Validation and Accreditation of Transient Stability Results

Final Project Report

Power Systems Engineering Research Center

*Empowering Minds to Engineer
the Future Electric Energy System*

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Final Project Report

Project Team

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Power Systems Engineering Research Center

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Acknowledgements

Executive Summary

The goal of this project was to perform validation of the transient stability packages used for Bonneville Power Administration (BPA) system analysis. It is commonly thought that different transient stability packages can give different results for the same system conditions. This project is just focused on validating the packages against each other, as opposed to with real world data. The ultimate aim of this was to enhance the utilization of the BPA transmission system by using validated, real-time transient stability analysis, and to have better planning/study tools and models.

We have successfully developed a methodology to validate transient stability results and packages.

Chapter 2 describes the Starting Point. At the beginning of this project, comparisons were made for a full 17,000 bus Western Electricity Coordinating Council (WECC) case provided by BPA, using three different packages namely GE's PSLF, TSAT and PowerWorld. The graph below shows the variation in the frequency of a bus for the loss of generation contingency in the southern part of the system.
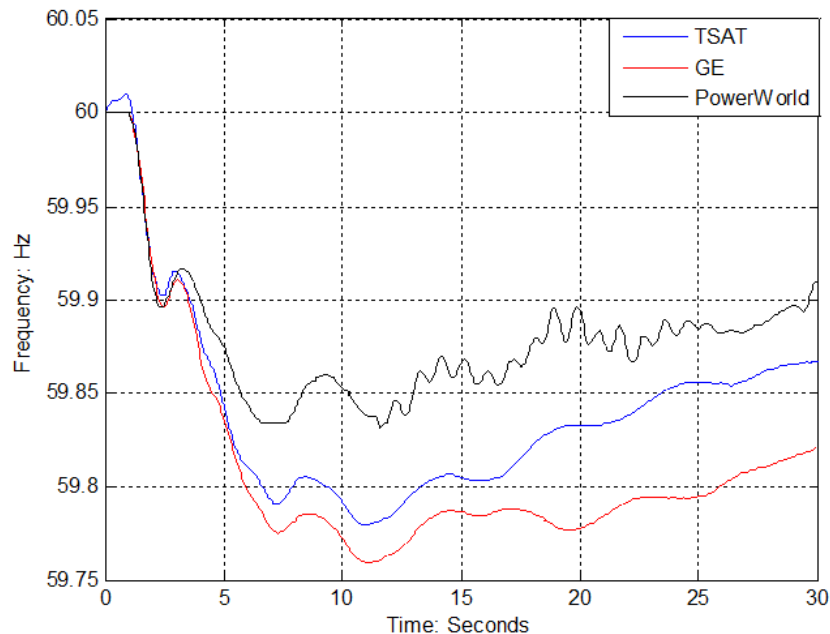

The Top-Down Approach is discussed in Chapter 4. This involved determining the individual models or components causing these variations, from the full case runs.
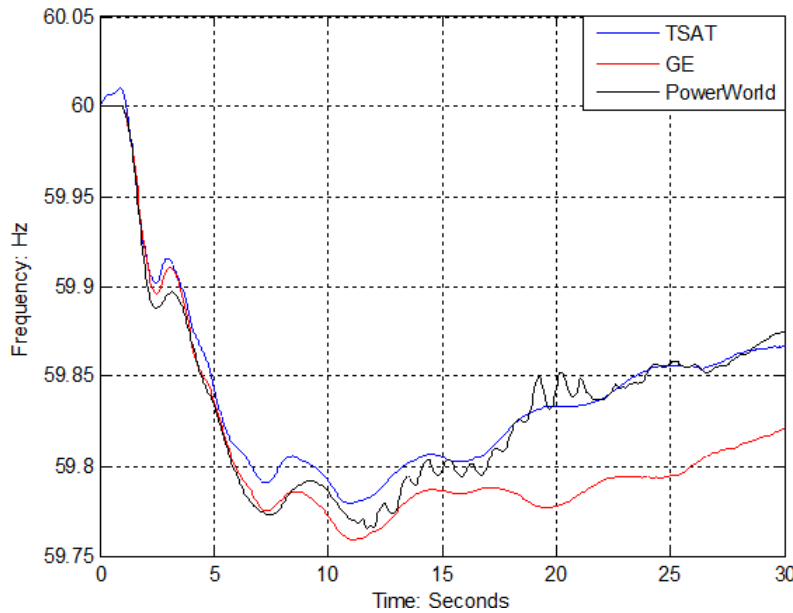
In this case, we determined that a bug in how the frequency deviations for the induction motor loads were being handled by PowerWorld was causing some of the frequency variation. The new run is shown in the figure above. The oscillations in the PowerWorld frequencies were tracked down to a model error. Similarly, several other model errors were tracked down using this approach.

Chapter 5 deals with our Bottom-Up Approach of validation. This consists of creating two bus equivalents for the most common WECC Generator models, and then running them in the different packages. We have validated several dynamic models using this method. Wherever discrepancies were found, we have tried to track down the cause and documented it. This has resulted in several software changes to PowerWorld with the new code often giving quite close matches. **We have validated all the major machine models and most of the exciter and stabilizer models prominently used in the WECC case**. The following figure illustrates the benefits reaped from this approach.
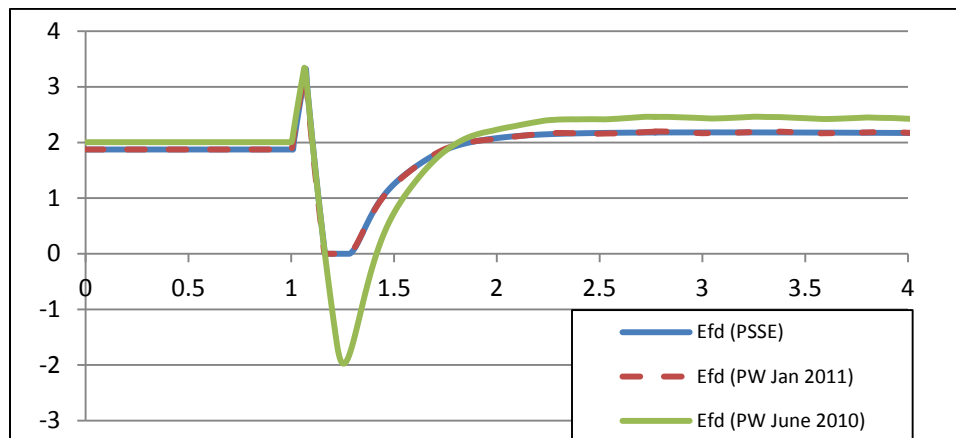
This graph shows a comparison of the field voltage at bus 21 for a fault on the two bus equivalent system between PSSE, and two versions of PowerWorld Simulator.

In this whole validation process, we have created a library of cases with benchmarked transient stability results that can be used by BPA to validate other software packages and thus better utilize their system. We have also reported many **data errors found in the WECC case reported in Chapter 2 to BPA that have helped improve the representation of the system as well as our validation studies.** Another major beneficial outcome has been the significant improvement in one of the participating software packages, PowerWorld and its growing compatibility with PSSE and PSLF software packages.

Chapter 6 talks about the validation of crucial Generator parameters such as saturation and also of modeling compensation. In this part, comparisons between PSLF and PowerWorld were made, while also at the same time highlighting the differences between the modeling of generators in PSLF and PSSE. PowerWorld seems to have the capability to seamlessly integrate both these types of models which aided our studies.

Chapter 7 briefly illustrates the impact of changing time steps on transient stability simulations and results. This was performed in light of the auto-correction feature that exists in PowerWorld for adjusting time constants according to the time step. We observed that, in the larger scheme of things for the 17,000 bus case, the time step and consequent auto-corrections had no significant impact on the results. Of course this holds for the selection of a reasonable time-step that doesn't compromise the stability or accuracy of the simulation.

Chapter 8 describes our most recent work with frequency comparisons between PSLF and PowerWorld. In the effort to track down the cause for the observed differences, we narrowed it down to several factors including the complex load model and software bugs in PowerWorld. Despite so many breakthroughs however, we were unable to figure out the exact cause and eliminate the discrepancies completely; thus pointing us to the future work required in Transient Stability Validation of the WECC system.

Finally, Chapter 9 documents some of the bugs we discovered in GE PSLF which were reported to GE. These were verified by the concerned authorities at GE, and are being addressed and rectified. Thus we have been reasonably successful in one of our main goals of suggesting and bringing about improvements in commercial software packages like PowerWorld and PSLF.

In Chapter 10, we discuss possible directions for future research. As concluded in Chapter 8, we need to further investigate and determine the source of the frequency discrepancies. Apart from this, other likely steps would be to perform validation of dynamic models pertaining to wind turbines, solar models etc. given the thrust on integrating renewables into the grid. A significant future agenda would be to validate these packages and their simulation results with real-world data obtained from PMUs and other sensing devices.

Student Thesis: This project is also the basis for the Master's thesis titled **'Validation of Transient Stability Results'** written by Komal Sudhir Shetye from the University of Illinois at Urbana-Champaign. This thesis will be completed in December 2011.

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1. Introduction

1.1 Background and Problem Overview

Simulation of the transient stability problem, which is the assessment of the short term (several to 30 seconds) angular and voltage stability of the power system following a disturbance, is of vital importance. For some portions of the North American power grids, such as WECC, transient stability has always been an important consideration, while for other portions it is of growing concern due partially to the widespread integration of wind generation.

It is widely known in the industry that different transient stability packages can give substantially different results for the same (or at least similar) system models. The goal of this project is to develop validation and accreditation methodologies for transient stability packages with a focus on the WECC system models.

For validation within the power system transient stability domain, there is usually a lack of real-world data to allow a direct comparison between the simulation results and the real-world. Rather in this project the main task is to simulate the WECC power system models using different commercial transient stability packages, and use them to "validate" each other. This process will be aided by the fact that all the packages claim to implement the same system models. Hence if the packages give a "substantially" similar result, we may assume the models to be valid. If say two out of three give the same result, then our bias (but not foregone conclusion) will be that the third package is incorrect, particularly if the mismatches are consistently from one of the packages. However, how to define "similar" versus "dissimilar" simulations is one of the project objectives. For those cases with discrepancies in the results in which we cannot determine a clear cause, we will provide documentation and example cases to BPA that they can provide to the software vendors.

The ultimate goal for this project is to develop procedures and example cases that could be proposed by BPA to WECC to be used for the accreditation of new transient stability packages for WECC system studies. We are not proposing to do any type of official certification ourselves.

This software packages being validated are PowerWorld, GE's PSLF, PowerTech TSAT and PSSE. University of Illinois at Urbana-Champaign is taking the lead with PowerWorld and PSSE, Washington State University with PowerTech TSAT and BPA with GE.

In this project, we received three different versions of the full 17,000 bus WECC case in GE format and one in the PTI format from BPA. Each successive PSLF case was an improved and updated one. In this report, we will refer to the case files by the following names. We converted these files to *.pwb files for the ease of our studies across different packages. Throughout this report we refer to them by the following names:

1. WECC Case 1: PSLF format

2. WECC Case 2: PSLF format
   This updated case, received on June 28 2010, fixed some 2000 errors in the previous version

3. WECC Case 3: PSSE format
   This was the only WECC case received in the PSSE format, in December 2010.

4. WECC Case 4: PSLF format
   This was the most recent and updated case provided to us.

Following the WECC standard, a time step of ¼ cycle was used in all the simulations, unless specified otherwise.

1.2 Report Organization

The organization of the report is as follows. Chapter 2 represents the starting point of this project with WECC Case 1 runs and the validation results. Chapter 3 covers a brief discussion on the detection of 'bad' data in WECC cases and the principles of time step and auto-correction. Chapter 4 describes in detail the Top-Down approach with the help of an example and eventually highlighting the significance of single-machine infinite bus (SMIB) equivalents in the debugging process. Chapter 5 covers in some detail the SMIB equivalents method being used to validate the major generator models. Chapter 6 discusses validation of generator saturation and voltage compensation. Chapter 7 provides an insight into time step comparison of results. Chapter 8 describes the latest runs being done on Case 4, some comparison results and the issues encountered. Lastly Chapter 9 documents some suspected software bugs.

Also, another note to be added is that, the cases corresponding to the SMIB results given in this report will be supplied to our industry sponsor BPA for their reference and possible benchmarking studies. The generator buses from where these equivalents were derived are mentioned in this report.

Lastly, since this is a public report; in order to ensure confidentiality of the WECC system data, alternative bus numbers, area names etc. have been assigned in this report, which do not reflect, in any way, the actual numbers or names of any part of the system. This is also the reason why we have maintained ambiguity about locations and names of components such as generating units.

2. Initial Runs of Full WECC Case 1

2.1 Background

In order to get an estimate of the initial direction of the project, we started off with a system wide frequency comparison, using TSAT, GE-PSLF and PowerWorld. Results of the same are depicted for the loss of a large amount of generation in the southern part of WECC. Frequencies were monitored at 10 key buses as specified by BPA. Some representative results are shown below:
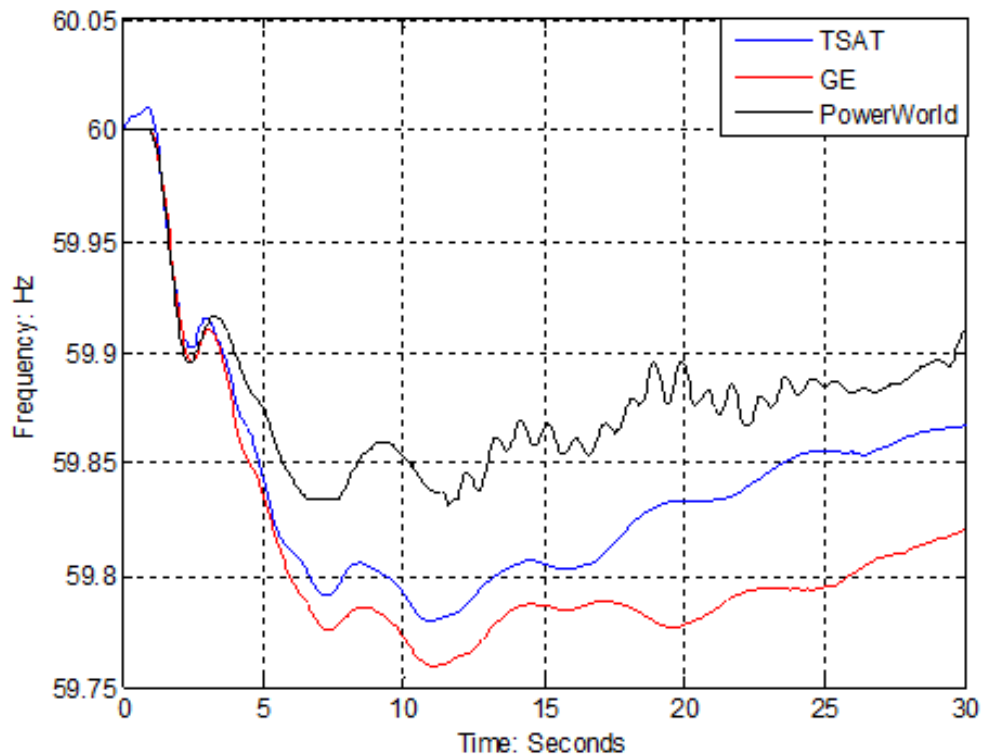
Figure 2.1(a): Frequency Response at bus 1

3
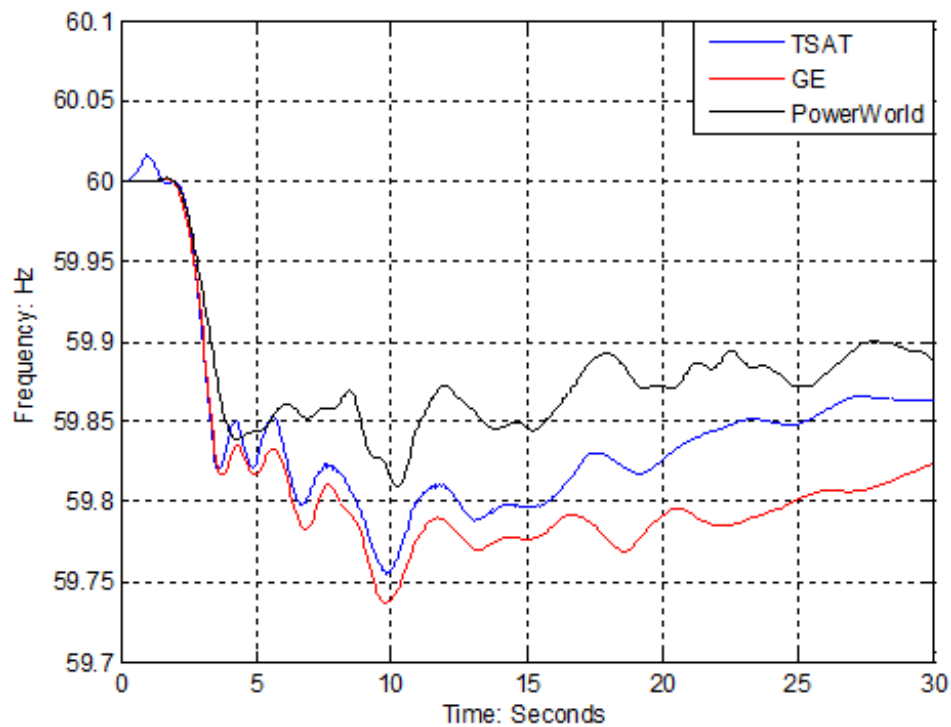
Figure 2.1(b): Frequency Response at bus 2
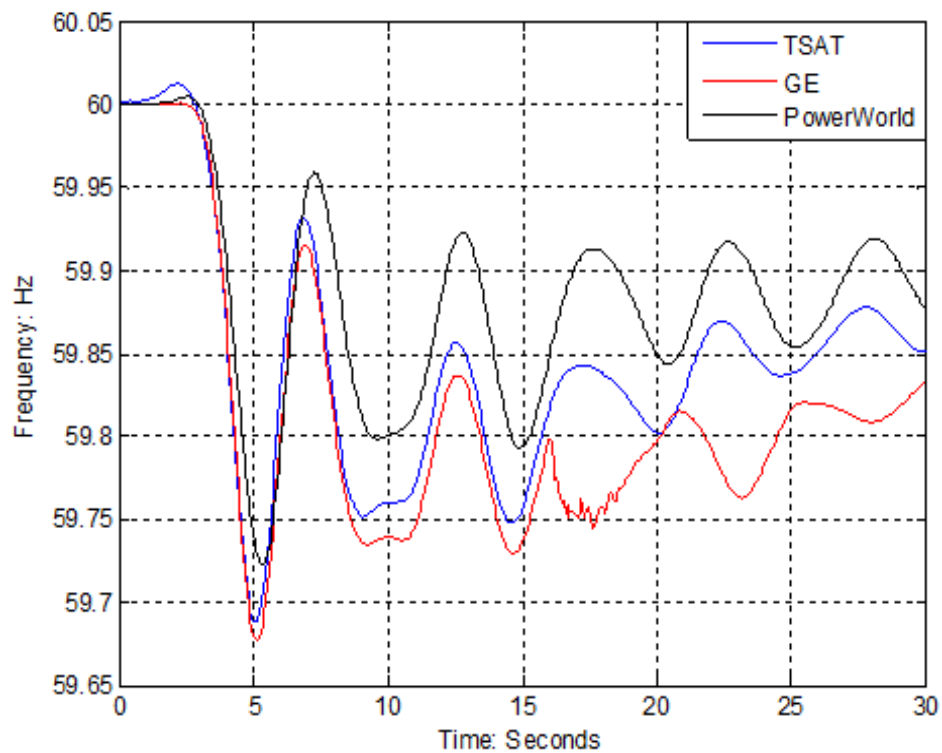
Figure 2.1(c): Frequency Response at bus 3

4
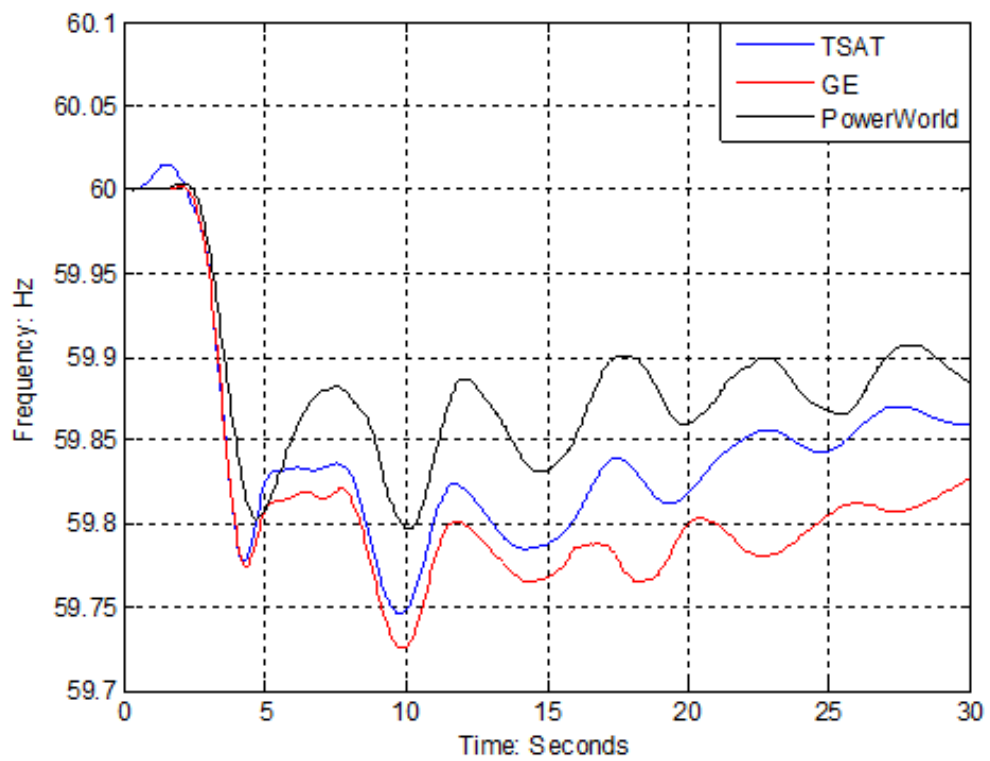
Figure 2.1(d): Frequency Response at bus 4
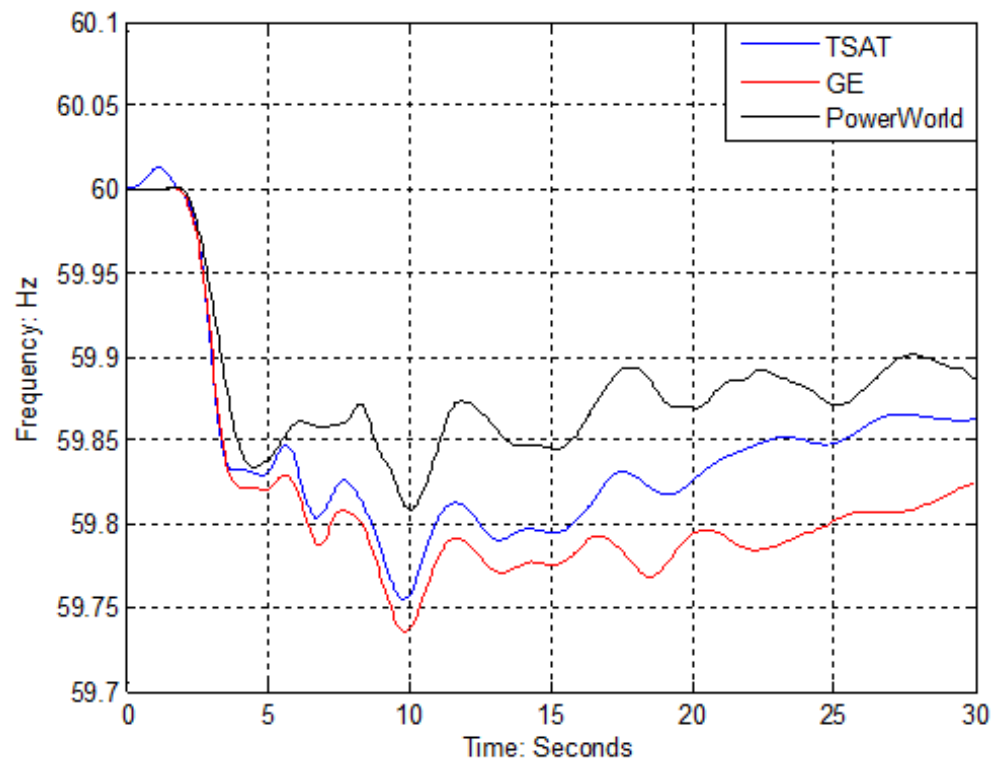
Figure 2.1(e): Frequency Response at bus 5

5
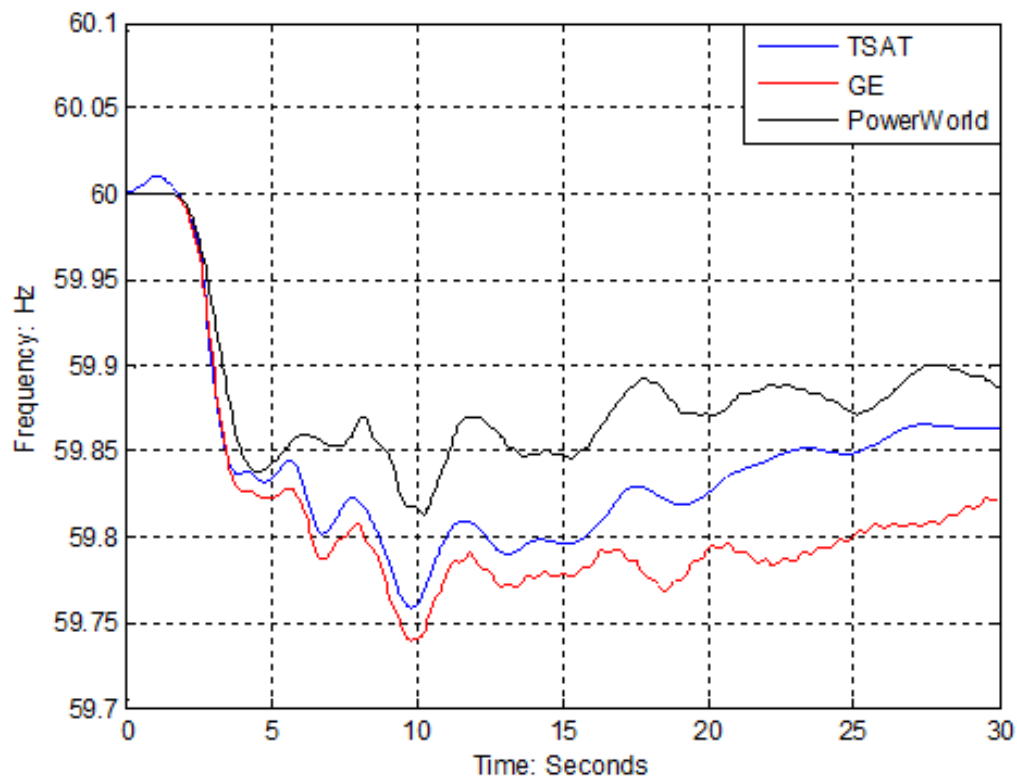
Figure 2.1(f): Frequency Response at bus 6
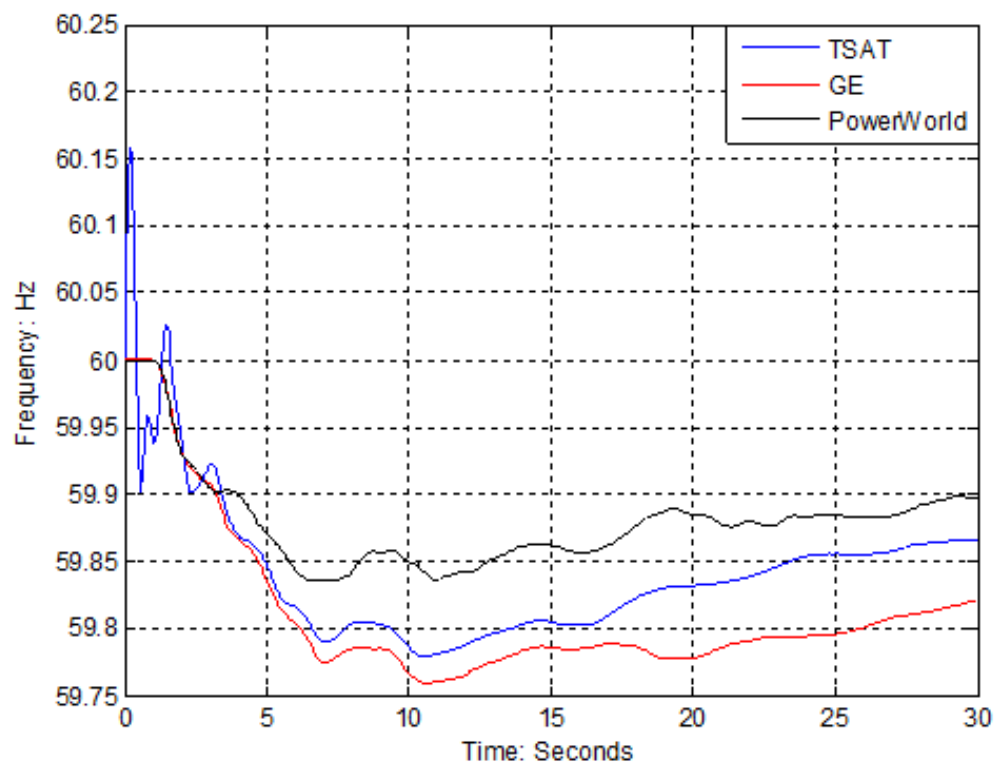
Figure 2.1(g): Frequency Response at bus 7
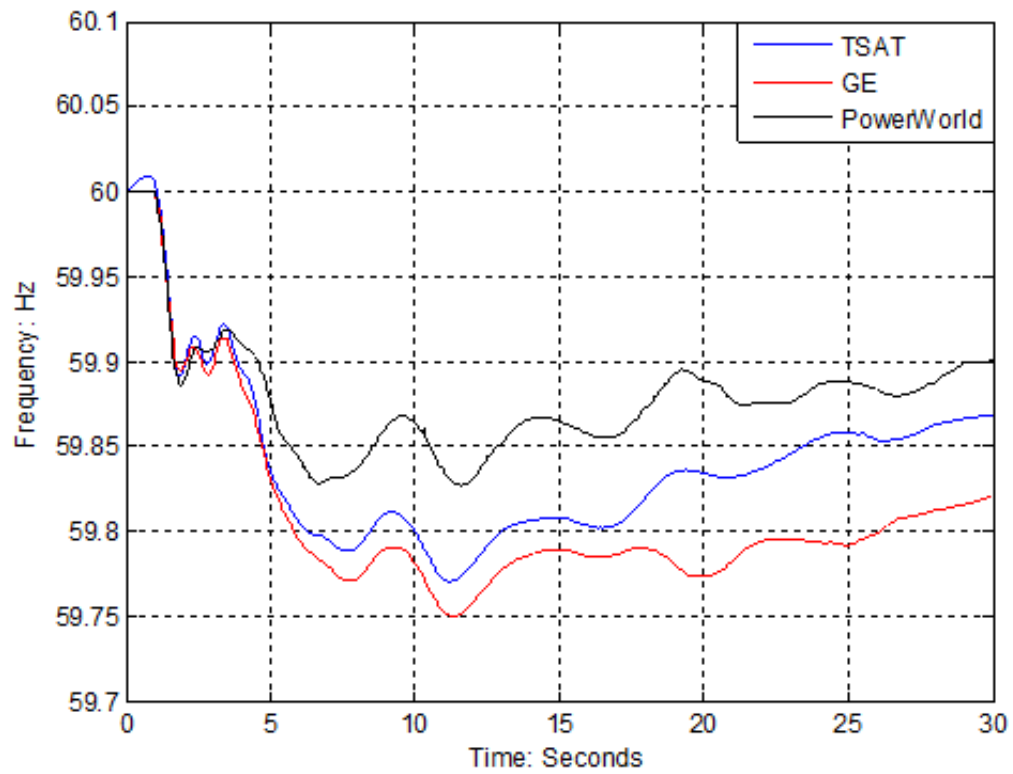
Figure 2.1(h): Frequency Response at bus 8
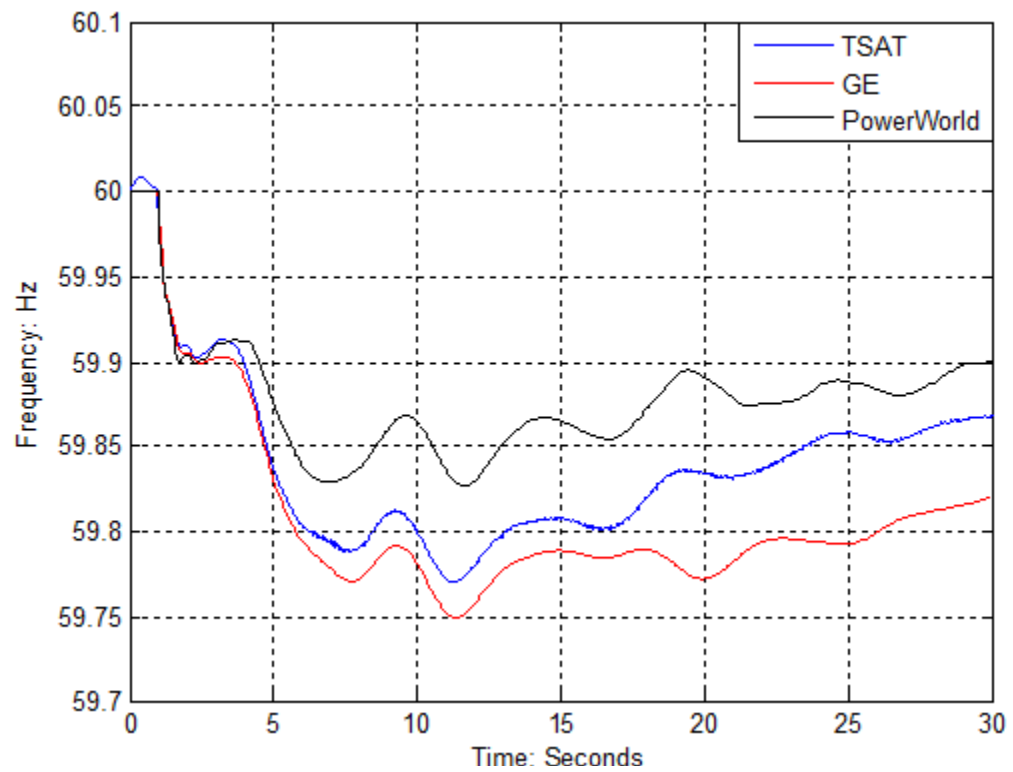
Figure 2.1(i): Frequency Response at bus 9
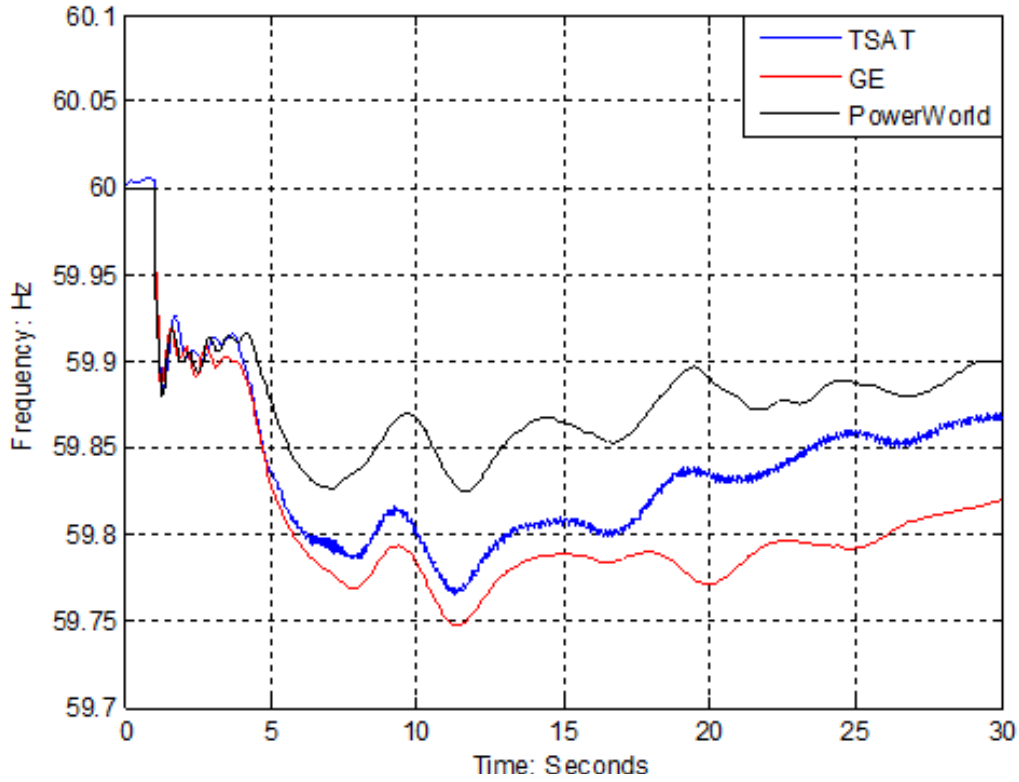
Figure 2.1(j): Frequency Response at bus 10

2.2 Reasons for Discrepancies

From these results, we tracked down the following reasons for the discrepancies:

1. We were able to determine that a bug in how the frequency deviations for the induction motor loads were being handled by PowerWorld was causing some of the frequency variation.
2. The oscillation in the PowerWorld frequencies at Bus 1 was tracked down to a model error. The model error was at some generators in the south-western part of the WECC system, associated with line drop compensation; fixed by auto-correction.
3. For the GENTPF generators, PowerWorld was not taking into account the frequency dependence of the direct and quadrature axis stator flux linkage values in the calculation of the Norton current.

2.3 Corrections and Improved Results

Following these findings, corrections were made to the PowerWorld code. With these changes, the net effect was that the PowerWorld results matched better with the TSAT results, previously being higher.

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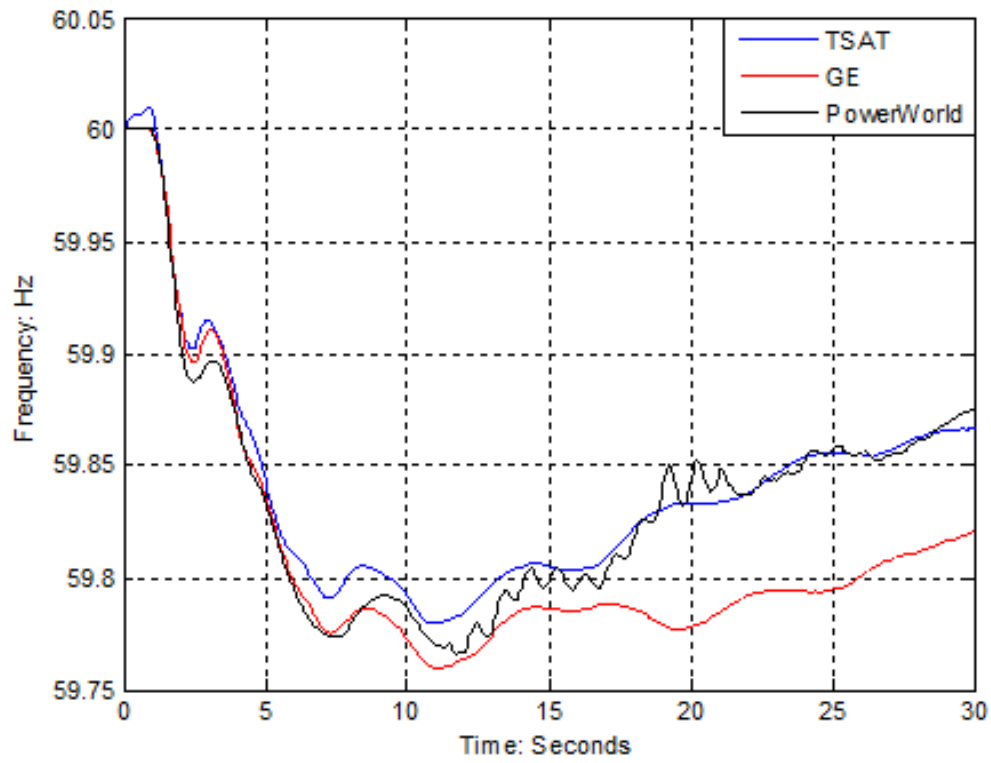
Figure 2.2(a): Corrected Frequency Response at bus 1
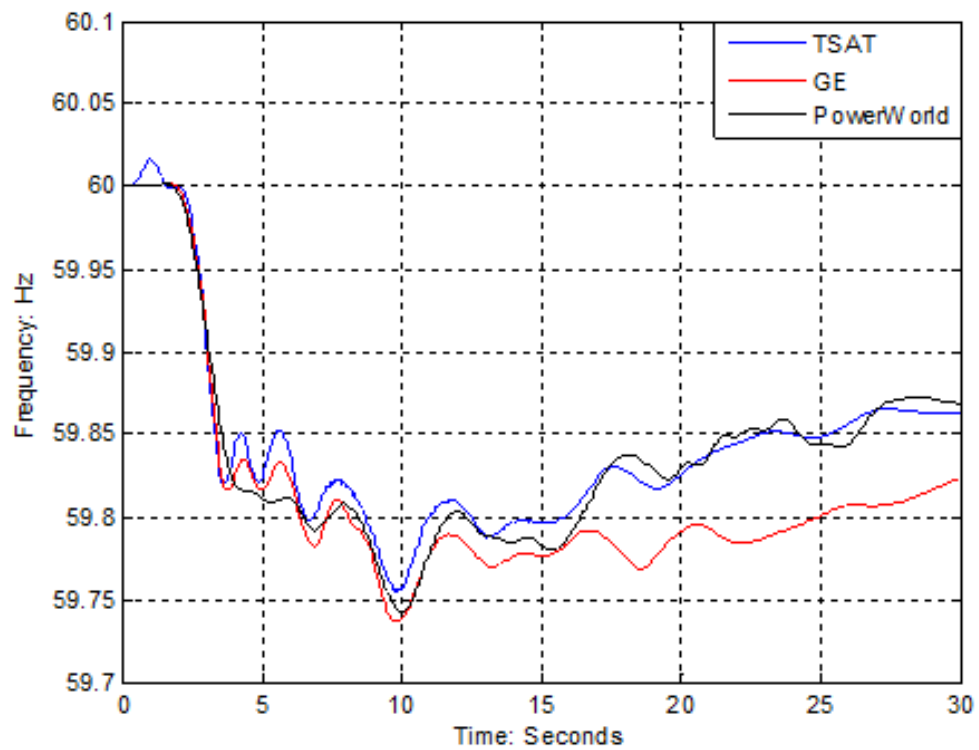
Figure 2.2(b): Corrected Frequency Response at bus 2
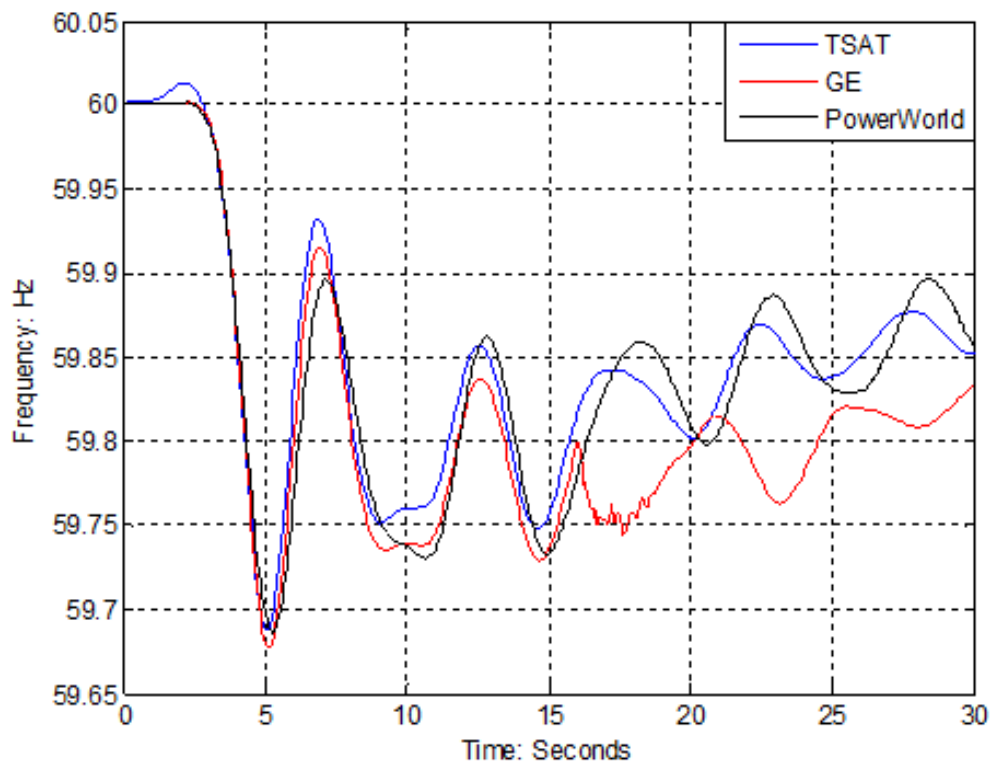
Figure 2.2(c): Corrected Frequency Response at bus 3
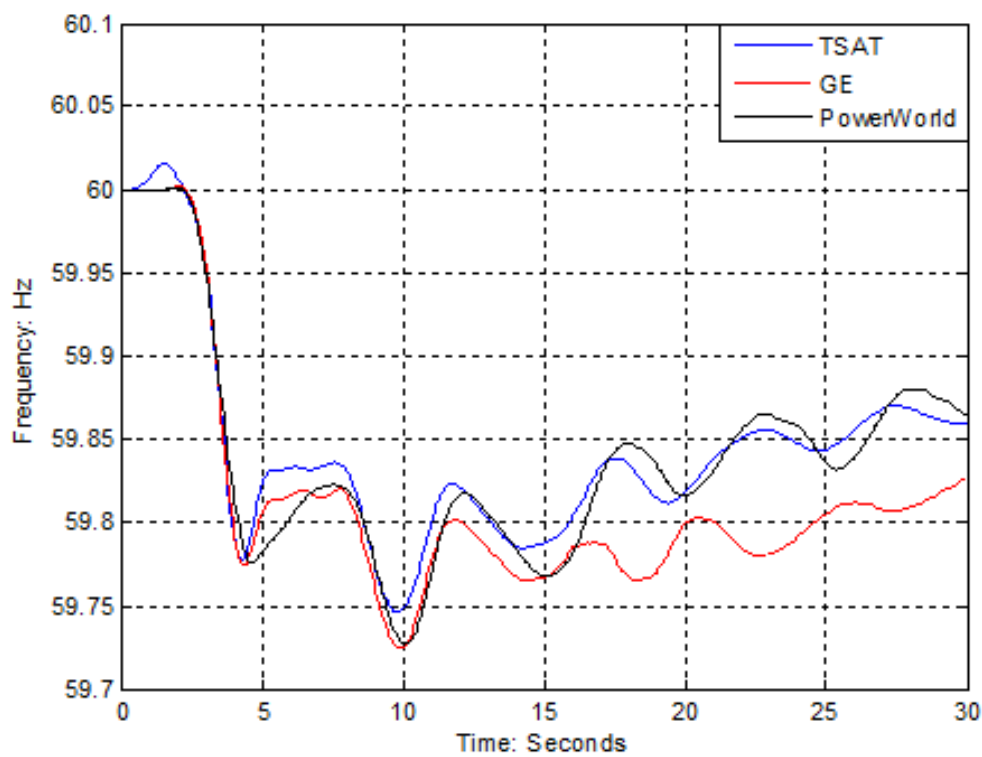
Figure 2.2(d): Corrected Frequency Response at bus 4

10
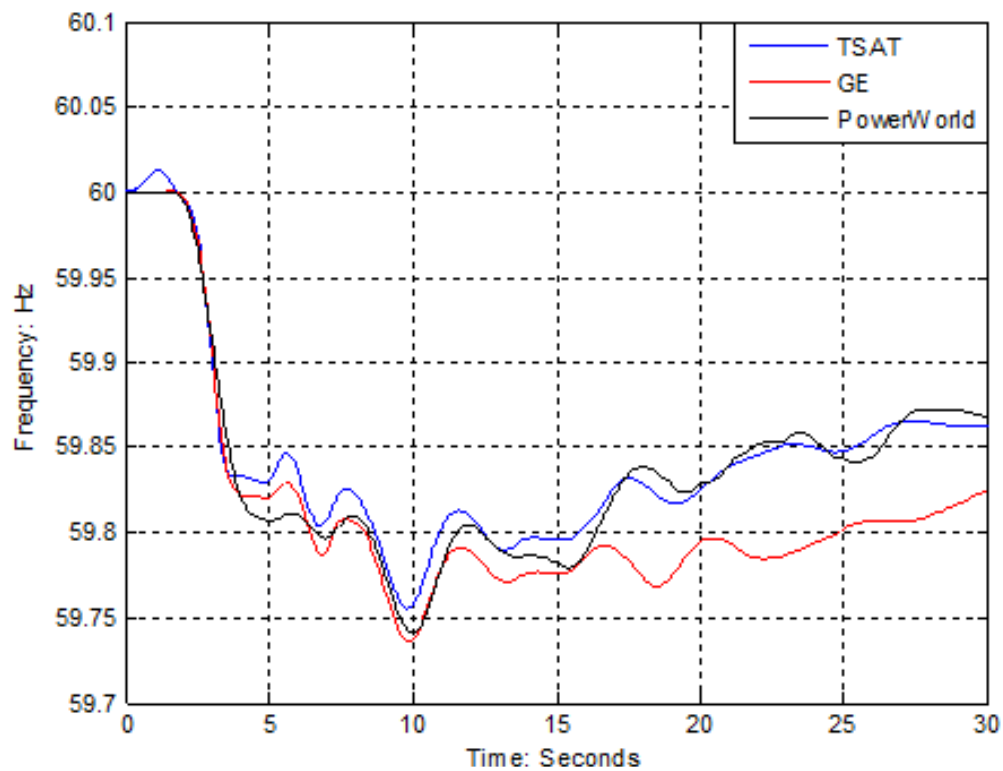
Figure 2.2(e): Corrected Frequency Response at bus 5
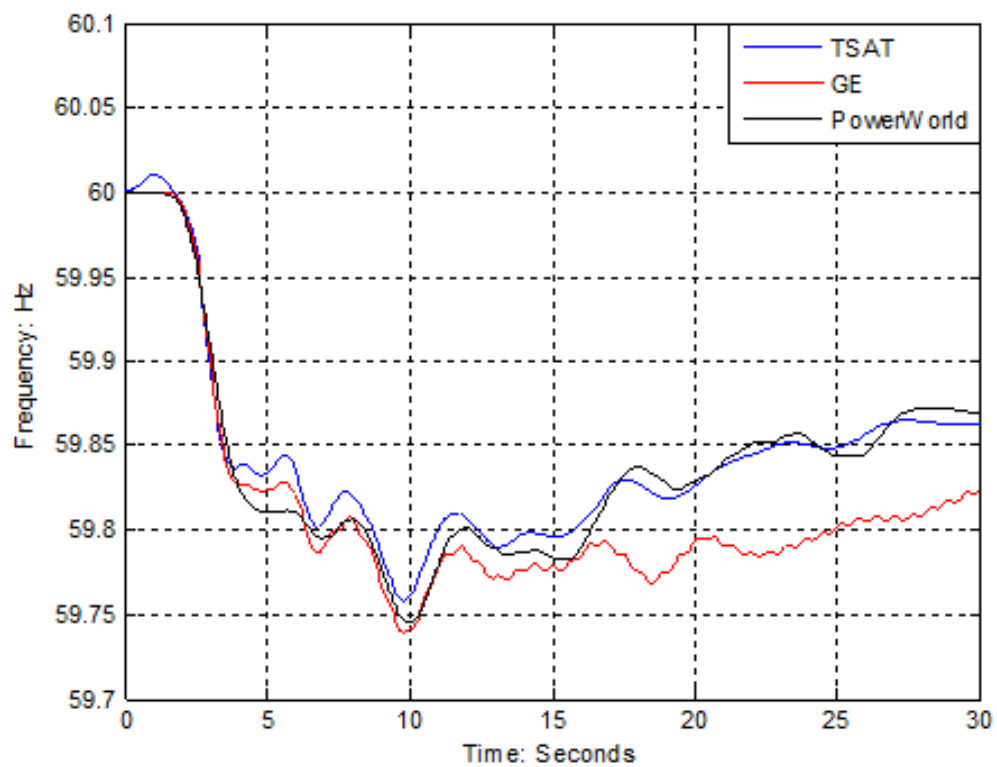
Figure 2.2(f): Corrected Frequency Response at bus 6

11
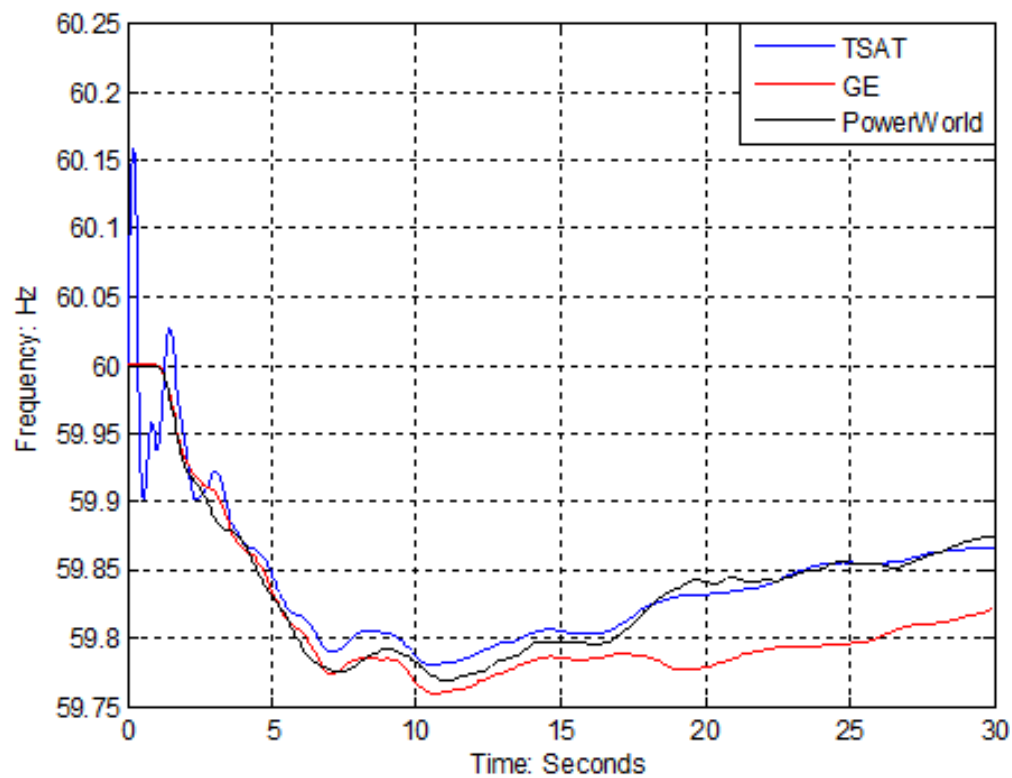
Figure 2.2(g): Corrected Frequency Response at bus 7
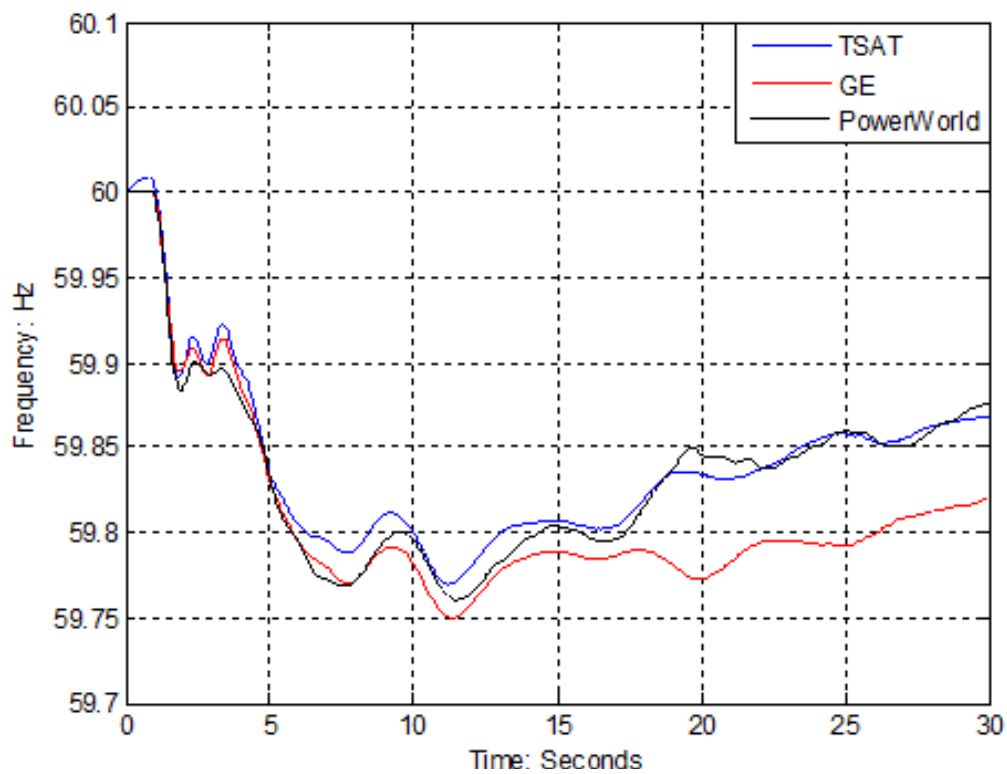
Figure 2.2(h): Corrected Frequency Response at bus 8
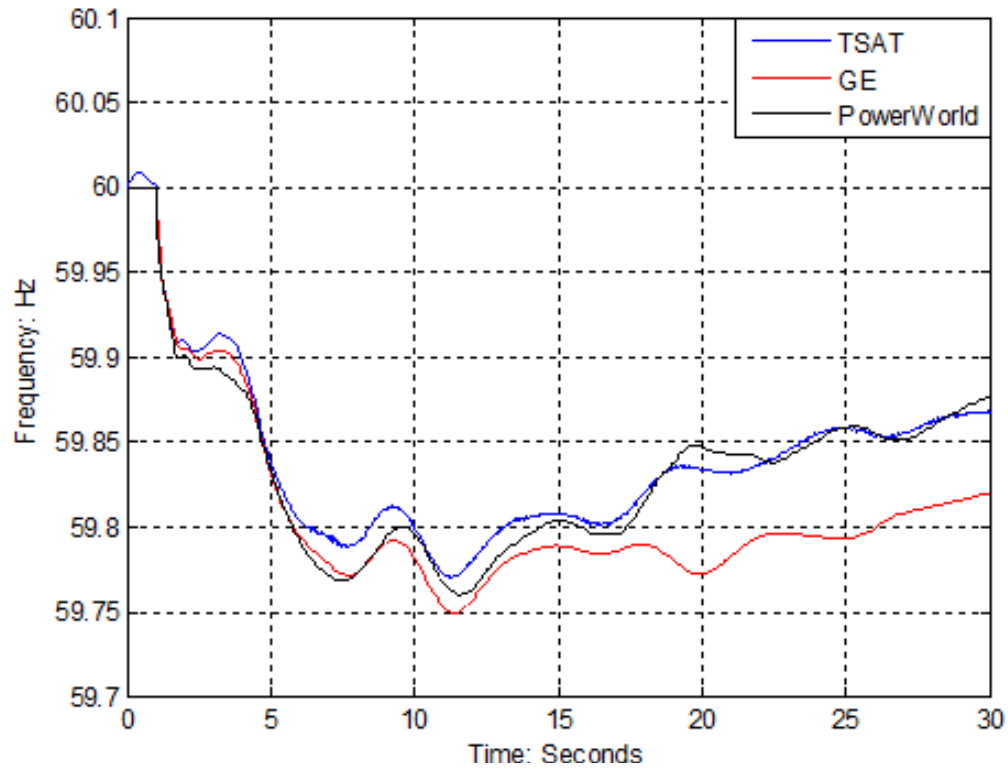
Figure 2.2(i): Corrected Frequency Response at bus 9
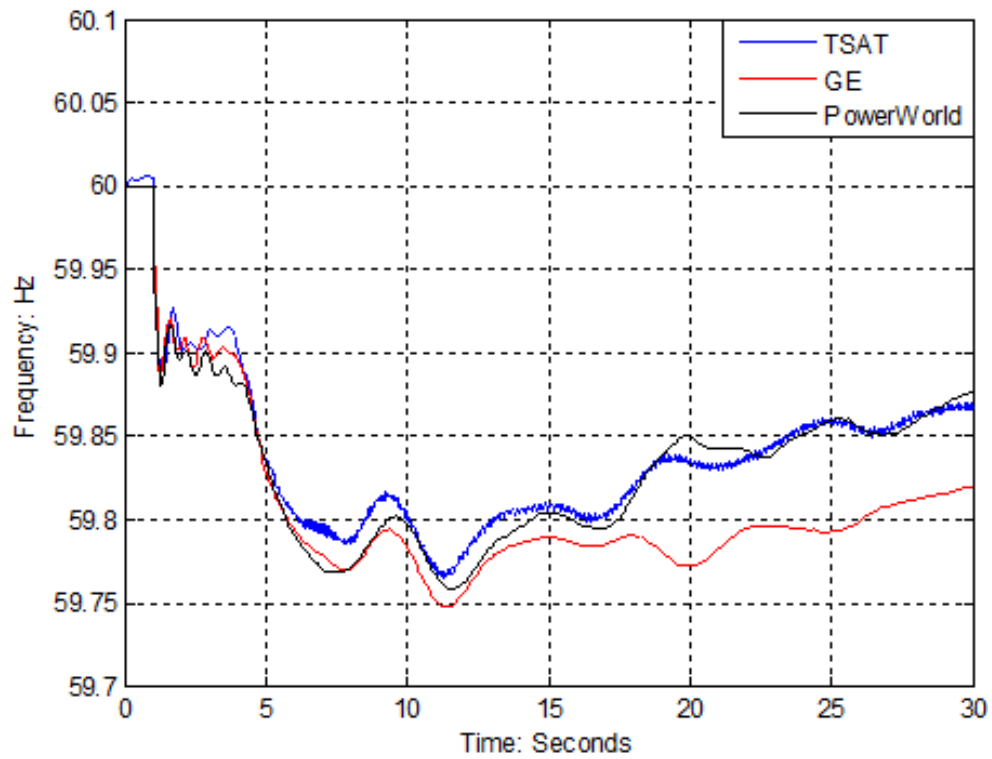
Figure 2.2(j): Corrected Frequency Response at bus 10

3. Detection and Correction of 'Bad' Data

3.1 Background

The 'Run Validation' option in the Transient Stability module of PowerWorld allows the user to check for any data imperfections prior to running a transient stability simulation. The 'Validation Errors' essentially are a list of parameters that depict non-physical scenarios or those which might cause the simulation to be numerically unstable or compromise accuracy. Suggestions for auto-correcting some of these parameters are made by PowerWorld, when these errors are encountered. Quite a few of such errors were found in the WECC full cases, which were reported to BPA. Detecting the errors thus made vast improvements in the WECC model. The following sections throw light on this detection and correction of 'bad' data.

3.2 Correction of Bad Saturation Data

Magnetic saturation affects the various mutual and leakage inductances within a machine, except the GENCLS model [2]. Saturation data for a machine is entered by specifying the values of two parameters S(1.0) and S(1.2), which are defined in Figure 3.1. It is a known fact that magnetic material saturates with higher flux. Therefore the value of S(1.2) can never be less than the value of S(1.0)

For WECC Case 2, the saturation data for about 28 generators failed to meet the criteria $S(1.2) >= S(1.0)$. This was detected in the PowerWorld validation run.

The suggested auto-correction was to swap the values of $S(1.0)$ with $S(1.2)$.

3.3 Machine Impedance Values

The validation of dynamics data associated with a particular model is important in our validation studies. For a Generator machine model, this data includes parameters such as inertia constant, stator resistance, transient and sub-transient reactances and time constants, saturation and impedance values of the compensation circuit (if applicable).

In the aforementioned WECC case, we also found some incorrect reactance values. For instance, we found for the following 75 generators, the stator leakage reactance X_l was more than the sub-transient direct or quadrature axis reactance, X_{dpp} or X_{qpp}. This is clearly not physically possible for a synchronous machine model, as explained in equation 4.41 of [1].

The figure shows a saturation curve with axis label $e_{to.c.} = E'_{qo.c} = \Psi''_{o.c}$ on the vertical axis and $L_{ad}I_{fd}$ on the horizontal axis, with the following equations:

$$S(1.2) = \frac{A_{1.2} - B_{1.2}}{B_{1.2}}$$

$$S(1.0) = \frac{A_{1.0} - B_{1.0}}{B_{1.0}}$$

Horizontal reference lines at 1.2 and 1.0. Vertical markers: $\frac{A_{1.0}}{B_{1.0}}$, $A_{1.0}$, $B_{1.0}$, $B_{1.2}$, $A_{1.2}$.
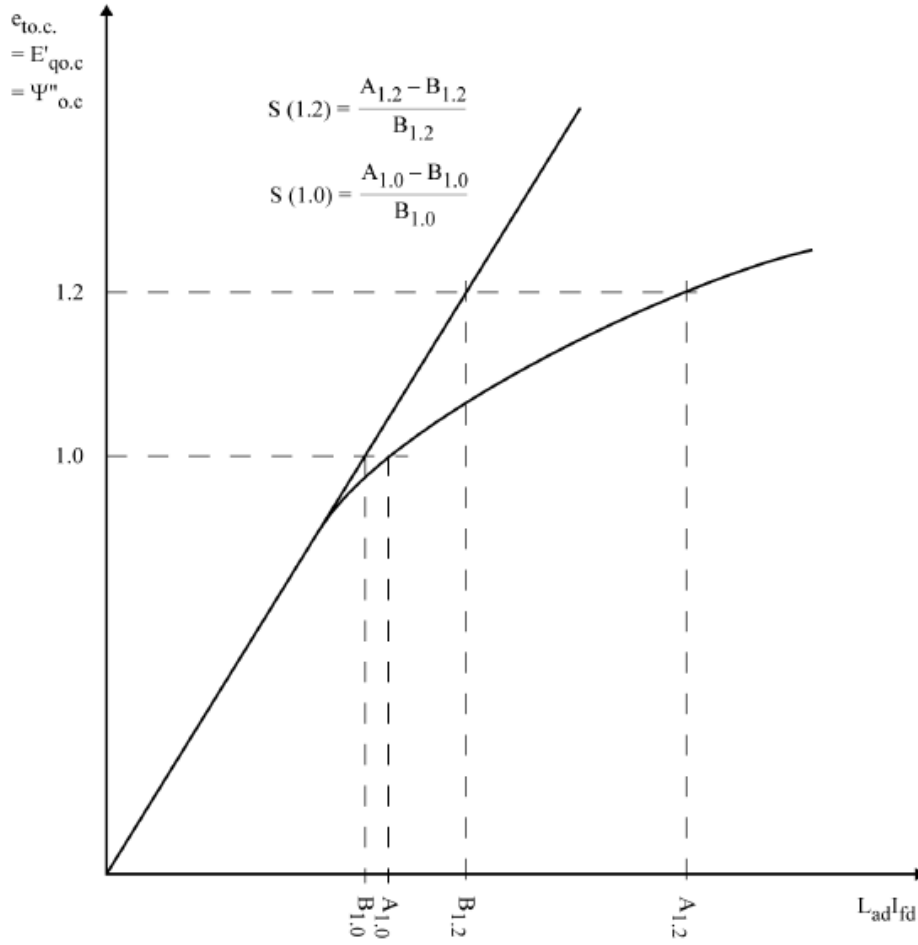
Figure 3.1: Definition of Saturation factor, S, for entry and Generator Data [2]

3.4 Correction of Time Constants

Setting the appropriate time step is important from the point of view of accuracy and numerical stability of the simulation. Time step is specified either in seconds or a fraction of one cycle. As recommended by BPA to follow the WECC standard, a time step of ¼ cycle has been used all throughout this project to conduct all the transient stability simulations.

From equations 12.3 to 12.7 of [2], it is clear that the numerical integration process in a dynamic simulation can be accurate and stable only if the time step Δt is small in comparison to the time constants used in the simulation; otherwise the integration process might develop an error that grows unstably [2].

PSSE uses the second order Euler scheme to perform numerical integration. From the experience of these transient stability package developers, it is indicated that numerical instability problems will be avoided and the accuracy will be sufficient if the time step is kept 1/4 to 1/5 times smaller than the shortest time constant being used in the simulation.

In the validation run, PowerWorld also detected some time constants that were not at least 4 times the time step Δt. These were reported as validation errors. The auto-correction converts these time constants to higher values to meet the criteria with reference to the time step size.

3.5 Correction of Dynamic Model Parameters

Besides machine model parameters, data errors were also found in the parameters of a particular governor model namely 1981 IEEE type 1 turbine-governor model or commonly known as IEEEG1.
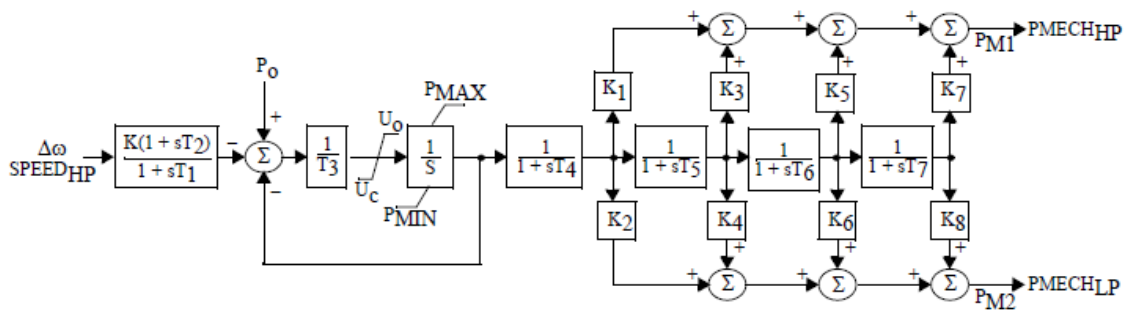
Figure 3.2: Block diagram of IEEEG1 as represented in [7]

Referring to Figure 3.2, for this governor model, the output of the integrator block is the total per unit mechanical power. This output gets multiplied by ($k1+k2+k3+k4$) which was found to be 20.216 in these four governors. This sets an unreasonably high upper limit on the mechanical power output of the generator. Therefore, ($k1+k2+k3+k4$) should be less than or equal to one. The governor outputs have an impact on the frequency response of the system.

These validation warnings and errors thus enabled us to suggest significant changes and improvements to the dynamic data of the WECC system, which is one of the important benefits of this work.

4. Validation and Debugging Process: Top-Down Approach

This section highlights how large case simulations can be used to detect potential analysis software problems. This example uses WECC Case 4. Again, the loss of generation in the southern part of the system was simulated here. The validation process was comparing the transient stability done by PowerWorld Simulator Version 16 (beta) with the PSLF transient stability (version 17) results provided by BPA. During the simulation the bus frequencies and voltages were modeled at 20 locations selected by BPA to give a representation for system behavior. For the simulations the system was initially allowed to run unperturbed for two seconds to demonstrate a stable initial contingency. Then the contingency was applied at time t = 2.0 seconds and the simulation run for a total of 30 seconds. In PowerWorld the simulation was run using a ½ cycle time step. The first two graphs show the bus frequencies and per unit voltage magnitudes at the selected buses.
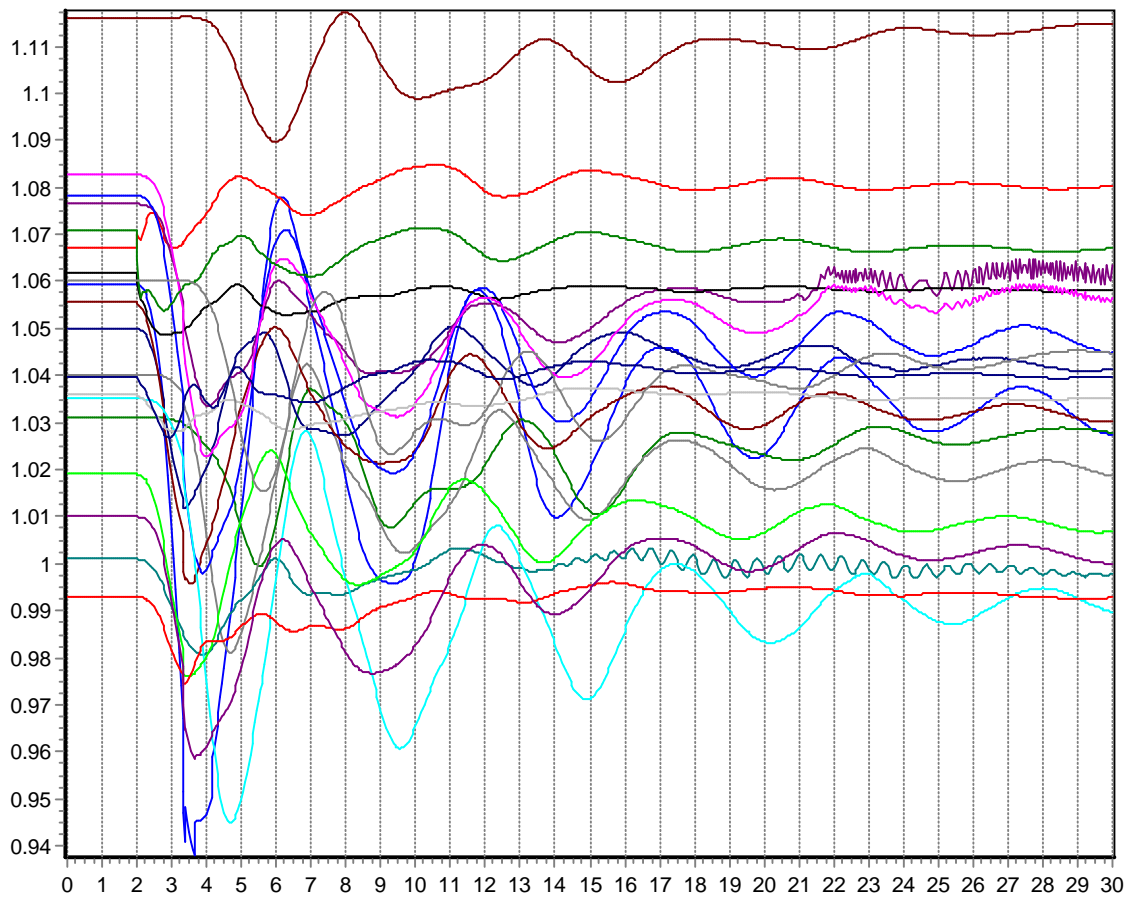
Figure 4.1: Initial Per Unit Bus Voltage Magnitudes for 30 Seconds
of Simulation in PowerWorld
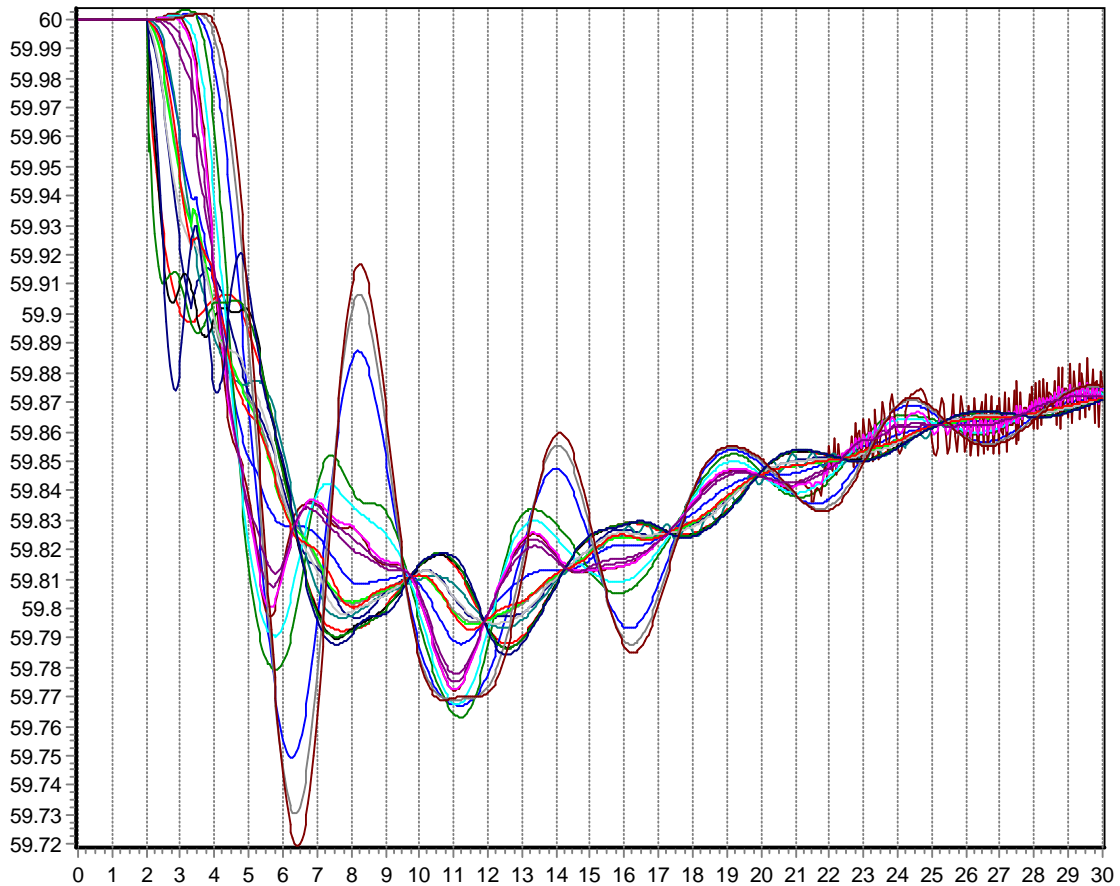
Figure 4.2: Initial Bus Frequencies for 30 Seconds of Simulation

Prominently visible in Figure 4.1 is the oscillation starting at about 13 seconds into the simulation. This example details how this anomaly was used to help validate and improve the software. Given that this oscillation did not appear in any of the other voltage magnitude plots, it appears to be an isolated issue. Using the plotting tool's interactive features, the associated bus is immediately identified as Bus 11. However, the cause is unlikely to be at that bus.

The next step in the validation is to determine whether this oscillation also occurs in the PSLF results. Figure 4.3 compares the voltage magnitude at this bus for the two simulations. Clearly the results differ, but most germane here is the oscillation does not appear with PSLF. So the focus is to determine what is causing the oscillation in PowerWorld. Switching from the plotting tool, to the detailed results showing the voltages at all the buses, isolated plots can be quickly created.
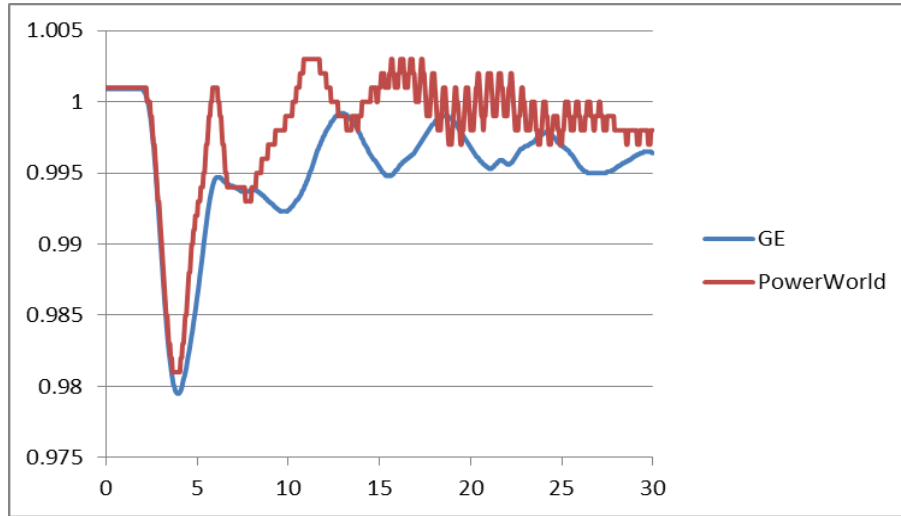
Figure 4.3: Comparison of GE-PSLF and PowerWorld Results
for Voltage Magnitude at Bus 11

Figure 4.4 shows a plot of the voltage at bus 11. Since this is a high voltage bus with no generation, the cause of the oscillations is not at that. One approach to tracking down the source of the oscillations is to look at first neighbor buses so see which have larger or smaller oscillations. This is done in the next three figures (Figures 4.5(a) to 4.5(c)) for the three first neighbor buses. In this case the oscillation appears to be in the direction of 12, which is joined to 11 through three low impedance branches, and not in the direction of the other two branches, which have relatively higher impedances. The process is then repeated for the neighbors of 11, with the highest shown in Figure 4.6 for bus 15. Repeating one last time results in the likely sources of the oscillations, two near identical generators at buses 16 and 17 (the voltage at 16 is shown in Figure 4.7).
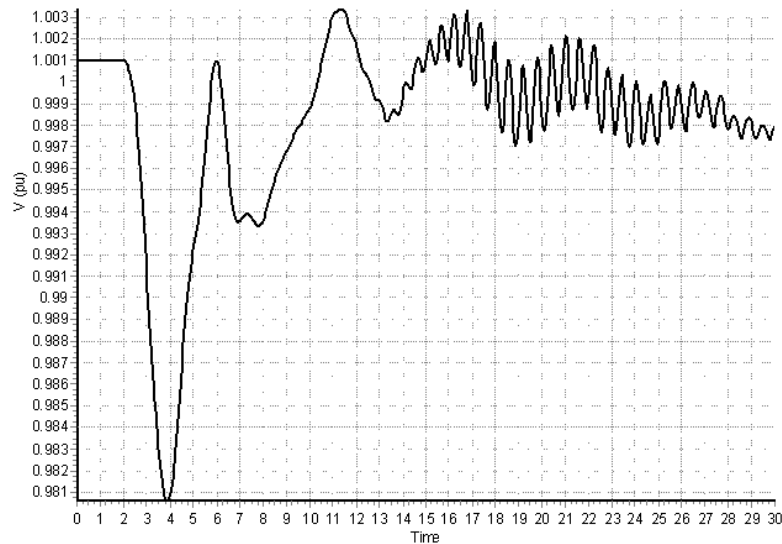
Figure 4.4:"Quick" Plot of Voltage Magnitude at Just Bus 11.

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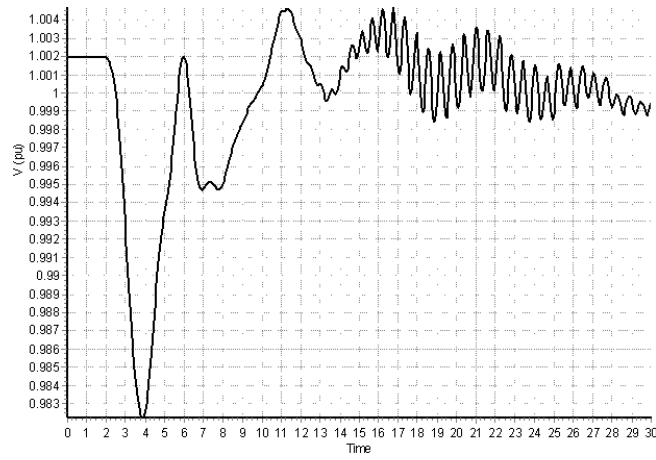
Figure 4.5 (a): Quick Plot of Voltage Magnitude at First Neighbor Bus 12
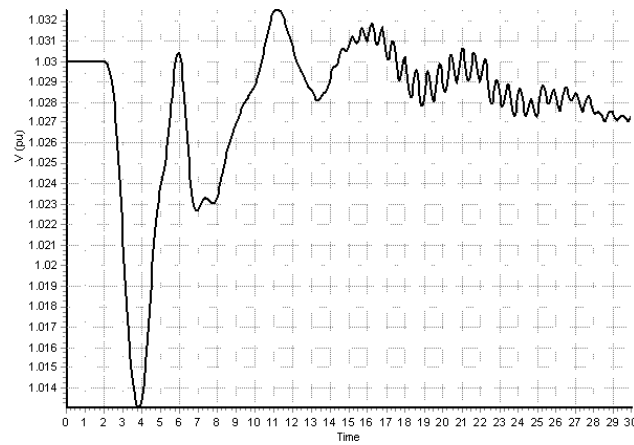
Figure 4.5(b): "Quick" Plot of Voltage Magnitude at 1st Neighbor Bus 13.
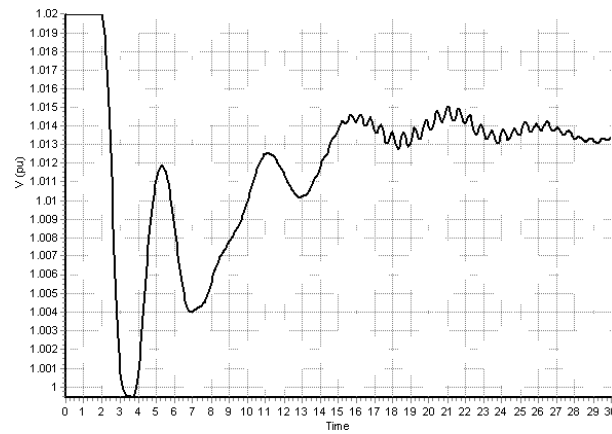
Figure 4.5(c): "Quick" Plot of the Voltage Magnitude at 1st Neighbor Bus 14

20
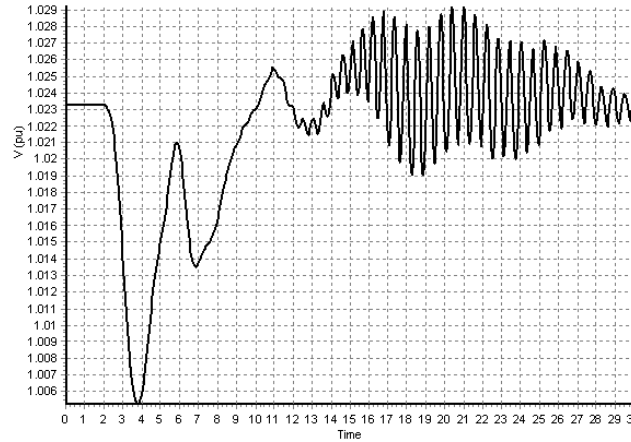
Figure 4.6: "Quick" Plot of the Voltage Magnitude at Second Neighbor Bus 15
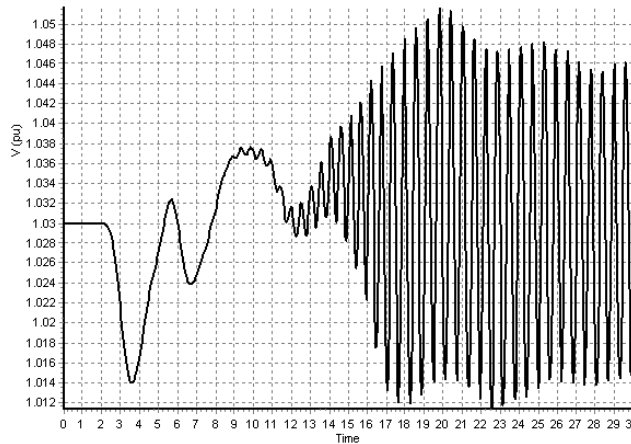
Figure 4.7: "Quick" Plot of the Voltage Magnitude at Generator Bus 16.
(Note the Change in Y-axis Scaling from the Earlier Plots)

An alternative process, is to utilize the single-machine, infinite bus (SMIB) eigenvalue analysis process to see if there are any generators with positive eigenvalues in the vicinity of bus 11. For this example this process worked quite quickly since there were only two Generators in the same area as 11 with positive eigenvalues, 16 and 17.

Regardless of process, once the problem generator(s) has been identified, the next step is to determine the reason for the unexpected behavior. A useful approach is to create a two bus equivalent consisting of the desired generator supplying an infinite bus through its driving point impedance. PowerWorld software allows this to be done in an automated process. Once the two bus equivalent is created a balanced three phase fault is placed on the terminals of the generator at time t=1.0 seconds for 3 cycles to perturb the system. This provides an initial assessment of the stability of the generator, and probably a confirmation of the eigenvalue results. Figure 4.8 plots the generator's field voltage for this scenario. Clearly the generator is not stable. This result also helps to validate the

eigenvalue analysis since the unstable eigenvalue had a damped frequency of 1.86 Hz, very close to what is shown in the figure.
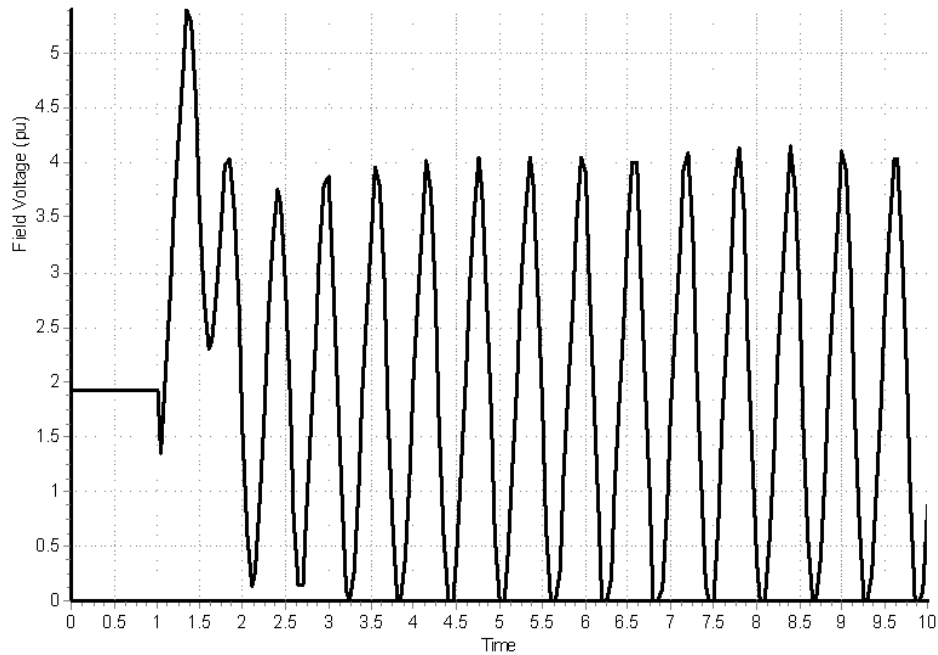
Figure 4.8: Generator 16 Field Voltage for Two Bus Equivalent Fault Scenario

The next step of the process is to determine whether the reason for the unstable results is an input data issue or associated with how the generator's models are represented in PowerWorld. This process is greatly facilitated by working with a two bus equivalent, as opposed to the entire 17,000 bus WECC case. Disabling the stabilizer gives a stable result, indicating the issue is probably with the stabilizer model – Figure 4.9 shows the generator's field voltage when the stabilizer is disabled.
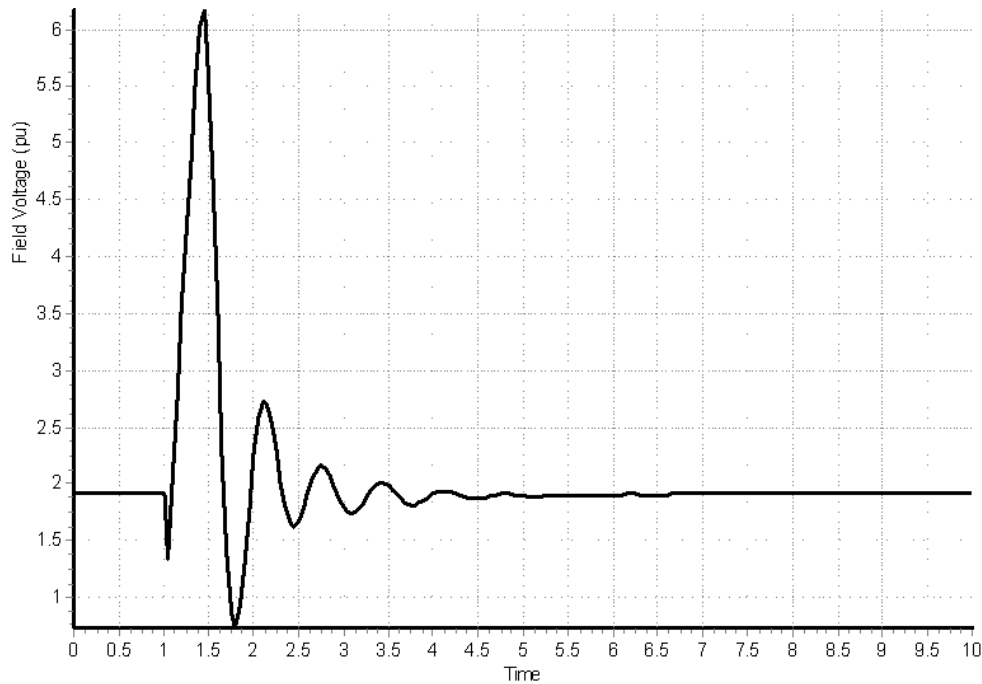
Figure 4.9: Generator 16 Field Voltage for Two Bus Equivalent Fault Scenario with the Stabilizer Disabled

Determining the exact cause of the instability is then a bit of a trial and error process, primarily through modifying parameters to see which have the most impact on the result. Another useful step is to verify that the parameters in the two bus model actually match those in the original PSLF *.dyd file. These values might be different because 1) an error with the input process or 2) modification by the "auto correction" during the model validation process that automatically occurs before the case is simulated.

For this example the problem was actually due to too "aggressive" auto correction of the stabilizer parameters. These generators use PSS2A stabilizer models, with the block diagram shown in Figure 4.10. For numerical stability reasons, as is common with other transient stability packages, PowerWorld was "auto-correcting" the denominator terms in the lead-lag blocks if the values were less than 4 times the time step (1/2 cycle in this case). Autocorrected values were either rounded up to 4 times the time step of 0.0333 seconds or down to zero. In comparing the values in the original *.dyd file, T2 was being changed from 0.025 to 0.0333 while T4 was being changed from 0.016 to 0.0 (which bypassed that lead-lag since anytime the denominator in a lead-lag is zero, the numerator term must also be set to zero).

Stabilizer PSS2A
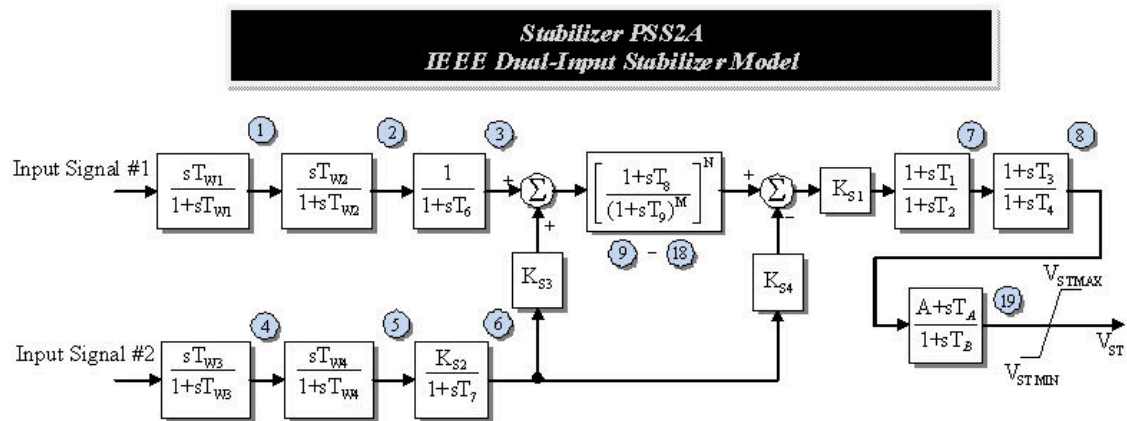
Figure 4.10: Block Diagram for PSS2A Stabilizer Model Used at Generators 16 and 17

Using the two bus equivalent the original values were restored and tested. This gives the stable results shown in Figure 4.11. PowerWorld Corporation was notified of this issue, and as a result the validation code for all the stabilizers was modified to be less aggressive. In cases in which lead-lag denominator time constants were small, multirate integration techniques are used. Given that the WECC case has more than 1000 stabilizers, this change actually affected 1226 separate parameter values, allowing the entered values to be retained. The results of the 30 second simulation for the full WECC Case 4 with these changes are shown in Figures 4.12(a) and 4.12(b). We notice that the oscillations at bus 11 are now gone.
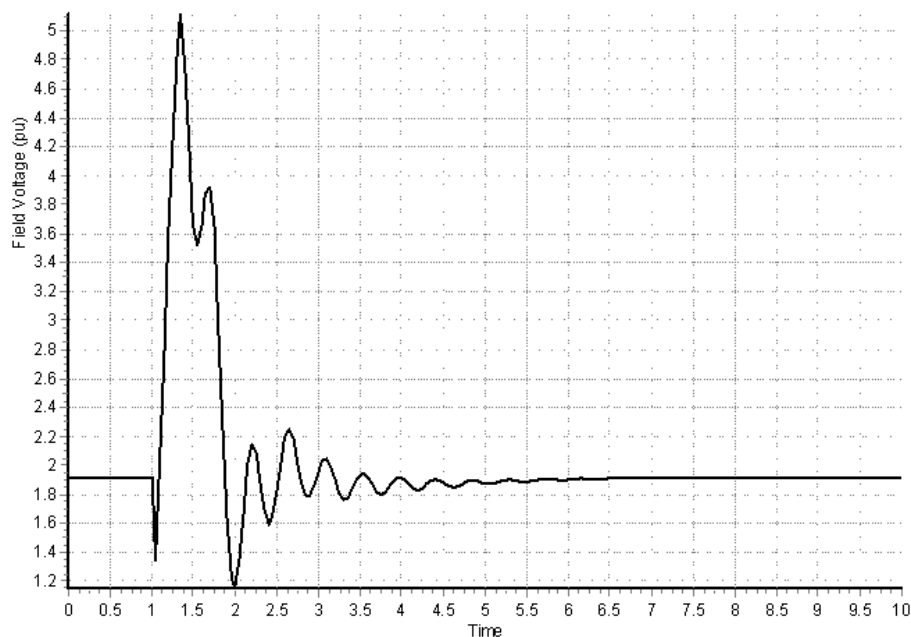
Figure 4.11: Generator 16 Field Voltage with Stabilizer Parameters
Returned to Original Value
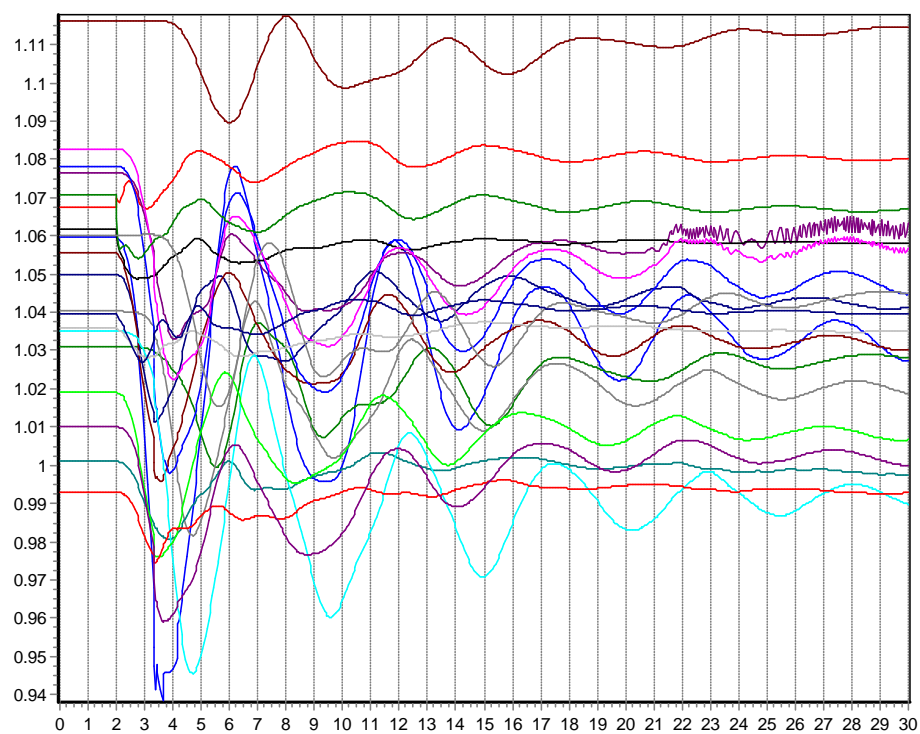
Figure 4.12(a): Corrected WECC Case Per Unit Bus Voltage Magnitudes for 30 Seconds of Simulation
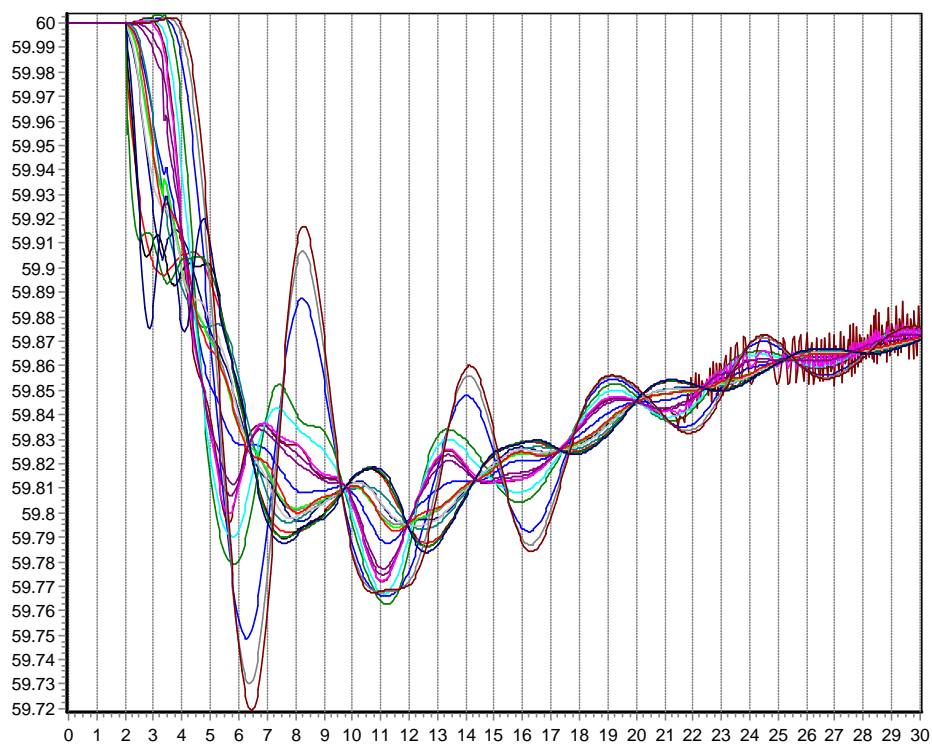
Figure 4.12(b): Corrected WECC Case Bus Frequencies for 30 Seconds of Simulation

However, it is also readily apparent in both Figures 4.12(a) and 4.12(b) that there are some other oscillations occurring. Using a similar process to what was done previously, the bus with the most prominent oscillations was identified as being 18. A comparison between the PowerWorld and PSLF results was then developed, with the comparisons for frequency and voltage shown in Figures 4.13(a) and 4.13(b). Two things are noteworthy about this plot. First, while there are certainly some differences, the overall the shape of both the frequency and voltage curves is fairly similar. They start at the same values (dictated by the power flow solution), reach almost the same low values, recover at about the same rate, and return to about the same value thirty second value. Second, both packages show oscillations in the vicinity of this bus, so the issue is probably model related.
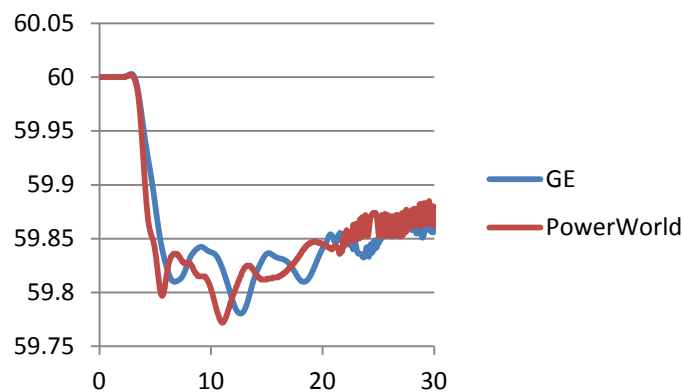
Figure 4.13(a): Comparison of GE-PSLF and PowerWorld Results for Frequency at Bus 18
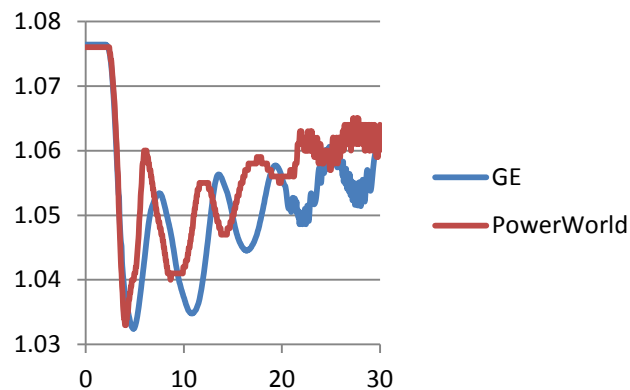
Figure 4.13(b): Comparison of GE-PSLF and PowerWorld Results for Voltage Magnitude at Bus 18

In this case the "guilty" generator was identified by looking at the bus min/max voltage summary display. For each bus in the system this display shows the highest and lowest voltage magnitudes obtained during the study for each bus in the system. Bus 19 was

found to have by far the lowest voltage of 0.2404 per unit. The generator could also have been identified through eigenvalue analysis (it has a positive eigenvalue), or by tracing the magnitude of the oscillations (more tedious though since it is seven buses away from the bus 18 monitored bus). Figure 40 shows a plot of the Bus 4.14 voltage magnitude.
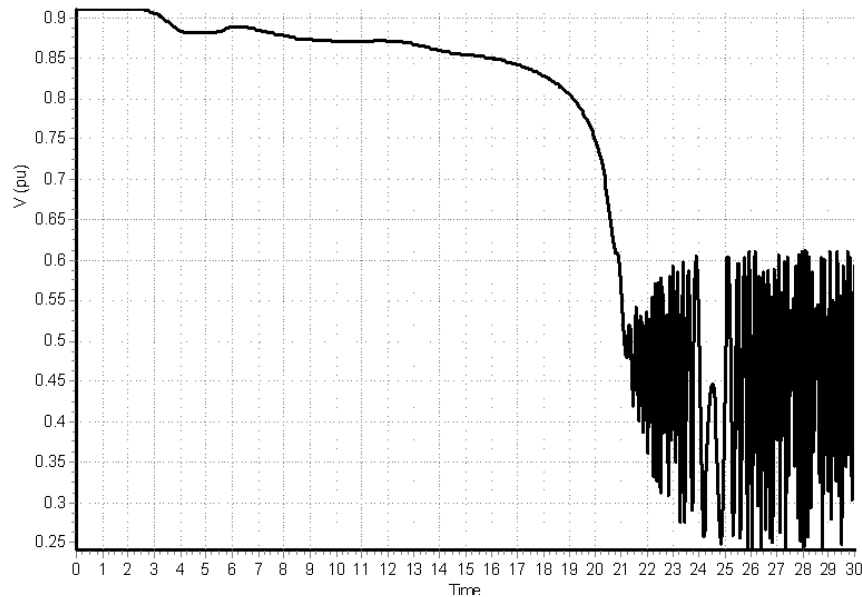
Figure 4.14: Bus 19 Bus Voltage Magnitude Results

By again creating a two bus equivalent tracking down the reason for the voltage oscillations was straightforward. Bus 19 is modeled with a GENTPF machine model (a two-axis generator model that allows for subtransient saliency) but without an exciter model; it also had a GGOV1 governor model. In the two bus equivalent this generator is unstable with or without the GGOV1 model. The reason is in the power flow the generator's setpoint voltage of 1.0 per unit (for a remote bus) was quite low, causing it to operate at its lower reactive power limit of -20Mvars. The generator becomes stable when its reactive power output is increased to about -15 Mvars. This was confirmed by re-running the WECC Case 4 with the 19 voltage setpoint increased from 1.0 to 1.02 per unit (which corresponds to a Generator output of -4.4 Mvar), with the voltage results shown in Figure 4.15. Note, in the WECC Case 2 that was tested the 19 voltage setpoint was 1.03 per unit.

From the point of view of validation, we note that both PSLF and PowerWorld appeared to correctly model the Bus 19 generator instability. One really can't expect accuracy for such an unusual operating condition in which the voltages are below 0.5 per unit. The issue with this generator was actually first detected in PowerWorld by looking at the event log following a simulation. By default PowerWorld trips generators if their frequencies exceed a frequency threshold (by default either above 62.4 Hz or below 57.6 Hz for two seconds). This generic protection was disabled since there did not appear to be any default protection in the GE run.
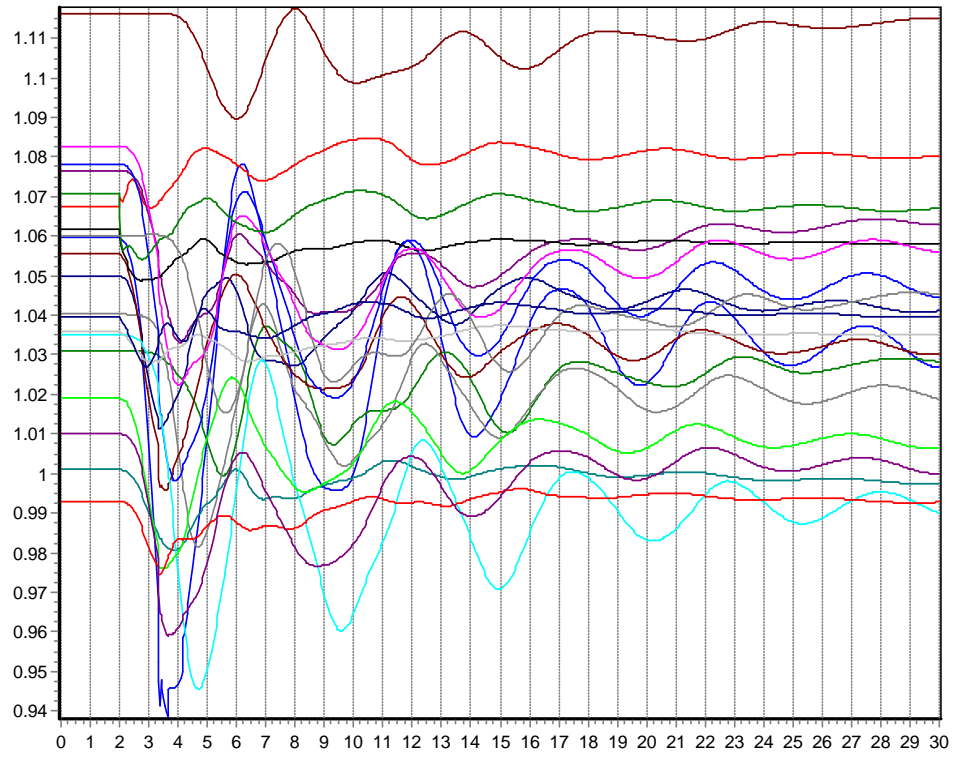
Figure 4.15: WECC Bus Voltages with Generator Voltage Setpoint Modified at Bus 19

Thus, this example highlights the significance of tracking down the cause of discrepancies between results obtained for the full 17,000 bus case from different packages by analyzing single-machine infinite bus cases of the dynamic models.

5. Validation using Single Machine Infinite Bus Equivalents/Bottom-Up Approach

5.1 Background

WECC case has a total of 17,709 models in 77 model types. But the 20 most common model types contain 15,949 (90%) of these models. These are the key focus areas for the bottom-up analysis which are discussed in the following sections.

5.2 Machine Model Validation

In WECC Case 4, there are a total of 3308 machine models in the whole system. Of these, a summary of the major models, by count, is given below.

Table 5.1: Summary of major machine models in use in WECC Case 4

Name	GENROU	GENSAL	GENTPF	GENCC	GENTPJ	GEWTG	MOTOR1
Count	1194	1091	780	56	30	47	73

It is evident that the models GENROU, GENSAL and GENTPF each account for nearly one-third of the total machine models. Hence validating these key models will certainly have a big impact in providing validation of the generators in the WECC system.

5.2.1 GENROU – Round Rotor Generator Model with Quadratic Saturation
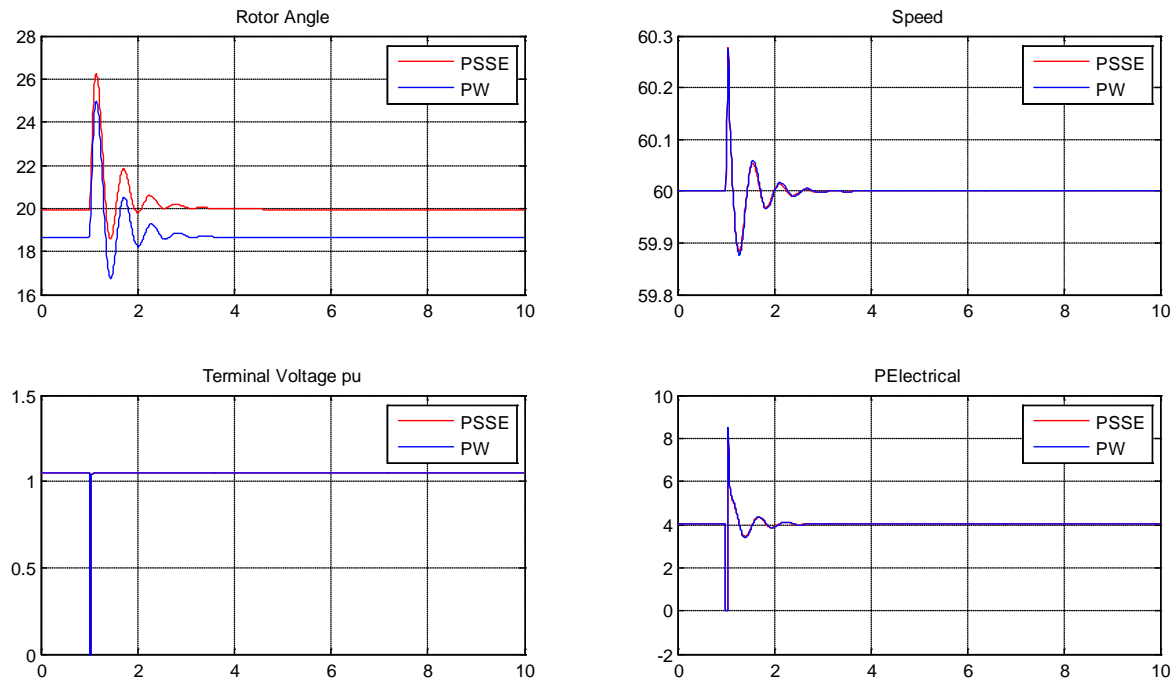
Figure 5.1: Comparisons between Rotor Angle, Frequency, Terminal Voltage and Machine Electrical Power for SMIB equivalent Gen. 1, Bus 20

Figure 5.1 shows the comparison between PowerWorld and PSSE results on a single machine infinite bus equivalent case obtained from WECC Case 1, at the bus 20, generator 1. A solid three-phase balanced fault was applied at t = 1 sec at this bus, which was self-cleared in 0.05 sec. Thereafter the response is shown for 10 seconds. A time step of ½ cycle was used.

The rotor angle comparison clearly points to an issue in the initialization process. To get to the root of this, we explored another more publicly available example referring to Figure 5.2, obtained from [2] used for basic dynamic simulation studies.
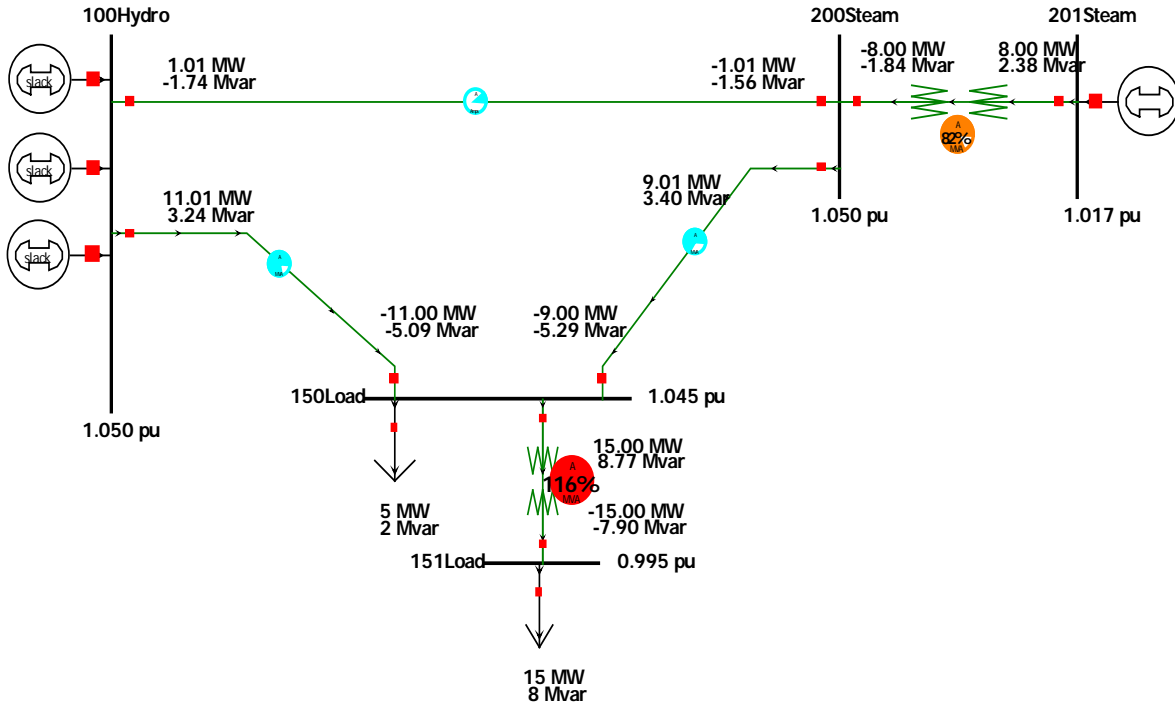
Figure 5.2: Five Bus Example System

The Generator at bus 201 steam has a GENROU model for the purpose of our study. We compared the initialization of states for the GENROU model in PowerWorld and PSSE and the following results were obtained. Initialization is more challenging when saturation in included in the machine model, so we studied the system for different values of saturation. The results are shown for a fixed value of $S(1.0) = 0.03$ with increasing values of $S(1.2)$. Table 5.2 represents the PSSE results and table 5.3 gives PowerWorld results.

Table 5.2: Initialization of GENROU model states at bus 201 Steam of the 5 bus case in PSSE for different saturation levels

S(1.2) →	S(1.2) = 0.4	S(1.2) = 1.0	S(1.2) = 2.0
STATES ↓			
Eqp	1.014	1.028	1.045
Edp	0.3086	0.2704	0.2195
PsiDp	0.8830	0.9000	0.9212
PsiQpp	0.5553	0.5273	0.4894
Δspeed (p.u.)	0	0	0
Angle (radians)	0.6980	0.666	0.6250

Table 5.3: Initialization of GENROU model states at bus 201 Steam of the 5 bus case in PowerWorld for different saturation levels

S(1.2) →	S(1.2) = 0.4	S(1.2) = 1.0	S(1.2) = 2.0
STATES ↓			
Eqp	1.0152	1.0299	1.0478
Edp	0.3061	0.2651	0.2099
PsiDp	0.8842	0.9023	0.9249
PsiQpp	0.5535	0.5234	0.4822
Δspeed (p.u.)	0	0	0
Angle (radians)	0.6959	0.6623	0.6172

This process enabled us to conclude that the issues lie at the very initialization itself. These discrepancies were reported to PowerWorld. The issue that was tracked down was that the non-linear (quadratic) initialization equations for GENROU to account for generator saturation were not being solved appropriately. This was corrected, the software was updated and the results were validated, as shown in Table 5.4

Table 5.4: 'Corrected' Initialization of GENROU model states at bus 201 Steam of the 5 bus case in PW for different saturation levels

S(1.2) →	S(1.2) = 0.4	S(1.2) = 1.0	S(1.2) = 2.0
STATES ↓			
Eqp	1.014	1.028	1.045
Edp	0.3086	0.2704	0.2195
PsiDp	0.883	0.900	0.9212
PsiQpp	0.5553	0.5273	0.4894
Δspeed (p.u.)	0	0	0
Angle (radians)	0.698	0.666	0.6250

The updated PowerWorld software was then used to simulate the two-bus system for the bus 20 to yield validated results as in Figure 5.3
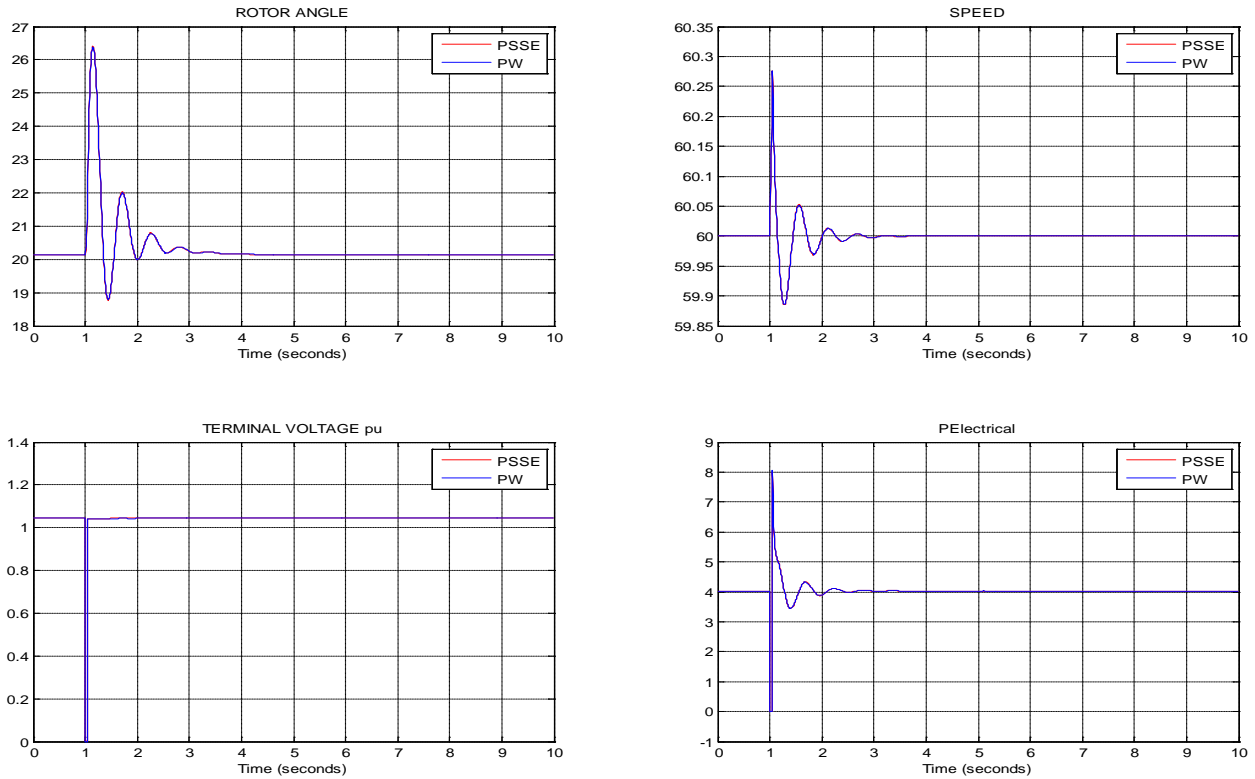
Figure 5.3: 'Corrected' Comparisons between Rotor Angle, Frequency, Terminal Voltage and Machine Electrical Power for SMIB equivalent Gen1, Bus 20

5.2.2 GENSAL – Salient Pole Generator Model with Quadratic Saturation on d-Axis

To validate this model, another two-bus equivalent was created at the bus 21, generator 1, from WECC Case 2. In addition to the machine model, the generator here also has an exciter model of the type ESAC8B. A solid three-phase balanced fault was applied at t = 1 sec at this bus, which was self-cleared in 0.05 sec. Thereafter the response is shown for 10 seconds. A time step of ½ cycle was used. The preliminary comparisons are given in Figure 5.4

Looking at these results initially, it is not trivial to figure out whether the issue lies in the machine model or the exciter or both. An important aspect of our methodology has been to break down the problem to the individual components to check for discrepancies and then add these components back until the problem is encountered again. We therefore repeated this comparison with the exciter model disabled. The results are shown in Figure 5.5.
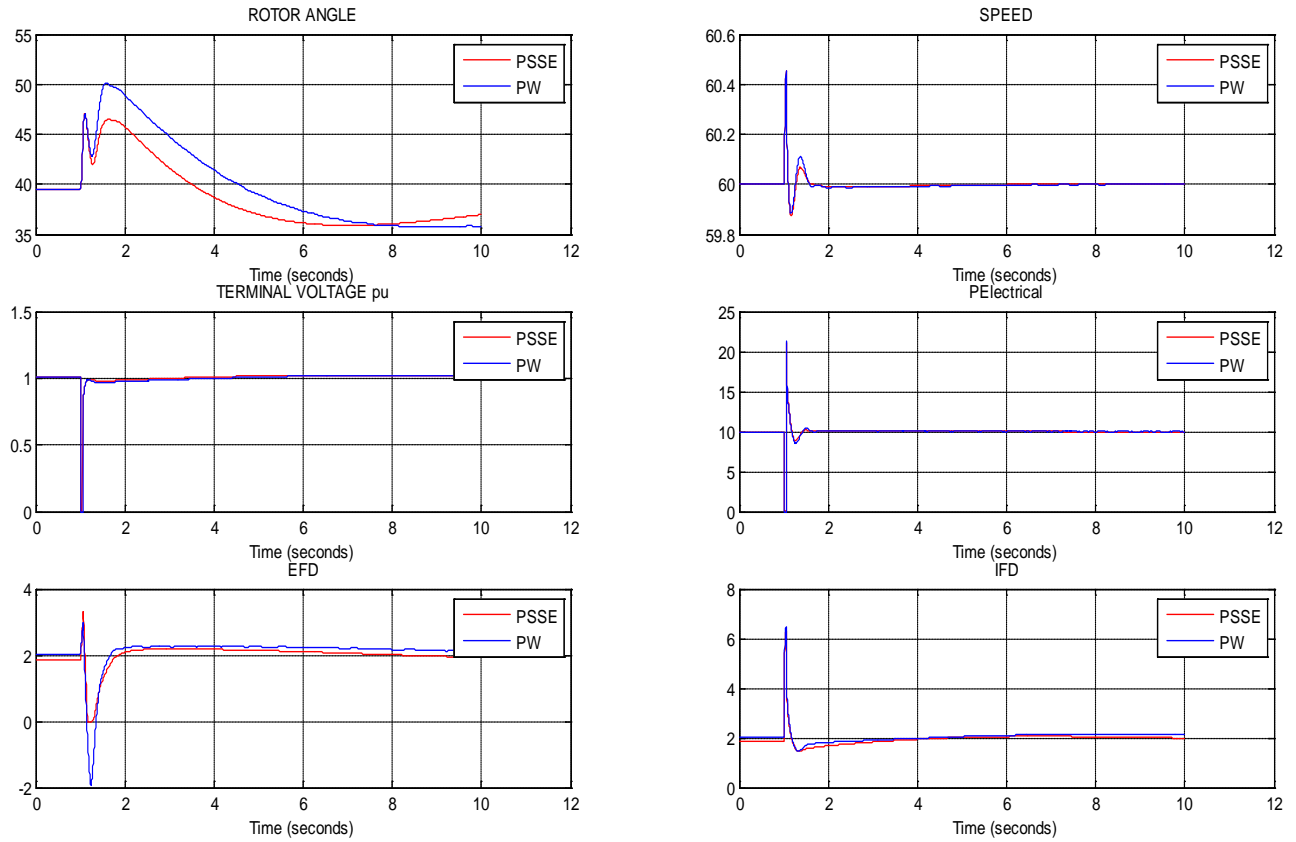
Figure 5.4: Comparison of Rotor Angle, Speed, Terminal Voltage, Electrical Power, Field Voltage (EFD) and Field Current (IFD) for the SMIB case GEn1, Bus 21

By disabling the exciter we were able to determine that there were inherent issues in both the GENSAL and ESAC8B model. The process of debugging the ESAC8B results will be discussed in the next section. Now, we focus on the GENSAL model. From Figure 5.5, it is clear that the initialization of the field voltages (EFD) is discrepant.
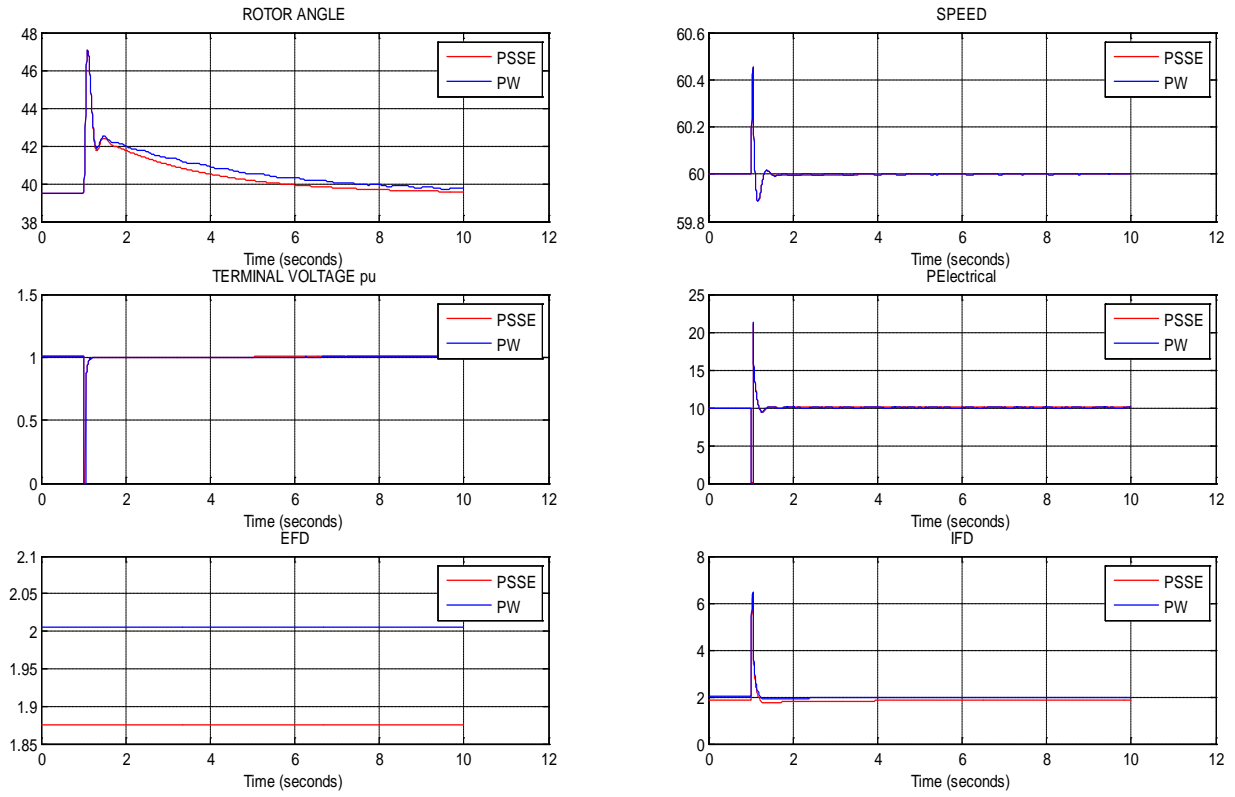
Figure 5.5: Comparison of Rotor Angle, Speed, Terminal Voltage, Electrical Power, Field Voltage (EFD) and Field Current (IFD) for the SMIB case at bus 21, gen 1 with the exciter disabled
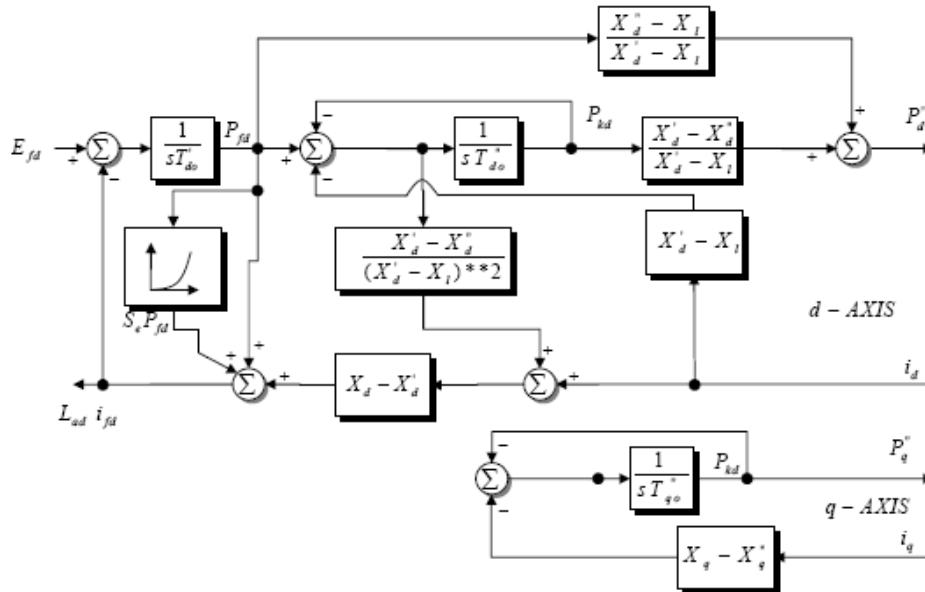
Figure 5.6 : Block diagram of GENSAL model as represented in [7]

34

PowerWorld looked into this and found that the saturation S_e was being directly fed as an input to the field current instead of it being multiplied by the state P_{fd} as is depicted in Figure 5.6. After these corrections, the EFD initializations were now agreeing with each other, as per Figure 5.7
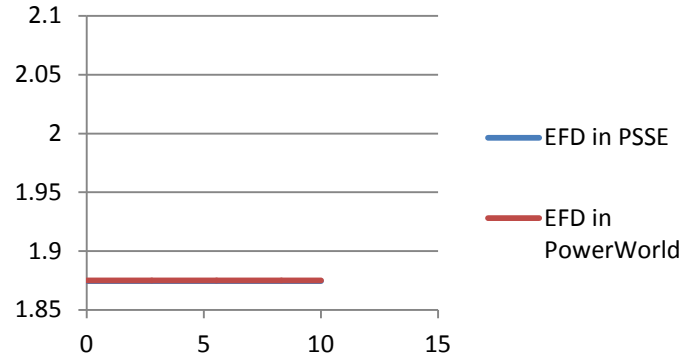
Figure 5.7: 'Corrected' comparison of Field Voltages for the SMIB equivalent of bus 21, gen1 with the exciter disabled

5.2.3 GENTPF
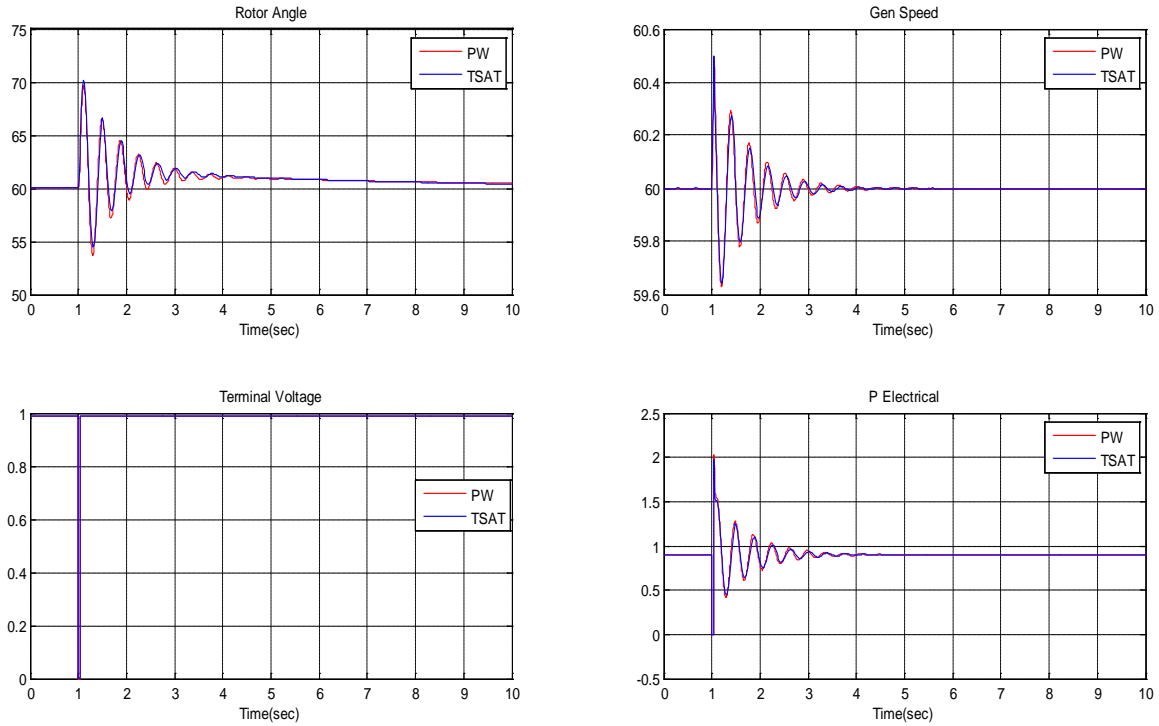
Figure 5.8: Validated Results for GENTPF model for the SMIB case at bus 24

The SMIB equivalent created at generator bus 24 was used here. It consists of a GENTPF model only. Again, a solid three-phase balanced fault was applied at $t = 1$ second for 0.05 seconds. The validation of this model was quite straightforward and the corresponding results are given in Figure 5.8

With the validation of GENROU, GENSAL and GENTPF models, we have thus successfully validated 90% of all the generator models in the WECC system.

5.3   Exciter Model Validation

In WECC Case 4, there are a total of 2763 exciter models in the whole system. Of these, a summary of the major models, by count, is given below.

Table 5.5: Summary of the major exciter models in use in WECC Case 4

Name	EXST1	EXST4B	EXAC1	EXDC1	EXAC8B	REXS
Count	869	357	149	288	166	231

It is important to note here that these models are GE-PSLF models as the base case was derived from *.epc and *.dyd files. There are subtle differences in the names and implementations of these models in PSLF and PSSE. Therefore to perform validation studies using PSSE, we had to convert some of these models in their PSSE 'equivalent' models. For instance EXAC8B in PSLF is modeled under the name AC8B in PSSE. A WECC approved list of these equivalencies is given in [3].

5.3.1 ESAC8B – Basler DECS model

Referring to the SMIB case for the Generator bus 21 discussed in the GENSAL validation process. We concluded that there were some discrepancies in the exciter behavior as well.

Figure 5.9: Block Diagram of exciter model ESAC8B as represented in PSSE [7]

Referring to Figure 5.9, the issue was found to be due to the fact that PowerWorld wasn't enforcing the lower limit of 0 in the integration process to calculate EFD. Figure 5.10 shows the

validation of PowerWorld results with PSSE, in a subsequent version of the PowerWorld software. As we see, the revised PowerWorld results now perfectly match the PSSE results.
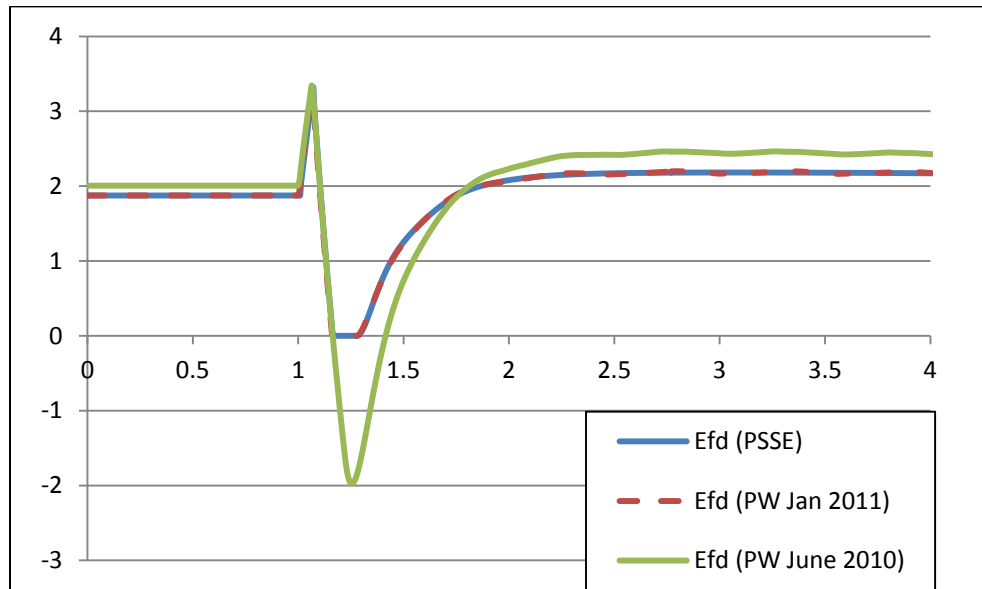
Figure 5.10: Comparison of EFD values of SMIB case at bus 21, gen 1 between different versions of PowerWorld and PSSE

5.3.2 Exciter Saturation Modeling

One of the most significant findings in the process of validating excitation system models was that of the existence of three different saturation functions being used to model exciters.

Table 5.6: Types of saturation functions modeled in different packages for excitation systems

Type of Saturation Model	Function	Software
Quadratic	$S(x) = B(x - A)^2$	GE GE
Scaled Quadratic	$S(x) = B(x - A)^2 / x$	PTI PSS/E
Exponential	$S(x) = B \exp(A*x)$	BPA IPF

Initially, PowerWorld was following BPA's convention of saturation modeling. However, from our benchmarking studies, we discovered these other two methods used in PSLF and PSSE. These options have been added to PowerWorld to aid the validation process with other packages.
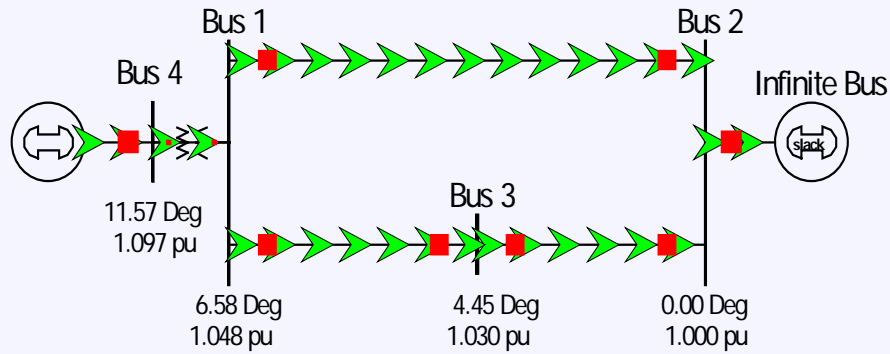
Figure 5.11: Example 4 bus single-machine infinite bus case with GENROU and IEEE
Type 1 Exciter (IEET1) at Bus 4

The case depicted in Figure 5.11 was used to study the impact of different types of exciter
saturation modeling on the system behavior, mainly the field voltage. A solid three-phase
balanced fault was applied at t = 1 sec at bus 4, which was self-cleared in 0.05 sec. Thereafter
the response is shown for 10 seconds. A time step of 1/4 cycle was used. Figure 5.12 illustrates
these differences.
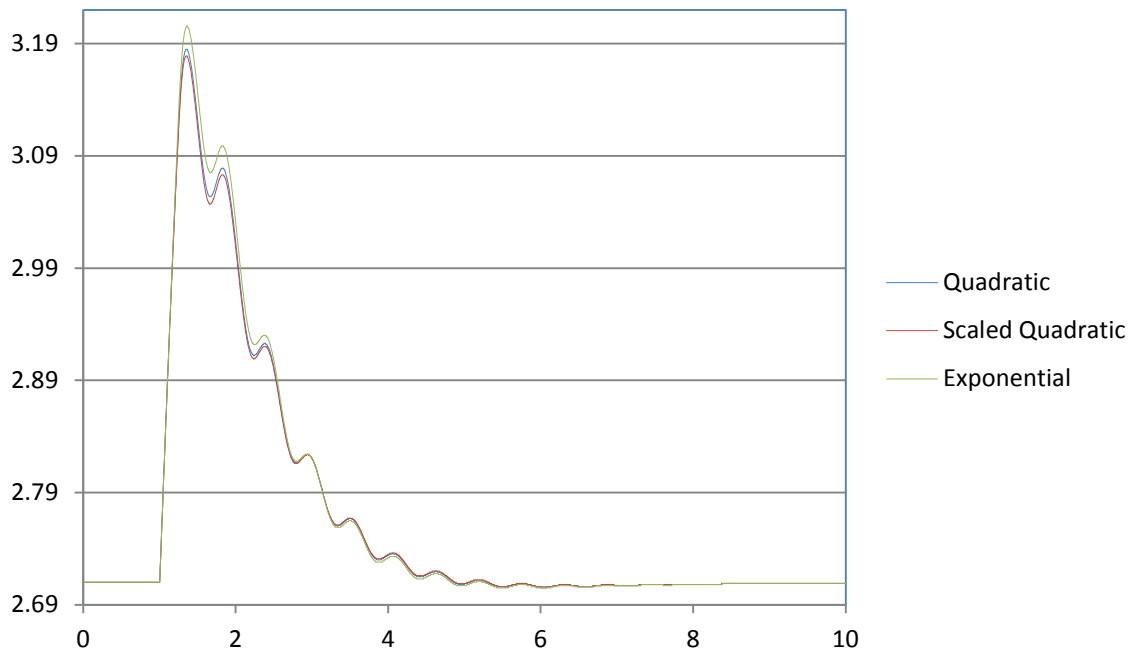
Figure 5.12: Field voltages for different exciter saturation models for the case
shown in Figure 5.11

5.3.3 EXAC1 – IEEE Type AC1 Excitation System

This model was validated by creating a SMIB equivalent at the bus 22, Generator 1. This generator has a GENROU machine model. The advantage of having the machine models validated before is that now the discrepancies, if any, can be attributed to the added component i.e. the exciter. A solid three-phase balanced fault was applied at t = 1 sec at the generator bus, which was self-cleared in 0.05 sec. Thereafter the response is shown for 10 seconds. A time step of 1/4 cycle was used. Figure 5.13 represents the first results obtained for this comparison.
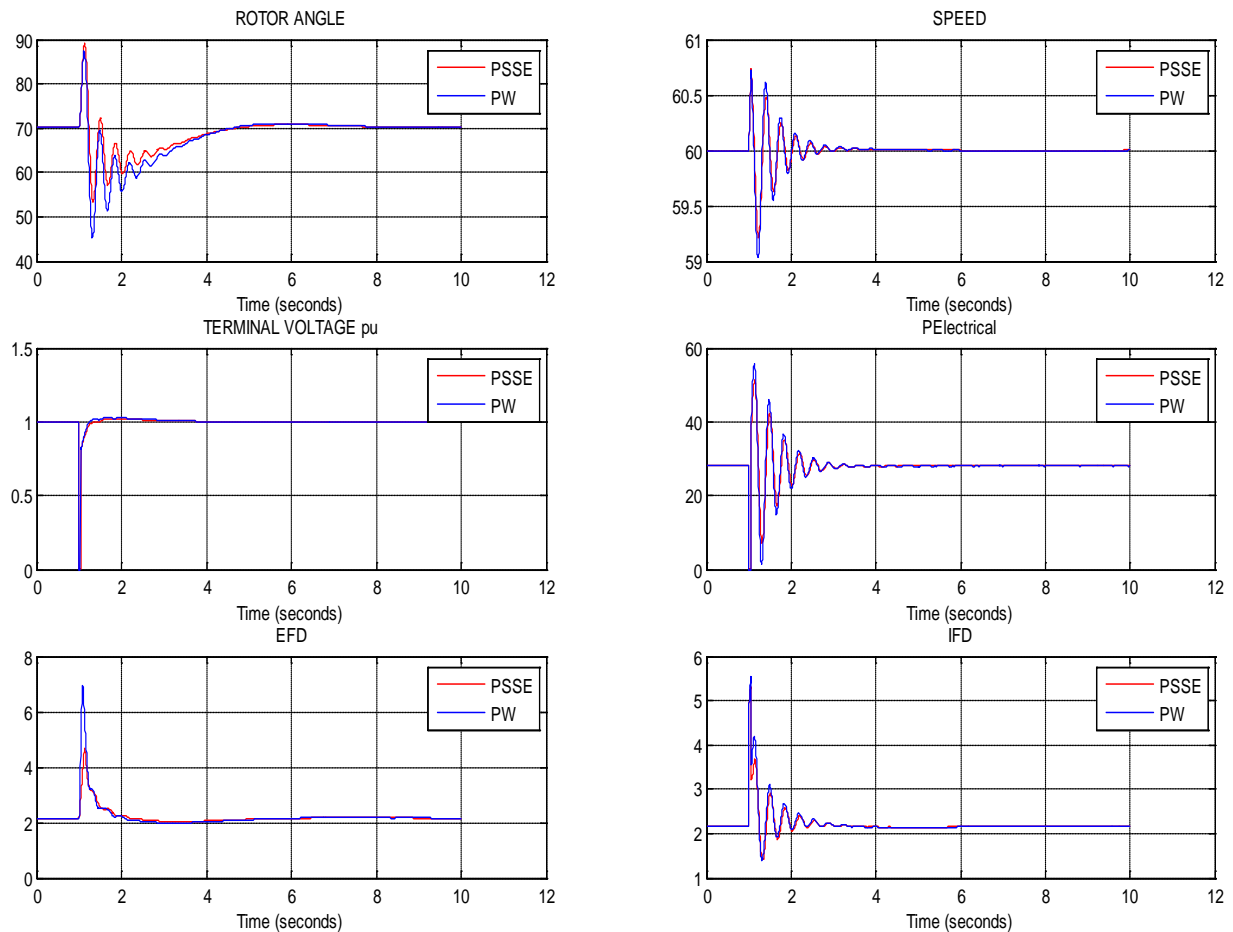
Figure 5.13: Comparison of results between PowerWorld and PSSE
for SMIB case at bus 22, gen1

One can quickly make out the gross error in the field voltage values and also the error in the rotor angle.
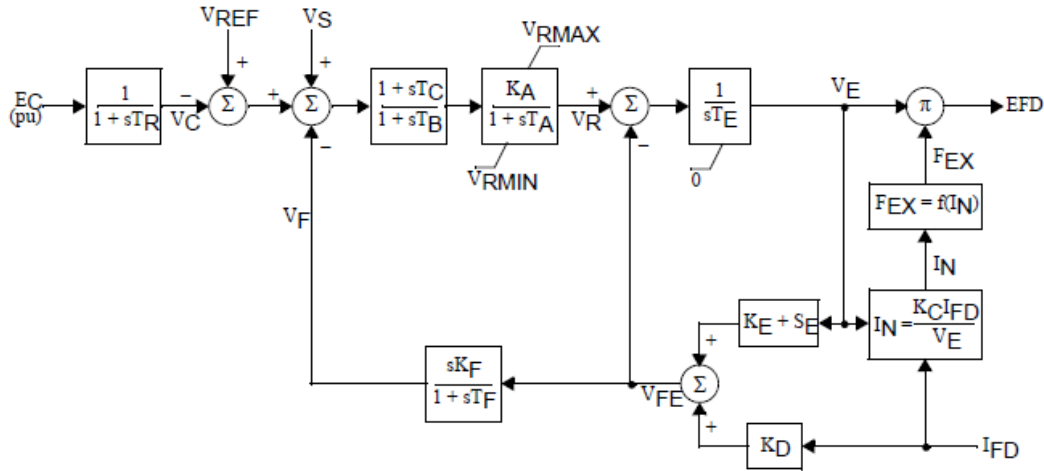
Figure 5.14: Block diagram on EXAC1 exciter in PSSE [7]

The debugging process followed from Figure 5.14 was as described ahead. In this SMIB case, for the exciter, the *Kc* parameter was zero. This means that *In* is always zero, meaning that *fEx* is always 1. Hence EFD is always equal to *Ve*. Since *Te* = 1 in this case, the derivative of *Ve* is just *Vr – Vfe*. This *Vr* has minimum and maximum limits which cap the response for Vr. The issue here was that *Ve* was rising too quickly in PowerWorld. We then numerically estimated the rate of change in *Ve* for the PSSE results. Since *Vrmax* = 24, the rate of change of *Ve* in PSSE which was 20 or 21 looked correct owing to the fact that the derivative is (*Vr – Vfe*), *Vr* rapidly rises to its maximum during the fault and *Vfe* is a positive value. In PowerWorld, the rate of change of *Ve* was found to be much higher. This pointed out to an error in the integration process for this exciter in PowerWorld. Subsequent changes were made to the PowerWorld program and this exciter was thus validated. Figures 5.15(a) and 5.15(b) show the corrected values of the rotor angle and field voltages respectively.
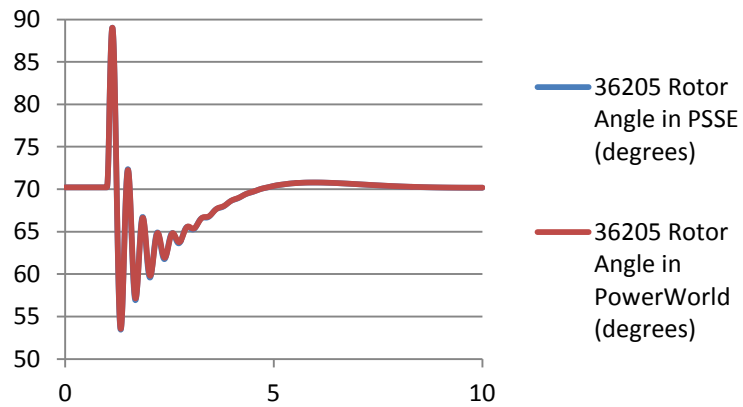
Figure 5.15(a): 'Corrected' Rotor Angles for the SMIB case at bus 22, gen1
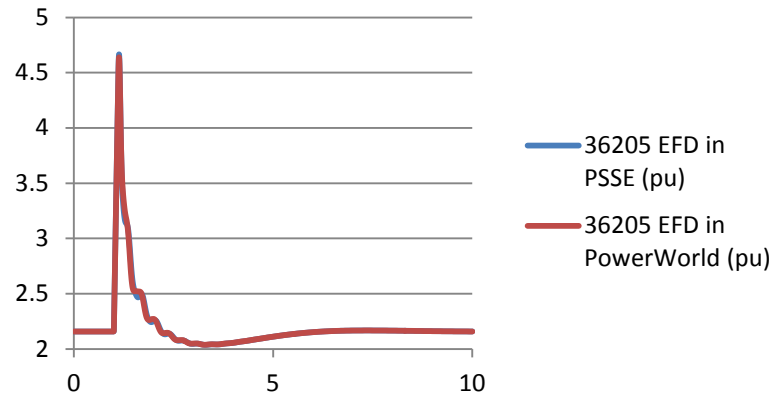
Figure 5.15(b): 'Corrected' field voltages for the SMIB case at bus 22, gen1

5.3.4 EXST2 – IEEE Type ST2 Excitation System
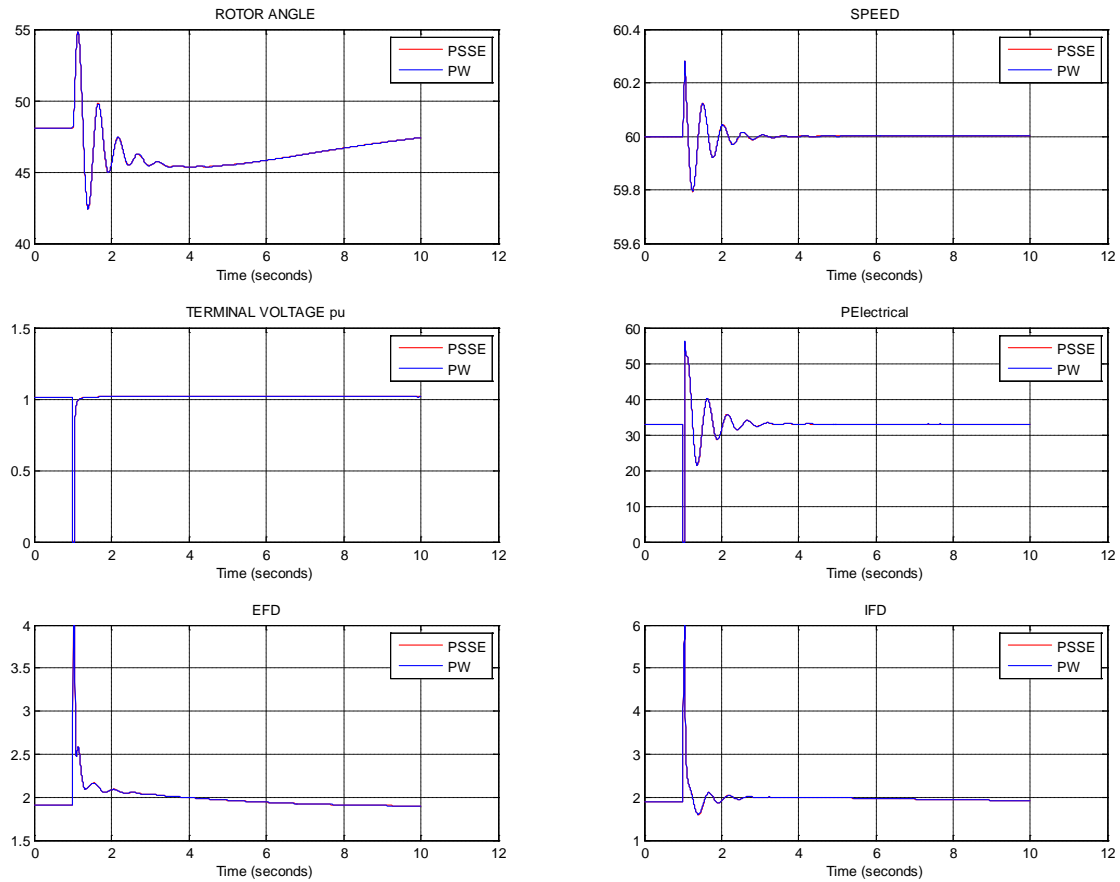
Figure 5.16: Validated results for EXST2 for the SMIB equivalent of generator 1, bus 23

The SMIB equivalent created at generator 1, bus 23 was used here. It consists of a GENROU model and EXST2. This case validation was quite straightforward, except for the fact that the PSSE model lacks a lead-lag block. So this block was bypassed in PowerWorld, for the PSLF model. Again, a solid three-phase balanced fault was applied at t=1 second for 0.05 seconds. The results are given in Figure 5.16. This exciter did not show any discrepancies and was thus validated.

5.3.5 ESST4B – IEEE (2005) Type ST4B Excitation System

The SMIB equivalent created at generator bus 24 was used here. It consists of a GENROU model and ESST4B exciter. Again, a solid three-phase balanced fault was applied at t=1 second for 0.05 seconds. The validated results are given in Figure 5.17.
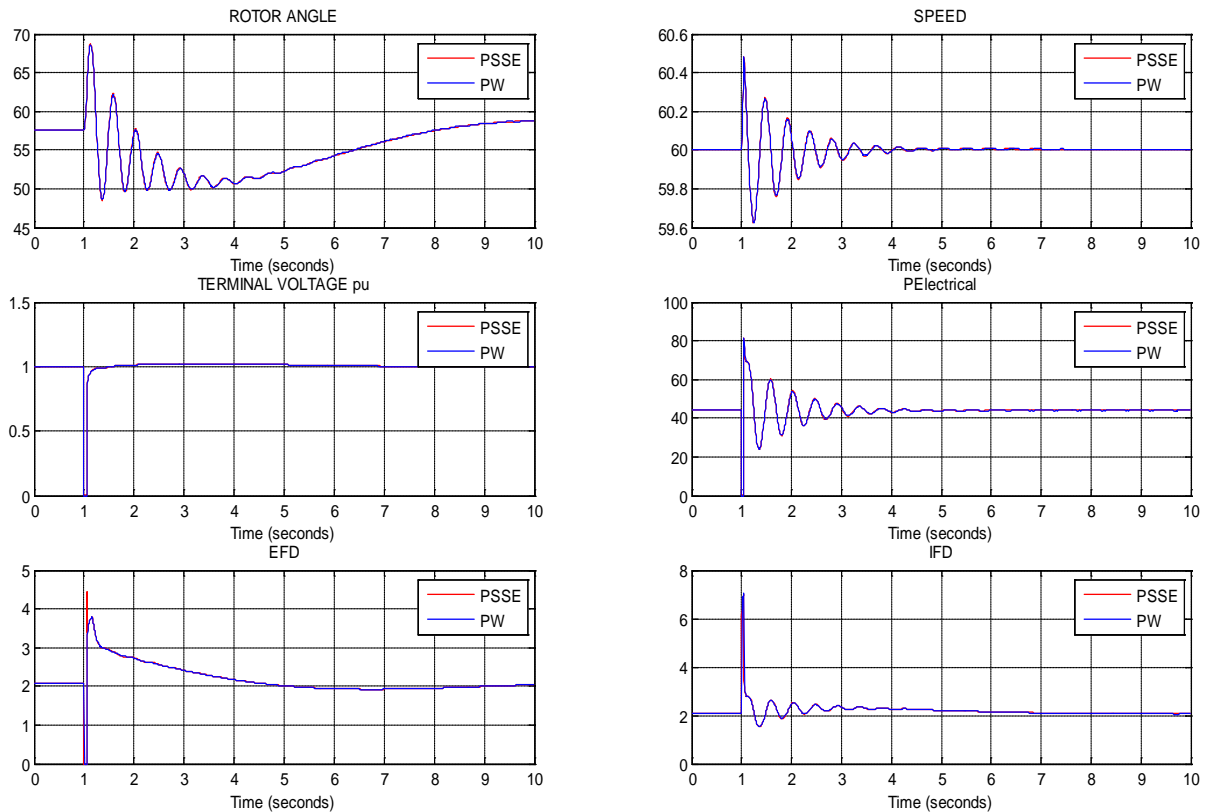
Figure 5.17: Validated results for ESST4B for the SMIB equivalent of gen 1, bus 24

5.3.6 EXST1 – IEEE Type ST1 Excitation System Model

This model of exciters is the most commonly used model in the WECC case. It accounts for one third of the total exciter model usage. The validation of this model was a little challenging due to its different implementations in PSLF and PSSE. PowerWorld has

implemented both these models, as EXST1_GE and EXST1_PTI, thus making validation easier.
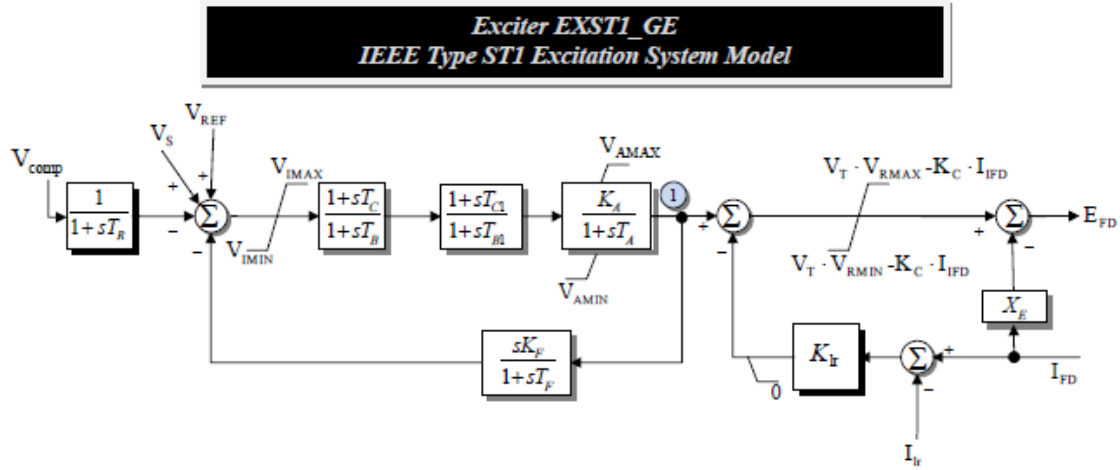
Figure 5.18(a): Block Diagram of EXST1_GE as implemented in PowerWorld [9]
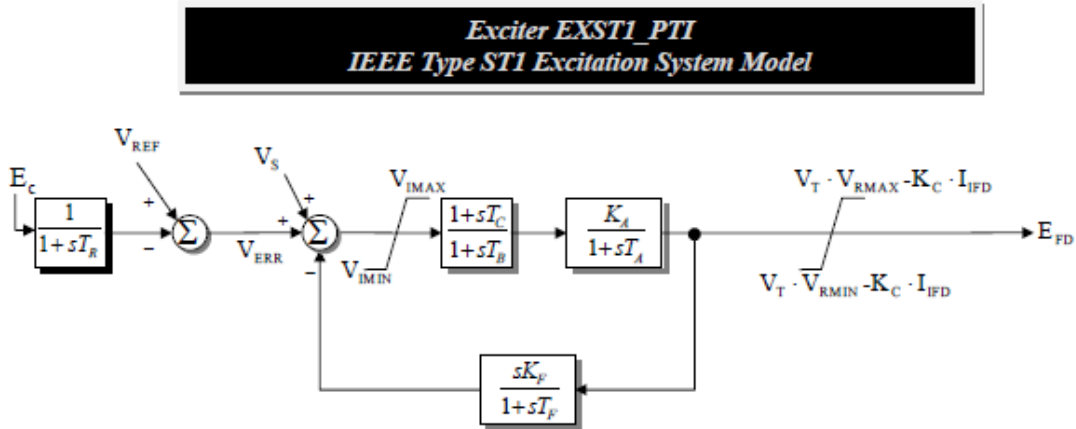
Figure 5.18(b): Block Diagram of EXST1_PTI as implemented in PowerWorld [9]

We chose an example of the SMIB equivalent at bus 25, generator 1, derived from WECC Case 4. This generator has a GENROU model, an EXST1_GE model as well as a PSS2A stabilizer. The governor at this generator bus was disabled for the purpose of our study.

In order to run this case in PSSE, the EXST1_GE model was replaced by EXST1_PTI. From Figures 5.18(a) and 5.18(b), it is important to not here that the behavior of these two exciter models will differ, unless there are no limits enforced on *Va* and unless $Tc_1 = Tb_1 = Klr = Xe = 0$.

A solid balanced three phase fault was applied at the generator bus at t = 1 second. The fault was cleared in 0.15 second. A time step of ¼ cycle was used. The results for this case with EXST1_PTI model are as given in Figures 5.19(a) and 5.19(b).
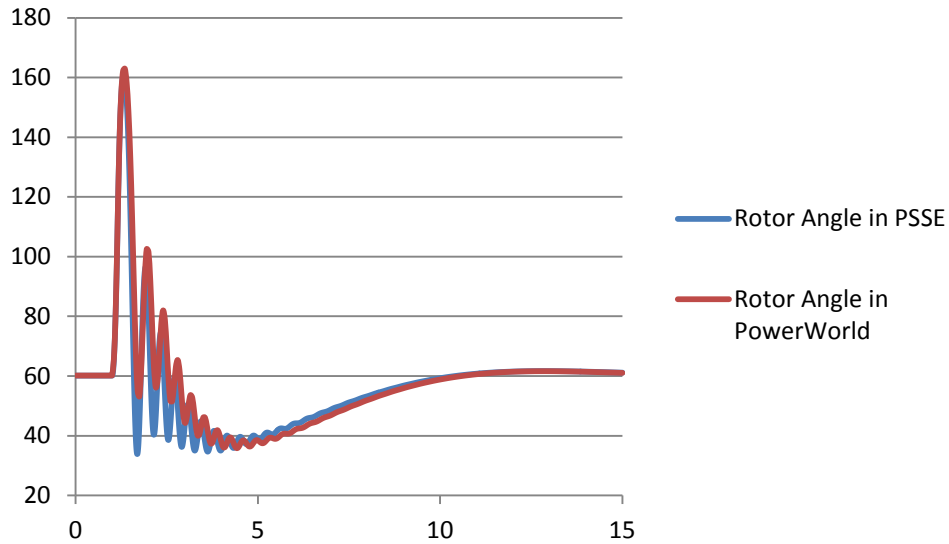
Figure 5.19(a): Comparison of rotor angles for the case with EXST1_PTI
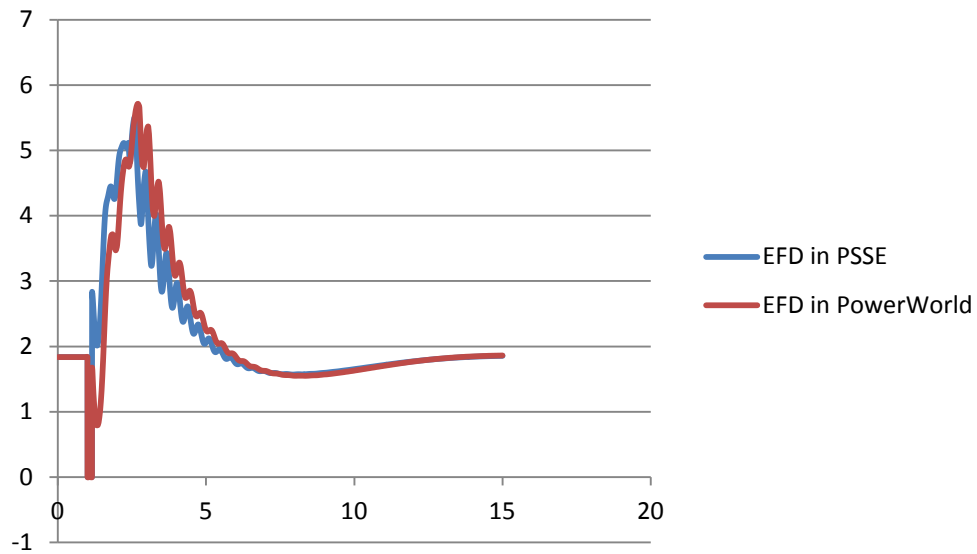
Figure 5.19(b): Comparison of rotor angles for the case with EXST1_PTI

The errors were due to the fact that, in the EFD limit, PowerWorld was incorrectly multiplying *Vrmax* by the square root of the terminal voltage *Vt* instead of *Vt* itself as it should be from Figure 5.18(b). This has now been fixed by PowerWorld.

To validate the PSLF model of this exciter with the PSSE model, we run this case setting a high *Vamax* and low *Vamin* to the PSLF model to account for the lack of the limiter in the PSSE model. A comparison of the results is shown in Figure 5.20
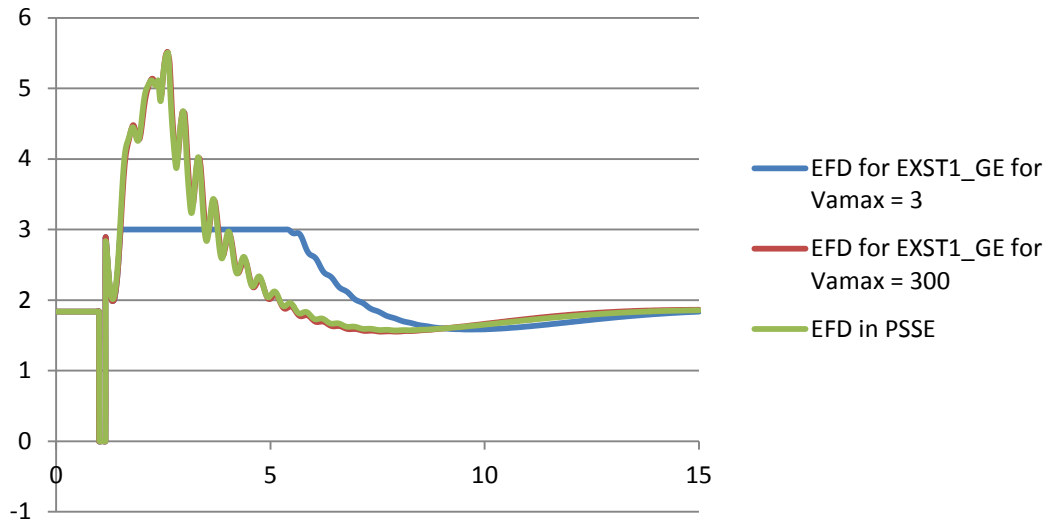
Figure 5.20: Comparison of field voltages for EXST1 GE models with a low and very high Vamax limit to the field voltage obtained in the PSSE model

From Figure 5.20, note that for a Vamax limit set on the PSLF model, EFD gets clipped to Vamax if it tries to exceed it.

Thus, we have validated the implementation of EXST1_GE in PowerWorld to EXST1_PTI in PSSE.

In the WECC Case 4, there 869 EXST1 exciters, of which 639 have the *Vamax/min >= 99* that is the limits are set at high values. Hence it is crucial to note that the remaining 230 limits could become active in certain situations. This can lead to discrepant results between the two different implementations that were described here.

5.3.7 EXDC1

An SMIB equivalent was created at bus 28, generator 1 which has a EXDC1 exciter model. The results are given in Figures 5.21(a), 5.21(b) and 5.22. PowerWorld and PSSE agree well, even for the key exciter output i.e. EFD. TSAT doesn't seem to agree with either of these. We could not determine the cause behind this so this could be something that BPA or WECC can report to PowerTech. Moreover, PSSE doesn't have an EXDC1 model; the equivalent model called IEEEX1 was used.

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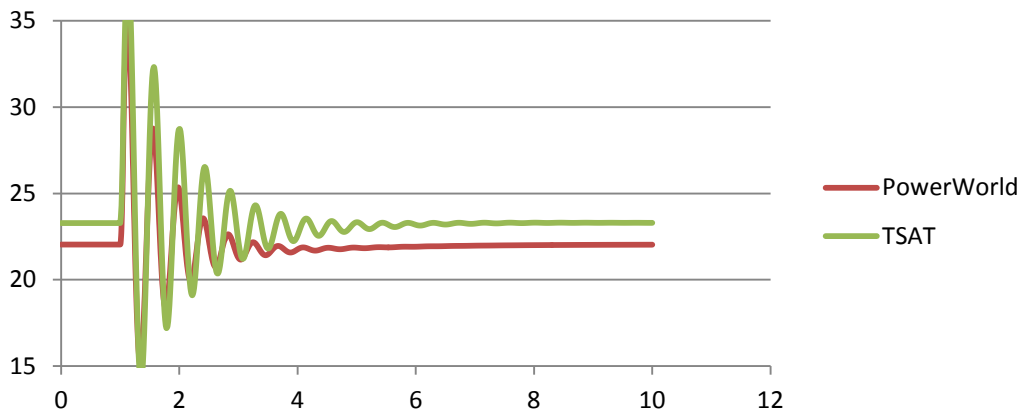
Figure 5.21(a): Comparison of Rotor Angles in degrees for SMIB case from bus 22, generator 1
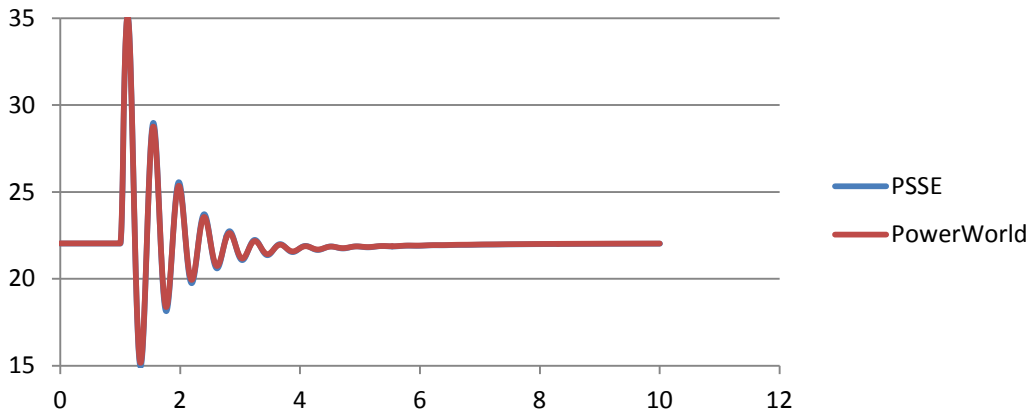
Figure 5.21(b): Comparison of Rotor Angles in degrees for SMIB case from bus 22, generator 1
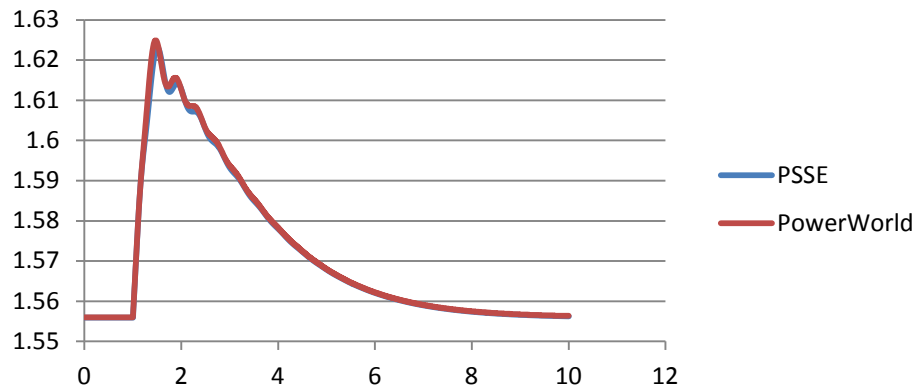
Figure 5.22: Comparison of EFD in pu for SMIB case from bus 22, generator 1

5.4   Stabilizer Model Validation

PSS2A – IEEE Dual Input Stabilizer Model: Out of the 1375 stabilizer models present in WECC Case 4, 903 are of the type PSS2A. Hence validation of this model will account for a major part of the stabilizer model validation of the whole system.

To validate this model, we revisit the immediately previous SMIB equivalent created at Generator 1, bus 25. The same simulation was repeated and the stabilizer outputs were recorded in PSSE and PowerWorld.
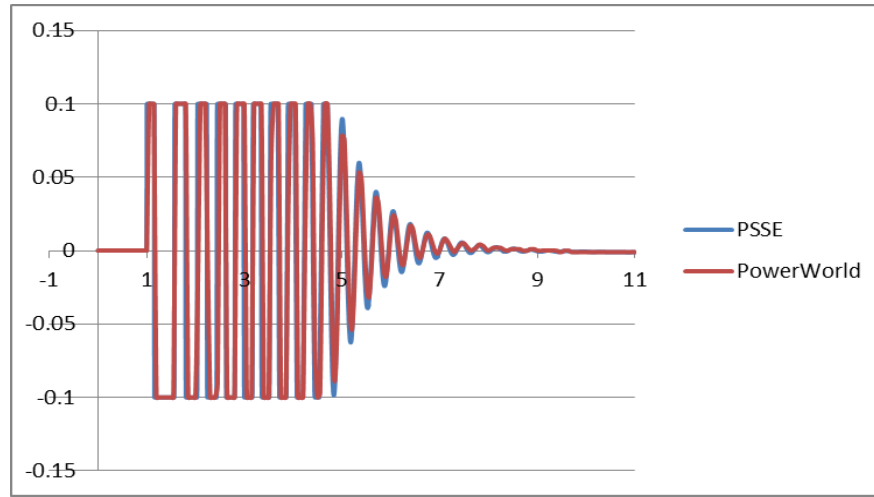
Figure 5.23: Comparison of Stabilizer Signal (VOTHSG) in pu of PSS2A
for the SMIB case gen1, bus 25

The two signals seem to match reasonably well.

Here are some general observations that were made in the process of this two-bus validation between PowerWorld and PSSE

1. Reference angle - By default PowerWorld uses a center of inertia reference angle whereas is PSSE the reference angle is the internal angle for a generator. Care has to be taken to follow the same convention of reference angle to achieve proper validation of results of the same system in two different software packages. PowerWorld provides several options to choose angle reference in order to maintain compatibility with other software packages.

2. Generator Compensation – In PSLF and PowerWorld, Generator compensation (*Rcomp* and *Xcomp*) values are modeled as the parameters of the machine model. In PSSE however, a separate compensation model has to be associated with the machine model where these values can be entered. This was a one of the causes of a lot of discrepant results when *.raw and *.dyr files were exported from PowerWorld to PSSE to perform validation. Before making any such comparisons, either Rcomp and Xcomp should be set to 0 in the machine model in PowerWorld or the compensator model with appropriate values should be added to the machine model in PSSE. There will be a broader discussion on compensation in subsequent chapters.

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6. Validation of Generator Saturation and Voltage Compensation

6.1 Validation of Generator Models Saturation Using BPA Data

In the previous section, GENROU and GENSAL models were validated between PSSE and PowerWorld using two bus equivalent systems. Based on the previous analysis these models match quite closely. In this section, the PowerWorld GENROU, GENSAL and GENTPF models were validated with the PSLF models using the generator field current values for a number of BPA generators (at initialization the field current is identical to the field voltage).

Since the initial field current is sensitive to the generator's reactive power output, the first step in the comparison was to determine how closely these values matched. Using the stored generator reactive power outputs for the *.epc input file and the solved PowerWorld case, the match was quite good, but not always exact. For the 2580 online generators in the case, only six had differences above 10 Mvar, 117 above 1 Mvar and a total of 132 above 0.5 Mvar. While the reason for these power flow differences is beyond the scope of the study, it is mostly likely due to differences in how reactive power is shared between generators regulating the same bus.

Without correcting for the power flow reactive power injection differences, there can be substantial differences in the field current that have nothing to do with the transient stability models. For example at the bus 39 generator there is a 9.8 Mvar difference, resulting in a 0.04 per unit field current difference. These differences become more significant for the lower MVA units. To remove this bias, the generator power flow reactive outputs in the PowerWorld case were modified to exactly match the PSLF case values for the 78 BPA units in which the value was above 0.5 Mvars.

In performing the generator field voltage validation, it was noted that sometimes the PSSE and PSLF models gave slightly different results. While the differences were not large (usually less than one percent), they were large enough to require investigation. The result is the differences appear to be due to a difference between the PSLF and PSSE implementations of generator saturation modeling for the GENSAL and GENROU models (PSSE currently does not have an equivalent for the GENTPF and GENTPJ models). Both models use a quadratic model in which the amount of saturation is inputted at values of 1.0 and 1.2 (with these saturation values denoted as S1 and S12). For the GENSAL model the saturation is a function of the Eqp (the direct-axis transient flux) whereas for the GENROU model it is a function of the total sub-transient flux). In PSSE the saturation function is explicitly given in the documentation as

$$S(input) = \frac{B_{psse}(input - A_{psse})^2}{input}$$

(6.1)

This will be denoted as the scaled quadratic approach. In PSLF the saturation function is not given, but based on numeric testing it appears to be

$$S(input) = B_{GE}(input - A_{GE})^2 \tag{6.2}$$

This will be denoted as the quadratic approach. Since both curves are fit to the same points (1,S[1.0]) and (1.2,S[1.2]) the A and B coefficients are obviously different, as are the S(input) values for inputs other than 1.0 and 1.2. PowerWorld Simulator implements both models, with an option specifying which model to use.

As an example, the generator at bus 29 is represented using a GENSAL model with

$S(1.0) = 0.1710$ and $S(1.2) = 0.9010$

Curve fitting the two points gives the following equation for the scaled quadratic approach

$$S(input) = \frac{9.8057(input - 0.8679)^2}{input}$$

And for the quadratic approach

$$S(input) = 7.1741(input - 0.8456)^2$$

Figure 6.1 compares the two curves for varying levels of flux, with it readily apparent that both curves correctly pass through the points S(1.0)=0.171 and S(1.2)=0.901. While the difference between the curves is relatively slight, it is not zero. To better illustrate, Figure 6.2 plots the difference between the two using the same x-axis scale as Figure 6.1.
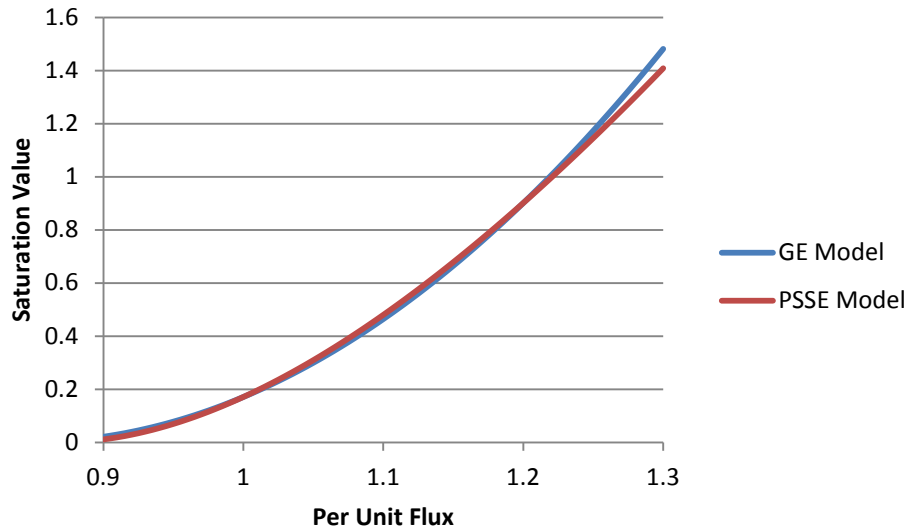

Figure 6.1: Comparison of Saturation for Scaled Quadratic and Quadratic Saturation Functions
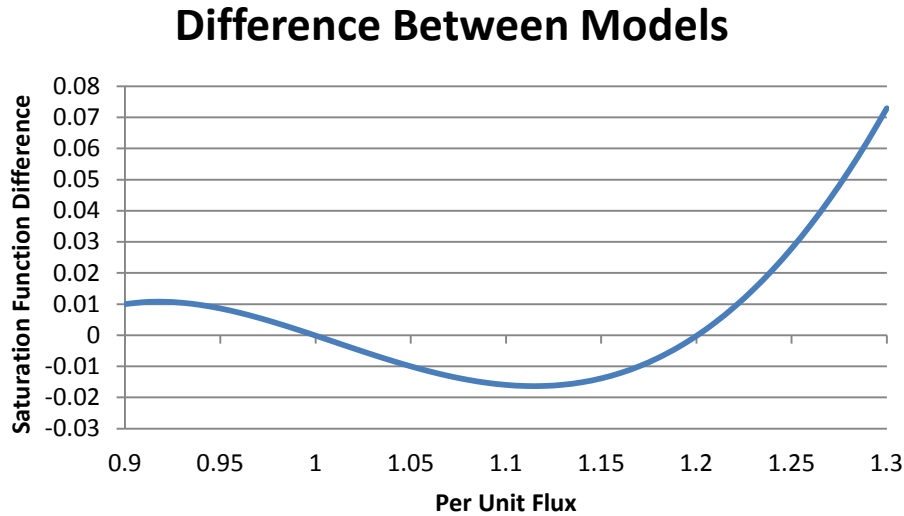
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Difference Between Models

Figure 6.2: Comparison of Difference in Saturation between PSSE and PSLF Functions

The difference in the saturation values for fluxes other than 1.0 and 1.2 results in differences in the field voltage and subsequently in the exciter state variable values. For the bus 29 example, in which the initial per unit flux is 1.051, the scaled quadratic gives an initial field voltage of 2.5137 (based on results using a two bus equivalent) while the quadratic gives a value of 2.5034 (based on results from the WECC Case 4). Note that that -0.0103 difference is quite close to what would be expected from Figure 6.2. The initial field voltage is 2.5147 in PowerWorld when solved with the scaled quadratic saturation modeling and 2.5036 when solved with the quadratic approach, with both values closely matching those from the other two programs.

A second example is for the two generators at bus 30 in which the generator 1 and 2 initial field voltages are 1.6445 and 1.5561 in PSSE and 1.6394 and 1.5506 in PSLF. Solving in PowerWorld the values are 1.6430 and 1.5543 using the scaled quadratic (PSSE) approach, and 1.6401 and 1.5513 using the quadratic (PSLF) approach; again all closely match.

To validate this approach, the initial field current values for the 200 largest on-line generators (in terms of real power output) in BPA (for which we had data) were compared. Using the quadratic saturation function the average error in the initial field current values was 0.0084 per unit, while with the scaled quadratic saturation function the average error was 0.01223 per unit. If the values are limited to the just the 100 largest units, for which small initial differences in the power flow reactive power output would have the least affect, the average was 0.0031 per unit for the quadratic approach and 0.0083 for the scaled quadratic. Since the actual PSLF values were only available with a precision of 0.001, the conclusion appears to be that 1) the PowerWorld software closely matches the initial field values from PSLF, and 2) the quadratic approach is the best way to match the PSLF results.

Since PowerWorld implements both approaches, the significance of the issue can be studied. In the WECC model there are 2533 generators with active generator models. The largest difference in the initial field voltage between the two models is 0.0339 per unit (at the generator at bus 31), with only five generators having differences above 0.03, a total of 23 having differences above 0.02 and a total of 111 above 0.01 per unit. In terms of percentage, the largest difference is 1.66% at 31, with 25 generators having differences above 1.0%.

This issue is not considered significant, but it does need to be considered during validation between the different packages since differences in the field voltages can get amplified into differences in the initial exciter values.

6.2 Validation of Generator XComp Values

As described in [8] a compensated voltage value is sometimes used as an input to the Generator exciter, with the equation (using the IEEE 421.5 sign convention) given by

$$Vc = \left| \overline{V}_T + (R_c + jX_c)\overline{I}_T \right|$$

(6.3)

in which V_T is the per unit terminal voltage, I_T is the per unit current, R_c is the per unit resistance (practically always zero) and X_c is the per unit reactance. The values of R_c and X_c are entered in per unit using the generator per unit MVA base. Using the IEEE 421.5 sign convention, a positive value for X_c results in moving the voltage regulation point into the synchronous machine, whereas a negative value places the voltage regulation point beyond the terminal of the generator.

However, PSLF uses the opposite sign convention, with the compensated voltage given by the below equation.

$$Vc = \left| \overline{V}_T - (R_c + jX_c)\overline{I}_T \right|$$

(6.4)

Since the sign is flipped, positive values for X_c place the regulation point in the network, while negative values place the regulation point inside the machine. In the remainder of the document the PSLF sign convention is used.

In the WECC model 171 out of 1194 GENROU models have negative values for X_c, 53 have positive values and two have non-zero R_c values (both negative). For the GENSAL model, 206 out of 1091 have negative values for X_c, while 43 have positive values; none have resistance. For the GENTPF model type, 39 out of 780 have negative values for X_c, while 45 have positive values, and five have non-zero resistance. So compensation is quite common, affecting slightly less than 20% of the total machines.

For the most part, a sampling of the field current response for generators with compensation revealed a mostly good match between PSLF and PowerWorld. For

example, Figure 6.3 shows a comparison of the field current for a generating unit (at bus 32), which is modeled with a GENSAL machine and an X_c value of 0.08 per unit (on the unit's 825.6 MVA base). For this case the response matches quite closely, albeit with the PSLF response showing a slightly higher damping.
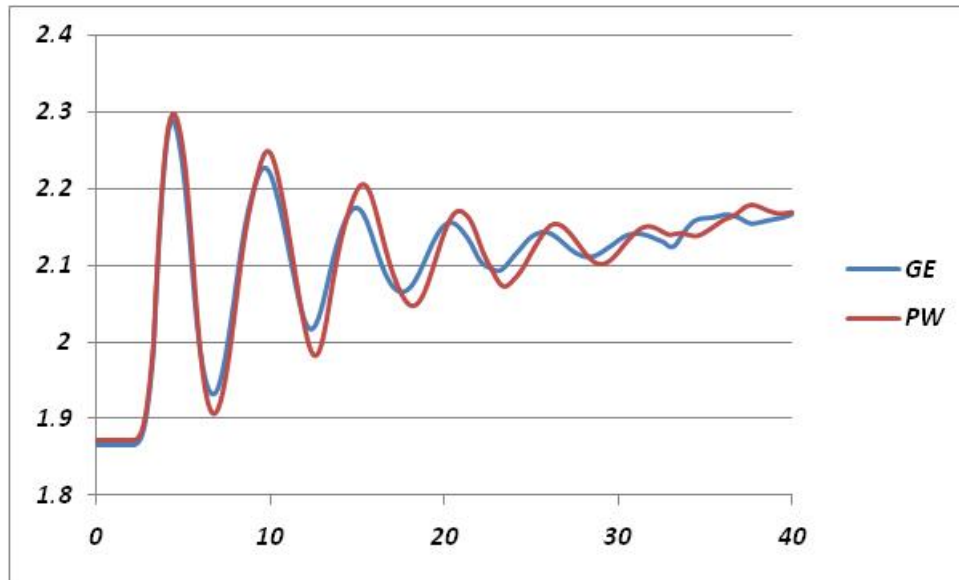

Figure 6.3: Generator Field Current Comparison at Bus 32

However, there were some units in which the behavior was quite suspect, calling into question either the WECC dynamics data or the assumed models. An example in which the data in the WECC data seems suspect is the generator at bus 33 (none of the suspected data errors occurred in BPA). This is a 20.5 MVA base generator with an X_c of 0.07 per unit. The issue is the X_c value is per unit on the generator's MVA base. Converting this to the 100 MVA system base gives a value of $0.07/0.205 = 0.34$ per unit. Usually positive compensation is used to place the voltage regulation point somewhere in the step-up transformer. For example, with the previous bus 32 generator example the 0.08 per unit compensation on a 825.6 MVA base is 0.0097. With a step-up transformer reactance of 0.021, this places the regulation point about midway through the transformer.

Yet for the bus 33 case the transformer reactance is just 0.132 per unit. Hence the generator is trying to regulate the voltage at a point well beyond the step-up transformer, with the result being the regulated point voltage actually decreases as the field current is increased, resulting in unstable behavior. Figure 6.4 plots the field current for this generator in PowerWorld while Figure 6.5 plots the reactive power output. While no PSLF results were currently available for comparison, such a comparison is certainly warranted. Clearly these results are incorrect since they show a 20.5 MVA generator having a reactive power output of 320 Mvar. Yet there is nothing in the model to prevent this from occurring. There is no over excitation system modeled for the generator, and while it is modeled with an EXAC8B exciter the Vrmax value is set to 9999 and there is

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little saturation in the model to limit this rise in field current. Since the 0.07 per unit value matches the value for the three units, which occur immediately before in the model at the neighboring buses, a hypothesis is the 0.07 entry at bus 33 was a simple data entry error.
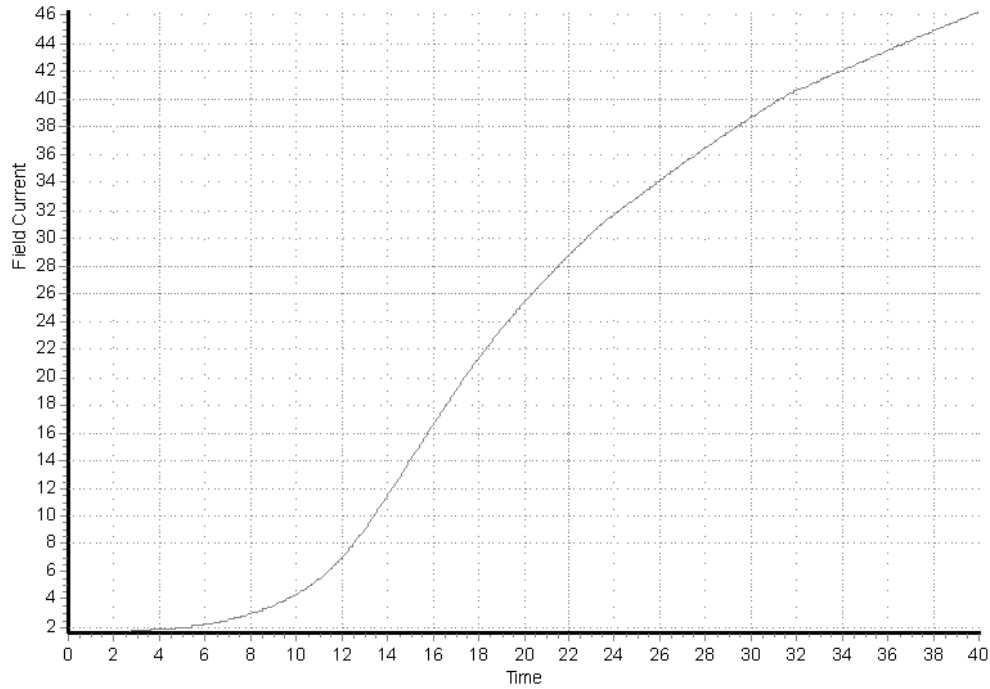

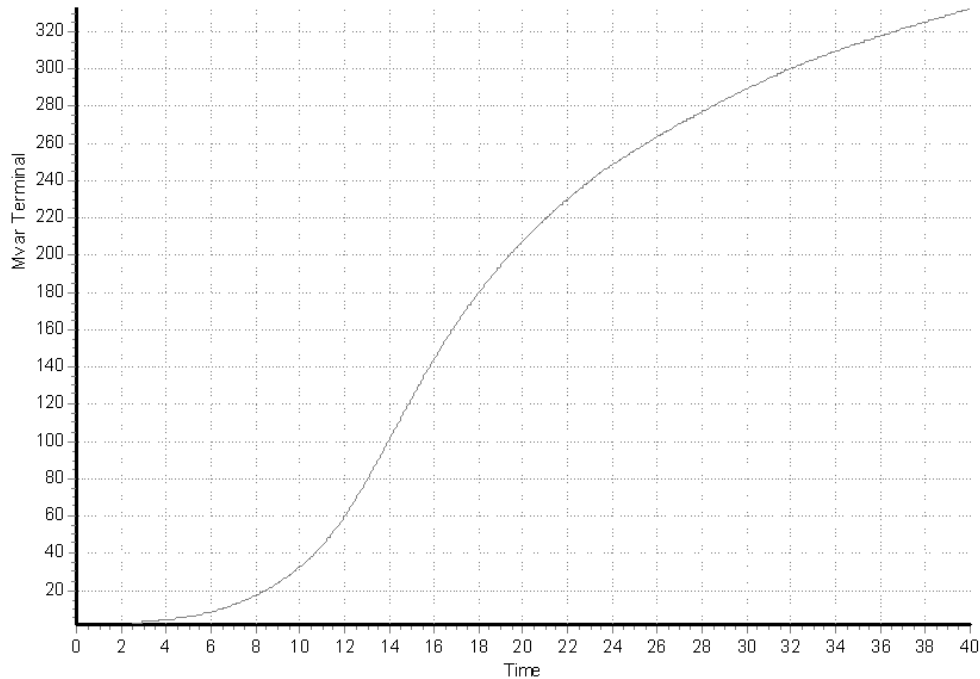Figure 6.4: Generator at Bus 33 Per Unit Field Current

Figure 6.5: Generator at Bus 33 Reactive Power Output (Mvar)

The second issue arises with the assumed MVA base when there are multiple generators at a bus trying to regulate a point outside of the generators. Even if the generators have the same value for X_c they will tend to fight each other since both are trying to regulate the same point. Rather, a coordinated approach is needed, as described in [8], with the equation below for the two generator case using the PSLF sign convention (the equation can be readily extended to more Generators):

$$Vc = \left| \overline{V}_T - (R_{c1} + jX_{c1})\overline{I}_{T1} - (R_{c2} + jX_{c2})\overline{I}_{T2} \right|$$

(6.5)

Both PSLF and PowerWorld appear to be doing this integrated control. However, there is an issue about the correct per unit base to use with the X_c values. What PowerWorld had been doing was to use the individual generator's MVA for each of the calculations, as is implied by the above equation. However, this caused the compensation voltage drops to sum pushing the regulation point further out into the system. Rather, what appears to be the correct approach is to perform the calculation using as an MVA base that is the summation of the MVA bases of the participating generators. This causes the regulation point to have coordinated control and to be independent of the number of on-line generators.

To validate these changes the following two figures compare the field current for a generator at bus 34 between PSLF, PowerWorld before the above change, and PowerWorld after the change. Bus 34 has three identical 25 MVA generators, each modeled with a GENTPF model with an XComp of 0.052 per unit on the generator base and hence $0.052/(25/100) = 0.204$ on the 100 MVA system base. The impedance of the step-up transformer is 0.146 per unit on the 100 MVA system MVA base. Prior to the change, PowerWorld as attempting to regulate a point that was three times distant, resulting in an unstable situation in which increased field current resulted in a decrease in the regulated voltage. Figure 6.6 shows how the change has resulted in a much closer match, with a zoomed view shown in Figure 6.7. While the match is not perfect, clearly it is much improved. Figure 6.8 shows similar improvement at bus 35 which has two 29.9 MVA units.
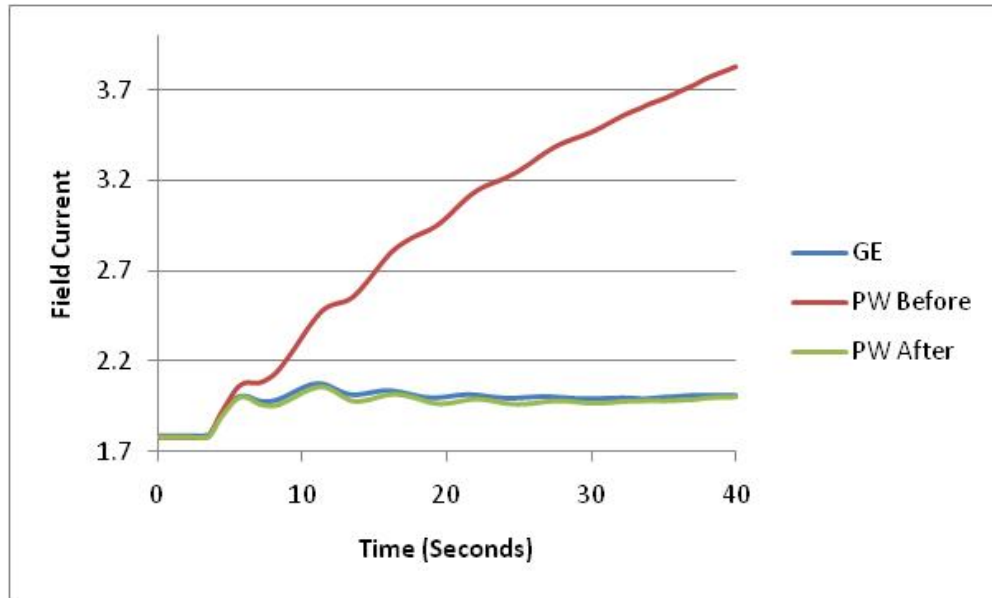
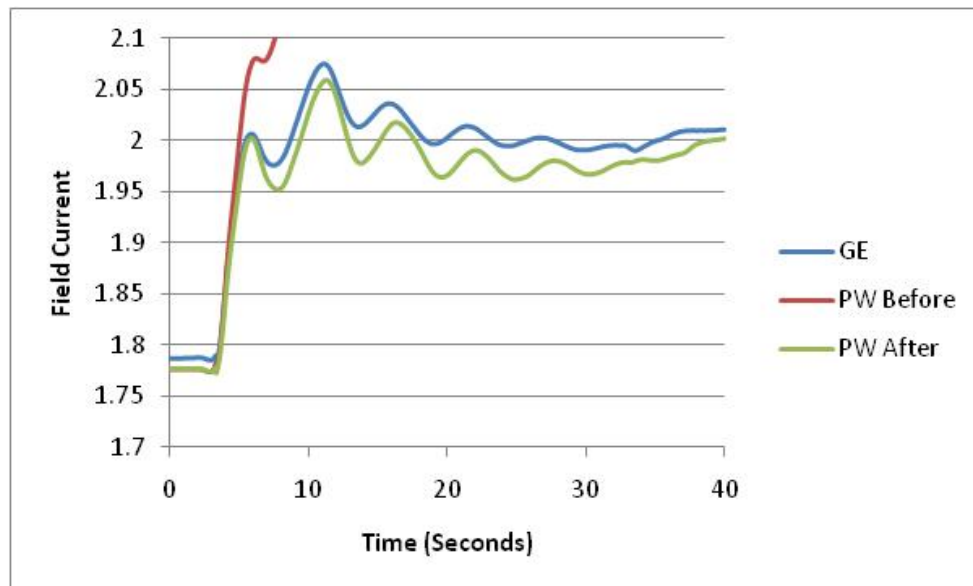Figure 6.6: Zoomed Field Current Comparison for Generator BA at Bus 34s

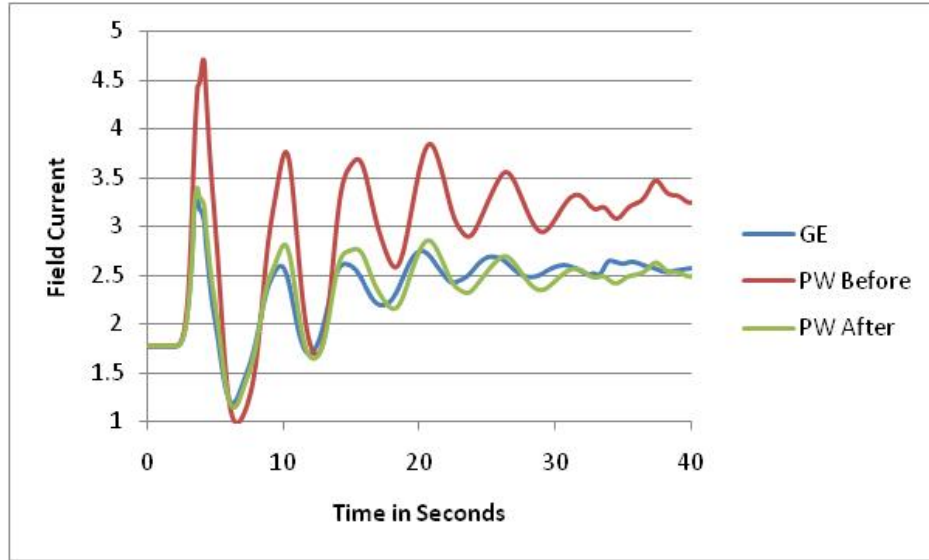Figure 6.7: Zoomed Field Current Comparison for Generator BA at Bus 34s

Figure 6.8: Field Current Comparison for Generator #1 at Bus 35 After PowerWorld Changes

6.3 Validation of Exciters using BPA data

EFD Speed Dependence: After applying the loss of generation contingency as mentioned earlier, the EFD values initially decreased, such as at bus 36. In looking further, this is due to exciter field voltage output being multiplied by the speed. This is something PSLF does on some exciters, but PSSE does not. PowerWorld had this speed effect modeled for some exciters, but not all. This has now been corrected in PowerWorld. The below graph shows the impact on EFD at bus 36 (with an EXDC1 exciter), now with a much closer match to GE-PSLF. The initial dip in EFD is caused by declining generator frequency.
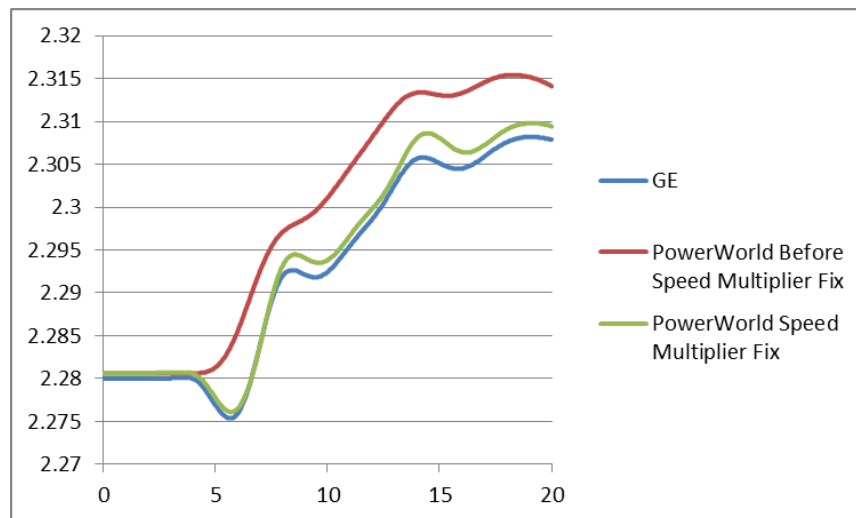

Figure 6.9 : Comparison of EFDs in pu at bus 36 with and without considering speed multiplication factor

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7. Time Step Comparisons

Throughout the course of this project, we have mostly used a time step of ¼ cycle since it is the WECC standard. However, in light of the discussion in Chapter 3, it would be interesting to study the system response using different time steps and the corresponding time constant auto-corrections.

In the time step comparison study, we used WECC Case 4. The loss of the same units as simulated earlier was the contingency applied at t = 2 seconds. We used time steps of ¼ cycle and ½ cycle for our comparisons. The simulation was run for a total of 30 seconds.

On 'running validation' on this case for each of these time steps, the following validation statistics were obtained in PowerWorld.

Table 7.1: Summary of Validation messages obtained for WECC Case 4, using different time steps

Time Step ↓	Validation messaGE fields →	Validation Errors	Validation Warnings	Validation Warnings after Auto-Correction
¼ cycle		941	41	39
½ cycle		3038	43	41

The large number of validation errors in the instance where ½ cycle is used is intuitive as the most of the time constants of the WECC case must be designed for the standard time step of ¼ cycle. A majority of the auto-corrections consist of those for the time constants, the remaining being reactance and saturation values as discussed in Chapter 3.

The solution statistics using these two different time steps were as follows. The network solution statistics are represented by the number of forward/backwards substitutions and Jacobian factorizations.

Table 7.2: Summary of solution statistics for WECC Case 4, using different time steps

Time Step ↓	Solution statistics →	Time to solve	Number of Jacobian Factorizations	Number of Forward/Backward substitutions
¼ cycle		913	73	13725
½ cycle		597	77	9798

Some of the preliminary results obtained from this time step comparison are given in Figures 7.1(a) to 7.1(d).
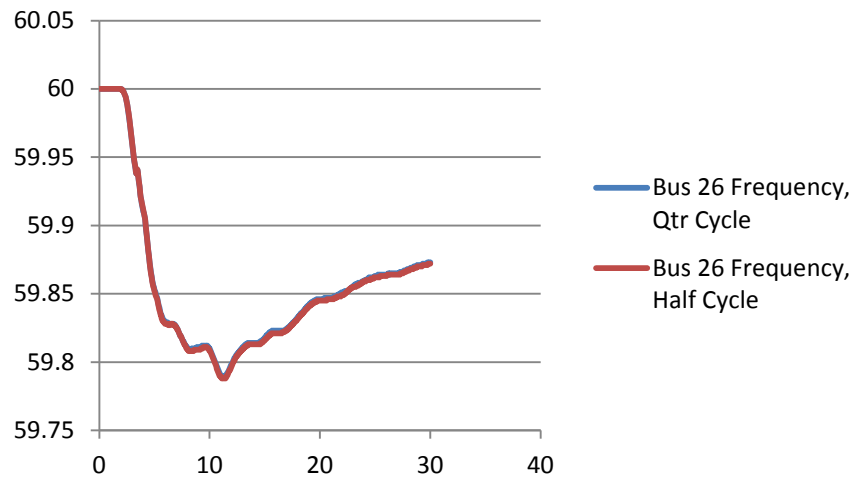
Figure 7.1(a): Comparison of frequency response at Bus 26 for simulations of different time steps
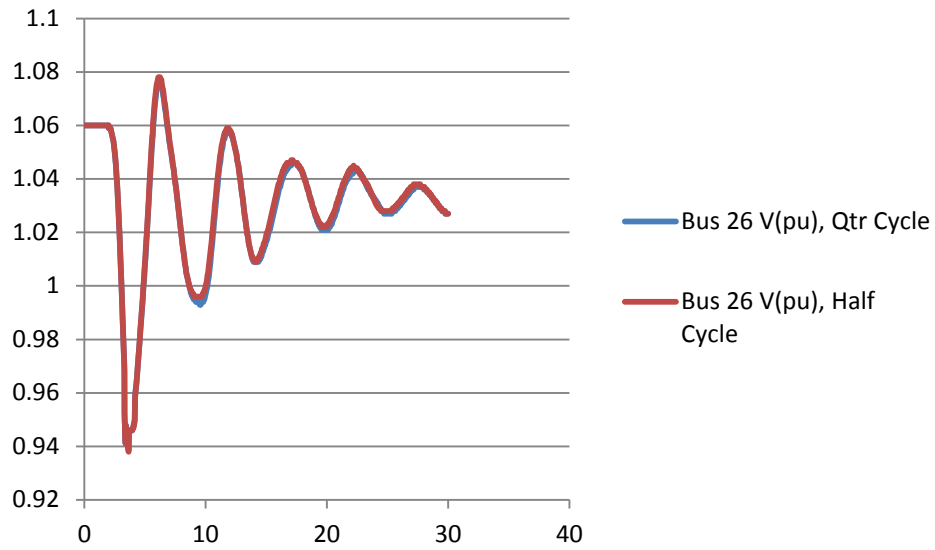

Figure 7.1(b): Comparison of Voltages at Bus 26 for simulations of different time steps
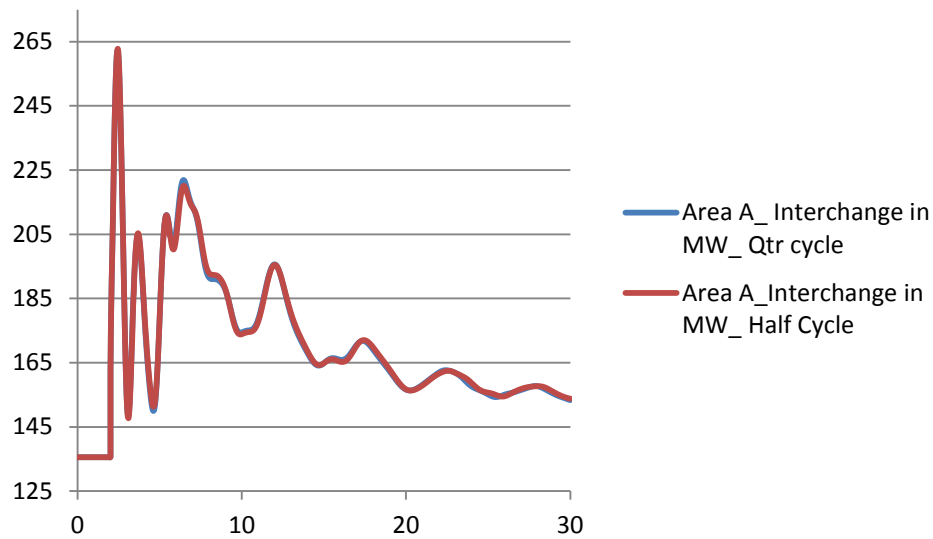
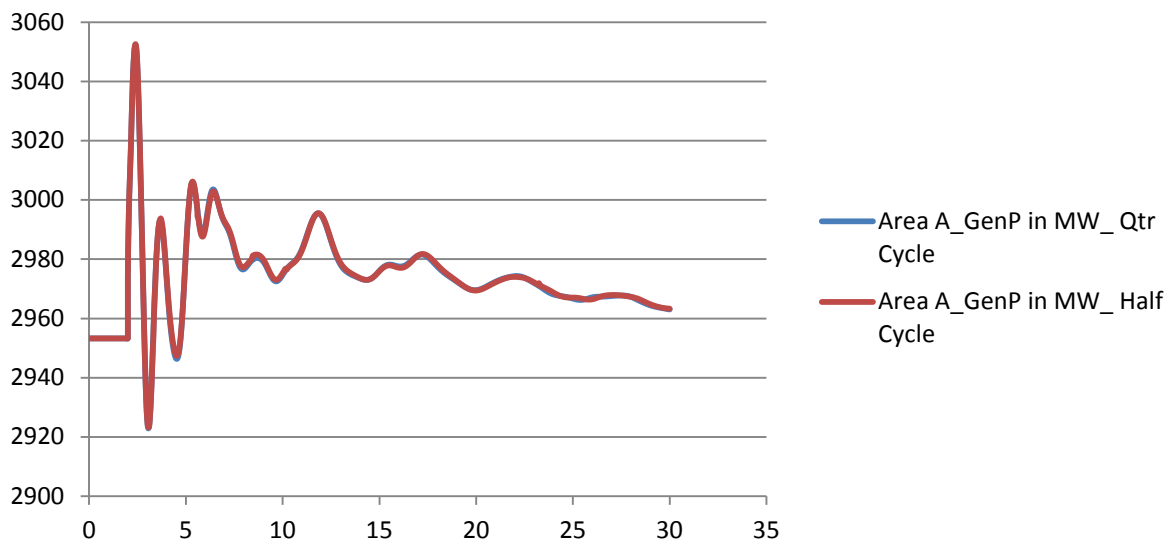Figure 7.1(c): Comparison of Area Interchange in MW for Area A, for simulations of different time steps

Figure 7.1(d): Comparison of Net generation in MW for Area A, for simulations of different time steps

Such comparisons were repeated for several buses, generators and areas and we found that for simulating the whole 17,000 bus system, changing the time step and the subsequent auto-corrections in PowerWorld didn't make a significant difference to the results. Thus it is probably safe to assume that changing the time step within a certain acceptable range for the stability and accuracy of the simulation won't have much of an impact on the results.

8. Frequency Comparisons of WECC Case 4 and Scope for Future Work

8.1 Overview

This section covers the comparison of results between PowerWorld (version 16 beta).and PSLF (version 17) for the most recent WECC case 4, consisting of 17710 buses and 3470 generators. The tested scenario is the loss of the same generating units, as studied earlier. For the simulations the system was initially allowed to run unperturbed for two seconds to demonstrate a stable initial contingency. Then the contingency was applied at time t = 2.0 seconds and the simulation run for a total of 30 seconds. Both cases were integrated using a ¼ cycle time step.

8.2 Frequency Comparison

During the simulation the bus frequencies and voltages were modeled at 20 locations selected by the industrial partner to give a representation for system behavior.

Table 8.1: Final frequencies at the specified 20 buses at the end of 30 seconds

	Bus Number	Final frequency in PowerWorld (Hz)	Final frequency in GE (Hz)
1.	26	59.873	59.862
2.	27	59.872	59.867
3.	40	59.877	59.851
4.	41	59.875	59.853
5.	42	59.872	59.864
6.	43	59.872	59.865
7.	18	59.869	59.862
8.	44	59.873	59.858
9.	11	59.872	59.865
10.	45	59.872	59.867
11.	46	59.875	59.855
12.	47	59.872	59.859
13.	48	59.872	59.864
14.	49	59.872	59.865
15.	50	59.872	59.864
16.	51	59.872	59.867
17.	52	59.877	59.850
18.	53	59.872	59.867
19.	54	59.877	59.850
20.	55	59.873	59.859

The bus frequency response is compared for five different locations in the system in Figures 8.1(a) to 8.1(e), with increasing distance from the contingency location. With the

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exception of Figure 8.1(e) the figures show a fairly good correlation in the frequency response, with all recovering to roughly the same 30 second frequency value. The initial drop in frequency, roughly to about 59.9 Hz, is almost identical in all the figures. This phase corresponds to the inertia response of the generators, indicating that both packages have quite similar inertia representations for the generators. The final frequency recovery value is determined by the droop settings on the governors that are allowed to respond to under frequency events. That the final values appear to be converging indicates that these values are probably modeled correctly.
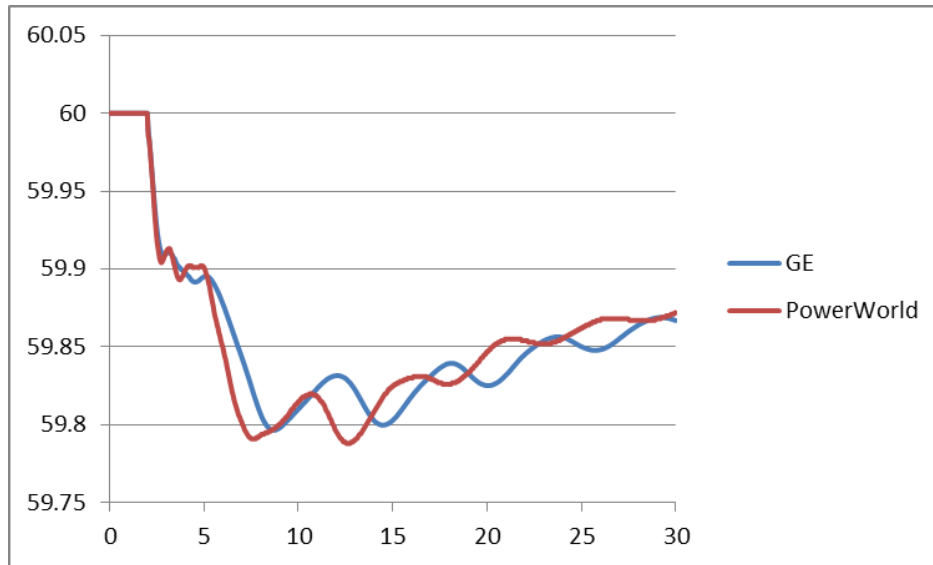

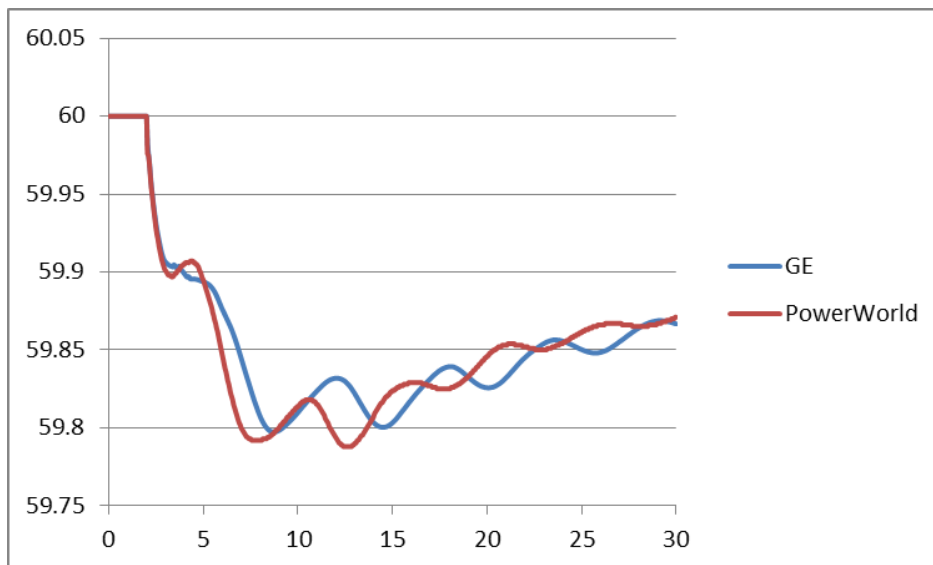Figure 8.1(a): Frequency Comparison at Bus 45

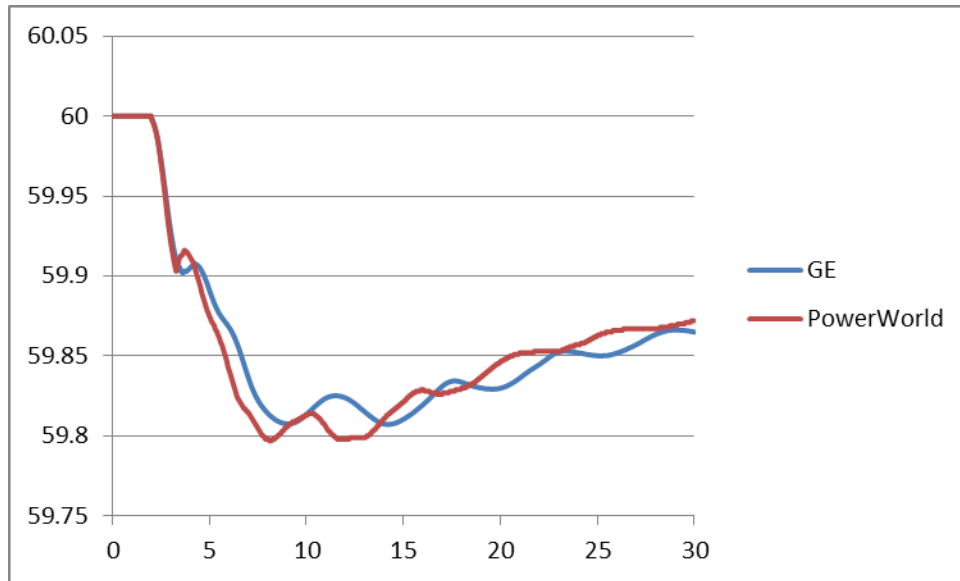Figure 8.1(b): Frequency Comparison at Bus 27
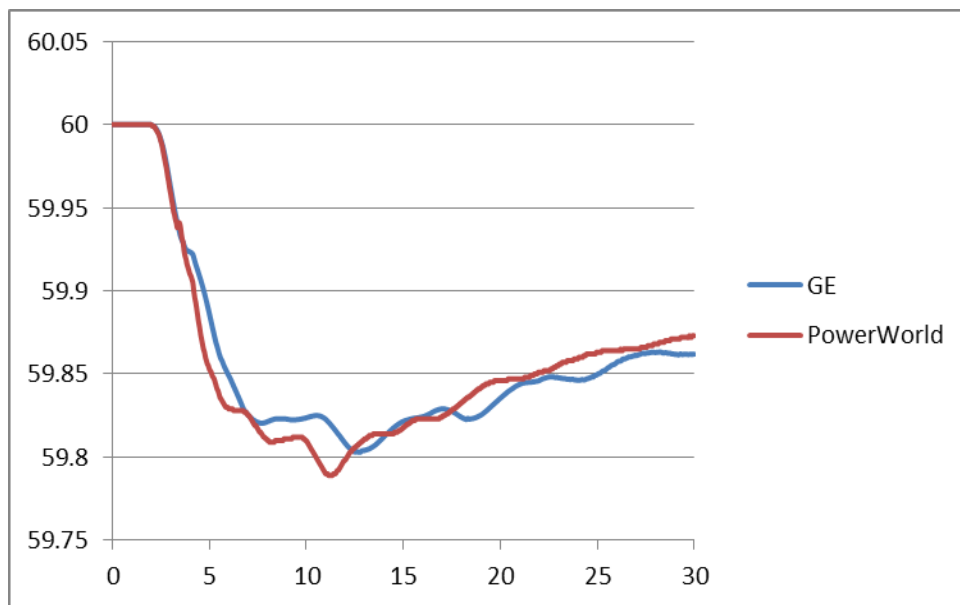
Figure 8.1(c): Frequency Comparison at Bus 43

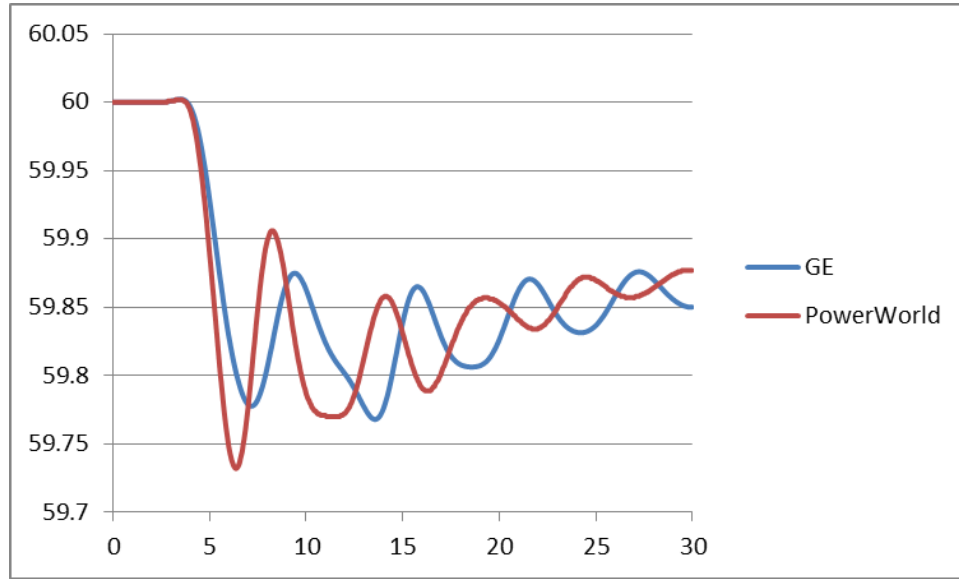Figure 8.1(d): Frequency Comparison at Bus 26

Figure 8.1(e): Frequency Comparison at Bus 37

The most significant difference in all five figures is that PowerWorld has a slightly quicker decay in the frequency, and its lowest frequency is lower than that for PSLF. While this is most significant for bus 37, it is present to a lesser extent at the other buses as well.

The frequency response difference especially in the region of bus 37 is of a major concern. After some trial and error techniques, it was found that some of the issues were arising due to the dynamic load models. To verify this, all the dynamic load models in the case were simplified and converted to real power-constant current and reactive power-constant impedance type loads. The system was subjected to the same simulation and some improvements in the results were obtained, as seen in Figure 8.2(a) and 8.2(b)
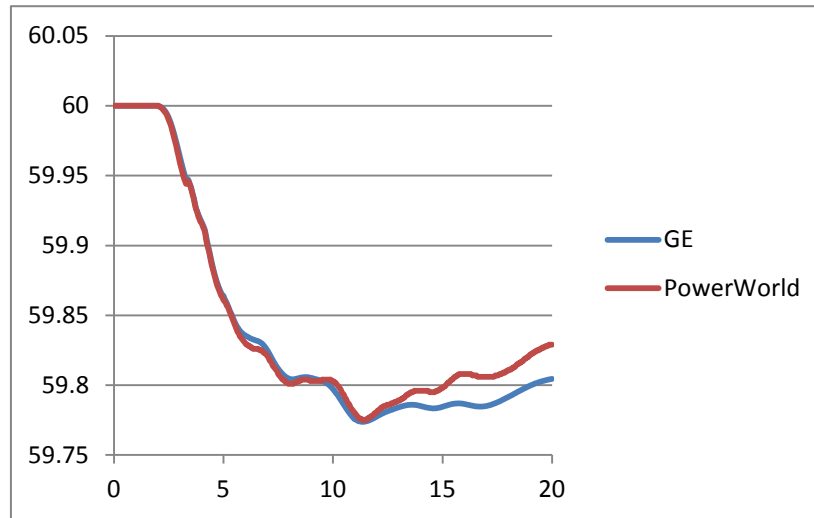
Figure 8.2(a): Bus 26 frequency response with PIQZ load showing improved results
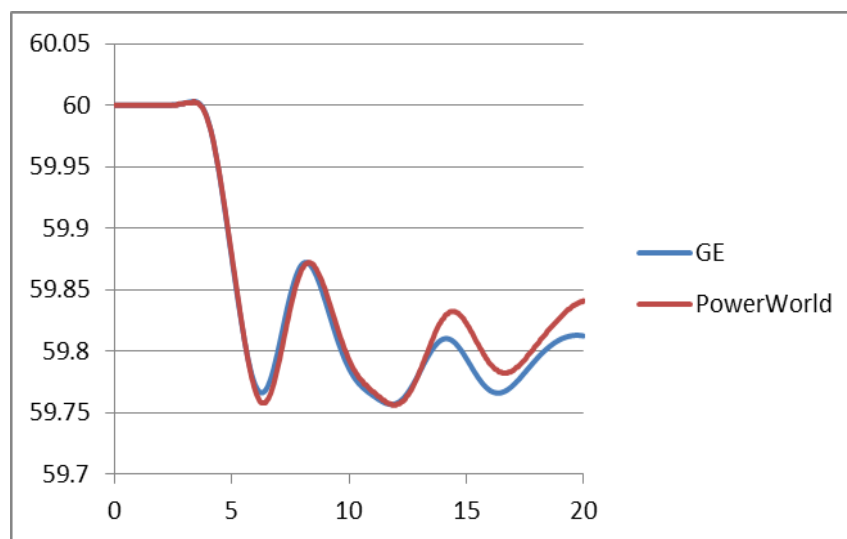

Figure 8.2(b): Bus 40 frequency response with PIQZ load showing improved results

However, there were still some voltage variations at Bus 40, pointing to the fact there might be an inherent voltage issue here.
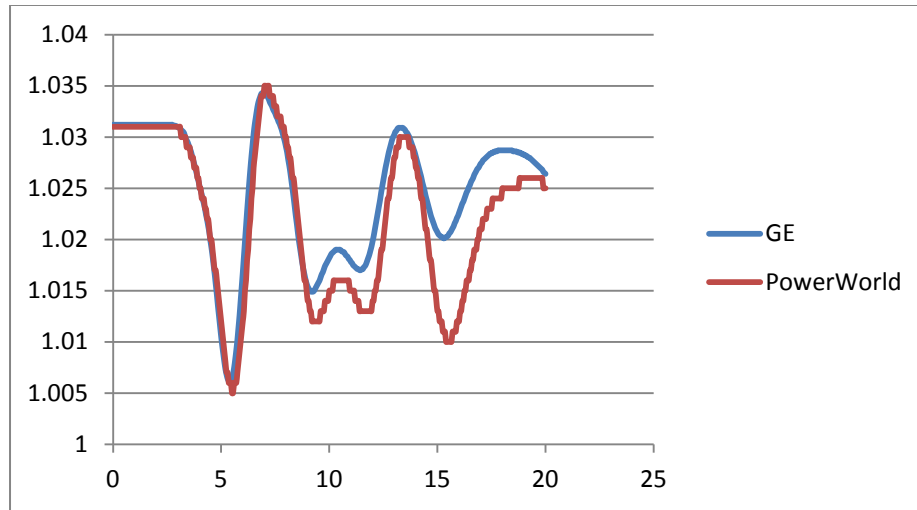
Figure 8.3: Bus 40 voltage comparisons with PIQZ load

After delving more into the governor model GGOV1, an error was found in PowerWorld associated with the GGOV1 load limiter module. Figure 8.4 shows the mechanical power output of the largest active Generator in Area A before and after this change, compared to GE. However, despite the prevalence of the GGOV1 models in the WECC system, this change did not have a significant impact on the frequency errors we being encountered, particularly after 15 seconds as shown in Figure 8.5.
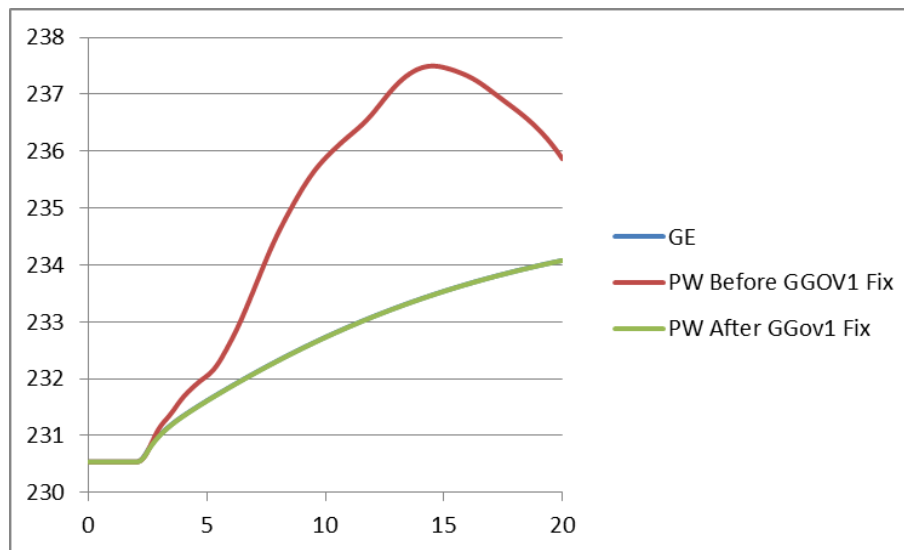

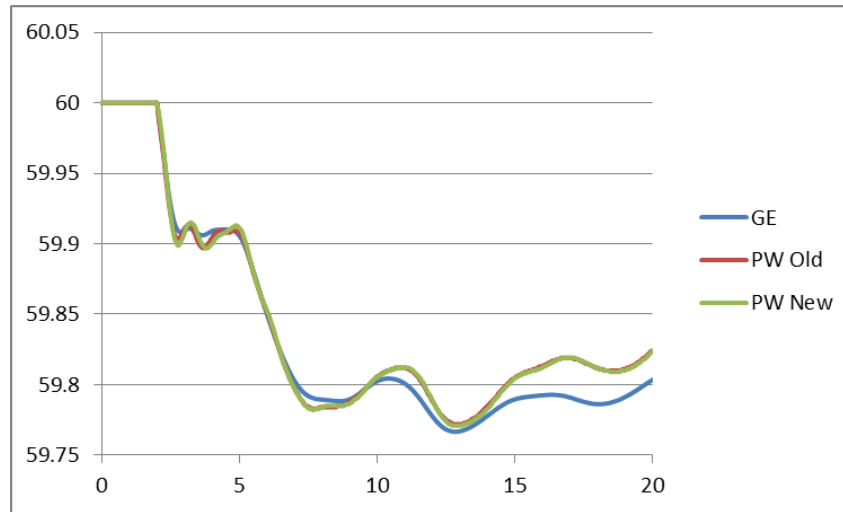Figure 8.4: Comparison of Mechanical Power Output of largest active generator in Area A

Figure 8.5: Frequency response after rectifying GGOV1 errors

There are still issues as far as the frequencies are concerned. At the culmination of this project, we are still left with figuring out the reasons behind these discrepancies. This leads to a direction for future work.

9. Suspected GE-PSLF Bugs

A very important benefit of this project was to bring to light certain errors that exist in the software code of commercial software packages. This section highlights the 'bugs' we encountered in GE-PSLF. It needs to be noted that all of the following issues were reported to GE and were confirmed as either coding errors (PIDGOV) or insufficient documentation describing the implementation of limits (EXAC8B and REXS). These issues are being addressed and rectified.

9.1 EXAC8B Exciter

In looking at bus 30, generator 1 (with an EXAC8B exciter) it was that noticed the PSLF code was ignoring the Vrmax limit. We are not sure about Vrmin since that did not become active in this case. There are 136 active EXAC8B exciters in the WECC case, so this is a common model. Below is a comparison between PSLF and PowerWorld for Vr; the limit on this variable is 5.43.
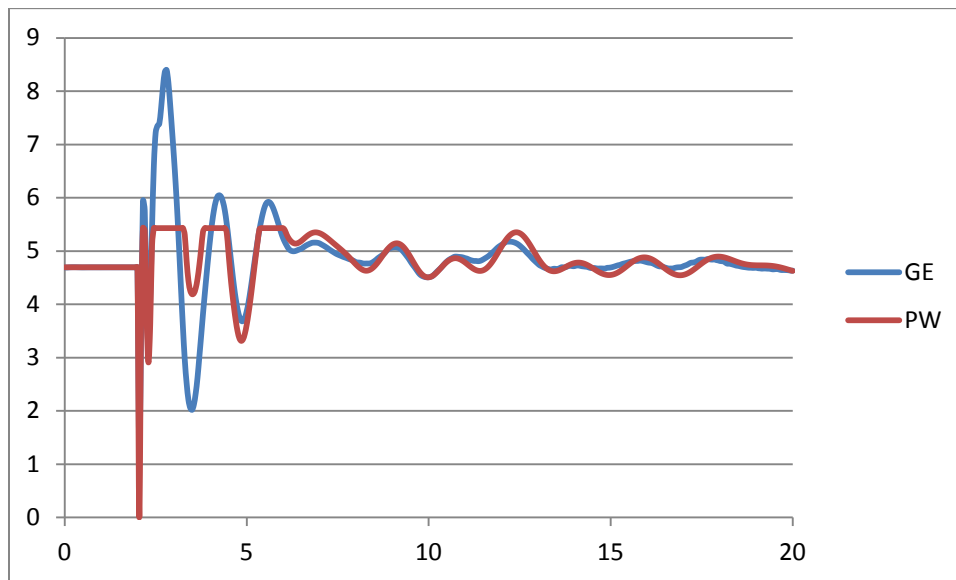

Figure 9.1: Vr comparison between PowerWorld and GE-PSLF at bus 30, generator 1

To verify that this is the issue, this case was simulated in PowerWorld again with the Vr limit set high (999). The below result shows that the value closely matches PSLF.
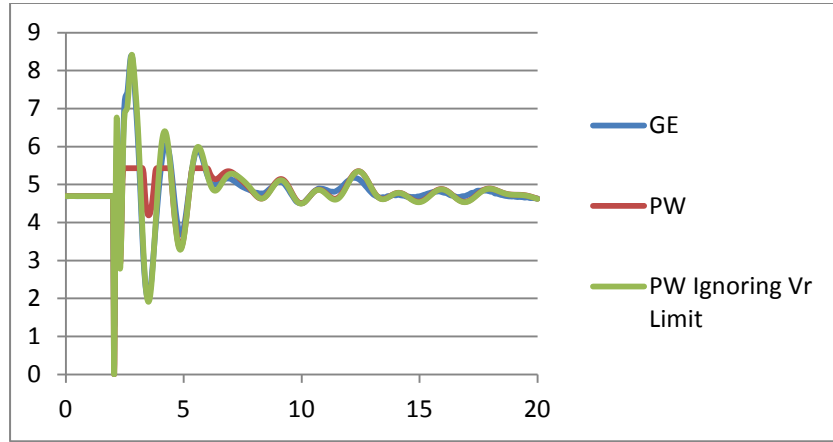
Figure 9.2: Vr comparison between PowerWorld with and without Vr limit
and GE- PSLF at bus 30, Generator 1

9.2 REXS Exciter

In looking at the REXS exciter model for the generator at bus 56, it was noticed that
GE does not appear to be enforcing the Vfmin/Vfmax limits as per their documentation.
Referring to the REXS block diagram[9], for the exciter $Xc = 0$ in our study case, so Vfe
should not go above the limit of 6. But it does as shown in Figure 9.3. Note, if the
parameter flimf = 1 then the Vrmax, Vrmin, Vfmax and Vfmin limits are scaled by the
terminal voltage. But in this case the flimf = 0. Note from Figure 9.3 that PowerWorld
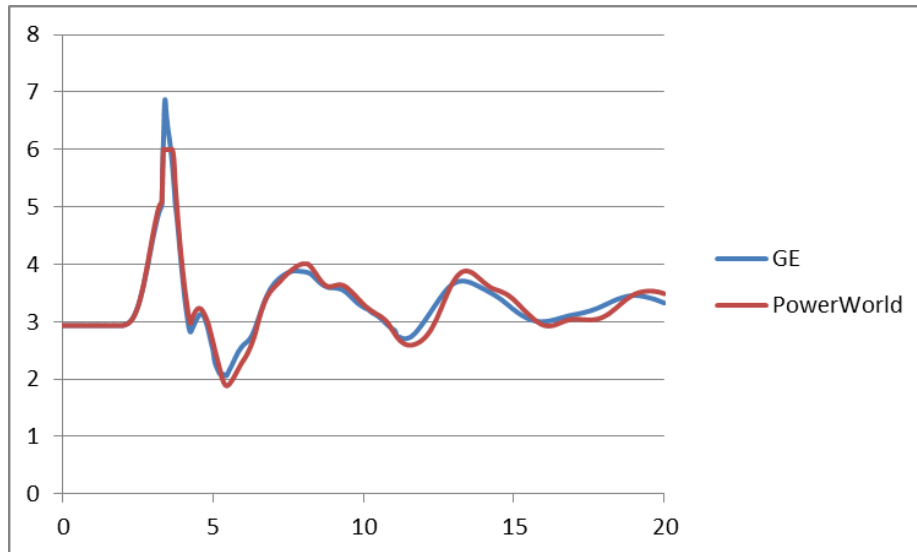enforces the limit but GE does not.

Figure 9.3: Vfe comparison for Generator at bus 56 between GE-PSLF and
PowerWorld showing PSLF violating Vfmax = 6 limit

9.3 PIDGOV Model

PSLF and PowerWorld were getting substantially different Pmech values where this model was used. Looking more carefully into the PIDGOV model it was found that PSLF is using the Generator MVA base in the calculations, not the Trate value from the input file.

Supporting evidence is

1) The gate values outputted from PSLF are in pu on the Generator MVA base

2) There is no mention in the documentation of using Trate, yet for all other governors they say this is what they do

3) When we set Trate =0 in PowerWorld (defaulting to the gen MVA base) the results match almost exactly, as shown in the below Figure 9.4 for the Generator at bus 57.
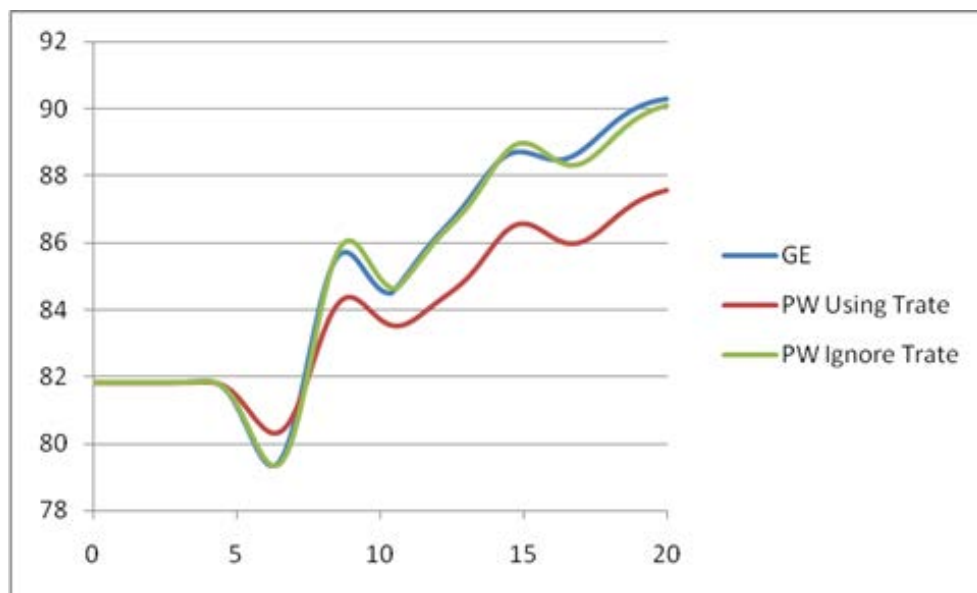

Figure 9.4: PMech value comparisons for Generator at bus 57 between PW and GE-PSLF, with the effect of Trate

10. Summary and Directions for Future Work

From the vast differences in results obtained for essentially the same system and similar models across different transient stability packages, this project highlighted the need for validation or software packages, transient stability models as well as results.

In Chapter 8, we concluded that we need to further investigate the reason for the difference in frequency responses. The resolution of some of the suspected software bugs we mentioned can lead us in that direction.

Another direction would be to try and automate these comparisons and the whole validation process; both top-down and bottom-up to handle the huge volumes of data and get meaningful results quickly and efficiently.

Given the research thrust on increasing the penetration of renewables in the grid, validation of dynamic models pertaining to wind turbines, solar models, etc. is also another avenue that can and should be pursued

Additionally, a logical future step would be to validate these packages and their simulation results with real-world data obtained from PMUs and other sensing devices.

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