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Power Plant Model Validation Using On-Line Disturbance Monitoring

Technical Update on Latest Results

1017801

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Technical Update, December 2009

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PRODUCT DESCRIPTION

This report is a technical update of recent results of EPRI base funded research work related to on-line model validation and derivation for power plants, conducted under Program 40.001 Load and Generator Modeling. The work is follow-on work from the EPRI R&D program that was published earlier this year in the report *Automated Model Validation for Power Plants Using On-line Disturbance Monitoring*, EPRI report 1016000 (2009).

Results and Findings

The technical update outlines the latest lessons learned from the on-line disturbance based model validation technique developed by EPRI.

Challenges and Objectives

Historically, it is well understood that the turbine-governor portion of the power plant model is perhaps the most simplistic. This study was conducted to see if some simple modifications to the turbine-governor model for large steam-turbine governors could help to improve the ability to simulate the response of coordinate boiler-turbine units to system disturbances. The project also looked at some other issues such as model validation using recorded responses to unbalanced faults.

Applications, Values, and Use

This report updates work on model validation using data captured by event recorders, such as digital fault recorders (DFRs), in the power plant during systemwide disturbances. These data are used to validate and fine-tune the power plant model. The benefits are that there is no need to schedule time for testing the unit, the unit need not be maneuvered or taken off-line, and there is no additional risk of damage to the unit. Another key benefit is that the unit's response to actual events is seen. However, for this process to work, good baseline data on the applicable models for the power plant are required, hence the need for some form of staged testing or model validation upon plant commissioning.

EPRI Perspective

EPRI's involvement in synchronous machine parameter testing goes back to the 1980s and 90s with the advent of stand still frequency response-based parameter estimation techniques and the PIDAS project. This report is part of an ongoing effort by EPRI to investigate not only state of the art in power plant model parameter derivation, but also to keep such efforts focused on meeting the needs of the industry as dictated by reliability standards while at the same time keeping the approach to such work as simple, practical, and effective as possible.

Approach

The approach taken was to investigate the potential for fitting boiler-turbine models for large steam-turbine generator response to system disturbances in the MATLAB® environment, using the algorithms developed in the EPRI PPPD tool— see *Power Plant Parameter Derivation (PPPD) Software User's Manual: Version 2.0*, EPRI report 1017803 (2009).

Keywords
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1
INTRODUCTION

1.1 Background

Generator model validation and testing is certainly not a new subject. Efforts have been on-going in this area for many decades. In 1997, the Western Electricity Coordinating Council[1] (WECC) started a major effort, in the aftermath of the 1996 system break-ups, to improve system planning models. One aspect of this was the mandated testing of generating units which has been ongoing since, with the requirement in WECC to revalidate the models once every 5 years. NERC is presently working to bring similar mandates to bear nation wide thorough MOD-026 and MOD-027.

In 2007 EPRI's Power Delivery & Utilization (PDU) sector performed a supplemental research project (cosponsored by FE, Duke Energy and TVA) to develop a prototype software tool for power plant parameter derivation using field recorded data from "staged testing" of generating units. This tool thus provided a significant reduction in the engineering time needed for model parameter derivation and validation, by automating the iterative process of parameter fitting. The document "Power Plant Modeling and Parameter Derivation for Power System Studies: Present Practice and Recommended Approach for Future Procedures." EPRI, Palo Alto, CA: 2007, Product ID # 1015241, provides the background for such staged testing procedures. This work was then carried on through the combined funding of EPRI base funded research work conducted under Program 40.004 Generator Dynamic Model Parameters Identification and Validation, and Program 65 Steam Turbine Frequency Response Modeling and Validation Using Ambient Monitoring in 2008. These two projects were conducted in parallel by the author (due to their synergies) and culminated in further developments in the software tool to include the ability to use on-line disturbance recordings from digital fault recorders (DFRs) installed in the power plant for power plant model validation – this is reported in[1]. Furthermore, in 2009 the software tool was enhanced to add the on-line disturbance data fitting feature and several other features and models. The software tool has now been released capable of using either field test data or on-line disturbance recorded data for power plant model validation [2]. This tool is called the Power Plant Parameter Derivation (PPPD) software tool and is currently in version 2.0 of its release.

This report is a technical updated which summarizes some further research conducted to investigate some additional modeling issues related to synchronous generator power plants.

1.2 Goals and Objectives of this Report

In the 2008 (early 2009) work [1] an issue was demonstrated with respect to turbine-governor modeling. Namely, the inability of standard (relatively simple) models used in planning studies for steam-turbines to be able to properly represent the behavior of boiler dynamics. This is not necessarily a new observation, and there have been several proposed models for representing boiler-dynamics in the literature. The question is whether the on-line disturbance monitoring data

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[1] The 1997 the WECC was called the Western Systems Coordinating Council. Its name changed to WECC in 2002.

captured in [1] can be used to fit the response of the unit to more complicated boiler-turbine models in order to achieve a better representation of the unit's behavior. Furthermore, what minimum additions to the standard planning models are needed to achieve such a better fit? This is one of the goals of this report.

A second goal of this report is to reinvestigate the possibility of using on-line data captured from unbalanced fault events for model validation purposes – particularly validating the electrical generator and excitation system response.

A third goal of this report is to look at model validation for large salient pole synchronous generators. All the generators investigated and studied under [1] were for large steam or gas turbines and thus primarily round-rotor generators. For round rotor generators the typical model used is the *genrou* model. In [1] for many different cases this was shown to be a sufficient model. Hitherto, it was commonly accepted that for modeling large salient pole machines, such as used for hydro-turbine generators the *gensal* model should be used. Recently, in the past year, work in WECC has shown that the *gensal* model is incapable of adequately representing the on-load saturated behavior of these salient pole generators. Thus, the newly approved *gentpj* model was developed in WECC. Thus, another goal of this technical update is to review the *gentpj* model and its use in validating the response of a large salient pole generator.

2

BOILER-TURBINE MODELING

2.1 Introduction

The most typical model used in power system planning studies for representing steam-turbines is the IEEEG1 model, or some variation of this model. Figure 2-2 shows this model – note: the IEEEG1 model is only the lower half of this figure, in the figure it has been augmented with an outer-loop power controller. There are a number of key assumptions behind the IEEEG1 model. These are that:

1. Steam pressure and temperature remain constant under all conditions.
2. That the unit is in boiler follow mode – that is, the main steam control valve (MCV) is used primarily for regulating power and the boiler follows the turbine in producing additional steam as needed.
3. That there is an indefinite source of steam from the boiler to be provided once the main steam control valve opens.

It is not difficult to realize that all these assumptions are quite simplistic and not truly indicative of the physics of a steam turbine. Assumption two can indeed be true for many older steam-turbines – that is, boiler-follow control. However, assumptions one and three are clearly extreme simplifications. Any significant sudden change in the MCV would constitute a sudden drop in steam throttle pressure. Thus, turbine output power would proportionally drop. Thus, additional fuel would need to be spent to increase steam production and steam pressure in the boiler. These pressure drop effects would actually be most significant under a boiler follow control strategy. Modern steam-turbine controls often employ a coordinate control scheme where the movement of the MCV is controlled by a combined coordinated effort of regulating power (due to droop response) and main steam pressure. In this section we will illustrate some of these pressure transient effects through an actual recorded turbine response to system a frequency event. The modeling of the boiler dynamics discussed here is based on [3].

2.2 Event and Unit Studied

In [1] an event was investigated for a generating unit in Texas, related to a system frequency excursion. Figure 2-1 shows the response of the unit to a system frequency event as recorded by the plants Honeywell DCS. The sampling rate is one sample per second. The unit is owned and operated by CPS Energy. It is clear from the figure (and discussions with CPS staff) that the unit is on Automatic Generation Control (AGC). Thus, roughly 40 or so seconds after the event AGC starts to ramp the unit up (as well as presumably other units in the system) in order to restore system frequency. Modeling AGC is outside the scope of this project. However, if we look only at the first 40 to 50 seconds prior to AGC action we can attempt to fit the turbine-governor response. In [1] an attempt was made to do this using the standard IEEEG1 steam-turbine governor model – shown in Figure 2-2.

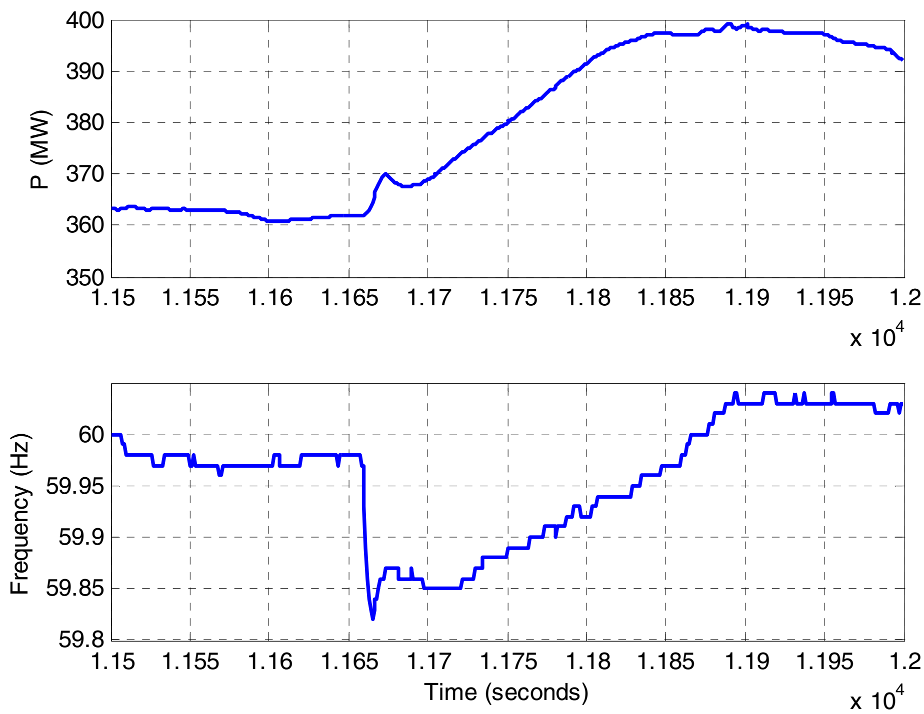


Figure 2-1
Steam turbine response to system frequency event.

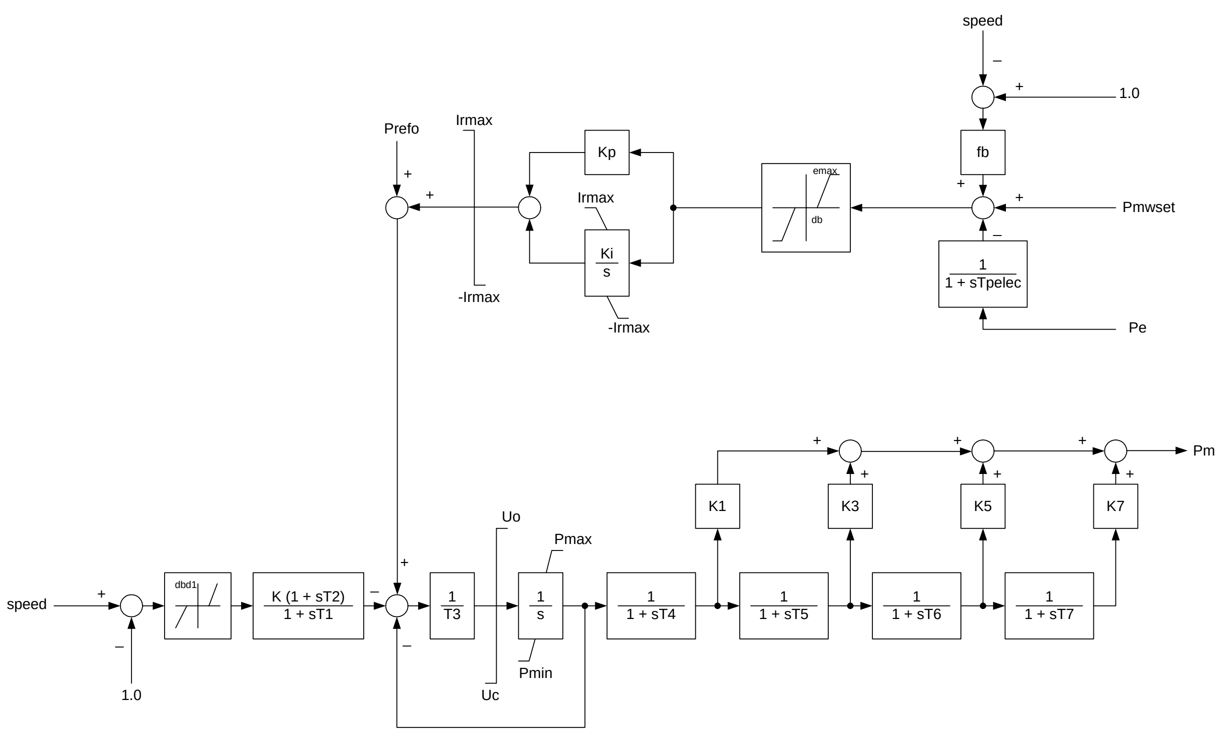


Figure 2-2
Steam-Turbine model. This is a model developed by combining the standard IEEEG1 steam-turbine model with an outer-loop MW-controller (the *lcfb1* model in GE PLSF®).

For completeness, we will repeat the description of the analysis performed in [1] to identify the issue to be investigated here. The data obtained from the Honeywell DCS has a sampling rate of 1 Hz (1 sample per second). Since the response of the turbine-governor is quite slow (as compared to the excitation system), this level of sampling is adequate. However, before importing the data into PPPD (see [2] for a description of PPPD) two actions were taken:

1. Since the initial system frequency was 59.98 Hz (just prior to the event), 0.02 Hz (0.00033 pu) was added to the entire frequency record to make the initial frequency 60 Hz to avoid initialization problems with the model. This is a negligible frequency deviation and thus has no significant affect on the results. It is simply an easier action than changing the code to make the initial system frequency equal to 59.98 Hz in the model.
2. The data was re-sampled, using a simple sample-and-hold method, to increase its sampling rate to 200 Hz. This is because PPPD uses an Euler integration technique and thus this was done to provide an integration time-step of at least one-half cycle or more for reasonable fidelity for this event.

The fits obtained using the model in Figure 2-2 are shown in Figure 2-3 and Figure 2-4, with the respective fits provided in Table 2-1. It might be tempting to think, based on these results, that the second fit is a better fit and thus the re-heater time constant is of the order of 200 seconds. This, however, would be in correct. In fact, the first fit is the more correct one, which agrees with the staged test results [1]. The unit does indeed have a droop of 5% (as confirmed by staged testing and discussions with the equipment vendor – see Appendix C of [1]) and the re-heater time constant is of the order of 10 seconds. The reason for the large discrepancy between the fitted and measured response in Figure 2-3 is that the IEEEG1 model (and most other standard IEEE models for steam-turbines) is not adequate for representing the full dynamics of this unit. This can be seen in Figure 2-5. As shown, when the frequency disturbance occurs the main steam control valve immediately begins to open based on droop control action. This leads to a sudden drop in main steam pressure. Thus, the coordinated control scheme begins to shut the valve to restore pressure and as pressure is restored the valve begins to open again. Thus, the turbine controls are controlling frequency and steam conditions in a "coordinated way", rather than allowing the valves to go wide open to deliver the requested power all at once. This is because suddenly opening the valves all the way may result in unacceptable steam conditions and result in an unstable boiler condition. Also, note that even if we do not represent the coordinated control, it is clear from the turbine response that the inherent assumption of "constant pressure and temperature steam" in the IEEEG1 model is not valid. Thus, to truly capture the dynamics presented here we need a more detailed model.

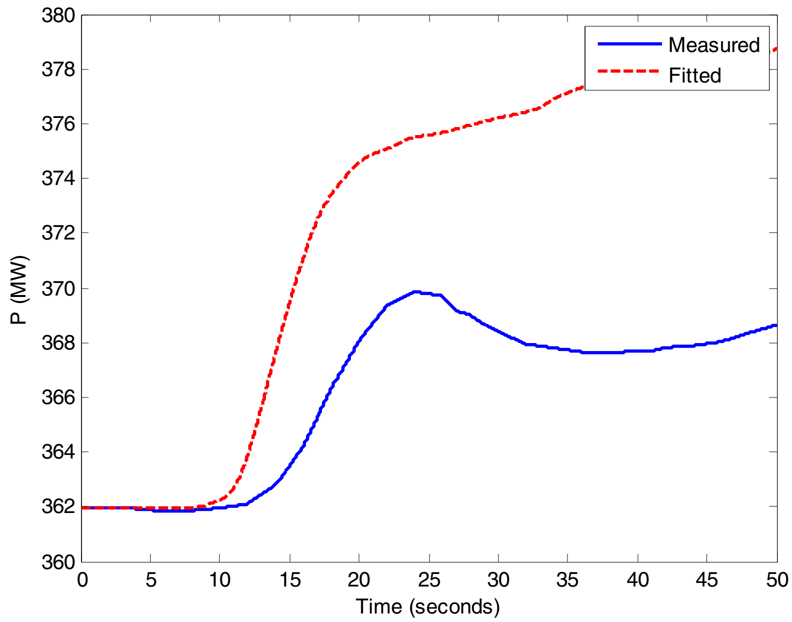


Figure 2-3
Unit response to system frequency dip – prior to AGC action. (First fit)

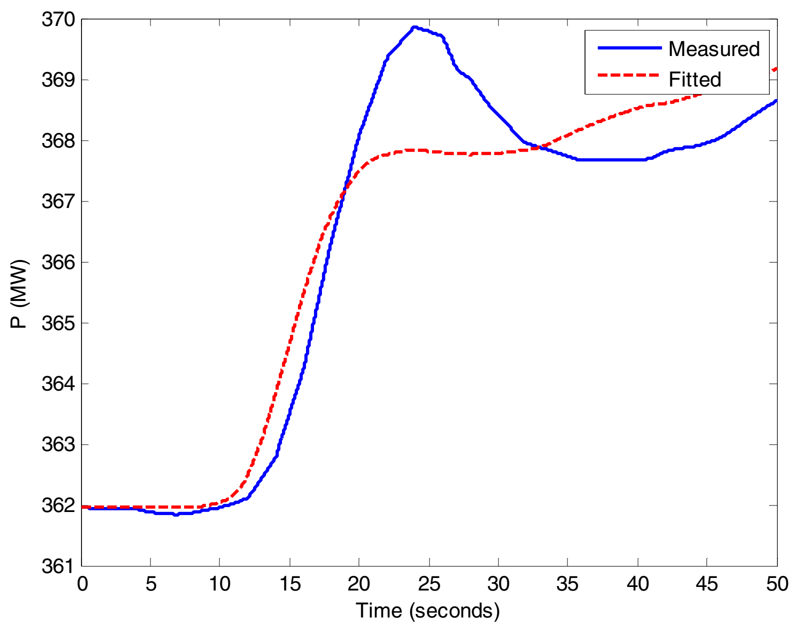


Figure 2-4
Unit response to system frequency dip – prior to AGC action. (Second fit)

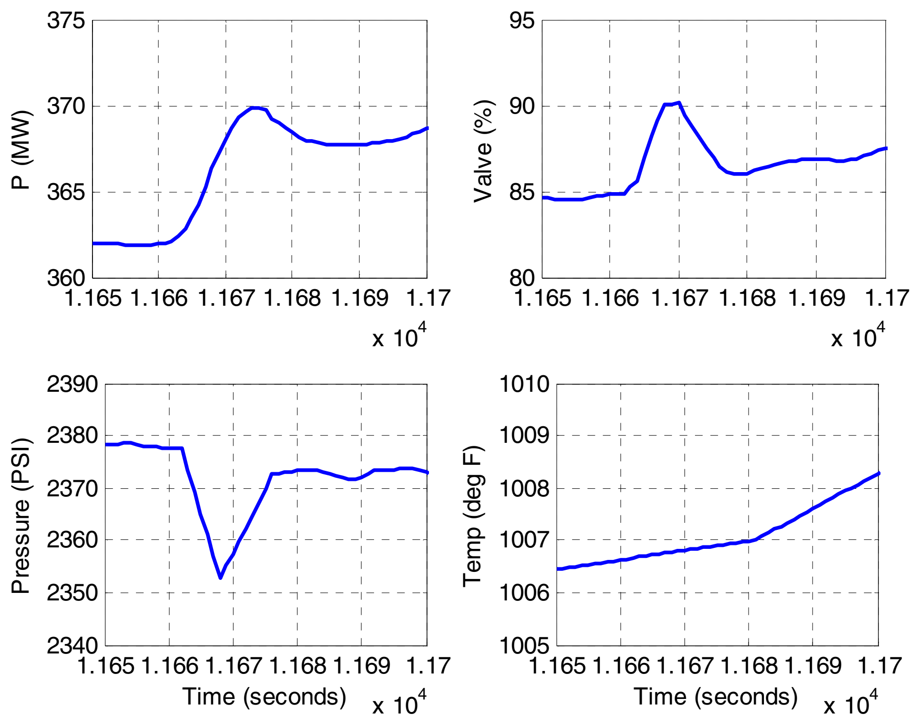


Figure 2-5
A plot of the various turbine-boiler variables; Main steam control valve position, main steam pressure and main steam temperature.

Table 2-1
Fitted parameters for the turbine-governor model

Parameter	Staged Test	First Fit of Event	Second Fit of Event	Description
K	20	20	20.5	Control setting
T1	0	0	0	Not used
T2	0	0	0	Not used
T3	0.2	1	1	Simulation
Uo	0.1	0.1	0.1	Simulation
Uc	-0.1	-0.1	-0.1	Simulation
Pmax	1.0	1	1	By definition
Pmin	0	0	0	By definition
T4	0.5	0.6	4.12	Simulation
K1	0.3	0.3	0.3	Simulation
K2	0	0	0	Not used
T5	10.0	11	200	Simulation
K3	0.7	0.7	0.7	Simulation
K4	0	0	0	Not used
T6	0	0	0	Not used
K5	0	0	0	Not used
K6	0	0	0	Not used
T7	0	0	0	Not used
K7	0	0	0	Not used
K8	0	0	0	Not used

2.3 Boiler-Turbine Model

Modeling the dynamics of a steam turbine boiler has been documented in the literature. For the purposes of power system dynamic simulations, a simplified approach to modeling the boiler dynamics is presented in [3] – which is perhaps the definitive paper on the subject. In two of the commercially available software programs, GE PSLF® and Siemens PTI PSS®E such models exist in the form of the so-called *ccbt1* model in GE PSLF® and the *tgov5* model in Siemens PTI PSS®E. The models *ccbt1* and *tgov5* are quite large – *ccbt1* has 72 parameters and *tgov5* has 48. Here we propose a simpler representation as shown in Figure 2-6 – this model can be seen as a simpler version of *tgov5* or *ccbt1*, and is still based on the simple boiler-dynamics representation presented in [3].

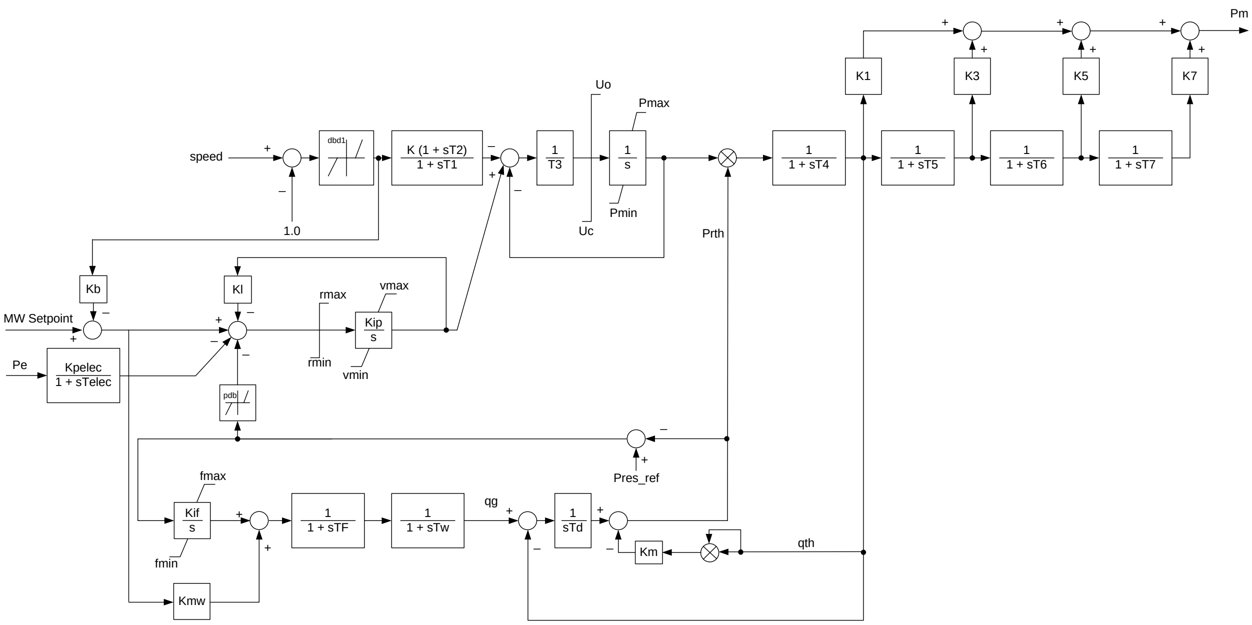


Figure 2-6
Steam-turbine model including simplified representation of boiler-dynamics.

The model can be easily explained. The top half is simply the well-know IEEEG1 model, representing the droop feedback loop, the valve actuator and the multiple turbine stages. The lower half represents the boiler dynamics (1/sTd), pressure losses in the steam path (Km), the time constants associated with the water-wall in the boiler (Tw) and the fuel system (TF), and two simple control loops (Kif and Kip) to effect coordinate pressure control. Also, in the Kip control loop we have the option of introducing outer-loop MW control through electrical power feedback (Pe). Note: this is still a simplified model, and is proposed here to illustrate some of the boiler dynamics, it is not adequate for modeling the dynamics of the boiler-turbine over its entire operating range, since even in this model we have made the simplifying assumption that steam temperature is constant (which is reasonable for the type of events we are studying see Figure 2-5) and the reference pressure is also shown as a constant, this is not true since the steam pressure is changed as the unit loads and unloads (see Appendix C of [1]).

2.4 Results

Based on staged testing conducted by the author (see Appendix C of [1]) we know for this unit that the droop control is based on speed error feedback and set at 5% droop on turbine rating. So the parameters K, T3, T2, T1, Uo, Uc, Pmax and Pmin are based on the results from [1].

The turbine sections part of the model can be set based on the actual design. Figure 2-7 shows the actual design of this turbine diagrammatically. Thus, T4/K1 represent the high-pressure turbine stage (HP), T5 represents the reheater delay (we would set K3 to zero, since there is not power developed in the reheater of course), T6/K5 represent the intermediate pressure turbine stage (IP) and T7/K7 the low-pressure turbine stage (LP). Based on the manufacturer data the turbine fractions are: K1 = 0.249, K3 = 0; K5 = 0.249 and K7 =0.502. The time constants were confirmed to be T4 = 0.25, T5 = 10; T6 = 0.25 and T7 = 1 based on simulations, as shown in Figure 2-8.

First, if we take the measured valve position and the measured steam-pressure and per unitize these values and multiply them, then we will obtain the per unit steam mass flow through the MCV. This also corresponds to the per unit steam power into the HP turbine from the MCV. Thus, as shown in the lower half of Figure 2-7 by imposing the product of measured valve position by measured steam-pressure on the input of the turbine-section model we can compared the measured power response with the simulated power response to confirm our model of the turbine-section. This is what is illustrated in Figure 2-8 a). The simulation in Figure 2-8 a) shows the simulated versus measured power response for the case where the product of the measured valve-position and steam-pressure is imposed on the turbine-section model shown in Figure 2-7, with the parameters given above, i.e. K1 = 0.249, K3 = 0; K5 = 0.249, K7 =0.50, T4 = 0.25, T5 = 10; T6 = 0.25 and T7 = 1.

At first sight, one might be inclined to think that the fit shown in Figure 2-8 a) is not quite adequate and needs further fine tuning. Consider the plot shown in Figure 2-9. Here a plot is provided of the quasi steady-state (slow ramping down of power) values of turbine (generator) power output versus MCV where steam-pressure was kept essentially constant. It can be seen that the valve/power relationship is slightly non-linear. If we fit a curve to this response (dotted red-line in the figure) and then apply this non-linear behavior as a look-up table in the model to represent the actual valve characteristic then we get the response shown in Figure 2-8 b). Thus, it is seen that the parameters for the turbine model are quite adequate. For the rest of the simulations below, we neglected this slight non-linearity in the valve characteristic and assumed a perfectly linear valve.

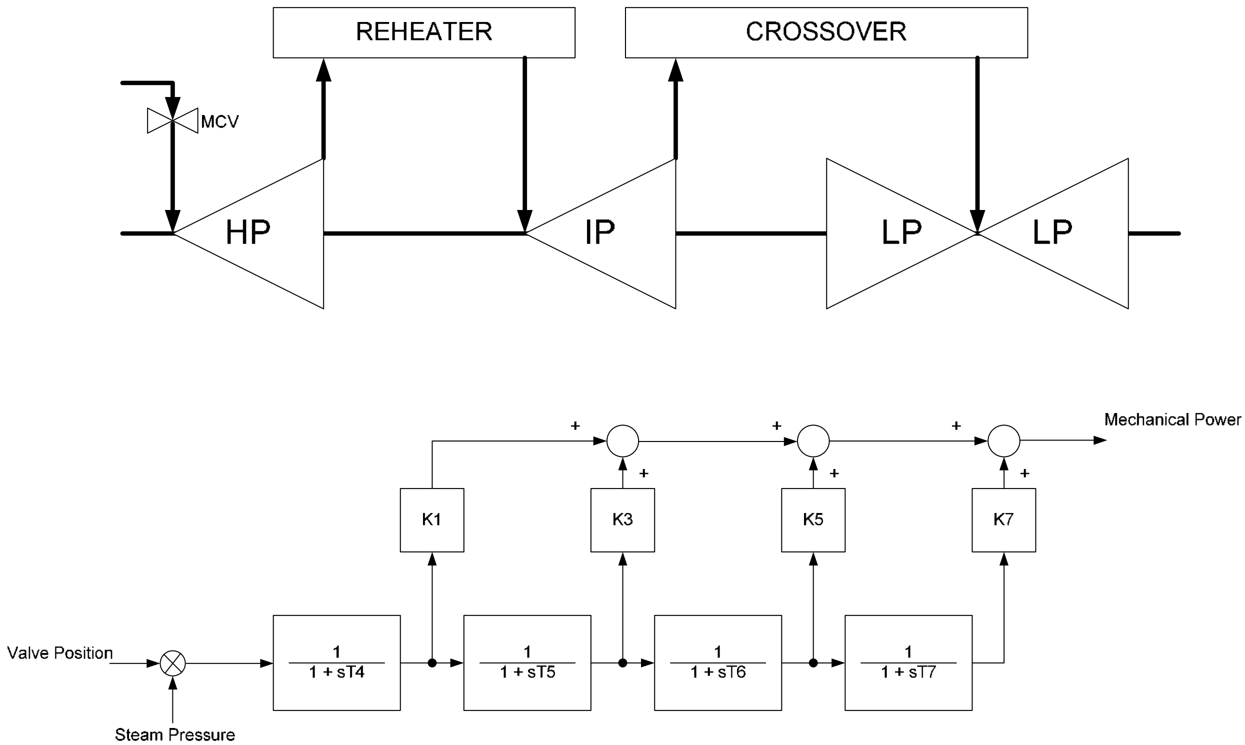
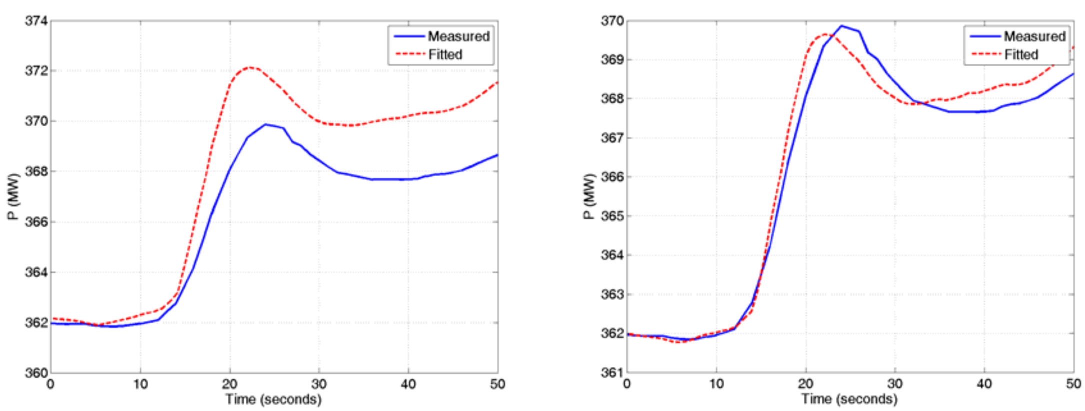


Figure 2-7
Turbine sections for the steam-turbine.



a) Turbine model response – linear valve **b) Turbine model response – non-linear valve.**

Figure 2-8
Response of turbine model – the measured steam pressure times measured valve position was imposed on the turbine only model input and the corresponding simulated power compared to the measured power (see Figure 2-7). In a) is shown the case where the valve characteristic is assumed ideal (linear), and b) shows the case where it is modeled as non-linear (per red curve in Figure 2-9).

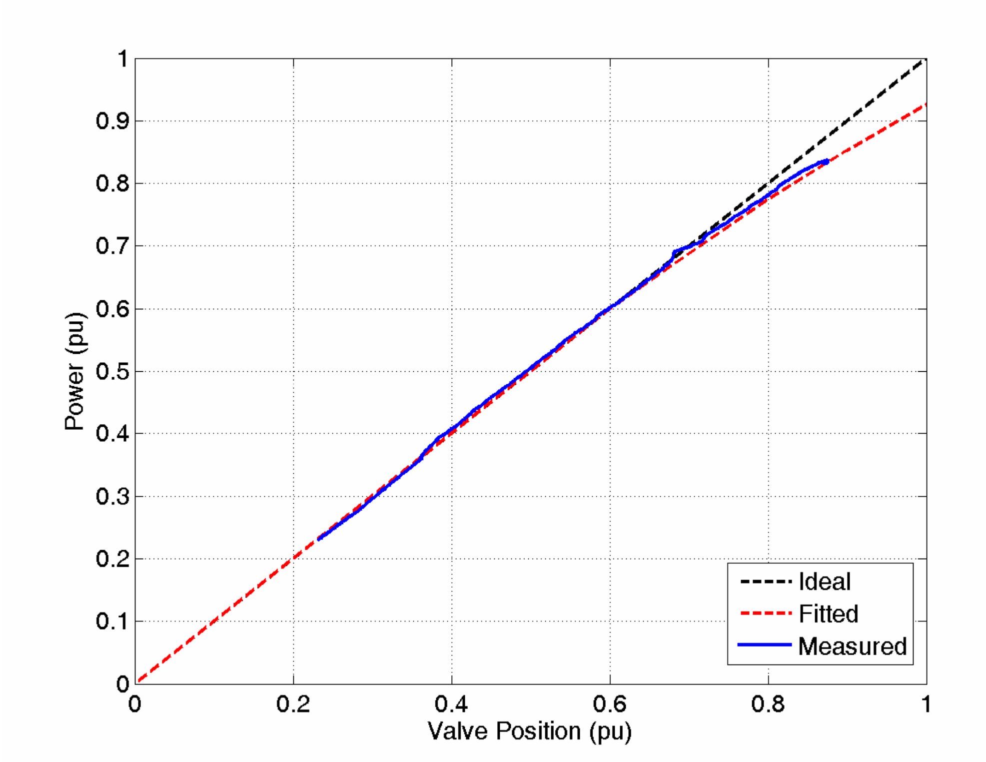


Figure 2-9
Main Control Valve characteristic. Measured power versus MCV position is shown at relatively constant steam-pressure, during quasi steady-state conditions while unloading the unit from near base-load.

The next step, after having established the turbine-section model, was to introduce the turbine controls. Thus we move to the full model shown in Figure 2-6. Thus, measured speed[2] becomes the input to the model and power is the output. With the parameters of the turbine-section set to that discussed above, the other controllers were fitted to achieve the response shown in Figure 2-10. The fitted parameters are listed in Table 2-2. Note that the fitting exercise here was not done through an automated least-squares algorithm as with the other models in PPPD [2]. Here we developed the model piece by piece in MATLAB® and simulated/verified each piece through trial and error, with some prior knowledge of the turbine fractions from manufacturer data.

The final fit in Figure 2-10 shows a much closer match between the modeled and actual response of the unit than that initially achieved with the IEEEG1 model (see Figure 2-3). So from this exercise we may conclude that the mismatch in Figure 2-3 was indeed due to the lack of representation of the boiler dynamics and control, and by adding some rudimentary emulation of these dynamics and control we are indeed able to get a closer match between measured and simulated response. It should be emphasized that the model in Figure 2-6 is a highly simplified representation of the boiler dynamics and control and in no way claims to be an exact representation. Thus, we see that even in Figure 2-10 we do not have a perfect fit, but rather a

[2] In our case we have measured frequency at the terminals of the generator, which for the purposes of this analysis is synonymous to speed.

better representation of the general dynamics. With this said it should be realized that the purpose of this exercise was simply to illustrate the reasons for the initial observed mismatch and the missing dynamics. This analysis is not intended to imply that we need to move to more complex models for steam-turbines in transmission planning studies – this is a subject for further discussion and outside the scope of this document. Suffice it to say there is no such thing as a perfect model. All models have limitations and uncertainties associated with them. When embarking on any study one must first identify the dynamics and parameters to which the system under study is likely to be most sensitive to and thus choose the appropriate model for the task – which then must be validated.

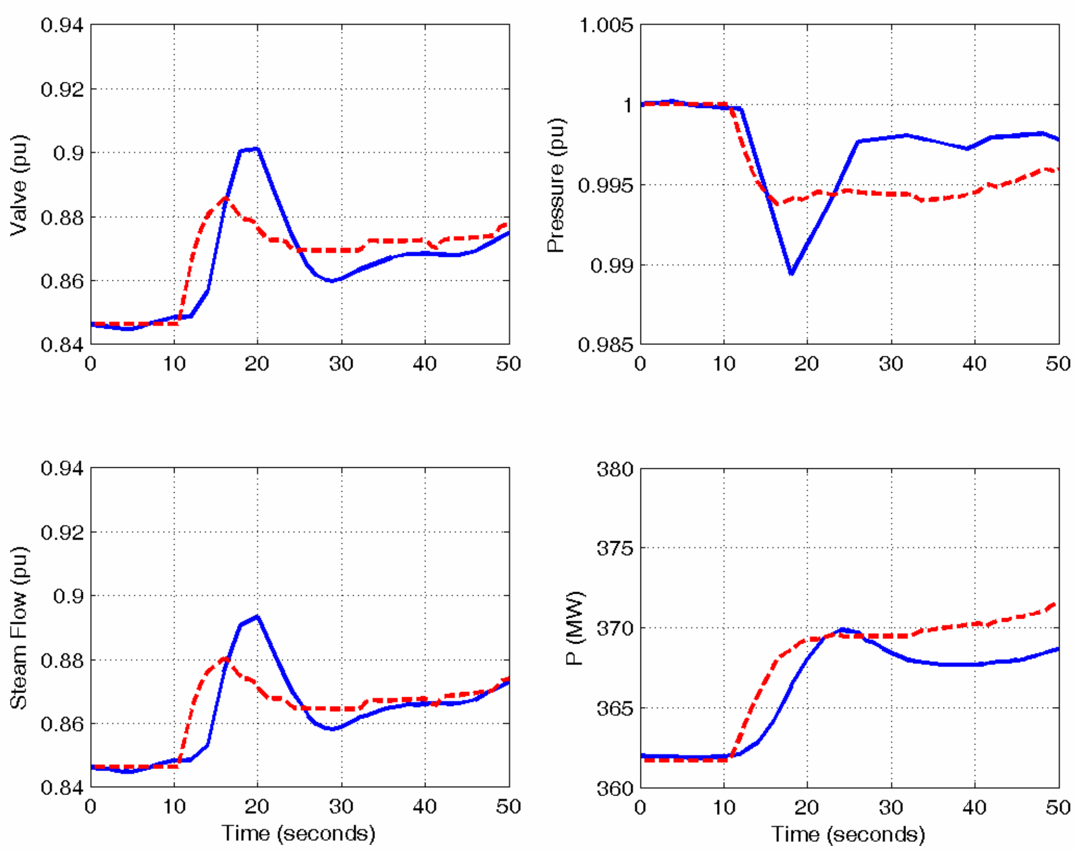


Figure 2-10
Comparison of simulated and measured response for the full turbine-boiler model.

Table 2-2
Fitted parameters for the turbine-boiler model

Parameter	Fitted value	Description
K	20	Control setting
T1	0	Not used
T2	0	Not used
T3	0.2	Simulation
Uo	0.1	Simulation
Uc	-0.1	Simulation
Pmax	1.0	By definition
Pmin	0	By definition
T4	0.25	Simulation
K1	0.249	Manufacturer Data
T5	10.0	Simulation; re-heater time constant
K3	0.0	Manufacturer Data; T5 represents the re-heater
T6	0.25	Simulation
K5	0.249	Manufacturer Data
T7	1	Simulation
K7	0.502	Manufacturer Data
Kb	0	Disabled
Kl	1.0	Unity feedback
pdb	0	Disabled
Kpelec	0	Disabled Outer Loop Control
Telec	0	Disabled Outer Loop Control
Kip	1	Simulation
rmax	99	Disabled
rmin	-99	Disabled
vmax	1	
vmin	-1	
Pres_ref	1	Set initial pressure to 1 pu and defined as reference
Kif	0.5	Simulation
fmax	0.5	
fmin	-0.5	
Kmw	1	
TF	10	Simulation
Tw	5	Simulation
Td	120	Simulation
Km	0.088	Simulation

2.4 Conclusion

The purpose of this exercise was simply to illustrate the reason for the initial observed mismatch between the IEEEG1 model's simulated response and the measured response of the steam-turbine generator studied in [1]. It has been successfully shown that the reason was due to the missing dynamics of the boiler and associated controls. This analysis is not intended to imply that we need to move to more complex models for steam-turbines in transmission planning studies – this is a subject for further discussion and outside the scope of this document. All models have limitations and uncertainties associated with them. When embarking on any study one must first identify the dynamics and parameters to which the system under study is likely to be most sensitive to and thus choose the appropriate model for the task –which then must be validated.

3
FITTING RESPONSE BASED ON FAULT DATA

In the 2008 work [1] it was stated that unbalanced events, such as an unbalanced fault tended to be not so useful for model validation. This was based on the fact that the models under question are positive sequence models for stability analysis, which are unable to represent unbalanced conditions. Here we present some further investigation of this issue.

Figure 3-1 shows an event capture, by a digital fault recorder (DFR) in the plant, for an unbalanced fault. This data was captured for a Tri-State unit in the course of a supplemental project EPRI is conducting together with Tri-State – thus, we would like to acknowledge and thank Tri-State for the data. The DFR data was captured on a large (496 MVA) steam-turbine generator. As can be seen the event is clearly an unbalanced fault. In the middle plot is shown the extracted "positive-sequence" component of the three-phase stator voltage. This can be easily done using Park's transformer. It was accomplished in this case using a library block in the MATLB® SimPower Systems Toolbox, which can extract the positive-sequence component of a 3-phase set of signals. For this event the unit was at 97% of its rated MW output.

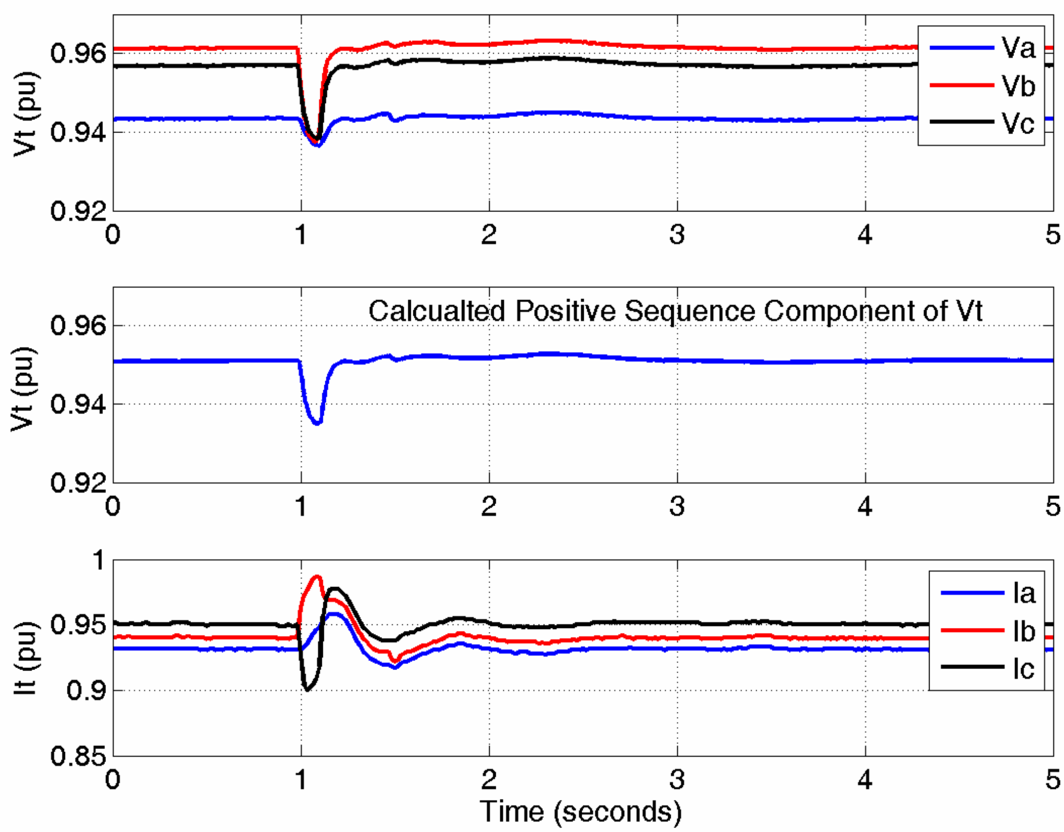


Figure 3-1
Nearby fault event on September 20, 2009 for a large steam-turbine generator unit.

If we now apply the PPPD tool (knowing the base-line data) to the positive-sequence component of voltage and the measured field quantities, speed, and 3-phase real and reactive power, we get the fit shown in Figure 3-2. This clearly validates the electrical generator and excitation system response, since as can be seen the fit is actual relatively good. There are a few pertinent comments:

1. Although not discussed here in detail, this same unit has been validated for several balanced disturbances and the results of those validation cases (i.e. confirmed model parameters) agree with those from this event (see Figure 3-3).
2. In Figure 3-2 there is a slight mismatch just after the fault clears. This is likely attributable to the fact that we have an unbalanced case. Fits for the same unit with balanced events give an almost perfect fit between the stator-voltage that is measured and simulated – for example, see Figure 3-3.
3. There is a small (~4% relative error) bias error between the simulated and measured field current, as seen in the bottom half of Figure 3-2. The same exact error was seen at several operating points. This error can be attributed to several possible sources as discussed in detail in [1] – namely, measurement error in the field current measurement transducer, residual flux due to magnetic hysteresis etc.

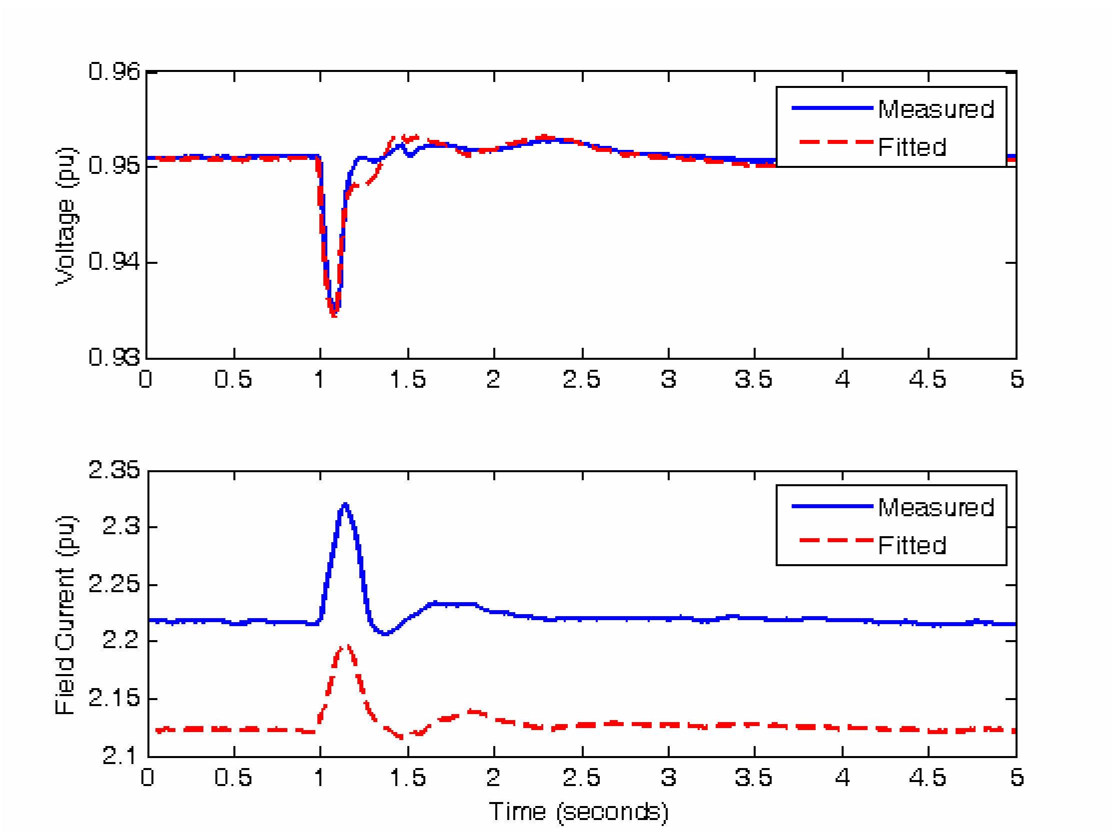


Figure 3-2
Fit for the captured event using PPPD.

It is not shown here, but of course as illustrated in [1] the initial rotor acceleration during such a fault can be used to verify the unit's inertia.

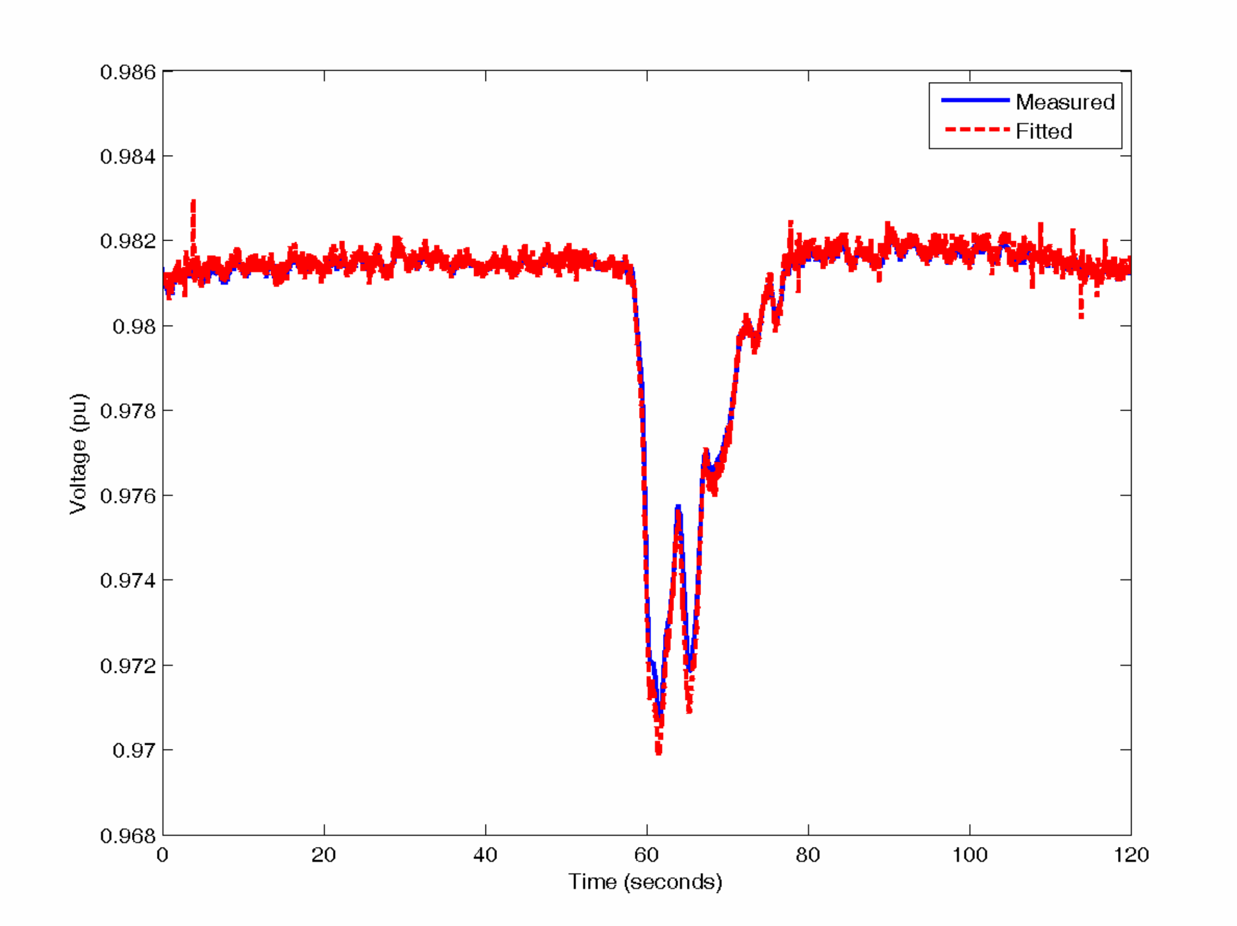


Figure 3-3
Fit for the same large steam-turbine generator unit for a balanced event.

3.1 Conclusion

Based on the results shown here we can conclude that by extracting the positive-sequence component of the 3-phase stator voltage and using it for model validation, unbalanced events may be used for validation purposes. There of course may be a limit to such an approach for extreme unbalanced conditions, e.g. a close in single-line to ground fault.

4
HYDRO-TURBINE GENERATORS

3.1 Introduction

All the generators investigated in our previous report [1] were for large steam or gas turbines and thus primarily round-rotor generators. For round rotor generators the typical model used is the *genrou* model. In [1] for many different cases this was shown to be a sufficient model. Hitherto, it was commonly accepted that for modeling large salient pole machines, such as used for hydro-turbine generators the *gensal* model should be used. Recently, in roughly the past year, work in WECC has shown that the *gensal* model is incapable of adequately representing the on-load saturated behavior of these salient pole generators. Thus, the newly approved *gentpj* model was developed in WECC. Here we take a look at this model.

2.3 The WECC *gentpj* Model

The WECC gentpj model, which has been presented, discussed and approved at WECC Modeling and Validation Working Group meetings, is an augmentation to the existing *gentpf* generator model. In brief terms, the key difference between this model and the hitherto widely used generator models is that it introduces a new parameter, *kis*, which incorporates a component of the generator saturation that is proportional to stator current magnitude. In addition, of course, the sign of this component changes based on the direction of flow of the direct-axis component of current, i.e. whether the generator is absorbing or providing reactive power to the system.

2.4 Results and Conclusions

We were able to get on-line disturbance recorded data, through a Non-Disclosure Agreement from one utility for a large hydro-turbine generator. Regrettably though, after some extensive work some data issues were identified. The data issues have not yet been adequately rectified and so we were not able to perform any useful analysis to present results in this update. Thus, this subject will need to be further pursued as part of the User's Group for the PPPD software, which will start in 2010.

5 CONCLUSIONS AND RECOMMENDATIONS

In the 2008 (early 2009) work [1] an issue was demonstrated with respect to turbine-governor modeling. Namely, the inability of standard (relatively simple) models used in planning studies for steam-turbines to be able to properly represent the behavior of boiler dynamics. This is not necessarily a new observation, and there have been several proposed models for representing boiler-dynamics in the literature. The question is whether the on-line disturbance monitoring data captured in [1] can be used to fit the response of the unit to more complicated boiler-turbine models in order to achieve a better representation of the unit's behavior. It has been illustrated here that this is possible with the addition of a simplified representation of the boiler dynamics and associated coordinated boiler-turbine controls. However, we clearly do not achieve a perfect fit since only a simplified emulation was added to the model for representing the boiler dynamics. It is again emphasized that this result alone does not necessarily justify the need to pursue more complex turbine-governor models for large-steam turbines – such a discussion is beyond the scope of this work. At this stage we do not necessarily see the value of adding such a model to PPPD.

A second goal of this report was to reinvestigate the possibility of using on-line data captured from unbalanced fault events for model validation purposes – particularly validating the electrical generator and excitation system response. Based on an actual event capture of an unbalanced fault near a large steam-turbine generator unit, it has been shown that it is possible to use such data for model validation. There may, however, be a limitation for cases of extreme unbalance.

A third goal of this report was to look at model validation for large salient pole synchronous generators. All the generators investigated and studied under [1] were for large steam or gas turbines and thus primarily round-rotor generators. For round rotor generators the typical model used is the *genrou* model. In [1] for many different cases this was shown to be a sufficient model. Hitherto, it was commonly accepted that for modeling large salient pole machines, such as used for hydro-turbine generators the *gensal* model should be used. Recently, in the past year, work in WECC has shown that the *gensal* model is incapable of adequately representing the on-load saturated behavior of these salient pole generators. Thus, the newly approved *gentpj* model was developed in WECC. We were able to get on-line disturbance recorded data, through a Non-Disclosure Agreement from one utility for a large hydro-turbine generator. Regrettably though, after some extensive work some data issues were identified, which have not yet been resolved. Thus, we were not able to perform any useful analysis to present results in this report. This subject will need to be further pursued as part of the User's Group for the PPPD software, which will start in 2010.

6
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[1] *Automated Model Validation for Power Plants Using On-line Disturbance Monitoring*. EPRI, Palo Alto, CA: 2009. Product ID # 1016000.

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