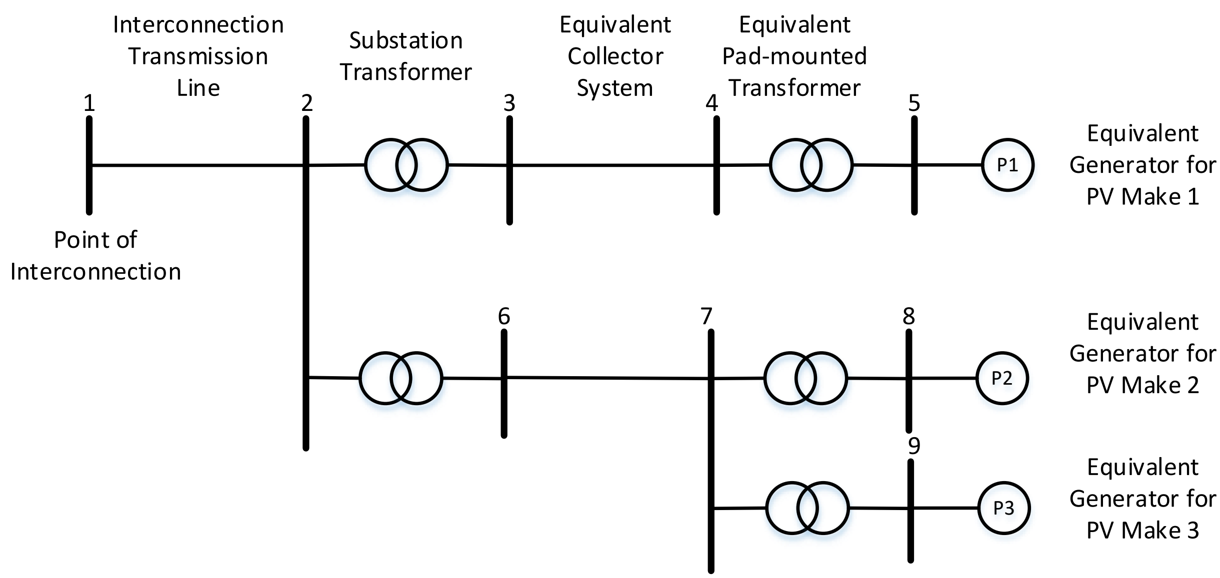


Figure 2: Multiple-Generator Equivalent Power Flow Representation for a Solar PV Power Plant



5. Dynamic Model Description and Applicability

The WECC approved dynamic models required to represent inverter-based resources (IBRs) are shown in Table 1 and the most common forms of IBR technologies that utilize these models are type 3 and 4 wind turbine generators (WTGs), solar PV resources, and battery energy storage systems (BESS).

General model description:

- **REGC** is used to represent the generator/converter model. It processes the real (Ipcmd) and reactive (Iqcmd) current commands from the **REEC** model and controls the output of real (Ip) and reactive (Iq) current injection to the grid.
- **REEC** is used to represent the electrical control model. It processes the active (Pref) and reactive (Qref) power reference from the **REPC** model, with feedback from the terminal voltage (vref0) to control the real (Ipcmd) and reactive (Iqcmd) current commands to the **REGC** model.
- **REPC** is used to represent the plant-level controller. It processes voltage and reactive power output to emulate plant-level volt/VAR control. It also processes frequency and active power output to emulate plant-level active power control. This model provides active (Pref) and reactive (Qref) power reference to the **REEC** model.
- **LHVRT** is used to represent a protection function that trips the resource for defined low and high voltage conditions.
- **LHFRT** is used to represent a protection function that trips the resource for defined low and high frequency conditions.
- **WTGT_A** is used to represent the wind turbine. It processes the generator electrical power and initial mechanical torque, and outputs the turbine speed to the **WTGP_A** model and the generator speed to the **WTGQ_A** and **REEC** model.
- **WTGAR_A** (named **WTGA_A** in PSLF) is used to represent the turbine aerodynamics. It processes the wind turbine blade pitch angle and outputs the mechanical torque to the **WTGT_A** model.
- **WTGPT_A** (named **WTGP_A** in PSLF) is used to present the pitch controller. It processes the turbine speed and power order to provide the turbine pitch angle to the **WTGA_A** model.
- **WTGTRQ_A** (named **WTGQ_A** in PSLF) is used to represent the torque controller. It processes the generator speed and initial power reference to provide power reference to the **REEC** model.

Mathematically, only REGC and REEC are required to run the simulation. However, the purpose of the modeling is to accurately capture the performance of the IBR plants. All models representing the actual plant controls are required. The REPC model is required for all IBR plants that have a power plant controller (PPC) and all the WT* models are required for Type 3 WTGs because they are part of the wind turbine controls that affect the dynamic response. ***A monitored branch should always be defined in the repc_* models.***

Table 1: Applicable WECC Approved IBR Dynamic Models

Description	Model	Applicability Notes
Converter[a]	regc_a	All IBR
	regc_b	All IBR, voltage source interface to grid for numerical robustness
Electrical control[b]	reec_a	Type 3 and 4 WTG Solar PV DC-coupled: BESS not charging from grid
	reec_c	Stand-alone BESS DC-coupled: BESS charging from grid
	reec_d	All IBR, enhanced modeling capability from reec_a and reec_b
Plant controller[c]	repc_a	For single generator control (except for plant level PF control)
	repc_b	For single and multiple generator control
Ride-through protection	lhvrt	Voltage ride-through
	lhfrt	Frequency ride-through
Drive-train	wtgt_a	Type 3 WTG Type 4 WTG if pflag = 1 in reec_a
Turbine aero-dynamics	wtga_a	Type 3 WTG
Pitch control	wtgp_a	Type 3 WTG
Torque controller	wtgq_a	Type 3 WTG

Model Selection Notes

a. Both REGC_A and REGC_B are valid models for any type of IBR. REGC_B is proper if any of the modeling enhancement features are needed. Refer to reference [4] for details of REGC_B modeling enhancement. The CAISO and PTO may also request replacement of REGC_A with REGC_B if numerical issues are encountered and can be resolved by voltage source interface.

b. REEC_D model can be used for any type of IBR. However, REEC_A and REEC_C are still valid models. REEC_D is proper if any of the modeling enhancements are needed. Refer to reference [4] for details of REEC_D modeling enhancement. To model momentary cessation, REEC_D is required in the future model submission.

c. REPC_B shall be used when multiple generators receive the P and Q references from the common power plant controller. REPC_B could coordinate controls among generators and other var devices. For hybrid interconnection requests, REPC_B shall be used to coordinate controls and enforce plant level limits. Refer to Reference [5] for more details. REPC_B may also be used for single generator representation for the plant level power factor control. Plant level power factor control is acceptable only in coordination with the inverter level voltage regulation such that the plant meets the voltage regulation requirement below. REPC_B uses system MVA base (100 MVA). All per unit parameters in REPC_B shall be provided on the system MVA base (100 MVA).

6. Scaling PMAX and MVA Base for Equivalent Generator Size

Power flow model

The maximum active power output (Pmax) for an equivalent generator is based on the sum of the associated individual inverter MW output[3] to achieve the desired MW at the POI.

The total MVA base of an equivalent generator is based on the sum of all the associated individual inverter MVA ratings.

Dynamic model

Majority of the parameters in the dynamic models are expressed in per unit and are determined based on the generator MVA base. Therefore, the MVA base used in the dynamic models should be consistent with the value used in the power flow model, except for the REPC_B model, which uses the system MVA base (i.e. 100 MVA). Pmax/Pmin and Qmax/Qmin in REPC_B models are relative limits, i.e.

[repc_b].pmax = (pmax – pgen)/100

[repc_b].pmin = (pmin – pgen)/100

[repc_b].qmax = (qmax – qgen)/100

[repc_b].qmin = (qmin – qgen)/100

where pmax/pmin and qmax/qmin on the right side are plant level limits and may not be equal to the sum of individual equivalent generation limits. For example, pmax corresponds to the maximum plant output achieving the maximum allowed MW injection at the Point of Interconnection.

Given that these parameters depend on the generation dispatch which is unknown to the Interconnection Customers or Generator Owners, it is agreed that the parameters are set as if pgen=0 and qgen=0 by the IC or GO. A pre-run epcl will offset the parameters by actual pgen and qgen when performing studies.

REPC_A model has a parameter puflag that allows the model being on the model MVA base or system MVA base. If puflag is set to 0, the inputs pbranch and qbranch are on system MVA base and the parameters should be on system MVA base as well. It is recommended to set puflag to 1 to avoid inconsistent parameters.

[3] The individual inverter MW output is often lower than the individual rated MW output, due to the practice of oversizing inverters.

7. Primary Frequency Response Requirement

IBRs executing Generation Interconnection Agreement or filing unexecuted Generator Interconnection Agreement at FERC on or after May 15, 2018 are required to provide active power primary frequency response capability with a 5% droop for both under[4] and over-frequency conditions, and a maximum deadband of ±36 mHz. The required control options to simulate the primary frequency response in governor power flow and dynamic simulations are shown below.

Power flow model: base load flag (BL)

Base load flag descriptions are as follows:

- BL = 0: Pgen can be dispatched downward and upward; this is the expected setting for BESS and may also be used for solar or wind resources if they will carry headroom for low frequency response.
- BL = 1: Pgen can be dispatched downward only; this is the typical setting for solar or wind resources as they usually do not have headroom for low frequency response.
- BL = 2: Pgen is fixed; this is **not compliant with the requirement.**

Dynamic model: REPC

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)

Since REPC_B is on the system MVA base, ddn and dup in REPC_B should be set to

$$dup\ or\ ddn = \frac{1}{droop} \times \sum_{all\ gens\ on\ REPC\_B} Generator\ Pmax\ /100$$

[4] Although IBRs are required to provide primary frequency response, they may not be able to respond to under-frequency conditions, since these resources are typically operated at maximum available active power with no headroom.

Note that the primary frequency response is required based on the installed nameplate capacity instead of the contractual plant level MW limit. The sum of the generator Pmax could exceed the plant level MW limit in the calculation.

The active power control weighting factor Kzi should be set to

$$Generator_i\ Pmax / \sum_{all\ gens\ on\ REPC\_B} Generator\ Pmax$$

A recent modeling enhancement has been made to distinguish the frequency response capability from the frequency response availability in operation. Ddn and dup represent the capability of the inverters without considering operational headroom. BL flag represents the availability of operational headroom. If BL is 1, upward frequency response is blocked by setting Pmax to Pgen in the simulation.

Table 2: Primary Frequency Response Settings Required for New Interconnection Requests

Functionality	BL	frqflag	ddn	dup	fdbd1	fdbd2
Down regulation only (wind or solar)	1	1	≥20 or equivalent on the model MVA base	≥20 or equivalent on the model MVA base	[-0.0006,0)	(0, 0.0006]
Up and down regulation (wind, solar, BESS or hybrid)	0					

IBRs executing Generation Interconnection Agreement or filing unexecuted Generator Interconnection Agreement at FERC prior to May 15, 2018 do not have the primary frequency response requirement. The baseload flag and repc_* model should reflect the field settings and the IBR operation.

8. Automatic Voltage Regulation Requirement

IBRs that are subject to FERC Order 827[5] 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 model and refflag in the REPC model. However, not all meet the automatic voltage regulation requirements. Table 3 lists all the compliant plant-level voltage control mode combinations. Other plant-level voltage control mode combinations not shown in Table 3 are invalid.

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)

[5] CAISO tariff filing on FERC Order 827, refer page 5, second paragraph
https://www.caiso.com/Documents/Oct14_2016_ComplianceFiling_FERCOrderNo827_OrderNo828_ER17-114.pdf
CAISO tariff filing on automatic voltage regulator requirements, refer page 6, paragraph (A)
http://www.caiso.com/Documents/Dec5_2016_TariffAmendment_ReactivePowerRequirements_AutomaticVoltageRegulator_ER17-490.pdf

- **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)

Table 3: Plant-level Voltage Control Mode Combinations

REEC			REPC	Notes	
pfflag	vflag	qflag	refflag	Mode	Compliant
0	N/A[6]	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.

9. 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

[6] "N/A" is used to indicate that the state of the switch (0 or 1) for vflag does not affect the control mode.

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.

Generation projects executing generator interconnection agreement or replacing their inverters or generating units on or after April 30, 2019[7] must be compliant with the requirement above and **should not** use momentary cessation except for high voltage of 1.20 per unit or more. Generation projects executing interconnection agreement before April 29, 2019, if using momentary cessation, should model momentary cessation properly. To model momentary cessation, reec_d model should be used.

Table 4: REEC_D Parameter Range for Legacy Projects Using Momentary Cessation

REEC Model Parameters	
Parameter	Recommendation
vblkl	as low as possible, ≤ 0.9
vblkh	as high as possible, ≥ 1.1
tblk_delay	as small as possible

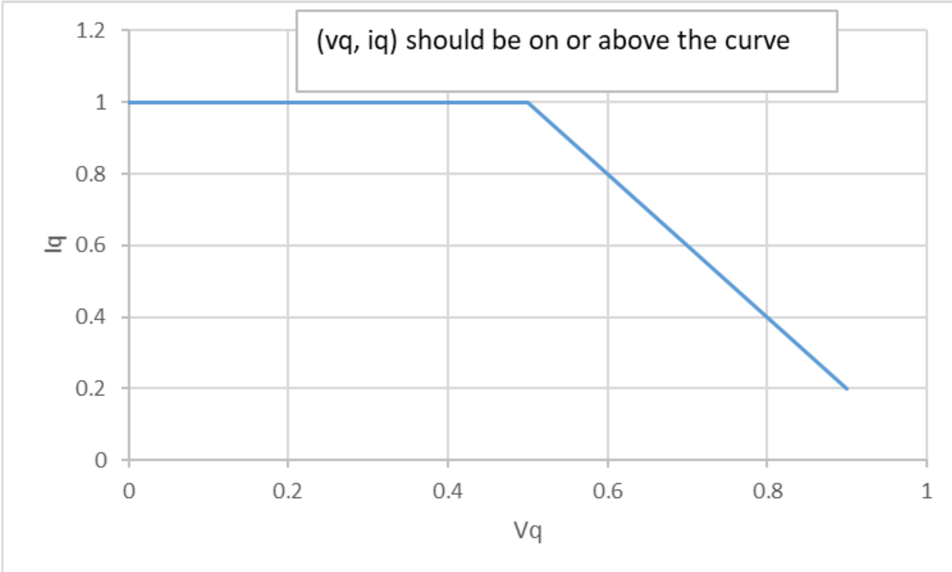
Transient Low Voltage

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.

Pqflag is set to 0 in reec model (i.e., Q-priority control). Reactive current limit should be equal to or greater than 2×(1.0-terminal voltage) for voltages between 0.5 p.u. and 1.0 p.u. and equal to or greater than 1.0 p.u. for voltages below 0.5 p.u.. If VDL1 table is used to define voltage-dependent current limit, the points in VDL1 table should be above the curve shown in **Figure 3**.

[7] CAISO tariff filing acceptance on momentary cessation and transient data recording requirements, page 4, item (8)
https://www.caiso.com/Documents/Jul2-2019-OrderAcceptingTariffAmendment-Inverter-BasedInterconnectionRequirements-ER19-1153.pdf

Figure 3: VDL Setup with pqflag=0



Some power plants could have different P/Q priority depending on the voltage. For example, the plant may operate in P-priority under normal conditions and high voltage condition, but in Q-priority under low voltage condition. For modeling purpose, pqflag can still be set to 0 (Q-priority). The P/Q priority is only active when the total current to meet both P and Q control targets exceeds the inverter current limit, which usually happens under low-voltage condition. Under normal condition and high voltage condition, the voltage deviation is up to 0.2 p.u. and typically does not require high amount of reactive current that would sacrifice active current if set to Q-priority. If for any reason, modeling in Q-priority is not sufficient for normal condition and high voltage condition, pqflag can be set to 1 (P-priority) and use the VDL1 and VDL2 tables to achieve Q-priority under low voltage. The following example illustrates how it can be done.

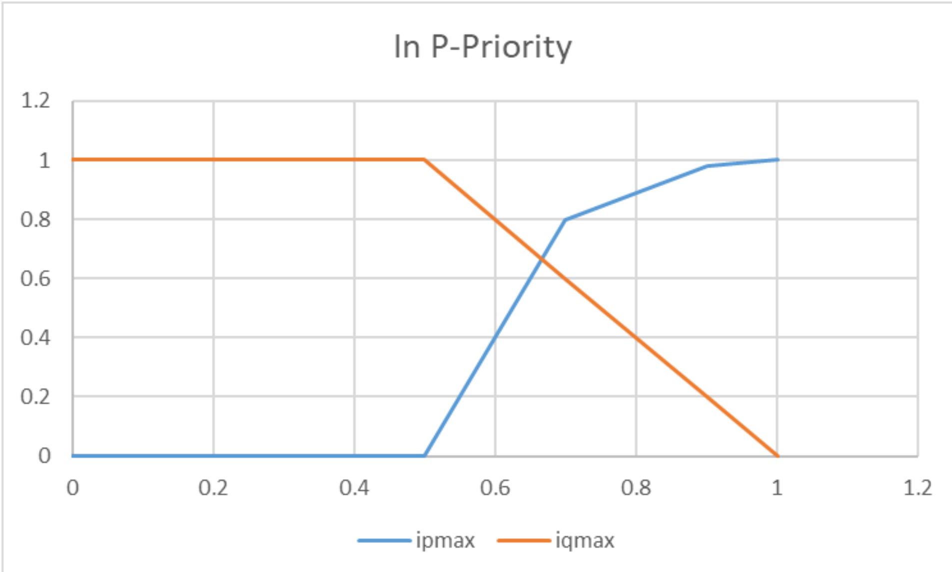
Table 5: Example of Q Injection Control with pqflag=1 (P-priority) under Low Voltage

Parameter Name	Value
pqflag	1: P priority
(vq1, iq1)	(-1, 1)
(vq2, iq2)	(2, 1)
(vq3, iq3)	(0, 0): not used
(vq4, iq4)	(0, 0): not used
(vp1, ip1)	(0.5, 0)
(vp2, ip2)	(0.7, 0.8)
(vp3, ip3)	(0.9, 0.98)
(vp4, ip4)	(1, 1)

Since it is in P-priority, the effective Q current limit is $\sqrt{Imax^2 - Ip^2}$. By limiting Ip, the effective Iqmax is the same as in **Figure 3**, as shown below in **Figure 4**.

Figure 4: Example of Q Injection Control with pqflag=1

Effective Ip and Iq Limits at Different Voltages



Similarly, there are different 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:

- Use voltage dip logic: vdip between 0 and 1.0 (typically 0.9) and kqv ≥ 2; or
- If voltage dip logic is disabled, 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:

- Use voltage dip logic: vup = 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. Revision History

Date	Description
10/15/2020	Initial release
05/18/2021	Updates to ddn and dup in repc model; addition of plant V and local V as a valid control mode
6/2/2021	More clarification on repc model

11. 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/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf

[3] Approved dynamic models https://www.wecc.org/Administrative/Approved%20Dynamic%20Models%20August%202020.pdf

[4] Memo RES Modeling Updates 083120_Rev17 https://www.wecc.org/Administrative/Memo_RES_Modeling_Updates_083120_Rev17_Clean.pdf

[5] Hybrid Plant Modeling Enhancement https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/WECC%20White%20Paper%20on%20modeling%20hybrid%20solar-battery.pdf