NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Parameterization of the DER_A Model for Aggregate DER

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RELIABILITY | RESILIENCE | SECURITY




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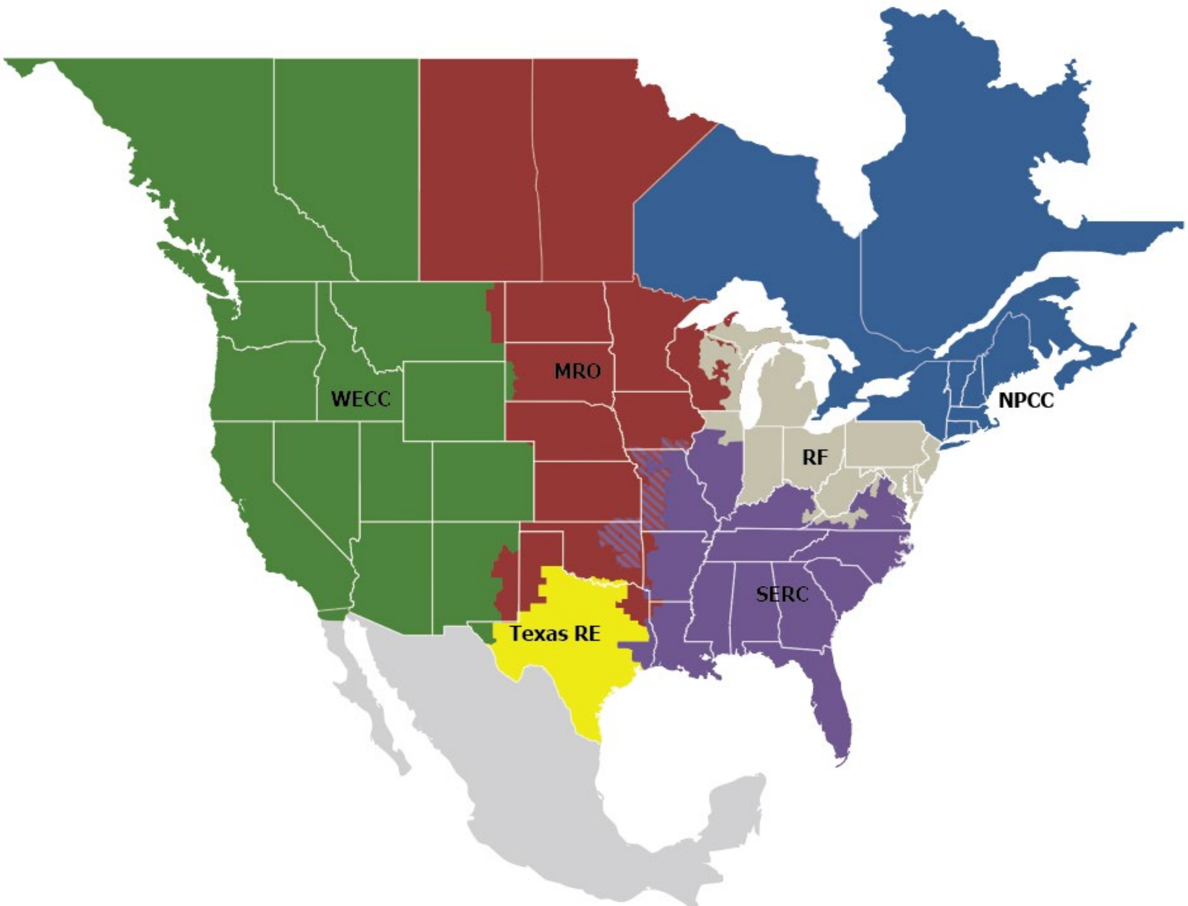
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners /Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Preamble

The NERC Reliability and Security Technical Committee (RSTC), through its subcommittees and working groups, develops and triennially reviews reliability guidelines in accordance with the procedures set forth in the RSTC charter. Reliability guidelines include the collective experience, expertise, and judgment of the industry on matters that impact BPS operations, planning, and security. Reliability guidelines provide key practices, guidance, and information on specific issues critical to promote and maintain a highly reliable and secure BPS.

Each entity registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with applicable mandatory Reliability Standards. Reliability guidelines are not binding norms or parameters nor are they Reliability Standards; however, NERC encourages entities to review, validate, adjust, and/or develop a program with the practices set forth in this guideline. Entities should review this guideline in detail and in conjunction with evaluations of their internal processes and procedures; these reviews could highlight that appropriate changes are needed, and these changes should be done with consideration of system design, configuration, and business practices.

Executive Summary

This guideline provides background material on the recommended DER modeling framework, including the concepts of retail-scale DERs (R-DERs) and utility-scale DERs (U-DERs), information on relevant interconnection standards (IEEE Std. 1547-2003, IEEE Std. 1547a-2014, IEEE Std. 1547-2018, and CA Rule 21), and how the DER_A model parameters can be modified to account for a mixture of vintages of inverter-interfaced DERs. The block diagram of the DER_A model is annotated and described so that Transmission Planners (TPs) and Planning Coordinators (PCs) are able to understand the relevant control logic of the dynamic model with respect to the various rules. This guideline also provides TPs and PCs with a set of recommendations for developing the modeling parameters for the DER_A dynamic model. These recommendations can also be extrapolated to TOPs, Reliability Coordinators (RCs), and other entities performing positive sequence stability simulations of the BPS where an aggregate representation of DERs is required.

The recommendations developed in this guideline are based on extensive testing of the DER_A dynamic model in the Western Electricity Coordinating Council (WECC) Modeling and Validation Work Group (MVWG) as well as industry expertise and studies discussed in detail in the NERC System Planning Impacts of DER Working Group (SPIDERWG) analysis subgroup. This guideline also serves as a useful reference for building DER models and selecting representative DER model parameters in situations where more detailed information is not yet available.

Introduction

Applicability

This reliability guideline is applicable to TPs, PCs, and other users of DER models for representing aggregate or stand-alone inverter-based DERs.

Related Standards

The topics covered in this guideline are intended as useful guidance and reference materials as TPs and PCs create DER models and modeling assumptions for use in studies generally conducted in the long-term planning and operations planning horizons. While this guidance does not provide compliance guidance of any sort, the concepts apply generally to the following standards:

- MOD-032
- MOD-033
- TPL-001
- PRC-006
- FAC-002
- IRO-008
- IRO-010

Purpose

With the proliferation of distributed energy resources (DER), modeling capabilities and practices should be adapted and refined so that transmission planning and operations planning engineers can differentiate between actual end-use loads and DER resources. In the past and at lower penetrations of DERs integrating into the distribution system, net load reduction has been used. Net load reduction is the result of the same or greater demand with an offset due to DERs. However, these practices may not be sustainable moving forward as the distribution system continues to integrate more DERs. Increasing DER penetration will impact the BES, resulting in changes in transmission loading levels, voltage regulation, and determination of operating limits. It is important to accurately represent the total end-use load and its composition, and model the amount of DERs as a separate resource. This will allow entities to adequately represent the impact of future DER integration as well as the performance of DERs during transmission system events. Distribution Providers (DPs) should coordinate with their TPs and PCs to ensure sufficient data for load composition and DER resources is provided, as necessary, for reliable planning and operation of the BES. While many of these resources are not considered BES, sharing of this information is important for developing representative models and performing system studies.[1]

The purpose of this guideline document is to provide a DER_A dynamic model common framework and modeling parameterization for entities to consider when modeling DERs in transient stability and powerflow simulations. The framework recommended in this guideline is expected to be particularly useful for representing load and DERs in Interconnection-wide studies. More detailed, localized studies may require additional or more advanced modeling if necessary or appropriate. The modeling practices described here may also be modified to meet the needs of particular systems or utilities and are intended as a reference point for Interconnection-wide modeling practices.

[1] Transmission planning simulations take into account both BES and non-BES equipment in order to accurately depict the impact on the BES. While DERs are inherently non-BES (as they connect to the distribution system), modeling information is required in order to represent the resources in simulation.

Background

The NERC DERTF published a report[2] in February 2017 that focused on connection modeling and reliability considerations for DERs. The report provided DER definitions, an overview of data and modeling needs, characteristics of nonsynchronous DERs, and potential reliability impacts of DERs on the BPS.

The NERC Load Modeling Task Force (LMTF)[3] worked in coordination with the NERC Distributed Energy Resource Task Force (DERTF) and published two detailed guidelines on modeling DERs as either stand-alone generating resources or as part of the composite load model (CLM):

- The *Reliability Guideline: Modeling DER in Dynamic Load Models*, published in December 2016, established a framework for modeling DERs in steady-state powerflow and dynamic simulations.
- The *Reliability Guideline: Distributed Energy Resource Modeling*, published in September 2017, utilized the framework established in the preceding guideline, and provided default parameter values for various DER dynamic models.

At the time of development of these guidelines, the DER_A model was still under development and testing and was therefore only briefly mentioned. With the DER_A model now implemented and tested across the major commercial software vendors, the SPIDERWG provided background and guidance on parameterizing the DER_A model for representing aggregate or stand-alone inverter-based DER resources. This was published in the *Reliability Guideline: Parameterization of the DER_A Dynamic Model*.

This reliability guideline, titled *Reliability Guideline: Parameterization of the DER_A Dynamic Model for Aggregate DER,* combines the two LMTF/DERTF reliability guidelines with the SPIDERWG reliability guideline to provide the same technical guidance, but housed in one document. This was done as part of an effectiveness and efficiency review in the RSTC.

The following sections briefly describe the DER modeling framework and the definitions and terminology used in that framework. Further, definitions that are used in multiple SPIDERWG documents are posted to the SPIDERWG webpage and are useful for understanding the terms used in this guideline.[4] Models used prior to the DER_A model are also summarized below. Guidance contained in the background and chapters of this document are focused to TPs and PCs; however, other users of the DER_A dynamic model, such as RCs and TOPs, can also find this guidance useful for their studies.

Historic DER Model Usage and Development

DER model development for use in transmission planning models began with a framework and dynamic model behavior to represent the resources on the distribution system. While some synchronous facilities exist, the historical information has shown that solar PV has been and continues to be the largest DER type. This section describes an overview of data collection for various uses of a DER model.

DER Data Collection

TPs and PCs are required to collect steady-state and dynamic models for Interconnection-wide base case creation. As part of this process, each PC and each of its TPs jointly develop data requirements and reporting procedures for the PC's planning area as outlined in MOD-032-1. In addition to the aggregate demand collected from the DP, accurate modeling of DERs should also be included in the data collection process. Accurate modeling of DERs as part of the overall demand and load composition is critical for accurate and representative modeling of the overall end-use load in both the powerflow and dynamics cases. DPs (and RPs, if applicable) should coordinate with their respective TP

[2] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf.
[3] https://www.nerc.com/comm/PC/Pages/Load%20Modeling%20Task%20Force%20(LMTF)/Load-Modeling-Task-Force.aspx.
[4] Available here: https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf

and PC to provide sufficient data to accurately represent the aggregate loads, aggregate R-DERs and distinct U-DERs in their system for both steady-state and dynamic models. At a minimum, TPs and PCs should have the following information related to DERs (also reproduced in Table I.1):

- DERs modeled as U-DERs
  - Type of generating resource (e.g., reciprocating engine, wind, solar PV, battery energy storage)
  - Distribution bus nominal voltage where the U-DER is connected
  - Feeder characteristics for connecting the U-DER to distribution bus if applicable
  - The location, both electric and geographic. Related to bulk system bus
  - The capacity of each U-DER resource (Pmax, Qmax, rated MVA, rated power factor, capability curve of U-DER reactive output with respect to different real power outputs down to Pmin)
  - The vintage of IEEE 1547 (e.g., -2018) or other relevant interconnection standard requirements that specify DER performance of legacy and modern DERs (e.g., CA Rule 21)
  - Actual plant control modes in operation: voltage control, frequency response, active-reactive power priority
- DERs modeled as R-DERs
  - Type of generating resource (e.g., reciprocating engine, wind, solar PV, battery energy storage)
  - Aggregate capacity (Pmax, Qmax) of R-DERs behind the T–D Interface and a reasonable representation of the aggregate "capability curve" of reactive output with respect to different real power outputs down to Pmin
  - Location, both electric and geographic (Related to bulk system bus)
  - Vintage of IEEE 1547 (e.g., 2018) or other relevant interconnection standard requirements that specify DER performance of legacy and modern DERs (e.g., CA Rule 21)

Table I.1: Data Collection Applicability to U-DERs and R-DERs

Description	U-DERs	R-DERs
Type of generating resource (e.g., reciprocating engine, wind, solar PV, battery energy storage)	X	X
Distribution bus nominal voltage	X	
Information characterizing the distribution circuits (X, R)	X	X
Capacity and capability (Pmax, Qmax, reactive capability with respect to real power output)	X	X
Rating (rated MVA, rated power factor)	X	X
Vintage of IEEE 1547 (e.g., 2018) or other relevant interconnection standard requirements that specify DER performance of legacy and modern DERs (e.g., CA Rule 21)	X	X
Control modes: voltage control, frequency response	X	
Location (electrical bus and geographic area)	X	X

Note: The technical capabilities and default settings of R-DERs for frequency response, volt/var control, and P/Q priority as specified by the revised IEEE Std 1547 should also be considered.

This information will help the PC, and TP in more representative modeling[5] of U-DERs and R-DERs. In situations where this data is not readily available, the entities should use engineering judgment to map the model parameters to expected types of operating modes. The technical capabilities and default settings of R-DERs for frequency response, volt/var control, and P/Q priority as specified by the revised IEEE Std 1547 should also be considered.

Furthermore, while the above has been focused on TPs and PCs, DER models are available in the software tools that are used by RCs and Transmission Operators (TOPs) in order to perform their real-time analyses, and operational planning analyses. Should the RC desire to model aggregate DERs at one of their monitored buses in simulation, the guidance on parameterizing the model should be applicable to describe powerflow and transient dynamic behavior.

Synchronous DER Models

Small, synchronous DERs connected at the distribution level can be modeled with standard synchronous machine models. TPs and PCs should determine if any synchronous DERs should be modeled as applicable and develop reasonable model parameters for these resources in coordination with the DPs as necessary. It is recommended to use the genqec model for representing synchronous machines.[6] The classical machine model, gencls, should not be used to model DERs to avoid any unintentional poorly damped oscillations. In most situations, a generator model alone will capture the dynamic behavior of the machine in sufficient detail; however, if data is available and the PC or TP find it necessary, a suitable governor and excitation system may also be modeled. **Table I.2** shows examples of model parameters for a steam unit, small hydro unit, and gas unit for reference. These default parameters are used solely as a base set to start from with the assumption of zero information about the synchronous DERs. These parameters should change in order to accurately represent the characteristics of the synchronous DERs to be modeled.

Table I.2: Synchronous DER Default Model Parameters

Parameter	Steam	Small Hydro	Natural Gas	“Really Small”
MVA	14	32	15	5
T’d0	6	6	6.5	7
T’’d0	0.035	0.027	0.03	0.03
T’q0	1	0	1	0.75
T’’q0	0.035	0.065	0.03	0.05
H	3	1.7	4.2	3
D	0	0	0	0
Xd	1.8	1.45	1.6	2.1
Xq	1.7	1.05	1.5	2.0
X’d	0.2	0.47	0.2	0.2
X’q	0.4	1.05	0.3	0.5
X’’d	0.18	0.33	0.13	0.18
X’’q	0.18	0.33	0.13	0.18

[5] In some instances, a complete dynamic and steady-state model can be provided should the TP and PC allow and approve of it. In this case, much of the listed equipment information as well as supplemental protection and other models can be placed inside the file without needing to report the information to the TP/PC outside of the model submittal.

[6] The model parameters listed may not be a complete set for genqec; however, the other parameters are more suited for limitations on bulk equipment, and the software defaults are adequate for default parameters. Still, should the resource require alterations from the listed table, the general guidance to adapt the parameters to model the equipment still holds.

Table I.2: Synchronous DER Default Model Parameters				
Parameter	Steam	Small Hydro	Natural Gas	"Really Small"
Xl	0.12	0.28	0.1	0.15
S(1.0)	0.2	0.2	0.1	0.05
S(1.2)	0.6	0.6	0.4	0.3

The tripping profile of IEEE 1547 is applicable for synchronous DERs for the states that have adopted the standard. As most states adopted the 1547-2003 version, the tripping profiles for synchronous DERs are more likely to behave like that version of the standard. For states that have adopted 1547-2018, the trip profiles are applicable to synchronous DERs as well as inverter-based DERs. Parameterization of the voltage thresholds on these models can be parameterized to account for the tripping assumptions in this reliability guideline.

As there is a potential to aggregate an amount of synchronous DERs (using synchronous models) akin to the inverter-based DERs (modeled by DER_A), the same guidance in the chapters below hold with respect to altering the parameters based on engineering judgement to reflect the aggregate behavior of that particular T–D composition. The synchronous models are not directly an aggregate model,[7] so care will be needed in parameterizing the models to reflect aggregate behavior, and supplemental models may be needed. The T–D Interface represents a variety of points of interconnection for synchronous DERs and an aggregate model is a suitable representation; however, the TP or PC can model all synchronous DERs individually as indicated in the DER Modeling Framework section below.

Second Generation Renewable Energy System Models

The second generation generic renewable energy system models were developed between 2010 and 2013 and have since been adopted by the most commonly used commercial software vendors. The suite of models that have been developed can be used to model different types of renewable energy resources:

- Type 1 Wind Power Plants
- Type 2 Wind Power Plants
- Type 3 Wind Power Plants
- Type 4 Wind Power Plants
- Solar PV Power Plants
- Battery Energy Storage Systems (BESS)

These models were originally developed to represent large utility-scale resources connected to the BPS at transmission level voltage[8] and provide the greatest degree of flexibility and modeling capability from the commercial software vendor tools using generic models. However, the flexibility also results in a significant number of settings and controls that must be modeled that may be cumbersome for representing DERs. If modeling DERs using the second generation models, a set of generic parameters can be used for specific studies, such as generation interconnection system impact studies (e.g., large capacity resources relative to the local interconnecting network) or other special studies. The generic models for these studies should be accompanied by sufficient model and parameter validation for large DER owners to ensure the model represents the installed equipment. Where actual

[7] It is not anticipated to impose major functional differences in response when using the genqec model as an aggregate model. However, parameters changes are expected and care needs to be taken when adjusting to represent aggregate behavior. It is not anticipated to have a consequential impact in simulation at this time due to the lower share of synchronous DER in the totality of the DER on the system.

[8] P. Pourbeik, J. Sanchez-Gasca, J. Senthil, J. Weber, P. Zadehkhost, Y. Kazachkov, S. Tacke, J. Wen and A. Ellis, "Generic Dynamic Models for Modeling Wind Power Plants and other Renewable Technologies in Large Scale Power System Studies", IEEE Transactions on Energy Conversion, published on IEEE Xplore 12/13/16, DOI 10.1109/TEC.2016.2639050.

equipment is to be modeled, specific data from the equipment vendor or at least an understanding of the actual equipment control strategy and performance (e.g., constant power factor control vs. voltage control) is extremely important and should be used.

The dynamic behavior of renewable energy systems that are connected to the grid using a power electronic converter interface (i.e., Type 3 and Type 4 wind turbine generators, solar PV, and battery storage) are dominated by the response of the power electronic converter. The converter is a power electronic device, and its dynamic response is more a function of software programming than inherent physics as in the case of synchronous machines. Therefore, the concept of default and typical parameters is much less applicable to renewable energy systems than other technologies.[9] For example, setting lvplsw = 1 describes the flag that turns on low voltage power logic and is used to emulate the behavior typical of some vendor equipment under low voltage conditions. However, lvplsw is a function of the software and vendor controls in the power converter and should be set according to the respective vendor characteristics to be emulated, if that information is available. The default example values in software for modeling DERs as a second generation renewable model should be altered to reflect the distribution-connected alterations and equipment settings.

This reliability guideline focuses on the der_a dynamic model, which is a model to represent aggregate dynamic behavior. These second generation renewable models are more appropriate for single plant representations. The SPIDERWG recommends the use of the der_a dynamic model for representing aggregate DERs in simulation[10] rather than using the second generation renewable models that could be used for representation of a single, larger plant connected to the distribution system.

DER Modeling Framework

For the purposes of steady-state and dynamic modeling of DERs in BPS reliability studies, DERs can be defined as either utility-scale DERs, U-DERs, or R-DERs defined as follows:

- **U-DERs:** These are DERs directly or closely connected to the distribution bus[11] or connected to the distribution bus through a dedicated,[12] non-load serving feeder. These resources are typically three-phase interconnections and can range in capacity (e.g., 0.5 to 20 MW).
- **R-DERs:** These are DERs that offset customer load, including residential,[13] commercial, and industrial customers.[14] Typically, the residential units are single-phase while the commercial and industrial units can be single- or three-phase facilities.[15]

[9] Generic models representing renewable energy systems include a common model structure that allows for representing different types of control strategies and characteristics. These models can be tuned or configured to represent specific vendor equipment by adjusting the model parameters.

[10] It is possible to use the der_a model to represent a single plant; however, careful parameterization is required to ensure the aggregate dynamic model is properly representing the single plant.

[11] The distribution bus is connected to a transmission voltage bus via the transmission/distribution transformer. Resources not directly connected to this bus do not meet the criteria for this definition.

[12] In some cases, U-DERs may not be located on a dedicated feeder; U-DERs may be installed on the load-serving feeders near the head of the feeder. In either case, the framework presented here can and should be adapted to each TP and PC needs. In this case, these larger DER installations can still be represented as U-DERs. In other cases, they may be better suited to be modeled as R-DERs. Engineering judgment should be used to determine which modeling approach is most appropriate.

[13] This also applies to community DERs that do not serve any load directly but are interconnected directly to a distribution load serving feeder.

[14] This often includes behind the meter generation but may also include individually metered DERs and systems that export beyond customer load at a particular site boundary.

[15] For the purposes of modeling, some larger utility-scale U-DERs may exist along the load-serving distribution feeder and may be electrically distant from the distribution substation. In these cases, they may be represented as R-DERs since they offset customer load. The aggregate power output can potentially exceed the total load demand of the distribution feeder.

Both U-DERs and R-DERs can be differentiated and should be accounted for in powerflow base cases and dynamic simulations. Modeling U-DERs and R-DERs in the powerflow provides an effective platform for linking this data to the dynamics records and ensuring that the dynamics of these resources are accounted for. R-DERs represent the truly distributed resources throughout the distribution system whose controls are generally reflective of IEEE Std. 1547[16] vintages or other relevant requirements for the region they are being interconnected. U-DERs are typically relatively large, stand-alone installations that may have more complex controls or requirements associated with their interconnections. The vintage of IEEE Std. 1547 is an indicator for a large set of controls; however, the interconnection requirements of that local area may be over and above, so looking at the requirements of a particular interconnection for these larger, stand-alone installations will be a better representation of the equipment's operation. That said, IEEE 1547 would be applicable to the equipment, and any settings would be above and beyond.

TPs and PCs should identify thresholds where U-DERs should be explicitly modeled, and R-DERs should be accounted for in the powerflow and dynamics cases. The thresholds should be based on either the individual or aggregate impact of DERs on the BPS: [17]

- Gross aggregate nameplate rating of an individual U-DERs facility directly connected to the distribution bus or interconnected to the distribution bus through a dedicated, non-load serving feeder
- Gross aggregate nameplate rating of all connected R-DERs that offset customer load including residential, commercial, and industrial customers

The thresholds that are determined with engineering judgment for modeling U-DERs and R-DERs[18] can be defined as follows:

- **U-DER Modeling:** Any individual U-DER facility rated at or higher than the defined individual U-DER modeling threshold should be modeled explicitly in the powerflow case at the low-side of the transmission–distribution transformer. A dynamics record should be used to account for the transient behavior[19] of the individual U-DER plant. Individual U-DERs less than the defined threshold should be accounted for in powerflow and dynamics as an R-DER (as described below). Multiple similar U-DERs connected to the same substation low-side bus could be modeled as an aggregate resource as deemed suitable by the TP or PC. This is also a good modeling practice to aggregate DERs that are closer to the feeder head and would have less impact by the modeled feeder equivalent in the simulation. Facilities that are lower than the individual modeling threshold should either be modeled as R-DERs or as a separate aggregation near the feeder head in the framework.
- **R-DER Modeling:** If the gross aggregate nameplate rating of R-DERs connected to a feeder exceeds the defined R-DER modeling threshold in the TP and PC modeling practices, these R-DERs should be accounted

[16] IEEE Std. 1547-2003, Standard for Interconnecting Distributed Resources with Electric Power Systems, July 2003: https://standards.ieee.org/standard/1547-2003.html.
IEEE Std. 1547a-2014, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems – Amendment 1, May 2014: https://standards.ieee.org/standard/1547a-2014.html,
IEEE Std. 1547-2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, April 2018: https://standards.ieee.org/findstds/standard/1547-2018.html.
IEEE Std. 1547-2018, 6/4/2018: Errata to IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces: http://standards.ieee.org/findstds/errata/1547-2018_errata.pdf.

[17] This may include many different types of DERs, including distributed solar PV, energy storage, synchronous generation, and other types of DERs. Including synchronous generation in the CLM as a component of R-DERs may not be possible across all software platforms.

[18] SCADA data points and monitoring of native load may provide some level of engineering judgement for the amount of DER that is represented by one load record. However, determination of nameplate ratings to represent in models requires further data collection practices. TPs and PCs should interface with their DPs to obtain known DER capacities and determine the gross aggregate nameplate for their simulations.

[19] Depending on complexity of actual U-DERs, more sophisticated models, such as the second generation generic renewable energy system models may also be used for inverter coupled U-DERs (i.e., regc_a, reec_b and repc_a). Other U-DERs (e.g., synchronous natural gas or steam-turbine generators) can also be modeled by using standard models available in commercial software platforms.

for in dynamic simulations as part of the dynamic load model. While this may not require any explicit model representation in the powerflow base case, the amount of R-DERs can be accounted for as part of the powerflow load record and integrated into the dynamic model as an explicit DER component. The threshold for modeling R-DERs should be 0 MVA, meaning that all forms of DERs should be accounted for (and not netted with the load) to the extent possible. Furthermore, this does not mean that a single generator record is required for each R-DER. Rather, establishing a threshold of 0 MVA for R-DERs means that a TP or PC should represent all DERs in their system.[20]

Figure I.1 shows the recommended powerflow representation for accounting for U-DERs. The left side of Figure I.1 shows the conventional powerflow representation of the load record. This has conventionally included both load and DERs (representing a net load quantity as opposed to a gross load quantity). However, the right side of Figure I.1 shows how the transmission–distribution (T–D) transformer can be modeled explicitly and the gross load can be moved to the low side distribution bus. U-DERs above the specified threshold can be modeled explicitly via their own step-up transformers as applicable. If the U-DERs are connected through a dedicated feeder or circuit to the low-side bus, then that would also be explicitly modeled in the powerflow.

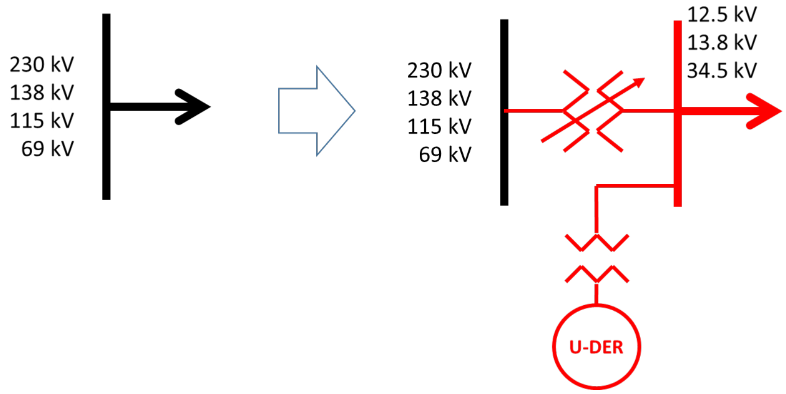


Figure I.1 Representing U-DERs in the Powerflow Base Case

To capture the R-DERs in the powerflow, the load records now[21] have the capability to input the R-DER quantity along with the gross load amount. Figure I.2 shows an example of the R-DERs included in the powerflow load records. The red box shows the specified R-DERs, and the blue box shows the net load equal to the actual load minus the R-DERs. For example, 80 MW and 20 MVar of actual load with 40 MW and 0 MVar of R-DERs at Bus 2.

	Number of Bus	Name of Bus	Area Name of Load	Zone Name of Load	ID	Status	MW	Mvar	MVA	S MW	S Mvar	Dist Status	Dist MW Input	Dist Mvar Input	Dist MW	Dist Mvar	Net Mvar	Net MW
1	2	Two	Top	1	1	Closed	80.00	20.00	82.46	80.00	20.00	Closed	40.00	0.00	40.000	0.000	20.000	40.000
2	3	Three	Top	1	1	Closed	220.00	40.00	223.61	220.00	40.00	Open	110.00	0.00	0.000	0.000	40.000	220.000
3	4	Four	Top	1	1	Closed	160.00	30.00	162.79	160.00	30.00	Closed	80.00	0.00	80.000	0.000	30.000	80.000
4	5	Five	Top	1	1	Closed	260.00	40.00	263.06	260.00	40.00	Open	130.00	0.00	0.000	0.000	40.000	260.000
5	6	Six	Left	1	1	Closed	400.00	0.00	400.00	400.00	0.00	Closed	200.00	0.00	200.000	0.000	0.000	200.000
6	7	Seven	Right	1	1	Closed	400.00	0.00	400.00	400.00	0.00	Closed	200.00	0.00	200.000	0.000	0.000	200.000

Figure I.2: Capturing R-DERs in the Powerflow Load Records [Source: PowerWorld]

[20] TPs and PCs should establish this zero MVA threshold as a best practice for modeling as it requires data collection of resources prior to needing modeling information past a non-zero threshold. It has been reported that information needed from facilities after the non-zero threshold has been met is limited and model development is restricted for the facilities that were interconnected under that limit. The zero MVA threshold prevents data loss like this from occurring.

[21] All commonly used commercial simulation software platforms now have the ability to represent DERs as part of the powerflow load record in an attempt to standardize and unify modeling practices for representing DERs in powerflow base cases.

Once represented in the powerflow base case, data for the CLM can be modified to account for explicit representation of the DERs and the T–D transformer. Figure I.3 shows the dynamic representation of the CLM, where the distribution transformer impedance is not represented in the dynamic load record. Rather, it is modeled explicitly in the powerflow to accommodate one or more U-DERs.[22] Any load tap changer (LTC) modeling[23] would be done outside the CLM, such as enabling tap changing in the powerflow[24] and using the *ltc1* model in dynamic simulations. Motor load and the distribution equivalent are modeled as part of the CLM, and the R-DERs are represented at the load bus based on the data entered in the load record table.

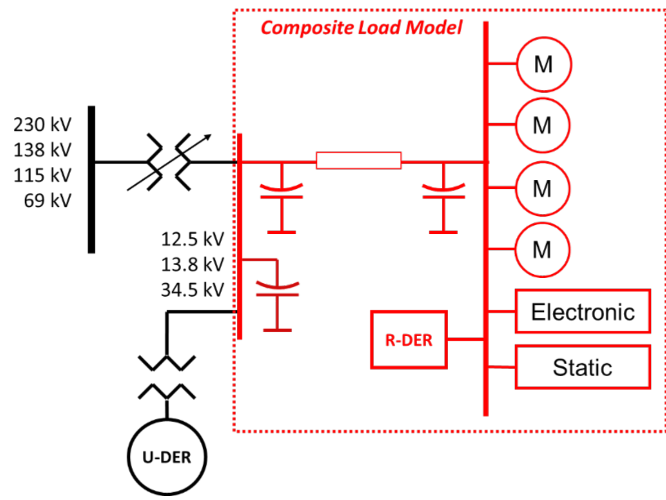


Figure I.3: CLM Representation with U-DERs Represented in the Powerflow Base Case

FERC Order 2222[25] introduces the DER aggregator, an entity that can control an aggregate capacity of various technology types of DER. As such the initial split of capacity and the granularity of parameter information provided from such entities is key to model DER at T-D Interfaces containing DER Aggregators or similar entities. SPIDERWG produced a white paper that highlighted some BPS reliability tie-ins to DER aggregators; however, when parameterizing the steady state representation, logical flow charts as in Figure I.4 assist in providing planners a way to disaggregate information provided from a DP or a DER aggregator for representation in transmission cases. In short, these logical flows provide a crude method to begin placing DERs into model representations. Note that these percentage splits in Figure I.4 are to be considered as initial default values, and value modifications may be necessary based on the information received from a DP or a DER aggregator.

[22] If only R-DERs are represented at a bus (no U-DERs), then the T–D transformer does not necessarily need to be explicitly modeled in the powerflow since it can be accounted for in the CLM dynamic record, including LTC action. However, if LTC action needs to be modeled in the steady-state analyses in any way, then explicit modeling of the T–D transformer in the powerflow may be needed.
[23] Utilities using transformers without under-load tap changers (ULTCs) capability but with voltage regulators at the head of the feeder could model this in the CLM with a minimal transformer impedance but active LTCs to represent the voltage regulator.
[24] For example, by specifying settings in the transformer record and enabling tap changing in the powerflow solution options.
[25] The text of this order can be found here: https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf

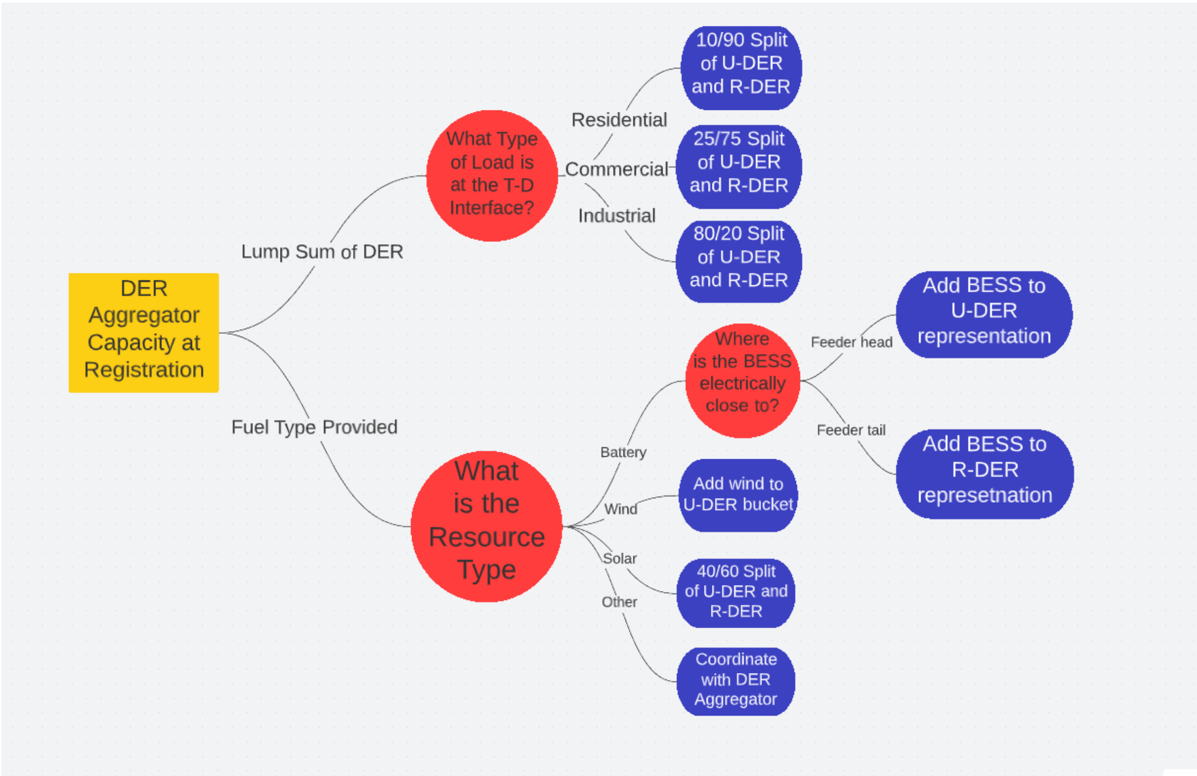


Figure I.4: Decision Tree for DER Disaggregation

Overview of the DER_A Model

The DER_A model is a simplified version of the second-generation generic renewable energy system models (i.e., regc_a, reec_b, repc_a, lhvrt, lhfrt) that are used to represent inverter-based DERs (i.e., utility-scale wind, solar photovoltaic (PV), and battery energy storage resources). The DER_A model uses a reduced set of parameters meant to represent the aggregation of a large number of inverter-interfaced DERs. It is also an improvement over the pvd1 model in that it includes additional modeling flexibility for more advanced and representative capabilities introduced in IEEE Std. 1547-2018 and California Rule 21. The DER_A model can be used to represent U-DERs (individual DER resources, or a group of similar U-DERs) and can also be used to represent R-DERs as either a standalone DER dynamic model or as part of the CLM. The DER_A model includes the following features:

- Constant power factor and constant reactive power control modes (allows voltage control to be active along with PF/Q control, depending on whether voltage is within the deadband or not)
- Active power-frequency control with droop and asymmetric deadband
- Voltage control with proportional control and asymmetric deadband (may be used to either represent steady-state voltage control or dynamic voltage support, depending on chosen time constants)
- Representation of a fraction of resources tripping or entering momentary cessation[26] at low and high voltage, including a four-point piece-wise linear gain (partial tripping includes a timer feature as well)
- Representation of a fraction of resources that restore output following a low or high voltage or frequency condition (representation of legacy trip and modern ride-through capabilities in a single model)

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[26] Momentary cessation is a mode of operation during which no current is injected into the grid by the inverter during low or high voltage conditions outside the continuous operating range. This leads to no current injection from the inverter and no active or reactive current (and no active or reactive power). Refer to the NERC R*eliability Guideline: BPS-Connected Inverter-Based Resource Performance*. The concept applies to both BPS-connected inverter-based resources and DERs: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf.

- Active power ramp rate limits during return to service after trip or enter service following a fault or during frequency response
- Active-reactive current priority options (used to represent dynamic voltage support during fault events)
- The capability to represent generating or energy storage resources[27] (The model allows for absorption of active power; however, charging and discharging as modeled in reec_c is not included. Therefore, the DER_A model should not be used for devices with only a few seconds of energy injection (e.g., super capacitor systems))

The overall block diagram for the DER_A model can be found in **Appendix C**

[27] This guideline focuses mostly on using the DER_A model to represent generating resources, primarily distributed solar PV generation. However, the DER_A model can be used to represent energy storage, and future guidelines may be developed on this topic as necessary.

Chapter 1: Annotated DER_A Block Diagram

This chapter briefly describes the functional sections of the DER_A model and provides a high-level overview of what the various blocks represent. Refer to the DER_A specification document[28] for more detailed information regarding implementation. The sections below describe the general control aspects of the different functional sections of the model.

Active Power-Frequency Controls

The active power-frequency controls portion of the DER_A model are shown in **Figure 1.1**. The frequency input signal feeding the active-power frequency controls is first passed through a frequency measurement time constant, *Trf*. The filtered voltage is compared against a reference signal. The *fdbd1* and *fdbd2* parameters represent the active power-frequency control deadband for overfrequency and underfrequency, respectively. The *Ddn* and *Dup* parameters represent the overfrequency and underfrequency droop gains, respectively. *Tp* represents an active power measurement time constant. When active power-frequency control is enabled, *Freq_flag* is set to 1. To disable active power-frequency control of the model, set *Freq_flag* to 0. The frequency error is limited by *femax* and *femin* and goes through a PI controller with *Kpg* and *Kig* parameters. The *dPmax* and *dPmin* parameters limit active power upward and downward ramp rates. *Pmax* and *Pmin* represent the maximum and minimum power output, respectively. *Tpord* is the power-order time constant, and it can be used to represent the small time lag for changing the power reference (when *Freq_flag* = 0) or the open-loop time constant associated with the full controls (when *Freq_flag* = 1) as specified in IEEE Std. 1547-2018. Active current command (*ipcmd*) is calculated by using power-order (*Pord*) divided by filtered terminal voltage (*Vt_filt*); it is limited by *Ipmax* and *Ipmin*.

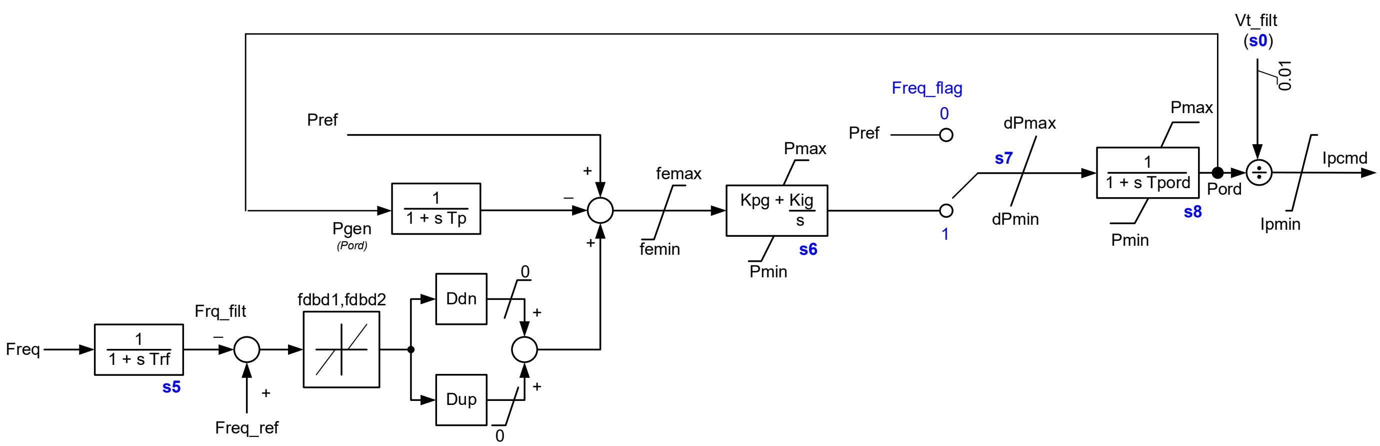

Figure 1.1: Active Power-Frequency Controls

Frequency Tripping Logic Input

The frequency input signal feeding the active-power frequency controls is first passed through a frequency measurement time constant, *Trf*. A low voltage inhibit logic was added to the model, which is shown in **Figure 1.2**. When voltage falls below a threshold (*Vpr*), the frequency relay model is bypassed. This is common in frequency protective functions to avoid spurious tripping during transients. In numerical simulations, this low voltage inhibit is also used to avoid tripping on numerical spikes during discontinuities.[29]

[28] P. Pourbeik, "Proposal for DER_A Model," June 19, 2019: https://www.wecc.org/Reliability/DER_A_Final_061919.pdf.
[29] https://www.wecc.biz/Reliability/WECC_White_Paper_Frequency_062618_Clean_Final.pdf

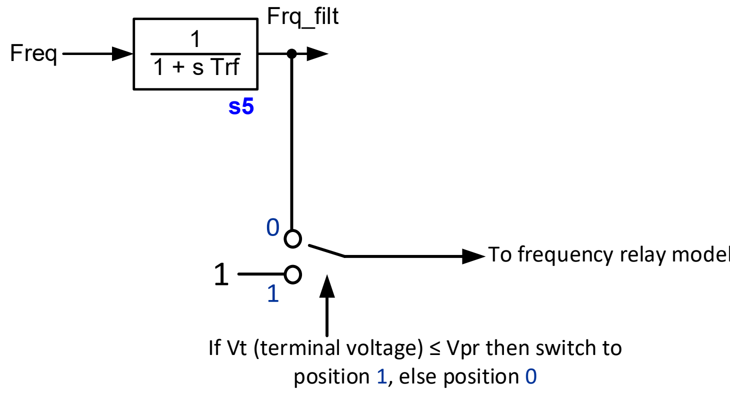

Figure 1.2: Frequency Tripping Logic Controls

Reactive Power-Voltage Controls

The reactive power-voltage controls portion of the DER_A model is shown in **Figure 1.3**. Setting *pflag* to 0 or 1 selects either constant reactive power control or constant power factor control, respectively. The *pfaref* parameter is internally calculated to achieve the necessary reactive power order for the current active power order. Reactive power is then divided by filtered terminal voltage (*Vt_filt*) and passed through a reactive current calculation time constant (*Tiq*). Voltage control is included in the model. Terminal voltage (*Vt*), after a measurement time constant (*Trv*), passes through a lower (*dbd1*) and upper (*dbd2*) deadband and proportional control gain (*Kqv*). Iqh1 and Iql1 specify maximum and minimum limits, respectively, of reactive current injection. To disable the reactive power-voltage control function of the model, set *Kqv* to 0.

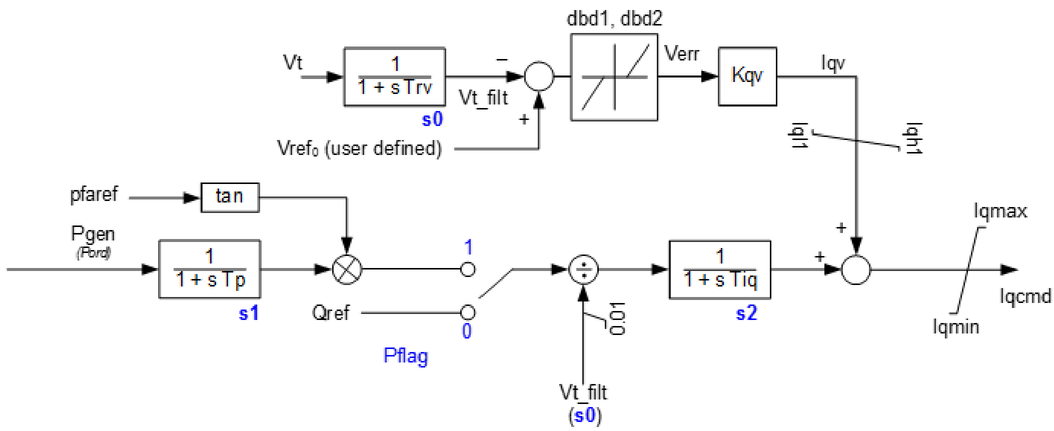

Figure 1.3: Reactive Power-Voltage Controls

Active-Reactive Current Priority Logic

With the active and reactive command values established in the active power-frequency and reactive power-voltage control elements, the command values are passed through maximum (*Ipmax*/*Iqmax*) and minimum (*Ipmin*/*Iqmin*) active and reactive current limits. **Figure 1.4** shows the current limit logic and how that logic interacts with the limiters. When the *typeflag* parameter is set to 1, this denotes a DER that is a generating unit with *Ipmin* = 0 while setting it to 0 denotes a DER that is an energy storage device with *Ipmin* = -*Ipmax*.

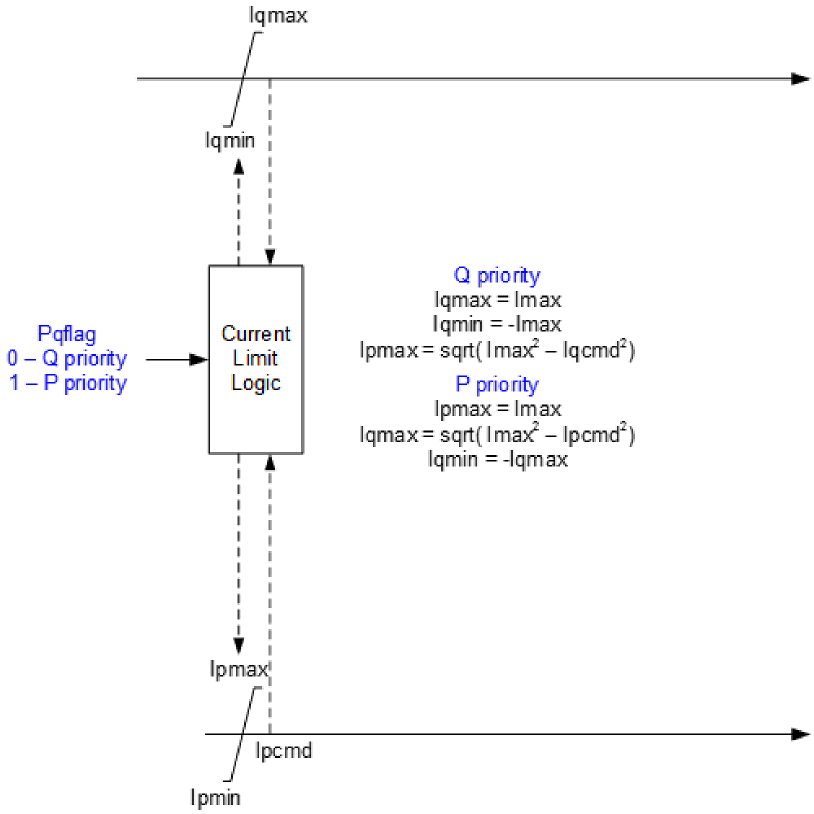

Figure 1.4: Active-Reactive Current Priority Controls

Current limits, particularly in inverter-based resources, determine how the resource responds to large grid disturbances, such as faults on the BPS. The current limit logic is determined based on whether the resource is operated in active or reactive current priority and dictated by the *pqflag* parameter. The priority logic controls *Iqmax* and *Iqmin* based on the priority setting and maximum total current of the inverter (*Imax*). Figure 1.4 also shows the equations used for this control. For example, if reactive current priority is selected, then *Iqmax* and *Iqmin* are limited to *Imax* and -*Imax*, respectively. Based on the reactive current ordered from the controls, the active current limit is then simultaneously calculated to utilize the remaining amount of total apparent current capability (*Imax*). A circular capability curve is assumed.

Example Consideration of Q Priority and P Priority

As an example, if the magnitude of current is limited to 1.2 pu (*Imax*) and the priority scheme is defined by reactive current priority, then a maximum limit of 1.2 pu is imposed on the reactive portion of current. The maximum active current (at this reactive current limit) will be $0.0 \text{ pu} = \sqrt{1.2^2 - 1.2^2}$. However, this does not imply that the active current will always be zero. This is the limited value of active current only when the reactive current is at its limit. However, if a reactive current of 1.0 pu is sufficient for the system as decided by the reactive power-voltage controls, then the maximum active current can be $0.66 \text{ pu} = \sqrt{1.2^2 - 1.0^2}$. Hence, the reactive power-voltage controller not only decides the amount of reactive current to be injected but also the maximum amount of active current that can be injected for the decided value of reactive current. The active current controller then decides the actual value of active current to be injected. An opposite situation occurs when an inverter is in active current priority.

Prior to approval of IEEE Std. 1547-2018, all DERs on the system were not required to have reactive power-voltage control capability. Thus, the vintage of inverters that conform to this standard should have a P priority setting. With the approval of IEEE Std. 1547-2018, which requires inverters to have reactive power-voltage control capability (with preference to reactive current), it is expected that this capability will be used by the inverter, so the current priority setting should be set to Q priority. However, the impact of setting DERs to P priority versus Q priority should be assessed with detailed studies since both settings could have a positive impact.

For example, upon the occurrence of a fault, a larger percentage of gross load can trip if located electrically close to the fault and if adjacent DERs are in Q priority compared to when adjacent DERs are in P priority. However, at locations located electrically further away from the fault, a larger percentage of gross load can trip when adjacent DERs are in P priority compared to when adjacent DERs are in Q priority. Closer to the fault, the DER reactive current would hit *Imax* and active current reduces to zero when in Q priority and with voltage control enabled. The intention behind this is to try and support local voltage and prevent gross load tripping. However, when the DER's active current contribution reduces to zero due to full output of reactive current (bear in mind that this is not to be confused with momentary cessation), the net load at the load substation bus increases, potentially resulting in voltage reduction at nearby non-DERs and tripping load. Now, the net load at the load bus would be lower when the DER is in P priority (assuming that the DERs have not gone into momentary cessation mode), so the voltage wouldn't fall as much at nearby non-DER buses, and as a result, a trip of gross load is lesser. Farther away from the fault, due to the initial higher voltage levels (as compared to the voltage levels closer to the faults), voltage support in Q priority has a greater effect, so (due to decrease in active current contribution from DERs to accommodate injection of reactive current) the voltage drop (due to increase in net load) does not counterbalance the voltage support from the DER even though the net load may increase. Therefore, there is less gross load tripping.[30] It should be noted that this behavior may not be the norm, but it is a possibility; setting DER priority settings should be conducted based on detailed system studies.

Fractional Tripping

The DER_A model includes a fractional tripping control[31] that is intended to represent a portion of the DER tripping on low or high voltage[32] as shown in **Figure 1.5**. The *vtripflag* controls voltage tripping, and the *ftripflag* controls frequency tripping separately.[33] *Vrfrac* defines the fraction of DERs that recover after voltage returns to within acceptable limits after dropping below or above the threshold values. For frequency tripping, a single low (*fl*) and high (*fh*) frequency cutout breakpoint is implemented since frequency variation along the distribution feeder is relatively constant (as compared with voltage). Hence, there is no partial tripping due to frequency.[34] *Tv* is a time constant that represents the time delay for voltage related partial tripping (shown in **Figure 1.5**).

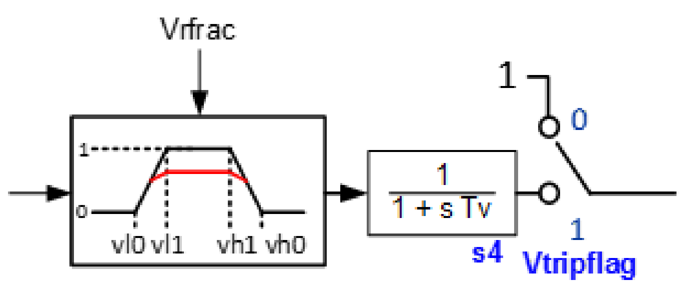

Figure 1.5: Fractional Tripping Controls

The *vl0* and *vl1* parameters are the low voltage cutout breakpoints, and the *vh0* and *vh1* parameters are the high voltage cutout breakpoints. For example, when voltage falls below *vl1*, a fraction of the DERs will cut out with a

[30] R. Quint, I. Green, D. Ramasubramanian, P. Pourbeik, J. Boemer, A. Gaikwad, D. Kosterev, C. DuPlessis, M. Osman, "Recommended DER Modeling Practices in North America," *25th International Conference and Exhibition on Electricity Distribution (CIRED) [under review]*.
[31] Fractional tripping should not be confused with dispatch scenario development that can take into account other outages (e.g., maintenance outages) in the powerflow models and not the dynamic transient set of models.
[32] There is no partial tripping due to frequency in the DER_A model. If there is a frequency trip, then the entire DER amount trips.
[33] GE PSLF does not have these flags; however, Siemens PTI PSS®E, PowerWorld Simulator, and Powertech TSAT do have these flags.
[34] If there is a frequency trip, then the entire amount of DER trips.

linearly increasing amount of DERs experiencing cutouts down to *vl0* where all DERs will have cut out. The output of the fractional tripping block is the value that gets applied to *ipcmd* and *iqcmd*.[35] If voltage falls outside the specified thresholds for the predefined amount of time (below *tvl0* or *tvl1* or above *tvh0* or *tvh1*), then the recovery of resources changes from the black line to the red line. This is intended to represent only a fraction of resources recovering from the decrease in voltage (*Vrfrac*); these resources are expected to trip off-line and return to service some time beyond a typical transient simulation.

The fractional tripping logic does not represent any actual controls but is rather an attempt at emulating the fact that not all R-DERs will experience the same terminal voltage on a feeder so may not trip at the same time and for the same level of voltage excursion at the head of the feeder. Thus, this is an attempt based on much deliberation among many participants and stakeholders to come up with a method to emulate such behavior. As experience is gained with the model, this and perhaps other aspects may be refined over time.

Refer to the model specification document for more details related to model implementation and pseudo code.[36]

Fractional Tripping Derivation

Specific data related to DERs tripping is often not available, and engineering judgment must be used to determine reasonable tripping values. These values should be based on the expected vintage of DERs and the distribution circuit characteristic. Each interconnection standard (e.g., IEEE Std. 1547-2003, IEEE Std. 1547a-2014, IEEE Std. 1547-2018) may have different ride-through and trip settings for abnormal voltage and frequency with multiple magnitude/time duration pairs. Refer to **Table 2.1** and **Table 3.1** for initial details on setting these parameter values. It should be noted that these values may need to be changed depending on the individual system where the DER_A is applied. TPs should coordinate with their DPs to attempt to track the proportion of DERs that could be expected to fall within each category. The proportion of DERs within each category may be inferred by DPs by assessing the date of each DER installation. The DER_A model does not include multiple points; however, these are likely not needed for stability studies in most cases. Typically, it is recommended to model the trip thresholds that relate to the shorter trip times[37] since this scenario is what covers most stability simulations. The thresholds are selected to account for the varied response of aggregate DERs tripping across a distribution system while taking into account the voltage drop (V_{DROP}) across the feeder.

> **Key Takeaway:**
> The DER_A model does not include multiple points for tripping; however, these are likely not needed for stability studies in most cases. Typically, it is recommended to model the trip thresholds that relate to the shorter trip times since this scenario is what covers most stability simulations.

Fractional trip settings are based on how the DERs are represented in powerflow and dynamics. There are multiple modeling options for how to set these fractional trip settings including the following (see **Figure 1.6**):

- **Option 1 (Recommended for U-DERs):** The U-DER is represented in the powerflow base case as a generator, and has an associated DER_A model in dynamics. The modeled U-DER is intended to represent one or multiple U-DERs connected directly to or very close to the distribution substation. In this case, load modeling is unrelated, since the U-DER model explicitly represents a single or group of U-DERs. Partial tripping is not applied, and the DER trip settings can mirror those specified in the respective interconnection requirements. Parameters *vl0*, *vl1*, *vh0*, and *vh1* have a direct relation to those interconnection requirements. *Vrfrac* can be set to 1 or 0 depending on the DER vintage.

[35] Refer to the DER_A Model Specification document for a detailed pseudo code explanation of how the fraction/partial tripping is calculated: https://www.wecc.biz/Reliability/DER_A_Final.pdf.
[36] P. Pourbeik, "Proposal for DER_A Model," June 19, 2019: https://www.wecc.org/Reliability/DER_A_Final_061919.pdf.
[37] As in, if the specification includes multiple trip magnitude-duration points, use the shortest duration point.

- **Option 2 (Recommended for R-DERs):** An aggregate amount of R-DERs spread throughout the distribution system is represented in the powerflow base case as a DER component of the load record. In dynamics, this information is integrated into the CLM with DER representation (e.g., cmpldwg). The equivalent distribution impedance is then represented in the CLM as well with both load and DER represented at the load bus across the equivalent feeder impedance. Voltage drop (V_{DROP}) across the feeder is accounted for explicitly ($V_{DROP} = V_{SUB} - V_{LOAD}$. The Electric Power Research Institute (EPRI) has shown that a V_{DROP} of 2–8% is typical for most distribution feeders; a value around 5% is a reasonable assumption for DER and load modeling. With the assumption of a trip setting of 0.5 pu (see **Figure 1.6**), DERs start tripping when the load bus voltage reaches 0.5 pu. All DERs have tripped when the substation bus voltage reaches 0.5 pu, meaning that the load bus voltage is at 0.45 pu. Therefore, *vl1* equals 0.5 pu and *vl0* equals 0.45 pu in this example. This concept can be used to determine trip settings for other standards as well.
- **Option 3:** An aggregate amount of R-DERs spread throughout the distribution system can also be represented in the powerflow base case as a stand-alone generator. This does not necessarily follow the recommended framework described above; however, it is a modeling option. In this case, the same concept as presented in Option 2 applies with some minor modifications. In this case, the DERs are connected to the substation bus. The DERs start tripping when the implied load-side bus (distribution feeder impedance not represented) reaches 0.5 pu (so VSUB = VLOAD + VDROP = 0.55 pu) and all are tripped when the substation bus voltage reaches 0.5 pu, so vl1 equals 0.55 pu and vl0 equals 0.5 pu in this example. Again, this concept can be applied to determine trip settings for other standards as well.

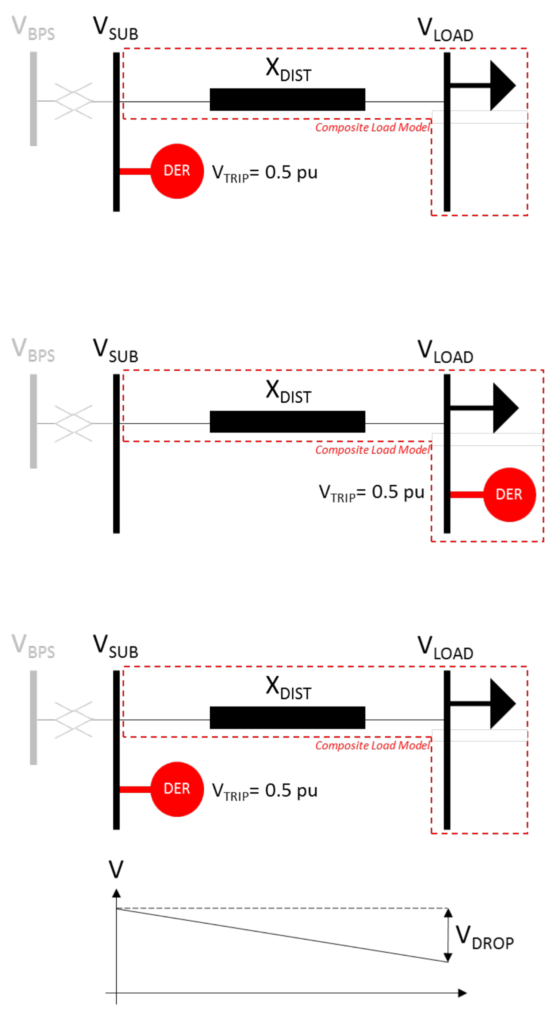

Figure 1.6: Fractional Trip Derivation Examples

The fractional trip settings can be used to model momentary cessation in a relatively crude manner if needed. For example, setting *vl1* and *vl0* to the momentary cessation settings will result in the cessation of current below the specified thresholds. Selecting times *tvl0* and *tvl1* should be done with care to ensure the resources appropriately return following voltage recovery.[38] Note that momentary cessation is not required for Category II resources in IEEE Std. 1547-2018; however, the permissive operation range does allow for momentary cessation. TPs should consider sensitivity studies to understand the impact that this may have on studies.[39]

Voltage Source Interface Representation

In the DER_A model, a voltage source interface representation[40] is implemented at the network interface to support numerical stability of the model in the simulation tools (see **Figure 1.7**).[41] In reality, all modern inverters on the grid-side of power-electronic-interfaced energy sources use a voltage source converter, specifically a dc voltage source behind a full four-quadrant controlled dc to ac power electronic converter.[42] The current through the voltage source converter is strictly controlled by the inverter controls, so this can be represented as a voltage source behind an impedance. In order to develop the value of the voltage behind the impedance, the values of *ipcmd* and *iqcmd* are used to evaluate the voltage drop across the impedance and thereby develop the complex voltage. The representation is a voltage behind a reactance, *Xe*. Typical values for *Xe* are in the range of 0.25 pu.[43]

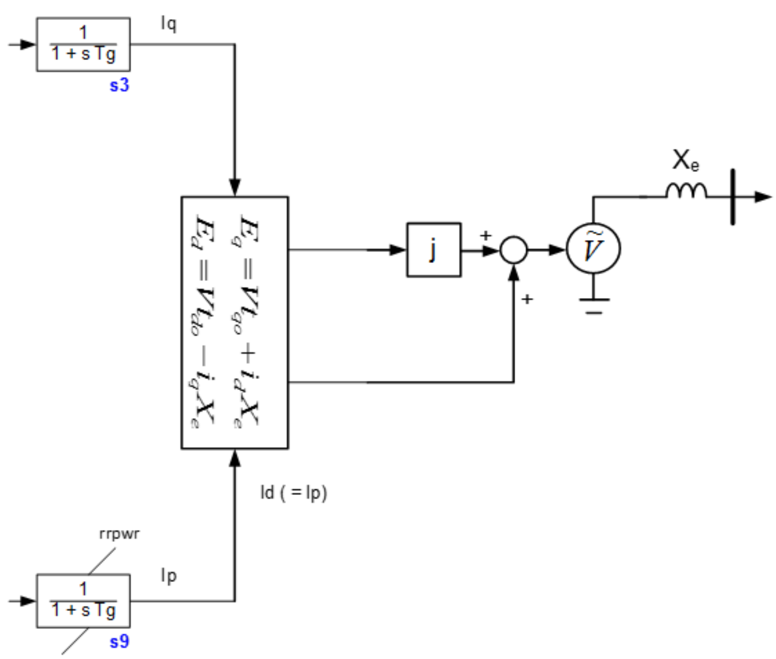

Figure 1.7: Voltage Source Representation

[38] The settings *tvl0* and *tvl1* are related to the trip characteristics and do not apply to momentary cessation. Parameter *vl0* can be set to the highest undervoltage point in which momentary cessation starts occurring.

[39] The fractional trip settings are not intended to match the IEEE Std. 1547 trip characteristics exactly; the DER_A model is intended to represent an aggregate DER behavior.

[40] D. Ramasubramanian, Z. Yu, R. Ayyanar, V. Vittal and J. M. Undrill, "Converter Model for Representing Converter Interfaced Generation in Large Scale Grid Simulations", IEEE Trans. PWRS, April 2016.

[41] The *PVD1* and second generation renewable energy system models use a current source representation that has proved to cause numerical issues in simulations—particularly at increased penetration levels of these models.

[42] A *typeflag* parameter exists in the model to denote whether the model is representing a generator or a BESS. The model does not explicitly represent four-quadrant control, as it does not represent a single BESS but rather an aggregated model. If the model is used to represent BESS, the model can operate with both positive and negative injection of active and reactive current.

[43] Resistance is neglected, and the reactance value (*Xe*) is also a default value for numerical stability. A value of *Xe* of around 0.25 pu is reasonable for this model.

Chapter 2: Parameterization of the DER_A Model

A challenge with any DER model is developing a reasonable set of parameters to represent an aggregate response of many individual resources spread across a distribution system or feeder. Table 2.1 provides a list of parameter values to represent different vintages of Interconnection standards. These include IEEE Std. 1547-2003, IEEE Std. 1547a-2014, IEEE Std. 1547-2018 Category II[44] defaults, and CA Rule 21 defaults. Refer to the DER_A specification document[45] or the simulation software model libraries for a description of the model parameters. It is to be noted that these parameter values are to be considered as initial default values, and modifications to the values may be necessary based on the individual jurisdiction of application[46] of the model.

Table 2.1: Default DER_A Model Parameters

Param[47]	IEEE Std. 1547-2003 Default	IEEE Std. 1547a-2014 Default	CA Rule 21 Default	IEEE Std. 1547-2018 Category II Default	Notes
trv	0.02	0.02	0.02	0.02	† Note 1
dbd1	-99	-99	-99	-99	† Note 1
dbd2	99	99	99	99	† Note 1
kqv	0	0	0	0	† Note 1
vref0	0	0	0	0	† Note 2
tp	0.02	0.02	0.02	0.02	†
tiq	0.02	0.02	0.02	0.02	†
ddn	0	0	20	20	Note 3
dup	0	0	20	20	Note 3
fdbd1	-99	-99	-0.0006	-0.0006	Note 3
fdbd2	99	99	0.0006	0.0006	Note 3
femax	0	0	99	99	Note 3
femin	0	0	-99	-99	Note 3
pmax	1	1	1	1	† Note 4
pmin	0	0	0	0	Note 4
dpmax	99	99	99	99	†
dpmin	-99	-99	-99	-99	†
tpord	0.02	0.02	5	5	Note 3
Imax	1.2	1.2	1.2	1.2	† Note 4
vl0	0.44	0.44	0.49	0.44	Note 5
vl1	$0.44+V_{DROP}$	$0.44+V_{DROP}$	$0.49+V_{DROP}$	$0.44+V_{DROP}$	Note 5

[44] In IEEE Std. 1547-2018, the abnormal operating performance Category II "covers all BPS stability/reliability needs and is coordinated with existing reliability standards to avoid tripping for a wider range of disturbances of concern to BPS stability."
[45] P. Pourbeik, "Proposal for DER_A Model," June 19, 2019. [Online]: https://www.wecc.org/Reliability/DER_A_Final_061919.pdf.
[46] Further, some engineering analysis requires scenario development of a "best" and "worst" case scenarios. This will require engineering judgement to alter the provided parameters to reflect such scenarios.
[47] Refer to the DER_A model specification for parameter names: https://www.wecc.biz/Reliability/DER_A_Final.pdf.

Table 2.1: Default DER_A Model Parameters					
Param[47]	IEEE Std. 1547-2003 Default	IEEE Std. 1547a-2014 Default	CA Rule 21 Default	IEEE Std. 1547-2018 Category II Default	Notes
vh0	1.2	1.2	1.2	1.2	Note 5
vh1	1.2–V_{DROP}	1.2–V_{DROP}	1.2–V_{DROP}	1.2–V_{DROP}	Note 5
tvl0	0.16	0.16	1.5	0.16	Note 5
tvl1	0.16	0.16	1.5	0.16	Note 5
tvh0	0.16	0.16	0.16	0.16	Note 5
tvh1	0.16	0.16	0.16	0.16	Note 5
Vrfrac	0	0	1	1	Note 5
fltrp	59.3	59.5 OR 57.0	58.5 OR 56.5	58.5 OR 56.5	Note 6
fhtrp	60.5	60.5 OR 62.0	61.2 OR 62.0	61.2 OR 62.0	Note 6
tfl	0.16	2.0 OR 0.16	300.0 OR 0.16	300.0 OR 0.16	Note 6
tfh	0.16	2.0 OR 0.16	300.0 OR 0.16	300.0 OR 0.16	Note 6
tg	0.02	0.02	0.02	0.02	†
rrpwr	0.1	0.1	2.0	2.0	Note 8
tv	0.02	0.02	0.02	0.02	†
Kpg	0	0	0.1	0.1	Note 3
Kig	0	0	10	10	Note 3
xe	0.25	0.25	0.25	0.25	† Note 8
vpr	0.8	0.8	0.3	0.3	Note 6
iqh1	0	0	1	1	Note 1
iql1	0	0	-1	-1	Note 1
pflag	1	1	1	1	† Note 7
frqflag	0	0	1	1	Note 7
pqflag	P priority	P priority	Q priority	Q priority	Note 7
typeflag	1	1	0 OR 1	0 OR 1	Note 7

Parameterization Notes

The following notes describe considerations and background on the parameter values selected in **Table 2.1**. Refer to each respective interconnection standard for more information.

NOTE †: Default Parameters Not Typically Subject to Change

These parameters do not typically change across different implementations of the DER_A model. Any modification from the recommended default values should be carefully analyzed and justified.

NOTE 1: Voltage Control Parameters

In most existing applications, DERs do not control voltage. In such cases, the voltage control function should be disabled by setting the voltage control gain, *Kqv*, to 0. The lower and upper voltage deadbands, *dbd1* and *dbd2*, should be set large values (e.g., -99 and 99), respectively. However, interconnection standards state that the voltage control "capability" must be provided in the DER. If the capability is being utilized or required by the local utility, this setting should be modified accordingly.

When DERs are controlling voltage, the dynamic model needs to be adapted to account for this. As the model is not able to simultaneously represent both steady-state voltage control (Clause 5.3.3. voltage-reactive power mode in IEEE Std. 1547-2018) and dynamic voltage control (Clause 6.4.2. dynamic voltage support in IEEE Std. 1547-2018), a modeling compromise must be made. Therefore, the dynamic voltage support settings should be implemented since most simulations involve fault-type conditions with large voltage fluctuations. Reasonable default values are *trv* = 0.02, *kqv* = 5,[48] *dbd1* = –0.12, *dbd2* = 0.1, *iqh1* = 1, and *iql1* = –1.[49] In any situation where *Kqv* is non-zero (dynamic voltage control is enabled), care should be taken to ensure that the corresponding deadband is not too small; this would lead to voltages possibly jumping across deadband thresholds each simulation iteration.

NOTE 2: Voltage Reference

The recommended setting for *Vref0* is 0. Setting *Vref0* equal to 0 allows the model to set its own terminal voltage reference based on the initial conditions. This is consistent with the language in IEEE Std. 1547-2018 and in 5.3.3 (voltage-reactive power mode), which require that DERs shall be capable of autonomously adjusting reference voltage (*Vref*) with *Vref* being equal to the (low pass filtered) measured voltage.

NOTE 3: Active Power-Frequency Control

In IEEE Std. 1547-2003 and IEEE Std. 1547a-2014, active power-frequency control is not specified. Therefore, the gains *Ddn* and *Dup* as well as the frequency errors *femax* and *femin* are set to 0. This disables the active power-frequency controls in the model for these two standards. In CA Rule 21 and IEEE Std. 1547-2018, the capability for resources to have active power-frequency controls installed and enabled (as default) are specified. Therefore, per the standard *Dup* and *Ddn* should be set to 20 (representing a 5% droop characteristic).[50] The default deadband for both standards is set to ±0.0006 pu, or ±36 mHz. *Tpord* is used to represent the specified open loop time constant of five seconds per IEEE Std. 1547-2018 and CA Rule 21 and is set to a small value (0.02 sec) when these controls are disabled in previous IEEE Std. 1547 versions.[51] Parameters *Kpg* and *Kpi* are not directly mapped to the interconnection standards; values describe in **Table 2.1**were used in benchmark testing of the DER_A model are based on engineering judgment and were found to provide satisfactory response. Note that if the DERs are assumed to be operating at maximum available power, the *Dup* should be set to 0. This is explained further in **Chapter 3**

NOTE 4: Active Power Capability

The maximum active power output is set to a default of 1 pu. Minimum active power output is assumed to be 0 pu for generating resources but can be negative (i.e., -1 pu) for energy storage resources. These maximum and minimum active power capability values can be modified if more detailed information is known about specific DERs. Inverter-based DERs have an overload capability of around 110–120%, so *Imax* is set to 1.2 pu. Other types of DERs may have a different current limit, and this can be adjusted carefully if additional information is known. However, for most inverter-based installations (e.g., solar PV), a value of 1.2 pu is a reasonable approximation.

[48] Allows for maximum reactive current injection when voltage falls below around 0.7 pu, taking into consideration the voltage deadband.

[49] Again, note that the values in Table 2.1 do not use these settings because the respective interconnection agreements do not require dynamic voltage control to be used. Hence, *kqv* is set to 0.

[50] See Chapter 3 on recommended settings. Since most DER will be operated at maximum available power, and will not have available generating capability to respond in the upward direction for underfrequency events, *Dup* should be set to 0, from a practical standpoint.

[51] Setting *tpord* should be studied on an individual system basis.

NOTE 5: Partial Tripping

Vrfac, the DER ratio that restores output upon voltage recovery, should be set to 0 for legacy[52] DERs (i.e., no DER restore output following a ride-through event), 1.0 for modern DERs (i.e., all DERs restore output following a ride-through event), and some value in between for a mix of a legacy and modern DERs based on the assumed vintage of the deployed DERs. A value of *Vrfrac* = 0 is a conservative assumption and should be used if no detailed DER information is available. Since CA Rule 21 and IEEE Std. 1547-2018 are relatively new standards, it can be expected that *Vrfrac* can be set at or near 0 for now. When using the der_a dynamic model to represent a single plant,[53] the partial tripping parameter should be set to 0 to represent the entire plant tripping.

The interconnection standards include different levels of trip settings: typically a longer duration trip time with magnitude closer to nominal and a shorter duration trip time with lower (or higher) magnitude away from nominal. **Table 2.1** includes values for the shorter duration trip thresholds since these values are likely the most useful and relevant settings for stability studies. Consult the relevant interconnection standards and requirements for more information on longer duration trip settings. Higher magnitude with longer duration trip settings may need to be studied in simulations involving delayed voltage recovery.

V_{DROP} should be set to a reasonable equivalent voltage drop across the distribution system in the range of 2–8% (reasonable default of 5%) if no detailed information is available. Voltage trip thresholds include a 0.01 pu offset from the interconnection standard values to correctly account for the beginning and completion of partial tripping.

The values specified in the **Table 2.1** represent R-DERs as part of the CLM. If individual or multiple similar U-DERs are represented, trip settings should be equal and set to the corresponding value in the interconnection standard. If aggregate R-DERs are to be represented by a generator record, use the methodology described in **Chapter 1** to determine correct trip settings.

In cases where momentary cessation of inverter-based resources needs to be represented, use *vl1* and *vl0* with extended trip times. Note that this may hinder the ability to capture any tripping effects due to existing model limitations. Engineering judgment and sensitivity studies should be used when applying these types of settings.

NOTE 6: Frequency Trip Levels

High (*fhtrp*) and low (*fltrp*) frequency tripping have different thresholds in a few of the interconnection standards as described in **Table 2.1**. Each has a specified time threshold. The frequency thresholds closer to nominal frequency have a longer duration while the thresholds further from nominal have a shorter duration.

In simulations where frequency does not fall below under-frequency load shedding (UFLS) levels, the setting values for CA Rule 21 and IEEE Std. 1547-2018 are not significant.[54] However, the settings representing IEEE Std. 1547-2003 and IEEE Std. 1547a-2014 are relevant, particularly for the thresholds closer to nominal frequency. IEEE Std. 1547-2003 has only one magnitude and time value. IEEE Std. 1547a-2014 has two thresholds, but most commonly only the 59.5 Hz and 60.5 Hz thresholds with two second timers are applicable.

Disabling tripping on frequency during low voltage is implemented in almost all relay models as the relay needs a sufficient voltage waveform to measure frequency. Under fault conditions, due to the large change in voltage, the frequency calculation can result in a spurious spike, so frequency tripping should be disabled. IEEE Standard C37.117[55] recommends disabling the frequency trip when the voltage is below 50–70% of nominal. For DERs, this voltage levels

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[52] Use of the term "legacy" generally refers to DERs compliant with IEEE Std. 1547-2003 and IEEE Std. 1547a-2014 that typically involve limited or no controls and ride-through capability.

[53] This is more common for a single, large distribution-connected generation plant. A non-zero parameter here would indicate that a portion of the plant trips.

[54] Unless specific studies are being performed to configure UFLS systems.

[55] IEEE C37.117-2007, IEEE Guide for the Application of Protective Relays Used for Abnormal Frequency Load Shedding and Restoration.

was increased to 80% to account for further inaccuracies in frequency calculation that may arise in positive sequence simulations.[56] The first sentence of IEEE Std. 1547-2018, Clause 6.5.1, states that the DER can respond when frequency meets a certain criteria and "the fundamental-frequency component of voltage on any phase is greater than 30% of nominal." However, if the frequency is outside acceptable range, but voltage is less than the 30% threshold, then the DER should not trip. This represents a low voltage inhibit function in the frequency tripping, and it is represented by parameter *Vpr*.[57] Regardless, study engineers should monitor for false trips by the DER_A model that may not be realistic; rather, they are an artifact of positive sequence stability simulation calculation of frequency. Close review of any frequency-related tripping is strongly recommended.

NOTE 7: Control Flags

The parameter *pflag* sets power factor control. If set to 1, then the power factor angle reference is used based on initialization of the model. Otherwise, if set to 0, then the reactive power reference (*Qref*) will be used.

The parameter *frqflg* sets the active power-frequency control capability. If set to 0, then active power reference (*Pref*) is used. Otherwise, if set to 1, then the active power-frequency control loop is enabled. If *frqflg* is set to 1, the resource will response to over- and under-frequency disturbances. However, if the user sets *Dup* to 0, the resource will not respond to underfrequency. This configuration emulates the unit(s) operating at maximum available power output.

The parameter *pqflag* specifies whether to use active or reactive current priority, which is effective when the current limit logic is in effect. This is particularly used during response to large disturbances (i.e., faults).

The parameter *typeflag* specifies whether the resource is a generating resource (set to 1) or an energy storage device (set to 0). The setting as an energy storage device allows for absorption of active power and emulates distributed energy storage. This does not, however, emulate charging and discharging of the resource.

NOTE 8: Voltage Source Interface Representation

The *rrpwr* specifies the active current ramp rate. IEEE Stds. 1547-2003 and 1547a-2014 do not specify an active current ramp rate; however, IEEE Std. 1547-2018 and CA Rule 21 use an 80% recovery within 0.4 seconds that can be approximated with a gain of 2 pu/sec, which equates to full recovery within 0.5 seconds. The voltage source impedance also uses a default values for *Xe* of 0.25 based on robustness testing of the DER_A model during its development.

Future Model Implementation Improvement

Commercial simulation software vendors should consider adding a new global flag for inverter-based resources (particularly renewable energy resources) that sets the maximum available power to the current power output (*Pgen*) upon initialization of the inverter-based models. This can then be changed by the user on a case-by-case basis during the simulation if necessary (e.g., to represent curtailing). For example, simulations with renewable generation dispatched at less than maximum capacity (*Pmax*) may represent less solar irradiance or lower wind speed. However, this is the maximum available power output for the assumed conditions. As more resources are being installed with the capability to provide active power-frequency control, the ability to distinguish whether units are operating at maximum available power output will be increasingly important. This parameter is similar to the baseload flag for synchronous generating resources.

[56] https://www.wecc.biz/Reliability/WECC_White_Paper_Frequency_062618_Clean_Final.pdf.

[57] *Vpr* may also be referred to as *Vfth*.

Chapter 3: Practical DER_A Model Implementation

Table 2.1 in the previous chapter provides parameter values that relate to specific interconnection standards and requirements; however, many systems are faced with aggregate DERs that encompass many vintages of interconnection requirements and settings. **Table 3.1** provides a set of default parameter values for different systems based on the penetration of different IEEE Std. 1547 vintages, ranging from a system dominated by IEEE Std. 1547-2003 interconnections to a system of modern IEEE Std. 1547-2018 interconnections.[58] Also shown are default values for penetrations at 70% for 2003 vintage and 30% for 2018 vintage as well as 30% for 2003 vintage and 70% for 2018 vintage. These default values are based on engineering judgment and intended to be used as a starting point for more detailed studies and sensitivities.[59] Note that individual utilities or jurisdictions may have additional or more stringent requirements that should be considered when developing a set of DER modeling parameters in addition to the IEEE Std. 1547 default settings. TPs and PCs should consider any modifications to the default IEEE Std. 1547 parameters as well as local requirements and should adapt the models accordingly.

Parameter values that are subject to changes across interconnection vintages are highlighted in red in **Table 3.1** and described in this chapter. Note that some of the parameter values subject to change are a linear interpolation based on the penetration of specific vintages of DERs. Sensitivity studies should be performed by the TP and PC to understand the impacts of these parameter values to system study results.

Table 3.1: Default Parameter Selection for Mixed Vintages of DERs

Parameter	Early Vintage DER System IEEE Std. 1547-2003	70% of -2003 30% of -2018	30% of -2003 70% of -2018	Newer Vintage DER System IEEE Std. 1547-2018 (Category II)
trv	0.02	0.02	0.02	0.02
dbd1	-99	-99	-99	-99
dbd2	99	99	99	99
kqv	0	0	0	0
vref0	0	0	0	0
tp	0.02	0.02	0.02	0.02
tiq	0.02	0.02	0.02	0.02
ddn	0	6	14	20
dup	0	0	0	0
fdbd1	-99	-0.0006	-0.0006	-0.0006
fdbd2	99	0.0006	0.0006	0.0006
femax	0	0	99	99
femin	0	0	-99	-99
pmax	1	1	1	1
pmin	0	0	0	0
dpmax	99	99	99	99

[58] Note that application and enforcement of IEEE Std. 1547-2018 for newly interconnecting inverters is likely to take time to implement in many jurisdictions, often requiring regulatory updates to enable enhanced capabilities. Some degree of verification and alignment with these implementation time lines should be performed by each TP and PC when representing DERs in BPS reliability studies.

[59] Transmission–distribution co-simulation techniques may be used to help further parameterize DER_A models based on specific distribution feeder configurations and DER penetration levels.

Table 3.1: Default Parameter Selection for Mixed Vintages of DERs				
Parameter	**Early Vintage DER System IEEE Std. 1547-2003**	**70% of -2003 30% of -2018**	**30% of -2003 70% of -2018**	**Newer Vintage DER System IEEE Std. 1547-2018 (Category II)**
dpmin	-99	-99	-99	-99
tpord[60]	0.02	0.02	5	5
Imax	1.2	1.2	1.2	1.2
vl0	0.44	0.44	0.44	0.44
vl1	0.49	0.49	0.49	0.49
vh0	1.2	1.2	1.2	1.2
vh1	1.15	1.15	1.15	1.15
tvl0	0.16	0.16	0.16	0.16
tvl1	0.16	0.16	0.16	0.16
tvh0	0.16	0.16	0.16	0.16
tvh1	0.16	0.16	0.16	0.16
Vrfrac	0	0.3	0.7	1.0
fltrp	59.3	58.5	57.5	56.5
fhtrp	60.5	61	61.5	62.0
tfl	0.16	0.16	0.16	0.16
tfh	0.16	0.16	0.16	0.16
tg	0.02	0.02	0.02	0.02
rrpwr	0.1	0.6	1.4	2.0
tv	0.02	0.02	0.02	0.02
Kpg	0	0.1	0.1	0.1
Kig	0	10.0	10.0	10.0
xe	0.25	0.25	0.25	0.25
vfth	0.8	0.3	0.3	0.3
iqh1	0	1.0	1.0	1.0
iql1	0	-1.0	-1.0	-1.0
pfflag	1	1	1	1
frqflag	0	1	1	1
pqflag	P priority	P priority	Q priority	Q priority
typeflag	1	1	1	1

The following considerations are made in the development of these default parameter values and intended to provide transparency and understanding of how these parameters were devised; however, they are intended as default values that may be subject to change if more detailed information is known:

[60] The active power-frequency response from DERs if utilized in studies, should be tuned to achieve and ensure a closed-loop stable control. This parameter may need to be adapted based on this tuning.

- **Upward Frequency Responsiveness for Underfrequency Conditions (*Dup, Pmax*):** In this set of default parameters, it is assumed that the vast majority (if not all) DERs are operated at maximum available[61] power and thus cannot provide frequency response for underfrequency conditions.[62] To model the inability to provide response in the upward direction, the *Dup* parameter value is set to 0. This disables upward movement regardless of where the DER resource(s) is dispatched relative to *Pmax* in the dynamics data. This allows for easy manipulation of DER output levels without needing to modify additional parameter values for each sensitivity case. Another option is to set the *Dup* parameter value according to the expected performance and then modifying *Pmax* value in the dynamics data to match the predisturbance output for each operating conditions studied. However, this requires an additional step and may lead to unexpected frequency responsiveness from DERs if not adequately handled when changing DER dispatch levels.
- **Downward Frequency Responsiveness for Overfrequency Conditions (*Ddn*):** *Ddn* is modified across the different penetration levels to represent an effective droop characteristic, or a response from a fractional DER value based on the penetration of modern inverters. The 5% droop (*Ddn* = 20) is multiplied by a linear factor based on this penetration (e.g., 70% of 20 equals 14).
- **Frequency Deadband and Error Limits (*fdb1, fdb2*):** When frequency response is enabled in the model, the deadband settings of *fdb1* and *fdb2* as well as the frequency error settings of *femax* and *femin* need to be modified to enable accurate representation of these controls. A default value is used in all cases where control is enabled.
- **Voltage-Related Trip Settings and Times:** Refer to the **Chapter 1** for the derivation of the partial trip values. Note that trip thresholds and times may vary if applying CA Rule 21. Values assume a voltage drop, V_{DROP}, of 5%.
- **Fraction of Resources Recovering (*Vrfrac*):** The parameter *Vrfrac* represents the fraction of resources that recover upon voltage recovery following abnormal voltage conditions. It is expected that resources meeting IEEE Std. 1547-2018 will recover from abnormal voltages and ride through disturbances while IEEE Std. 1547-2003 resources will likely trip and remain disconnected for the duration of stability simulations. A linear multiplier is used based on the fraction of resources connected to the system. For example, *Vrfrac* equals 0.7 for a 70% IEEE Std. 1547-2018 system.
- **Frequency-Related Trip Settings (*fltrp, fhtrp*):** Frequency-related trip settings of *fltrp* and *fhtrp* are assumed to slightly vary based on the aggregate vintage of connected DERs. For the shorter-term tripping, IEEE Std. 1547-2003 has trip settings at 59.3 Hz and 60.5 Hz while IEEE Std. 1547-2018 has trip settings at 57.5 Hz and 62 Hz. For mixed penetrations, a linear multiplier is used to vary the level of DER tripping. This is an approximate; yet, these trip settings are below the first stage of UFLS, and they are therefore not likely to make a substantive impact in most stability simulations.[63] More detailed studies should consider identifying more accurate information for these settings.
- **Active Current Recovery Ramp Rate (*rrpwr*):** The parameter *rrpwr* is modified across different penetration levels to represent the fraction of resources that recover from abnormal voltage conditions. A 2.0 pu/sec (recovery in 0.5 seconds) is used for IEEE Std. 1547-2018 resources, and a linear multiplier is used for the mixed penetration conditions. For example, 70% of 2.0 pu/sec equals 1.4 pu/sec.
- **Frequency Response PI Controls (*Kpg, Kig*):** When frequency response controls are enabled in the model, default parameter values of *Kpg* = 0.1 and Kig = 10 are used.

[61] If studies are assuming that DERs are curtailed for any reason, IEEE Std. 1547-2018 vintage DERs will have the capability to respond to underfrequency events.
[62] This statement relates to DERs that are generating resources; this may not be the case for energy storage. Energy storage, not injecting maximum power, will be able to respond to underfrequency events following a droop characteristic.
[63] Stability studies for establishing UFLS set points, where simulated frequency can fall well below UFLS, should ensure reasonable frequency-related trip settings are used for DER.

- **Type Flag (*typeflag*):** The *typeflag* is set to 1 In these default data sets, representing a generating resource. This flag and relevant parameter values can also be modified to represent an energy storage resource.

Chapter 4: DER_A Model Benchmarking and Testing

To ensure that a model is usable for industry-wide studies, some form of model benchmarking and testing is typically performed by industry partners. DER_A model development and testing was led by the WECC Renewable Energy Modeling Task Force and the NERC LMTF with EPRI providing the model benchmarking support.

EPRI performed extensive DER_A model benchmarking while working with the major commercial software vendors[64] following their implementation of the standalone DER_A model. A test system with a play-in voltage source model at the transmission bus with constant impedance load adjacent to the DERs was used for the testing. A suite of 19 tests was used to apply small and large disturbances of voltage and frequency, and then the model's active and reactive power response and set points were observed. The response of the DER_A model was compared for each test across all platforms to determine whether the models match the same general trend in response (i.e., they are considered suitably benchmarked). Refer to an EPRI white paper on this topic (reference 11 in **Appendix A**).[65] **Figure 4.1** shows an example benchmarking simulation, and it demonstrates how the DER_A model in each of the software platforms matches the same general performance characteristic.

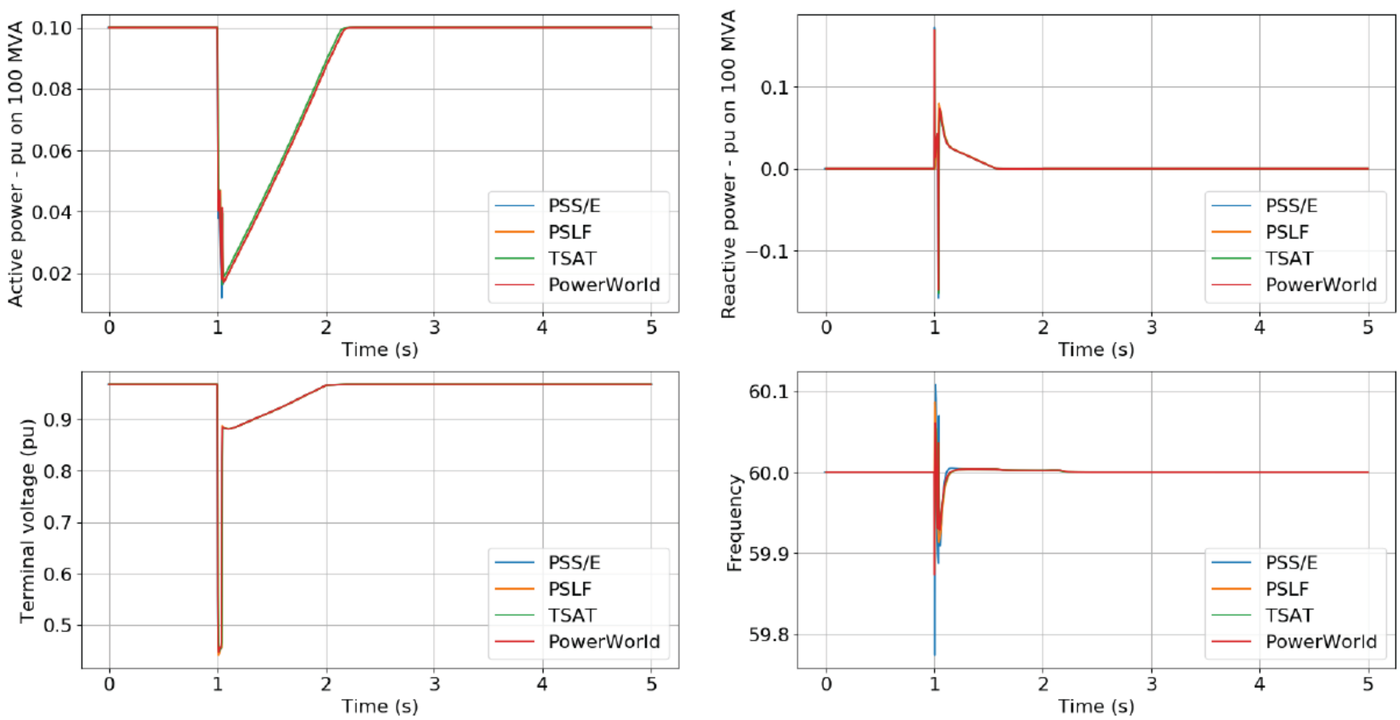

Figure 4.1: Voltage Sag Benchmarking Test Result [Source: EPRI]

To ensure that the model is numerically robust and usable in system studies on a large-scale case, California Independent System Operator (CAISO) has been testing the DER_A model on WECC-wide base cases for their reliability studies. **Figure 4.2** shows one example of the types of sensitivity studies performed by CAISO. CAISO has been testing the model with different parameter values, including CA Rule 21 and the new IEEE Std. 1547-2018 default settings. The model has performed well and is numerically robust in these studies using GE PSLF™.[66]

[64] Including GE-PSLF™, Siemens PTI PSS®E, PowerWorld Simulator, and Powertech Labs TSAT.
[65] The New Aggregated Distributed Energy Resources (der_a) Model for Transmission Planning Studies. 2019 Update. White Paper. 3002015320. Electric Power Research Institute (EPRI). Palo Alto, CA (https://www.epri.com/#/pages/product/000000003002015320/?lang=en-US).
[66] CAISO, "CMPLDWG Composite Model with Distributed Generation DER_A CAISO Assessment," NERC LMTF Meeting, May 2018: https://www.nerc.com/comm/PC/LoadModelingTaskForceDL/CMPLDWG_DER_A_CAISO_NERC.pdf.

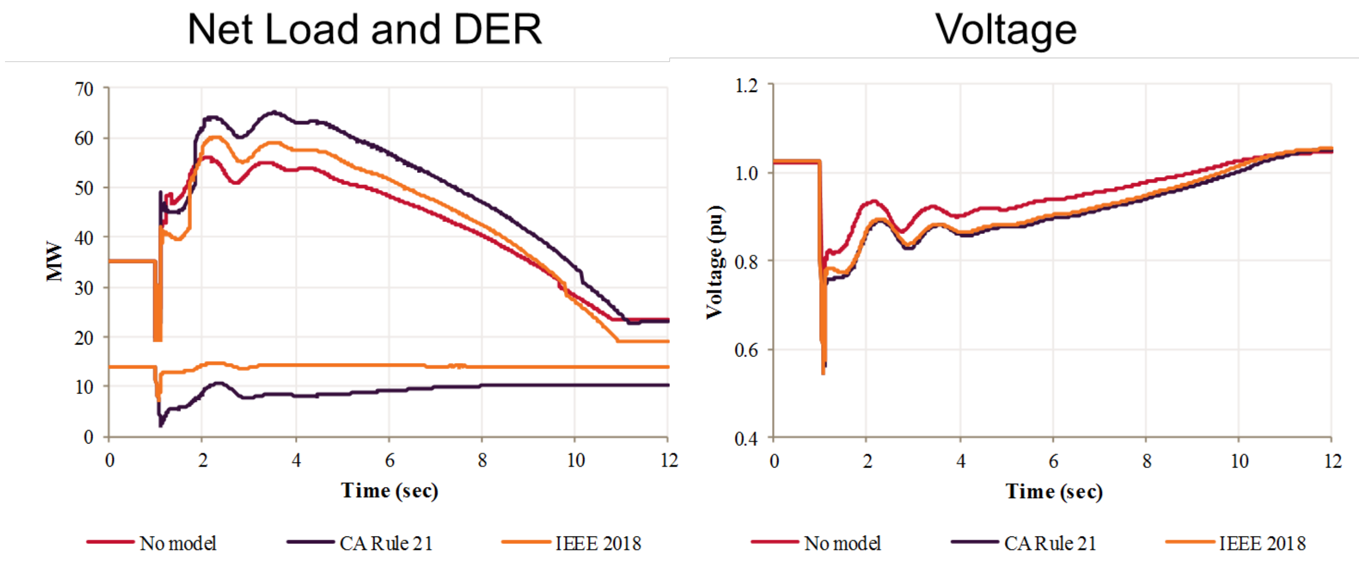

Figure 4.2: CAISO DER Study Example including DER_A Model [Source: CAISO]

EPRI has also performed system studies on the full Eastern Interconnection base case in coordination with Duke Energy. These studies implemented the DER_A model on 138 U-DER installations with a capacity of 1,300 MW. **Figure 4.3** shows the DER response from an example simulation using these models. It shows that some of the DER_A models near the fault location respond to the disturbance with active and reactive power response, and those further away from the disturbance do not provide a significant response. Again, the implemented DER_A models are numerically robust.[67] EPRI further did analysis on the DER_A model when used as part of the CLM to test modeled R-DER in the SPIDERWG recommended modeling framework.[68] Again, the models were numerically robust.

[67] EPRI, "Preliminary results of DER_A model parameterization", NERC LMTF Meeting, July 2018: https://www.nerc.com/comm/PC/LoadModelingTaskForceDL/Parameterization_of_DER_A_Model_v1_DR.pdf.
[68] EPRI, "Results on CMPLDWg – DER_A Benchmark", NERC LMTF Meeting, July 2019: https://www.nerc.com/comm/PC/LoadModelingTaskForceDL/CMPLDWg-DER_A-benchmark_v1_DR.pdf

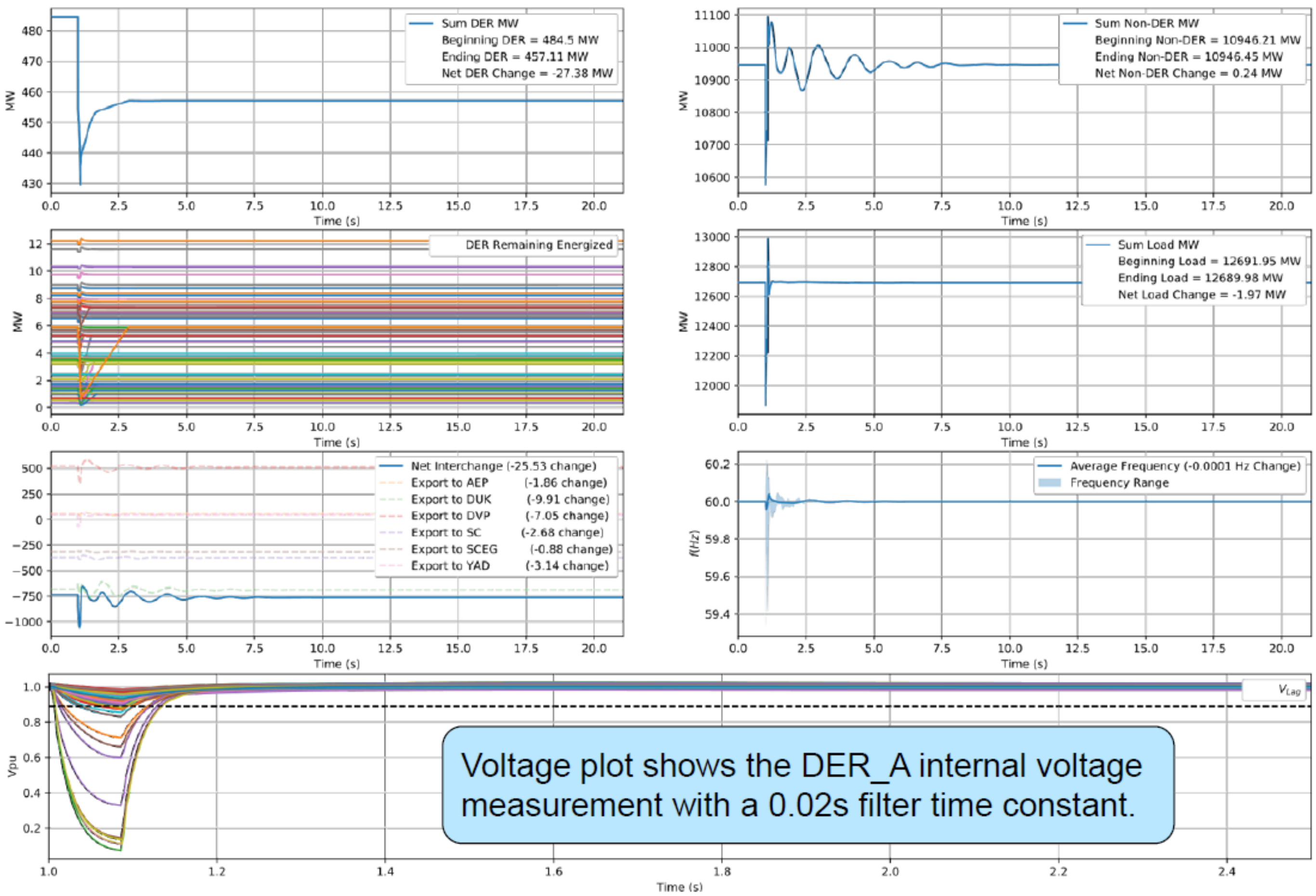

Figure 4.3: DER Study Example including DER_A Model [Source: EPRI]

Appendix A: Contributors

NERC gratefully acknowledges the contributions and assistance of the following industry experts in the preparation of this guideline. NERC would like to acknowledge EPRI for the technical leadership in developing this guideline.

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Song Wang	PacifiCorp
Shannon Mickens	SPP
Scott Jordan	SPP
Brad Marszalkowski	ISO-NE
Nick Hatton	WECC

Appendix B: References

DER_A Model Specification Document

[1] P. Pourbeik, "Proposal for DER_A Model," September 11, 2018. [Online]: https://www.wecc.org/Reliability/DER_A_Final_061919.pdf.

Relevant Interconnection Standards

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Appendix C: DER_A Block Diagram

This appendix serves to house the entirety of the block diagram of the DER_A dynamic model.

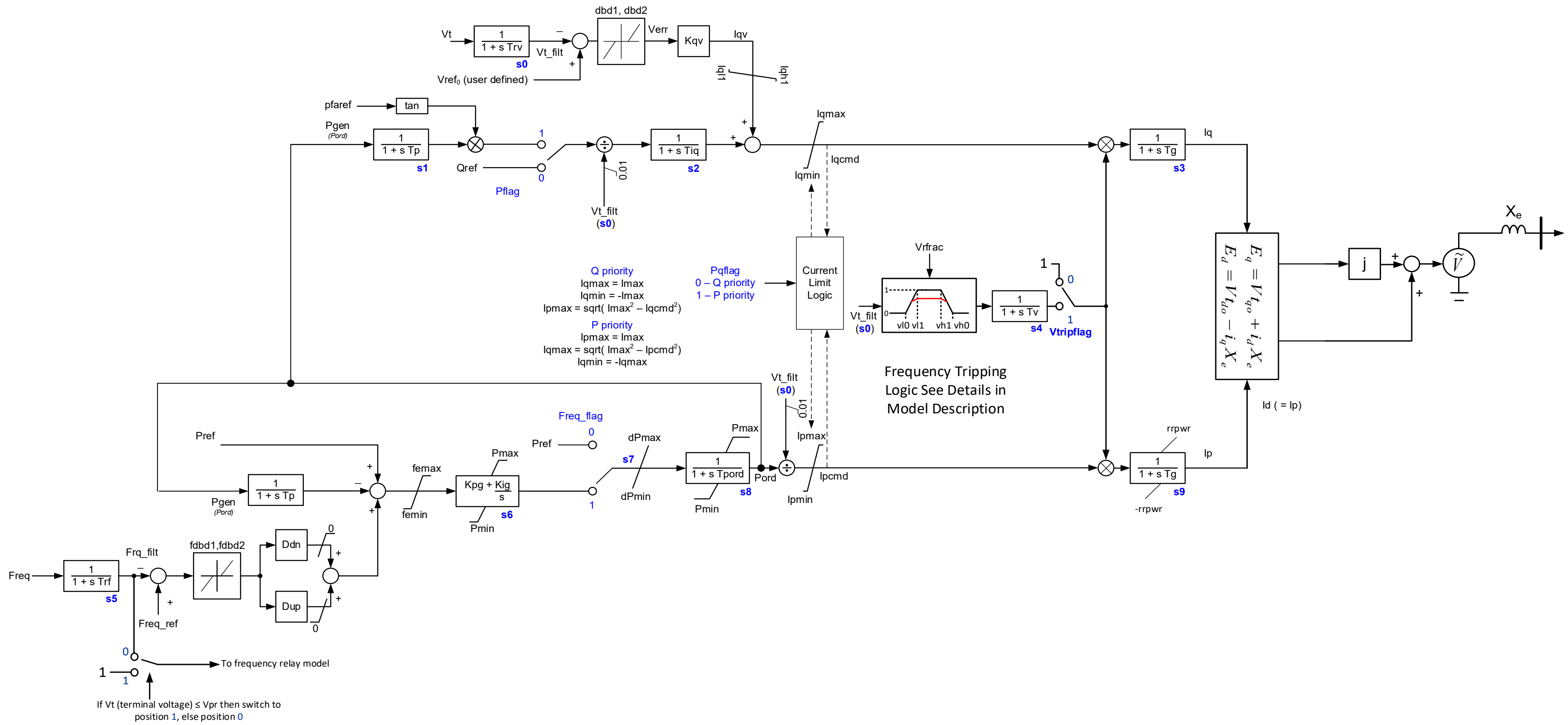

Figure C.1: DER_A Model Block Diagram

Guideline Information and Revision History

Guideline Information	
Category/Topic: Parameterization of the DER_A Model for Aggregate DER	**Reliability Guideline/Security Guideline/Hybrid:** Reliability Guideline
Identification Number: RG-MOD-0223-1	**Subgroup:** SPIDERWG

Revision History		
Version	**Comments**	**Approval Date**
1.0	This guideline is a combination of the following Guideline that have been retired: • Reliability Guideline: Parameterization of the DER_A Model • Reliability Guideline: Modeling DER in Dynamic Load Models • Reliability Guideline: Distributed Energy Resource Modeling	2/15/2023

Metrics

Pursuant to the Commission's Order on January 19, 2021, *North American Electric Reliability Corporation*, 174 FERC ¶ 61,030 (2021), reliability guidelines shall now include metrics to support evaluation during triennial review consistent with the RSTC Charter.

Baseline Metrics

All NERC reliability guidelines include the following baseline metrics:

- BPS performance prior to and after a reliability guideline as reflected in NERC's State of Reliability Report and Long-Term Reliability Assessments (e.g., Long-Term Reliability Assessment and seasonal assessments)
- Use and effectiveness of a reliability guideline as reported by industry via survey
- Industry assessment of the extent to which a reliability guideline is addressing risk as reported via survey

Specific Metrics

The RSTC or any of its subcommittees can modify and propose metrics specific to the guideline in order to measure and evaluate its effectiveness, listed as follows:

- Ascertain use of DER_A model in planning studies
- Ascertain software used in the planning studies with the DER_A model implemented
- Ascertain applicability of DER_A model when using adequately parameterized models to showcase aggregate behavior of DER opposed to use of other models
- Benchmarking of DER_A model versus a validated and more detailed representation (e.g., PSCAD representation) to align at the T–D Interface, when performed[69]
- Parameterization of DER_A model using defaults or engineering judgement provided in this reliability guideline versus parameters developed from field measurements or individual utilities and jurisdiction requirements

Effectiveness Survey

On January 19, 2021, FERC accepted the NERC proposed approach for evaluating Reliability Guidelines. This evaluation process takes place under the leadership of the RSTC and includes:

- industry survey on effectiveness of Reliability Guidelines;
- triennial review with a recommendation to NERC on the effectiveness of a Reliability Guideline and/or whether risks warrant additional measures; and
- NERC's determination whether additional action might be appropriate to address potential risks to reliability in light of the RSTC's recommendation and all other data within NERC's possession pertaining to the relevant issue.

NERC is asking entities who are users of Reliability and Security Guidelines to respond to the short survey provided in the link below.

Guideline Effectiveness Survey [Effectiveness Survey](#)

[69] This requires validation of transmission and distribution elements outside of the DERs modeled. SPIDERWG members have found that in current benchmarking efforts the validated representation is an ongoing effort to improve a variety of models and not just the dynamic response of the inverter-based DER represented by the DER_A dynamic model.

Errata