NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Guideline

Power Plant Model Verification for Inverter-Based Resources

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RELIABILITY | ACCOUNTABILITY




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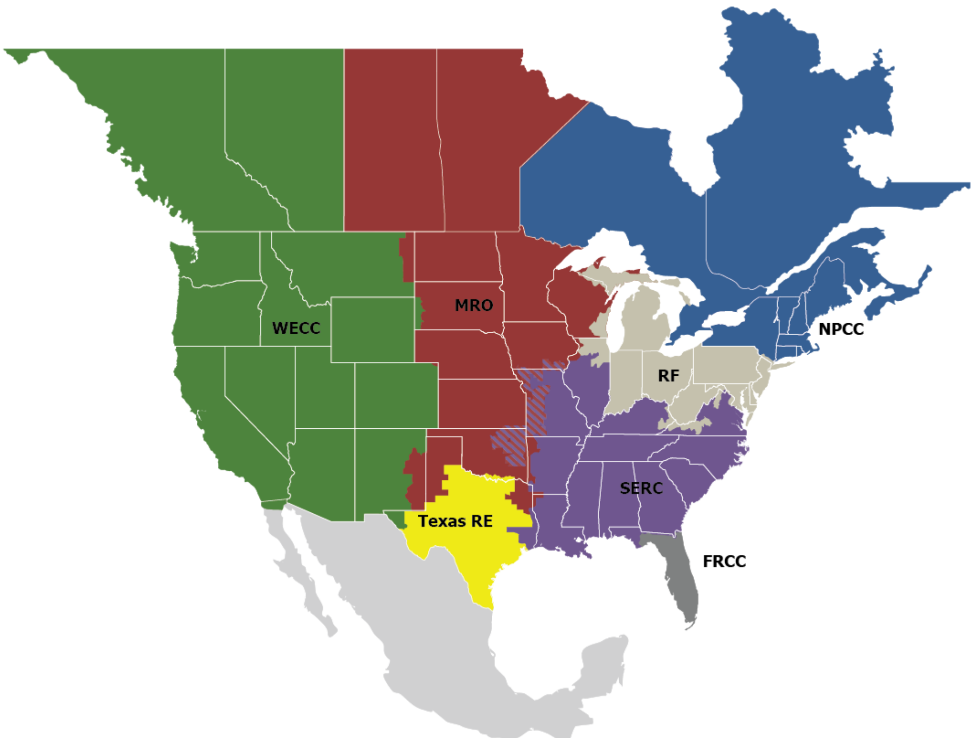
Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven Regional Entities (REs), is a highly reliable 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.

The North American BPS is divided into seven RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



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

Preamble

It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). The Technical Committees of NERC—Operating Committee, Planning Committee, and the Critical Infrastructure Protection Committee—per their charters,[1] are authorized by the NERC Board of Trustees (Board) to develop Reliability and Security Guidelines. These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise, and judgment of the industry. The objective of this reliability guideline is to distribute key practices and information on specific issues critical to maintaining the highest levels of BES reliability. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation of guideline practices are strictly voluntary, reviewing, revising, or developing a program using these practices is highly encouraged to promote and achieve the highest levels of reliability for the BES.

NERC, as the FERC certified ERO,[2] is responsible for the reliability of the BES and has a suite of tools to accomplish this responsibility, including but not limited to the following: lessons learned, reliability and security guidelines, assessments and reports, the Event Analysis program, the Compliance Monitoring and Enforcement Program, and mandatory reliability standards. Each entity, as registered in the NERC compliance registry, is responsible and accountable for maintaining reliability and compliance with the mandatory standards to maintain the reliability of their portions of the BES. Entities should review this guideline in detail in conjunction with the periodic review of their internal processes and procedures and make any needed changes to their procedures based on their system design, configuration, and business practices.

[1] http://www.nerc.com/comm/OC/Related%20Files%20DL/OC%20Charter%2020131011%20(Clean).pdf
http://www.nerc.com/comm/CIPC/Related%20Files%20DL/CIPC%20Charter%20(2)%20with%20BOT%20approval%20footer.pdf
http://www.nerc.com/comm/PC/Related%20Files%202013/PC%20Charter%20-%20Board%20Approved%20November%202013.pdf
[2] http://www.ferc.gov/whats-new/comm-meet/072006/E-5.pdf

Executive Summary

As the penetration of inverter-based resources continues to increase across North America, it is becoming increasingly important that the dynamic models used to represent these generating resources accurately match the performance of the actual installed equipment in the field. In particular, newer technology wind and solar PV resources use power electronic controls, so they are referred to as inverter-based resources. The NERC MOD Reliability Standards are applicable to both synchronous generators and inverter-based resources that meet the size criteria. Despite the significant industry experience and expertise in testing and verifying the dynamic models of synchronous generating resources, verification of inverter-based resources is a relatively new topic since the technology has not been around nearly as long. This guideline provides recommended practices related to verification testing, disturbance-based model verification using actual grid disturbances, and modeling practices that should be considered for inverter-based resources. The guideline is intended to support industry in their efforts related to testing and verification for NERC Reliability Standards MOD-025-2, MOD-026-1, and MOD-027-1.

The aforementioned NERC Reliability Standards primarily apply to the equipment owners, and it is their responsibility to perform verification to prove that the modeled response reasonably represents the actual generator response when the equipment is in-service and operational. This often requires some form of testing or other methods to demonstrate the responses match. The guideline recommends close coordination between the equipment owner (e.g., Generator Owners (GOs)), the testing engineer (if different than the GO), the Transmission Planner (TP), and Planning Coordinator (PC) (the model user). In addition, other entities are often involved in the testing, development, or use of these models including the Generator Operator (GOP), Transmission Operator (TOP), and Reliability Coordinator (RC). Coordination with the equipment manufacturer(s) is often an essential element, particularly for inverter-based resources, to ensure the dynamic models accurately represent the installed equipment.

The guideline covers many of the potential tests that may need to be performed to develop or ensure a verified model; however, not all of these tests are necessary under all verification scenarios. A well-developed baseline model created during commissioning may still be accurate many years later, and verification may be completed relatively easily with certain verification tests. On the other hand, when detailed equipment data is not available or there is little confidence in the models provided to-date, more extensive testing may need to be performed to ensure a reasonable match. Most importantly, testing and verification should ensure the safety of plant personnel and protection of the equipment under test at all times. The intent of the guideline is to serve as a foundational repository of useful information related to testing; however, the expertise of plant personnel and the testing engineer should take precedence over any other guidance.

This guideline aligns with the NERC's mission of improved reliability through sharing industry practices for planning and operating the BPS. It primarily applies to GOs, GOPs, PCs, TPs, TOPs, RCs, testing engineers, and other applicable subject matter experts related to NERC MOD standards pertaining to model verification and capability testing.

Introduction

The development and verification of accurate steady-state and dynamic power system models is a complex and crucial component of BPS modeling and system studies.[3] These studies are the foundation for decision making in both the planning and operations horizon, and the results of these studies have a direct impact on BPS reliability. The equipment owners, including GOs, supply verified models to the TPs and PCs to create base cases of the interconnected system. Models are not exact representations of actual equipment installed in the field, but they should reasonably match the actual dynamic response of these resources. Model verification activities serve to verify that the modeled response of the plant reasonably matches the actual response for different types of grid events. Some level of adjustment and compromise may be needed to achieve a suitable match between the modeled and actual response. These activities also allow for minor tuning of model parameters, which is assisted by engineering judgment. The quality of system studies using these models is directly correlated with the quality of the models used to perform the study. Confidence in the individual component models, as well as the information used to develop these models, helps ensure confidence in the conclusions drawn from system studies.

This Reliability Guideline ("guideline") provides GOs, TPs, and PCs, with technical guidance related to power plant testing, model verification, and modeling practices for inverter-based (nonsynchronous) generating resources.[4] It also briefly touches on renewable resources that are not inverter-based for completeness (e.g., Type 1 and Type 2 wind power plants (WPPs)). Examples of testing and verification activities that support efforts to meet relevant NERC Reliability Standards are described throughout. In particular, the following standards are a primary focus:

- **MOD-025-2:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability
- **MOD-026-1:** Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Function
- **MOD-027-1:** Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

The majority of topics covered in this guideline relate to testing and model verification for inverter-based resources. However, other standards that are interrelated to the testing and verification activities are discussed in varying depths throughout this guideline. These standards include the following:

- **MOD-032-1:** Data for Power System Modeling and Analysis
- **MOD-033-1:** Steady-State and Dynamic System Model Validation
- **PRC-019-2:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

As such, this guideline covers an array of testing considerations, recommended testing practices, and explanations as to how these tests help derive model parameters in support of MOD-025-2, MOD-026-1, and MOD-027-1. The guideline serves as a compendium of potential tests that may or may not need to be performed, depending on specific situations for each generating facility. In general, a broader set of tests may be performed during commissioning in the development of a baseline[5] model while a reduced set of tests may suffice for model re-verification purposes.

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[3] In general, the dynamic models described in this guideline are used to develop the interconnection-wide models used to plan and operate the BPS. Refer to the NERC List of Acceptable Models. Available: https://www.nerc.com/comm/PC/Pages/System-Analysis-and-Modeling-Subcommittee-(SAMS)-2013.aspx.

[4] In particular, renewable energy resources, such as solar photovoltaic (PV), and Type 3 and Type 4 wind power plants. Battery energy storage system (BESS) resources are also mentioned throughout the guideline.

[5] The development of a baseline model, particularly during commissioning, is critical in the overall model creation and verification process. The ability to perform a broader suite of tests and develop an accurate and representative model during this time period can often simplify the

The guideline serves as a focal point to raise industry awareness, understanding, and expertise in the area of power plant model verification and testing (predominantly the responsibility of GOs) and how these efforts support the development of accurate and representative interconnection-wide models (predominantly the responsibility of the TP, PC, and RC) used to plan and operate the BPS.

Background

Since the influx of wind generation interconnecting to the BPS began worldwide in the early 2000s, there has been a need for publicly available, standardized, flexible, and openly documented (commonly referred to as "generic") models to represent WPPs that can be incorporated in commonly used power system simulation software platforms. Several organizations attempted these efforts in the early 2000s (e.g., CIGRE Working Group C4.601 [1]),[6] and the early efforts did much to clearly document the dynamic performance of these technologies. However, these efforts were unable to bring sufficiently accurate generic models to production. There were still concerns regarding the proprietary nature of the data, and it was difficult to acquire information from equipment vendors.

In 2004, the Western Electricity Coordinating Council (WECC) commissioned the Wind Generation Modeling Task Force under the Modeling and Validation Work Group (MVWG), which took the lead in producing the first generation of generic WPP models [13]. Shortly after the release of these first generation models in 2010, several concerns were raised regarding the accuracy and usability of these models. Namely, that the Type 3 and 4 wind turbine generator (WTG) models catered primarily to one manufacturer[7] and that there were some issues with the performance of the pitch controller model associated with the Type 1 and Type 2 WTGs. At the same time, NERC issued a special report highlighting the need for generic models for variable energy resource technologies (e.g., wind and solar photovoltaic (PV)) [2]. The WECC task force was renamed the Renewable Energy Modeling Task Force (REMTF), and the International Electrotechnical Commission (IEC) started a working group (IEC TC88 WG27) charged with creating an international standard specifying generic stability models for WTGs.

The WECC REMTF then began creating the second generation generic models, including both wind and solar photovoltaic (PV) and possible future technologies. Since many of the United States members of the IEC group were also members of the WECC REMTF, the two groups coordinated activities and created a core structure of the models for WPPs that are essentially the same. A recent publication highlights the similarities and differences between the WECC and IEC models due to European grid codes [3]. These differences were presented to WECC REMTF [4, 5], but the WECC membership decided not to adopt them due to the added complexity without yielding added fidelity for the specific dynamic performance aspects of the models that were of interest to WECC at the time. However, since both groups adopted a modular approach for developing the models, changes can be made to these models in the future to address these differences, if necessary [6–12].

While the WECC REMTF developed these models and gained experience with using these models, other Interconnections across North America continued to use the first generation generic models. This created a discontinuity between state-of-the-art generic modeling of renewable energy systems and current modeling practices used by GOs and TPs. However, since the MOD-032 designees ("Designees"),[8] NERC, and PCs/TPs are developing a list of acceptable dynamic models,[9] GOs of renewable resources are beginning to explore model verification activities and ensure the models reasonably represent the dynamic behavior of the actual equipment.

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verification process in the future and minimize potential model discrepancies in the longer term. These initial tests are often termed "baseline testing" to develop a "baseline model".

[6] Refer to Appendix A for list of references.

[7] At the time, only one equipment manufacturer was forthcoming with data to develop these generic models.

[8] Refer to MOD-032-1 for more information regarding the entities designated by the electric reliability organization (ERO) to create the interconnection-wide planning cases.

[9] See the NERC List of Acceptable Models. Available: https://www.nerc.com/comm/PC/System%20Analysis%20and%20Modeling%20Subcommittee%20SAMS%20201/Acceptable_Models_List_2017-08-19.xlsx.

Detailed accounts of the technologies for wind generation can be found in [1], much of which is equally applicable today. Likewise, documentation can also be found on photovoltaic (PV) technologies. A brief overview is provided to identify some of the challenges and issues around modeling and model verification.

Inverter-Based Technologies

The majority of recently installed BPS-connected renewable energy systems are inverter-based (inverter-interfaced). The most common forms of inverter-based resources are Type 3 and 4 wind turbine generators (WTGs), solar photovoltaic (PV) resources, and battery energy storage systems.[10] In almost all cases, the interface to the grid is a voltage source converter (VSC) using insulated-gate bipolar transistors (IGBTs) or similar power electronic devices. The converter is self-commutated, meaning the switching is completely controlled, allowing the device to generate or absorb reactive power independent of the real power transfer as long as the device is operating within its current ratings. For this reason, inverter-based technologies are fully capable, if designed and operated accordingly, of providing voltage regulation and independent control of reactive and active power.

Wind generation may be categorized into four main technologies (see **Figure I.1**). Type 1 WTGs are based on passive induction generators. The electrical generator runs at essentially constant speed and is unable to control active power, reactive power, or voltage. It is a squirrel-cage induction machine running at super-synchronous speed, and thus always absorbs reactive power from the grid and has no electrical controls [1]. Most small-scale Type 1 WTGs are associated with a stall wind turbine (fixed position turbine blades) [1], and the WTG is truly a passive device with no active controls. Type 2 WTGs have a fairly similar electrical response characteristic to Type 1 WTGs. The primary difference is that Type 2 resources have some level of variable speed operation due to the wound rotor of the induction machine coupled with a controlled variable resistance to flatten and extend the torque-speed characteristic of the machine. Both Type 1 and Type 2 technologies require additional electrical equipment at the turbine level and in the collector system (typically at the substation/Point of Interconnection (POI)) to compensate for the reactive power consumption of the induction generators and to facilitate voltage regulation at the POI. Switched shunt capacitor banks and/or some type of dynamic reactive power device (e.g., SVC or STATCOM) are used in these instances. While Type 3 and Type 4 machines have dominated the newly interconnecting WTGs around most of the world, Type 1 and Type 2 WTGs do still exist in the United States. However, one of the major manufacturers of Type 2 WTGs discontinued that product line several years ago with others following that path. Type 3 and Type 4 WTGs now dominate, particularly due to technological advances in inverters, and the full capability of providing essential reliability services (ERSs) that are provided by other conventional, synchronous generating resources, such as reactive power control, voltage regulation, and primary frequency response [18]. Solar PV resources are also equally capable of providing ERS [12]. They consist of PV arrays connected to a direct current (dc) bus and inverter that interfaces with the BPS. Filters, a step-up transformer, and other switchgear and protection are included as well (as shown in **Figure I.2**).

[10] There are exceptions of inverter-interfaced hydroelectric generation for pumped storage. If interested, refer to: http://ceeesa.es.anl.gov/projects/psh/ANL_DIS-13_06_Modeling_AS_PSH.pdf

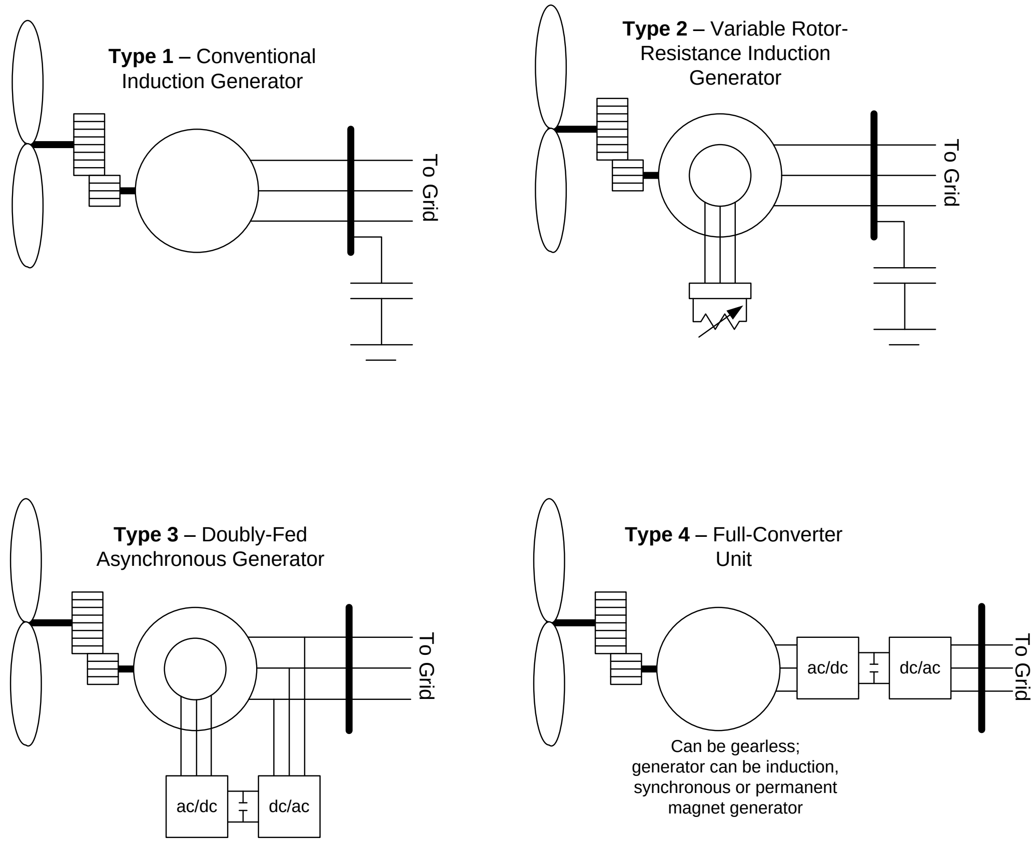

Figure I.1: Wind Turbine Technologies (Source: EPRI [9])

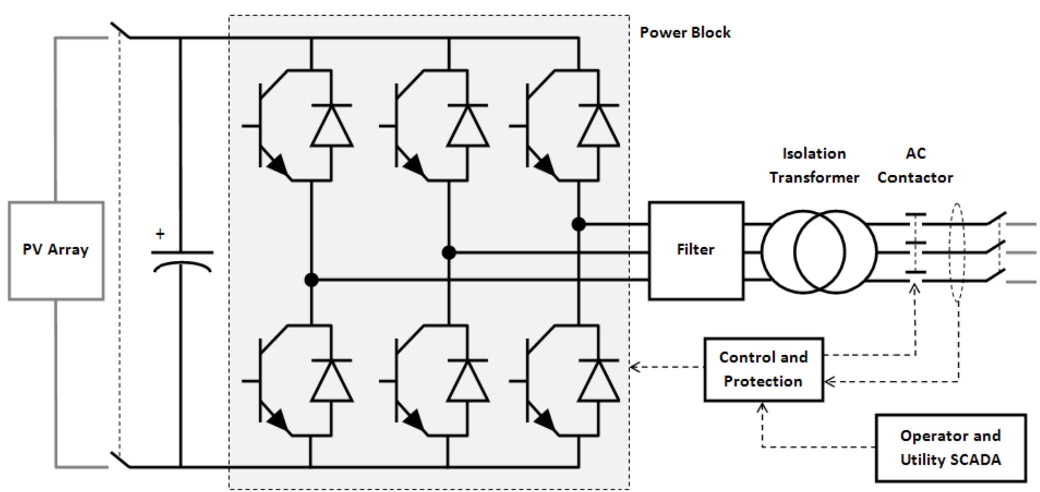

Figure I.2: One Line Diagram of a Solar PV Plant [Source: WECC [8]]

Verification Applicability of Inverter-Based Resources

The MOD-026-1 and MOD-027-1 standards apply to both synchronous and inverter-based generating resources. While an inverter-based resource may not have a turbine-governor or a generator excitation control system, it does have active power/frequency controls as well as reactive power/voltage controls that should be verified as part of MOD-026-1 and MOD-027-1. The models used to represent these resources are aggregated models; therefore, verification activities should ensure that the dynamic model response matches reasonably well to the overall response of the plant. In particular, MOD-026-1 and MOD-027-1 explicitly describe the applicability of inverter-based resources, respectively, as follows:

1. Excitation control system or plant volt/var control function:
    a. For individual synchronous machines, the generator excitation control system includes the generator, exciter, voltage regulator, impedance compensation, and power system stabilizer.
    b. For an aggregate generating plant, the volt/var control system includes the voltage regulator and reactive power control system controlling and coordinating plant voltage and associated reactive capable resources.
2. Turbine/governor and load control or active power/frequency control:
    a. Turbine/governor and load control applies to conventional synchronous generation.
    b. Active power/frequency control applies to inverter connected generators (often found at variable energy plants).

Table I.1 shows the generating resource size criteria for each interconnection for applicability to the NERC MOD-026-1 and MOD-027-1 standards. It specifies that each "individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than" the specified values are applicable units subject to the requirements of the standard. Regardless, some level of verification of dynamic models for all resources connected to the BPS, including inverter-based resources, is recommended.

Table I.1: MOD-026-1 and MOD-027-1 Plant Size Applicability

Interconnection	Power Plant MVA
Eastern or Quebec	100 MVA
Western	75 MVA
Texas	75 MVA

Note that the TP and PC can develop modeling data requirements and reporting procedures under NERC MOD-032-1 and can also have local interconnection requirements that are more stringent in terms of modeling resources (e.g., less than the size thresholds listed in **Table I.1**). MOD-032-1 is used to develop the interconnection-wide base cases and dynamic models. MOD-026-1 and MOD-027-1 are used for verifying the models provided are of sufficient accuracy and fidelity.

Reviewing and Verifying OEM and Other Documentation

One important aspect of inverter-based resources is that some modeling parameters cannot be safely or effectively verified by tests in the field. In these cases, the GO should ensure that documentation is provided by the OEM that verifies that parameters are appropriate for the unit/plant in question and should be made available to the TP/PC upon request since these entities need confirmation of model accuracy for their stability studies. This verification may be based on a comparison with factory test data, electromagnetic transient (EMT) simulation benchmarking, or commissioning test reports can all be used as demonstration that the modeled response matches the response of the unit (e.g., individual turbine/inverter type testing [11]). Verification can be performed for user-written detailed models as well as generic models used for interconnection-wide models. See **Appendix C** for examples of this comparison.

Benchmarking between EMT models and positive sequence models, particularly for fault events used in stability studies, should be performed or required by the TP in their modeling requirements documentation. An example of benchmarking a fault simulation between the positive sequence RMS model and an EMT model is shown in **Figure I.3**.

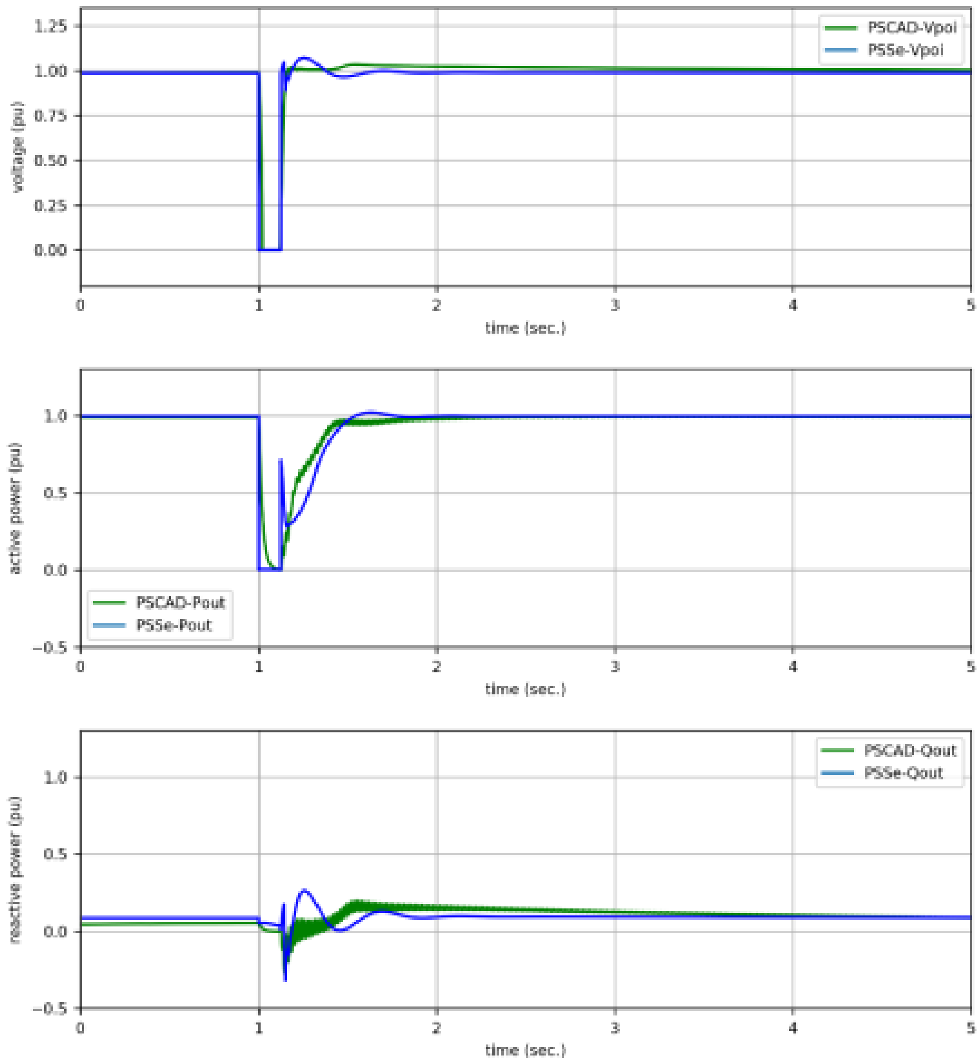

Figure I.3: Benchmarking EMT and Positive Sequence Models [Source: GE]

Examples of model parameters that likely need to be verified by collection of this information and review of OEM-supplied material include the following:

- The low/high voltage and frequency ride-through capabilities of the generating units (typically, the *lhvrt* and *lhfrt* models)
- The aerodynamics model for wind turbines (e.g., *wtga_a* model)
- The pitch and torque controller for wind turbines (*wtgp_a* and *wtgq_a*)
- The generator-converter controls (*regc_a*) and the voltage-current characteristic of these controls
- Use of momentary cessation and applicable settings (in *reec_a*) [21]

Verification of OEM-supplied data is important for modeled behavior when voltages fall outside the continuous operation range of the plant-level controller and inverters. These “ride-through” conditions, where local inverter controls take over, should be reasonably and accurately modeled even though on-site testing may not verify performance. A unique characteristic of inverter-based resources is that the dynamic behavior of these resources is often explicitly programmed in the logic of the inverter rather than based on the physical characteristics of the equipment (like a synchronous machine). Therefore, it is critical that the OEM-supplied data be reviewed and verified by the GO so that the model parameters and modeled response match expected dynamic behavior.

In addition to the control characteristics and the post-disturbance dynamics represented in the generic models, some inverter-based resources have power flow, transient stability, or short circuit behavior that cannot be easily reproduced by the generic models. If these characteristics were observed during testing or documented in the OEM documentation, the model verification report should discuss these observations. If vendor-specific models are required, the OEM documentation should describe the conditions where these vendor-specific models are required. If no vendor-specific model is available, these characteristics of interest to BPS planning studies should nonetheless be at least highlighted and described to the extent possible with the available data. Examples of such characteristics include the following:

- Switchable shunt reactive devices controlled by a dynamic reactive resources, such as STATCOMs, with large deadbands and cool down delays
- A wind power plant with integrated battery storage facilities
- Special control schemes for inverter-based resources operating in low short-circuit strength systems
- Vendor-specific models used for studying close-in faults
- Inverter-base resources with large voltage control deadbands that switch from power factor to voltage control

GOs should have accurate information regarding the origin and subsequent history of model parameter values (through OEM-supplied documentation). PCs and TPs should confirm that verification reports provided by the GOs for MOD-026-1 and MOD-027-1 include descriptions of the data review as well as the origin and the subsequent history of the data. The MOD-032 Designees gathering data from all PCs should have reasonability checks for inverter-based resources to ensure high quality and fidelity of the interconnection-wide base cases.

Model verification activities focus primarily on the plant-level controller (*repc_a*) and the aggregate performance of the electrical controls of the individual units (e.g., *reec_a*) [16]. Many of the model parameters (e.g., reactive power/voltage control flag, active power/frequency control flag) are selected based on OEM settings. Some of the gains, delays, and time constants can often be looked up directly in the digital control systems. In these cases, testing should be used to verify the model parameters rather than arbitrarily optimize them.

Measurements for Verification

Model verification can typically be performed using plant-level data captured at the plant POM (high-side voltage level of the collector substation). The data needed for model verification is typically captured at the POM of the inverter-based resource and includes the following quantities:

- Total RMS, 3-phase active power output
- Total RMS, 3-phase reactive power output
- Positive-sequence RMS phase or phase-phase bus voltage
- Bus phase angle or bus frequency 11

This data is calculated from high resolution measurements of three-phase voltage and three-phase current from the potential transformers (PTs) and current transformers (CTs), respectively, at the POM. Data is typically reported by a measurement recording device at rates of 30–60 samples per second, although higher resolution point-on-wave data

[11] Depending on the methods used for signal playback and model verification.

is also recommended. Data from individual inverters are not necessary and typically not useable for plant-level model verification.[12] Dynamic disturbance recorder (DDR) devices can be used to collect data for the purposes of model verification, including the following:

- Digital relays configured as PMUs
- Standalone PMUs
- Digital fault recorders (DFRs)
- Power quality meters configured as PMUs
- Triggered DDRs
- Recording capability in the plant-level controller

For model verification purposes, data does not need to be reported in real-time to a central location. Rather, these measurements can be stored locally at the plant in a Phasor Data Concentrator (PDC) or other storage device.

Disturbance-Based Model Verification

One effective approach to power plant model verification is to use DDR data that captures the dynamic response of the plant under consideration and compares that response to the expected (modeled) response (see **Figure I.4**). This can be an effective alternative approach to off-line staged testing, and it can be used for both MOD-026-1 and MOD-027-1 verification activities. Refer to the NERC Reliability Guideline on *Disturbance-Based Dynamic Power Plant Model Verification*[13] for more information on the functional methods and tools used for performing these simulations.

Once the measurement data described above is collected that captures the response of the inverter-based resource, the bus voltage and frequency (or phase angle) can be played back into the simulation platforms. The active and reactive power are used as measures of success to compare the model performance against the actual performance. MOD-027-1 focuses on the active power-frequency controls, and MOD-026-1 focuses on the reactive power-voltage controls.

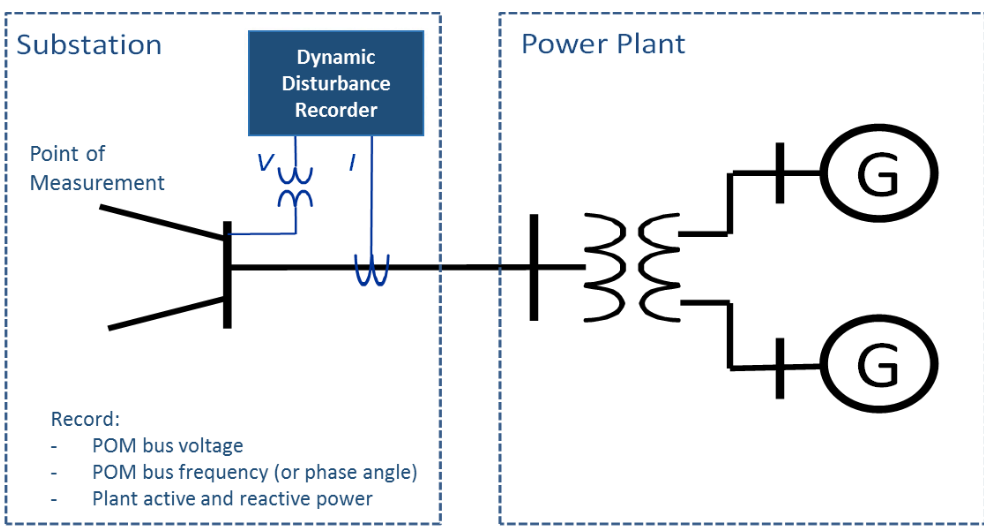

Figure I.4: Illustration of DDR Recording for Disturbance-Based Model Verification

[12] High resolution measurement data at that level can help analyze plant response to actual grid events (particularly for unbalanced conditions) and help explain any model discrepancies.
[13] Available here: http://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability%20Guideline%20-%20Power%20Plant%20Model%20Verification%20using%20PMUs%20-%20Resp.pdf.

One important aspect related to disturbance-based model verification for inverter-based resources, which are typically renewable energy resource, is accounting for the variable energy source driving the electrical power output. Simulations, including model verification, assume a constant mechanical input power. Therefore, disturbance-based model verification should set a starting simulation time that is fairly close to the disturbance itself to minimize input source variability such that the disturbance itself can be analyzed with sufficient detail. For disturbances that last many tens of seconds or longer, deviations between modeled and actual response may be attributable to changing input power. This is particularly a challenge for MOD-027-1 verification of active power-frequency control and less so for MOD-026-1. Many verification examples in this guideline show mismatch in active power response when focusing on MOD-026-1 reactive power-voltage verification. Future industry efforts may consider adding the energy input source (e.g., wind speed, solar irradiance) as an optional input to the dynamic model such that playback verification can incorporate these changes.

Another important aspect, which is also applicable to synchronous machines, is the use of unbalanced faults or close-in faults for verification testing. Unbalanced faults may not be correctly represented in positive sequence simulation tools, and the inverter-based resource may take actions (controls, protection, etc.) on phase-based quantities as opposed to positive sequence. Similarly, close-in faults may drive inverter controls to different operating modes that may not be captured by the positive sequence representation. Lastly, the close-in faults may be filtered by the DDR device itself (unless very high speed data is captured), and it may result in some variance when using that captured data for play-in in the simulation.

Figure I.5 shows an example of disturbance-based model verification used for MOD-026-1 from a local BPS fault. The fault causes a change in POM voltage at the Type 4 WPP and the reactive power output responds accordingly. Modeled response is verified by playing back into the model the voltage measurement and comparing simulated and actual reactive power responses. The comparison shows a fairly close match that should be suitable for verification purposes. Minor tuning using multiple grid events could be used to achieve a slightly improved match over time. However, the general characteristic shape of the response matches quite well. Some deviations can be attributable to the fact that the fault was likely not balanced. If these differences become too pronounced (i.e., the unbalanced fault event happens very close to the plant) the recorded response will likely not yield useful results for verification purposes.

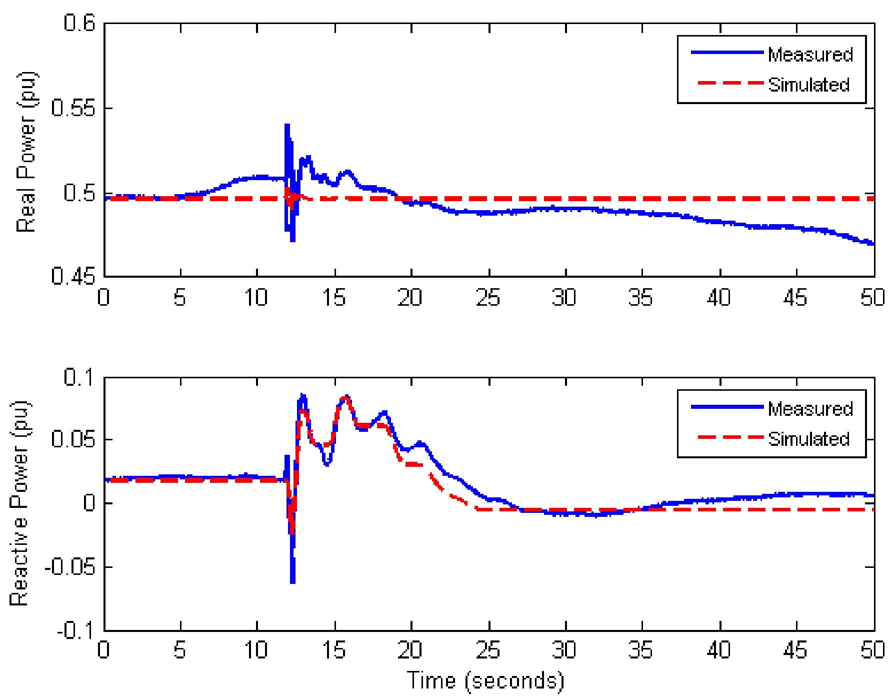

Figure I.5: Disturbance-Based Model Verification for Type 4 Wind Power Plant [Source: IEEE©2016 [11]]

Another example shown in **Figure I.6** demonstrates disturbance-based model verification of active power/frequency controls (demonstration of primary frequency response) for a Type 4 WPP. This plant is in the Texas Interconnection and required to have primary frequency response capability, per BAL-001-TRE-1.[14] Disturbance data was gathered from a PMU located at the POM for this WPP. For this event, the unit was operating in a condition where it was able to provide primary frequency response for the underfrequency event (i.e., not operating at maximum available power output due to being curtailed for other reasons). The simulation model was set up to match initial conditions, and the dynamics model was modified to account for the reduced output relative to maximum available input power. The frequency was played into the simulation model and active power comparison between actual and modeled response of the plant (i.e., total plant MW output). The simulated and measured active power output match closely for this event. Slight differences in the active power response may be attributed to changing wind speed, as described above, although this is a very good match for this 200 second time period.

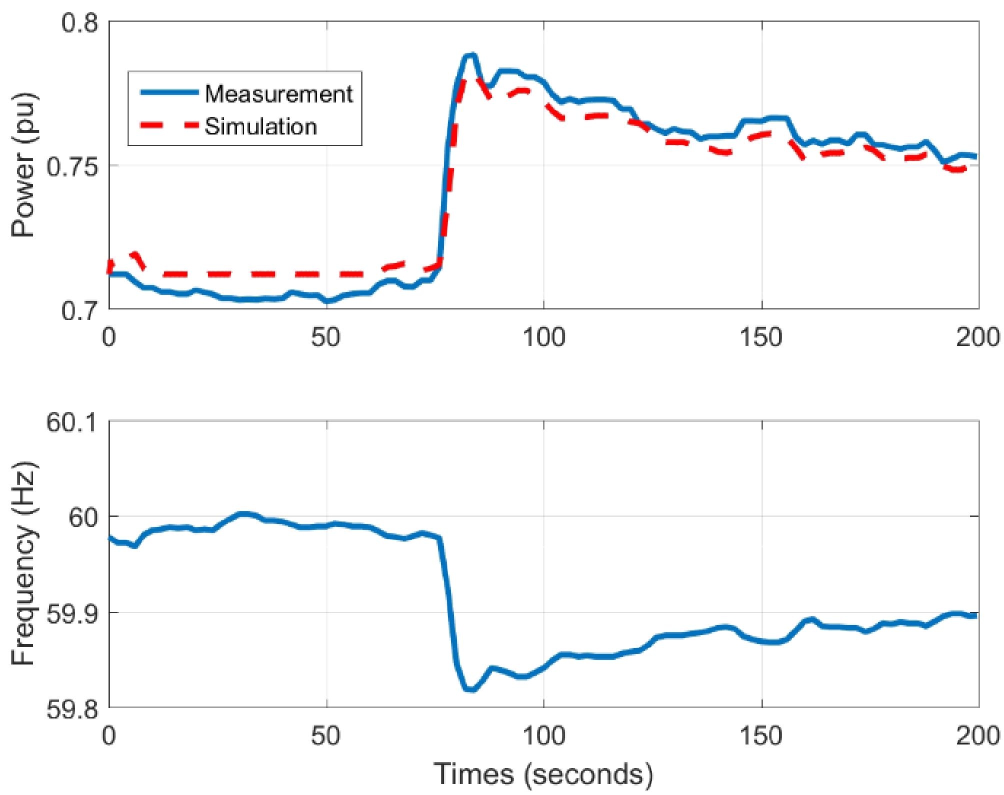

Figure I.6: Underfrequency Disturbance Model Verification for Type 4 WPP [Source: IEEE ©2016 [11]]

[14] Available here: http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=BAL-001-TRE-1&title=Primary Frequency Response in the ERCOT Region&jurisdiction=United States.

Chapter 1: Modeling Nonsynchronous Generating Resources

This chapter focuses on steady-state and dynamics modeling aspects for nonsynchronous[15] generating resources that are interrelated to model verification, testing activities, and use of these models in system studies.

Steady-State Modeling of Wind and Solar PV Plants

Utility-scale wind and solar PV plants connected to the BPS are typically modeled as aggregated, single-machine equivalent representations for stability studies. **Figure 1.1** shows simplified oneline diagrams for a WPP and solar PV plant. The steady-state load flow model includes any of the following:

- An aggregated generator model that represents all on-line WTGs or solar PV inverters. This is the model of one WTG or inverter[16] scaled up by the nominal MVA capacity of the plant (i.e., if there are 100 WTGs of 2 MVA each, then the aggregate model is the model of one inverter in per unit, with the aggregate model having an MVA based of 100 × 2 = 200 MVA, assuming all inverters are on-line and operating).
- There may be mechanically-switched shunt capacitors (MSCs) for power factor correction at the terminals of the WTGs that are modeled explicitly, particularly for Type 1 and Type 2 WTGs.
- An aggregated model of the pad-mount step-up transformer, again scaled up appropriately by the pad-mount transformer unit MVA and the number of WTG units using the transformer.
- An equivalent feeder model used to represent voltage drop and losses across the collector system. The feeder impedance is often calculated using the NREL approach.[17]
- Shunt compensation (e.g., switched capacitors or reactors) or dynamic reactive devices (e.g., SVCs or STATCOMs) modeled explicitly, as applicable, at the low-side of the substation transformer. The SVC or STATCOM can often be modeled using the svsmo1 or svsmo3 models.[18] [19]
- The substation transformer is modeled explicitly as well as any tie-line impedance to the POI with the transmission system.

This equivalent representation is particularly effective when the plant consists of WTGs or inverters from the same manufacturer. When the plant includes different manufacturers' WTGs or inverters, multiple equivalent representations may need to be used for that plant depending on the fractions of different types of WTGs or inverters and how they are distributed in the collector system. In the dynamic models, the controls for these different WTGs or inverters will likely be different, and this needs to be accounted for appropriately.

Synchronous machines typically control their terminal quantities and may be represented in powerflow as regulating the bus voltage of the high-side of the GSU to represent plant-level control of a TOP's voltage schedule. For inverter-based resources, this is particularly important since these resources often control a remote bus at the POI, which may not be directly at the high-side of the substation transformer. Therefore, it is important to ensure that the load flow

[15] The material presented in this chapter can mostly apply to inverter-based resources (e.g., solar PV, BESS, and Type 3 and 4 WPPs) and can also apply to Type 1 and Type 2 WPPs as well in many cases.

[16] The individual turbine MVA should be the same MVA for which the manufacturer has per unitized the dynamic model (e.g., the 2nd generation renewable energy system models).

[17] E. Muljadi, C. P. Butterfield, A. Ellis, J. Mechenbier, J. Hochheimer, R. Young, N. Miller, R. Delmerico, R. Zavadil, and J. C. Smith, "Equivalencing the collector system of a large wind power plant," in Proc. IEEE Power Eng. Soc. General Meeting, Montreal, QC, Canada, Jun. 2006. Available: https://www.nrel.gov/docs/fy06osti/38940.pdf.

[18] https://www.wecc.biz/Reliability/WECC-Static-Var-System-Modeling-Aug-2011.pdf.

[19] P. Pourbeik, D. J. Sullivan, A. Boström, J. Sanchez-Gasca, Y. Kazachkov, J. Kowalski, A. Salazar, A. Meyer, R. Lau, D. Davies and E. Allen, "Generic Model Structures for Simulating Static Var Systems in Power System Studies—A WECC Task Force Effort", IEEE Transactions on PWRS, August 2012.

representation of these resources is accurate before performing dynamic simulations. In addition, the additional switched shunt and dynamic reactive elements within an inverter-based resource also need to be modeled correctly (e.g., status set appropriately, output coordinated with the inverter output appropriately, control mode set correctly).

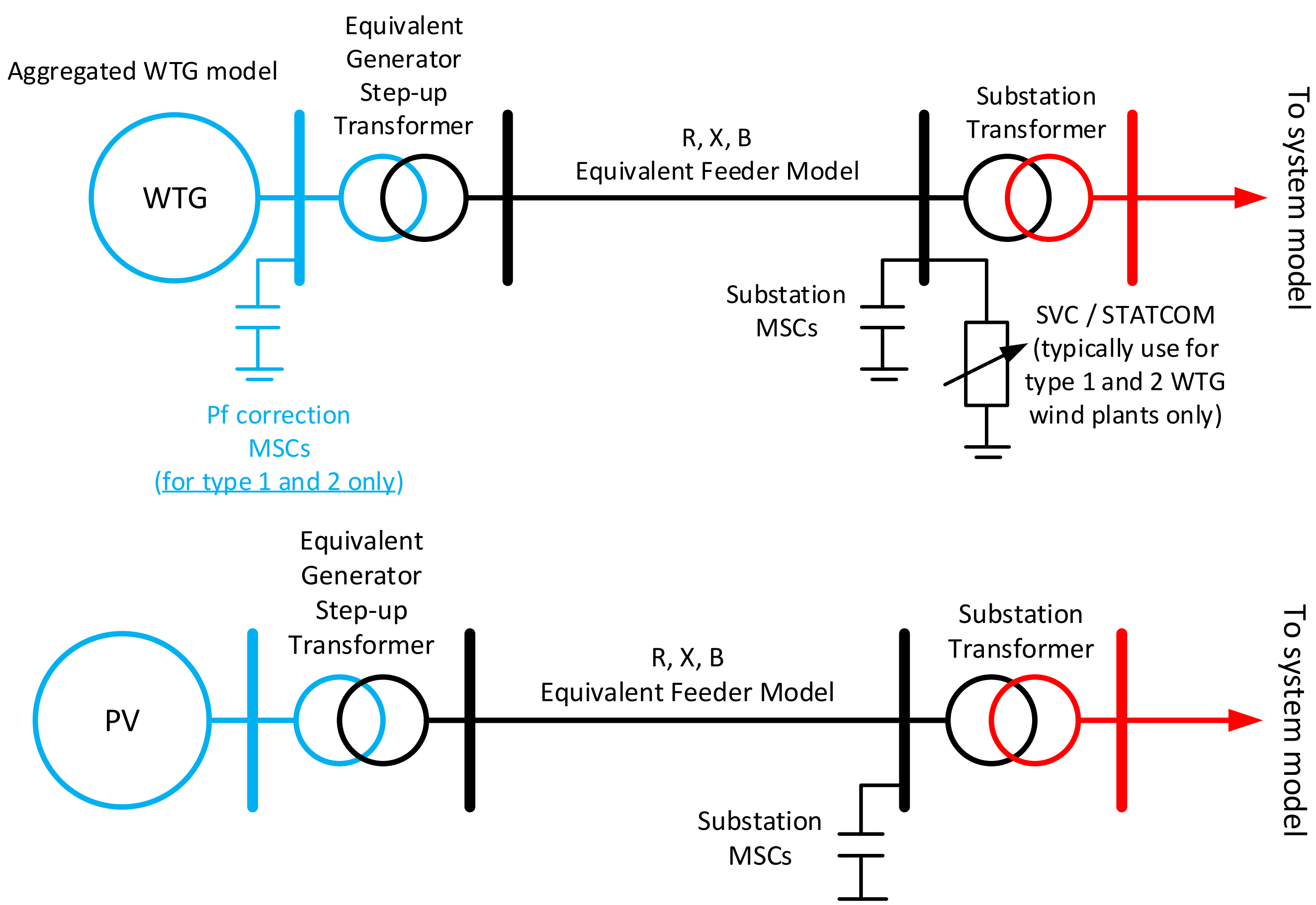

Figure 1.1: Aggregated Model Representation for a Wind or Solar PV Plant

If model verification efforts for MOD-026-1 or MOD-027-1 incorporate changes to the steady-state powerflow model, that information should also be provided along with the verification documentation and verified dynamic models. This information should also be provided by the TP and PC to the MOD-032 Designee for incorporation into the interconnection-wide base cases. The GO should also provide this updated and verified information for any interconnection-wide case creation data submittals per MOD-032-1.

Modeling Voltage Control and Droop

Reactive power droop (or line drop compensation) is typically used for synchronous generation in situations where two or more generators are controlling the same bus. Similarly, reactive power droop (in percentage or per unit voltage/percent or per unit var) may be used for wind and solar resources operating in voltage control mode to control voltage of a designated Point of Measurement (POM) (or POI). This point is electrically closer (lower impedance) to the BPS; therefore, a carefully selected droop can be used in the plant-level controller to prevent large changes in reactive power output for the inverter-based resource for small changes in system voltage. Droop compensation systems use voltage measurements from the POM in conjunction with a virtual impedance at a regulated bus. These controls are sometimes required by the TOP to maintain unity power factor when voltage is within the normal operating voltage while still maintaining an ability for the plant to respond to voltage disturbances.

Modeling reactive droop is a steady-state modeling challenge since it is not easily represented in the powerflow solution or model parameters in any of the major commercial software platforms.[20] Presently, when a synchronous generator is modeled with a voltage regulating control mode, the user of the software selects a bus for the equivalent generator to control, and the powerflow solution maintains the regulated bus voltage schedule until the Qmin/Qmax limit is reached. Inverter-based resource plant controllers that use a Q-V droop characteristic cannot be easily modeled in this manner. Further, these controllers may have a deadband around the scheduled voltage value that is also not represented. Generally, deadbands are not modeled in powerflow since they lead to an indeterminate powerflow solution if applied at numerous buses. Planning engineers are forced to manually adjust the voltage schedule of plant models to achieve a reasonable reactive power output for the given voltage. Often, this meticulous base case preparation cannot be completed for every plant because it is time consuming and some assumptions have to be made. However, this may result in incorrectly modeling the initial operating conditions and overestimating output in contingency analysis for post-contingency operating conditions. **Figure 1.2** shows an example of testing the actual plant reactive droop versus how the model would represent it. The measurements were taken on the high-side of the main plant station transformer. The plant uses a four percent voltage/reactive droop characteristic (blue measurement points). When the same plant is modeled in load flow as controlling the POI (with zero percent droop since this is a limitation in how the models represent the voltage control), the powerflow solution overestimates the amount of reactive power contribution from the plant (red simulation points). Note that if the plant operates in different modes (e.g., droop or no droop depending on SCADA control or local control), these should be noted and reflected in the model for the TP and PC for modeling purposes.

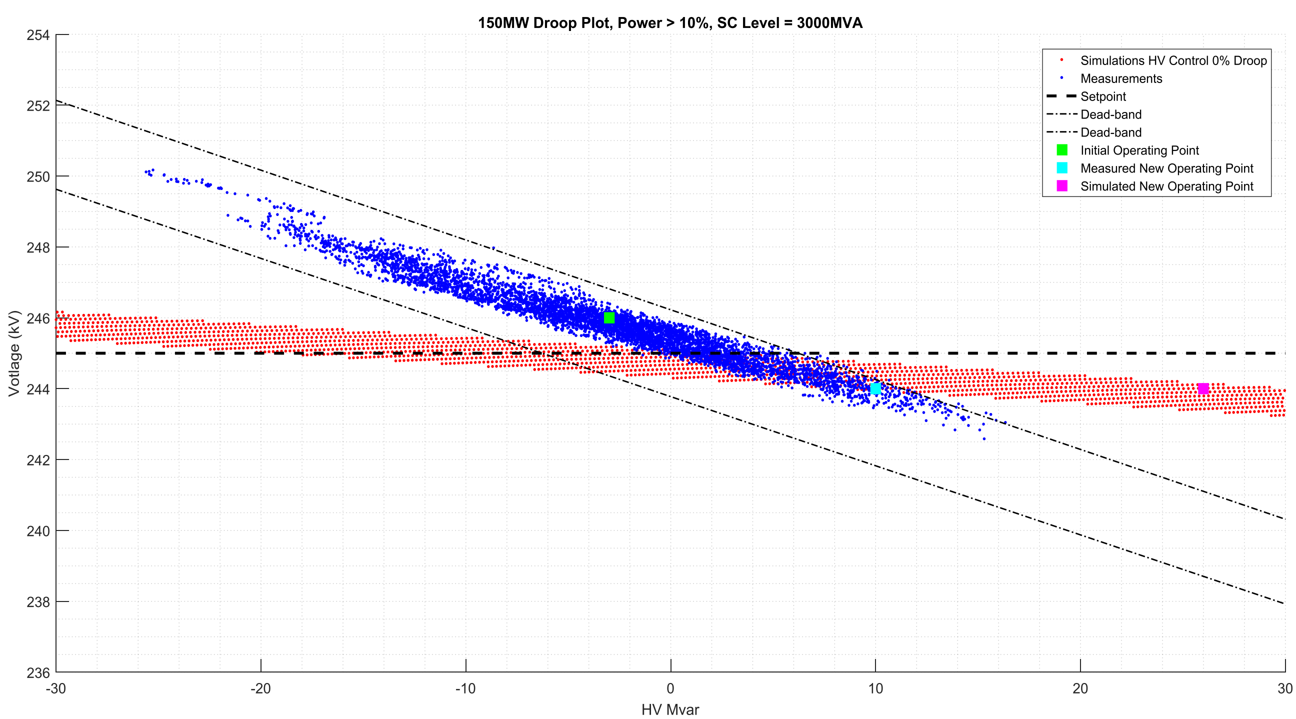

Figure 1.2: Modeled vs. Simulated Droop Characteristic [Source: IESO]

This verification technique is effective in confirming the presence of reactive droop and other features, such as the ability to control voltage without wind or solar irradiance. **Figure 1.3** shows another example of plotting data over time to observe these characteristics. Active power output of the plant is shown by the changing colors, ranging from purple to turquoise. Purple measurement points represent low active power output near zero MW. When the plant

[20] This is true for any modeled generating resource if voltage is being regulated at a remote bus, and not specifically inverter-based generation. The WECC REMTF is discussing potential solutions to these issues at the time of writing this guideline.

does not produce active power, reactive power measurements show a vertical line (the sum of charging and any other shunt devices connected). The crimson color vertical line shows that at low active power output, the plant cannot control voltage without the presence of the wind (or solar irradiance). Once the plant begins producing a certain active power output, the plant can operate on a voltage droop characteristic, calculated using the slope of diagonal line (in $\Delta V_{pu}/\Delta Q_{pu}$). If the plant were able to operate in voltage control at all times, all data points would operate on the sloped droop characteristic.

Figure 1.3: 100 MW Wind Farm Droop Characteristic and Active Power Output [Source: IESO]

The second generation generic models have the ability to model reactive droop control. In particular, the *repc_a* model in **Figure 1.4** includes the Kc parameter to specify reactive droop. Some entities may use a negative value of Xc if apparent current is used rather than reactive current (power) for the droop control. This needs to be carefully and correctly set accordingly. The discontinuity between capabilities to model reactive droop in dynamics versus the inability to model it in powerflow should be addressed by industry working with the software vendors. WECC REMTF is exploring potential solutions to this issue currently.

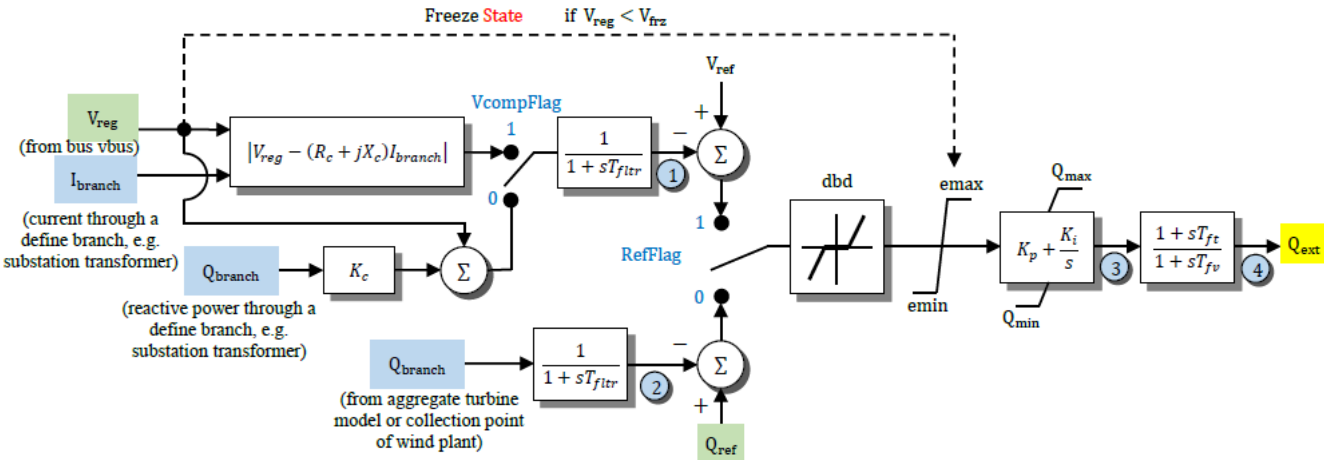

Figure 1.4: Reactive Power Component of REPC_A Model [Source: PowerWorld]

Dynamic Modeling of Inverter-Based Resources

With inverter-based resources, as with any other equipment, there are typically several levels of models:

- **Electromagnetic Transient (EMT) Model:** Detailed vendor-specific three-phase models are used for design studies by the vendor and may often be practically implemented in source code and then integrated into tools, such as PSCAD®, MATLAB®, EMTP-RV, etc. These models may, for WTGs, also include detailed models of the mechanical components as well. These models are owned and developed by the original equipment manufacturer (OEM) and are proprietary and typically not shared with equipment owners or commercial power system analysis software developers.

- **Reduced-Order Vendor-Specific EMT Models:** These models are based on the detailed equipment design models, but they represent only the key elements of the equipment as they pertain to the electrical grid and so certain aspects of the full-scale detailed model is simplified or hard-coded as dynamically linked libraries (*.dlls). These models are owned and developed by the OEM and are proprietary in nature. However, they can be shared with the GO, TP, and PC with nondisclosure agreements (NDA). These models are used for detailed studies related to the design and dynamic behavior of the power plant and its potential interactions with the BPS.

- **Reduced-Order Vendor-Specific Positive-Sequence Stability Models:** These models are typically benchmarked by the OEM against the high-level models described above within the bandwidth of stability analysis tools (typically 0.1 to 10 Hz or so, dealing with transients from a few tens of milliseconds to many seconds time frame and simulation times ranging up to 10 to 30 seconds). These models are typically implemented in positive sequence stability programs. Some OEMs make these models openly available in these commercial tools while others make them available through an NDA. These models are particularly used for project-specific detailed stability studies (e.g., fault ride through studies).

- **Generic Positive-Sequence Stability Models:** The latest version of open source, publicly available model structures in North America are the "second generation generic renewable energy system (RES) models" [6], [9], [11]. These are generic model structures that, when parameterized appropriately, can emulate the general dynamic behavior of a variety of RES in transient stability studies. These are positive sequence models for use in interconnection-wide stability simulations for BPS planning.

All models, including those described above, have advantages, disadvantages, limitations, and an applicable range of application in system studies. The models that are used in BPS planning studies are either the detailed positive-sequence models for local studies or the generic positive-sequence models for interconnection-wide modeling. The

NERC List of Acceptable Models[21] provides requirements for the purpose of interconnection-wide modeling; the entities designated to create the interconnection-wide powerflow and dynamics cases ("MOD-032 Designees") each have a list that is equally or more prescriptive to the NERC list of models. The second generation generic models are recommended for interconnection-wide modeling since they are available to all stakeholders and have been benchmarked for consistency across the major commercial software platforms. Furthermore, additional modules continue to be added to the second generation models, which are modular in format, in order to continue to improve them and add emerging features of the technologies.

The goal of model verification, whether it is based on staged testing or disturbance monitoring, is to demonstrate that the appropriately parameterized generic models can adequately simulate the measured/observed dynamic behavior of the actual RES plant.

[21] Available here: http://www.nerc.com/comm/PC/Pages/System-Analysis-and-Modeling-Subcommittee-(SAMS)-2013.aspx.

Chapter 2: MOD-025-2 Capability Testing

Reactive power capability testing related to MOD-025-2 for an inverter-based resource is quite similar to testing for synchronous machines. However, there are some notable differences and considerations that should be made, including the following:

1. **Control:** The type of resource should be documented. Type 1 and Type 2 WTGs are not inverter-based, and the turbine-generators have no reactive power capability since they are based on induction generator technology. Power factor requirements may be met using a combination of switched shunt capacitors at the turbines and an SVC or STATCOM at the POM.
2. **Availability:** At least 90 percent of the wind turbines or solar PV inverters should be on-line and producing some amount of power during testing as described in Attachment 1 of MOD-025-2. This is not to be confused with this being interpreted as the plant having to be at 90 percent of its nameplate MW rating. For lower availability, a provision is described in Attachment 1 to re-test within six months.
3. **Operating Active Power:** This is the prevailing active power given the wind or solar resource availability at the time of test, which is expected to fluctuate during testing. Certain turbines require a minimum active power output for an adequate reactive capability test.
4. **Duration:** While synchronous machines are expected to hold the maximum power overexcited point for at least one hour, this provision does not apply to inverter-based resources due to their variability. Data should be recorded from a reasonable steady-state condition where reactive power output is steady over the course of a few minutes. It is acceptable that active power may be fluctuating and also causing some changes in reactive power consumption.
5. **Load Tap Changers:** If the power plant transformer(s) is equipped with a load tap changer, the testing should be performed with the LTC tap setting in its normal operating condition. A brief description of the tap changer control should be documented.
6. **In-Plant Reactive Devices:** If there are shunt capacitors, shunt reactors, STATCOMs, SVCs, or synchronous condensers in the plant (behind the POM—typically on the low-voltage side of the power plant substation transformer), the tests should be conducted with those devices in their normal operating mode[22] and need not be explicitly exercised for this test. The control strategy for each device should be described in the report (e.g., voltage regulation at the medium voltage bus; switch in at 80 percent active power and switch out at 60 percent power, etc.).
7. **Reactive Capability Curve:** This should be provided by the OEM in a P-Q format and should be included in documentation for each turbine/inverter type in the plant. Some inverters may have fixed (square shape) or increasing (triangular) maximum and minimum reactive power capability over the active power operating range. This should be reflected in the documentation of capability and accurately reflected in the model.
8. **Attachment 2:** Gross plant real and reactive power capability may be considered as the sum of all individual capabilities measured at the equipment terminals (which may or may not include a low-medium voltage transformer). This data is specified by the OEM. Plant net capability may be considered the gross capability minus active and reactive losses due to the power plant transformer(s) and collector system. Losses for the plant transformer may be determined from datasheets or estimated from nameplate values and typical data. The power plant transformer(s) is typically responsible for most of the losses, and this information is relatively easy to obtain. Collector system losses should be estimated from collector impedance data.

Similar to synchronous generation, the full reactive capability of an inverter-based resource may not be achieved during testing conditions. In particular, large wind and solar plants where the resource is in a remote location away

[22] Normal operating mode refers to the operating mode that the unit is expected to operate in during in-service operation, with no specific operating changes used for testing purposes.

from the load centers have this issue. For large wind/PV plants, which are in remote areas, pushing the plant to its maximum reactive output may push transmission voltage(s) or even collector system voltages to unacceptable high-levels. Most, if not all, wind and solar PV plants have limits on the voltage reference set points that can be set in the controls (both at the plant and individual turbine/inverter level). Although it may be possible to remove these limits during a test, it is not advisable since the limits are intended to avoid pushing equipment beyond their acceptable continuous operating range (e.g., 0.9–1.1 pu voltage). Thus, based on prevailing system conditions, a voltage limit may be reached before the full plant lagging/leading reactive limits are achieved.

Therefore, MOD-025-2 testing is performed under the prevailing test conditions, which may or may not be the actual capability of the plant. While not required, if the full capabilities of the resources cannot be reached during testing, the powerflow model (**Figure 1.1**) should be developed with accurate information including the following:

- Pad-mount transformer equivalent representation (nameplate data)
- Plant substation transformer (explicitly modeled per nameplate data and actual tap settings)
- Equivalent collector system impedance representation
- Aggregated wind/PV generator
- Reactive components (e.g., MSCs, SVCs) explicitly modeled

The overall plant model should then be verified to demonstrate with reasonable accuracy the active and reactive power points measured in the field and then used to extrapolate or calculate the expected reactive power limits. This should suffice to provide a reasonable model of the plant. As previously discussed, future considerations may address modeling voltage droop in the powerflow; however, this is not available in commercial software tools today. Where available, historical data may also be used to reasonably demonstrate the full active and reactive power capability of the plant to the extent that such historic data shows such limits reached in recent history.

Figure 2.1 and **Figure 2.2** show inverter capability curves at rated voltage from two inverter manufacturers. These inverters are relatively large, on the order of 3–4 MVA capability. While some inverters can provide a nearly complete semi-circle in terms of capability (**Figure 2.1**), some inverters have “clipped” reactive capability at higher reactive power outputs. These inverter capability curves should be provided by the OEM to the GO for reference.

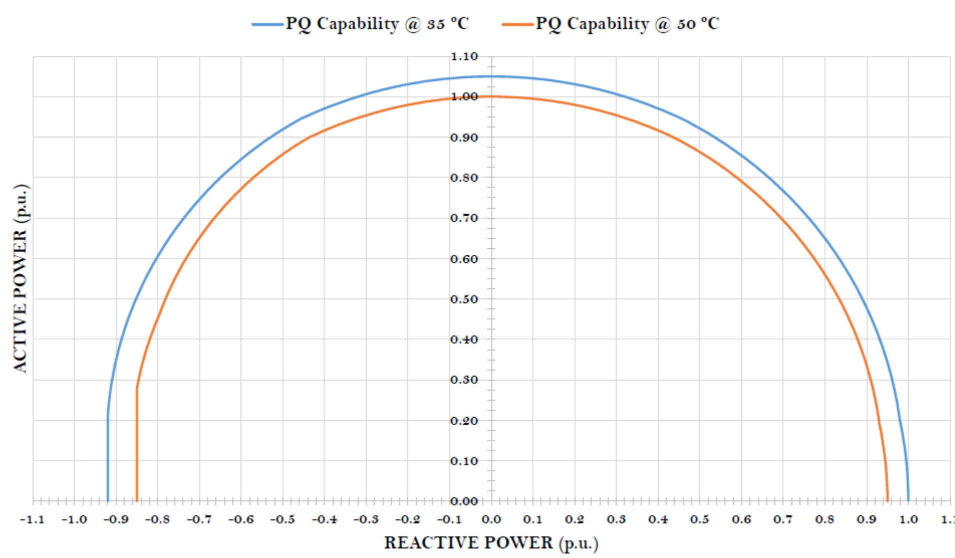

Figure 2.1: Inverter P-Q Capability—Vendor 1 [Source: First Solar]

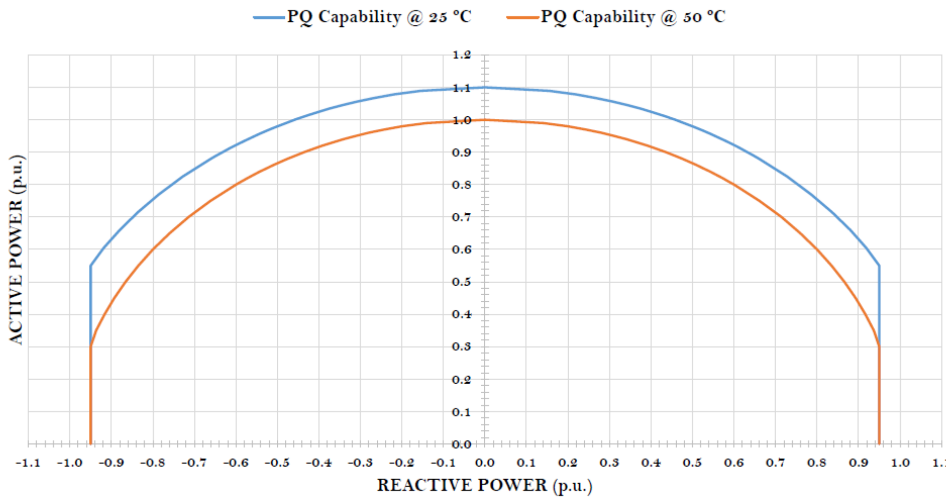

Figure 2.2: Inverter P-Q Capability—Vendor 2 [Source: First Solar]

Similar to synchronous machines, capability curves are typically provided at rated (or nominal) voltage. However, reactive power capability can vary significantly as voltage varies. Some manufacturers may be able to provide capability curves at different voltage levels. **Figure 2.3** shows an example of the reactive capability of a WTG at different voltage levels.

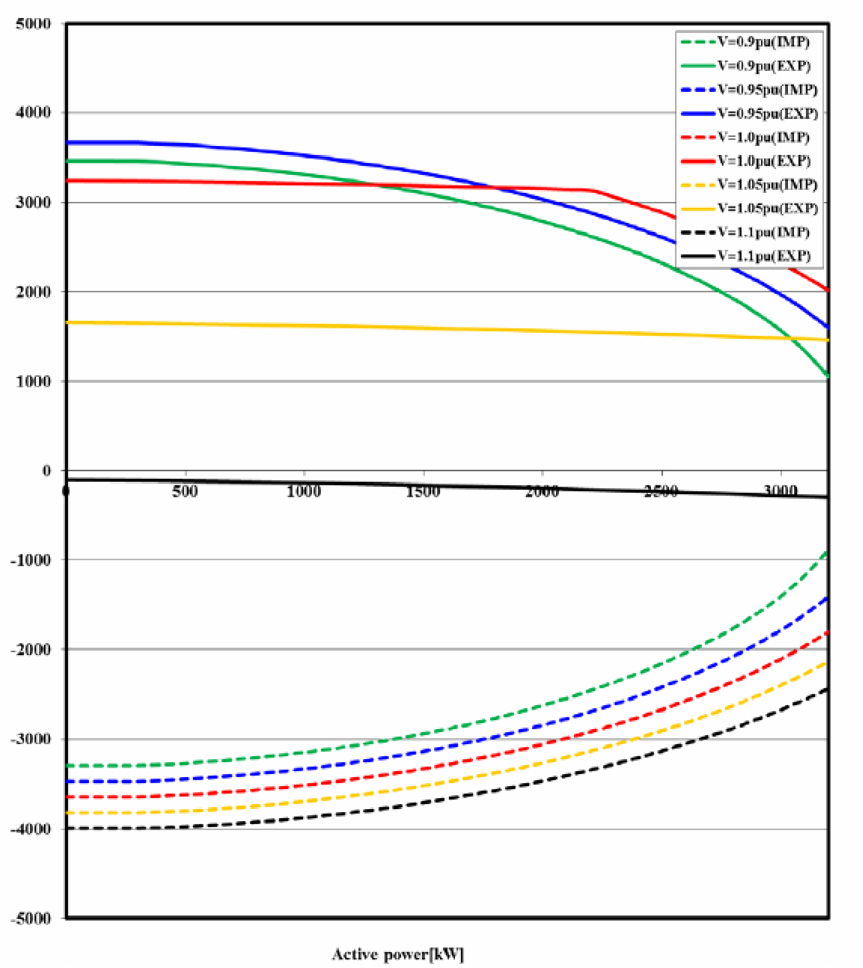

Figure 2.3: WTG P-Q Capability Curve – Siemens [Source: Siemens]

While information regarding individual inverter capability is useful for verification and testing purposes, MOD-025-2 tests for reactive capability of the overall plant, not an individual inverter. At the POM, the reactive capability may not be as robust due to collector system losses or requirements at the POM as compared with the capability of the inverters. Interconnection requirements and FERC Order No. 827[23] specify steady-state power factor requirements that need to be met by the resource.

FERC Order No. 827

FERC issued Order No. 827 on June 16, 2016, eliminating exemptions for wind generators from the requirement to provide reactive power by revising the pro forma Large Generator Interconnection Agreement (LGIA), Appendix G of the LGIA, and the pro forma Small Generator Interconnection Agreement (SGIA). FERC found that due to technological advancements, the cost of providing reactive power no longer creates an obstacle to wind power development, and this decline in cost resulted in the exemptions being "unjust, unreasonable, and unduly discriminatory and preferential." FERC addressed the following items in its Order:

- **Power Factor Range:** All newly interconnecting non-synchronous generators must "maintain a composite power delivery at continuous rated power output at the high-side of the generator substation… [and]… must provide dynamic reactive power within the power factor range of 0.95 leading to 0.95 lagging, unless the transmission provider has established a different power factor range that applies to all non-synchronous generators in the transmission provider's control area on a comparable basis."
- **Point of Measurement (POM):** All newly interconnecting non-synchronous generators are required to provide reactive power at the POM, or "high-side of the generator substation." See **Figure 3.2** for an illustration of the POM.
- **Dynamic Reactive Power Capability:** Dynamic reactive power can be achieved by "systems using a combination of dynamic capability from the inverters plus static reactive power devices to make up for losses." The static reactive power devices should only be used to make up for losses that occur between the inverters and the POM that would otherwise cause the overall non-synchronous resource to not meet the 0.95 leading to 0.95 lagging power factor requirement. However, the dynamic reactive capability of the inverters should be utilized to the greatest extent possible.
- **Real Power Output Threshold:** All newly interconnecting non-synchronous generators should be able to maintain the 0.95 leading to 0.95 lagging power factor requirement at all active power outputs down to 0 MW. FERC provided an example of a 100 MW generator required to provide 33 MVAR at 100 MW output and 3.3 MVAR at 10 MW output. This essentially is a triangle-shaped capability curve. However, this guideline recommends broader use of the inherent inverter capability beyond the triangular shape, as discussed in the following subsection.
- **Compensation:** The FERC Order covers compensation for reactive capability; however, this is outside the scope of this guideline.

[23] Federal Energy Regulatory Commission, Order No. 872, 16 June 2016. Available: http://www.ferc.gov/whats-new/comm-meet/2016/061616/E-1.pdf

Figure 2.4 shows an example of the capability of an inverter-based resource (entire plant). With the in-plant shunt compensation off, the plant is not able to meet the power factor requirements at rated active power output. However, when the in-plant shunt compensation is switched in, the capability curve is shifted, and the plant is able to meet the power factor requirements. Note that the plant capability is fairly flat at lower active power levels since the inverters do not have additional reactive capability at these lower active power output levels.

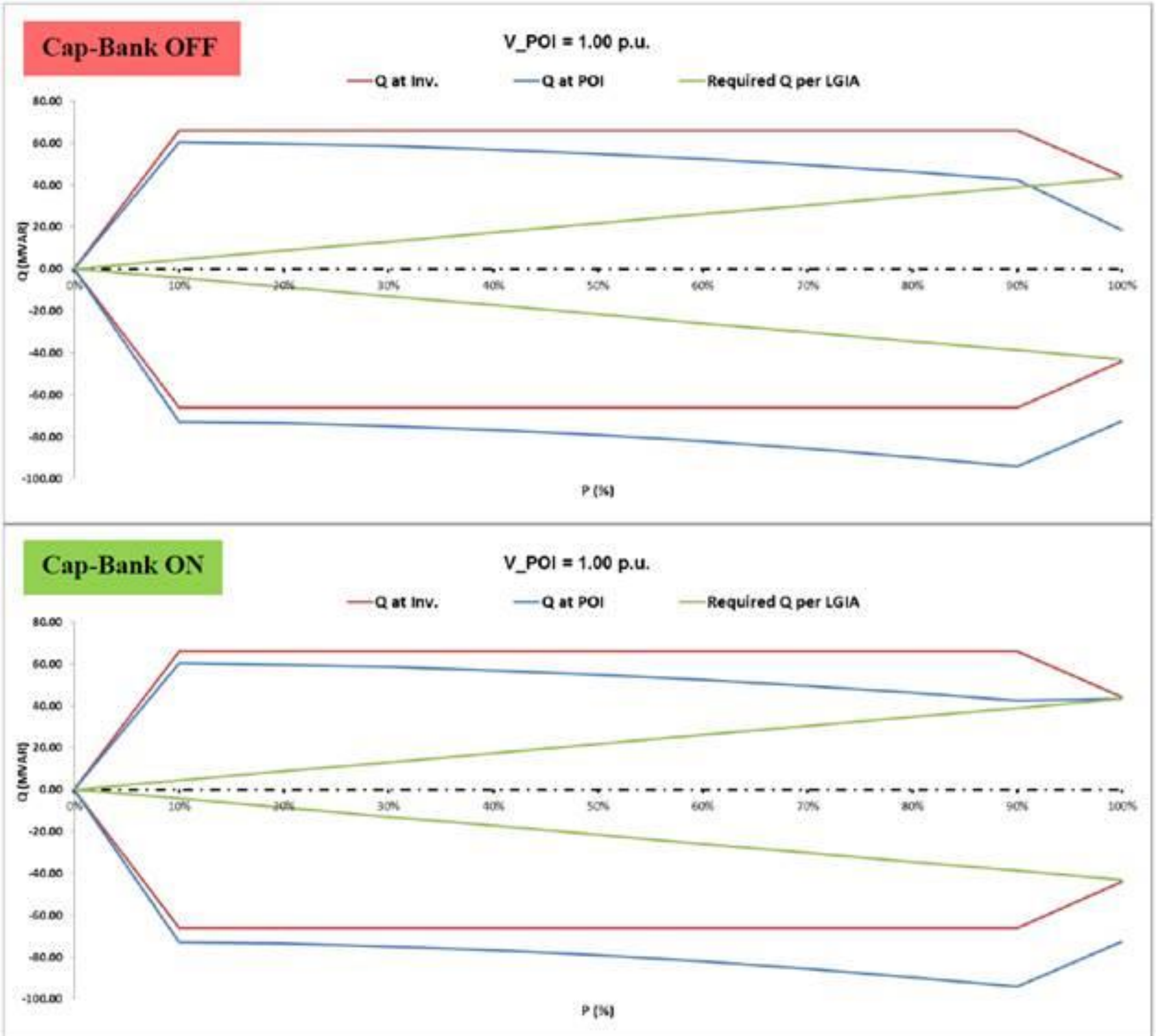

Figure 2.4: Plant Capability Curve – Example 1 [Source: First Solar]

Figure 2.5 shows another example of the capability of an inverter-based resource (entire plant) with the shunt capacitors in and out of service. In this case, the inverters have additional reactive capability at lower active power output levels, and the curve is more shaped like a semi-circle. In either example, the plant is only required to meet the triangular shaped capability (green line). However, reactive capability within the plant should not be artificially limited to this requirement.

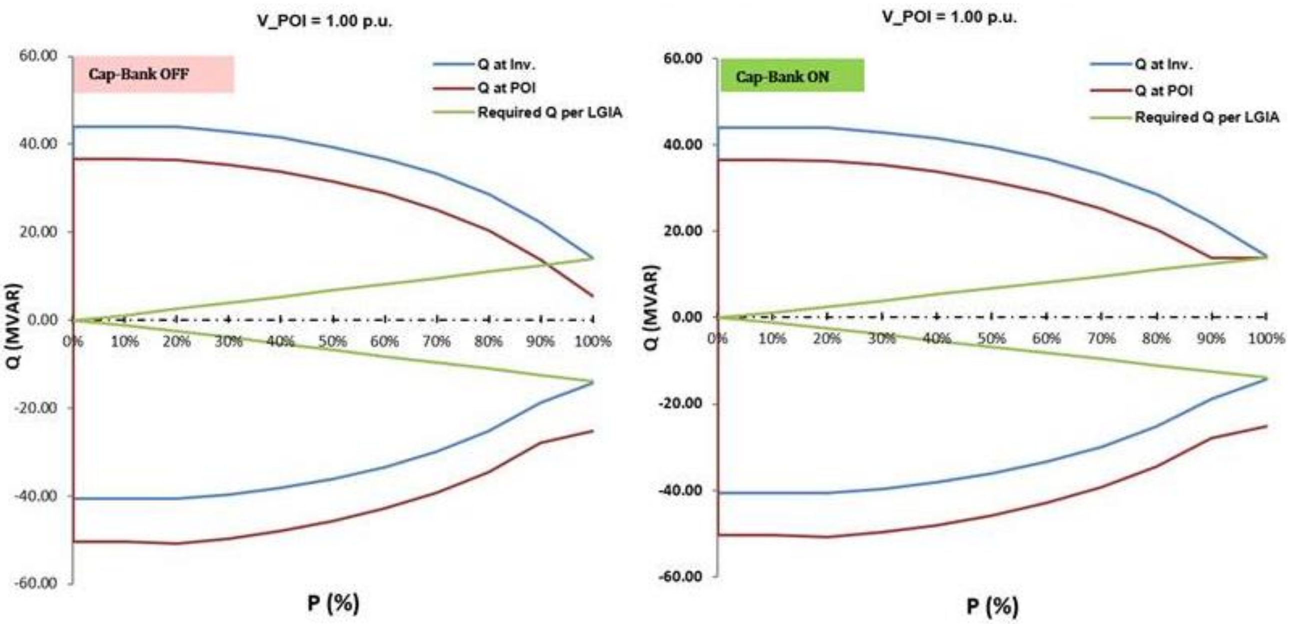

Figure 2.5: Plant Capability Curve – Example 2 [Source: First Solar]

The need for in-plant shunt compensation is predominantly driven by the power factor requirements at rated active power output. As FERC Order No. 827 highlights, the dynamic capability of the inverter-based resources should be utilized to the greatest extent, and static reactive capability (shunt compensation) should be used to account for losses. The inverter capability curves may be de-rated slightly based on the hottest expected hour/day of the year at that specific site location.

As with synchronous machines, the capability determined during MOD-025-2 test conditions should not necessarily be used as the data submitted for MOD-032-1. If the full reactive capability of the inverter-based resource is not reached during testing, these capabilities will differ from the expected capability when voltage conditions would warrant reaching those limits. The MOD-032-1 data supplied by the GO to the TP and PC for modeling purposes should reflect the full capability of the inverter-based resource when voltage is either low or high and naturally driving this reactive capability from the machine to support voltage set points.

The presence of a derated MVA limit, as well as identification of active or reactive power priority, can be confirmed during reactive power capability testing. A single WTG or solar PV inverter can be removed from the plant management system and operated in local terminal voltage control. The performance can be extrapolated up to a point where the values of Qmax and Qmin can be established for the equivalent turbine (inverter) model. An example of this is shown in **Figure 2.6** where the terminal voltage reference was lowered while the remainder of the turbines in the plant followed the voltage reference established from the plant controller. As the voltage decreased, the turbine withdrew more reactive power while decreasing active power to follow the MVA limit established by the limiter. The test cannot verify the entirety of the black line; however, it can get part of it and then engineering judgement can be used to extrapolate limits.

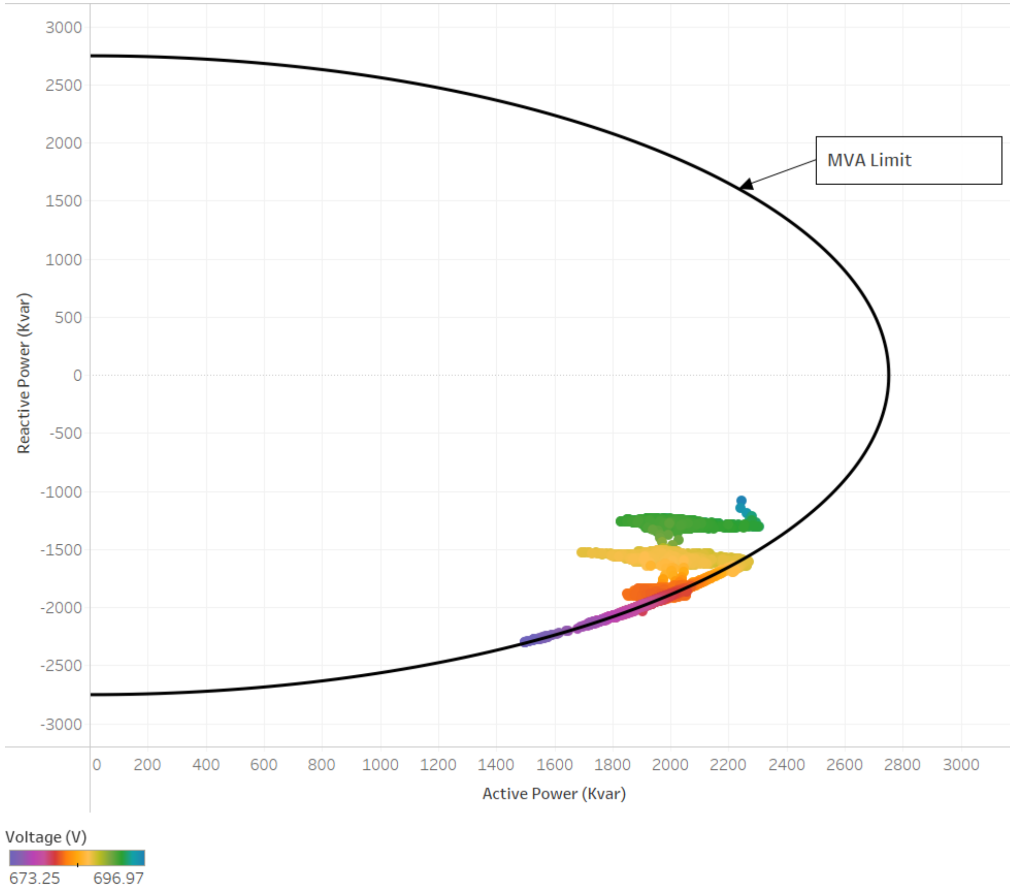

Figure 2.6: MVA Limiter on Type 4 Turbine Example [Source: IESO]

Chapter 3: PPMV for Type 1 and Type 2 Wind Power Plants

Type 1 and Type 2 wind turbine generators (WTGs) are generally no longer manufactured or installed in large wind power plants (WPPs). Most major equipment manufacturers of large BPS-connected WPPs have evolved to newer technologies that employ power electronics. Therefore, it can be challenging to obtain additional factory test information, detailed three-phase models, and other information for existing resources other than what already exists in the archives of the original equipment manufacturers (OEM).

Type 1 WTGs are essentially passive devices. The generator is a fixed-speed squirrel-cage induction generator with no controls. Smaller (typically < 1 MW) and older Type 1 WTGs were often stall controller turbines where the turbine blades are bolted to the rotor at a fixed pitch angle and the turbine acts as a passive device [1]. For this reason, the models for a Type 1 WPP typically include the following:

- Induction generator model
- Two-mass shaft dynamics – turbine-rotor mass and electrical generator mass, with representation of the effective spring constant between the two, and the damping.

The positive sequence generic models used to represent Type 1 machines are the *wt1g* and the *wt1t* models [6], [9]. The old first generation generic pseudo-governor model for Type 1 and Type 2 WTGs (*wt1p* and *wt2p*) should not be used[24] as they do not accurately represent the pitch-controls used in these WTG technologies. The new second generation generic model *wt1p_b* active-pitch controller more appropriately represents the action of the active-pitch controllers when used on these types of WTGs. Namely, on larger Type 1 WTGs with active-pitch controls, some vendors initiate a ramp-down in mechanical power (by pitching the blades). This occurs when a severe voltage dip is detected together with acceleration in the turbine speed to prevent the generator from exceeding its pull-out torque and going unstable [1].

A Type 2 WTG is a wound-rotor induction machine directly coupled to the grid and running at super-synchronous speed.[25] A variable external resistance is connected to the wound-rotor winding, which is controlled to change the effective rotor resistance over the operating range of the machine. This has the effect of flattening out the torque-speed curve of the machine and allows the machine to run over a range of speeds, typically from a super-synchronous slip of 1 percent to about 4–8 percent. Type 2 WTGs were the first step towards variable speed WTGs, which yield greater efficiency in converting the incident wind to electrical power [1]. Type 2 WTGs use the *wt2g* model and include an additional model (*wt2e* model) that emulates the external rotor resistance controls. It increases the resistance with increasing electrical power output to allow for higher slip-speed.

Model Verification for Type 1 and Type 2 WTGs

For Type 1 and Type 2 WTGs, there is little verification that can be performed since these resources are passive devices. The core model for Type 1 WPPs is the induction machine model (*wt1g*), which is the standard one-cage (transiency only) or two-cage (transiency and subtransiency) model of an induction machine. For Type 2 WPPs, the *wt2g* model is only a one-cage (transiency only) model. **Table 3.1** shows the parameters for the *wt1g* model for one of the typical commercial tools. The second model is the two-mass model of the turbine-generator shaft (*wt1t*). **Table 3.2** shows the parameters for this model. The *wt1p_b* model is used to model pitch controller (**Table 3.3**) for both

[24] The newer *wt1p_b* model should be used when data is available [6],[9]. If such data is not available, it is conservative (plant will be less stable) to not include the *wt1p_b* model. The wt1p_b model is used for both Type 1 and Type 2 generators. For stall-controlled turbines, there is no pitch control and therefore none should be modeled.

[25] An induction machine operates as a motor when it consumes real power to provide mechanical torque to serve a load, and it runs at sub-synchronous speed. If, however, the same machine is driven by a turbine running at super-synchronous speed and providing mechanical power, then the machine becomes an induction generator delivering active power. However, in both cases, the induction machine consumes a large amount of reactive power, which is the source for establishing and maintaining a rotating magnetic field in the machine airgap which is the means for magnetic induction between the rotor and stator windings.

Type 1 and Type 2 generators. For Type 2 WPPs, the *wt2g* generator model is used (**Table 3.4**), and the *wt2e* model is used to represent the control/change in external rotor resistance as a function of power and speed. The parameter list for *wt2e* is shown in **Table 3.5**. **Figure 3.1** through **Figure** 3.5 show the block diagrams for these models. Type 1 and type 2 wind turbines are similar with the only change being in the windings of the generator. Type 1 WTGs use squirrel cage induction generators while Type 2 WTGs use wound-rotor induction generators to allow variable resistance during machine startup and operation. The dynamic models used to represent these technologies are similar.

Table 3.1: Parameters for *wt1g* Induction Generator Model

Parameter	Description
Ls	Synchronous reactance
Lp	Transient reactance
Ra	Stator armature resistance
Tpo	Transient rotor time-constant
Se1	Saturation factor at 1 pu flux
Se2	Saturation factor at 1.2 pu flux
Acc	Acceleration factor (for numerical stability), typically = 0.5
Lpp	Subtransient reactance
Ll	Stator leakage reactance
Tppo	Subtransient rotor time-constant
ndelt	Time step subdivision factor (for numerical stability), typically = 10
wdelt	Speed threshold for applying ndelt (for numerical stability), typically = 0.8

Table 3.2: Parameters for *wt1t* WTG Drivetrain Model

Parameter	Description
H	Total WTG inertia [MW*sec/MVA]
D	Damping – not used for two-mass model
Htfrac	Turbine inertia fraction (i.e., Hturbine/Htotal)
Freq1	OEM provided frequency of the first torsional mode (Hz)
Dshaft	Shaft damping factor (typically 1 pu/pu)

Table 3.3: Parameters for *wt1p_b* Turbine Pitch Controller Model

Parameter	Description
Tr	Voltage transducer time constant (sec)
rmax	Rate limit for increasing power (pu/sec)
rmin	Rate limit for decreasing power (pu/sec)
To	Lag time constant (sec)
Pmin	Minimum power setting (pu)
Pset	If initial turbine mechanical power is greater than Pset, power is ramped
vt1-vt4	If filtered voltage < vt4, and initial turbine power (Po) ≥ Pset, then switch SW is set to position 1 for duration of T sec computed from the T vs. vtf function (see block diagram). Otherwise, SW is set to position 0.
t1-t4	

Table 3.4: Parameters for *wt2g* Generator Model

Parameter	Description
Ls	Synchronous reactance
Lp	Transient reactance
Ll	Stator leakage reactance
Ra	Stator armature resistance
Tpo	Transient rotor time constant
Se1	Saturation factor at 1 pu flux
Se2	Saturation factor at 1.2 pu flux
pdrot	Initial electrical rotor speed (pu of system frequency)
Acc	Acceleration factor (for numerical stability), typically = 0.5

Table 3.5: Parameters for *wt2e* Electrical Controls Model

Parameter	Description
Tw	Time constant
Kw	Gain
Tp	Time constant
Kp	Gain
Kpp	Proportional gain

Table 3.5: Parameters for *wt2e* Electrical Controls Model	
Parameter	**Description**
Kip	Integral gain
Rmax	Maximum external resistance
Rmin	Minimum external resistance
Slip1-Slip5	Piece-wise linear curve of slip versus power
Powr1-Power5	

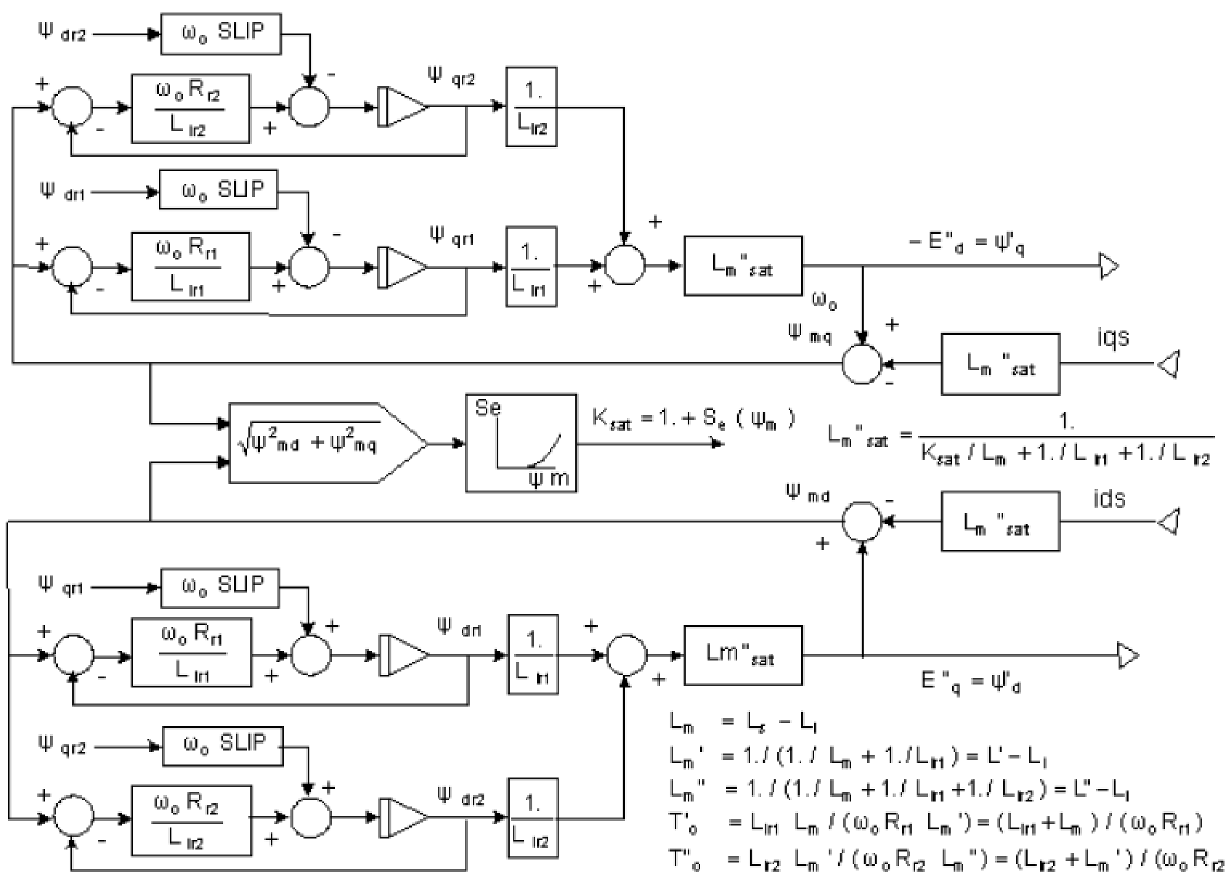

Figure 3.1: *wt1g* Generator Model Block Diagram [Source: GE]

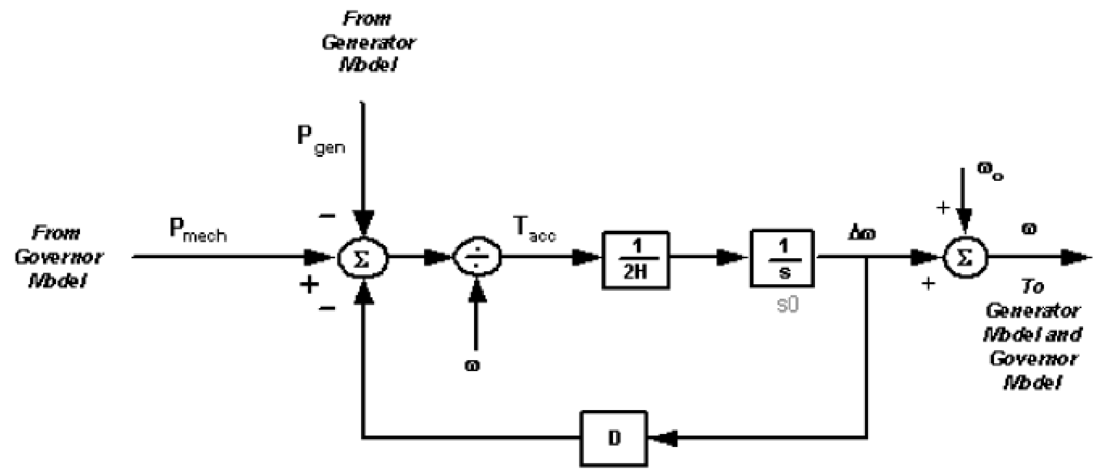

Figure 3.2: *wt1t* One-Mass Turbine Model Block Diagram [Source: GE]

$$H_t = H_{tfrac}\ H$$

$$H_g = H - H_t$$

$$K = 2\,(2\pi\ \mathrm{Freq1})^2\ H_t\ \frac{H_g}{H}$$

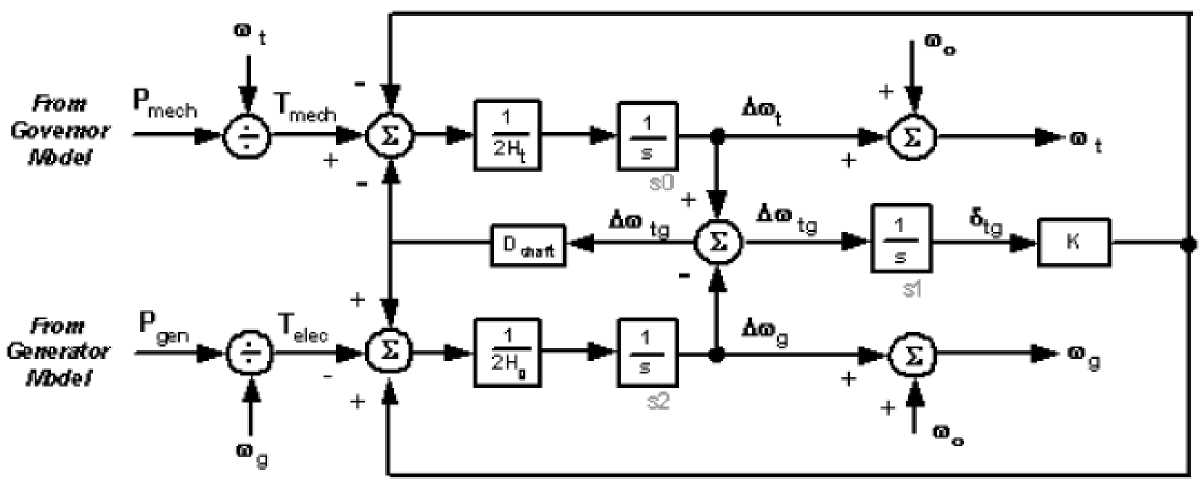

Figure 3.3: *wt1t* Two-Mass Turbine Model Block Diagram [Source: GE]

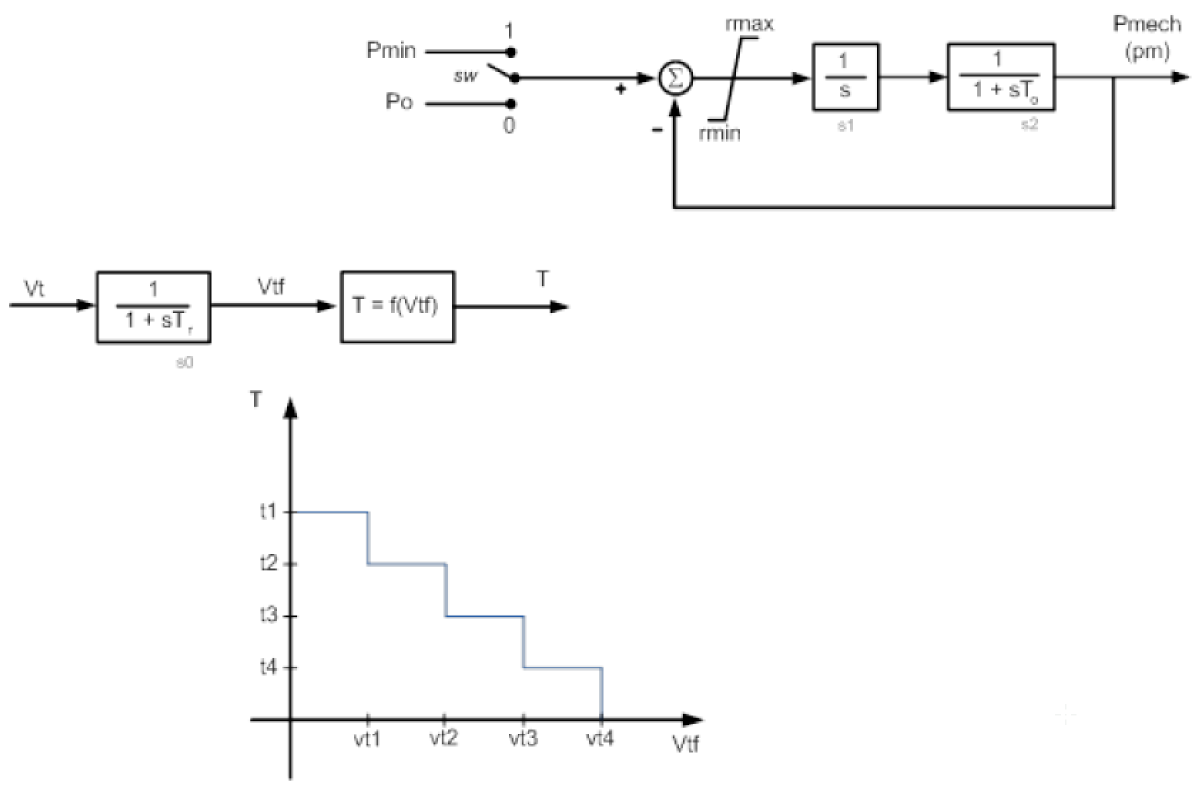

Figure 3.4: *wt1p_b* Turbine Pitch Controller Model Block Diagram [Source: GE]

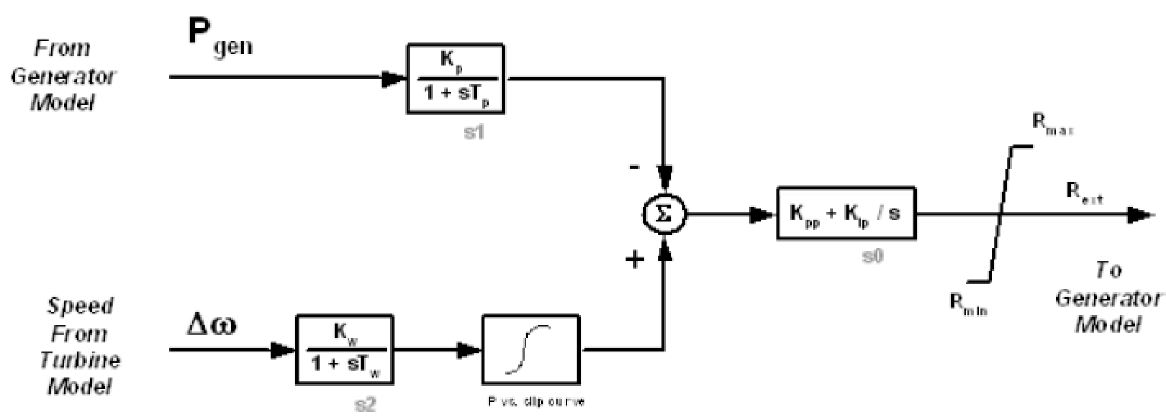

Figure 3.5: *wt2e* Electrical Model Block Diagram [Source: GE]

Since these WTGs are mostly passive devices, it is not possible to safely or effectively perform tests in the field to verify model parameters. To test the parameters of the electrical generator models and to excite the first torsional mode of the WTG to measure the torsional natural frequency, it would have to be exposed to large and sudden changes in voltage. Such tests are not viable or safe to be performed in the field; therefore, these tests are not conducted. The only feasible and practical means of model verification for Type 1 and 2 WTGs is to obtain design data from the OEM and derive from it model parameters. In particular, the following considerations should be made:

- Parameters for *wt1t* come from the OEM design data. The inertia constant (*H*) can be calculated, similarly as it is done with synchronous generators, from the OEM calculations of the polar mass moment of inertia (*J*) of the WTG ($H = ½\, J\, \omega_0^2/MVA$).

- Parameters for the *wt1g* (*wt2g*) electrical generator are also obtained from the OEM. In many cases, the OEM provides the single-cage equivalent circuit parameters of the machine (see **Figure 3.6**). These can be converted to the operational impedance parameters in **Table 3.1** as shown below:

  $Ls = Lm+La$

  $Lp = La + 1/(1/Lm + 1/L1))$

  $Ll = La$

  $Tpo = (L1 + Lm)/(2\pi*60*R1))$

  Ra is the stator resistance, *La* is the stator leakage reactance, *Lm* magnetizing reactance, *L1* is the rotor leakage reactance, *R1* is the rotor resistance. In most commercial software platforms, *Tppo = 0* and *Lpp = Lp* eliminates the subtransient circuit and models the induction machine as a single-cage machine.

Lastly, the induction machine model may be used to calculate the pull-out torque and rated power factor of the machine. These values can be compared with the OEM-supplied values as a final verification of the model.

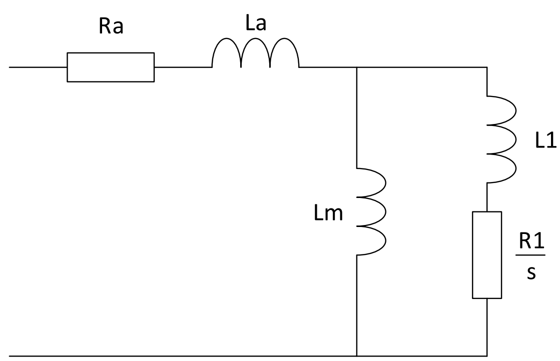

Figure 3.6: Single-Cage Equivalent-Circuit Model of an Induction Machine

In the case where a DDR is installed at the POM of the WPP, disturbance-based model verification can be used. However, a sufficiently large disturbance (e.g., close-in fault) to invoke a response from the plant is necessary to verify the dynamic response.

Proposed Type 5 WTGs

Although there are no known installations to-date of such technologies in the U.S., there is a “Type 5” WTG that has been discussed in the literature (see Appendix C of [1]). These are synchronous generator-based WTGs that use a unique patented mechanical drive system that allows for variable speed mechanical torque conversion. While the turbine is running at variable speed, the mechanical system is able to convert this to a torque delivered to the generator shaft at constant speed. In these cases, the models and model verification process for the electrical generator and its controls are likely to be no different than those obtained for a synchronous generator.

Chapter 4: Inverter-Based PPMV for MOD-026-1

Inverter-based resources are active elements controlled with closed-loop controls. MOD-026-1 focuses on verification of the excitation control system or plant volt/var control function model. Therefore, verification of reactive power/voltage controls (MOD-026-1) is required for applicable resources that meet the size thresholds. The techniques used for testing inverter-based resources mirrors the techniques used for verification of synchronous machines. Particularly for inverter-based resources, model verification activities can be categorized into staged testing and on-line disturbance monitoring, and supported with verification of documentation (as described previously) supplied by the OEM or gathered from commissioning that helps demonstrate that the modeled response reasonably matches the recorded response. All of these activities, where possible, should be performed when verifying a dynamic model. Testing and verification engineers should explore any of these options based on the equipment installed, the verification results obtained, and the type and manufacturer of the equipment. This chapter describes the types of verification tests that can be performed, applicable to any inverter-based resource, and also gives examples[26] of these tests performed on actual BPS-connected generating resources.

Staged Testing

There are multiple tests that can be performed to verify the overall performance of the aggregated response of the dynamic models associated with the excitation control system or plant volt/var controls. For inverter-based resources, the types of tests often used to perform model verification for MOD-026-1 include the following:

- **Voltage Reference Step Test:** For inverter-based resources, the volt/var control typically operates in one of the following operating modes: voltage control, power factor control, or constant var control. These quantities are typically controlled at the POM[27] using a plant-level controller (modeled using the *repc_a* or *repc_b* models [9]). The plant controller model (and to a great extent the aggregated electrical controls of the inverters using the *reec_a*, *reec_b*, or *reec_c* models) can be tested and verified by injecting a voltage reference step into the voltage reference set point of the automatic voltage regulator at the plant level. This is shown in **Figure 4.1**, using the *repc_a* model, which reasonably resembles the basic supervisory control structure at the plant-level in wind and solar PV plants. The plant controller (both in the models and in the field) sends reactive power or voltage set point commands to the inverters to adjust their reactive power output to modify the voltage at the POM. The reactive power response of the plant is recorded and then compared against the aggregated model response to verify a reasonable match. Voltage reference steps typically do not exceed 2–3 percent. Voltages at the POI and within the collector system should not exceed acceptable voltage limits during the test. The step in voltage reference should be held for at least several minutes to allow dynamics to settle down. For WPPs, it is typical to slow down the plant-level voltage control so that it takes tens of seconds to reach a new steady state output since in many cases the turbines have a faster voltage control loop controlling their terminals. Voltage deadband, or some form of current compensation/reactive droop, may also be employed on some facilities, and those need to be accounted for during testing and verification and modeled in the dynamic models.
- **Reactive Power Reference Step Test:** Another method of testing the dynamic response of the plant controller is to perform a reactive power reference step test. This test is used for plants operating in either constant reactive power or constant power factor mode. It is not necessary for plants operating in voltage control mode (which is the preferred control mode for all BES power plants). In this test, a step is injected in the reactive power reference for the plant. A relatively small (e.g., around 5–10 percent of total dynamic reactive power available at the time of testing) step should be injected, ensuring that voltages remain within acceptable limits.

[26] Examples in this guideline are for Type 3 and 4 WPPs and solar PV plants. The approaches are also applicable to other inverter-based resources, such as battery energy storage systems. The same 2nd generation generic renewable energy system models can also be used [17].
[27] Historically the POI, until FERC Order No. 827.

- **Shunt Capacitor (or Reactor) Switching Test:** Another means of testing the voltage/var response of the plant controller is to switch a shunt capacitor (or reactor) either at the POI (in the substation within the plant) or nearby on the transmission system. This is not always available as some plants may not have switched shunts in their collector system, and other devices within the transmission system may not be nearby or available for switching. Switching the shunt device will cause the volt/var control system of the plant to either regulate POI voltage or power factor. The RC must be notified prior to switching capacitors or reactors. Again, the dynamic response of the plant can be recorded and compared to the simulated response for model verification purposes. This also results in an initial response of the turbine-level voltage control loop and thus also verifies those controls.

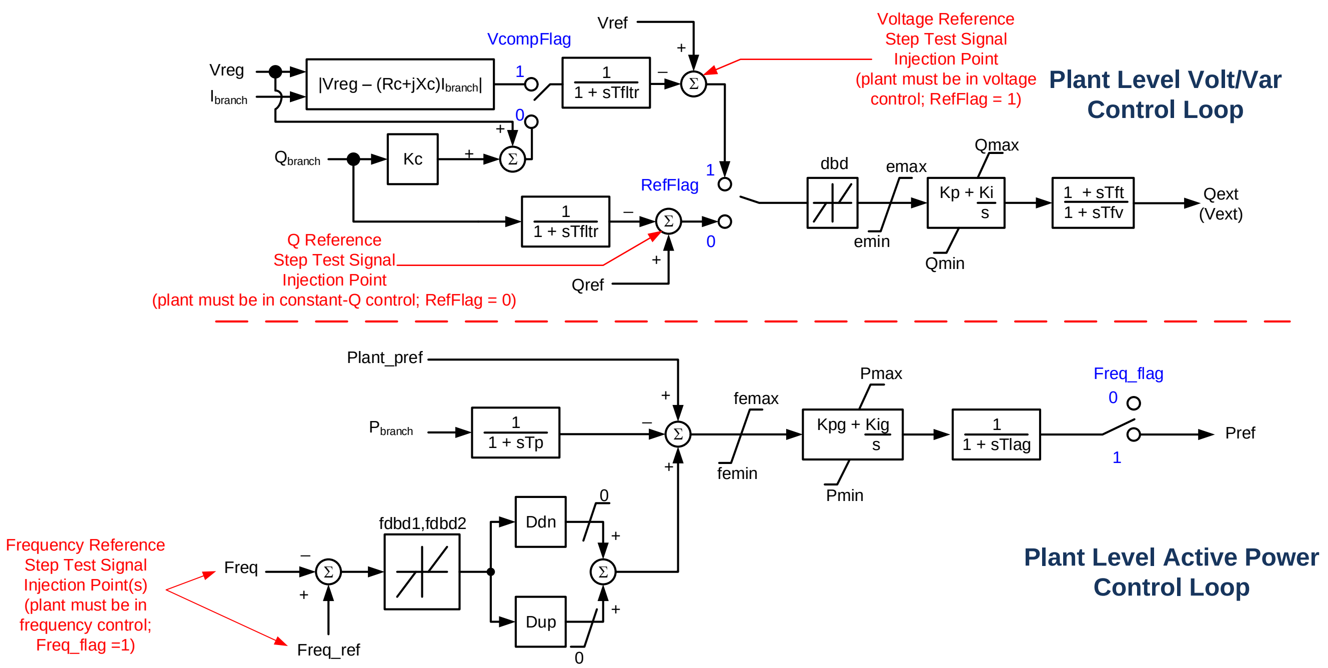

Figure 4.1: Injection Points in REPC_A Model for Voltage and Frequency Reference Step Tests[28] [Source: PEACE®]

Voltage Reference Step Test Examples

Voltage reference step tests are commonly performed to meet the requirements of MOD-026-1 to demonstrate the plant's response to a deviation between controlled voltage and set point voltage. This section shows a few examples of tests performed for different inverter-based resources.

Type 3 Wind Power Plant Example

This example uses the second generation generic Type 3 WPP models to represent the dynamics of the WPP, including six modules: electrical control, torque control, pitch control, drive-train, aerodynamics, and generator/converter. In addition, a low/high voltage ride-through protection module was included in the plant representation [9], [11], [15]. Measurements during the test were taken at the plant POM, including bus voltage, frequency, and real and reactive power. **Figure 4.2** shows the dynamic response of the plant to a change in the voltage reference set point, and compares the voltage, real power, and reactive power. The modeled response matches the actual response very closely.

[28] As applied in both the model (*repc_a*) and in the actual control system

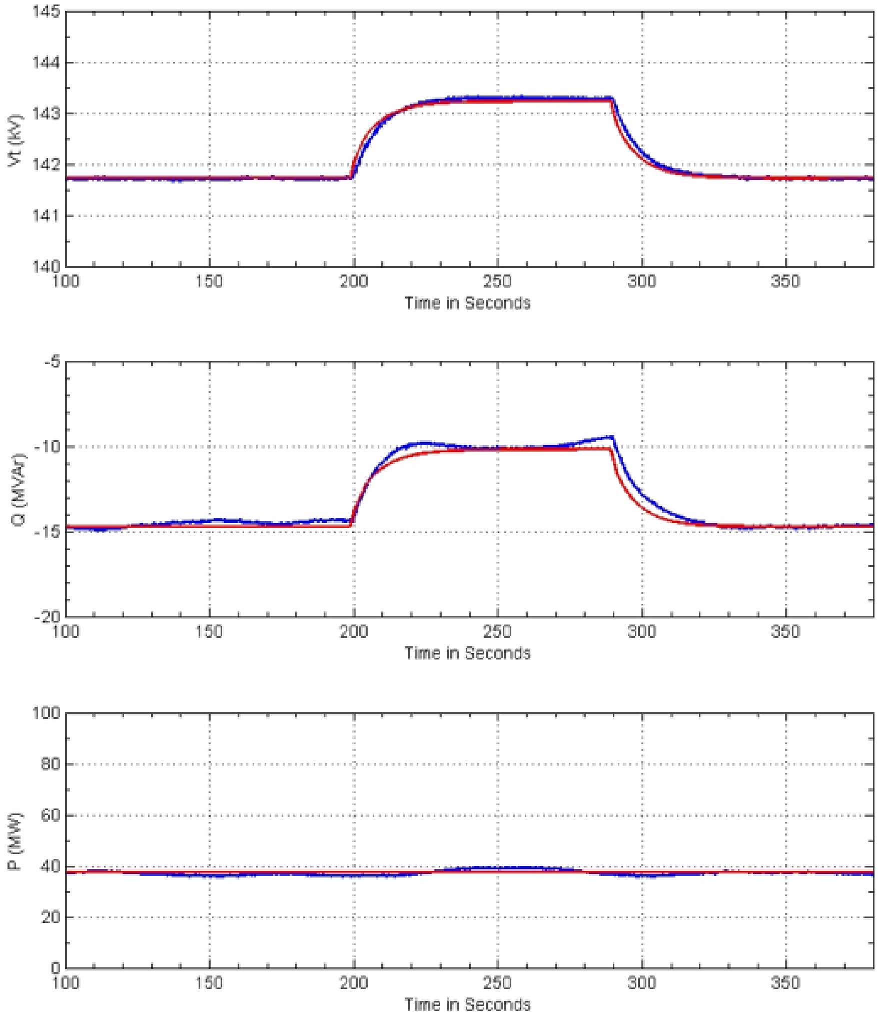

Figure 4.2: Voltage Reference Step Test. Simulated (Red) vs. Measured Response (Blue)

Multiple Wind Power Plant Example

In this example, a voltage reference step test is applied in the plant-level controller at one of three WPPs. **Figure 4.3** shows the response of that WPP to the test at its POM (red is simulated, blue is measured). A localized system model was used for verification simulations, including nearby WPPs that were previously verified. Results of the overall verification are shown in **Figure 4.4**. Small discrepancies exist between the observed and measured reactive power output for Plants 1 and 2 and are attributed to slight errors in the system model. Although initial conditions do not match exactly, the gain, droop setting, and other features of the controls are verified through this test in the dynamic response of the plant(s).

Individual WTG responses within each WPP were also monitored for these tests, and their dynamic response matched closely to the aggregated plant model when divided by the number of turbines on-line. The only difference, as expected, was in the steady-state values of reactive power and voltage since the equivalent feeder model cannot capture the voltage at all points in the collector system [16]. While not relevant to MOD-026-1 or MOD-027-1 verification, this observation lends some empirical evidence to the reasonableness of the single machine aggregated model (**Figure 1.1**) for large-scale wind and solar PV plants in stability studies where all WTGs or solar PV inverters in the plant are identical. If there is a mixture of technologies, a more complex model made be necessary (e.g., an aggregated model for each turbine or inverter type in the plant).

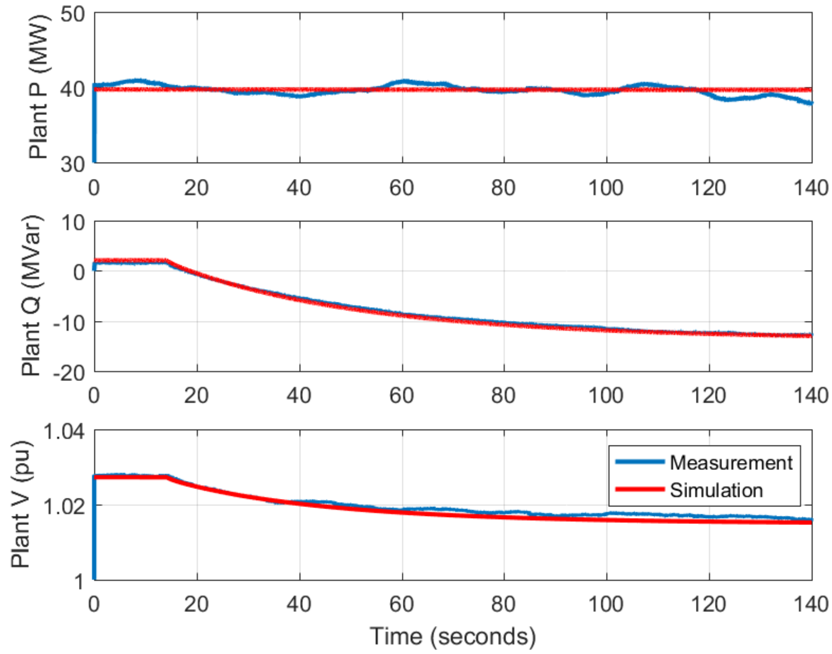

Figure 4.3: Voltage Reference Step Test at Plant-Level Controller [Source: PEACE®/PacifiCorp]

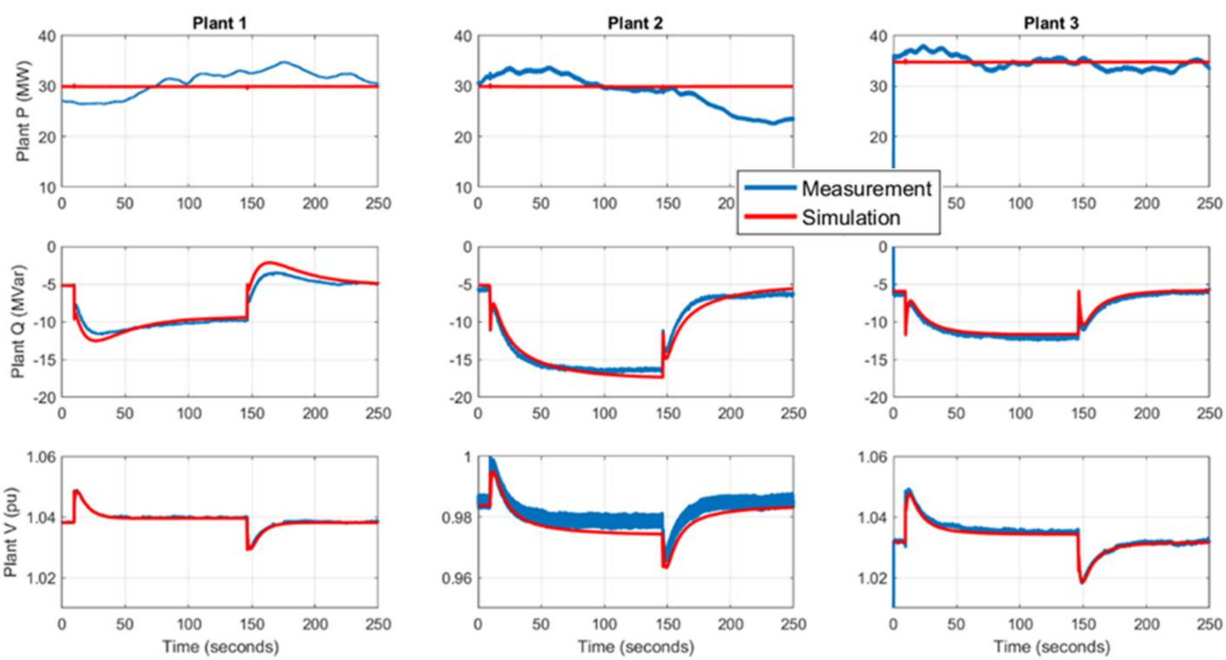

Figure 4.4: Three Type 3 WPP Responses to Transmission-Level Capacitor Switching [Source: PEACE®/PacifiCorp]

Type 4 WPP Voltage Reference Step Test Example

Figure 4.5 shows a voltage reference step test applied to a Type 4 WPP. The voltage reference step of 1 kV was injected at the plant-level controller. Bus voltage and plant total reactive power were measured at the POM. The actual measured POM voltage was then played back into the stability model and simulated reactive power output was compared against the actual response of the plant. Results show a very close match between the simulated and actual reactive power response of the plant.

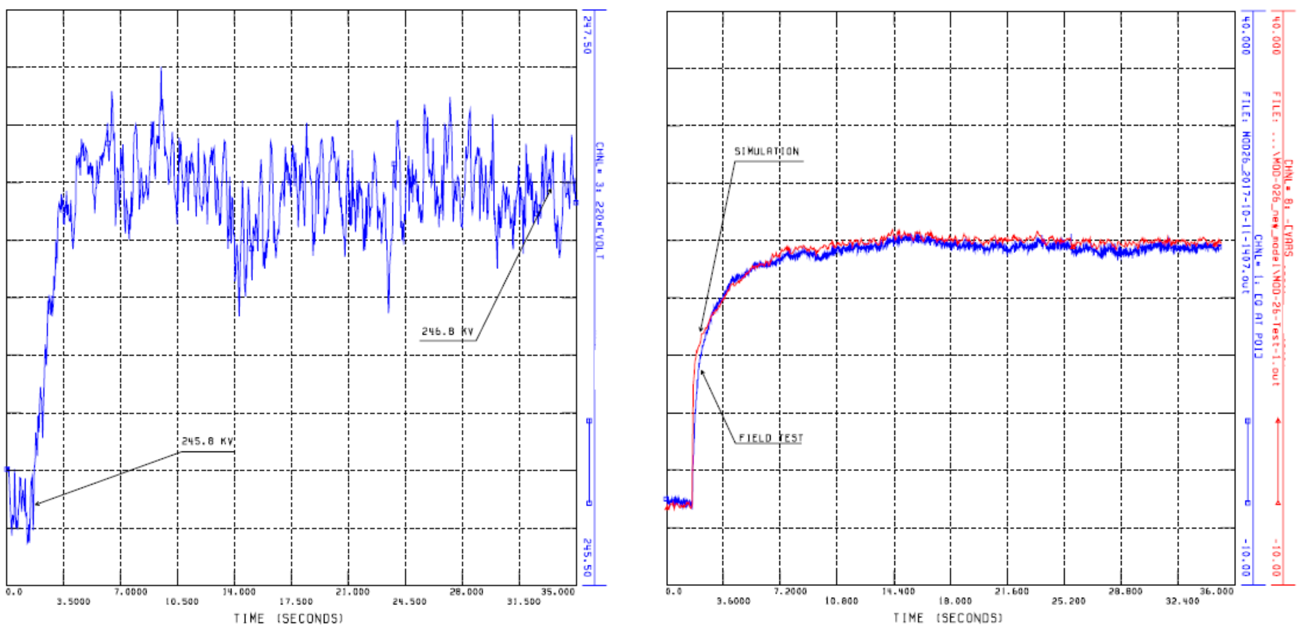

Figure 4.5: POM Voltage Play-In and Reactive Power Comparison [Source: Siemens]

Solar PV Plant Voltage Reference Step Test Example

This example shows a voltage reference step test applied at the plant-level controller of a solar PV plant. The controller is maintaining voltage at the POM, and a step change in voltage set point from 1.0 pu to 0.997 pu (0.3 percent) was introduced at the plant-level controller. This caused the controller to send changes to the commanded reactive power output from the inverters. The inverters then reduced reactive power output to maintain desired POM voltage. **Figure 4.6** shows the results of this test as compared with the modeled response. The change in reactive power over a ramped response is based on the reactive power ramp rate in the plant-level controller. This should be modeled in the dynamic models and verified as part of testing the overall plant performance.

Because the local inverters are responding only to a commanded reactive power output level, and the plant-level controller is set to respond with a fairly slow response time, the change in reactive power (and voltage) occurs over a relatively long period. This is, in part, because the local inverters are not operating on local voltage control and only on commanded reactive power set point control.

Figure 4.6: Voltage Reference Step Test at Solar PV Plant with No Local Inverter Voltage Controls (Plant-Level Control Only)

Equipment Interactions Example

As in any verification testing, there is the potential for other equipment (e.g., other power plants, SVCs, STATCOMs) to experience the changes in grid conditions caused by the tests and respond to the change in terminal conditions. This can particularly be an issue if the other equipment not under test is electrically very close (impedance between facilities is small) and also operating in voltage regulation mode. The reason for this is that if both elements are attempting to regulate bus voltage that is heavily impacted by the plant under test, these controls can interact.

When this happens, having test measurements and recording for not only the response to the plant under test but also the response of the other equipment is beneficial (although not always achievable). An interaction can be observed from inspection of the test results by comparing the shape of the voltage measurement with the shape of the reactive power measurement. When an interaction occurs, it is recommended to not use the collected data for model verification but to instead determine the equipment that is likely interacting and to request to find a time to test the plant when the interacting equipment will be out-of-service or temporarily placed in a non-voltage-regulating mode. An example of a test with interacting equipment that needed to be repeated is shown in **Figure 4.7**.

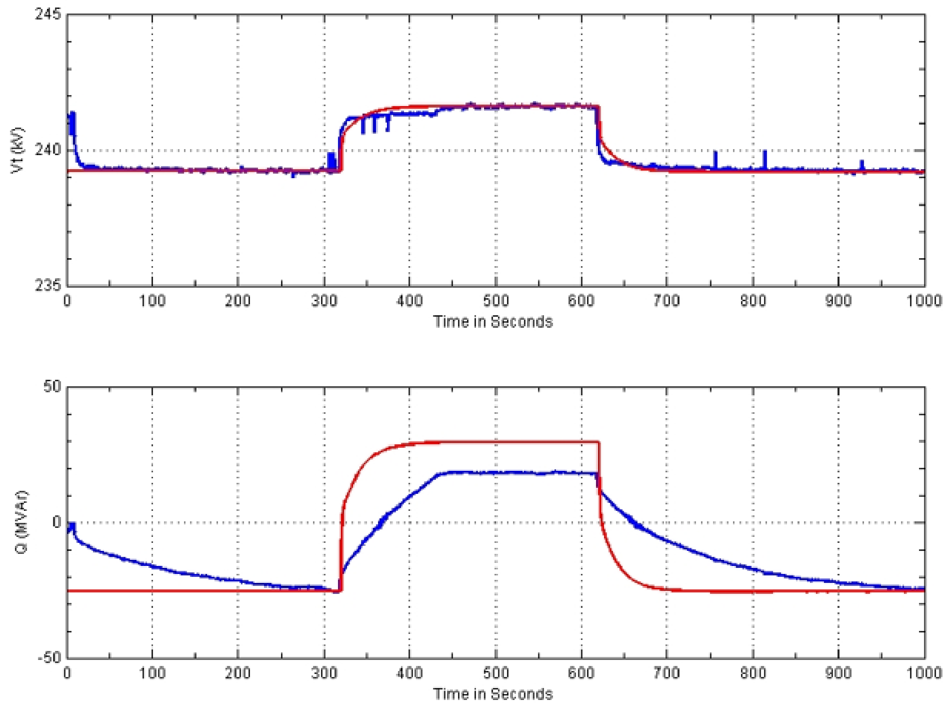

Figure 4.7: Example of Interacting Equipment and Resulting Mismatch. Simulated (Red) vs. Measured Response (Blue) [Source: GE]

These issues can be overcome in some cases by ensuring that the test data used to play back into the simulation for verification only captures the response of a single plant (radial connection of that plant). The system equivalent added to the generator model under test should represent that distinct measurement and should not include other elements past the equivalent system representation.

Capacitor Switching Test Example

Another method that can be employed for verification testing is capturing and modeling the response of the inverter-based resource to a change in shunt compensation (and inherent impact on voltage). The voltage regulation response of an inverter-based resource can be exercised by switching shunt compensation in and out of service close to the point of regulation. This section describes examples related to this method.

Type 3 Wind Power Plant Cap Switching Example

Figure 4.8 shows an example of shunt capacitor switching. The bank is switched in causing the high-side bus voltage to rise. Correspondingly, reactive power contribution from the WPP decreases to reduce the voltage as the plant is in voltage regulation mode with voltage droop. The voltage during the time period when the shunt capacitor is switched in does not return to its preswitched value but remains above this value due to voltage droop.

Upon closer examination of measured and simulated responses, brief spikes are seen in the traces particularly for the reactive power response. Immediately after shunt capacitor switching, the fast voltage regulator at each of the wind turbines responds by quickly absorbing reactive power to attempt to maintain terminal voltage at the last voltage reference. As time goes on, the outer-loop regulators, which are intentionally tuned to respond more slowly, are seen as the voltage and reactive power move towards the new-steady-state point that is ultimately determined by the plant-level controls acting in voltage regulation mode with voltage droop.

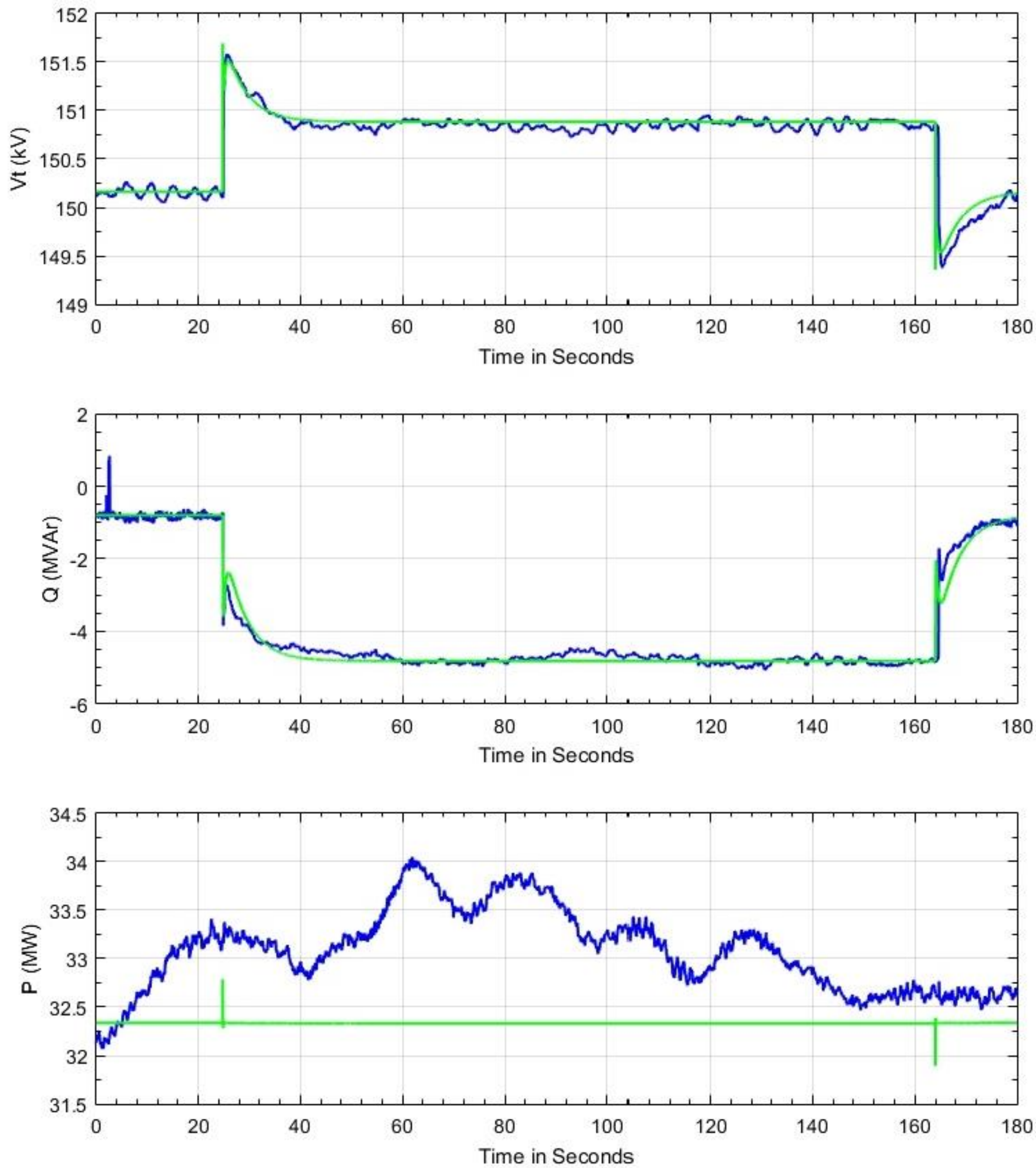

Figure 4.8: Capacitor Bank Switch Test. Simulated (Green) vs. Measured Response (Blue) [Source: GE]

Solar PV Switched Capacitor Bank Test Example

This example shows switching capacitor/reactor bank(s) at the medium voltage collector system of a solar PV plant. The capacitor bank is located at one of the medium voltage feeders (34.5 kV), and is inserted by the plant-level controller. The reactive power target at the POM is set higher than the net sum of cumulative reactive power capability of all inverters on-line during the test period plus reactive power losses within the plant. When the target reactive power is set in the SCADA HMI, the inverters respond immediately to achieve the requested set point by ramping up reactive power within power factor limits. When the desired set point cannot be reached by inverter(s) alone, the plant-level controller sends a command to switch in a capacitor bank (4.75 MVAR in this case) automatically. This is seen around 43 seconds in the time series in **Figure 4.9**. The inverters ramp down after the capacitor is switched in to maintain desired reactive power target. The plant is later commanded to maintain 0 MVar at the POM at 55 sec, -3.5 MVAr at 88 sec, and back to 0 MVAr at 118 sec. The overall dynamic response of the plant is monitored as well as the status and injection of MVAR by the shunt capacitors involved.

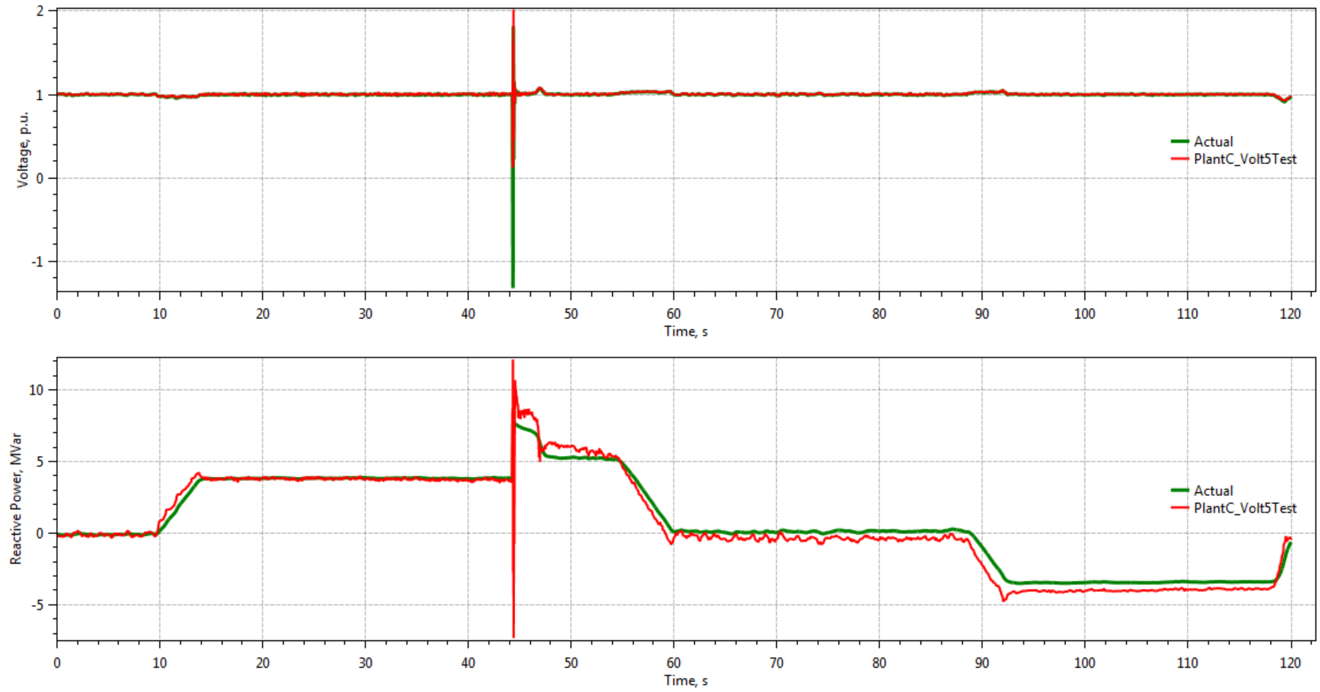

Figure 4.9: PV Plant Actual and Simulated Response for Capacitor Bank Switching Test (Source: First Solar)

Solar PV Switched Capacitor Bank Test Example

The solar PV plant in this example consists of 80 inverters with a total installed capability of 76 MW. All inverters are operated on local V/Q-coordinated control, and the plant-level controller is configured to regulate voltage at the high-side of the station transformer. There are two 12 MVA shunt capacitors available at the collector station. The generic model package (*regc_a*, *reec_b*, and *repc_a*) is used to represent the power plant.

Figure 4.10 shows the measured and simulated response of the plant for a capacitor switching test where one of the 12 MVA capacitors is switched in service. Voltage at the high-side of the station transformer (top) is simulated and played into the model. The reactive power response of the solar PV plant is measured (middle) as well as active power (ignored for this test). Overall, a reasonable match is observed between the measured and simulated response. According to the plots, the response of the plant is clearly divided into two parts: the transient response (first four seconds) and the longer-term response (one to two minutes).

- In the transient response, as a result of the long time constant of the plant-level controller, the initial response of reactive power output is mainly dominated by the local V/Q coordinated control. The initial modeled response can be calibrated to match the actual measurement by tuning the control gains Kvp, Kvi, Kqp, Kqi in the *reec_a* model.
- In the long-term response, the response of voltage and reactive power output is mostly governed by the plant-level controller parameters. The plant-level controller acts to regulate POI voltage and resets the reactive power output of the plant to the initial value in response to the voltage excursion caused by capacitor switching. By adjusting the control gains in the *repc_a* model, the effect of reactive power reset can be replicated.

This example clearly shows that dividing the model parameters into different time range does not only help the modeler better understand the dynamic responses of the control but also simplifies the model calibration procedure.

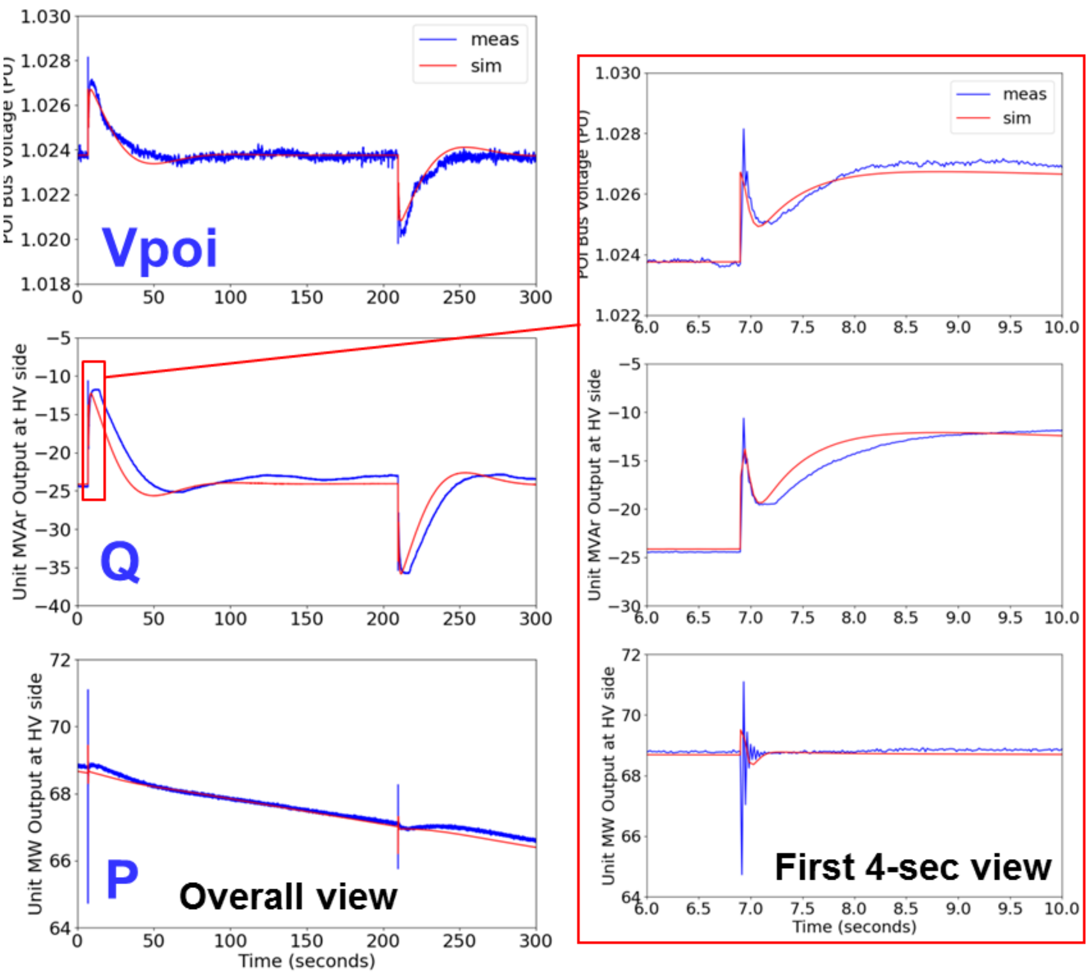

Figure 4.10: Comparison of Solar PV Plant to a Capacitor Switching Test [Source: Powertech Labs]

Reactive Power Reference Step Test Example

In this example, a change in reactive power reference set point is applied at the plant-level controller. The controller is set to maintain a specified reactive power output at the POM. The shunt capacitor/reactor banks within the solar PV plant were not engaged to meet the desired reactive power set point during this test. The set point was changed by applying steps in command from 0 MVAR to 1.6 MVAR and then back to 0 MVAR. These steps were applied at the SCADA human-machine interface (HMI). The POM voltage and reactive power output of the plant were measured and compared against the modeled response, as shown in **Figure 4.11**. The voltage plot show that the plant is connected to a system with moderate short circuit strength since the voltage profile remained fairly constant despite the $\pm$ 1.6 MVAR change in output.

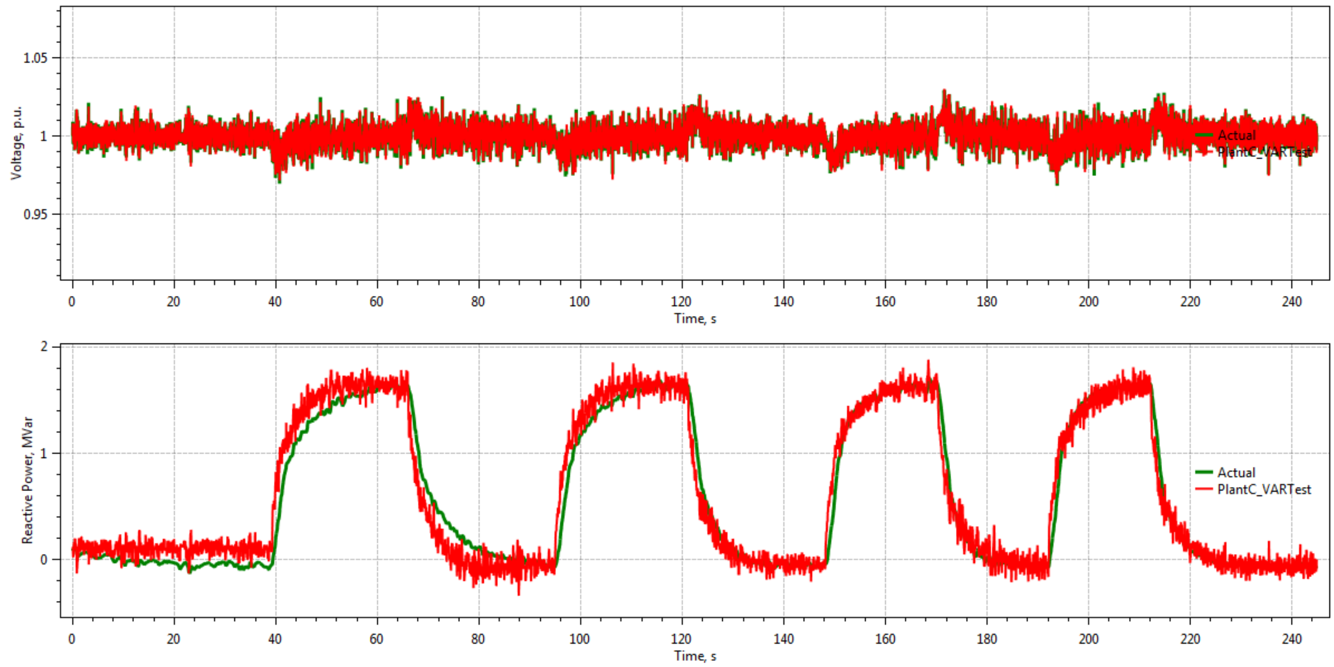

Figure 4.11: PV Plant Actual and Simulated Response for Change in Reactive Power Reference [Source: First Solar]

A second example of a reactive power control test performed on a 290 MW solar PV plant is shown in **Figure 4.12**. Reactive power control maintains capacitive or inductive VARs at the plant POI. For this particular plant during the test, all inverters are running under plant-level control. In the beginning, the reactive power output set point is set to 0 MVAR. That set point is changed in steps up to the High Operating Limit (HOL), then lowered to the Low Operating Limit (LOL), and then returned back to 0 MVAR. It is important to verify at each step that the plant reactive output reaches the target and the plant reactive power ramp rates are maintained without any reactive power oscillations. Capacitors and reactors were kept out of service during the test.

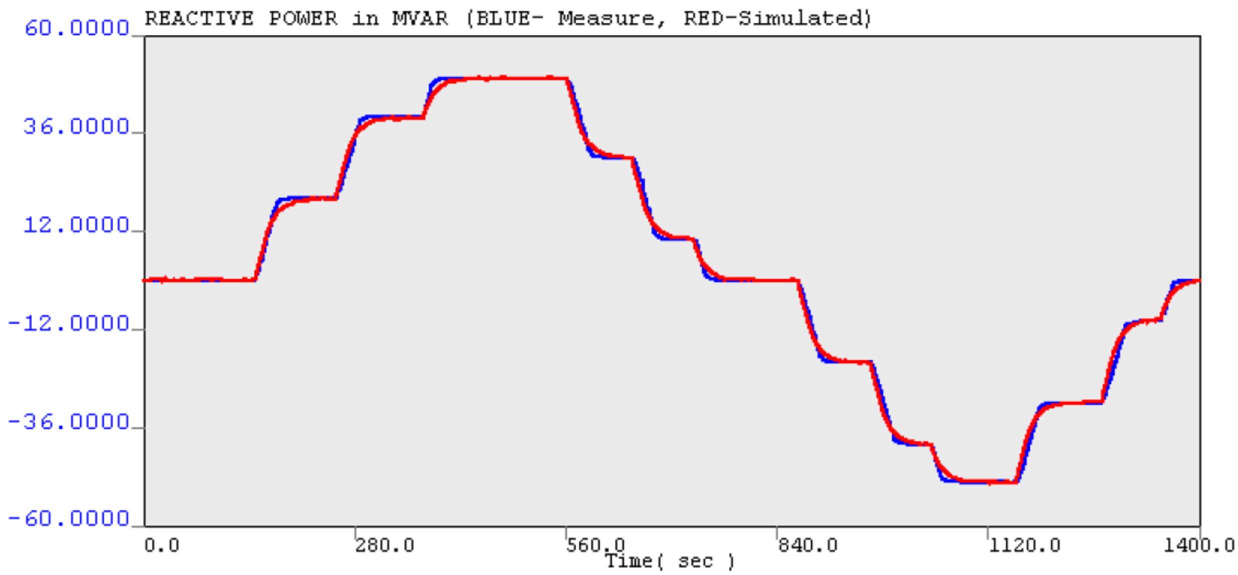

Figure 4.12: 290 MW Solar Plant Reactive Power Control Test [Source: First Solar]

Another example of reactive power reference step testing on a 250 MW solar PV plant is shown in **Figure 4.13** where plant active power output was between 75 to 100 percent of rated. For the step test, the reactive power reference set point in the SCADA HMI was changed from 55 to 73 MVAR, resulting in the dynamic response of the plant reaching the desired set-point in overexcited mode. The reactive power was brought back down with a 37 MVAR order command. The modeled response closely followed the recorded response. The voltage plot shows the change in voltage at plant POI in response to commanded reactive power set-point change.

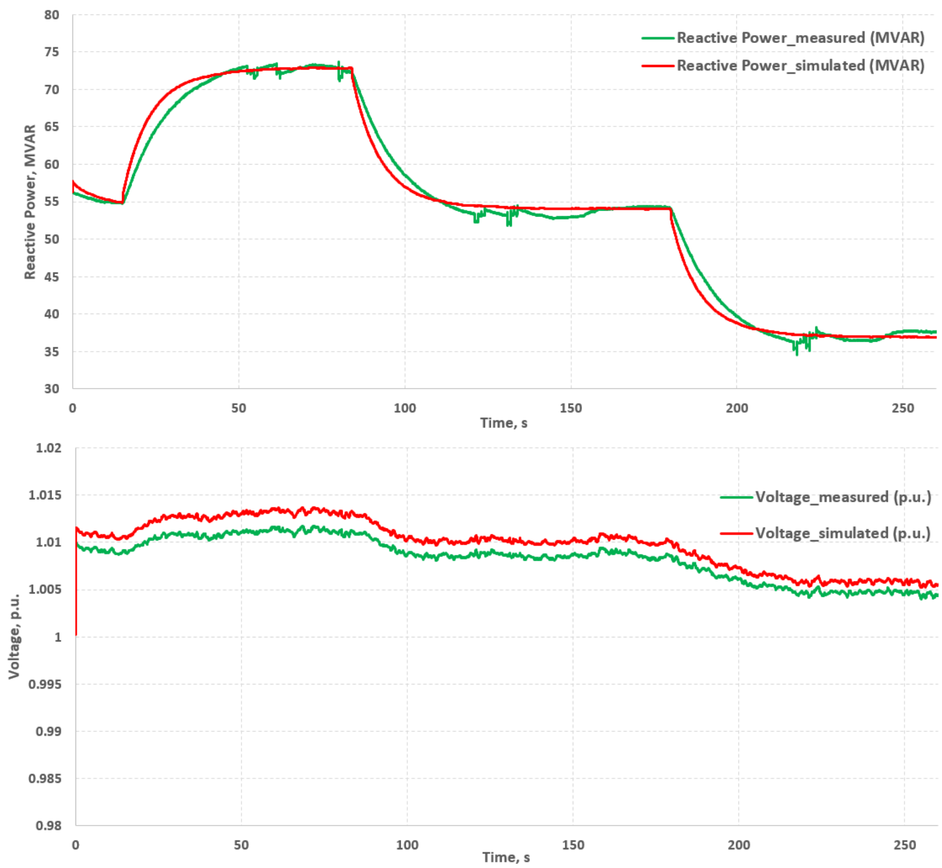

Figure 4.13: Reactive Power Reference Step Test Example [Source: First Solar]

Another possible step test, which is a variant to this test, is to change the power factor set point in the SCADA HMI. The plant-level controller calculates the derived reactive power set points to be sent to individual inverters using the actual plant active power set point and the commanded power factor set point. With the *repc_a* model, this test cannot be simulated since it does not model plant-level power factor control. However, the *repc_b* model can be used, which does model plant-level power factor control.

Chapter 5: Inverter-Based PPMV for MOD-027-1

NERC Reliability Standard MOD-027-1 focuses on verification activities for the turbine-governor and load control or active power-frequency control model. Similar to MOD-026-1 verification, these activities can be achieved either using disturbance-based verification or through staged testing. However, conducting staged tests can be more challenging for inverter-based resources than for synchronous machines due to external factors. For example, disturbance-based verification methods using simulation play-in models assume a constant energy source (e.g., wind speed or solar irradiance). When the input energy source changes, causing natural change in active power output of the facility, this cannot be accounted for in the simulation methods. If the change in output caused by external factors is too large relative to the change in output caused by the disturbance, then the signal to noise ratio is too small and the disturbance cannot be used for verification purposes. Similarly, for staged tests over a relatively long duration (tens or hundreds of seconds), the constant energy source assumption again could become a problem.

FERC Order No. 842[29] amended the *pro forma* LGIA and SGIA to require that all newly interconnecting resources install, maintain, and operate a functioning governor or equivalent controls as a precondition of interconnection. FERC Order No. 842 requires new generation to have the capability as well as respond, when possible, to frequency excursion events when frequency falls outside the deadband of +/- 0.036 Hz and adjust its output in accordance to a five percent droop on turbine MW base. This response must be timely and sustained rather than injected for a short period and then withdrawn. In other words the new generation is expected to adjust its output to follow its droop of five percent whenever the frequency is outside of +/- 0.036 Hz. Reserving generation headroom to provide frequency response to underfrequency events is not required.[30] Therefore, a response is only expected for underfrequency events if the plant has been curtailed or dispatched below maximum available power and has headroom to respond. However, resources should respond to overfrequency excursion events outside the deadband by reducing active power output in accordance with the five percent droop provisions.

Similarly, some regional standards or interconnection agreements have also required resources to have the capability to actively control frequency and at least be responsive in one direction (e.g., downward movement for overfrequency events). For example, Hydro Quebec *Transmission Provider Technical Requirements for the Connection of Power Plants to Hydro-Quebec Transmission System*[31] states in Requirement 5.3.3 that “asynchronous generating units able to control frequency and having a rated capacity above 10 MW must…be equipped with a feedback system” that performs active power-frequency control.

On the other hand, many existing inverter-based resources do not have active power-frequency control capability or do not have those controls enabled. MOD-027-1 Attachment 1, Row 7 describes this situation (see **Figure 5.1**). It states that verification can be met with a written statement to the TP in two distinct situations where the applicable unit:

- is not responsive to both over and under frequency excursion events (the applicable unit does not operate in a frequency control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response), or
- either does not have an installed frequency control system or has a disabled frequency control system.

[29] FERC Order No. 842 can be accessed here: https://elibrary.ferc.gov/IDMWS/common/downloadOpen.asp?downloadfile=20180215%2D3099%2832695275%29%2Epdf&folder=15219837&fileid=14823757&trial=1

[30] Wind and solar PV plants are typically operated at the maximum available incident wind/solar resource; therefore, typically, unable to respond to underfrequency events. However, it is possible that the plant may be curtailed due to other reasons (e.g., transmission congestion) in which case it then can respond to an underfrequency event.

[31] http://www.hydroquebec.com/transenergie/fr/commerce/pdf/exigence_raccordement_fev_09_en.pdf.

The first condition relates to resources that operate in a mode (other than start up or shut down) where the active power is not dependent on measured frequency. This is particularly relevant for some thermal generating resources and less relevant for inverter-based resources. The second condition is more relevant to inverter-based resources in situations where the capability does not exist or that capability is not enabled (frequency response capability disabled). Both conditions do imply that resources that can respond in one direction but not the other (e.g., operating a maximum available power yet decrease output for overfrequency conditions) do require verification methods, and the exemption does not apply. Similarly, if the deadband is set relatively large such that the unit does not respond, this does not meet the conditions listed above.

MOD-027 Attachment 1

Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity

Row Number	Verification Condition	Required Action
7	Applicable unit is not responsive to both over and under frequency excursion events (The applicable unit does not operate in a frequency control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.); OR Applicable unit either does not have an installed frequency control system or has a disabled frequency control system. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Perform verification per the periodicity specified in Row 4 for a "New Generating Unit" (or new equipment) only if responsive control mode operation for connected operations is established.

Figure 5.1: MOD-027-1 Attachment 1 Row 7

Based on the variance in requirements for existing and future inverter-based resources connected to the BPS, the following guidance is provided from a modeling standpoint:

- **No Capability:** The resource is not required to provide any active power response to changes in frequency; therefore, it does not have a functional active power/frequency control system. In this case, the model should also show no frequency response capability (e.g., when using the *repc_a* model *Freq_flag* = 0, see **Figure 4.1**) and testing for verification is not necessary for MOD-027-1 since there are no controls that adjust output for changes in frequency. System disturbance recordings can easily confirm that the plant has no frequency response capability.
- **Capability but No Reserve Requirement:** The resource is required to have the capability to respond to frequency excursions by changing active power output. However, the resource always operates at maximum available input power (e.g., solar irradiance, wind speed) and does not have any ability to provide a sustained increase in active power for underfrequency conditions. It does, on the other hand, have the ability to provide response for overfrequency events. In this case, the active power/frequency control system should be verified for overfrequency conditions. This should include verification of the droop characteristic, deadband, and response times using the testing procedures described in this document. System disturbance recordings can easily confirm that the plant does not respond to underfrequency events.
- **Capability and Reserve Requirement:** The resource is required to have the capability to respond to frequency excursions by changing active power output. It may also participate in a primary frequency response market or operate in a condition where it could provide response to underfrequency events. Therefore, it could provide response in the upward or downward power output direction. In this case, the active power/frequency control system should be verified for both underfrequency and overfrequency conditions. This should include verification of the droop characteristic(s), deadband(s), and response times using the testing procedures described in this document.

- **Inertial-based Response:** Some inverter-based WTGs may be fitted with the ability to provide a short-duration increase in active power response where mechanical kinetic-energy stored in the rotating shaft of the wind-turbine rotor is converted to electrical energy; however, this energy must be returned and extracted back from the grid shortly thereafter to bring the turbine back to it optimal rotational speed. These types of responses do not meet FERC Order No. 842 requirements although they may exist in regional requirements.[32] In this case, the second-generation renewable energy system models are not currently able to capture these effects. Either a detailed model should be used or a reasonable representation of the other characteristics (excluding this effect) may be modeled upon agreement with the PC and TP.

FERC Order No. 842 requires that applicable generating units have active power-frequency controls that are active and able to respond to over- and underfrequency excursion outside a reasonable deadband when the unit is operating in a condition where the operating reserve is available. Newly interconnecting resources after the effective day of implementation of the order are required to meet these requirements while existing resources are subject to prior requirements. Both are also subject to any regional requirements, interconnection agreements, and market rules that may apply.

Modeling Non-Responsive Resources

As explained previously, prior to FERC Order No. 842, some regions may have had local requirements for generators to have active power/frequency response capability.[33] Where controls are not enabled or the capability does not exist (as described above), this control can easily be modeled by setting the *Freq_flag* = 0 (see block diagram in **Figure 4.1**) and then verified a number of ways. Two options include the following:

- **Primary Option:** The unit does not operate in a frequency control mode or have an installed frequency control system (or it is disabled during normal operation). Historical data can be used to show evidence of non-responsiveness to under- and overfrequency events. **Figure 5.2** shows PMU data captured for a frequency excursion event and shows no response from the WPP.
- **Alternative Option:** For plants that do not have access to historical data, detailed OEM documentation and review of the plant-level controls can be used to show evidence of non-responsiveness. Verification of actual response may not be necessary. However, documentation of the lack of responsiveness should be provided as part of the MOD-027-1 submittal. This could include block diagrams or control settings that show this feature disabled or non-existent at the facility.

[32] Hydro Québec, Section 14.4, http://www.hydroquebec.com/transenergie/fr/commerce/pdf/exigence_raccordement_fev_09_en.pdf.
M. Asmine, C. Langlois, N. Aubut, "Inertial response from wind power plants during a frequency disturbance on the Hydro-Quebec system – event analysis and validation," IET Renewable Power Generation, vol. 12, no. 5, pp. 515-522, 2018.
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Hydro Quebec, Section 5.3.3, http://www.hydroquebec.com/transenergie/fr/commerce/pdf/exigence_raccordement_fev_09_en.pdf.

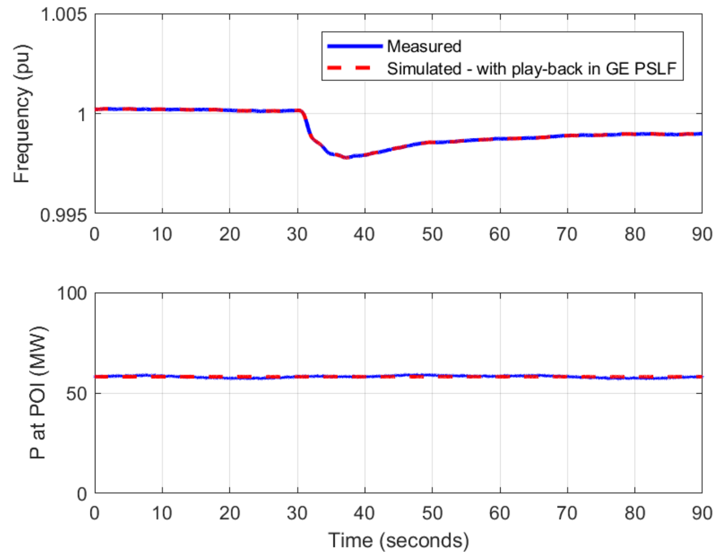

Figure 5.2: Example of Non-Responsive WPP for Underfrequency Excursion [Source: PEACE®/PacifiCorp]

For WPPs that are capable of providing frequency response in either the upward or downward direction, they should be modeled appropriately by setting *Freq_flag* = 1. However, when performing planning studies, the TP and PC should give careful consideration to how the models are used. For example, if the WPP (or solar plant) operates at maximum available power without any curtailment (typical operation for these types of resources), the model should be appropriately parameterized (e.g., setting *Pmax* in *repc_a* to the initial power output of the plant in the powerflow case) so that the model will not increase output for underfrequency events due to the fact that the energy source (wind speed/solar irradiance) cannot be increased.

Staged Testing Model Verification for MOD-027-1

One of the primary objectives of active power/frequency control system model verification is to verify droop, intentional deadband, and response time of the resource. For plants with active power/frequency controls, the simplest and predominant test method is to play in a measured or artificial frequency step or frequency disturbance to the plant-level controller. This is done by overriding the frequency reference or frequency signals (see **Figure 4.1**). If the signal is played into the frequency reference (*Freq_ref* in **Figure 4.1**), an increase in the signal will result in an increase in plant active power. The opposite is true if the signal is played into the actual frequency feedback signal (*Freq* in **Figure 4.1**). By doing this, inverters are sent a signal to respond to a frequency excursion event as if an actual event has occurred on the system. The play-in signal can be any of the following:

- An actual frequency signal measured/synthesized from a historical system frequency disturbance event
- A synthetic frequency signal created to emulate a realistic, large frequency increase or decrease
- A relatively small (e.g., 0.1–0.2 percent) step change in frequency in the upward or downward direction, large enough to be greater than any control deadbands.

Frequency Disturbance Play-In Examples

Two frequency response tests are provided here. The first test is from an actual event in the Texas Interconnection measured on November 29, 2011. The frequency measurement from this disturbance is injected into the plant-level controller to emulate a grid event, and the dynamic response of the plant is monitored. This particular event was a relatively large disturbance (loss of 1.365 GW of generation) during a demand level of 30.07 GW. For test purposes, the plant was set to operate with a 1.67 percent droop setting (i.e., 59.88 pu governor gain), and the plant was operated in curtailed mode at the level of approximately 12 MW when the event started (nearly 50 percent of actual MW capacity). In response to the emulated frequency decline, the solar PV plant increased its active power based on the droop characteristic. Measured and simulated response of the plant during this event is shown in **Figure 5.3**.

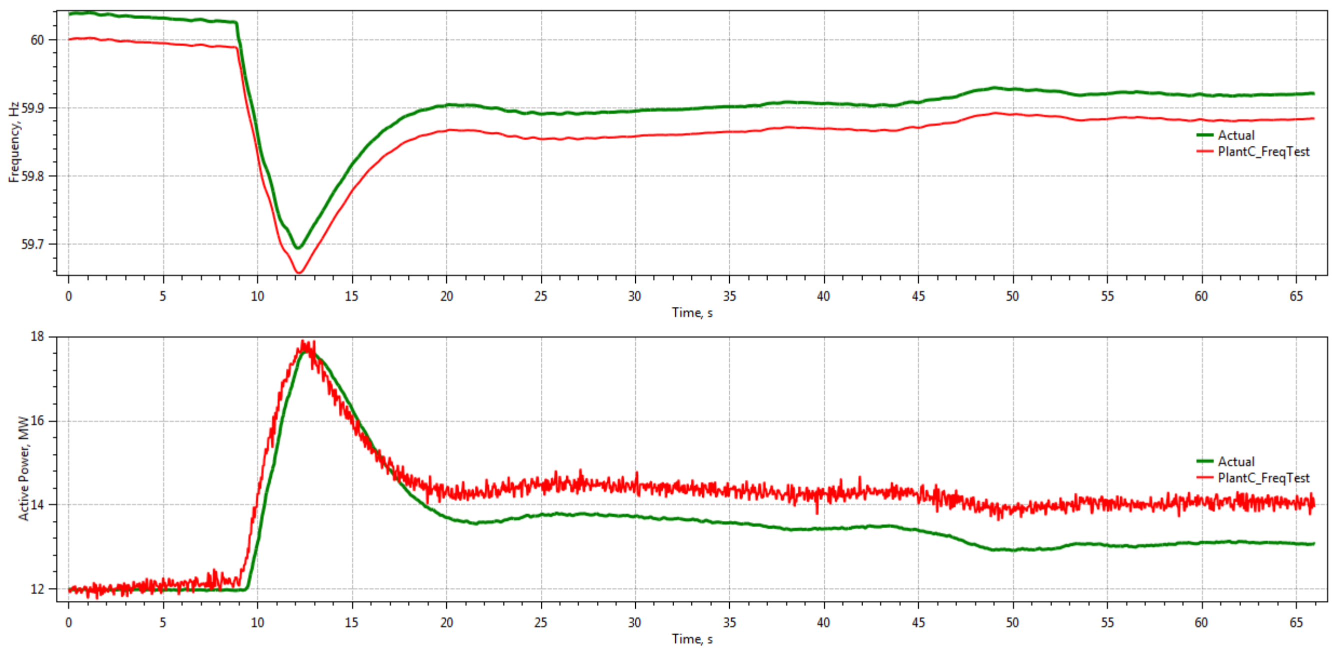

Figure 5.3: PV Plant Actual and Simulated Response to Underfrequency Event [Source: First Solar]

Synthetic Frequency Disturbance Play-In Examples

Frequency response tests were also conducted on a 250 MW solar PV plant in the Western Interconnection in both the over- and underfrequency directions by playing into the plant-level controller a synthetic frequency signal. The underfrequency test was conducted during midday with the plant operating in a curtailed condition at 178 MW. **Figure 5.4** shows the underfrequency time series played into the controller and the plant active power response to the perceived frequency signal. The plant-level controller observes this signal as if it is actually occurring on the system. The plant active power response to the changing frequency was measured by a PMU at the plant POM. This plant operated on an active power-frequency droop with a ±36 mHz deadband, which were all confirmed (along with other control parameters) as part of the verification testing.

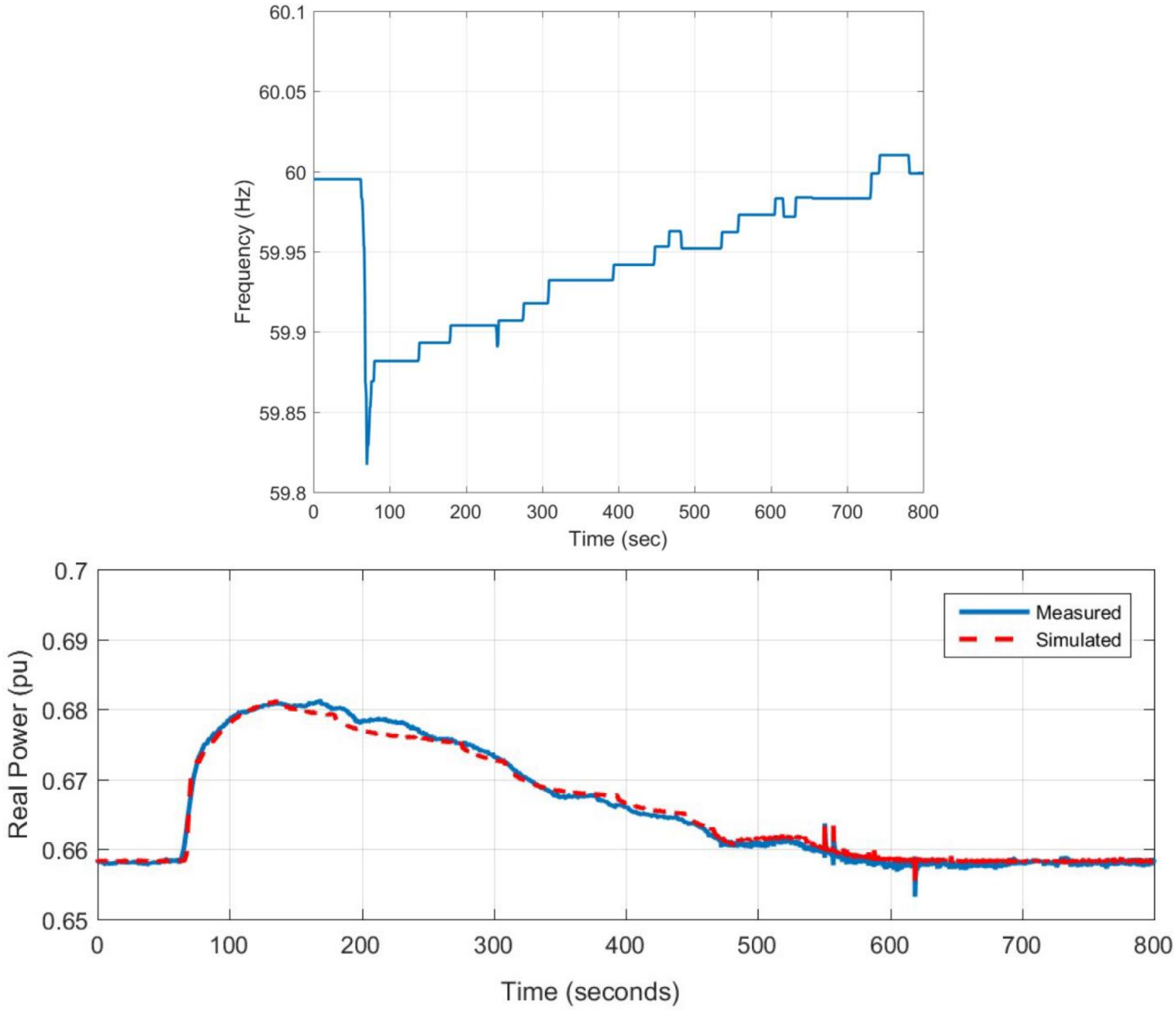

Figure 5.4: Underfrequency Test on a 250 MW Solar PV plant in WECC [12]

Testing for the overfrequency event was conducted during afternoon hours on the same 250 MW solar PV plant. The plant does not need to be curtailed from its maximum available power for this test since it will respond with a reduction in active power for overfrequency conditions. The solar PV plant dynamic response to the played-in overfrequency time series is shown in **Figure 5.5**. The active power plot shows that the plant reduces its power output linearly with the frequency when the synthetic signal input exceeds the ±36 mHz deadband and then gradually returns to its original level as frequency returned to its normal pre-fault level. Some tuning of model parameters could likely obtain a more accurate match with the actual response.

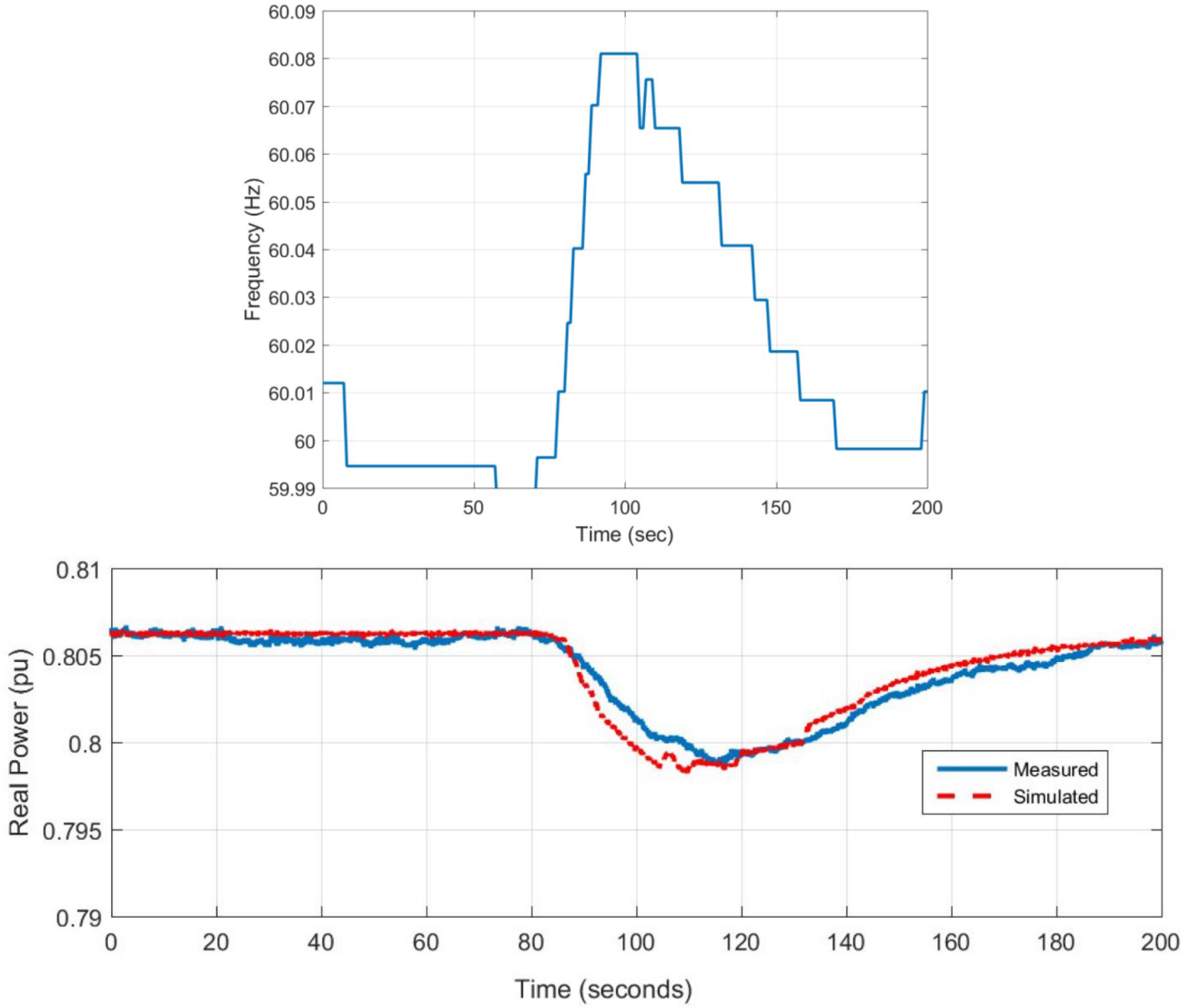

Figure 5.5: Overfrequency Test on a 250 MW Solar PV Plant in WECC [12]

Frequency Step Test Example

Figure 5.6 shows the results of the frequency step test where a +200 mHz synthetic frequency step signal is injected into the plant-level controller and added to the actual grid frequency. The plant controller “sees” the change in perceived grid frequency and changes the active power commands to the individual turbines under its control as a response. While the modeled and actual responses in active power response do not match exactly, the general shape is matched quite well. The differences can be attributed to changing wind speed during the test (as shown in the bottom plot of **Figure 5.6**).

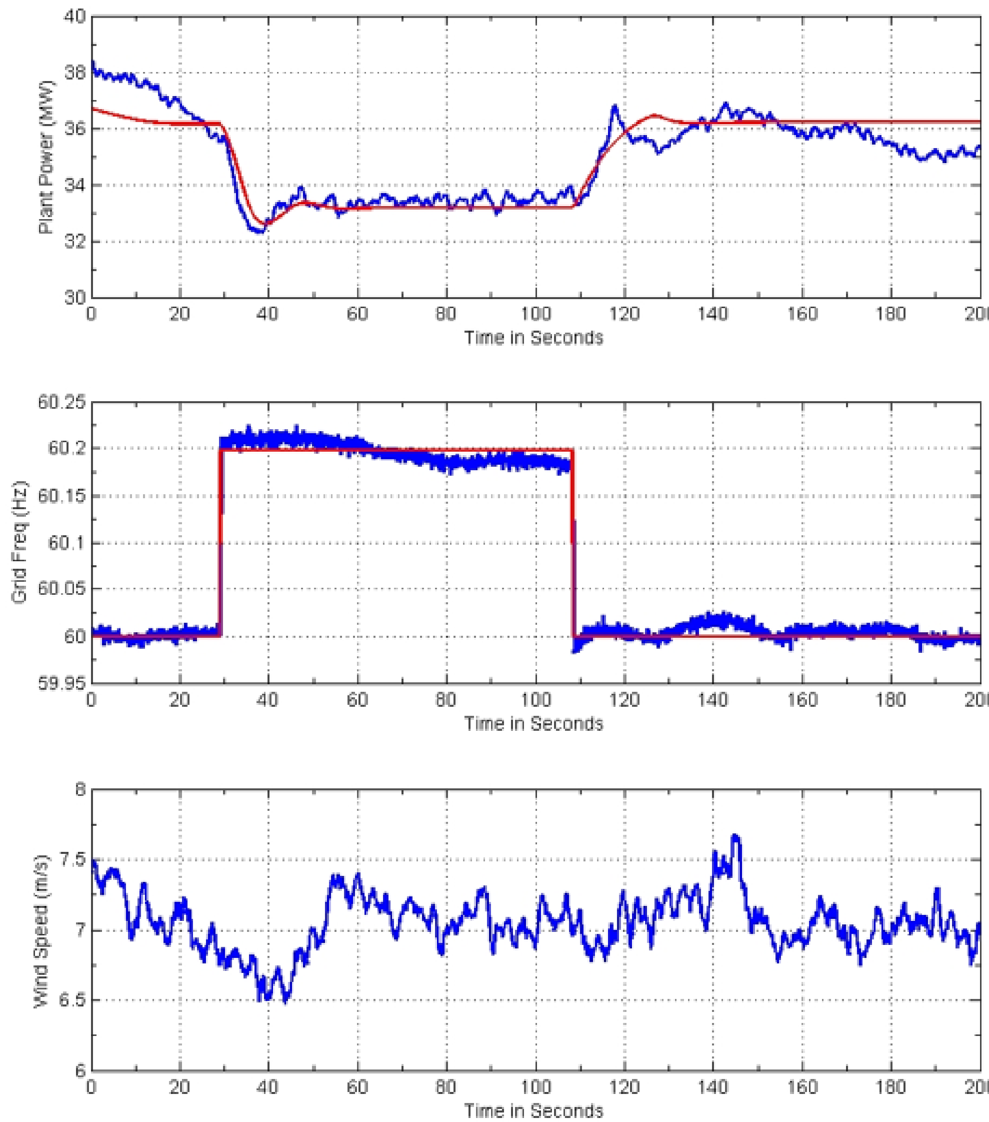

Figure 5.6: Frequency Injection Step Test. Simulated (Red) vs. Measured Response (Blue) [Source: GE]

Appendix A: References

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Appendix B: List of Acronyms

The following acronyms are used throughout this guideline.

Table B.1: List of Acronyms

Acronym	Term
BPS	Bulk Power System
BES	Bulk Electric System
CIGRE	International Council on Large Electric Systems
CT	Current Transformer
FERC	Federal Energy Regulatory Commission
GO	Generator Owner
GOP	Generator Operator
GSU	Generator Step-Up
HMI	Human-Machine Interface
IEC	International Electrotechnical Commission
IGBT	Insulated-Gate Bipolar Transistor
LGIA	Large Generator Interconnection Agreement
MSC	Mechanically-Switched Capacitor
NDA	Non-Disclosure Agreement
NERC	North American Electric Reliability Corporation
NERC PPMVTF	NERC Power Plant Modeling and Verification Task Force
OEM	Original Equipment Manufacturer
PC	Planning Coordinator
PMU	Phasor Measurement Unit
POI	Point of Interconnection
POM	Point of Measurement
PPMV	Power Plant Model Verification
PT	Potential Transformer
PV	Photovoltaic
RC	Reliability Coordinator

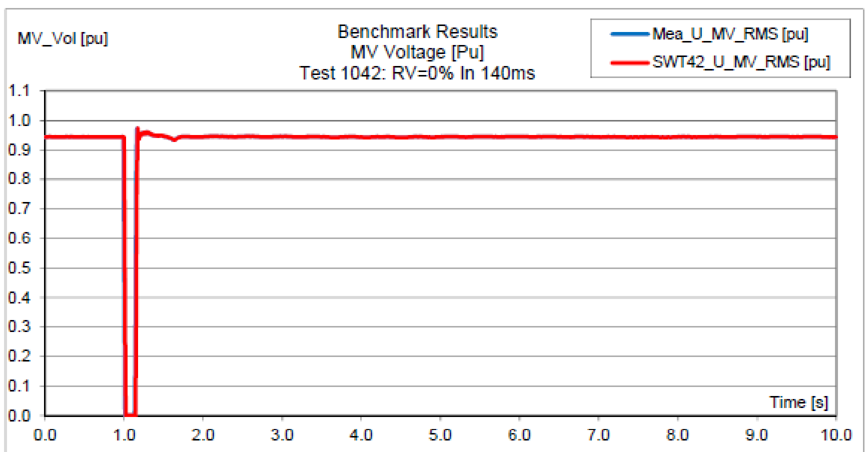
Table B.1: List of Acronyms	
Acronym	**Term**
SCADA	Supervisory Control and Data Acquisition
SGIA	Small Generator Interconnection Agreement
STATCOM	Static Compensator
SVC	Static Var Compensator
TO	Transmission Owner
TOP	Transmission Operator
TP	Transmission Planner
VSC	Voltage Source Converter
WECC	Western Electricity Coordinating Council
WECC MVWG	WECC Modeling and Validation Work Group
WECC REMTF	WECC Renewable Energy Modeling Task Force
WPP	Wind Power Plant
WTG	Wind Turbine Generator

Appendix C: Other Model Verification Examples

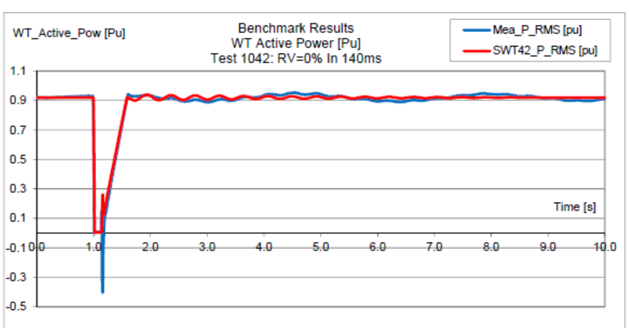
This appendix provides examples of verification tests related to MOD-026-1 and MOD-027-1 model verification activities. These are provided as useful examples and reference material.

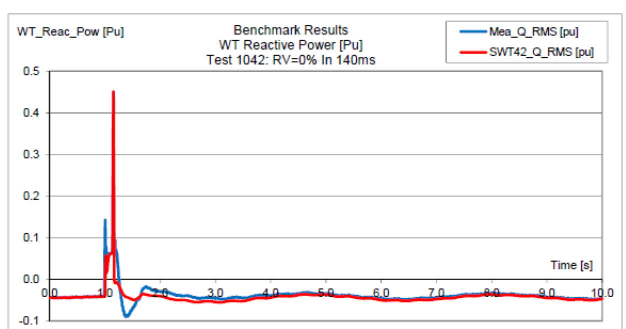
Benchmarking User-Written and Generic Models

This example shows verification of both a user-written model and the second generation generic renewable model for a Type 4 WTG. The fault ride-through events are applied at the high-side of the pad-mounted transformer (10.5 kV) of the test circuit, next to the 10.5 kV terminals of the transformer. To eliminate the influence of other wind turbines and the test grid, the simulation test grid is reduced to an AC voltage profile subjected at the high-side of the WTG transformer. The measured 10.5 kV RMS voltage from the fault ride-through tests are played into the simulations. Figure C.1 shows the voltage profile and the corresponding active and reactive power response from the WTG form the user-written model versus the actual response for a 0.0 pu voltage test. Figure C.2 shows the same comparison but using the generic model. Figure C.3 and **Figure C.4** show the same setup; however, the test is for a 0.5 pu retained voltage drop.



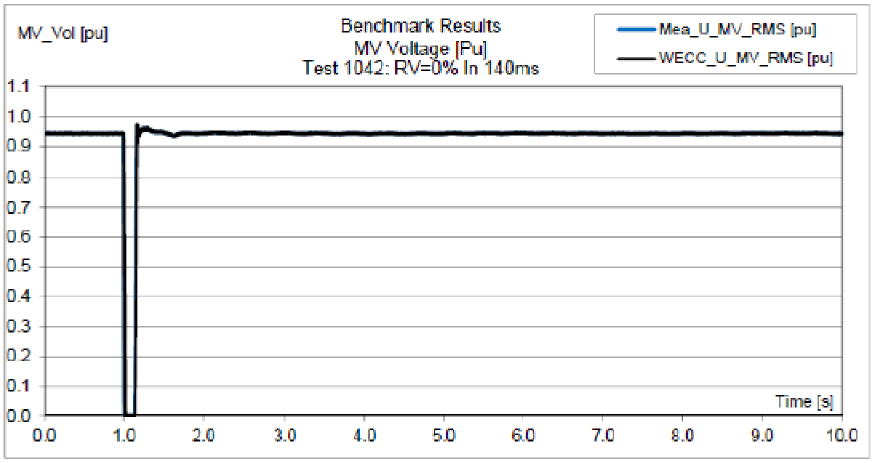
(a) Voltage at High-Side of Pad Mount Transformer



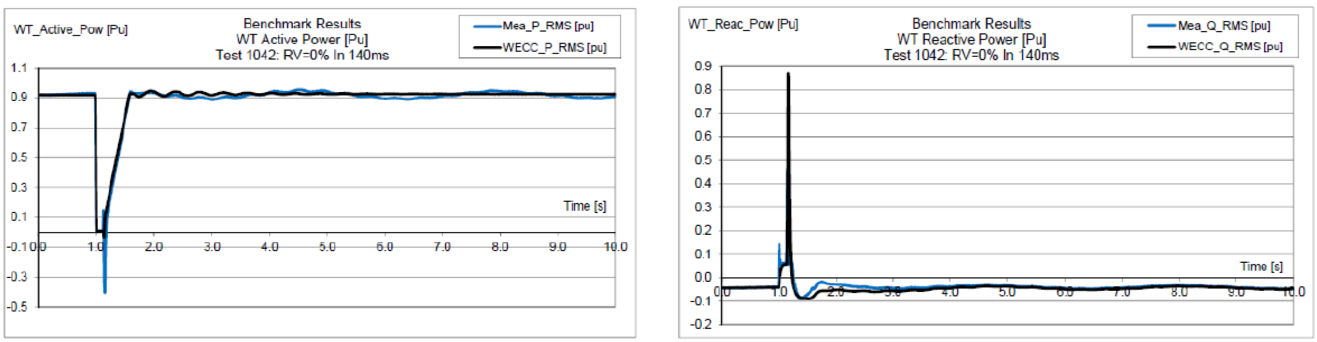


(b) Active Power (left) and Reactive Power (right) from WTG

Figure C.1: Verification of User-Written Model – 0.0 pu Voltage Step for 140 ms [Source: Siemens]

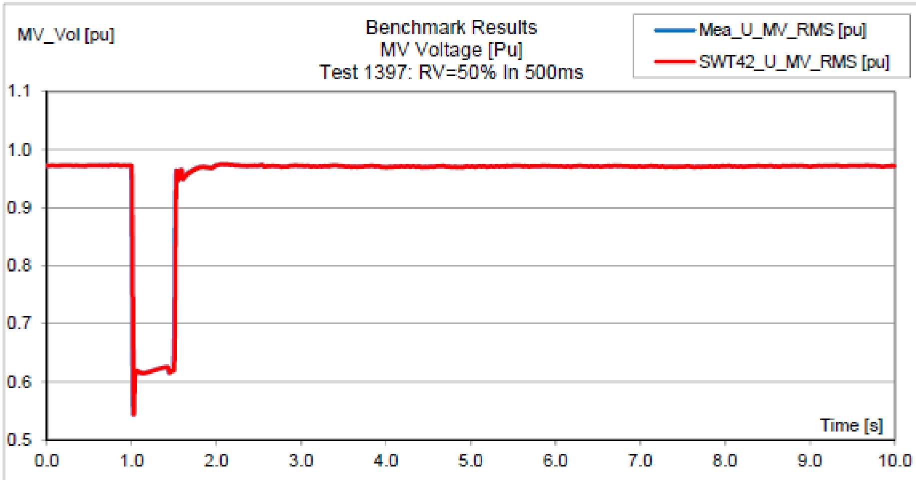


(a) Voltage at High-Side of Pad Mount Transformer

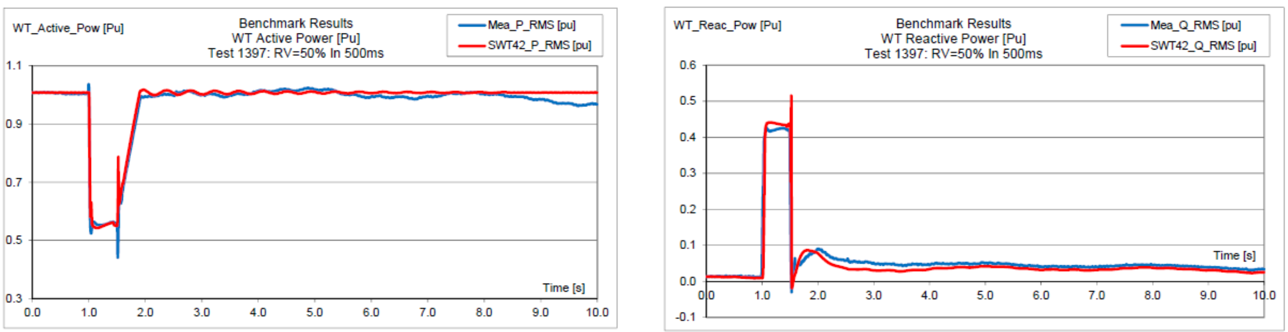


(b) Active Power (left) and Reactive Power (right) from WTG

Figure C.2: Verification of Generic Model – 0.0 pu Voltage Step for 140 ms [Source: Siemens]

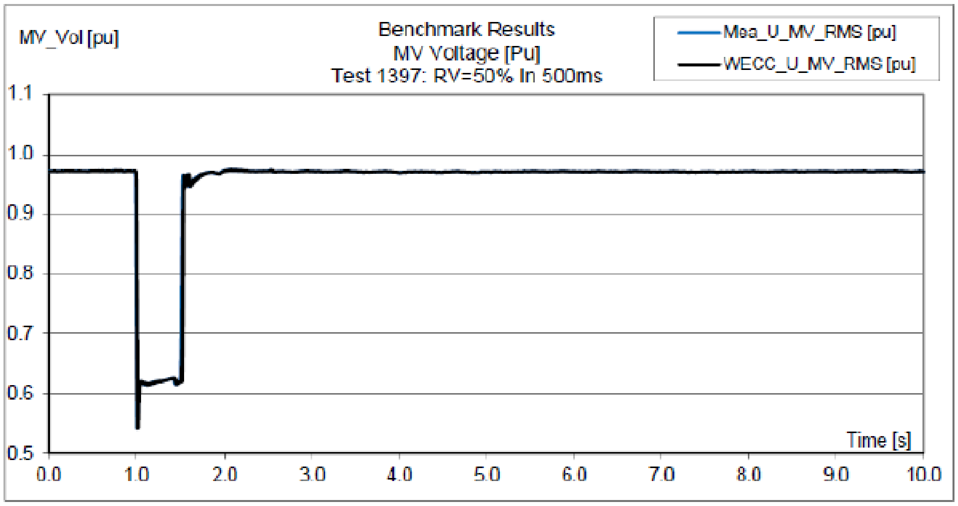


(a) Voltage at High-Side of Pad Mount Transformer

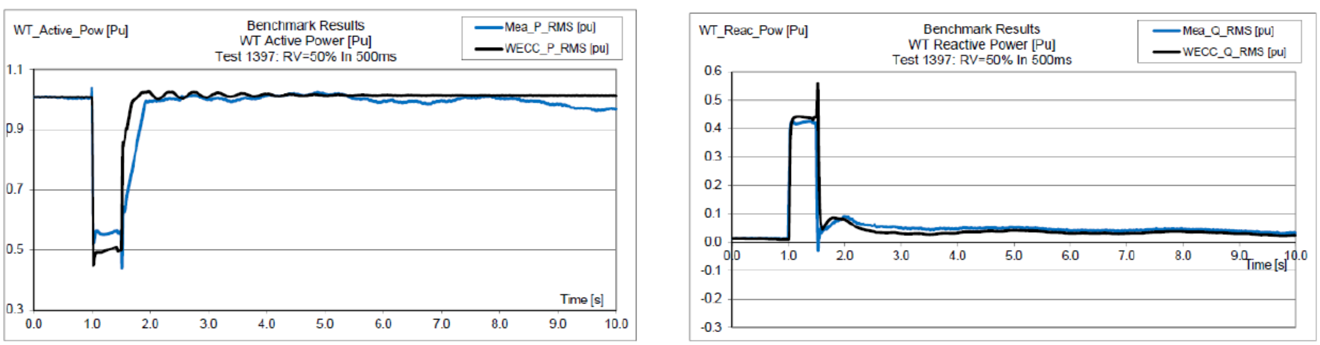


(b) Active Power (left) and Reactive Power (right) from WTG

Figure C.3: Verification of User-Written Model – 0.5 pu Voltage Step for 500 ms [Source: Siemens]



(a) Voltage at High-Side of Pad Mount Transformer



(b) Active Power (left) and Reactive Power (right) from WTG

Figure C.4: Verification of Generic Model – 0.5 pu Voltage Step for 500 ms [Source: Siemens]

Single Turbine Type Test Verification Examples

As shown in **Figure C.5** and **Figure C.6**, the second generation generic renewable energy system models can be parameterized to reasonably capture the large voltage-dip/under-fault behavior of a single WTG or solar PV inverter in many cases. These examples are measuring the response of a single inverter (WTG or solar inverter) to a forced voltage dip for the purpose of type testing a particular model of turbine. This may also be achieved by the OEM through factory tests. These types of tests are not recommended for staged testing in the field to meet the requirements of the NERC MOD standards, as they may pose risk to equipment integrity. However, where such test results may exist, the OEM should provide them to the GO as a means of illustrating the validity of those parameters of the models (e.g., the voltage-dependent current logic (VDL) tables in the *reec_a* model) that cannot be field tested and must be gathered from OEM data. The GO should then provide these types of test results as part of the verification package provided to the TP for MOD-026-1 and MOD-027-1.

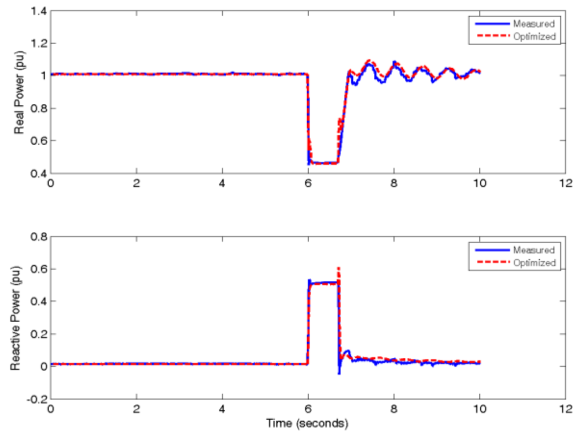


Figure C.5: Examples of Type Test Model Verification for a Single Type 4 WTG [Source: IEEE © 2017 [11]]

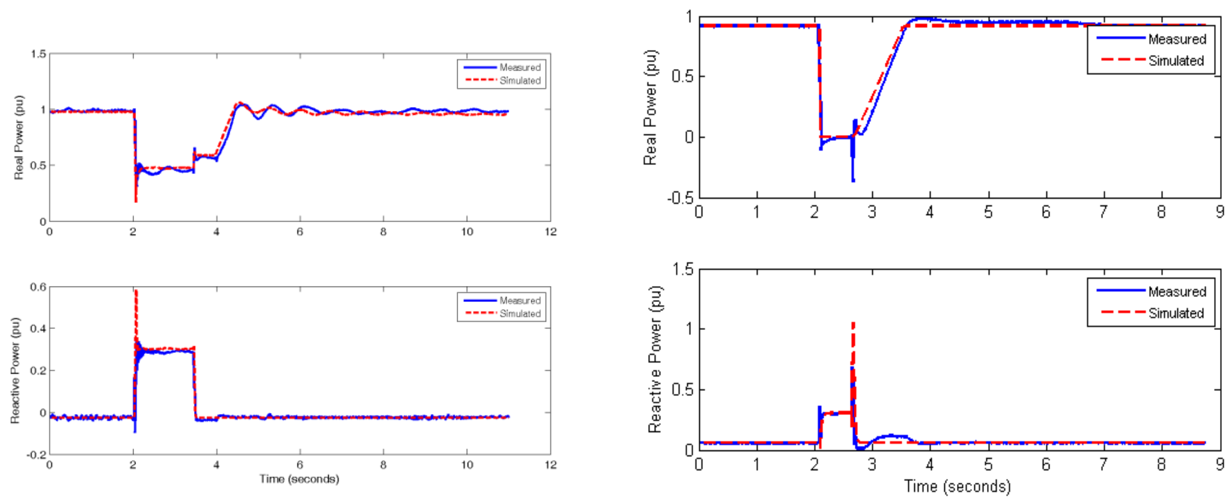


Figure C.6: Examples of Type Test Examples Model Verification for a Single Type 3 WTG (left) and Single Solar PV Inverter (right) [Source: IEEE © 2017 [11]]

Type 4 WPP Voltage Reference Step Test Example

This example demonstrates the voltage reference step testing of a Type 4 WPP. The facility consists of 20 Type 4 WTGs with a total installed capability of 46 MW. All turbines are operated on local voltage control mode and the plant-level controller is configured to regulate voltage at the low-side (34.5 kV side) of the station transformer. There is a 6 MVA shunt capacitor available at the collector station.

Figure C.7 shows the collector bus voltage at the low-side of the station transformer (top), the wind power plant reactive power output response (middle), and active power (which can be ignored for this test). A good match between modeled response and actual response is obtained through verification testing. The control gains, time constants, and reactive droop in the local and plant-level voltage control models were calibrated to match the simulation with the actual measurement.

Note that in the computer simulation, the external system was represented with a single-machine-infinite-bus (SMIB) equivalence. The determination of the external system strength (source impedance) at the time of testing was essential for obtaining a well matched result. Incorrect representation of the system strength could lead to mismatch in either the bus voltage or the reactive power output.

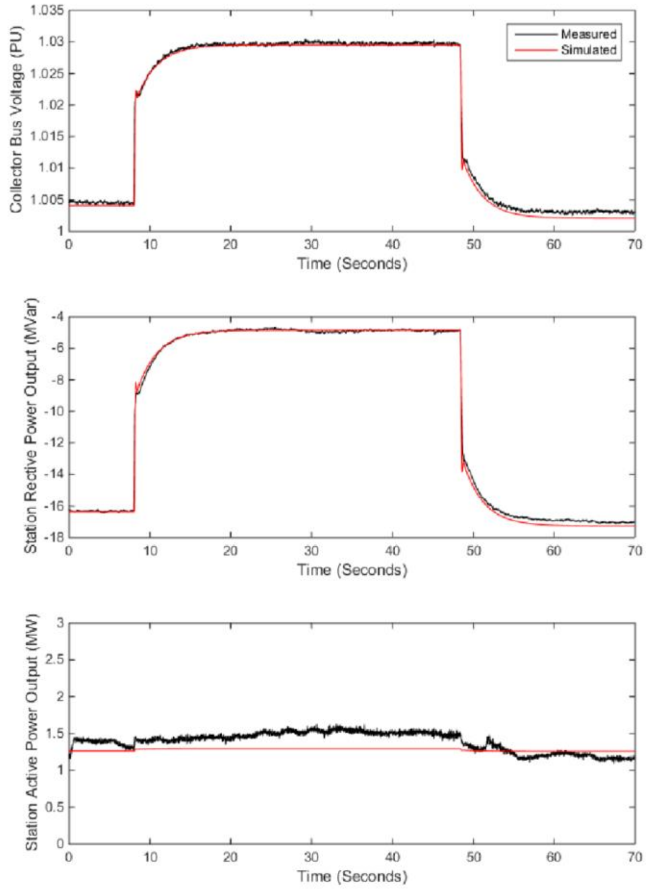


Figure C.7: Measured vs. Simulated Response of a Type 4 WPP to a 4% Voltage Reference Step Test [Source: Powertech Labs]

BPA Experience with Type 4 Wind Plant Verification – Example 1

Bonneville Power Administration (BPA) supported verification of a wind power plant consisting of 89 2.3 MW Type 4 WTGs connected to the BES via two POIs. Upon receiving the verification test report using staged testing techniques, BPA used disturbance-based verification with actual system disturbances using PMU data collected at the POI with the plant. That data was verified against the data submitted by the manufacturer as well as the data provided from the field test report submitted by the GO. Discrepancies between the actual response and the data provided by the manufacturer were identified, and BPA was unable to verify the report accuracy. BPA then asked the following questions to the testing consultant and the GO:

1. There are notable differences between the test report (parameter data) and what the manufacturer provided as "typical representative data for the WPP." BPA is requesting clarification as to these parameter differences to determine if the follow is the case:
    a. They are due to the GO or GOP setting parameter values within the turbine controls of the WPP to make it more compatible with the local network (e.g., based on system strength, local characteristics of the WPP).
    b. It can be contributed to the changes over the years that the manufacturer have performed in order to adjust the controller of this particular WPP thus making the present settings no longer a true representation of "typical" or expected parameters for that manufacturer.

c. There were adjustments made to tune parameters of the WTG representation to match the recorded data based on past events used for model verification.

2. BPA requests a copy of the control settings, particularly for the plant-level controller.

The testing consultant responded, stating that the dynamics data files were expected to be the recommended settings from the report but also noting that some of the settings in the dynamics file did not match the report settings as they had intended. They also noted that due to the low power levels that existed during staged testing, some of the values became skewed or perhaps was an issue with the software model.

In an attempt to resolve the discrepancies, the testing consultant inquired if the BPA could send the actual data for at least one disturbance so that they could also use this data to help verify model performance. The BPA shared PMU data with the GO and GOP and had them work with the testing consultant. The BPA is still awaiting final confirmation.

Figure C.8 shows the verification results derived from the test report data while **Figure C.9** shows the results using the generic manufacturer data in an attempt to fix their data discrepancy. The BPA managed to get somewhat better results using the generic data set compared with the test report data. Nonetheless, the BPA provided these results to the testing consultant as a way to highlight the problematic issues with their data.

The key takeaway for the BPA from this effort was that the testing verification data supplied to the TP/PC should be questioned and verified using disturbance-based PPMV using PMU data. This ensures that whatever model is provided has some level of assurance that it reflects actual plant behavior.

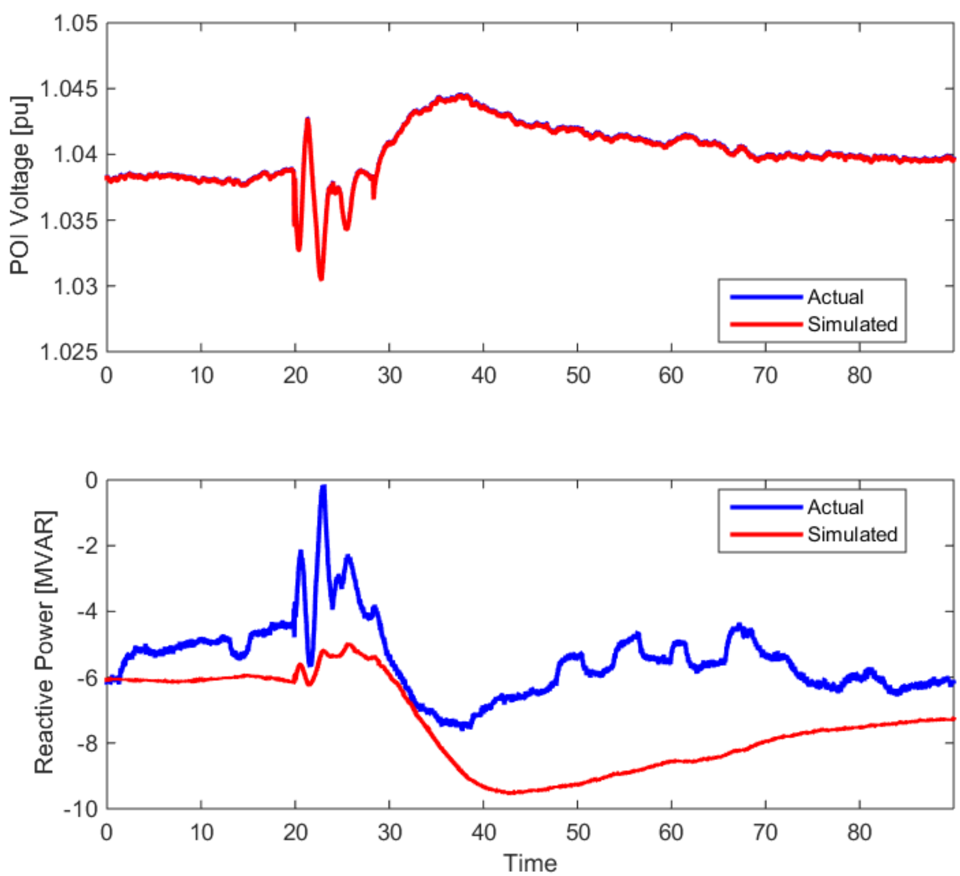


Figure C.8: Voltage and Reactive Power – Testing Consultant Data [Source: BPA]

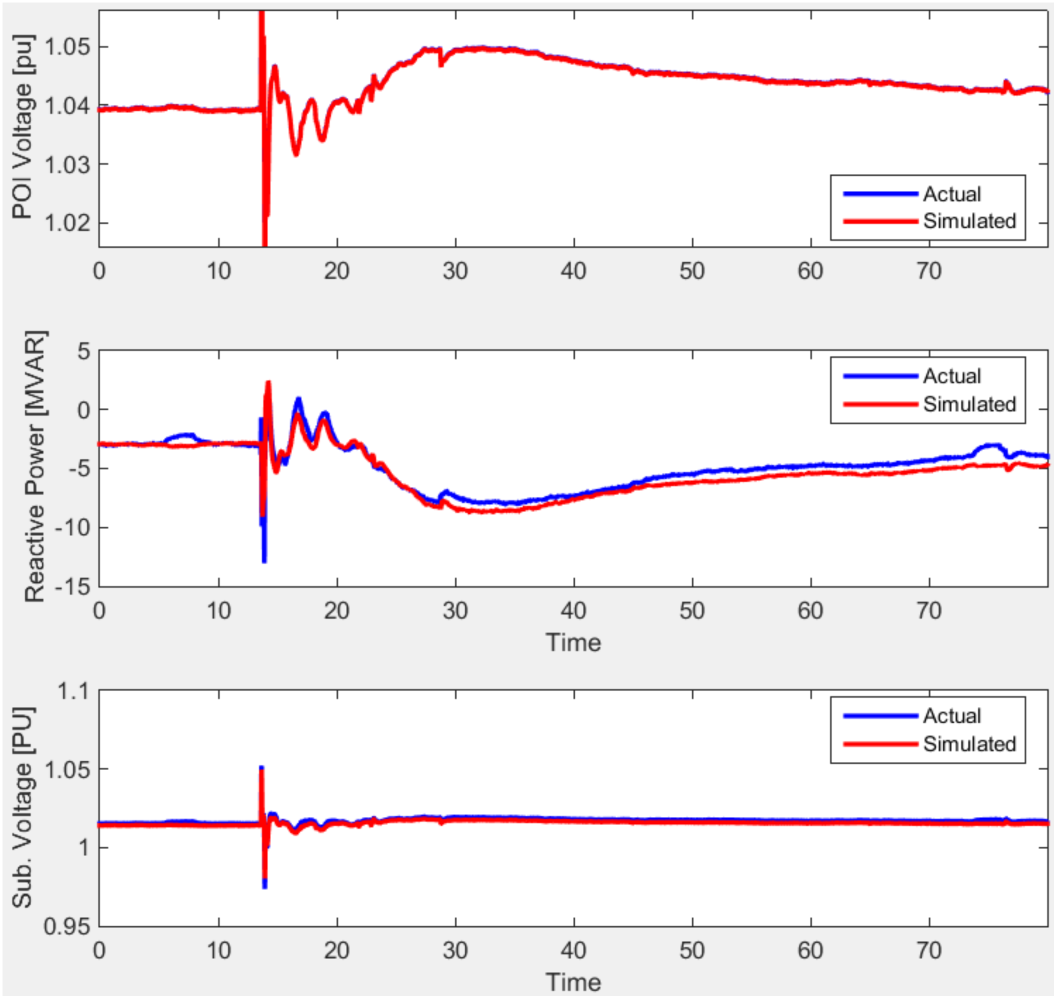


Figure C.9: Voltage and Reactive Power – Generic Manufacturer Data [Source: BPA]

BPA Experience with Type 4 Wind Plant Verification – Example 2

The BPA supported verification of another 343 MW wind power plant consisting of 149 Type 4 WTGs. The data in the interconnection-wide planning model along with disturbance-based verification results identified possible discrepancies. The BPA reached out to the subject matter experts and the equipment manufacturer together to collect data on control flags and to gain insights on control settings. To resolve the mismatch, the BPA started with "typical" data for this type of WTG and manufacturer. The models used included the following: *regc_a*, *wtgt_a*, *reec_a*, and *repc_a*. It was determined that the voltage droop parameter, *kc*, of the *repc_a* model needed to be tuned to obtain a reasonable match. This hypothesis was confirmed using four years of disturbance data and by stress testing the data against synthetic data sets. **Figure C.10** shows the old data (left) and updated data (right) for one event, and **Figure C.11** shows the same setup for a second event.

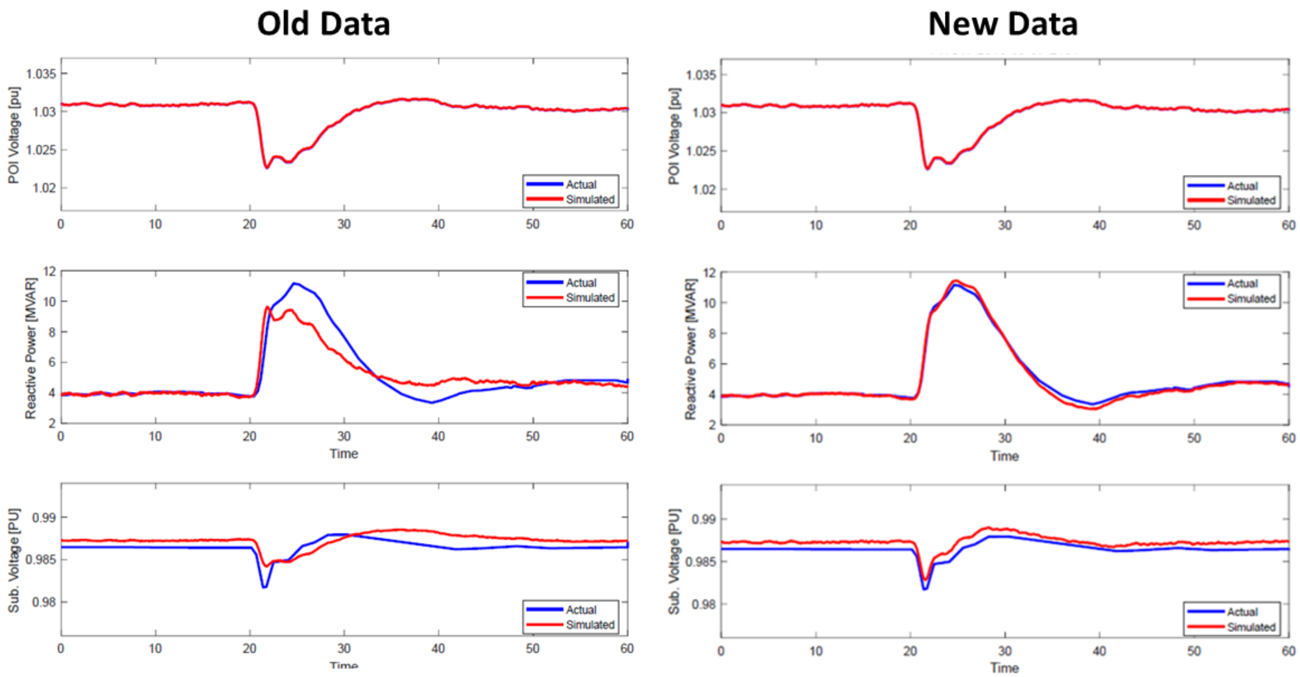


Figure C.10: Before (left) and After (right) Model Improvements – Event 1 [Source: BPA]

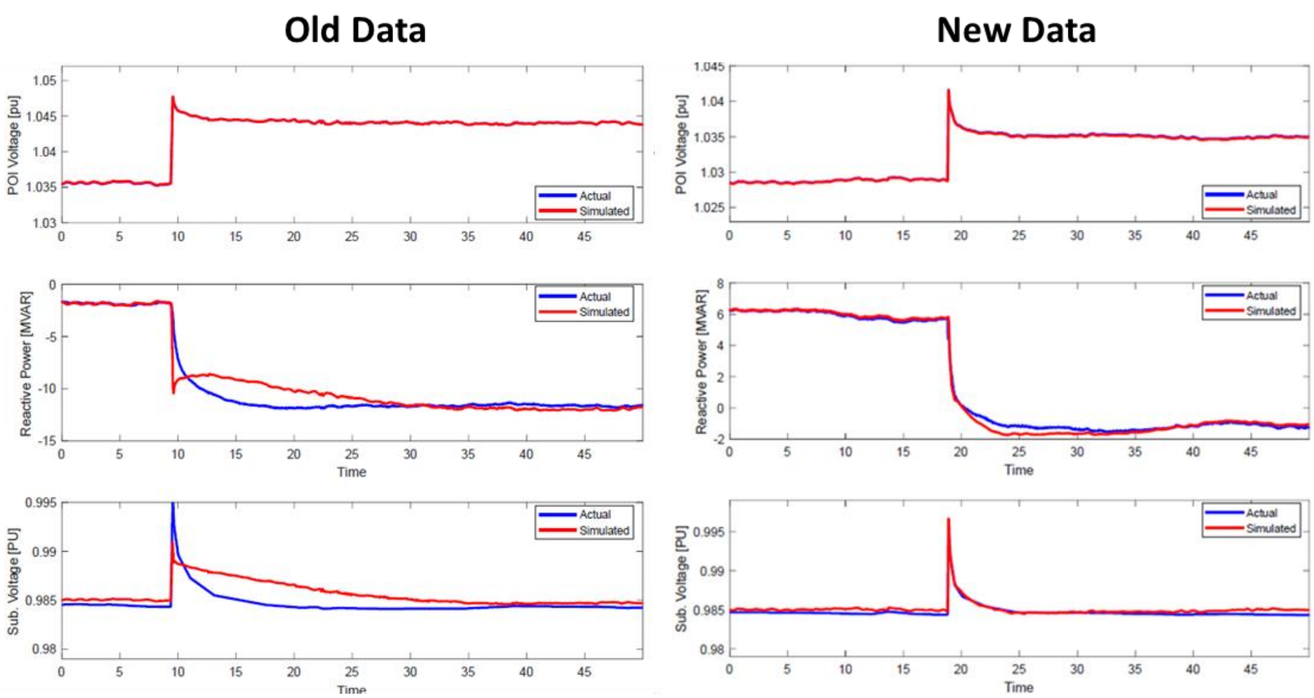


Figure C.11: Before (left) and After (right) Model Improvements – Event 2 [Source: BPA]

Model Verification with High Frequency Oscillations

During disturbance-based model verification, the BPA identified a fairly good match with a Type 4 wind power plant. However, the data clearly showed some high frequency oscillations after the fault event (see **Figure C.12**). This example shows how the overall match between modeled response and actual response is fairly accurate, yet the higher frequency oscillations are not captured. This is expected since the models do not represent torsional modes or certain parts of the faster turbine controls where these higher frequency oscillations manifest. While the model performance for the disturbance on the left could be improved a bit, both events show fairly good match between model and actual response when ignoring the higher frequency oscillations because they are not modeled and not intended to be modeled with positive sequence tools.

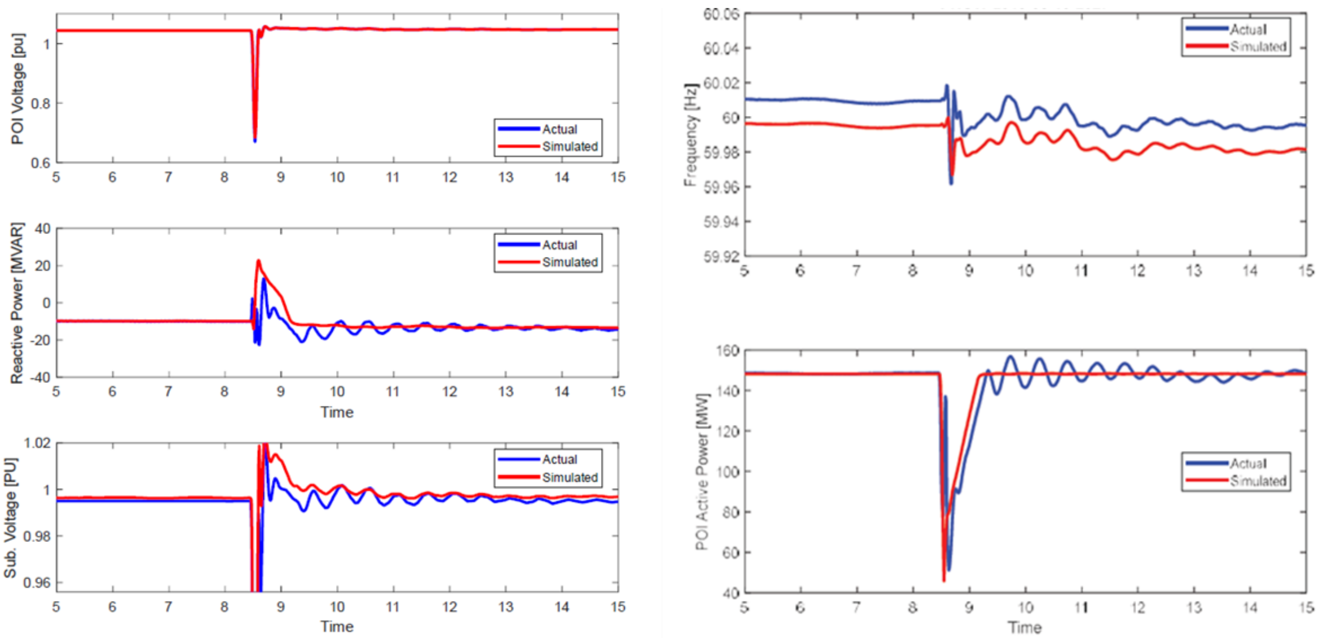


Figure C.12: Disturbance-Based Verification with High Frequency Oscillations [Source: BPA]

Fault Ride-Through Performance Verification using Power Quality Meter

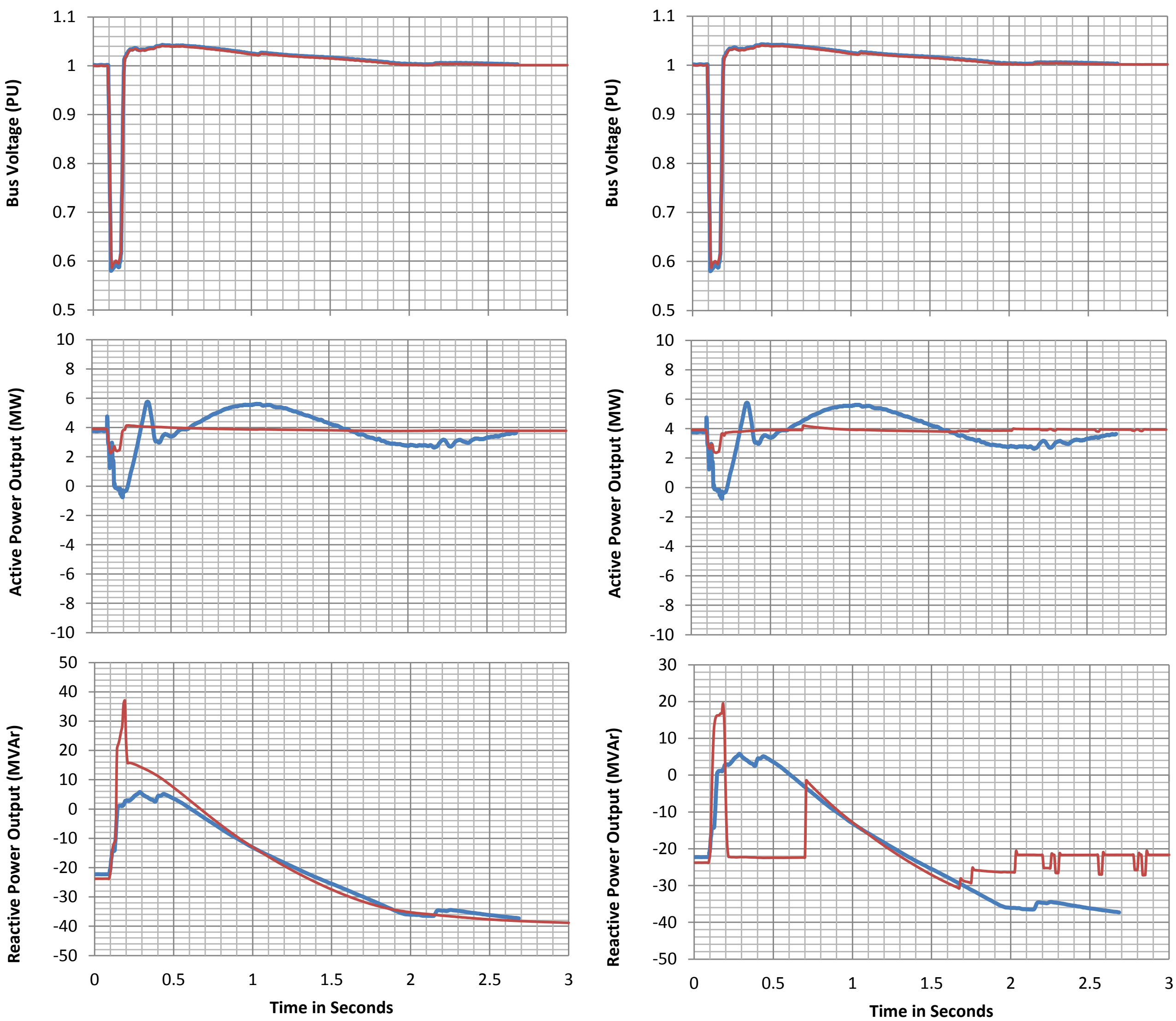
Although the majority of model verification for MOD-026-1 focuses on the response of the overall plant after a fault event, the reactive power response of a WPP or solar PV plant during and shortly after the fault needs particular attention. In reality, WTGs or inverters may be programmed to operate in different fault ride-through (FRT) modes, which either provide no reactive power support (i.e., momentary cessation [21]) or provide a specific level of reactive power support (V/Q coordinated control). Since the system voltage during the fault is known to have a significant impact on the transient stability of the system, the FRT performance of the turbine or inverter in the fault period needs to be accurately modeled.

Since verification of FRT performance only requires a short recording period (e.g., less than one second), the transient (waveform) data from many low-memory recording devices, such as a power quality meters (PQMs) can suffice. PQM data can serve as a good complement for staged tests, especially for plants that are not equipped with a phasor measurement unit (PMU) or dynamic disturbance recorder (DDR). Transient data from PQMs can be converted to positive sequence (voltage and active and reactive power output) before it is used for model verification purposes in the simulation tools.

Figure C.13 shows an example of a Type 4 WPP that responds to a balanced grid voltage dip. The simulation was performed using two FRT modes:

- FRT mode 1 follows regular P/Q command
- FRT mode 2 provides additional reactive current injection equal to two times the voltage excursion.

In FRT mode 2, the injection of additional reactive current was set to hold for another second after voltage returns. It is clearly shown that the WTG model when set to FRT Mode 1 better represents the behavior of the WTG during and shortly after the fault event. This also confirmed the implementation of FRT mode 1, the actual mode programmed in the field.



(a) FRT Mode 1 (b) FRT Mode 2

Figure C.13: Measured vs. Simulated Plant Response to Balanced Grid Voltage Dip with WTG Model Set to FRT Mode 1 and 2 [Source: BC Hydro]

Single WTG Voltage Set Point Step Test Example

The objective of this test is to verify that the WTG model (*REGCA1*) and voltage control settings in the electric control model (*REECA1*) with the effect of the plant-level controller isolated. During the test, a selected WTG was removed from the plant-level controller and a -4 percent step change was applied to the voltage set point of the WTG controller. Measurements were taken at the WTG terminal.

Verification simulations were conducted by playing back measured WTG terminal voltages (forcing WTG voltages to be as close as the measurements) and at the same time applying the set point step change. Simulated reactive power output from the WTG was compared against the measured reactive power output to verify model parameters. **Figure C.14** shows the measured and simulated bus voltage (left) and reactive power output (right) at WTG terminals for the -4 percent step test. There is a good match between simulation and measurement verified electric controller parameter settings in the model.

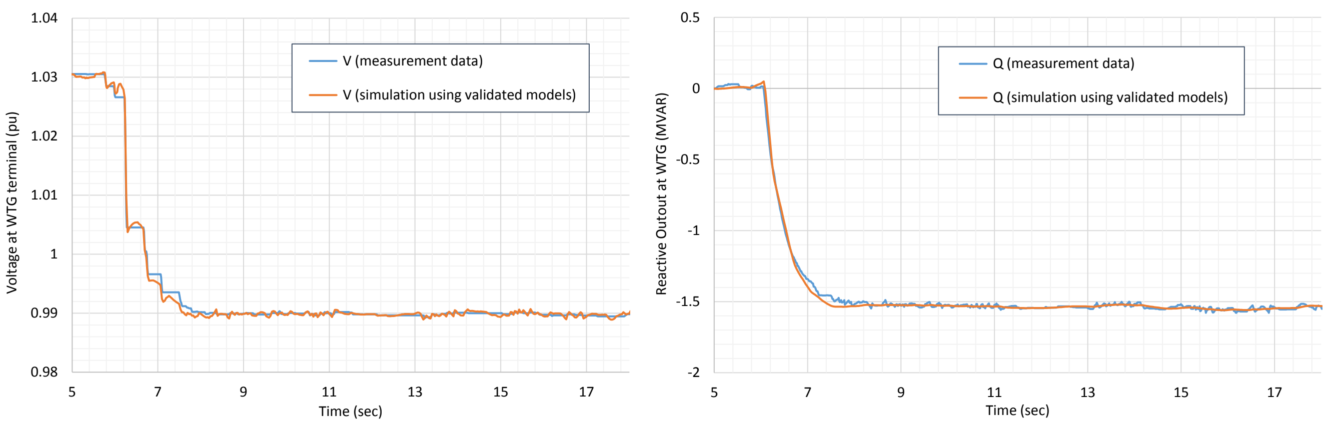


Figure C.14: Measured vs. Simulated Single WTG Response to Voltage Step Test [Source: Powertech Labs]

Disturbance-Based Verification of Momentary Cessation Settings

This example illustrates verification of momentary cessation settings using disturbance-based model verification techniques. Disturbance data (voltage, frequency, and active and reactive power) was captured during a grid disturbance using a PMU installed at the high-side (230 kV) of the solar PV project substation transformer. The inverters in the solar PV plant are programmed to use momentary cessation when voltage falls outside a continuous operating range threshold. The grid fault caused voltage at the POM (and individual inverters) to fall below this level.

Momentary cessation was modeled by using the *reec_a* model instead of the *reec_b* model to better represent the inverter controls, specifically the voltage-dependent control limits (VDCL control blocks). The *reec_a* model allows the modeler to represent voltage-dependent active and reactive current limits.

The disturbance data was played back into the simulation tools, and active and reactive power were compared between the simulated and actual responses. **Figure C.15** shows the match in comparison. As is evident from the plant response in **Figure C.15**, the inverters cease to produce any active current for almost 36 seconds after the fault clearing. This is attributed to the associated recovery delay that is modeled using the “thld2” parameter in the *reec_a* block. Following momentary cessation, a low active current recovery ramp rate (model parameter “rrpwr”) resulted in a very slow recovery of the active power. After the fault recovery and steady-state is achieved, the simulation model cannot achieve the same active power level as the measured plant response, which can be ascribed to the fact that some of the inverters tripped due to the grid disturbance. This difference denoted by ΔP shown in **Figure C.15** is due to the partial tripping of inverters, which cannot be well represented by the aggregated plant models currently available. The comparison of simulated and measured responses for both active and reactive power shows a close match, and this also indicates that momentary cessation can be captured using the second generation models if inverter parameters are specified accurately in the models.

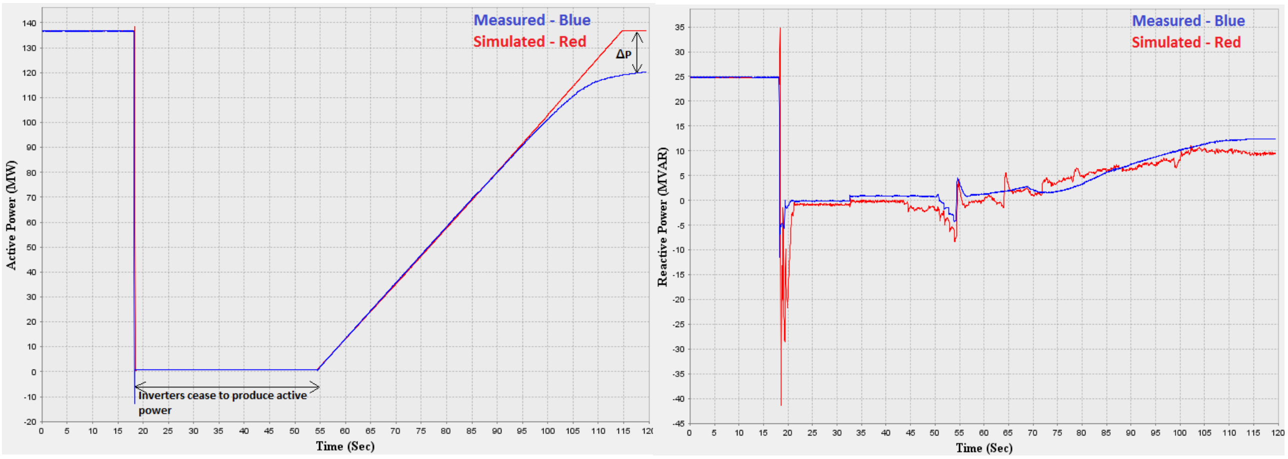


Figure C.15: Capturing Momentary Cessation in Active and Reactive Power Response of Solar PV Plant.
[Source: First Solar]

Appendix D: Contributors

NERC gratefully acknowledges entire PPMVTF membership, including the invaluable contributions and assistance of the following industry experts in the preparation of this guideline.

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Song Wang	PacifiCorp
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