NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Application Guide for Modeling Turbine-Governor and Active Power-Frequency Controls in Interconnection-Wide Stability Studies

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RELIABILITY | ACCOUNTABILITY




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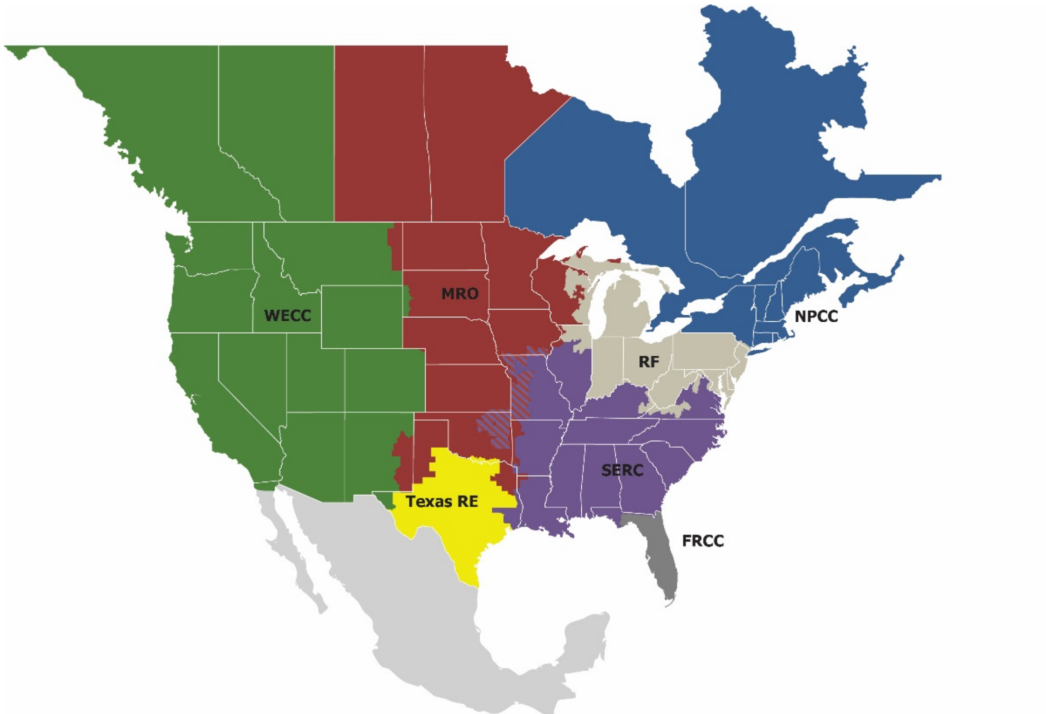
Table of Contents

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 NERC Technical Committees (i.e., the Operating Committee (OC), the Planning Committee, and the Critical Infrastructure Protection Committee (CIPC)) are authorized by the NERC Board of Trustees (Board) to develop reliability (OC and Planning Committee) and security guidelines (CIPC) per their charters.[1] 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

Dynamic models used in stability simulations are a critical component of BPS reliability assessments both in the planning and operations horizons. The large fleet of synchronous generators that exist on the BPS today have turbine-governor systems that need to be accurately modeled and applied in these studies.[3] Accurate turbine-governor modeling is essential to angular stability, frequency stability, and primary frequency response simulations. While the dynamic models available for most turbine-governor systems can sufficiently represent the dynamic behavior of the resource, the application of these models in interconnection-wide base cases has led to poor fidelity of system-wide simulations in some cases. This guideline addresses the primary contributors to poor model fidelity and provides recommended modeling practices to overcome these issues.

Based on review of interconnection-wide base cases and dynamics datasets, technical discussions with industry experts in the NERC Power Plant Modeling and Verification Task Force (PPMVTF), and analysis of library models across software platforms, the following topics are of primary focus in this guideline:[4]

- **Modeling Nonresponsive Units:** Generating units are modeled with a functional governor that is responsive to turbine speed. However, many units operate in modes that cause them to not be responsive to frequency events. This leads to overestimation of primary frequency response in simulations.
- **Correct Model Parameterization:** Commonly used models in certain software platforms per-unitize governor limits on a different base than maximum active power (P_{max}) represented in the base case; this can lead to unrealistic simulated response compared to actual response.
- **Turbine-Governor Deadband Modeling:** Some turbine-governor models do not represent governor deadband that exists in actual operation. This can have an impact on simulation results in some situations.

In addition to addressing these modeling issues, this guideline also provides a recommended framework for Transmission Planners (TPs) and Planning Coordinators (PCs) to use readily available data and modeling information to perform cursory checks on unit performance during actual grid frequency excursion events compared with expected (modeled) behavior. The approaches described in this guideline use an algebraic representation and simplified modeling approach to check if the general response characteristics between actual and modeled response match.[5] Experience has shown that the gross errors in modeling pertaining to active power-frequency controls and turbine-governor response can be identified using these approaches. Once the TP and PC verify that the general behaviors match, then more detailed dynamic model verification can be performed. However, the initial step of understanding the overall fidelity of the model is often not performed by industry, yet this understanding could lead to vastly improved modeling practices. These overall modeling improvement activities will support TPs and PCs in their efforts pertaining to MOD-033-1 regarding system-wide model verification.

The guideline provides appendices that describe more comprehensive analysis and recommended practices pertaining to various aspects of turbine-governor modeling and application of these models in steady-state and dynamic stability analyses.

[3] Or the equivalent active power-frequency control system for inverter-based resources.

[4] Verification of dynamic models for primary frequency response is dependent on the type of model used and the time scale of interest for which that model will be applied. The dynamic models typically used for interconnection-wide studies are suitable for frequency excursions studied by TPs and PCs (on the order of 1–2 Hz). Modeling experience in interconnections around the world have shown reasonable matches in these ranges.

[5] These verification approaches are not suitable for MOD-026-1 and MOD-027-1; however, they provide TPs and PCs with tools to effectively and efficiently check that the models generally represent the actual response of their generation fleet.

Introduction

Dynamic models are used to assess the stability of the interconnected BPS in the long-term planning and operations horizons. These models are essential to ensuring reliable operation of the BPS, including establishing system operating limits (SOLs) and planning transmission investments. One component of power plant modeling is the representation of the turbine-governor system.[6] Modeling turbine-governors accurately is essential to angular stability, frequency stability, and primary frequency response simulations. The initial response of the turbine-governor system can have a significant impact on transient and frequency stability, and longer-term response can have an impact on frequency stability of the BPS.

In 2007, the Institute of Electrical and Electronics Engineers (IEEE) Power & Energy Society (PES) created a task force on turbine-governor modeling under the Power System Stability Subcommittee of the Power System Dynamic Performance Committee. This task force reviewed recent publications related to turbine-governor modeling, reviewed the available models in commercial software tools, and provided recommendations for modeling turbine-governors in power system stability simulations. They published a report in January 2013 titled *Dynamic Models for Turbine-Governors in Power System Studies*[7] that serves as the de facto standard today. While some modifications and updates have been made to turbine-governor models since then, the recommendations made in that report are still relevant today. The vast majority of models described in the task force report are uniformly implemented in the major software platforms. However, industry continues to struggle with how these models are applied and used in power system stability simulations. **Figure I.1** shows an illustrative example of system frequency response for an actual disturbance in the Eastern Interconnection compared to the simulation of this same disturbance using a representative seasonal base case. While it is not expected that these responses match exactly, the simulated response should capture the general trends in performance. It is apparent that the modeled and actual response are quite disparate, indicating modeling errors throughout the case.

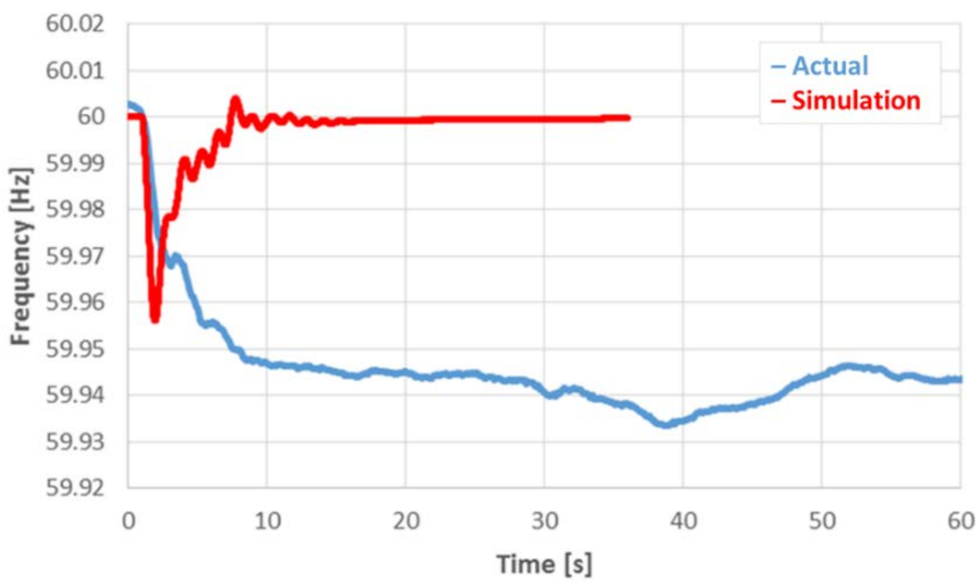


Figure I.1: Simulated vs. Actual Frequency for Large Disturbance

[6] Or the equivalent active power-frequency control system for inverter-based resources.
[7] Available here: http://sites.ieee.org/fw-pes/files/2013/01/PES_TR1.pdf.

This guideline is intended to clarify key aspects of how turbine-governor models are applied in an effort to improve the accuracy and fidelity of interconnection-wide simulations. Studies performed using these models are applicable to underfrequency load shedding (UFLS) studies for NERC Protection and Control Reliability Standard PRC-006-3, frequency response studies for NERC Balancing Reliability Standard BAL-003-1.1, and stability studies and post-contingency analysis for long-term planning and operation planning analyses (NERC Transmission Planning and Transmission Operations Reliability Standards). This document primarily applies to Generator Owners (GOs), Generator Operators (GOPs), TPs, PCs, and power plant modelers. The guidance in this document may also be relevant for Balancing Authorities (BAs), Transmission Operators (TOPs), and Reliability Coordinators (RCs) that are performing stability studies.

Background

This section contains relevant background information on the subject of turbine-governor modeling.

Fundamentals of Primary Frequency Response

Imbalance between generation and load is directly reflected in the frequency of an interconnected power system. Frequency control within predetermined boundaries around a nominal value is a critical component to reliable operation of the BPS. BAs are responsible for dispatching generation and managing area control error (ACE) in a manner that maintains frequency at the scheduled value. This is normally done by automatic generation control (AGC). NERC BAL standards establish the frequency control performance requirements for BAs. Frequency and net interchanges between BAs are controlled by the combined actions of primary, secondary, and tertiary controls. Primary controls are the governors of rotating generating units and the electronic controls of wind, solar photovoltaic, and energy storage facilities. Primary controls are supervised and directed by secondary controls. The principal secondary controls in regard to frequency and area interchange are power plant load controllers and BA AGC. Tertiary control includes automatic and manual control functions, such as optimal generation dispatch and unit startup.

The three tiers of control act on progressively longer time scales as illustrated by **Figure BG.1**, which shows the form of frequency and power trajectories that would be seen in a properly functioning system in response to a sudden loss of generation. As shown in the top trace, frequency starts to fall immediately upon the loss of generation. Primary control action (the solid blue line in bottom half of figure) starts to appear immediately as frequency falls. Primary control response increases until the fall is arrested and contributes the major part of the effort to make the arrest. The behavior of frequency after the arrest depends on the trajectories of primary and secondary response. Early withdrawal of primary response (dashed blue line) slows the recovery of frequency or may even allow frequency to continue to decrease though at a reduced rate. Secondary control actions may start very quickly after the initiating loss of generation, or may not appear for many seconds. Power plant load controllers can start to affect turbine response at a slower rate than primary controls within a second. As long as 10–20 seconds may pass before the action of a balancing area AGC system appears. Primary control action is taken in response to changes of frequency and generator power; its sole objective is to restore the balance between generation and load. The objectives of secondary controls are varied; balancing area AGC systems seek to zero-out the ACE signal; plant load controllers may be focused on variables as diverse as temperatures, hydro turbine efficiency, or power delivery contracts. With proper coordination, the quick action of primary controls is maintained until the slower action of secondary controls builds up and the control effort can be reallocated in accordance with the various objectives of the secondary controls. In summary, the arrest of

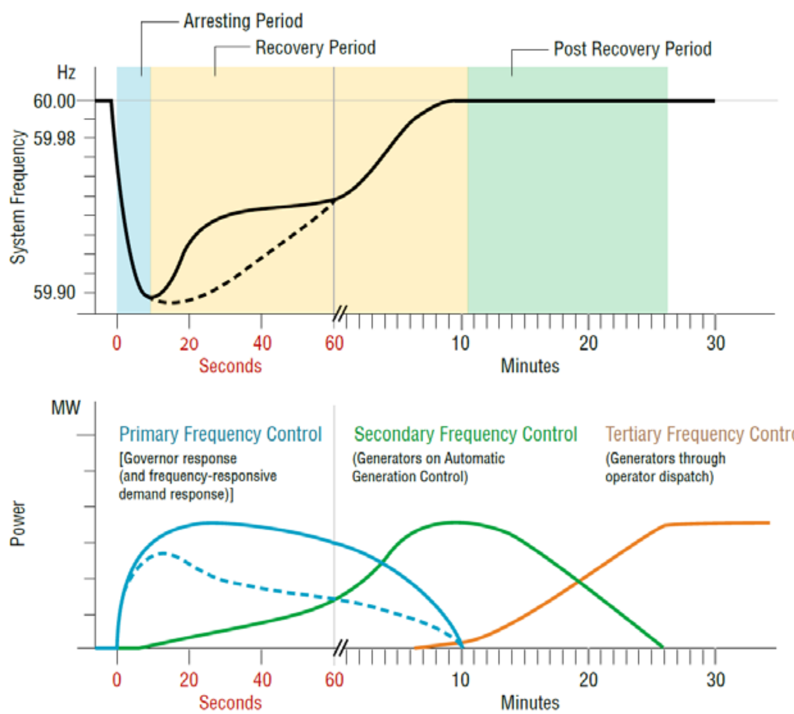


Figure BG.1: Frequency Response Fundamentals

[Source: LBNL]

deviations of frequency is the responsibility of primary controls and the restoration of frequency after the arrest is the responsibility of secondary controls.[8]

Turbine-Governor System Modeling Fundamentals

While the shape of the frequency response plots in each Interconnection gets significant attention, it is critical to remember that there are hundreds or even thousands of resources responding automatically to changes in speed or measured frequency.[9] The response from each individual generating resource is a highly complex process that involves turbine-governor controls, boiler controls, temperature controls, outer-loop plant-level controls, and other factors as applicable, depending on the generation type. All these factors should be considered when developing applicable models for stability studies and dynamic simulations. **Figure BG.2** shows a high-level representation of a steam plant with the portions enclosed in a red rectangle that represents the part of the model that TPs and PCs are typically made aware of and familiar with. However, a plant consists of other components that may or may not react in the times applicable to the TP or PC for the study of grid reliability and stability. If the equipment outside the red rectangle comes into play within these timeframes, its impact may need to be modeled or appropriately considered through sensitivity analyses in simulations. Conversely, if those responses have longer time constants than typical simulations, then they may be ignored. This is described in more detail throughout this guideline.

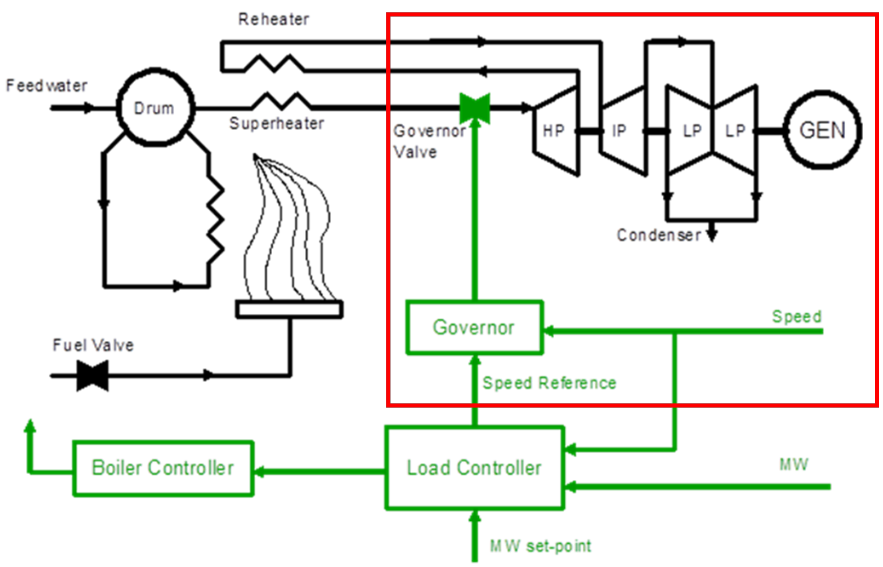


Figure BG.2: High Level Block Diagram of Related Turbine-Governor Controls [Source: BPA]

Unit or plant controls can vary widely; however, the type of response from a generating resource can be classified for the purposes of discussing turbine-governor modeling into the following:[10]

- **Sustained Frequency Responsive:** This includes operating modes where the turbine-governor is able to provide primary frequency response and sustain that response for a relatively long period (e.g., minutes to tens of minutes) while frequency is off-nominal.

[8] https://www.ferc.gov/industries/electric/indus-act/reliability/frequencyresponsemetrics-report.pdf
[9] Relevant for inverter-based resources.
[10] Refer to the frequency response work by Lawrence Berkeley National Laboratory (LBNL) for more information on frequency response fundamentals.https://certs.lbl.gov/project/interconnection-frequency-response.

- **Turbine Speed (Droop) Control:**[11] Many units operate on automatic speed control, also referred to as turbine-governor or speed-governor control. The governor reference may in turn be adjusted remotely by either the grid operator or the AGC system, but the automatic action to control speed by the use of the governor is the primary control. See **Figure BG.3** for an example of sustained governor response.

- **Plant Load Control with Frequency Bias:** Plant outer-loop controls (i.e., load control) apply control commands to the governor speed/load reference to maintain unit output to a prescheduled level when frequency is near nominal value. The plant control includes a bias signal based on grid frequency so it can sustain primary frequency response during off-nominal frequency conditions.

- **Nonsustained Frequency Responsive:** This includes operating modes where the turbine-governor is able to provide primary frequency response, but the response is not sustained (i.e., on the order of minutes). Other controls withdraw any primary turbine-governor response.

  - **Plant Load Control without Frequency Bias:** Plant outer-loop controls (i.e., load control) apply control commands to the governor speed/load reference to maintain unit output to a pre-scheduled level. This plant control does not include any biasing based on grid frequency and solely responds to deviations away from the prescheduled output level. This type of control will typically allow the turbine-governor to temporarily respond to changes in frequency; however, the response is typically withdrawn relatively quickly (within about 20–100 seconds) back to the prescheduled output set point. See **Figure BG.4** for an example of frequency response withdrawal.

- **AGC Control:** The power output of the unit or plant is controlled by signals from the external AGC system[12] of the BA. In this case, the unit may be governed by the AGC system and thus be responsive to frequency; however, its response is driven by the timing and signals of the AGC system, which may or may not provide a sustained response. This is not typically modeled in stability studies since AGC acts in the many tens of seconds to minutes time frame, and the assumption should be made to model the unit as nonresponsive (or use a governor model that can emulate the AGC type response). Alternatively, the unit may still have regular primary frequency response in the form of turbine-governor droop controls; however, the AGC controls take over after the first 30 seconds to a minute. In these cases, depending on the type of analysis being performed (e.g., transient stability analyzing the first 30 seconds of response), a governor model may be adequate to model the initial expected response of the unit.

- **Nonresponsive:** Many turbine operating modes can make the unit nonresponsive to changes in turbine speed or grid frequency (i.e., control valves wide open or in a fixed position, exhaust temperature or pressure control limits, or various other types of controls). See **Figure BG.5** for an example of a nonresponsive unit to changes in speed or grid frequency.

[11] The actual name of each control mode may be different between control software. However, this guideline refers to controls for when the unit is on-line and connected to the grid. The governor control software for each individual unit normally has speed droop control mode and MW control mode available to be chosen when connected to the BPS.

[12] As described in **Figure BG.1**, AGC has an impact on the overall performance of the interconnection to stabilize and return frequency back to nominal value. AGC can interact with primary frequency response, as shown in **Figure BG.1**, based on its timing and configuration. This topic is outside the scope of this document.

Key Takeaway:
All these considerations regarding unit active power-frequency responsiveness relate to the typical applicability of dynamic models in the time frame of 30 to 60 seconds. Interactions beyond these time frames involve external factors like AGC and are not typically represented in stability studies. However, impacts to the turbine-governor response within these time frames should be accounted for in studies.

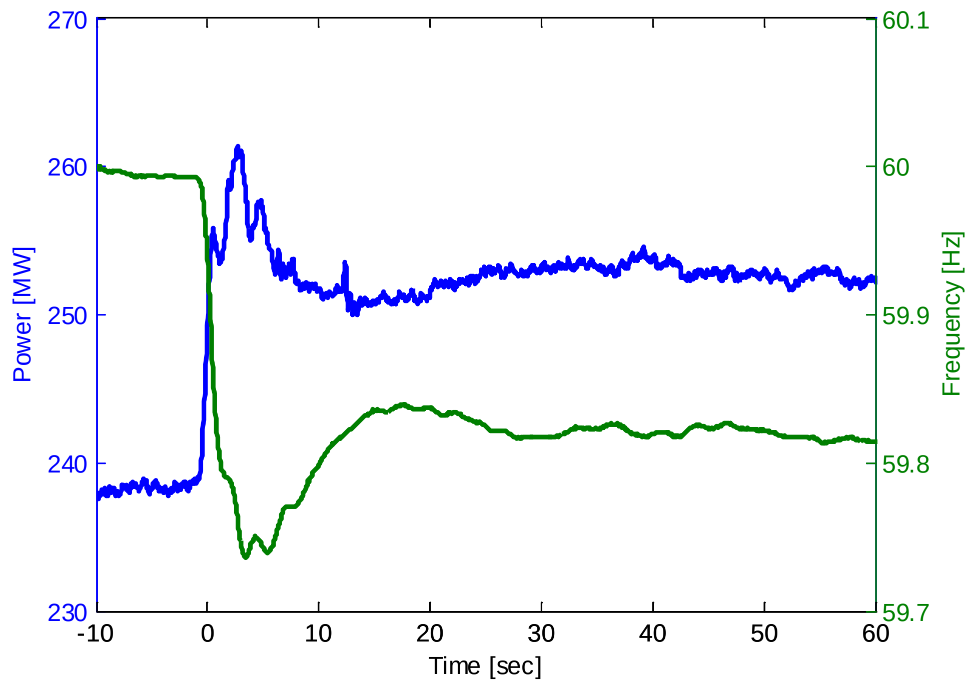


Figure BG.3: Sustained Primary Frequency Response [Source: BPA]

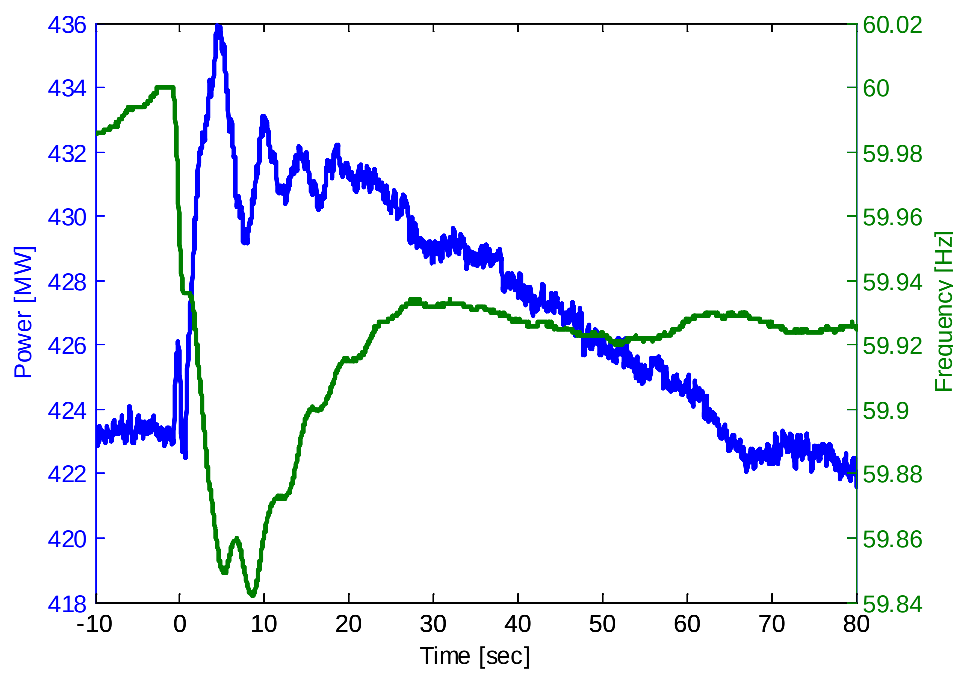


Figure BG.4: Nonsustained Frequency Response–Load Control [Source: BPA]

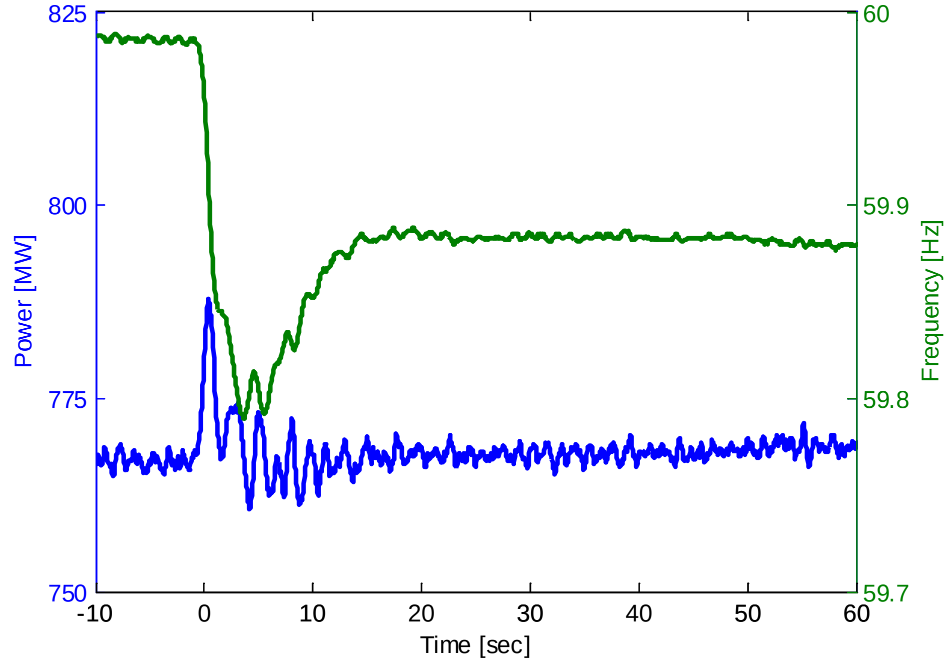


Figure BG.5: Nonresponsive Unit [Source: BPA]

Key Focus Areas of Turbine-Governor Modeling

This guideline covers primary turbine-governor controls and parameters that impact the fidelity of the model compared to actual operation. It also focuses on the most commonly used turbine-governor models to provide as much applicability to the synchronous generating fleet as possible. Inverter-based resources are briefly described in Appendix E.[13] The majority of this guideline focuses on thermal generating resources rather than hydroelectric[14] generating units for the following reasons:

- In the Eastern Interconnection, there is a significantly larger total aggregate MVA of thermal units compared to hydro units.
- Based on actual operating experience and model verification efforts, hydro units do not tend to have a prevalence of the issues described throughout this guideline.
- Most of the thermal units have a turbine-governor model represented by only a handful of models for which the MVA varies from smaller thermal units all the way up to units larger than 1000 MVA.

The guideline seeks to address the modeling issues shown in **Figure BG.6** that have been proven to have the most impact on model fidelity and are common issues with the Interconnection-wide cases.

[13] Reliability Guideline: BPS-Connected Inverter-Based Resource Performance:
https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf.
Reliability Guideline: Power Plant Model Verification for Inverter-Based Resources:
https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/PPMV_for_Inverter-Based_Resources.pdf.

[14] Many of the recommendations in this guideline can be applied to hydro units with some modification. However, the primary focus is on thermal generating units (i.e., steam and natural gas) for the reasons described above.

Modeling Non-Responsive Units as Responsive	Generating units are modeled with a functional governor that is responsive to turbine speed. However, many units operate in modes that cause them to not be responsive to frequency events. This leads to overestimation of primary frequency response in simulations.
Incorrect Per Unitizing Model Parameters	Some software platforms per unitize governor limits on a different base than P_{max} represented in the base case, which can lead to unrealistic response compared to actual unit behavior.
Unmodeled Governor Deadbands	Some turbine-governor models do not represent governor deadband that exists in actual operation. This can have an impact on simulation results in some situations.

Figure BG.6: Turbine-Governor Modeling Issues

Principles of Turbine-Governor Modeling and Governor Response

The following principles apply to turbine-governor modeling and modeling governor response in interconnection-wide stability studies:

- The governor control system should be accurately modeled to represent what is actually installed in the field. This includes the droop, deadband,[15] time constants, gains, and other parameter values.
- The governor model, maximum power output (P_{max}), turbine rating (mwcap or TRATE), and electrical generator MVA rating (MBASE) should be coordinated to ensure that limits are imposed properly. This ensures that the output of the turbine-governor model never exceeds in simulation what is physically possible and also avoids any initialization errors.[16]
- The modeled governor droop should be set to best represent the actual equipment. In reality, governor droop may be implemented on a variety[17] of control signals. The selection of droop signals can have an impact on the amount of primary frequency response.
- Any outer-loop or plant-level control systems that can override or offset the governor response should also be modeled accurately if they impact the response of the unit within time frames typically used for stability analysis (e.g., within 60 seconds following a disturbance).
- The turbine-governor should be modeled to reflect the operating mode that the plant uses for the majority of the time when on-line. If multiple operating modes may be used (e.g., the generator uses a variety of load control and speed-droop control), the GO should provide this information to the TP and PC so that the TP and PC can use engineering judgment to appropriately model or perform sensitivity studies around the unit's governor response for those particular operating modes.

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[15] In most cases in this document, deadband refers to the intentional deadband typically in a turbine governor controller, and does not refer to the unintentional (inherent) deadband that is a factor of mechanical linkage between speed sensing and valve/gate movement.

[16] In software programs where the electrical generators armature resistance is modeled in the dynamic model, it should be noted that the total mechanical power developed on the shaft in the dynamic model = Pe (power flow modeled electrical output) + I^2Ra (copper losses). Thus, when at P_{max}, the turbine rating, mwcap must be at least equal to P_{max} + I^2Ra to effect steady-state initialization of the model.

[17] e.g., electrical power output, governor output, fuel demand, value stroke, flow demand, and gate opening

- TPs and PCs should monitor the performance of generating resources within their footprint to ensure accurate modeling.
- Nonresponsive units should be modeled appropriately by either using control flags in the powerflow options or by disabling the governor in the dynamic records.

Considerations and Interactions with NERC MOD-027-1 Activities

NERC Reliability Standard MOD-027-1[18] is driving dynamic model verification activities to ensure that large BES generators have accurately modeled turbine-governor and active power-frequency controls. As testing continues across the generating fleet, it is likely that the models will more accurately reflect actual plant performance and response to grid events. However, there are specific aspects of turbine-governor modeling, that MOD-027-1 testing alone will likely not capture when creating Interconnection-wide base cases, so the TP, GO, and the testing consultant (where applicable) should be cognizant of these issues. In particular, MOD-027-1 does not require the following:

- **Models to Be Provided for Different Ambient Conditions:** A verified model is provided based on the ambient conditions at the time of testing that may differ greatly from the assumptions used to generate different base cases (e.g., summer, winter, and spring).
- **Verification of Turbine Limits (e.g., VMAX in TGOV1 or LDREF in GGOV1) that May Need to Be Modified Based on a Number of Factors:** Without attention to appropriately adjusting these limits, turbine-governor models can be verified but still grossly overestimate the amount of frequency responsive reserves (e.g., the testing may have been done during winter conditions, and so when a summer peak planning case is being built, the turbine load limit will need to be adjusted to its summer capacity).
- **Verification Testing for every Operating Mode the Unit May Experience:** For example, the unit may be verified in turbine speed control mode while in reality it is often operated in sliding pressure mode. The operating characteristics of these different modes greatly impact the results of a simulated frequency excursion.
- **Prevention of the Use of any Legacy Models although It Does Allow the TP to Maintain a List of Acceptable Models:** Some models do not capture governor deadband, and unless the TP/PC disallows the use of those models, the GO may continue to use those models. This will lead to issues when trying to simulate frequency disturbances in interconnection-wide studies. TPs and PCs should refer to the NERC List of Acceptable Models for more information.[19]
- **Every Unit to Be Tested, Particularly if They Do Not Run Often:** Row 3 in Attachment 1 of MOD-027-1 states that if a unit is not subjected to a frequency excursion of sufficient size within the next turbine-governor verification date (and “a frequency excursion from a system disturbance that meets Note 1 is selected for the verification method…”) then a “written statement to that effect” can be transmitted to the TP. Similarly, Row 8 states that if the unit as a current average net capacity factor over the most recent three-year period of 5% or less, then a similar written statement can be transmitted to the TP.

All these issues can lead to accurate model verification testing yet may yield models that do not match the assumptions used when developing interconnection-wide base cases. The TP should be aware of these issues and adjust the models as necessary to prevent these issues from occurring.[20] The overall improvement of turbine-governor model application will help industry more accurately reflect system-wide disturbances and help with MOD-033-1 activities for system-wide model verification.

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[18] NERC MOD-027-1. Verification of Models and Data for Turbine-Governor and Load Control or Active Power-Frequency Control Functions. https://www.nerc.com/pa/Stand/Pages/Default.aspx.

[19] https://www.nerc.com/comm/PC/Pages/System-Analysis-and-Modeling-Subcommittee-(SAMS)-2013.aspx

[20] Note that studies performed by the TP and PC may differ from those performed by the BA, and the accuracy and objectives of each study should also be considered.

Chapter 1: Turbine-Governor Modeling Considerations

This chapter describes a number of important considerations when developing and applying turbine-governor models in planning studies.

Deadband Representation

In February 2018, FERC issued Order No. 842,[21] which revised the pro forma Large Generator Interconnection Agreement (LGIA) and Small Generator Interconnection Agreement (SGIA) for both synchronous and nonsynchronous resources to install, maintain, and operate equipment capable of providing primary frequency response. The rule included requirements pertaining to droop, deadband, and sustained response. Related to deadband, the Order No. 842 required a maximum deadband parameter no greater than ±36 mHz. This provided some standardization of deadband values for newly interconnecting resources; however, there are no NERC requirements for GOs to have functional governors with maximum droop or deadband settings for existing resources. In areas where other requirements are in place, generating resources should then meet those requirements and provide models that match actual performance. Therefore, it is important to describe the various aspects of deadband modeling and how they can impact simulations.

Turbine-governors include a deadband, a range of speed (or frequency) where the prime mover does not respond to small variations. This deadband is typically separated into an inherent deadband and an intentional deadband.[22] The inherent deadband has been tested on various types of governors including mechanical, analog electronic, and digital, and is typically small (e.g., < ±5 mHz).[23] The intentional deadband is used by most turbine-governor manufacturers and GOPs to reduce control activity for relatively small (e.g., < ±36 mHz) speed deviations common during normal grid operation. However, as the magnitude of these combined deadbands increases, the responsiveness of the resource to frequency excursion events reduces. Any intentional deadband and estimation of inherent deadband should be accurately represented in the turbine-governor model.

Key Takeaway:
Turbine-governor deadband should be accurately represented in dynamic models. Models that do not currently have a deadband implemented should be updated/modified to account for deadband. For example, use of the "DU" models in Siemens PTI, which now accounts for deadband representation, is recommended.

Any models that do not currently have a deadband parameter implemented should be updated/modified to account for deadband. For example, Siemens PTI has implemented the "DU" models for many turbine-governor models that now account for deadband representation. **Figure 1.1** shows an example of the IEEEG1[24] model and the new IEEEG1SDU model with the addition of the deadband on speed. Note that, when switching to the "DU" version of the models in PSS®E, parameters will be based on TRATE rather than MBASE and may need to be adjusted accordingly. This includes the limit values as well as other model parameters, such as droop or turbine gains. A check should be performed to ensure the output of the model is as expected when switching to turbine rating.

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[21] FERC, "Essential Reliability Services and the Evolving Bulk-Power System–Primary Frequency Response," Docket No. RM16-6-000, Order No. 842, Feb 15, 2018: https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-2.pdf?csrt=10405686437913442809.

[22] Inherent (unintentional) deadband has a stochastic nature that makes it unpredictable and unreliable to model. It occurs in combinations of several parts of the mechanical linkage between speed sensing and valve/gate movement. It can vary with operating conditions and is best modeled by backlash sorts of blocks with unpredictable hysteresis amounts (see software manuals). Unintentional deadbands are typically small and not represented in dynamic models. Intentional deadband is typically more explicitly linked to a control set point or other tunable controls parameter, and have a more significant impact on dynamic behavior of the turbine-governor system.

[23] https://www.wecc.biz/Reliability/Governor%20Tutorial.pdf

[24] The naming convention of this model is often a source of confusion. In the IEEE guide, the IEEEG1 model includes a deadband as is also the case in some software platforms. However, in Siemens PTI PSS®E, there this distinction between IEEEG1 and IEEEG1SDU. The key here is to use the version of the IEEEG1 model that includes deadband and turbine rating in whatever software is being used.

The size of the deadband and the size of system frequency deviation can impact model fidelity for off-nominal frequency simulations (e.g., frequency response analysis). Units without a deadband modeled may show over response compared to actual operations, depending on their actual control settings. To illustrate this, consider a unit with 5% droop and a deadband of 100 mHz. Table 1.1 shows the overestimation of unit frequency response if deadband is not represented in the dynamic model. For example, if frequency deviates by 50 mHz, the model will show a 1.667% change in unit output but the unit will not move in reality. However, a 500 mHz frequency change would cause the unit to move 13.333% while the simulated response would be 16.667%, assuming a non-step deadband implementation in the actual controls.

Table 1.1: Overestimation and Deadband

Deviation [Hz]	Simulated Unit ΔP [%]	Actual Unit ΔP [%]
0.010	0.333	0
0.036	1.200	0
0.050	1.667	0
0.100	3.333	0
0.200	6.667	3.333
0.500	16.667	13.333

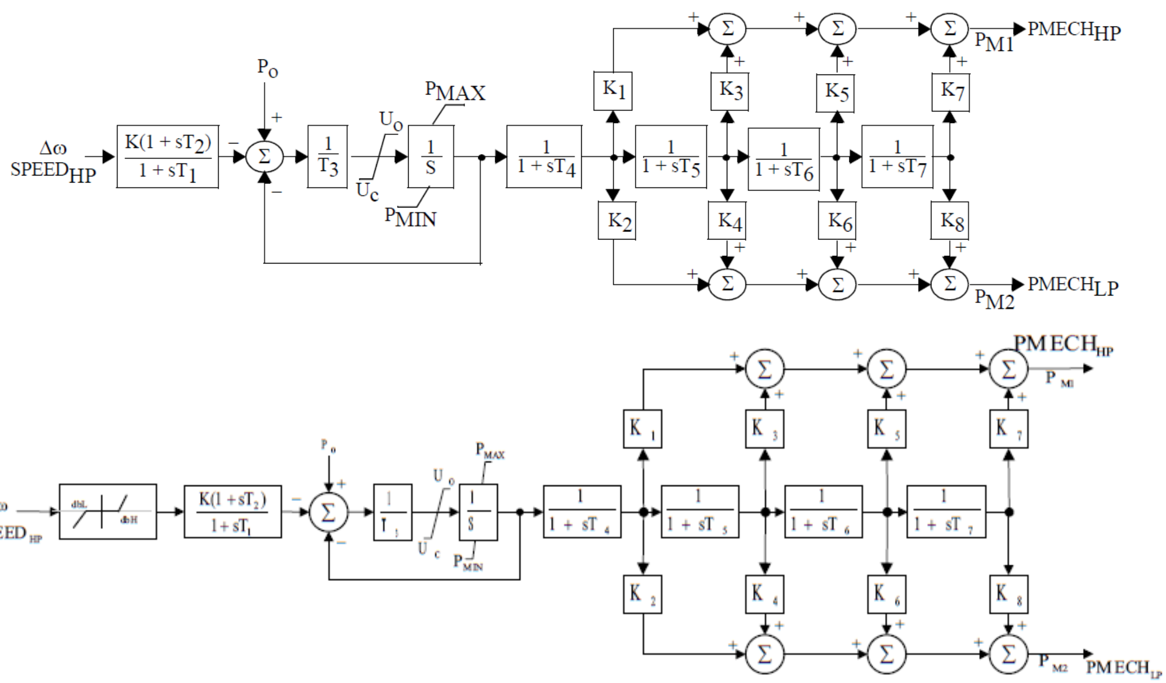

Figure 1.1: IEEEG1 and IEEEG1DU Models [Source: PSS®E]

For interconnections where typical disturbance events result in a relatively small frequency excursion (e.g., the Eastern Interconnection), accurate representation of deadband is important for model fidelity. For systems where disturbances cause larger frequency excursions (e.g., Quebec and Texas), accurate deadband modeling may be less of a concern than other topics described in this guideline, but the deadband for each unit should be represented and modeled as accurately as possible in either case.

The location of the deadband in the model is also an important factor for model accuracy. Different manufacturers may use deadband on different quantities. For example, one manufacturer may include a deadband on speed error (Δω) input while another may use a deadband on proportional-integral-derivative (PID) input. This would require a difference in modeling that may not be currently available in the generic models present in most commercially available tools. GOs should ensure that the model used has the location of deadband modeled correctly. Software vendors may be requested to implement additional modeling capability to select where deadband is applied.

> **Key Takeaway:**
> Location of deadband in the model is an important factor for model accuracy. Care should be given to ensuring correct deadband modeling, where applicable. Updates to existing models may be needed by software vendors.

Incorrectly representing the deadband location may result in a modeled response that does not match reality even if the deadband parameter value is set correctly. Figure 1.2 shows different implementations and how a modeled unit responds for an underfrequency simulation (blue). With a 0 mHz deadband (grey), the simulated response does not match at all. A GGOV1 deadband of 33 mHz on speed error (purple) gives a response that matches the initial transient but does not match actual data as frequency recovers. A modified GGOV1 model with deadband on speed (orange) gives a simulated response that matches the actual response very well. The governor deadband location should be verified via documentation (and measurements when possible) to ensure it is accurately modeled.

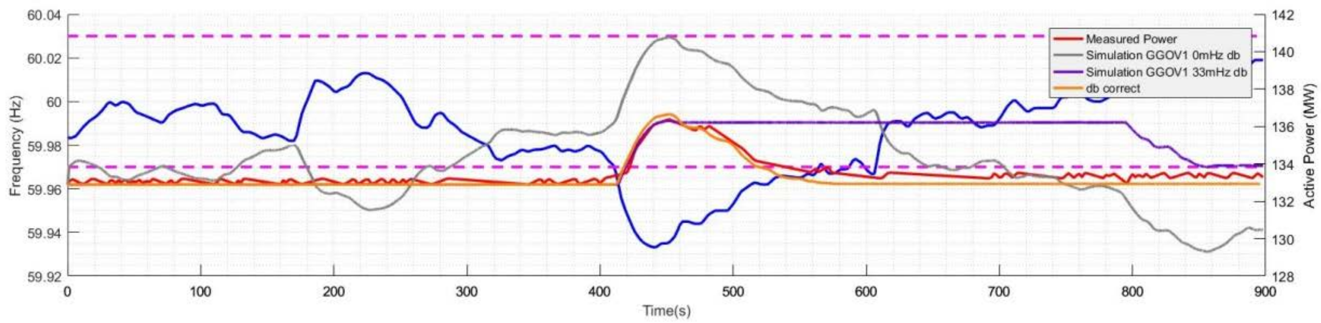

Figure 1.2: Impact of Different Deadband Implementations [Source: IESO]

Lastly, note that there are two implementations of deadbands as follows:[25]

1. **Non-Step Deadband:** The unit produces zero additional active power when measured frequency is within the deadband limits. When measured frequency falls outside the limits, unit output equals the difference between measured frequency and deadband limit thresholds (not rated frequency). No step change in unit output occurs when frequency crosses the deadband limit threshold.
2. **Step Deadband:** The unit produces zero additional active power when measured frequency is within deadband limits. However, when measured frequency falls outside the limits, the change in output is equal to the difference between measured and rated frequency. A step change in unit output occurs when frequency crosses the deadband limit threshold.

Refer to the NERC Reliability Guideline on Frequency Control,[26] which recommends a non-step implementation for any use of deadband. Modellers should use care to ensure correct implementation of deadband in the model compared with actual controls. In particular, the most unfavourable situation is when the actual unit uses a large deadband with a non-step implementation, but the model uses a step implementation. This leads to a large jump on MW output in simulation when the unit crosses the deadband that is not observed in reality.

Reasons for Unit Nonresponsiveness and Expected Modeling

Where any requirements may exist related to minimum primary frequency response performance, those requirements should be met by the generating resource. However, there may be reasons why a generating

[25] See Appendix B of the IEEE Guide (http://sites.ieee.org/fw-pes/files/2013/01/PES_TR1.pdf). These are referred to as a type 2 and type 1 deadband, respectively, in that guide.
[26] NERC, "Reliability Guideline: Primary Frequency Control," Atlanta, GA, Dec 2015. [Online]. https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Primary_Frequency_Control_final.pdf.

resource may not be responsive to changes in speed (or grid frequency). This section describes those reasons, and recommends appropriate modeling so that the simulated response matches the actual response of the resource. While resources should be capable of providing primary frequency response, any nonresponsiveness should be modeled correctly where appropriate.

Some reasons may lead to no model being needed for dynamic studies while other reasons may actually need to be modeled since the unit could respond in some situations. Fundamentally, if the turbine speed control (governor) is installed and enabled, then it should be modeled appropriately with a dynamic model. If the turbine speed control (governor) is not installed or disabled, or the plant is regularly operated in a mode where speed control is not operational, then a turbine-governor model may not be needed depending on the specific situation. **Table 1.2** shows various reasons why a generating unit may typically be nonresponsive to frequency events and the expected modeling practice for each of those situations.[27] In any case, the GO should provide information regarding what model or lack thereof was provided and other data requested from the TP or PC for the purposes of interconnection-wide modeling (e.g., ambient temperature curve) or other relevant purposes.

As described throughout this document, the TP should be monitoring the response of its generating fleet. Upon identifying any unit(s) that are not accurately represented, the TP can use Requirement R3 of MOD-032-1 as a technical basis that the modeling approach needs to be reconsidered. The TP and GO can then work together to determine the best modeling practice. Monitoring of generator performance can easily identify these situations, listed here:

- Units that have a functional turbine-governor model but do not provide any response to grid events should be flagged. Refer to **Table 1.2** for various reasons why the unit may not be responsive.
- Units that have been declared as nonresponsive (i.e., stated in the NERC MOD-027-1 verification report[28] with a corresponding written statement and possibly no governor model) that are observed responding to grid events should also be flagged.

More commonly are situations where a functional turbine-governor model has been provided per MOD-032-1, but the unit does not respond to frequency excursion events. A contributor to this issue is that the dynamics data files (e.g., .dyr or .dyd file) may not allow the GO to easily mark the unit as nonresponsive (model disabled).[29] In some software platforms, this cannot be denoted in the powerflow data either. Therefore, effective transfer of information may be hindered, and the TP and PC should ensure their data collection processes provide sufficient clarity and capability to provide the necessary information. This challenge leads to overestimation of frequency responsive capability in the simulations. Identifying these units by monitoring actual fleet performance should be a top priority for TPs and PCs to improve the fidelity of interconnection-wide models.

[27] Note that **Table 1.2** does not describe specific performance requirements or recommended performance of generating resources with respect to providing primary frequency response. **Table 1.2** focuses on ensuring that the dynamic models used for system planning and operations studies accurately reflect the actual performance of the resources.

[28] The GO may attest that the unit is not responsive to both under- and over-frequency conditions and provide a written response to the TP to that effect. The TP would then need supporting evidence (per the third bullet of Requirement R3 in MOD-027-1 or Requirement R3 of MOD-032-1) to instigate a model review.

[29] Implementation differs across software platforms. Regardless, the TP and PC should ensure that they have processes in place to gather information regarding the expected responsiveness (status) of the turbine-governor model for all expected operating points.

Example Steam Turbine Considerations:
As an example, steam turbines may use different modes of operation that should be reported to the TP and PC for their use when developing base cases. In some cases, the unit may change operating mode based on output level (i.e., responsive in some output ranges, non-responsive in other output ranges, or different type of response in other ranges). TPs should ensure they have a process in place to gather this additional information from the GO, when applicable, so that they can effectively create representative base cases. In the future, simulation software platforms may consider the capability to easily switch dynamic models or model parameters for different specified operating conditions. Note that in some software platforms, use of the baseload flag can be an effective means of capturing these different response characteristics.

Table 1.2: Expected Modeling Practices for Various Reasons of Nonresponsiveness	
Reason for Nonresponsiveness	**Expected Modeling Practice**
All Generating Technologies	
Operated at Baseload:[30] Some units have historically spent much of their operating time at full power output, so do not have reserves to respond to underfrequency events.	• Provide turbine-governor model with appropriate settings • Set baseload flag
Large Deadband:[31] Units with a large governor deadband will be nonresponsive to the majority of frequency excursions so will not support primary frequency response.	• Provide turbine-governor model with appropriate settings, including large deadband[32] • Set baseload flag • No model if acceptable by the TP/PC (not recommended)
Outer-Loop (Plant-Level) Controller: Any generator may have a plant-level, outer-loop controller (i.e., load controller) that either causes the unit to not respond to frequency excursions or causes the unit to quickly withdraw any response back to pre-disturbance output.	• Provide turbine-governor model with appropriate settings AND represent the load controller • No load controller model is need if the controller does not impact unit response within the timeframe used for stability analyses (e.g., within 30–60 seconds after a change in unit output) • Set baseload flag if controller reacts very quickly (use judgment here; modeling the load controller is perhaps more appropriate)

[30] Whether the turbine-governor model should be provided is not qualified by expected operating point. Determination of providing a turbine-governor model is based on whether those controls are installed and operational when the unit is on-line. For example, if a generating unit is dispatched at full output, it may still respond downward for over-frequency conditions that will need to be accurately represented in the model. Also, if the unit is dispatched off its maximum output level in the simulation and has a functional speed governor, the unit will then be responsive to under-frequency as well.

[31] Large deadbands are common in nuclear generators, making the unit non-responsive to typical frequency excursions. Other units should follow the NERC Reliability Guideline on Frequency Control. https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Primary_Frequency_Control_final.pdf.

[32] For example, PRC-006-3 underfrequency load shedding (UFLS) studies will need to know the settings of large deadbands, and have applicable models to study grid response to severe frequency disturbances to set UFLS programs accordingly.

Table 1.2: Expected Modeling Practices for Various Reasons of Nonresponsiveness	
Reason for Nonresponsiveness	**Expected Modeling Practice**
Steam Turbines[33]	
Turbine-Follow Mode: The turbine control valves are used primarily to control steam pressure, causing the output of the turbine to follow any changes in pressure. Thus, changes in power output follow the boiler controls and occur very slowly.	• Depending on the time frame of response, this behavior may be emulated by using the IEEEG1 model by setting a large time constant on the first steam stage.
Sliding Pressure Control: Control valves are left wide open, and unit output is a function of boiler controls (steam pressure). In some cases, cogeneration facilities may not operate in governor control mode and may operate in manual control to share steam production. In other cases, cogeneration facilities may respond to frequency excursions. Same concept applies to steam at combined cycle facilities.	• No governor model is often the best approach since turbine will not respond within simulation time frame. • For steam turbines in combined-cycle plants, this is also true.[34]
Steam Turbine Inlet Pressure Control (IPC) (for some Combined-Cycle Steam): Pressure is controlled at the inlet valve, so turbine output is fixed and nonresponsive to frequency.	• No turbine-governor model needed (response disabled) • Set baseload flag if this operating mode is not always used for the unit
Natural Gas Turbines	
Temperature Limit: [35] When the natural gas turbine reaches its maximum allowable exhaust temperature, the unit will be on its temperature limit and thus not able to increase output any further. This would also apply to a natural gas turbine in a combined cycle power plant.	• Provide turbine-governor model with appropriate settings; applicable temperature limits should be set based on ambient temperature assumptions.
Temperature Matching (Combined-Cycle CTs): For some manufacturers, in this mode the CTs are not allowed to respond to frequency excursions in order to maintain a desired exhaust temperature range.	• No turbine-governor model needed since its response is disabled

[33] Coordinated control for steam units is where the movement of the main steam control valves (MCV) is controlled by a combined coordinated effort of regulating power (due to droop response) and main steam pressure. Therefore, the unit is responsive to frequency. Similarly, for boiler follow mode turbines, the MCV is primarily controlled by the turbine-governor, and the boiler controls follow the turbine in order to regulate steam pressure. Therefore, these units are also typically responsive (although to a lesser extent). Reference the IEEE Dynamic Models for Turbine-Governors in Power System Studies. It is available here: http://sites.ieee.org/fw-pes/files/2013/01/PES_TR1.pdf.

[34] However, the CIGRE steam turbine model may be used if desired, but it still will only show response in the many minutes time frame (i.e., boiler time constant). See CIGRE Technical Brochure 238, Modeling of Gas Turbines and Steam Turbines in Combined-Cycle Power Plants, December 2003. www.e-cigre.org.

[35] Note that exhaust temperature limits and other types of limits are accounted for in models like GGOV1.

Table 1.2: Expected Modeling Practices for Various Reasons of Nonresponsiveness	
Reason for Nonresponsiveness	**Expected Modeling Practice**
Nuclear Generators	
Maximum Reactor Power Limitation: Nuclear Regulatory Commission requirements do not allow nuclear units to operate above their maximum power limit. Should the unit go above this limit, the plant operator is required to lower the power back to or below the limit.	• Provide turbine-governor model • Set baseload flag • No model if acceptable by the TP/PC (not recommended)
Boiler Pressure Control: Controls maintain boiler pressure and are therefore not responsive to frequency.	• No model if acceptable by the TP/PC
Hydro Turbines	
Forebay Level Control: Some implementations of forebay level control may strictly control hydro unit head level and bypass the speed governor.	• No model if acceptable by the TP/PC
Butterfly Valves: Simple open/close valves that do not have speed governing capability.	• No model if acceptable by the TP/PC
Manual/Fixed Gate Control: Power (gate position) is set by actuator (operator) and does not automatically respond to frequency.	• No model if acceptable by the TP/PC
Flow Control: Governor regulates water flow through the turbine.	• No model
Variable Energy Resources (e.g., wind and solar photovoltaic)	
Maximum Available Active Power Output: Operation at the maximum available power point prevents the resource from having additional active power generation for low frequency events.	• Provide accurate active power-frequency control settings • Ensure TP/PC are aware capability is enabled • TP/PC need to pay close attention to ensuring appropriate limits based on assumptions in study

Modeling Load Control Interactions

Generator "load control" typically refers to an outer loop controller commonly used on different types of resources to return them to a pre-set MW set point if any deviations occur. The load controller may have a frequency bias that allows the unit to sustain governor response for off-nominal frequency conditions. However, if the load controls do not include frequency bias, it is likely that the outer-loop controller will return the unit to its predisturbance MW set point relatively quickly (i.e., within the time frame for stability analysis).

If the slower outer-loop controls interact in any way with the governor response of the unit within the time frame typically used for stability analysis (e.g., within 30–60 seconds), those controls need to be modeled along with the turbine-governor model. Some models have these controls built directly into the model while others do not and require an additional model to be included. Two examples of such models are described below to give an idea of how to apply these models.

Integrated Load Control Blocks in Turbine-Governor Model–GGOV1 Example

Some models include the load control function directly in the turbine-governor model, such as the GGOV1 model. The outer loop load control path is shown in **Figure 1.3**, and is dominated by the unit MW load control gain parameter, *Kimw*. When the dynamic model initializes, the MW set point (Pmwset) is assigned as the dispatched unit MW level. If the *Kimw* parameter is nonzero, the unit will return to the MW set point after a disturbance. A higher value of *Kimw* will cause the unit to return to its MW set point faster. For example, Kimw = 0.05 corresponds to a reset time of 20 seconds while Kimw = 0.01 corresponds to a reset time of 100 seconds. **Figure 1.4** shows examples of Kimw parameter values and their impact on the simulated load control response.

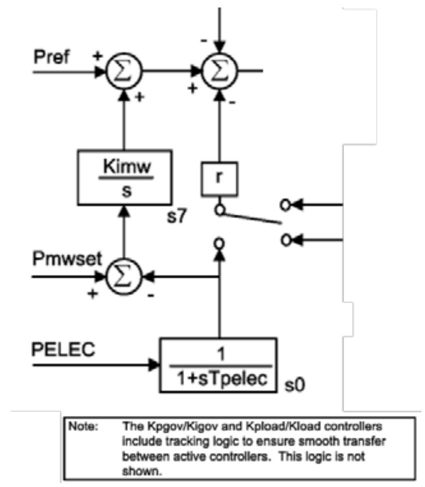

Figure 1.3: GGOV1 Natural Gas Turbine-Governor Model [Source: PSS®E]

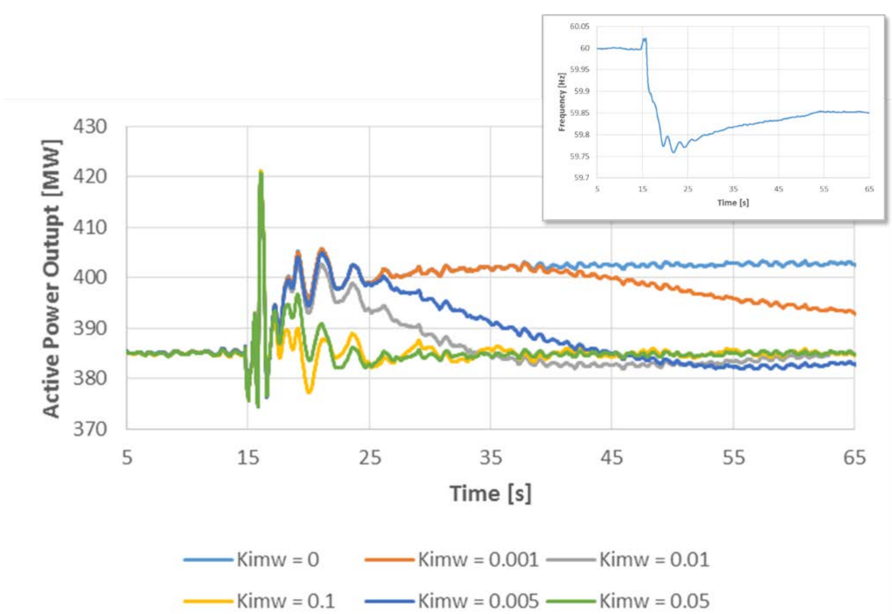

Figure 1.4: Impact of Kimw on Return to MW Set Point in GGOV1

Standalone Load Control Model–LCFB1 Example

Many turbine-governor models do not include load control blocks, but the actual unit may have these controls installed and enabled. In those cases, a complementary load control model needs to be included with the turbine-governor model to accurately represent the overall active power-frequency response of the generating resource.[36,37,38,39] The *lcfb1* model[40] is commonly[41] used to represent the load control actions that maintain turbine power at a set point value by adjustment to speed-load reference. **Figure 1.5** shows the block diagram for the *lcfb1* model.

Again, the Pmwset set point parameter is automatically assigned on initialization. The parameter Fb models the frequency bias gain when frequency bias is implemented in the controller. The model can apply either a speed reference or load reference depending on how it is configured. The references are generally as follows: speed reference = (1 + [initial power or valve position] × [droop]); load reference = (0 + [initial power or valve position]).[42] The controller is limited by an error maximum with associated deadband. A proportional-integral (PI) control (and droop parameter if specified) drives the load controller response. Output of the controller is limited to ± Irmax to prevent excessive adjustments to turbine power that should generally not exceed about half the governor droop (e.g., about 0.025 pu).

Figures 1.6 and **1.7** shows an example of simulating the governor frequency step response tests with and without the LCFB1 load controller model. In the tests, an emulated bias of 150 mHz was injected to the frequency set point and the governor responded immediately as if there was a system frequency excursion. The test shown in **Figure 1.6** was done with the load controller disabled and simulated with IEEEG1 model only, and the test shown in **Figure 1.7** was done with the load controller enabled in the field and simulated with IEEEG1 + LCFB1 model. It shows that the load control could quickly take effect after the governor reaction to withdraw primary frequency response and would need to be modeled appropriately.

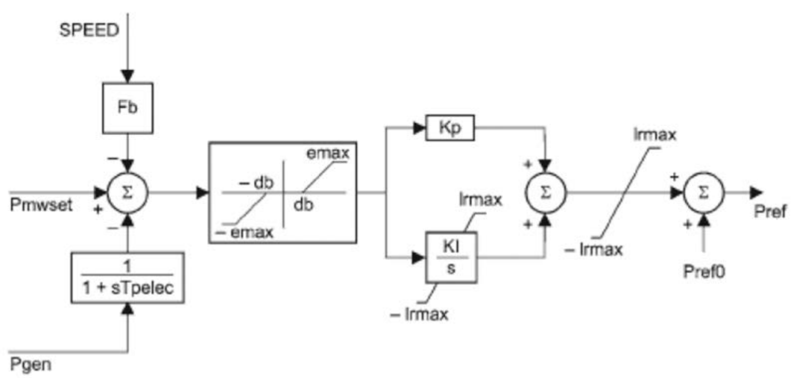

Figure 1.5: LCFB1 Load Controller Model [Source: PSS®E]

[36] IEEE Task Force on Large Interconnected Power Systems Response to Generation Governing, Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns, IEEE Special Publication 07TP180, May 2007. http://www.pes-store.org/continuing-education/interconnected-power-system-response-to-generation-governing-present-practice/p-13433.htm.

[37] IEEE Task Force on Turbine-Governor Modeling, "Dynamic Models for Turbine-Governors in Power System Studies," IEEE Technical Report 1, January 2013. [Online]. http://resourcecenter.ieee-pes.org/pes/product/technical-publications/PESTR1.

[38] CIGRE Technical Brochure 238, Modeling of Gas Turbines and Steam Turbines in Combined-Cycle Power Plants, December 2003. (www.e-cigre.org).

[39] WECC, "WECC Guidelines for Thermal Governor Modeling," Salt Lake City, Nov 2002. [Online]. https://www.wecc.biz/Reliability/WECC%20Guidelines%20for%20Thermal%20Governor%20Modeling.pdf.

[40] This model is implemented differently across software platforms. Care should be used when applying this model.

[41] The lcfb1 model works on a handful of turbine-governor models. Refer to each software manual for more information.

[42] See GE PSLF manual for more information.

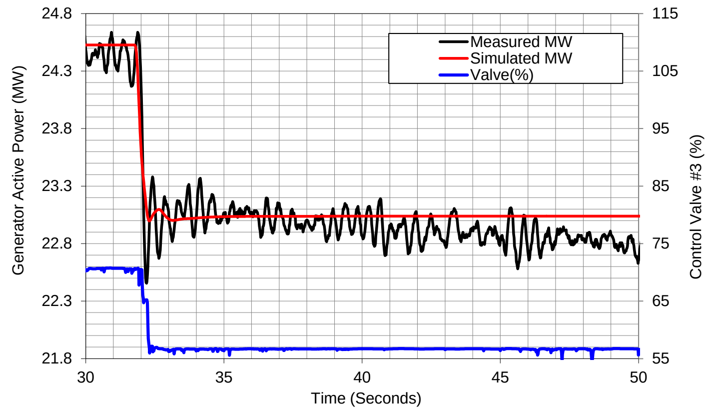

Figure 1.6: Governor frequency step response test with load controller disabled (IEEEG1)

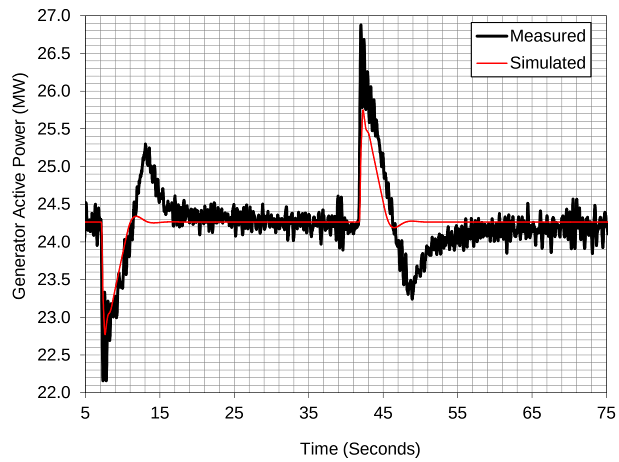

Figure 1.7: (b) Governor frequency step response test with load controller enabled (IEEEG1 + LCFB1)

[Source: Powertech]

Mitigating Frequency Response Withdrawal with Frequency Bias

Frequency response withdrawal from generating resources is not desired and can be mitigated by including a frequency bias component in the load controller. Figure 1.8 shows a simplified block diagram of a steam turbine generator and load controller as well as the frequency bias component. Measured speed is compared against a reference speed, and any modification to the MW load set point is calculated based on the active power-frequency droop characteristic with any applicable deadband. For example, assume a unit is operating at 100 MW and frequency is less than nominal (i.e., outside the deadband). The unit MW set point will be increased slightly due to the speed-governor controls trying to raise MW output. Rather than the unit output being compared against the MW load reference, the modification to that reference is made based on the frequency bias so that the frequency-biased MW load set point is compared against the actual MW output. This coordinates the load controller with the speed governor to avoid any withdrawal of response that the speed-governor may provide.

If a unit incorporates frequency bias into its controls, the load controller does not need to be represented in stability studies since it will not be affected by a deviation in turbine speed (i.e., system frequency). This can be verified with disturbance data or testing to ensure that a change in speed and subsequent response from the turbine-governor will not cause the unit to return to its MW set point.

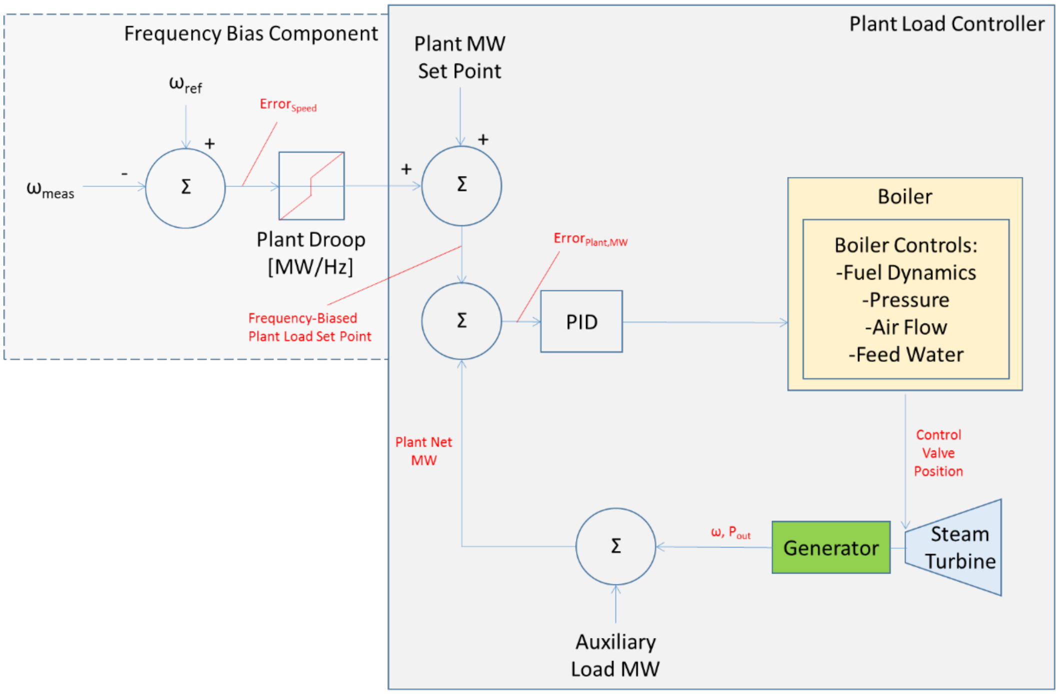

Figure 1.8: Simplified Control Diagram of a Load Controller with Frequency Bias [Source: Adapted from GE]

Figure 1.9 shows a screenshot of a steam turbine load demand controller, and the bottom section of the screen gives options for the operating mode: turbine follow, boiler follow, coordinated turbine follow, or coordinated boiler follow mode. Regardless of which operating mode is selected, a plant technician or engineer will need to ensure that the coordinated modes are set to include "frequency trim," or frequency bias, in the distributed control system (DCS) programmer's computer. Coordinated control mode simply refers to coordination between the boiler master and turbine master controls, not whether they include frequency bias.

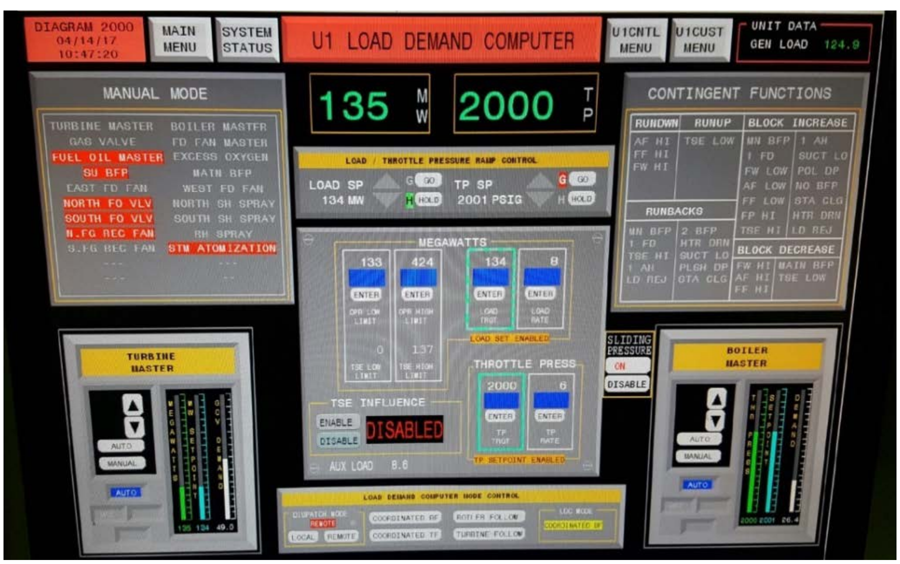

Figure 1.9: Steam Turbine Load Demand Controller [Source: Entergy]

Utilizing Baseload Flags

Some software platforms have implemented a "baseload flag"[43] as a steady-state generator model parameter that is entered as part of the load flow parameters. This parameter interacts with the turbine-governor dynamic models based on the how the flag is set for each machine. Setting the flag has the following effects during simulations:[44]

- **Baseload Flag = 0:** The turbine-governor model is not impacted, and the unit is able to respond to underfrequency and overfrequency events with an increase or decrease in mechanical input power.
- **Baseload Flag = 1:** The unit cannot respond to underfrequency events with additional mechanical power. The turbine-governor upper control valve limit is set at its initial condition valve position during the initialization process. The governor can close valve(s) to reduce output.
- **Baseload Flag = 2:** The unit cannot respond to either underfrequency or overfrequency events. The turbine-governor upper and lower valve limits are set at initial valve position, and the governor cannot change valve position. Setting this flag will cause most[45] turbines to run at nearly constant power.

While MOD-027-1 testing should help improve governor modeling to more accurately match actual performance, there is a significant amount of generating capacity that is modeled as responsive while nonresponsive during real-time operation. The reasons for this discrepancy, due to the application of these models in stability cases, are described throughout this guideline. Units that are nonresponsive as their normal mode of operation (i.e., units that behave this way for most grid disturbance events) should be modeled accordingly. TPs and PCs should review the active power response of generating resources in their footprint for actual grid disturbance events (this is described in detail in **Chapter 2: Analyzing Modeled versus Actual Response**) and ensure appropriate modeling for all resources. The baseload flag can be used to block the modeled response of a resource if it is responsive in simulation but is known to be nonresponsive in on-line operations.

The baseload flag provides an additional layer of modeling capability when modeling turbine-governor response for Interconnection-wide simulations. **Table 1.3** shows benefits and drawbacks of using the baseload flag (over simply representing nonresponse with "no model."

[43] In 2002, WECC made a recommendation for thermal governor modeling that focused primarily on underfrequency conditions to limit governor response in the upward direction. Hence the parameter was deemed a "baseload flag". Later modifications included the baseload flag settings that limited governor response in both directions. See: https://www.wecc.biz/Reliability/WECC%20MVWG%20Thermal%20Governor%20Model%20Revision%202012-06-20.pdf.

[44] Note that these settings may differ slightly across software vendors. Consult each software vendor's manual for more information.

[45] Power output of turbines that are sensitive to speed will still vary slightly as speed varies.

Table 1.3: Baseload Flag Benefits and Drawbacks
Benefits
• Baseload flags link steady-state base case and dynamics data. • Turbine-governor model can be accurately modeled and disabled if operating mode is not responsive to governor. • The TP and PC can identify the type of prime mover for the generating plant (e.g., ggov1 (natural gas), ieeeg1 (steam)). • The TP and PC can disable turbine-governor response if the plant has a submitted model, but the actual plant response shows nonresponsiveness • They grant the ability to restrain response in one direction but still allow response in the other direction where available in software platforms.
Drawbacks
• The added tracking of plant response needs to set baseload flags accordingly. • The ability of the TP and PC to change model parameters needs to be coordinated with the GO. • Implementation is required in software[46]

For users of software tools that do not include a baseload flag parameter, governors can be disabled prior to initialization to achieve the same performance objective during transient simulation. Other options include using a very large deadband or a very high droop value (e.g., 999) that would effectively disable the turbine-governor response. This should only be used as an interim solution, and software platforms that do not have a baseload flag should implement this feature for uniformity in modeling and simulation techniques across North America. The TPs, PCs, and MOD-032 Designees should track unit responsiveness and setting baseload flags accordingly in interconnection-wide base cases. Entities using software platforms that do not have a baseload flag implemented yet should be preparing procedures for effectively using the flag in the future.

Key Takeaway:
Software platforms that do not have a baseload flag should implement this feature for uniformity in modeling and simulation techniques across North America. The TPs, PCs, and MOD-032 Designees should be tracking unit responsiveness and setting baseload flags accordingly in interconnection-wide base cases.

Incorrect Per-Unitizing Leading to Overestimated Headroom

Turbine-governor dynamic models for thermal generators are meant to simulate the prime mover action to increase mechanical power on the generator shaft until either the desired operating point is reached or a limit is hit. The parameters that represent these limits represent a physical limit, such as a valve travel limit, temperature limit for natural gas turbines, or gross head level for hydro units. It is very important to understand how these limits should be used in dynamic simulations to represent realistic limits.

Model parameters are per-unitized to allow for computation in the per-unit system and are set to reflect the proper capability of the machine and turbine. The dynamic model should not allow the MW output of a machine with a responsive governor to produce more active power than can be produced under the studied operating conditions. When the values are not set accordingly, the model will either overestimate primary frequency response if the limit is set too high or underestimate the response if the limit is set too low. Most commonly, the limits are set too high or a base per unit value is used that is not correct, leading to overestimating primary frequency response and the ability of the machines to arrest frequency deviations when they do not provide such

[46] Where those software capabilities are not currently available.

capability in reality. This section focuses on overestimated frequency responsive reserves caused by incorrectly parameterizing the per unit values of the dynamic model.

In general, there should be a clear link between the following parameter values in the powerflow model and dynamic model data, listed as follows:

- **Generator Maximum Power:** This is a powerflow model parameter value that represents the maximum power output (P_{max}) of the unit.
- **Electrical Generator Volt-Amp (MVA) Capability:** This is the maximum machine capability that is typically the MVA rating at nominal voltage and unity power factor (i.e., the far right of machine capability curve). This is a physical thermal limit of the electrical generator. This may be a powerflow model record or a dynamic model parameter based on software implementation.
- **Turbine Rating:** Some software platforms allow the user to specify a turbine-governor turbine rating (i.e., TRATE or mwcap) in the dynamic model data that is used as the base value for the turbine-governor model parameters. For steam and natural gas turbines, this is a physically meaningful value that can be found on the turbine nameplate or in the vendor documentation.

Limit values in the dynamic model need to be set according to the per unit base used by the model. These parameters will be different depending on whether the model uses the electrical generator MVA base (MBASE) or the turbine rating (TRATE or mwcap) as the base value for the model, and need to be aligned accordingly as follows:

- If the model uses MBASE as the base value, then turbine-governor model limits (e.g., VMAX/VMIN in TGOV1, or corresponding parameters in other dynamic models) need to be correctly set such that they match the powerflow P_{max} value, assuming that the powerflow P_{max} value has been correctly calculated to reflect the actual turbine capability for the given ambient conditions. This is typically a fractional value less than 1.0 since the turbine rating (i.e., TRATE or mwcap) is less than the electrical generator MVA rating for thermal units. For hydro units, the opposite can be true. Furthermore, note that droop and some other parameters will also be affected by this change in base.
- If the model uses TRATE or mwcap as the base value, the turbine-governor model limits are based on that value explicitly, and that value needs to be coordinated with the powerflow P_{max} value.
- Attention needs to be given to the turbine model parameters (e.g., GGOV1 values for Kturb and wfnl, which are also base-dependent). These values are provided by the manufacturer and may be based on MBASE, TRATE or mwcap. Initialization errors are common when base values are not aligned.

Commercially available simulation tools use different base values for per unitizing the dynamic model parameters, and needs to be addressed appropriately by the model user. Table 1.4 reviews the turbine-governor models and whether each of the major software platforms per unitizes on MBASE or TRATE/mwcap.

Table 1.4: Review of Models using MBASE vs. TRATE

Model Name	PSS®E Versions Before v33.10 or v34.2[47]	PSS®E Versions After v33.10 or v34.2[48]	GE PSLF	PowerWorld Simulator	Powertech Labs TSAT v19
ccbt1	–	–	MWCAP	TRATE	–
ccst3	–	–	MWCAP	–	–

[47] The DU models are available in version 33.10 and all 33.x versions thereafter.

[48] The DU models are available in version 34.2 and all 34.x versions thereafter.

Table 1.4: Review of Models using MBASE vs. TRATE					
Model Name	**PSS®E Versions Before v33.10 or v34.2[47]**	**PSS®E Versions After v33.10 or v34.2[48]**	**GE PSLF**	**PowerWorld Simulator**	**Powertech Labs TSAT v19**
crcmgv	MBASE	MBASE	MWCAP	N/A (MBASE)	MBASE (GGOV4)
degov1	MBASE	TRATE/MBASE (DEGOV1DU)	MWCAP	N/A (MBASE)	MBASE
g2wscc	–	–	MWCAP	MWCAP	MWCAP
gast	MBASE	TRATE/MBASE (GASTDU)	MWCAP	MWCAP	MBASE (PSS®E) MWCAP (PSLF)
gast2a	MBASE	TRATE/MBASE (GAST2ADU)	–	TRATE	TRATE
gastwd	MBASE	TRATE/MBASE (GASTWDDU)	–	TRATE	TRATE
gegt1	–	–	MWCAP	–	–
ggov1	MBASE/TRATE	TRATE/MBASE (GGOV1DU)	MWCAP	TRATE	TRATE (PSS®E) MWCAP (PSLF)
ggov2	–	–	MWCAP	TRATE	–
ggov3	–	–	MWCAP	TRATE	MWCAP
gpwscc	–	–	MWCAP	MWCAP	MWCAP
h6b[49]	–	–	MWCAP	TRATE	MWCAP
hyg3	TRATE/MBASE	TRATE/MBASE	MWCAP	TRATE	MWCAP
hygov2	MBASE	TRATE/MBASE (HYGOV2DU)	–	MBASE	MBASE (PSS®E)
hygov4	–	–	MWCAP	TRATE	MBASE (PSS®E) MWCAP (PSLF)
hygov8	–	–	MWCAP[50]	–	–
hygov	MBASE	TRATE/MBASE (HYGOVDU)	MWCAP	TRATE	MBASE (PSS®E) MWCAP (PSLF)
hygovr	TRATE/MBASE	–	MWCAP	TRATE	MWCAP
hypid	–	–	MWCAP	MWCAP	–
hyst1	–	–	MWCAP	N/A (MBASE)	–
ieesgo	MBASE	TRATE/MBASE (IEESGODU)	–	MBASE	MBASE
ieeeg1	MBASE	TRATE/MBASE (IEEEG1DU)	MWCAP	TRATE	MBASE (PSS®E) MWCAP (PSLF)
ieeeg2	MBASE	MBASE	–	MBASE	MBASE
ieeeg3	MBASE	TRATE/MBASE (IEEEG3DU)	MWCAP	TRATE	MBASE (PSS®E) MWCAP (PSLF)
lm2500	–	–	MWCAP	–	–

[49] The h6e hydro model was recently approved and will be available in future software revisions.
[50] Can model up to four units, each with its own MW rating specified in the parameters.

Table 1.4: Review of Models using MBASE vs. TRATE					
Model Name	**PSS®E Versions Before v33.10 or v34.2[47]**	**PSS®E Versions After v33.10 or v34.2[48]**	**GE PSLF**	**PowerWorld Simulator**	**Powertech Labs TSAT v19**
lm6000	–	–	MWCAP	–	–
pidgov	MBASE	TRATE/MBASE (PIDGOVDU)	MWCAP	TRATE	MBASE (PSS®E) MWCAP (PSLF)
stag1	–	–	MWCAP	–	–
tgov1	MBASE	TRATE/MBASE (TGOV1DU)	MWCAP	TRATE	MBASE (PSS®E) MWCAP (PSLF)
tgov3	MBASE	TRATE/MBASE (TGOV3DU)	MWCAP	TRATE	MBASE
w2301	–	–	MWCAP	N/A (MBASE)	MWCAP
wesgov	MBASE	TRATE/MBASE (WESGOVDU)	–	MBASE	MBASE
wpidhy	MBASE	TRATE/MBASE (WPIDHYDU)	–	–	MBASE

NOTES:

- "–"means the model is not available.
- In GE PSLF, if mwcap is not provided, the MVA base of the electrical generator is used.
- For ieeeg1, if mwcap is not entered and two generators are present for cross-compound units, the sum of MVA bases of the electrical generators is used.
- In PowerWorld, MWCAP is the same as TRATE, N/A means the option is not there, so the default is MBASE.
- Siemens PTI PSS®E has created new "DU" models that incorporate turbine rating along with deadband. In the future, all new turbine-governor models added in PSS®E will have the option of MBASE or TRATE.

Software Implementation:
Dynamic models in different software platforms use different base values for the turbine-governor model parameters. Most models in GE PSLF, PowerWorld Simulator, and Powertech Labs DSATools have the capability for the user to specify turbine rating (i.e., either TRATE or MWCAP). Siemens PTI PSS®E historically used the electrical generator MVA base (i.e., MBASE) for most models. However, PSS®E has released the "DU" version of many turbine-governor models that now includes a TRATE parameter that should be specified. If the turbine rating is not explicitly defined in most platforms, the model defaults to MBASE. Note that, when switching to the "DU" version of the models in PSS®E, parameters will be based on TRATE rather than MBASE and may need to be adjusted accordingly. This includes the limit values as well as other model parameter values, such as droop or turbine gains. A check should be performed to ensure the output of the model is as expected when switching to turbine rating.

For example, consider a conversion from the TGOV1 model (on MBASE) to the TGOV1DU model using a nonzero TRATE value. Along with including a turbine rating (TRATE) in the dynamics file, the values enclosed in the red box in Figure 1.10 also need to be modified by a factor of TRATE/MBASE. The value enclosed by the purple box needs to be adjusted by the following equation:

$$Vmax_{dynamics} = Pmax_{powerflow} + I^2 Ra$$

Each model may have additional parameters that need to be adjusted when converting between models. A list of relevant parameters for popular dynamic models are listed in Table 1.5.

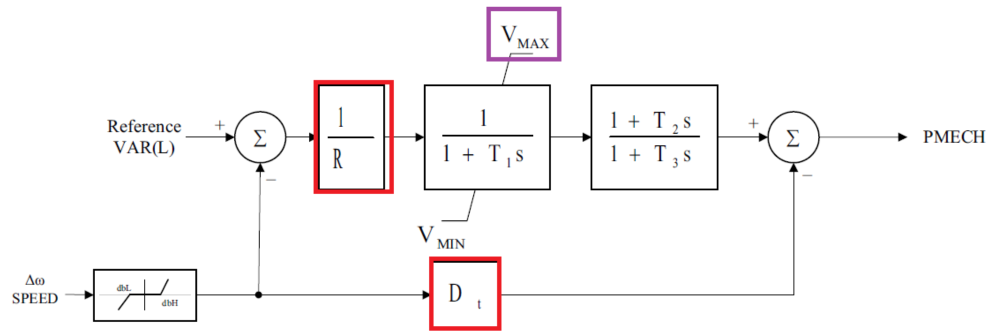

Figure 1.10: Annotated TGOV1DU Model for Conversion from TGOV1 [Source: Adapted from PSS®E]

Table 1.5: Parameters to Modify When Converting to DU Models

Model	Parameters
TGOV1	Dt, R, V_{max}, V_{min}
GAST	D_{turb}, R, At, V_{max}, V_{min}
GGOV1[51]	R, Kturb, Ldref, Dm
IEEEG1	K, P_{max}, P_{min}
IEESGO	K1, P_{max}, P_{min}

Assume in the above example that P_{max} from the powerflow is 200 MW, Trate is 200 MW, and the machine MVA (i.e., Mbase) is 250 MVA. When the models from the example above are subjected to a frequency excursion, three different values of mechanical power are extracted:

- **Blue:** TGOV1 model on an Mbase of 250 MVA and the correct droop
- **Red:** TGOV1 converted to TGOV1DU where droop was properly converted to the new base Trate
- **Green:** TGOV1 converted to TGOV1DU where droop was not properly converted to the new base Trate

Figure 1.11 shows the results of a simulation of these different models. The top plot shows a deviation in frequency while the bottom plot shows the three different models applied. The TGOV1DU model using a Trate of 200 MW with the correct value of droop (red trend) matches the original model (blue trend) until the correct Trate limit of 200 MW is reached. The original model, since it was per unitized on Mbase, was able to provide excess frequency response beyond its actual equipment rating due to poor model parameter selection. The TGOV1DU model with the incorrect conversion of droop (green) does not accurately match the original model (blue). This example shows the importance of ensuring that the parameter values are correctly converted between models when switching over to the "DU" version in PSS®E.

[51] In GGOV1, changing droop (R) may require coordination with Kpgov and Kturb, so the output power equals input power initially.

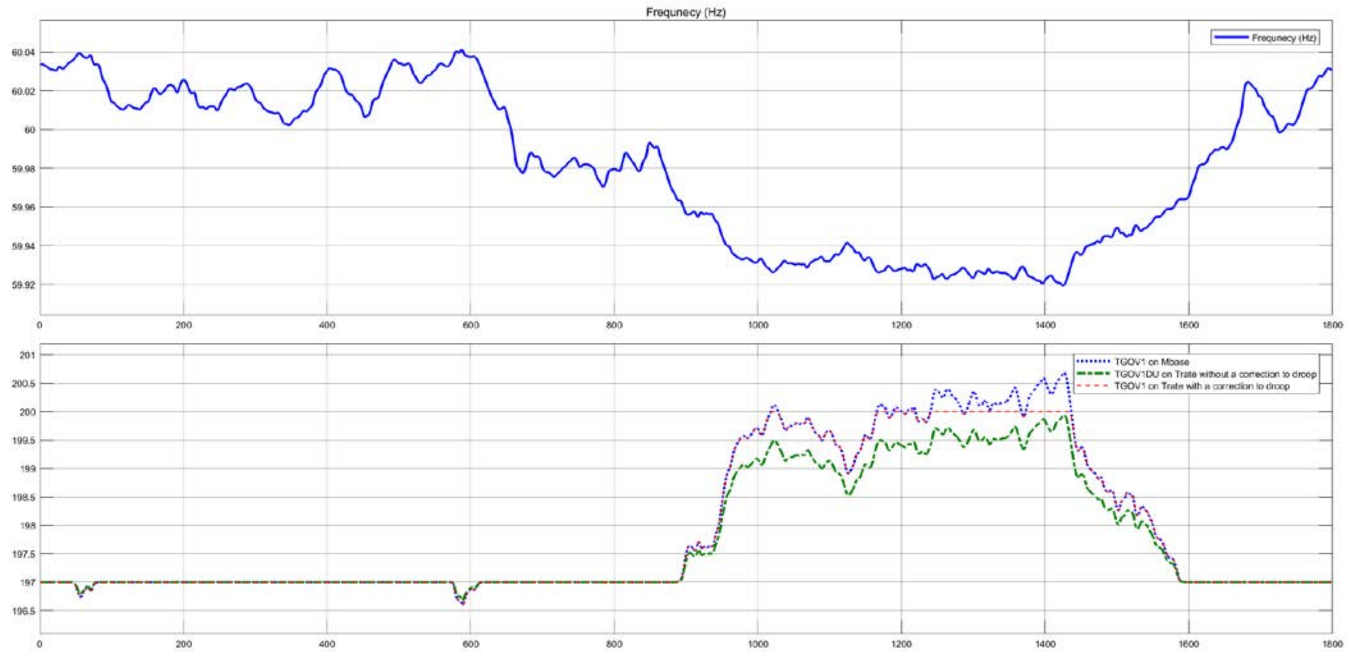

Figure 1.11: Illustration of Response in Converting from TGOV1 to TGOV1DU Model

For a more macro-level scale for implementation, consider **Figure 1.12**, which shows an illustrative example of a test system when dynamic turbine-governor limits use either machine base (MBASE) or turbine rating (mwcap). An underfrequency event was simulated by tripping a reasonably sized generator. In this case, it is assumed that the turbine rating (i.e., actual turbine capability) is 90% of the machine base (mwcap = 0.9xMVAbase). The orange plot (left) shows the unit total active power response when MBASE is used while the blue plot (left) shows response using mwcap. It is clear that the response using the blue plot is limited in capability since turbine rating is only 90% of machine capability. The corresponding frequency response plots are shown in **Figure 1.12** on the right. Overall frequency response appears better when MBASE is used since more frequency responsive reserve is available in the model. Due to the nonconservative base used when no mwcap is provided, up to 6% additional mechanical power is extracted from the turbine-governor model (ggov1 in this case). This leads to optimistic results since the frequency nadir is much deeper when the mwcap is used versus when it is not.

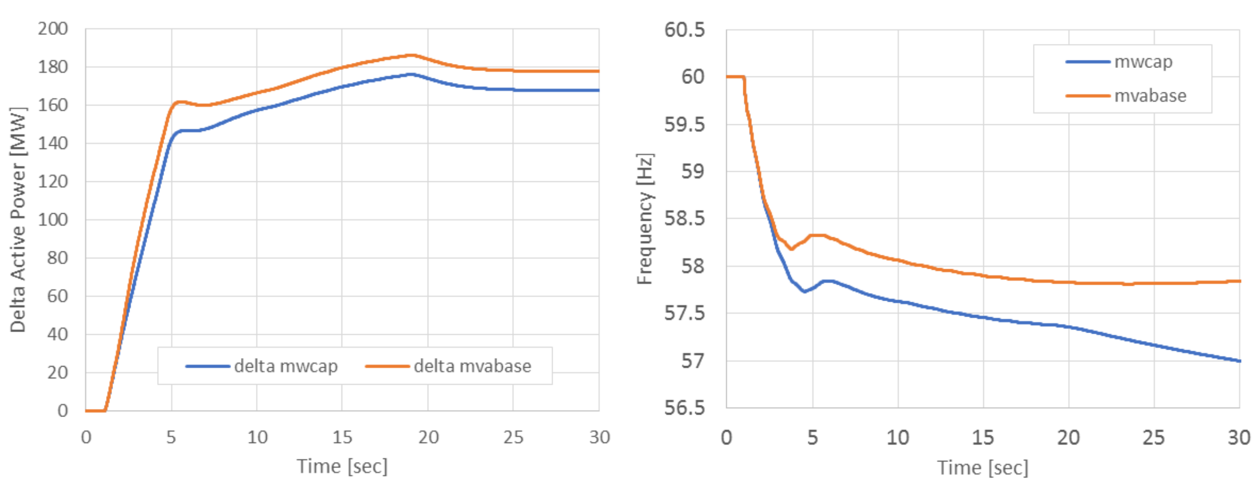

Figure 1.12: Illustration of Response using Machine Base versus Turbine Rating [Source: GE]

Accurately Representing Assumed Ambient Temperature Conditions

Data provided by the GO for the purposes of verification testing are typically representative of the operating conditions during the time of test or limits set back to default values; however, if the generating unit has a correlation between maximum power output and ambient temperature, this information needs to be provided to the TP and PC for modeling purposes or incorporated in the various models submitted to the TP and PC. Ambient temperature curves should be provided in MOD-032-1 data requests so the TP and PC can create base cases as necessary (example in **Figure 1.13**). Model parameters affected by ambient temperature need to be set according to the assumed temperature in the base case. The powerflow P_{max}[52] in the base case needs to be updated as well as the ambient temperature limits in the dynamics data.

This ambient temperature dependence is most notable on natural gas turbines. Steam turbines can have some ambient temperature dependency due to the efficiency of the cooling towers and condensers, but these dependencies are relatively small compared with the large changes in maximum power of a natural gas turbine due to ambient temperature changes. Also, many smaller natural gas turbines (particularly aero-derivatives) can have inlet air-chillers and heaters that attempt, at the expense of total cycle efficiency, to keep the inlet air conditions relatively constant in order to maintain a relative constant MW capability on the unit. All this should be kept in mind when collecting such data and using it for modeling.[53]

Figure 1.13: Capability and Ambient Temperature Curves [Source: IESO]

Figure 1.13 shows an example capability versus ambient temperature curve. At 10°C (50°F), the unit has a maximum capability of 95 MW; at 35°C (95°F), the capability is reduced to 84.5 MW. Assume the unit has the following parameters provided: MBASE = 119.2 MVA, Ra = 0.0006 pu (on 95 MVA base), TRATE = 95 MW. Referring to **Figure 1.13**, the TRATE value is clearly provided for ambient temperature conditions of 10°C (50°F) with Ra on that base value. Now consider the following modeling scenarios discussing a natural gas turbine using GGOV1:

- **Applying Model to Low Ambient Temperature Case on TRATE:** Assume that the model is applied to a case with assumed ambient temperature of 10°C. Powerflow P_{max} value is set correctly and TRATE is also set correctly. Therefore, the ambient temperature limit (LDREF) can be set to 1.0 pu plus the I^2R losses. (Blue cell in **Table 1.6**)
- **Applying Model to Heavy Summer Case on TRATE:** Assume that the model is to be used in a heavy summer base case where ambient temperature is assumed to be 35°C. The powerflow P_{max} value needs to be adjusted to 84.5 MW based on the curve in **Figure 1.13**. The dynamics data also needs to be adjusted. (Orange cell in **Table 1.6**)

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[52] $P_{max,dynamics} = P_{max,powerflow}+(I^2*Ra)$

[53] Confirm how the base value for model parameters area calculated. For example, in a few rare cases, gas turbine-governors have been tested with temperature-dependent speed droop. The format of the droop setting is %/MW and the MW base is the maximum MW based on the ambient temperature. Check with the governor manufacturer to determine the correct implementation and model parameters.

- **Model on MBASE:** Assume that the model is provided without a TRATE value set in GGOV1. The model defaults to using MBASE in this case, and the ambient temperature limit needs to be adjusted. (Yellow and pink highlighted cells in **Table 1.6**)

Table 1.6: Conversion of Parameter Values for Ambient Temperature

	Ambient Temp = 10°C*			Ambient Temp = 35°C *		
	MW	Value in pu on 119.2 MVA (MBase)	Value in pu on 95 MW (Trate)	MW	Value in pu on 119.2 MVA (MBase)	Value in pu on 95 MW (Trate)
P_{max} powerflow	95	0.7970	1	84.5	0.7089	0.8895
Current @119.2MVA, 0.95pu voltage	N/A	1.0526	1.3208	N/A	1.0526	1.3208
I^2R losses @ 119.2MVA, 0.95pu voltage	0.0792	0.0007	0.001	0.0792	0.0007	0.001
P_{max} LF + I^2R losses (Pmech Max)	95.0792	0.7976	1.001	84.5792	0.7096	0.8905
Ldref (pu) on Trate (95MW)	N/A	N/A	1.001	N/A	N/A	0.8905
Ldref (pu) on Mbase (119.2MVA)	N/A	0.7976	N/A	N/A	0.7096	N/A

* In **Figure 1.13**, the magenta line is ambient temperature of 10°C and orange line ambient temperature of 35°C.

Figure 1.14 shows a frequency variation and how the model will respond in terms of mechanical power (Pmech) to changes in speed. It demonstrates how using an incorrect value of Ldref will result in simulations where the resource has excess frequency responsive reserves due to incorrect modeling practices. This can be corrected by changing model parameters accordingly). The scenarios include a winter case with the correct value of Ldref (grey line), a summer case with the incorrect winter value of Ldref (blue line), and a summer case with the correct summer value of Ldref (green line). This example illustrates how the model parameters need to be updated to reflect different ambient conditions.

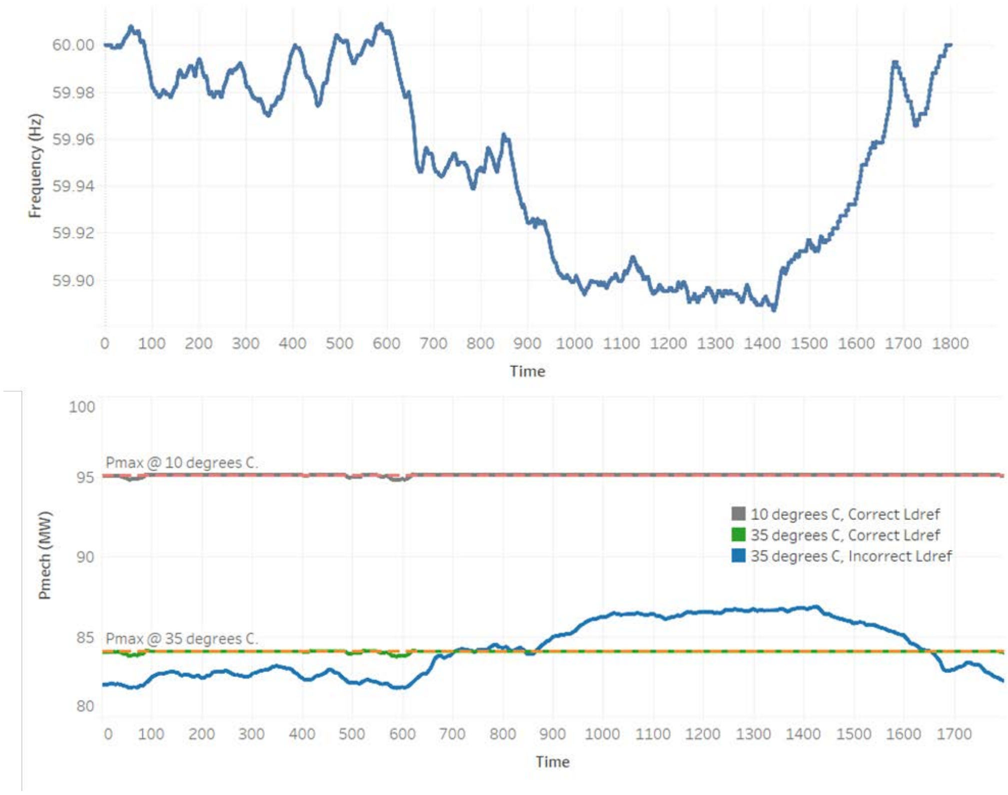

Figure 1.14: Frequency Variation and Modeled Responses [Source: IESO]

Errors with Estimating Headroom using Powerflow Data

Planning engineers who are setting up study cases will typically pay attention to the amount of on-line spinning reserves and frequency responsive reserves dispatched in the case. Planning cases should represent reasonable operating conditions, and the amount of on-line balancing reserves (and hence system inertia) are a key sensitivity that should be accounted for. However, it is clear that, based on the preceding sections, the calculation of spinning and frequency responsive reserves should be done carefully.

In the past, on-line spinning reserves have typically been calculated with the steady-state base case and have not considered the dynamics data behind each generating resource. Variable energy resources are almost always operated at maximum available output (e.g., not curtailed or energy-limited for normal dispatch), so they are hence removed from on-line reserve calculations. Therefore, on-line spinning reserves and frequency responsive reserves are typically defined as follows:

$$Reserve_{Spinning} = \sum_{i=1}^{n} K_i * \left(P_{max,i} - P_{gen,i}\right)$$

$$Reserve_{FrequencyResponsive} = \sum_{i=1}^{n} K_i * (1 - B_i) * \left(P_{max,i} - P_{gen,i}\right)$$

Where n is the total number of on-line units in the case, K_I is the status of unit i (K_i = 1 for on-line, K_i = 0 for off-line), $P_{max,I}$ is the maximum active power output of unit i, $P_{gen,I}$ is the active power output of unit i, and B_I is the "blocked flag"[54] for unit i (B_i = 1 for nonfrequency responsive, B_i = 0 for frequency responsive).

Moving forward, these calculations should be performed with actual dynamics data, including appropriate limiters that may restrict the maximum available active power. The software programs should automatically be making these calculations once a powerflow base case and dynamics data file have been loaded.

Recommended Software Improvement:
Simulation software tools should automatically calculate on-line spinning reserves and on-line frequency responsive reserves once a powerflow model and corresponding dynamics data set has been loaded. This calculation should account for each type of turbine-governor model applied to each generator, and should be based on the dynamics data set limits rather than the steady-state data calculation of P_{max}–P_{gen}. This data should be made available in summary tables for improved case creation. Software platforms should also include error checks to identify units where spinning reserves calculated using dynamics data significantly differ from reserves calculated using powerflow data.

[54] The blocked flag can represent units modeled with a baseload flag set to non-responsive, modeled with no turbine-governor, or account for other factors that would cause not response in the model. This could combine data from powerflow and dynamics models to accurately account for actual frequency responsive reserves; however, commonly used simulation platforms do not currently have this feature.

Chapter 2: Analyzing Modeled versus Actual Response

To maintain high fidelity Interconnection-wide models, it is important for the TP and PC to regularly monitor the performance of the generating fleet to ensure that the models submitted are appropriately applied in studies per MOD-032-1. Since different cases may represent different seasons, operating conditions, and other external factors, there is substantial room for error in the application of these models for study purposes. It is the responsibility of the TP and PC to ensure that sufficient modeling information[55] is gathered by the equipment owners, including GOs, such that these cases can be created effectively. The TPs and PCs also typically have the necessary measurement data from the generating resources in their footprint to be able to quickly and effectively gather disturbance data for validation of model response.

Turbine-governor models can be verified using different approaches, including the use of lower sampling rate data (e.g., SCADA data) and simple algebraic representation of turbine-governor controls to compare expected (modeled) response to measurement data for frequency excursion events. This comparison between measured and expected is a "quasi steady state" comparison, meaning that it assumes no governor dynamics. This is an approximation for the purposes of confirming primary frequency regulation and not for determining modeling parameters, so for this purpose, lower resolution data is acceptable. Advantages to this method, as opposed to running detailed dynamic playback simulations, include the speed of computation, simplicity, and availability of data to perform the analysis, and ability to regularly monitor many events.

Figure 2.1 shows a high-level overview of the process of analyzing modeled versus actual response of the generating fleet. The overall process that is described in the subsequent sub-sections includes the following steps:

- **Identifying Valid Events:** Frequency excursion events of interest are identified that are suitable in size for analyzing frequency responsiveness of generating resources.
- **Collecting Disturbance Data:** Data of sufficient quality and resolution is collected from a data historian.
- **Gathering Model Parameters:** The machine and model parameters for the unit(s) under test are collected from the powerflow and dynamic models.
- **Comparing Actual versus Modeled Response:** The expected unit response from the model is compared against the actual response measured during the disturbance.
- **Identifying Possible Modeling Issues:** A determination is made using engineering judgment as to whether the modeled response sufficiently matches the actual response. Any mismatches between responses can be compared against other events and known unit operational and modeling characteristics to determine potential reasons why the model did not match the actual response.

Regularly monitoring the generating fleet response to grid disturbances has multiple benefits that may address many of the modeling issues described in **Chapter 1: Turbine-Governor Modeling Considerations**, including the following:

- Changes in plant performance that do not match key model parameters
- Changes in model parameters that may have (re)entered the base case by mistake or error
- Confirmation of sustained response versus nonsustained (i.e., withdrawal of) primary frequency response
- Analysis of impacts of ambient temperature on thermal units, impacts of hydro head level, etc.

[55] TPs and PCs may request different models for different cases or may request one model and make the modifications themselves. Both approaches can be effective, assuming sufficient modeling rigor and verification is completed.

This chapter describes how TPs and PCs can collect disturbance data, compare plant performance, and identify plants where model application should be reviewed and modeling improvements made.

Collecting Disturbance Data

The TP and PC will typically have SCADA data measurements at the point of interconnection or sometimes terminals of each generating resource, or at least the point of interconnection of each power plant. While high speed data (e.g., phasor measurement unit (PMU) data) can capture the dynamic response of the generator, including turbine-governor controls, SCADA data is sufficient to get a high-level understanding of whether the modeled response is capturing the general behavior of the actual operation of the facility. Real-time measurement data can be captured by the SCADA system, easily stored and managed in a data historian, and exported to a tabular format. An illustrative example is shown in **Table 2.1**. The following data specifications should be used:

- **Event Data:** Frequency excursion events are typically the most useful type of data to use for this analysis, although any data outside the turbine-governor deadband can be used. Frequency excursions should be of sufficient size such that the generator power output changes can be distinguished from noise. Using SCADA data for comparison has proved effective for units greater than 100 MVA for frequency excursions of 20 mHz or more outside the deadband setting.
- **Event Type:** It is desirable to collect data for both under- and over-frequency events, preferably of different sizes and shapes. Solely relying on one side of the frequency event data can sometimes lead to inconclusive or incomplete analysis. For example, if a unit is found nonresponsive to an under-frequency event, it is hard to tell whether this is due to real-time operating limits (e.g., temperature limit) or due to a disabled governor. However, if a unit is nonresponsive to both sides of frequency excursion, there would be reason to question whether the governor functioned as expected.
- **Resolution:** SCADA data with a resolution of one sample every 2–4 seconds will likely suffice for this analysis. Higher resolution data will only improve granularity of analysis, but lower resolution data may still be usable in some situations.
- **Duration:** The time of disturbance(s) should be identified, and data should be collected for at least the 5 minutes prior to the disturbance and the 10 minutes following the disturbance based on how long the underfrequency condition occurs. While all this data is not entirely necessary for verification, it is useful to understand if there are any external factors at play (e.g., AGC action, unit redispatch, steam pressure drop, multiple disturbances, multiple crossings of 60 Hz and the possible deadbands). Frequency excursion conditions greater than one minute will typically suffice for analysis purposes.
- **Measurements:** Measurements quantities should include time, measured frequency, and the measured point of interconnection or individual generating unit active power.
- **Compression:** When comparing actual response with expected/modeled response, one must consider the compression settings used on the SCADA data. Compression settings should be checked prior to utilizing this method.[56] Devices like PMUs and disturbance recorders do not have compression so are the best. Higher compression could result in data that appears "stale" or nonresponsive but may just be within the compression settings of the energy management system. Larger units with more movement help eliminate this issue; smaller units that only move fractional amounts of a MW may run into compression issues.

[56] Lowering compression settings to 0.1% for MW output is recommended. Lower compression settings result in better analysis, yet the downside is that more data gets stored. For example, if a machine has a 30 mHz deadband and droop of 5% (on Machine MVA), and the frequency falls to 59.95 Hz, the machine will increase output by 0.6% (on machine MVA). Setting compression to 0.1% should capture sufficient data points.

- **Time Skew:** There may be some time skew in the data when compared against the modeled data, particularly if the time alignment between measured frequency and active power is not aligned. Some amount of time skew may be expected, but it should be relatively small.
- **Operating Conditions:** The generating unit being tested should be on-line. The unit can operate at any output level, depending on which aspect of the model is being tested.

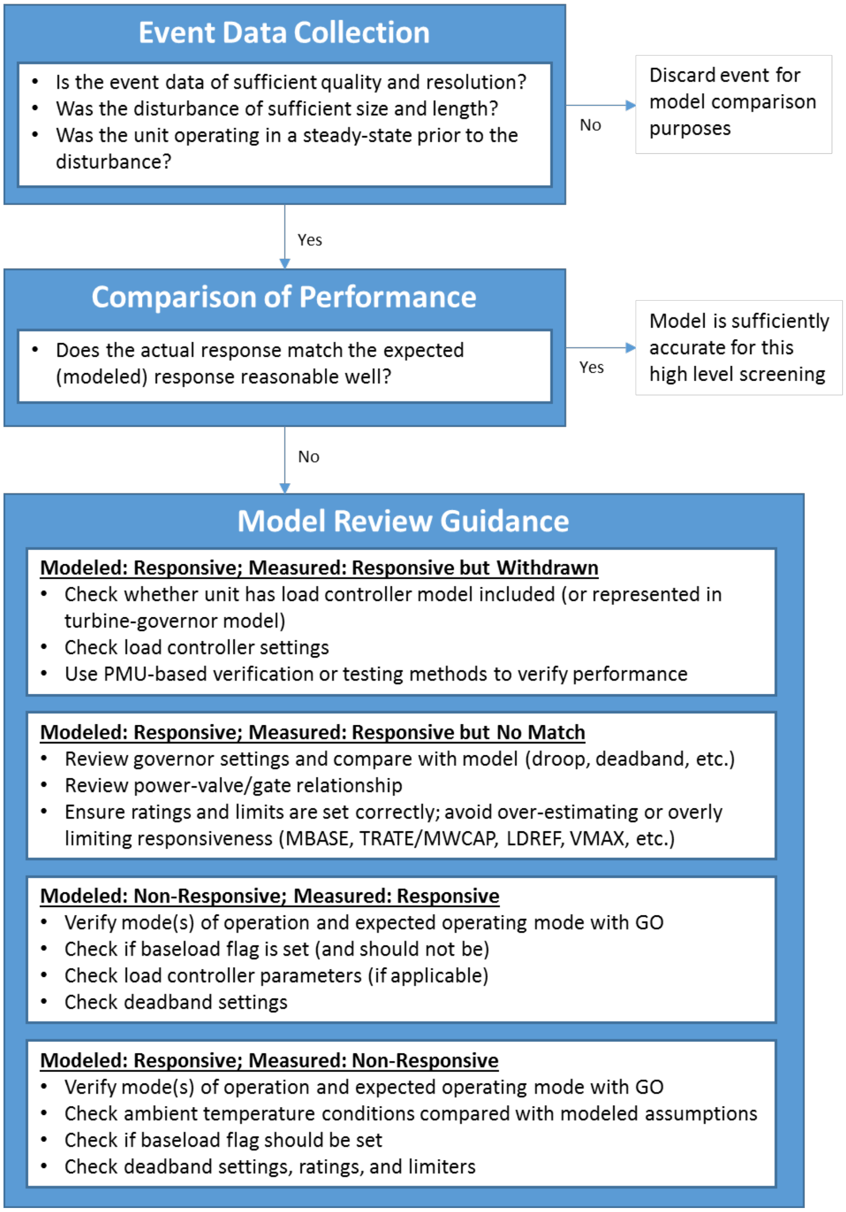

Figure 2.1: Overall Process for Analyzing Expected versus Actual Response

Frequency excursion events are quite regular in the BPS, and TPs and PCs can use triggers to identify events of interest for modeling. Figure 2.2 shows an illustration of disturbances in the Eastern Interconnection outside a 36 mHz deadband range.[57] The size and color of each disturbance dot shows how long the system was below or above the specified frequency.

[57] 36 mHz deadband range was chosen since it is a commonly used frequency regulation deadband. However, intentional deadband should not exceed 36 mHz and should be minimized to the extent possible.

Some transmission entities may experience separation from the rest of the BPS, and the separated area may have large frequency excursions of hundreds of millihertz. Although smaller frequency excursions suffice in most cases, these larger frequency excursions are desirable for analysis. This is particularly true for wind generation, which has output that sharply fluctuates because only sufficiently large frequency excursions can distinguish between noise and primary frequency response.

Table 2.1: Example Measurement Data Collection

Time	Measured F (Hz)	Measured P (MW)
9/25/2017 11:21:52	59.976	94.833
9/25/2017 11:21:54	59.977	94.926
9/25/2017 11:21:56	59.977	95.020
9/25/2017 11:21:58	59.977	95.113
. . .	. . .	. . .
9/25/2017 11:51:24	60.010	93.633
9/25/2017 11:51:26	60.010	93.528
9/25/2017 11:51:28	60.009	93.504
9/25/2017 11:51:30	60.007	93.560

Figure 2.2: Illustration of Frequency Excursions in 2017 in the Eastern Interconnection [Source: IESO]

Gathering Model Data

The first step to making sure that models are accurately representing actual performance is to ensure that the match is reasonably close at a high level. This can be accomplished without using the detailed dynamic models used for stability studies. Rather, an algebraic representation of the expected response can be used to get an estimate of response and also an understanding of the general characteristics of the response. Therefore, only a few critical parameters and dispatch values are needed. These values are obtained from either the steady-state powerflow data or the dynamic model(s). Table 2.2 shows the model data and its source.

Table 2.2: Model Data Needed			
Description	**Example Data**	**Units**	**Data Source**
Governor Droop	0.04	pu	This parameter is extracted from the dynamic model. It should be in the ballpark of 5%, expressed as a fraction value (e.g., 5% droop = 0.05). In some models, the value is represented as a gain and is presented as 1/Droop (e.g., IEEEG1 has K = 1/Droop).
Governor Deadband	0.006	Hz	This parameter is extracted from the dynamic model if it has a deadband parameter from a test report or from the GO. If no information is available other than the model that does not have deadband represented, this parameter may be suspect for modification. The model typically expresses this in a per unit metric, so it may need to be converted to Hz.
Generator MVA Rating or Turbine Base	250	MVA	This parameter is extracted from the powerflow record and should match the dynamic record for machine base as well. NOTE: If the dynamic model has an option to specify turbine rating (TRATE or mwcap) and that parameter is a nonzero value, then that value should be used instead of MBASE.
Generator Dispatch	93.5	MW	This is the dispatched value of the unit prior to the disturbance while the unit is within the deadband. This can be adjusted to move the modeled/expected response vertically based on where the unit is dispatched before the disturbance.
Generator P_{max}	200	MW	This parameter is extracted from the powerflow data and is the maximum output power (P_{max}).

The techniques that follow are not applicable to models that have a load controller enabled (i.e., LCFB1 model or GGOV1 with Kimw ≠ 0), units on AGC control, or for hydro turbines with gate position feedback. If either of these are the case, the dynamic playback of the event should be performed.

Comparing Actual Response to Expected Response

Using the simple algebraic representation of the linear turbine-governor response will provide a high-level estimate of how the unit should behave. The expected response from this modeled representation can be compared against the measured response over a period of time. Measured values of frequency and active power should be plotted for the duration of the event, including some time before and after the disturbance. The modeled response can then be compared against the measured response on the same plot. If the two match reasonably well, this may signify that the model is capturing the general behavior of the resource, but note that there may be differences that can be justified based on the simplified modeling approach. However, if the two are vastly different, the comparison of modeled and actual response should lead to model corrections.

Figure 2.3 shows an example this type of comparison. The top half of each plot shows system frequency over the analysis time window. The bottom half shows modeled versus actual response of the machine to this frequency deviation. Given that the algebraic equations do not have the ability to represent speed, there will be some inherit differences. This is illustrated in the top and bottom plots of Figure 2.3. The top plot is a comparison between the full dynamic model and the algebraic equation for a fast turbine-governor with small time constants and higher gains while the plot on the bottom is a comparison between the full dynamic model and the algebraic equation for much slower turbine-governor (larger time constants and smaller gains). The key takeaway is that the algebraic equations can do a satisfactory job of representing the full set of dynamic equations over a range of parameters for the purposes of comparing them to measurements. Again, note that this method can be useful in identifying vastly different responses between model and actual behavior (i.e., either model or actual behavior being nonresponsive).

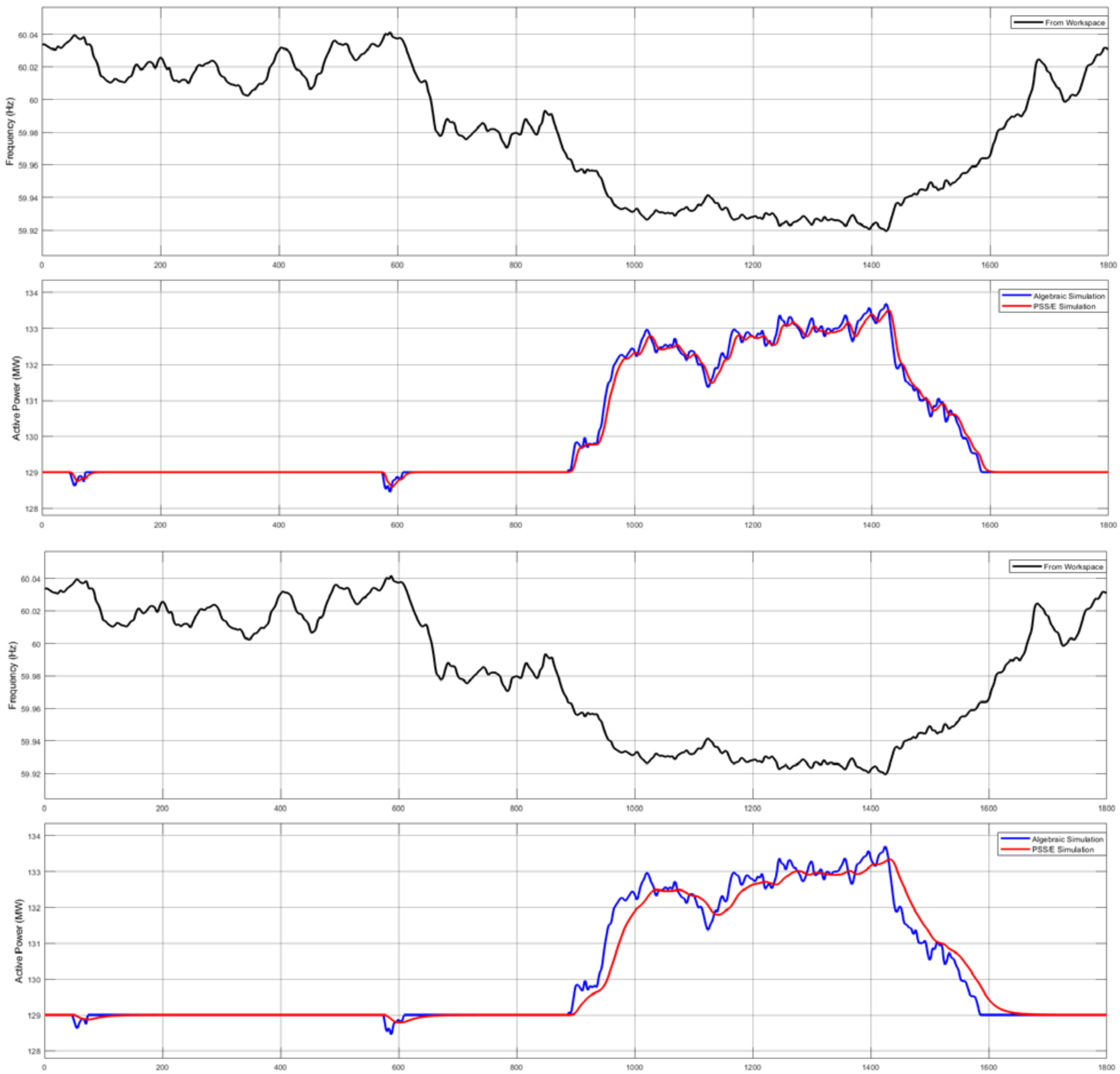

Figure 2.3: Illustration of Comparing Actual and Expected Response

The following formulas provide a mathematical explanation of how governors will increase the output power for a given frequency disturbance based on per-unit values of droop and the base quantity used to per-unitize droop. These are algebraic formulas that do not have a dependency on time whereas actual dynamic governor/turbine models use differential equations that do have a dependency on time. For the purposes stated above, the algebraic models can be used to sufficiently capture the general behavior of the resource over a period of time (for units that do not have a load controller). A linear representation of governor response can be represented by one of the equations below:[58]

$$\Delta MW = unit_{MW\ Capability} * \frac{60 - f - f_{db}}{60 * droop - f_{db}}, when\ f < 60Hz - db, else\ 0$$

$$\Delta MW = unit_{MW\ Capability} * \frac{60 - f + f_{db}}{60 * droop - f_{db}}, when\ f > 60Hz + db, else\ 0$$

[58] Governors may have a slightly different implementation of droop, but typically follow a similar approach.

or

$$\Delta MW = unit_{MW\ Capability} * \frac{60 - f - f_{db}}{60 * droop}, when\ f < 60Hz - db, else\ 0$$

$$\Delta MW = unit_{MW\ Capability} * \frac{60 - f + f_{db}}{60 * droop}, when\ f > 60Hz + db, else\ 0$$

Figure 2.4 illustrates the insignificant difference between these two implementations of droop.

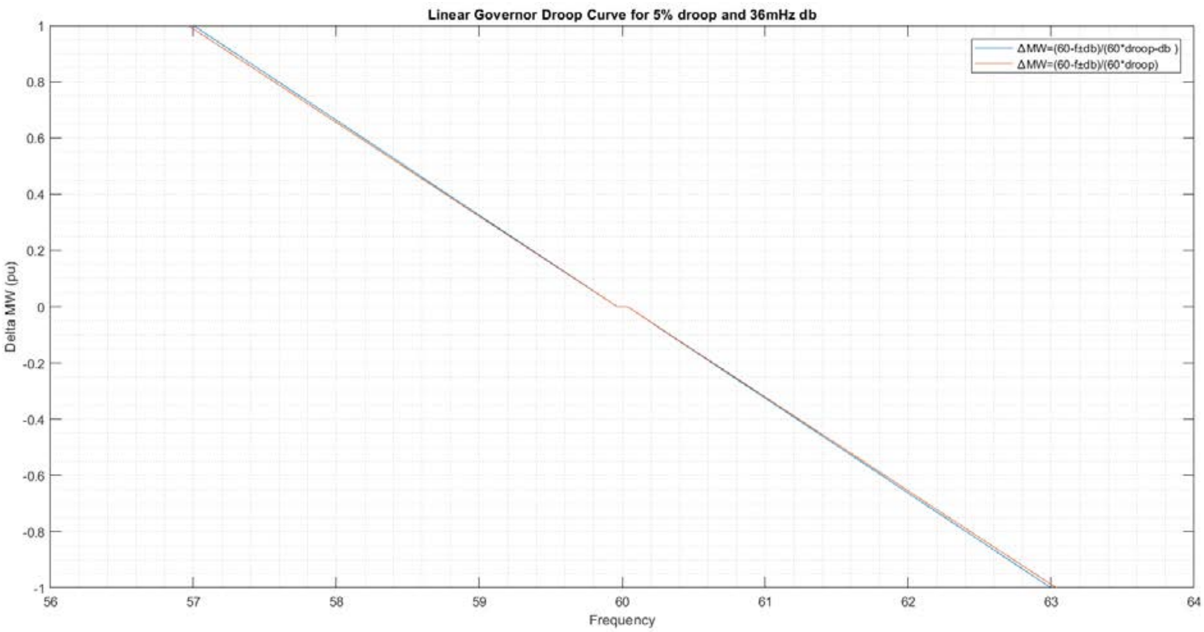

Figure 2.4: Illustration in Minor Variance in Droop Implementation

Refer to Appendix D: Examples of Analyzing Unit Response for examples of comparing modeled with measured response and how that analysis can lead to effective review of model parameters and identification of modeling issues.

Factors Affecting Mismatch between Expected and Actual Responses

When a mismatch between expected and actual unit response is found, the next step is to interpret the results and to identify the root causes. This process could help the TP shortlist a number of possible reasons and makes it easier for them to start a dialogue with the GO. Some examples of situations contributing to a mismatch between expected and actual responses include:

- **Droop Has Been Implemented in a Different Way**: Modeling techniques assumes droop (e.g., 4%) is implemented on the electrical power output that is per-unitized on the base of generator MVA rating or turbine base. In reality, the droop can be implemented on a variety of control variables, such as governor output, fuel demand, value stroke, flow demand and gate opening. Since many of these variables may not be on the same per-unit scale as the electrical power output, the droop estimated from the tool may differ from the actual setting programmed in the control equipment. Some governor models may have adopted the actual droop setting without field validation.
- **Unit Did Not Respond to Underfrequency Events because of Insufficient Frequency Responsive Reserve (Headroom)**: Attention should be taken for the unit that did not respond to under-frequency events, especially when it is operated at close to its full output. Factors could have an impact on the headroom achievable at the time of the frequency event (e.g., activation of temperature controls, steam pressure,

and water head). It is therefore suggested to check the governor responsiveness with both under- and over-frequency events.

- **The Governor Response Is Partially Offset by Change in Steam Pressure:** Specifically for steam turbines with coordinated controls, following a frequency excursion (e.g., underfrequency event), the main inlet control valve is opened up wider to increase the turbine output as a result of governor response. In an ideal steam turbine model, the steam pressure would stay constant, but in reality is does not. When the amount of steam produced by boiler cannot keep up with the increase in steam usage, the main steam pressure could gradually drop to a lower level after the opening of the control valve. This phenomenon effectively ends up with the governor response being slightly offset by pressure drops.

- **Large Deadband not Captured in the Governor Model:** It is common for governors to be (possibly incorrectly) programmed with an excessively large deadband (e.g. +/-1Hz). With the large dead band, the governor is effectively disabled in the majority of the time. If a unit with a working governor is found not providing any primary frequency response, the TP may find it reasonable to suspect whether the deadband is set within the allowed range, typically 36 mHz. If a larger than allowed deadband setting is confirmed, a dialogue between the TP and GO should be started to discuss the possibility of narrowing the deadband.

- **The Governor Is Being Operated in Load Control:** Units are commonly operated to provide a specific amount of MW regardless of system frequency. This may appear as if the unit initially responds but is withdrawn shortly after the initial response. A dialogue between the TP and GO should be started to discuss the possibility of operating in a speed droop mode.

Limitations of Reviewing Events

Techniques that use SCADA data and a simplified algebraic model of the turbine-governor may have limitations in identifying the issues described in **Chapter 1: Turbine-Governor Modeling Considerations**. These may include, but are not limited to, the following issues:

- Poor resolution of SCADA data that may not be suitable for analysis of certain types of turbine-governor response (e.g., cannot capture very quick withdrawal of response)
- Compression settings can cause poor data quality of active power or frequency measurements
- Data storage down-sampling or limitations may result in older events being unavailable or unsuitable for analysis
- Typical frequency excursion events are likely not suitable for analyzing the response of units with large deadbands
- Some units have a low capacity factor and may not be on-line when disturbances occur
- Complex dynamics[59] of turbine-governor controls make analysis using algebraic representation not suitable.[60]

In these cases, using higher resolution data from PMUs or other dynamic disturbance recording (DDR) data may be needed to perform validation. Refer to the NERC Reliability Guideline on Power Plant Dynamic Model Verification using PMUs.[61]

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[59] For example, relative head level and turbine efficiency may have a greater impact than turbine-governor settings (e.g., droop) on hydro response.

[60] However, the simplified algebraic model can still show responsiveness versus non-responsiveness in any case.

[61] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability%20Guideline%20-%20Power%20Plant%20Model%20Verification%20using%20PMUs%20-%20Resp.pdf

Appendix A: Assessment of Models in Planning Cases

The Eastern Interconnection dynamic model database was analyzed with respect to the state of turbine-governor modeling and potential modeling issues. The Eastern Interconnection case has historically struggled to recreate frequency excursion events; hence, the MMWG off-the-shelf case was analyzed for this reason. The analysis focused on the concepts described in Chapters 1 and 2 and provided a high-level overview of what is in the base case today by governor type, unit size, region, and settings (where applicable).

A 2017 series base case was first analyzed by generator and turbine-governor type. **Figure A.1** shows that the vast majority of units use the GENROU model. The primary turbine-governor models are No Model, IEEEG1, GGOV1, TGOV1, IEESGO, and GAST. Therefore, most analysis should focus on units with these models since they represent the majority of resources in the base case. The bottom right portion of **Figure A.1** shows the size ranges (in terms of MBASE [MVA]) for the respective models.

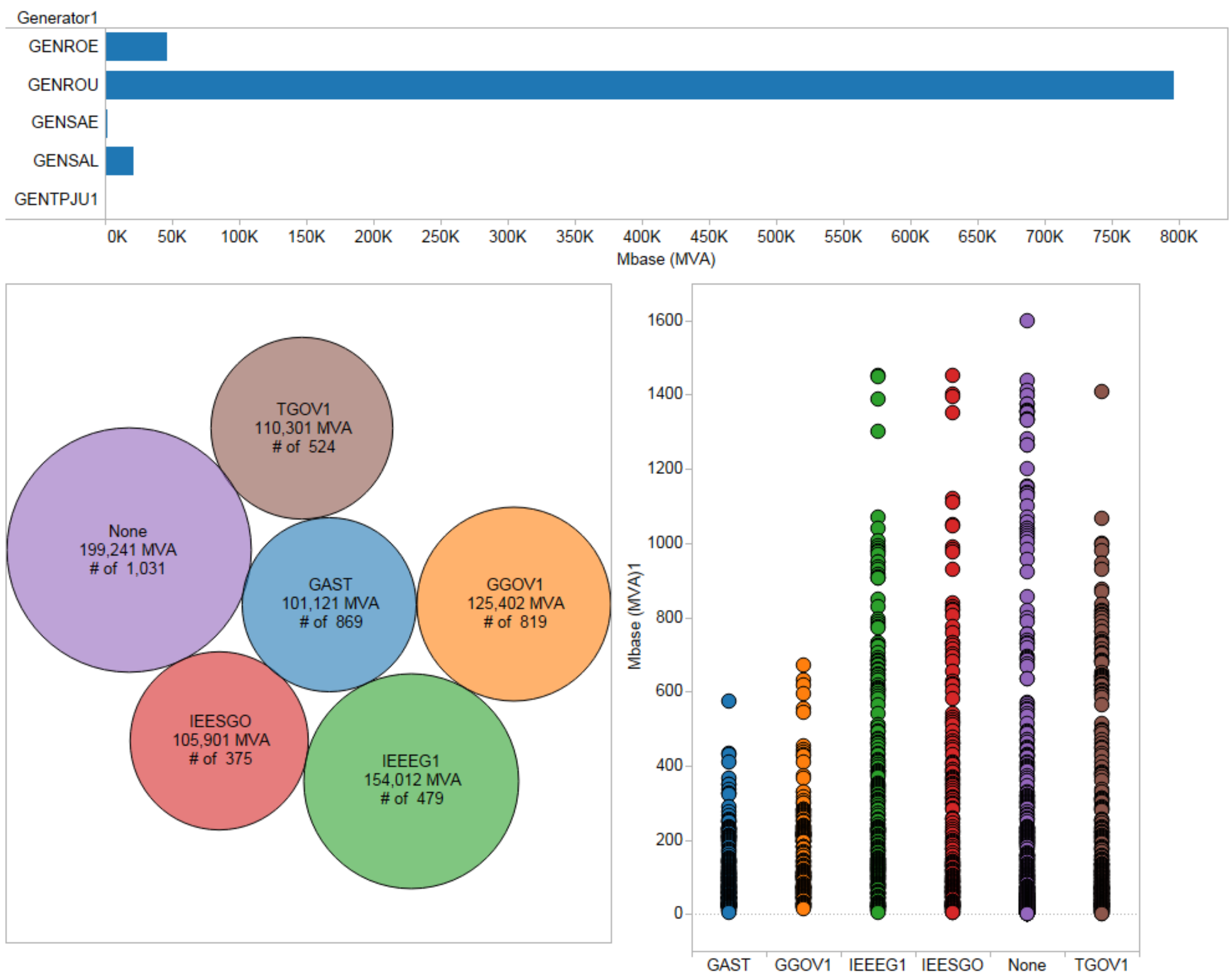

Figure A.1: Generating Resources by Generator and Turbine-Governor Model Type

The analysis of the round rotor models in **Figure A.1** helps explain why the simulated frequency response overestimates the observed response. Key drivers for this overestimation include:

- Of the models above, only GGOV1 have deadbands in the model. A total of 790 GGOV1 models have a deadband less than or equal to 36 mHz.

- Of the models above, only the GGOV1 has a built-in load controller. A total of 732 GGOV1 models have the load controller disabled. A total of 2,198 of the models do not have a load controller (excluding no model and GGOV1).
- Of the models above, the excess on-line spinning reserve ($P_{max,dynamics} - P_{max,powerflow}$) is listed in **Table A.1** for the various models. The table includes machines that were not on-line in the case, including the small portion of machines that have load controllers. Depending on whether the units are on-line and where they are dispatched, a portion of this reserve will not be noticed in simulations.

Table A.1: On-line Excess Spinning Reserve

	TGOV1	GAST	GGOV1	IEEEG1	IEEEGSO
Overestimated Spinning Reserve	20.2 GW	17.6 GW	10.1 GW	17.5 GW	331 GW* 12 GW

*This number is artificially inflated as there are some models where the maximum value entered in MW rather than pu. The corrected estimate is shown below.

Figure A.2 shows an assessment of one model type for one area in the case. Each column represents a generating resource. The following is shown in the plot:

- Green bar = Range of operation (P_{min} to P_{max}) from powerflow case
- Blue Bar = P_{gen} value from powerflow data
- Black Bar = P_{max} from dynamics data
- Red Bar = Overestimated on-line spinning reserve ($P_{max,dynamics} - P_{max,powerflow}$)

Almost all of the units have overestimated on-line spinning reserve. However, only some of the units will produce additional active power output beyond the powerflow P_{max} value because units are dispatched well below the $P_{max,powerflow}$. As the drop in frequency increases, the overestimation of reserves will also increase.

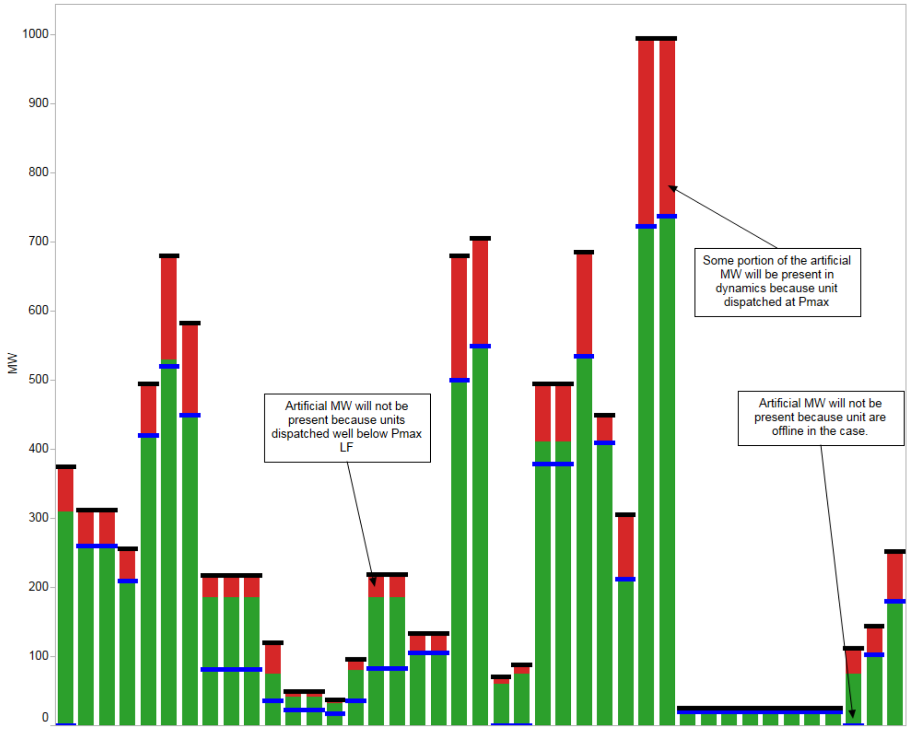

Figure A.2: Example of Overestimated On-Line Spinning Reserve for Area

Consider a different perspective using the TGOV1 model, which uses MBASE as the per unit base for the model parameters. Table A.2 shows the ten units with the largest overestimation of frequency responsive reserve based on comparing the powerflow data versus dynamics data.[62] While the full amount of the additional headroom is not used, these modeling errors each contribute to the overestimation (and underestimation for units with the opposite issue) of response capability. Figure A.3 shows the aggregate results for all units in the base case.

Table A.2: TGOV1 Model Examples

No.	VMAX	VMIN	MVA Base	P_{max} MW	ADDITIONAL HEADROOM [MW]	ADDITIONAL HEADROOM [% of P_{max}]
1	1	0	1000	250	750	300%
2	1	0	806.5	400	407	102%
3	1	0	994.6	723	272	38%
4	1	0	994.6	737	258	35%
5	1	0	818	600	218	36%
6	1	0	835	629	206	33%
7	0.91	0	221	0	201	N/A
8	1	0	814.7	623	192	31%
9	1	0	1000	815	185	23%
10	1	0	680.22	500	180	36%

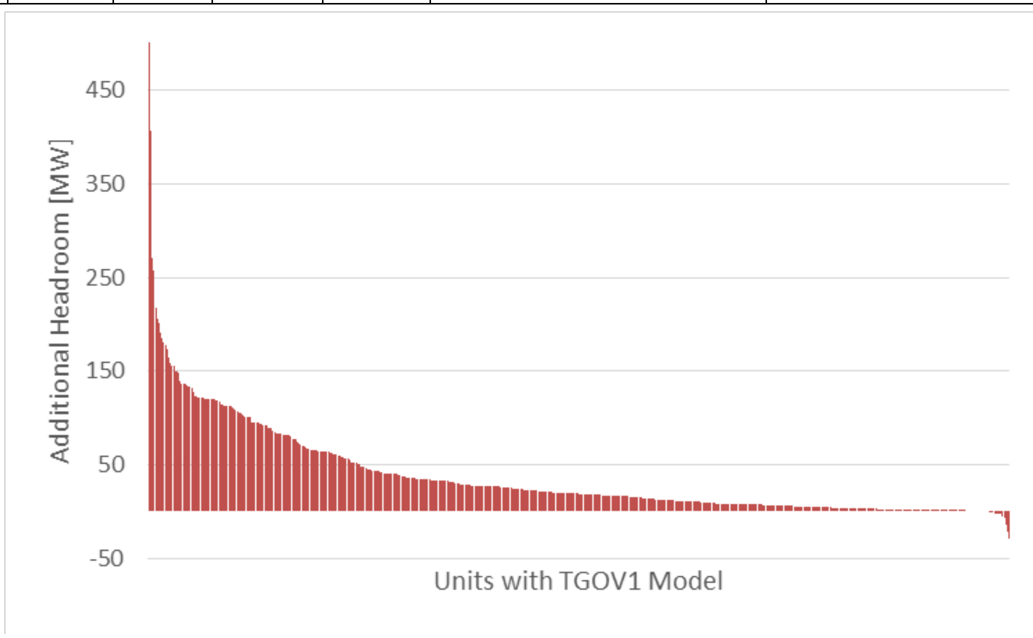

Figure A.3: Overview of TGOV1 Headroom Model Discrepancies

[62] Vmax and Vmin represent maximum and minimum valve positions for the governor and should align with the P_{max} value represented in the base case, which should be the maximum continuous capability of the generator.

Appendix B: Examples of Overestimated Reserves using MBASE

This section provides examples of how dynamic models can be misapplied or poorly parameterized. This can lead to overestimation of frequency responsive reserve (i.e., "artificial headroom") during frequency deviation simulations.

TGOV1 Example

Assume a TGOV1 model[63] that is per unitized on the MVA base of the machine with unit dispatch and model parameters shown in **Table B.1**.[64]

Table B.1: Generator Model Parameters

Powerflow Data	Value	TGOV1 Parameter	Value
Mbase	200	R	0.05[65]
P_{gen}	178	Dt	0
P_{max}	180	T1	0.1
Rsource	0*	T2	0
		T3	0.5
		V_{max}	1
		V_{min}	0

* For simplicity

The principles of the Laplace transform[66] can be applied to understand how the model initializes, shown in blue in **Figure B.1**. The input to the integrator block equals zero, the inputs to the lead/lag blocks equal the outputs, and the output of the derivative blocks equal zero. Speed error (Δω) is initialized to zero since simulations initialize at nominal frequency. The parameter P_{mech} is initialized based on powerflow values of P_{gen}, Mbase, R_{source}, and I_{gen}. Dynamic states and the speed reference are then calculated. Note that P_{mech} is on the machine base unless otherwise stated.

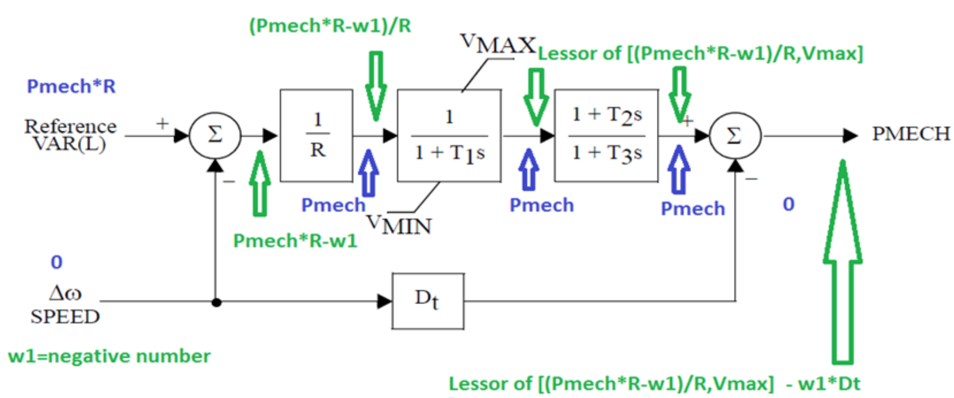

Figure B.1: Annotated TGOV1 Block Diagram

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[63] Analysis of the Eastern Interconnection base case has shown that entities are not parameterizing the TGOV1 model correctly, and this is one of the multiple contributors to overestimation of primary frequency response in that model.

[64] Rather than per unitized on turbine rating (TRATE or mwcap).

[65] Per unit on MBASE or TRATE or mwcap, based on model implementation.

[66] $\lim_{t\to\infty} F(t) = \lim_{s\to 0} sf(s)$

The green annotation in **Figure B.1** shows the calculation of states that relates to the top half of **Table B.2,** showing calculations for mechanical power and speed reference. Now assume a 100 mHz frequency deviation is simulated (to f = 59.9 Hz). Speed error ($\Delta\omega$) becomes negative since $\Delta\omega = \omega\text{-}\omega_0$ (referred to here as ω_1). The new output of TGOV1 ($P_{mech,new}$) will be the lessor of: VMAX or the right-side green equations shown in **Figure B.2**. The bottom half of **Table B.2** shows the new calculation of mechanical power for the 100 mHz frequency excursion.

Now, consider that the P_{max} value in the base case is set to 180 MW. The unit is dispatched in the powerflow at 178 MW, which is below P_{max}. Many planners assume that the model is limited to P_{max} in both steady-state and dynamics (i.e., assuming the powerflow and dynamics data are coordinated), and roughly estimate the amount of frequency responsive reserves using P_{max}-P_{gen}. With that assumption, the unit should be able to provide 2 MW of additional output power. However, once the model initializes for dynamics with Vmax = 1 pu (on 200 MVA base), the unit can actually respond to 200 MW, and, in this case, provides 6.6 MW of frequency response rather than the expected 2 MW. In this case, the Vmax value is set incorrectly, and should be set to Vmax = P_{max}/MBASE = 180/200 = 0.9 pu.

Table B.2: Example Equation to Calculate Mechanical Output Power
Initialization: • P_{mech} = P_{gen}/MBASE = 178 MW/200 MW = 0.89 • Reference = P_{mech}*R = 0.89*0.05 = 0.0445
Off-Nominal Frequency: • $\omega_1 = \omega\text{-}\omega_0$ = -100/60 = -0.00167 • $P_{mech,\ new}$ = 184.6 MW (lessor of below…) ▪ VMAX = 1 pu = 200 MW ▪ (P_{mech}*R-ω_1)/R = 0.923 pu = 184.6 MW

Low Value Select Limit in GAST Example

Certain models approximate the exhaust temperature control limit as shown in in the purple box for the GAST[67] model in **Figure B.2.** This portion of the model limits the mechanical torque that the prime mover can provide to the generator despite the valve(s) being less than fully open. This is accomplished by setting the ambient temperature coefficient, A_t, (e.g., Load Limit in GAST, LDREF in GGOV1) to an appropriate value per the assumptions used for the ambient temperature conditions of the study.

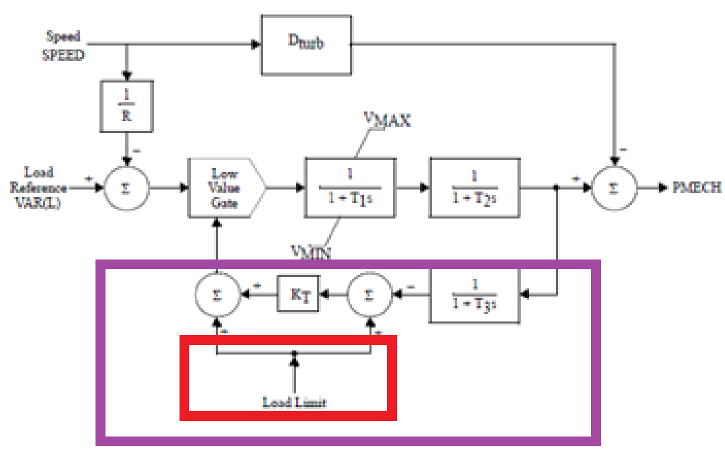

Figure B.2: GAST Model Block Diagram [Source: PSS®E]

[67] The GAST model is used in this example due to its prevalent use in the Eastern Interconnection. However, this is not considered an acceptable model for use in stability studies. It is used here for illustrative purposes only. See the NERC Approved Model List for more information. https://www.nerc.com/comm/PC/NERCModelingNotifications/Gas_Turbine_Governor_Modeling.pdf.

Assume that the frequency is low for a sufficiently long time, with unchanging frequency less than 60 Hz). This results in the lag blocks turning into gains with a magnitude of one (see **Figure B.3**). Based on the low value gate (ignoring Dturb), the P_{mech} can be calculated as the lessor with the following equations:

$$Pmech = Vmin < Ref - \frac{\omega}{R} < Vmax$$

or

$$Pmech = A_t + K_t(A_t - Pmech)$$
$$Pmech(1 + K_t) = A_t(1 + K_t)$$
$$Pmech = A_t$$

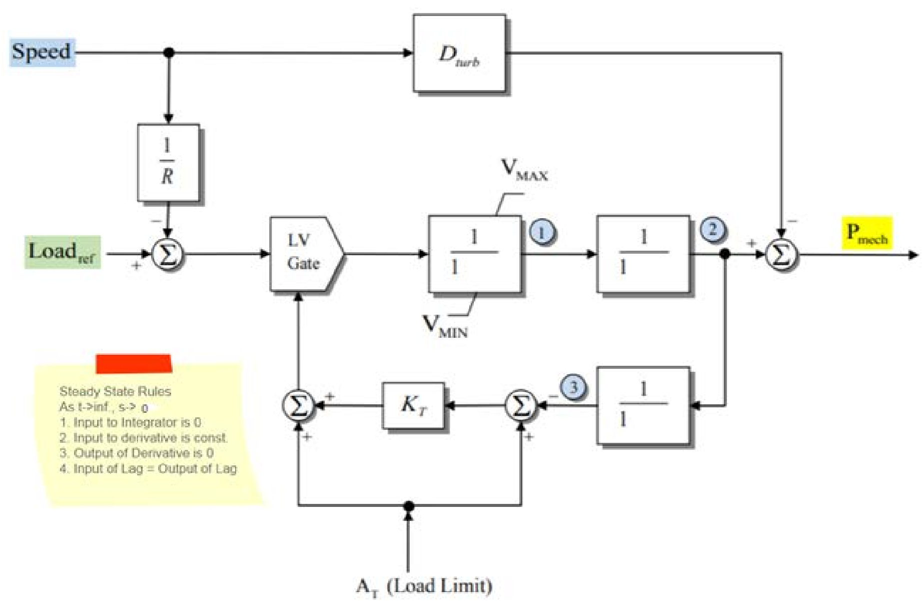

Figure B.3: GAST Model Assumption at Constant Low Frequency Condition [Source: Adapted from PowerWorld]

This example demonstrates how the Low Value Gate is used in the model to select the value in control of the mechanical power. If the speed error being fed into the Low Value Gate exceeds the ambient temperature limit, A_t, then that limit takes over seamlessly, and P_{mech} is limited regardless of speed error. If the load limit is set to 1.0 pu, as is typically done for default model parameters without acknowledging the ambient temperature assumptions, the model may overestimate the available frequency responsive reserves.

Appendix C: Example Application of GGOV1

GGOV1 is a commonly used natural gas turbine-governor dynamic model; it was originally developed specifically for GE heavy-frame machines. However, it has been used to represent other manufacturers' turbine-governor systems since it includes the fundamental control blocks that can be tuned to fit those controls relatively well.[68] This section provides a practical overview of the GGOV1 model and model parameters and describes how to parameterize the model.

Figure C.1 shows a block diagram of the GGOV1 model, annotated to show a high-level classification of the model components. The overall model includes the following components:

- **Turbine:** Turbine parameters represent the mechanical system of the turbine, fuel flow, and valve position limits and ramp rates.
- **Speed Droop Control:** Speed droop control represents the logic of the turbine-governor frequency controls based on droop setting and different feedback[69] signals.
- **Temperature Control:** Temperature control protects the hot sections of the turbine from over-temperature. It effectively limits the amount of fuel into the machine to prevent overheating the combustion cans, transition ducts, and first stage nozzles on the turbine. When a machine is operating on temperature control, the machine is at "base load," which is the maximum output the unit can achieve for those temperature conditions. The MW value of base load varies with the ambient temperature; the colder the outside air, the more mass is being pushed through the machine, meaning the more fuel is required to reach the maximum temperature. Therefore, the unit power will increase if temperature drops. In addition, some units have "peak" firing capabilities that increase the firing temperature and increase output; however, not all units are so equipped.
- **Acceleration Control:** The acceleration control mode is typically used to limit the change in speed during startup. It rarely functions during normal grid-connected operation.
- **Load Control:** Load control represent an outer loop controller that adjusts the speed set point to control power to a preset value. This models the "power control" mode (e.g., preselect load in GE terminology). Unless it is frequency biased, such as the GE PFR logic, it will override the speed governor frequency response.

Each form of control vies for overall control via a "low value select" block. The most limiting control mode (lowest value) then controls the main fuel valve, or fuel stroke reference (FSR).[70]

As with any model, one challenge is understanding how the model blocks relate to "real life" control settings and equipment components. GGOV1 is no exception. Below is a more detailed discussion of each of the different control modes, the explanation of the various parameters, and how to derive or determine them.

[68] However, in these cases, there may not be a direct link between control parameters and model parameters.
[69] The Rselect value determines which feedback signal to use, and can be compared with the governor control software.
[70] Nomenclature will vary but, for example, FSRN is the speed mode fuel valve output, FSRT is the temperature mode fuel valve output, and FSRA is the acceleration control fuel valve output.

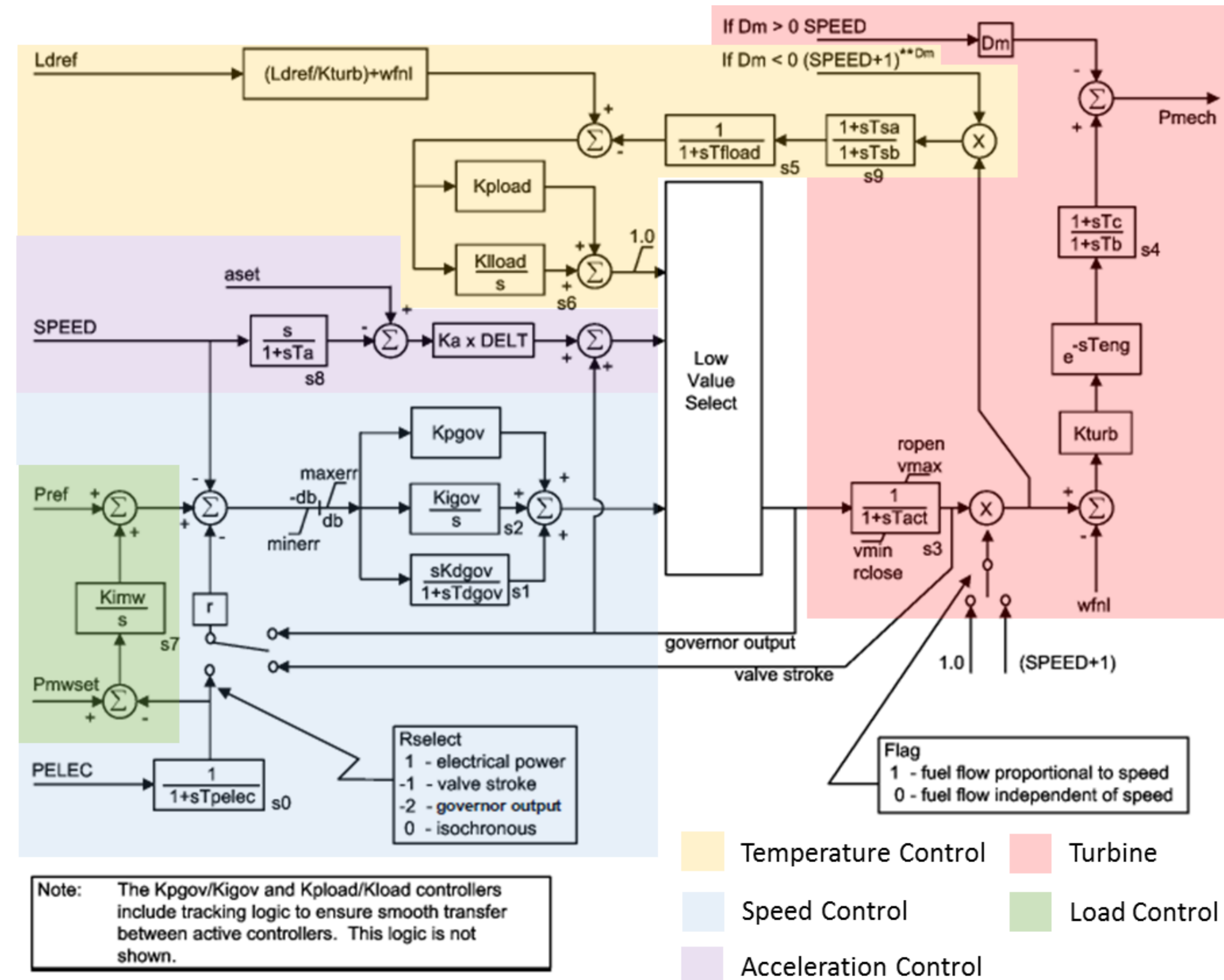

Figure C.1: Annotated GGOV1 Model [Source: Adapted from PSS®E][71]

Load Control Parameters

The load control parameters are fairly straightforward as described in **Chapter 1: Turbine-Governor Modeling Considerations**. Electrical power output (PELEC)[72] is compared against a MW set point (Pmwset) and passed through an integral control block that adds a bias to the set point (Pref). Kimw represents the load controller ramp rate. Actual turbine load controllers have a ramp rate to the set point, usually in MW/min, to prevent the machine from excessive thermal stress due to sudden load changes.

The actual limit is often a fixed ramp rate, not dependent on current loading or power set point. The Kimw parameter depends on the difference between the actual electrical power and the set point. These do not exactly correspond to each other, but can be tuned to match reasonably well.

One approach is to use the ramp rate as the initial slope of the model integral function. The initial slope of the integral will be Kimw*$e^{t(0)}$. A large frequency deviation of 0.2 Hz on a machine with 4% droop will be the following change in load (error):

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[71] Note that there may be some differences in model implementation compared across software platforms and against actual implementation in the field, particularly for the tracking and smooth transition of controls around the LV gate. This may be an area of future work to benchmark these models against each other.

[72] Converted to the base value of the model. TRATE in PSS®E, mwcap in PSLF, or generator MVA base if TRATE/mwcap is not provided.

$$\frac{\left(\frac{\Delta f}{f_{nom}}\right)}{r} = \frac{\left(\frac{0.2\ Hz}{60\ Hz}\right)}{0.04} = 0.0833\ pu$$

Therefore, the initial slope would be Kimw*0.0833. If a 75 MW machine (TRATE) had a 1 MW/min ramp rate, then:

$$\frac{1\ MW}{min} * \frac{1pu}{75\ MW} * \frac{1\ min}{60\ sec} = Kimw * 0.08333$$

$$Kimw = \frac{0.000222}{0.08333} = 0.0027$$

This compares favorably with the default model library value of 0.002.

The output of the integral block is a bias to Pref. In the model, Pref represents the turbine-governor power set point; whereas in reality, it is a speed set point (called turbine speed reference (TNR) in GE terminology) that is biased by discrete raise or lower pulses from the load controller.

Increasing the value of Kimw results in faster response from the load controller. The faster the response of the load controller, the greater the chance that the load controller would interfere with the droop response (primary frequency control) of the unit.

The load controller might not be implemented as part of the actual turbine control but rather via the plant DCS. The parameter Kimw might still provide an approximation to the overall response of the unit, but it is conceivable that the more detailed load controller model, LCFB1, might be necessary for achieving a closer match, especially if the load controller has a frequency bias function. In such cases, it is recommended to set Kimw to zero and represent the load controller response through the parameters of the LCFB1 model.

Acceleration Control Parameters

Acceleration control mode is rarely active while the unit is on-line and operational. It is typically active during startup and during a sudden speed change, such as a breaker opening. If the control mode is enabled, default values are typically used. Parameters aset, Ka, and Ta represent an acceleration limits and can be disabled by setting asset to a large value, so it is not selected in the low value select logic. These parameters are not typically verified by test due to the difficulty of conducting such tests.

Speed Droop Control Parameters

Speed reference (TNR) is compared to speed (TNH) and the error multiplied by a gain to represent the fuel valve position:

$$Pref = \frac{TNR - 100}{100} * \frac{1}{r}\ [pu]$$

The term "r" represents the effective droop of the machine. In the turbine control system, the speed error is multiplied by a gain of 1/r. In older Mark V turbine control logic, the gain was control constant FSKRN2. In order to calculate droop from the turbine parameters, the FSR at no load (FSKRN1) and the FSR at full load (FL_FSR) at whatever ambient conditions result in the maximum power being TRATE. Normally this should be at "ISO" conditions (59°F) for a GE turbine. The full load FSR is normally around 70%, at least for a GE turbine. However, turbine firing temperature uprates or peak firing capability can adjust the value. The equation for calculating "r" from the machine parameters is as follows:

$$r = \frac{1}{Valve\ Gain} * \left(Valve\ Position_{full\ load} - Valve\ Position_{min}\right) = \frac{FL\_FSR - FSKRN1}{FSKRN2}$$

One challenge is that testing is rarely done at ISO conditions. Therefore, full load FSR has to be estimated. To determine the rated full load FSR, plot FSR versus MW as the turbine starts – the plot should be fairly linear. Based on the slope of the curve and the turbine rated MW output, the rated FSR value can be estimated and the droop can be calculated. Note that the speed no load value of FSKRN1 is estimated by the control engineer. It may not be the exact value that corresponds to the actual speed value of the control valve on the specific day of the test.

In actual GE turbine logic, the fuel command value FSRN is calculated directly from the speed error and fed into the minimum select block. The resulting FSR then is fed to the valve positioning logic. The closed loop control is done on valve position in the valve servo controller logic within the turbine control system. In the model, FSRN is the output of the PID blocks, a different location from the real turbine; the PID blocks would be between the wfnl summing junction and Kturb. Although this can accurately represent the machine response, it likely does not reflect how the turbine control logic is designed.

Because of this difference between the design of the turbine logic and the model, any gain terms in the speed and valve control portions of the turbine control system may not directly transfer to the model. Thus, the easiest way to get the Ki and Kp model values is to adjust Ki and Kp so the model output matches the machine response, and avoid analytically determining them from the machine control parameters. As an aside, normally the derivative term (kdgov) is set to zero as derivative action is not present in the valve controller.

The "Rselect" parameter represents the feedback into the controller block of the governor. Recalling above that the closed loop control is on valve position on a typical General Electric (GE) turbine, the output valve position should be used as the feedback (i.e., Rselect = -1).[73] The droop block then feeds into the main summing junction and then into the PID controller blocks through settable deadbands. On GE turbines, there is no intentional deadband, so the speed governor deadband value should be set to zero.

Temperature Control Parameters

The third control function feeding the low value select logic is the temperature control that is active on most natural gas turbines. The most critical parameter for this function is the load limiter reference value Ldref, which models the temperature control limit of the turbine. This value can be determined by examining the "estimated turbine performance curve," which often provides a multiplier to the ISO turbine rating to determine an output for a particular ambient temperature. Assuming that the correct ISO rating of the machine is set as TRATE, the Ldref value is then a multiplier. For assumed ambient temperatures higher than 59°F, Ldref will be less than 1; for assumed ambient temperatures less than 59°F, Ldref will be greater than 1. One common issue is that the TRATE value is adjusted to represent the turbine output at different temperatures. This is not recommended since changing TRATE also changes the base of all the turbine parameters, which does not accurately represent the machine. Ideally, the TRATE value should be equal to the machine rating at ISO conditions, and the Ldref value modified to adjust the true turbine output for different seasonal cases. **Figure C.2** shows an example of an inlet temperature versus power output curve that can be used to correctly set Ldref based on the assumed conditions.

Tfload is a time constant for temperature measurement and Tsa and Tsb are temperature lead-lag constants to augment the exhaust natural gas temperature measurement, and Kpload and KIload represent gains for the temperature control function (typically set with a fast response). These functions are buried in complicated logic that the manufacturer does not generally allow access to. Default values are typically used since these parameters may be difficult to verify and work sufficiently well. Those values may be adjusted to match the turbine overshoot when transitioning from speed control to temperature control.

[73] The Tpelec block represents the frequency bandwidth of the MW transducer. Based on experience, the transducers are relatively slow, but since MW control is only used for the load controller, it does not affect results.

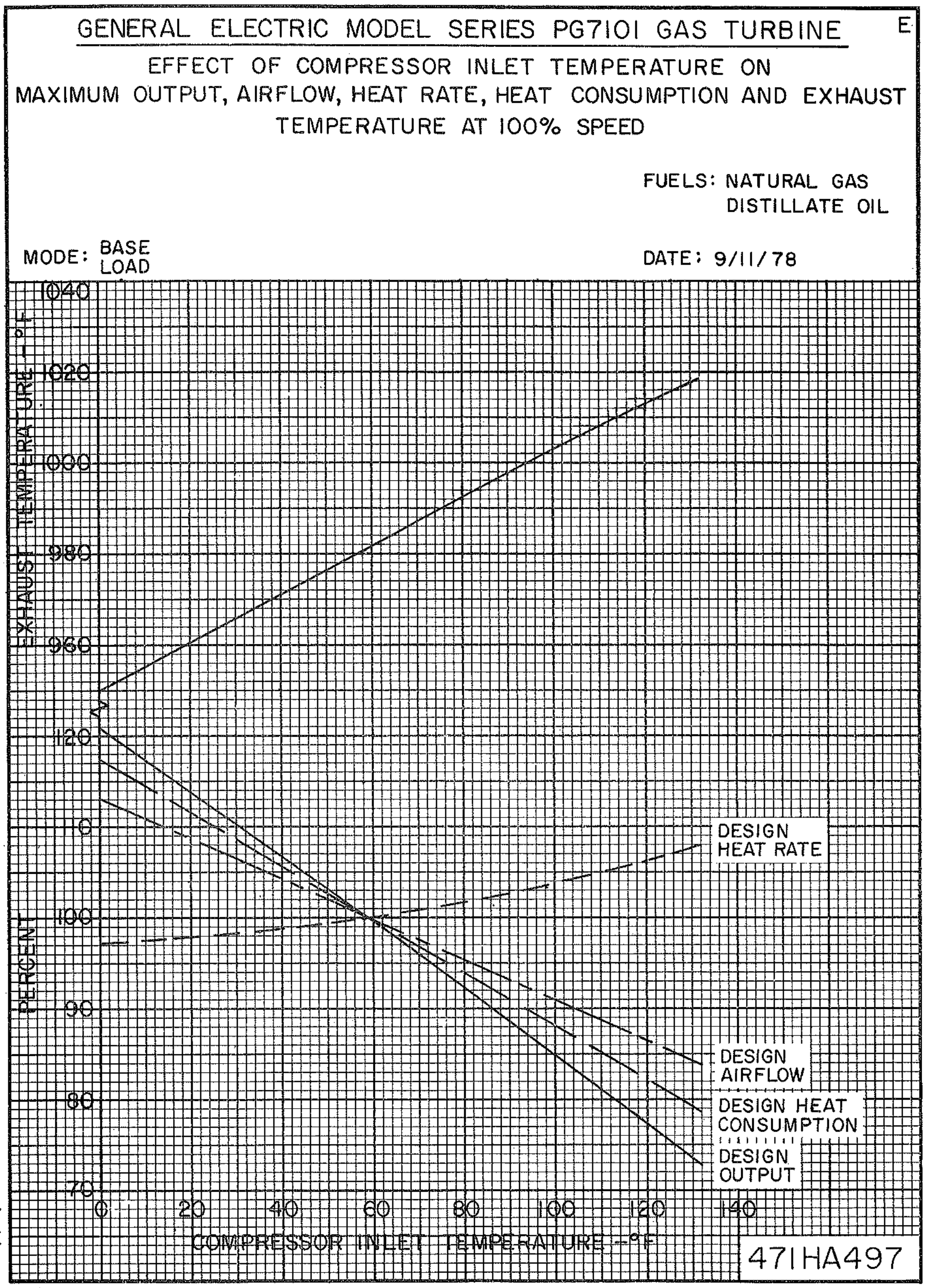

Figure C.2: Inlet Temperature versus Output Curve [Source: GE]

Turbine Parameters

The output of the minimum select block is supposed to represent FSR in GE turbines. FSR has maximum and minimum limits, represented in the model by vmax and vmin. On-line minimum FSR is above the minimum firing limit and can be found in the controller logic. For example, on one turbine, the minimum FSR above 85% speed is 11.3%. Vmin would be 0.113 in this case. Often in natural gas turbines, the FSR max limit is 100%, so Vmax is commonly set to 1.0. The parameter Tact represents the FSR actuator time constant, or the delay time for the valve to open. The ropen/rclose parameters represent the maximum open and close times for the valve. This data should be available from a valve calibration recording, a regular maintenance task on a natural gas turbine.

The parameter Wfnl represents the fuel needed to spin the turbine at speed with no load. It is an important value both in the control system and in the model. In the older GE Mark V logic, it is called FSKRN1 and is roughly 15%. This means that the fuel valve must be 15% open to spin the turbine at rated speed (wfnl = 0.15). The GE governor adds the parameter FSKRN1 to the valve position calculated by the droop to create the final fuel strike reference that is sent to the valve positioner. The dynamic model does it differently; it subtracts the value from the governor output. Because the model and the turbine logic are different in this regard, the only way to properly model the droop and valve position is to set wfnl to zero in the model. This makes the parameters in the turbine control logic match the model parameters, but it will affect the value of FSRMIN in the model – likely it will need to be set to zero to be accurate.

The parameter Kturb, or turbine gain, is also an important parameter in the model and is present in both the load controller piece of the model and the mechanical model of the turbine. Kturb represents the fact that, at ISO conditions, the fuel valve is not at 100% where turbine output is 1 pu on the base of Trate. Kturb can be calculated using the FSR at full speed with full load and no load, assuming the turbine rating (TRATE) is selected at ISO conditions:[74]

$$K_{turb} = \frac{1}{FL_{FSR} - SNL_{FSR}} = \frac{1}{FL_{FSR} - FSKRN1}$$

For example, if maximum output at ISO conditions FSR is around 70% and speed no-load FSR is around 15%, then Kturb = 1.82. Kturb can also be understood as a linear approximation (with no load fuel flow, Wfnl) of the relationship between valve position or fuel flow and the power output of the turbine. The GGOV1 model does not represent a nonlinear gain as other models do, so Kturb can also be estimated from a plot of fuel flow versus power output or valve position versus power output.

One important concept to remember is that the maximum output of the machine cannot have the fuel valve position greater than 100%; therefore, the powerflow model parameter P_{max} must be checked to ensure it does not exceed the maximum output of the GGOV1 model. The maximum power output of the GGOV1 model can be calculated (in steady-state) as:

$$P_{mech_{max}} = K_{turb}\left(V_{max} - W_{fnl}\right)$$

This corresponds to the maximum mechanical power output of the GGOV1 model if the maximum valve position Vmax is reached. This is calculated in per unit of the base value for the model with TRATE, mwcap, or the generator MVA base. This maximum power output can be limited to a lesser value via the limit for the temperature control loop, determined by the parameter Ldref. Therefore, the maximum mechanical power output in per unit of the base value for the model is either equal to Ldref or the value calculated by the expression above, whichever is the lowest value. There will be an initialization problem if this maximum mechanical power output is less than the declared maximum power output of the generator in the power flow case, P_{max}. Therefore, P_{max} should be set the same or less than the maximum power capable from the GGOV1 model to avoid initialization errors.

Most of the other parameters in the turbine section of the model use the default values as they provide a sufficiently good response. The parameter Teng represents a transport delay time constant for a diesel engine and is set to the default value of 0 for natural gas turbines. The parameter Dm represents the variation of engine power or maximum power with shaft speed. Typically, this doesn't affect natural gas turbine response, so the default value of 0 is used. Parameters Tb and Tc are part of a lead-lag function to represent the lag for the natural gas turbine to respond to changes in fuel flow. The default values of Tc = 0 and Tb = 0.1 are sufficiently accurate.

[74] TRATE can be at other ambient conditions, but it is much easier to calculate and verify the model using ISO values.

Appendix D: Examples of Analyzing Unit Response

This section provides illustrative examples of analyzing the expected (modeled) response versus the actual (measured) response of a generator to a grid disturbance or off-nominal frequency event. These examples are intended to demonstrate how the high-level analysis of using an algebraic representation of the turbine-governor can be used to identify potential modeling errors or inconsistencies.

Example 1. Analysis of Responsive Unit using SCADA Data

This example involves a natural gas turbine with the information shown in Table D.1 from powerflow and dynamic model data. This information explains that the unit should provide additional output when dispatched below the minimum of *At* and *VMAX* (per the low value select in the model),[75] which is $AT * MVA = 207MW$. Using the equation above, the baseline information for comparison is the following:

$$unit_{MW\ Capability} = 249MVA$$

$$droop = 0.04$$

$$f_{db} = 0.036Hz$$

Table D.1: Machine Data

	Value
MVA	249.00 MVA
P_{max} (Summer case)	207.00 MW
Model	GAST
VMAX	1.0 pu
At	0.83 pu
droop	0.04 pu
Deadband in model	N/A
Deadband provided by GO	36mHz

Figures D.1 and D.2 show that the measured results match the expected results when an intentional deadband of 36 mHz is used. The plots on the left use a 36 mHz deadband while the plots on the right use no deadband. The 36 mHz deadband estimate matches the actual response much closer. Therefore, this analysis confirms that the governor is responsive to frequency and likely has a deadband of approximately 36 mHz. Note that the general shapes of the plots are more important than the exact scales or values.

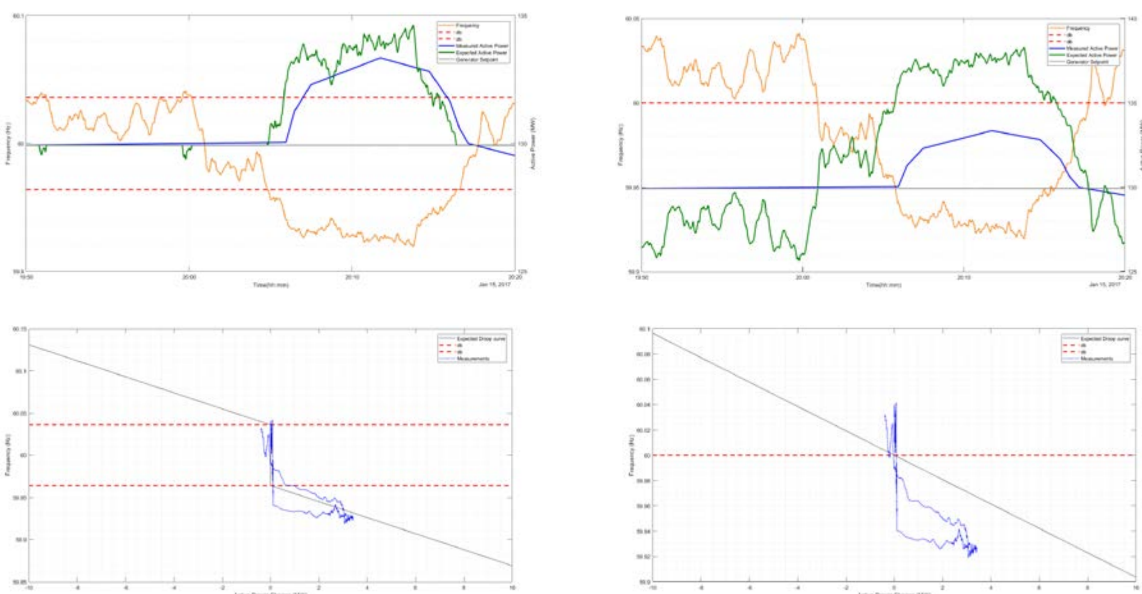

Figure D.1: Measured vs. Actual Performance – Match with Proper Intentional Deadband (Left), Overestimated Performance with Improper Deadband (Right)

[75] Both per-unit values use MBASE as the base value.

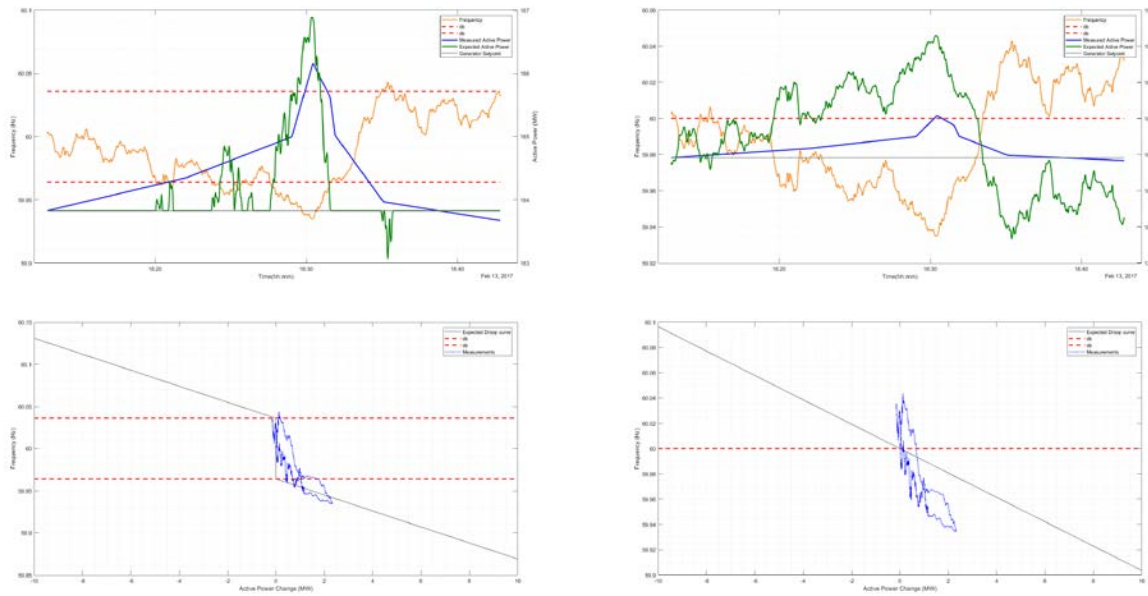

Figure D.2: Measured vs. Actual Performance – Match with Proper Intentional Deadband (Left), Overestimated Performance with Improper Deadband (Right)

These measurements do not confirm that the model headroom or any limits are correct since the unit was never dispatched at a point near its maximum limit. Therefore, one can conclude that the powerflow and dynamic model parameters should be used except for *At* since this is still unknown. Confirming that the headroom parameter (GAST model *At* = ambient temperature load limit) is modeled appropriately may require further analysis when the unit is operating closer to P_{max}. It may also require analysis for situations where the ambient conditions are closer to that of the assumed conditions used for the model. This may mean fewer opportunities depending on how the unit is operated. For example, maximum power output for this natural gas turbine decreases with higher ambient temperature (see **Figure D.4**). Therefore, some events from warmer months were evaluated. This particular generator is a peaking generator, so there are fewer opportunities to evaluate performance near its full output and when the weather is warm. When the event on September 24 was evaluated, the frequency dropped below the confirmed deadband and the generator did not produce any additional output (see **Figure D.3**). The model predicted the unit should have produced additional MW for this event because we have already seen that the unit is responsive to events outside of the deadband of 36 mHz thus we can conclude that the ambient temperature limit of the model may be incorrect.

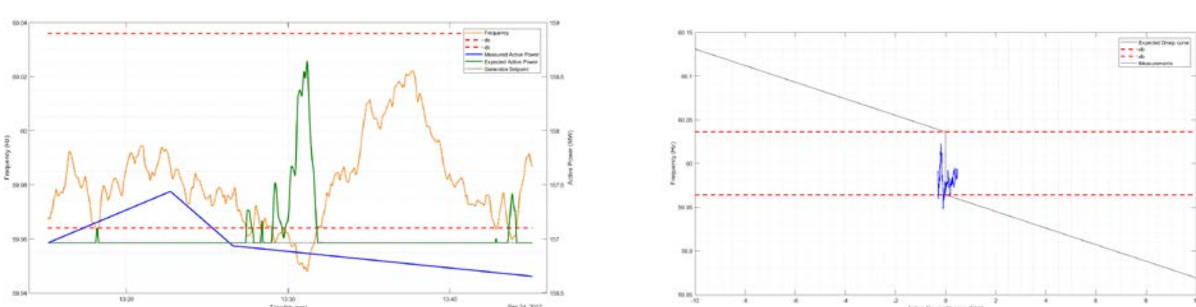

Figure D.3: Measured vs. Actual Performance – Properly Overestimates Performance at Higher Ambient Conditions Illustrating Headroom is Incorrect in Model

Measurements exhibiting non responsive behavior may lead to a review of the application of the model(s). Upon review of the ambient conditions at the time (~32 °C) and a review of the ambient temperature versus the output curve, it is clear that the our baseline of P_{max} in the dynamic model of $0.83 * 249 = 206.67MW$ is incorrect and over-optimistic. That is to say, in the summer peak case, where it is assumed to be 35 °C in the modeled region, the maximum output is too high in both the powerflow and the dynamics case. The powerflow should be adjusted to 160 MW and the value of *At* in the GAST model should be adjusted to ~0.65 pu. This eliminates ~45 MW of headroom that does not exist in actual operation under these operating conditions. The value of *At* (the dynamic model parameter) and value of P_{max} (powerflow) should be appropriately adjusted for each case being studied.

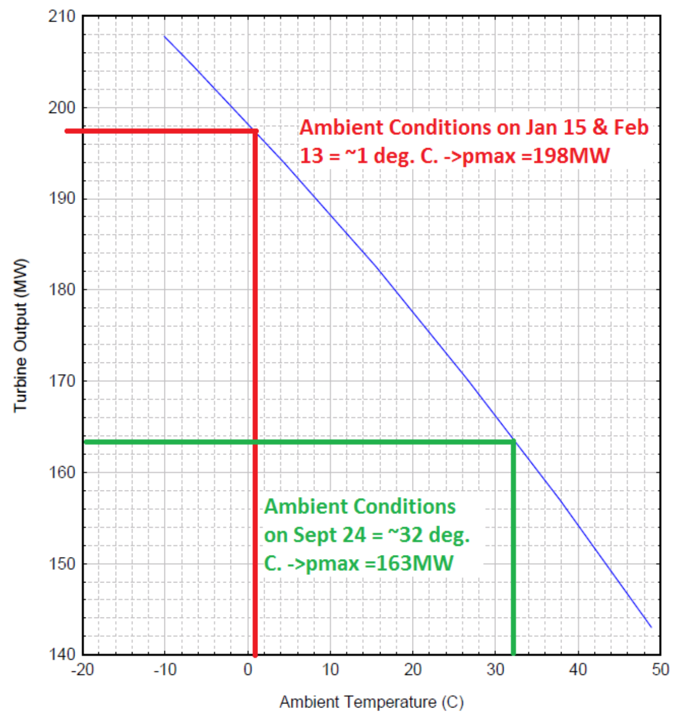

Figure D.4: Power-Ambient Temperature Curve [Source: IESO]

Example 2. Inconclusive Results due to Generator Ramping During Event

There may be times where this technique does not provide meaningful results. One example is when a generator is ramping to a new MW set point value and a frequency disturbance occurs during the ramp (see **Figure D.5**). The algebraic equations assume constant MW dispatch during the time interval. In this case, the unit ramping dominates the response, so the frequency response cannot be captured cleanly. Therefore, one cannot draw any modeling conclusions from this event and should not interpret this as undesired performance.

Figure D.5: Inconclusive SCADA Data Due to Machine Ramping to Different Set Points during Frequency Event

Example 3. Nonresponsive Governor When Dispatched Between P_{min} and P_{max}

A different natural gas turbine is used in this example with the machine data shown in **Table D.2**. The model provided by the GO does not contain a load controller, and it appears that the unit will provide additional output from the parameters until the minimum of *At* or *VMAX* is reached per the low value gate. Since the turbine-governor model has an MVA base of 249 MVA (this model uses machine MBASE for per unitizing), the maximum output the turbine can produce is $AT * MVA = 194.5MW$.

Figure D.6 shows the comparison of expected and actual response. The actual MW output (blue) of the unit during the frequency excursion (orange) does not change. The expected response (green) shows the generator should have provided additional MW until frequency returned to within the deadband (total of ~7 minutes).

Table D.2: Machine Data

	Value
MVA	249.00 MVA
P_{max} (Summer case)	179.00 MW
Model	GAST
VMAX	1.0 pu
At	0.719 pu
Droop	0.05 pu
Deadband (in model)	N/A
Deadband (provided by GO)	36 mHz

The comparison indicates that the model is showing responsiveness while actual operation is showing otherwise. This may be due to any of the following:

- The unit is operating in a mode that results in it being nonresponsive to changes in turbine speed.
- The deadband may be larger than was assumed or provided.
- The unit is operating at its maximum power and cannot increase further.
- The resolution of the data is too low to be used.

Given that the model predicted one outcome, and the simulation resulted in a very different outcome, the results should be flagged for further review (e.g., review other events, review past verification test reports, or review model data closely) and discussion with the GO.

To confirm what steps should be taken to correct the turbine-governor model application, the TP reached out to the GO for equipment documentation and settings. It was determined that this unit was operating in a load control mode that strictly held output power to a constant MW value despite changes in speed outside the intentional deadband. The proper solution in this case was to include a load controller model with appropriate parameter values, to utilize the 'baseload flag' to set it as nonresponsive, or to remove the turbine/governor model from the case to illustrate nonresponsive behavior. The first of these three options is the recommended approach, particularly for transient stability analysis.

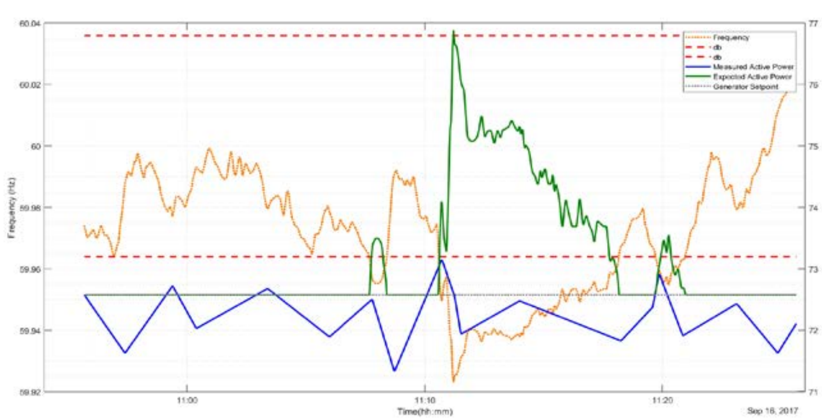

Figure D.6: Comparing SCADA Measurements to Estimated Model Showing Model Overestimates Actual Performance

Appendix E: Inverter-Based Resource Frequency Controls

Inverter-based resources do not have turbine-governors, but they do have active power-frequency control systems to provide similar electrical performance and frequency response. This chapter describes considerations for modeling these controls in inverter-based resources.

Controls Modeling Considerations

Inverter-based resources typically operate with one of the following characteristics that dictates how the resource should be modeled in terms of frequency response:

- **No Frequency Control:** Some existing resources may not have controls that change active power based on frequency. In this case, the *repc* plant-level controller model should have the frequency control flag parameter, *frqflg*, set to zero. In addition, although not required, set the droop settings (*Dup* and *Ddn*) to zero as well to show the model user that this control loop is disabled.
- **Capability but No Regulating Reserve Requirement:** Many existing inverter-based resources have the capability to provide active power-frequency response. FERC Order No. 842 amends the Commission's pro forma Large Generator and Small Generator Interconnection Agreements (LGIA/SGIA) to require that all newly interconnecting resources install, maintain, and operate a functioning governor or equivalent controls as a precondition of interconnection.[76] Reserving generation headroom (i.e., the difference between maximum available power output and actual power output) to provide frequency response to underfrequency events is not required by FERC Order No. 842 nor by most existing inverter-based resources. However, resources should be set to respond to overfrequency events outside the deadband by reducing active power output. When responsive in one direction but known to not be responsive in the other direction, Frqflg = 1, Dup = 0, and the parameter Ddn should be set based on the droop characteristic. (Note that in actual operation, units that are curtailed may provide upward frequency response. The modeled response may not capture this curtailed operating characteristic.)
- **Capability and Reserve Requirement:** In some situations, the resource may have the capability to provide frequency response and also could be dispatched with operating reserve where the unit is not dispatched at its maximum available power. In this case, set Frqflg = 1, and the Dup and Ddn parameters to their respective droop characteristic settings. The unit may have the ability to respond in both upward and downward direction. However, care must be given when dispatching the unit in powerflow to represent the unit when dispatched at values less than P_{max} yet not operating with reserve.
- **Inertial Response:** Some inverter-based resources may have the ability to provide a short-duration increase in active power response where mechanical energy is converted to electrical energy; however, this energy must be returned and extracted back from the grid shortly thereafter. This could include extracting rotational energy from the wind turbine generator (WTG) rotor that causes the resource to slow down and reduce output. These types of responses do not meet FERC Order No. 842 requirements, although they may exist in regional requirements.[77] This feature of inertial response is not currently represented in the second generation renewables models. 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.

The baseload flag does not interact with these models.

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[76] FERC Order No. 842 goes beyond requiring new generation units having the "capability", and requires generation resources to actually respond to frequency excursion events when frequency falls outside the deadband of +/- 0.036 Hz, and adjust its output in accordance to a 5% droop. This response must be timely and sustained rather than injected for a short period and then withdrawn.

[77] Hydro Quebec. Transmission Provider Technical Requirements for the Connection of Power Plants to the Hydro-Quebec Transmission System. http://www.hydroquebec.com/transenergie/fr/commerce/pdf/exigence_raccordement_fev_09_en.pdf.

Pseudo Governor Model for Type 1 and Type 2 Wind Machines

The first generation of Type 1 and Type 2 WTG pitch control models (*wt1p* and *wt2p*) are essentially a pseudo-governor model used to simulate the pitch controls during transmission faults. However, these models produce governor-like response during frequency excursion events, leading to unrealistic frequency response from these resources. These units operate at maximum power availability and do not have the capability to provide frequency response.

The notes related to the *wt1p* model in the simulation software model libraries are crucial to setting model correctly. An induction machine consumes reactive power from the network, so the MVA rating of the machine is always greater than the amount of MW the machine can deliver. For example, if P_{max} is 100 MW for a 111 MVA machine, then mwcap should be set to 100. The *wt1p* model does not have a parameter for mwcap, and the value of pimax in the model uses MBASE for per unitizing. Therefore, pimax should never be 1.0 pu (even though that is the default) because the induction generator always needs to absorb reactive power. Reactive power increases as slip increases, so if the machine has to be rotated at a higher speed, reactive power increases.

To address this modeling issue, the *wt1p_b* model[78] was developed to more accurately represent Type 1 and Type 1 WTG pitch controls. It is recommended to replace *wt1p* models with *wt1p_b* models, where appropriate.

Frequency Response Modeling for Inverter-Based Resources

Some inverter-based resources, particularly for newly interconnecting resources after FERC Order No. 842 (namely Type 3 and Type 4 wind, and solar photovoltaic),[79] will have the capability installed and enabled to respond to frequency excursions outside of a specified deadband setting. In these cases, this response should be modeled appropriately using the plant-level controller model, *repc_a* (see **Figure E.1**). However, most resources will operate at maximum available power unless curtailed. In planning studies, curtailment is typically not considered, so attention should be given to ensure that the resources are modeled and respond accordingly. For example, if the generator is modeled with frequency response capability in dynamics and dispatched below P_{max} in powerflow and is assumed to be operating at maximum available power, then the P_{max} value in the dynamics data needs to be updated to match the P_{gen} in the base case. Otherwise, the model will provide frequency response when the unit will not in reality. Another option is to set the under-frequency droop value in the plant controller (highlighted red in **Figure E.1**) to zero under the assumption that the unit is always operating at maximum available power and will respond in the downward direction for overfrequency conditions, not the upward direction.

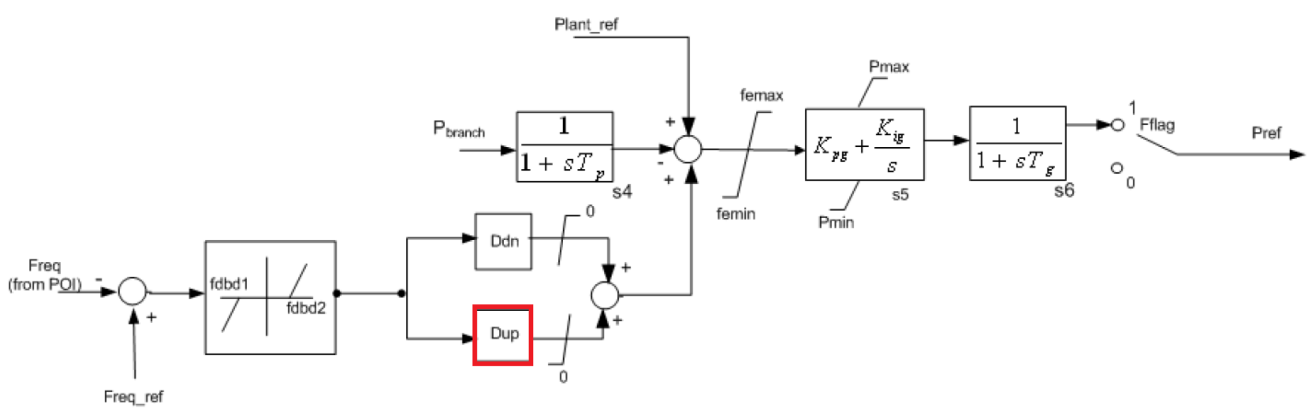

Figure E.1: Plant-Level Controller – Active Power Controls [Source: PSS®E]

[78] See Section 2 of the WECC 2nd Generation WTG Modeling Guide. https://www.wecc.biz/Reliability/WECC-Second-Generation-Wind-Turbine-Models-012314.pdf.
[79] https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-2.pdf?csrt=5283656277463770639.

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