“All-in-one” test system modelling and simulation for multiple instability scenarios

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“All-in-one” test system modelling and simulation for multiple instability scenarios

This report presents modelling and simulation results for multiple instability scenarios of the “All-in-one” test system originally introduced in . The test system is an alteration of the BPA test system described in [1, 2] constructed to capture transient (angle), frequency and voltage instability phenomena (resulting in system collapse) within one system. The report can be divided into two parts: (i) system modelling and (ii) simulation results. In the first part, system modelling and data associated with all the device models are briefly summarized. The second part of the report provides a description of different instability scenarios that can be simulated with this system.

1 System Modelling

A one-line diagram of the “All-in-one” test system is shown in Fig. 1. The system consists of a local area connected to a strong grid (Thevenin Equivalent) by two 380 kV transmission lines. A motor load (rated 750 MVA, 15 kV) is connected at Bus 4 and supplied via a 380/15 ratio transformer. A load with constant power characteristics and LTC dynamics of at the distribution transformer is explicitly modelled at Bus 5. A local generator (rated 450 MVa, 20 kV) is connected at Bus 2 to supply the loads through a 20/380 ratio transformer.

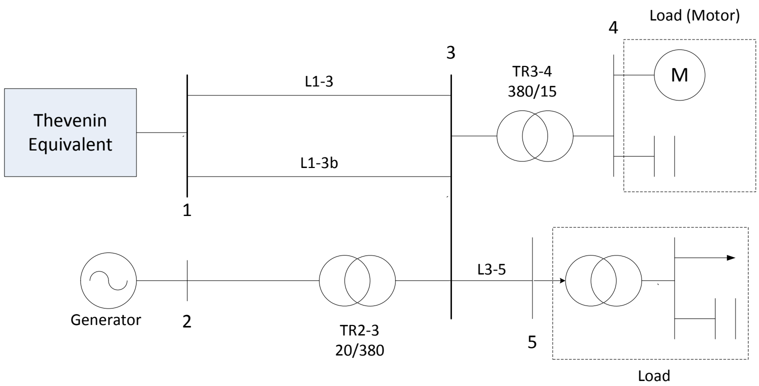


Figure 1: “All-in-one” test system

In addition, the following sections outline the different device models used for each component.

1.1 Excitation System

From the power system viewpoint, excitation systems should be capable of responding rapidly to a disturbance so that proper support is provided through excitation control. Thus, excitation systems should be designed to have fast acting response to enhance transient stability. This fast response need has been taken into consideration by manufactures which have developed excitation control systems, such as the GE EX2100 [3], Westinghouse’s static excitation system [4], and others, which can be modelled by using the IEEE Type ST excitation models recommended by the IEEE standard 421.5 [5]. In this study, the ST1A model (shown in Fig. 2) is implemented, simplications are made by setting model parameters to appropriate values.

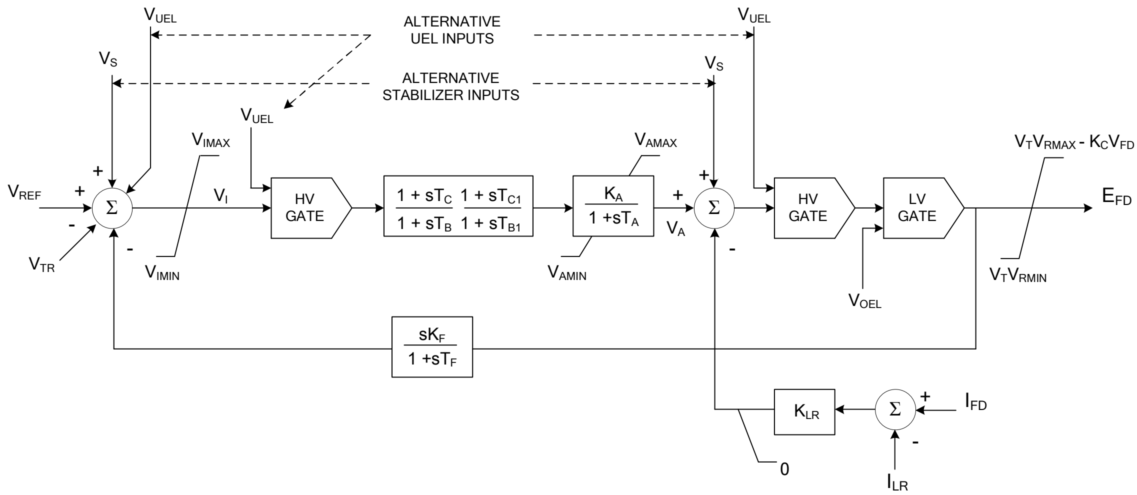


Figure 2: ST1A Excitation system block diagram showing major functional blocks (adapted from [5])

In order to simplify the ST1A excitation system, the time constants T_B, T_{B1}, T_C and T_{C1} in the forward path are set to zero. The internal excitation control system stabilization represents in the feedback path with the gain K_F and internal limits on V_I can be neglected in many cases [5]. Moreover, the current limit (I_{LR}) and gain K_{LR} of a field current limiter are set to zero. An underexcitation limiter (V_{UEL}) input voltage is also ignored, nevertheless an overexcitation limiter (V_{OEL}) is added at the first summation junction instead of the low voltage gate.
Figure 3 depicts the excitation system obtained from the simplifications above, and used in this study. The input signal of the excitation system is the output of the voltage transducer, V_{TR}. This voltage is compared with the voltage regulator reference, V_{REF}. Thus, the difference between these two voltages is the error signal which drives the excitation system. An additional signal from overexcitation limiter (OEL) output, V_{OEL}, becomes non-zero only in the case of unusual conditions. The operation of OEL is described in Section 1.2. Table 1 contains parameters for the excitation system in this study.

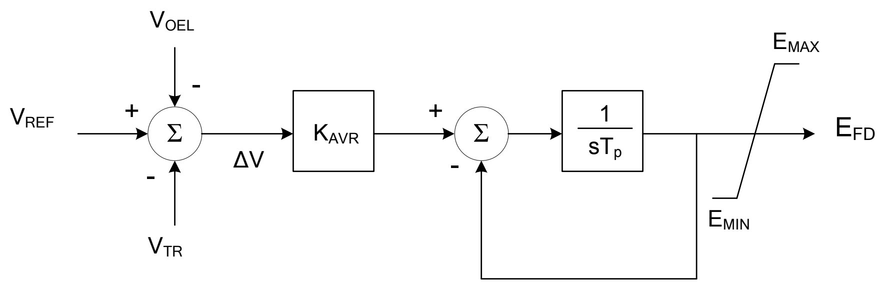


Figure 3: Simplified Excitation system model obtained by simplifying the IEEE ST1A excitation model

Table 1: Excitation system parameter values

Symbol	Description	Value
K_{AVR}	AVR gain	50.0 [p.u.]
E_{MAX}	Maximum excitation limit	1.0 [p.u.]
E_{MIN}	Minimum excitation limit	-1.0 [p.u.]
T_P	Excitation time constant	0.1[s]

1.2 Overexcitation Limiter (OEL)

An overexcitation limiter (OEL) model is necessary to capture slow acting phenomena, such as voltage collapse, which may force machines to operate at high excitation levels for a sustained duration. According to the IEEE recommended practice 421.5 [5], OELs are required in excitation systems to capture slow changing dynamics associated with long-term phenomena. The OEL's purpose is to protect generators from overheating due to prolonged field overcurrents. This can be caused either by the failure of a component inside the voltage regulator, or an abnormal system condition. In other words, it allows machines to operate for a defined time-overlaod period, and then reduces an excitation to a safe level. A standard model that can be used to implement most OELs can be found in [6]. In this study, an OEL is modelled and implemented as the block diagram shown in Fig. 4.

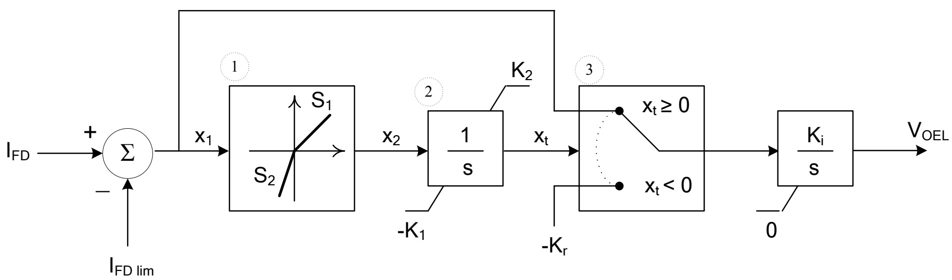


Figure 4: Overexcitation limiter (adapted from [7])

The OEL detects high field currents (I_{FD}) and outputs a voltage signal (V_{OEL}) which is sent to the excitation system summing junction. This signal is equal to zero in normal operation condition. In other words, V_{OEL} is zero if I_{FD} is less than I_{FDlim}. As a result the ΔV signal is altered so that the field current is decreased below overexcitation limits (forces I_{FD} to I_{FDlim}). As shown in Fig. 4, Block 1 is a two-slope gain obeying the following expressions.

$$x_2 = S_1 x_1 \quad \text{if } x_1 \geq 0, \tag{1}$$
$$= S_2 x_1 \quad \text{otherwise} \tag{2}$$

Assume that I_{FD} becomes larger than I_{FDlim}, this means that x_t is also greater than zero. Thus, Block 3 switches as indicated in Fig. 4 and the signal is sent to the wind-down limited integrator to produce V_{OEL}. Large values of S_2 and K_r cause V_{OEL} to return zero when I_{FD} is less than I_{FDlim}. Parameters for the OEL implemented in this study are given in the Table 2.

Table 2: OEL parameters

Parameters	Description	Value
K_1	Lower bound of OEL timer	20 [s]
K_2	Upper bound of OEL timer	0.1 [s]
K_r	Reset constant of OEL	1.0 [p.u.]
K_i	Integral gain of OEL	0.1 [p.u.]
I_{FDlim}	Max field current enforced by OEL	1.0 [p.u.]

1.3 Speed-Governing System

A typical mechanical-hydraulic speed-governing system consists of a speed governor, a speed relay, hydraulic servomotors, and controlled valves, which are represented in the functional block diagram in Fig. 5

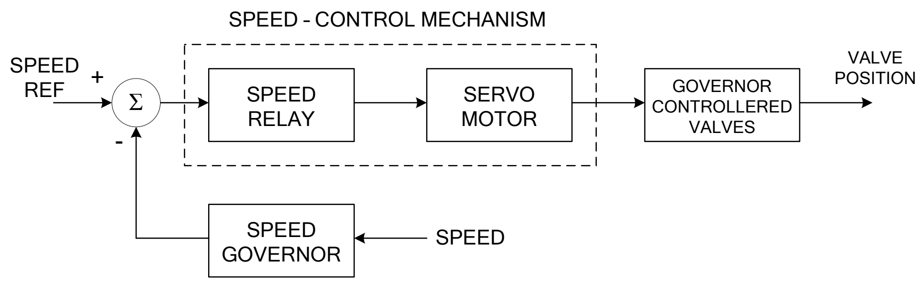


Figure 5: Functional block diagram of a typical speed-governing system

The speed-governor regulates the speed of a generator by comparing its output (obtained after a shaft speed is transformed into a valve position) with a predefined speed reference, the resulting error signal is sent to and amplified by a speed relay. The servomotor is necessary to move steam values (especially, in case of large turbines) and can be considered as an amplification. A standard model that can be used to represent a mechanical-hydraulic system as shown in Fig. 6, can be found in an IEEE Working Grouping Report [8]. This model is altered by many manufacturers, such as GE and Westinghouse, by applying different time constants T_1, T_2, and T_3. In this study, the Westinghouse EH Without Steam Feedback is considered and Table 3 provides a listing of the parameters used to represent this steam turbine system.

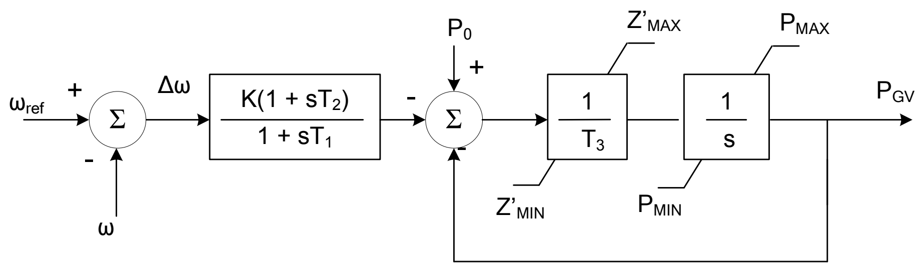


Figure 6: General model for a speed-governing steam turbine system

Table 3: Steam system parameters

Symbol	Description	Value
T_1	Governor time constant	0.0 [s]
T_2	Governor derivative time constant	0.0 [s]
T_3	Servo time constant	0.1 [s]
K_1	Controller gain	25 [p.u.]
Z'_{MAX}	Max rate of change of main valve position	0.1 [p.u./s]
Z'_{MIN}	Min rate of change of main valve position	-0.1 [p.u./s]
P_{MAX}	Maximum power limit imposed by Valve	1.0 [p.u.]
P_{MIN}	Minimum power limit imposed by Valve	-1.0 [p.u.]
P_0	Pre-fault mechanical power	–

1.4 Steam Turbine System

A steam turbine converts stored energy from high pressure and temperature steam into rotating energy, which in turn is converted into electrical energy by a generator. The general model used for representing steam turbines is provided in [8]. This model is applicable for common steam turbine system configurations which can be characterized by an appropriate choice of model parameters. A steam system, tandem compound single reheat turbine, was selected for this study, as shown in Fig. 7. This turbine is represented by a simplified linear model [8], which is shown in Fig. 8.

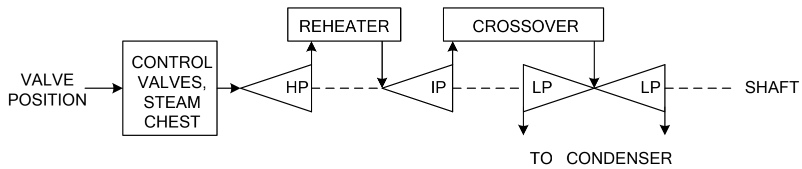


Figure 7: Steam turbine configuration

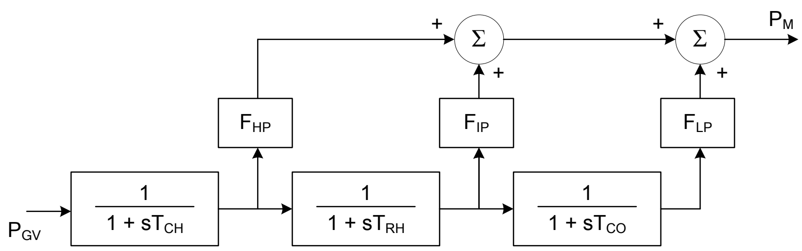


Figure 8: Approximate linear model representing the turbine in Fig. 7

From Fig. 7, steam enters the high pressure (HP) stage through the control valves and the inlet piping. The housing for the control valves is called "steam chest". Then, the HP exhaust steam is passed through a reheater. Physically, this steam returns to the boiler to be reheated for improving efficiency before flowing into the intermediate pressure (IP) stage and the inlet piping. Subsequently, the crossover piping provides a path for the steam from the IP section to the low pressure (LP) inlet. Table 4 contains a listing of the parameters used for modelling this steam turbine system.

Table 4: Steam turbine model parameters

Symbol	Description	Value
F_{HP}	High pressure power fraction	0.4 [p.u.]
F_{IP}	Intermediate pressure power fraction	0.3 [p.u.]
F_{LP}	Low pressure power fraction	0.3 [p.u.]
T_{CH}	Steam chest time constant	0.2 [s]
T_{RH}	Reheat time constant	4.0 [s]
T_{CO}	Crossover time constant	0.3 [s]
P_{GV}	Power at Gate or Valve outlet	–
P_M	Mechanical Power	–

1.5 Load Tap Changer (LTC)

Transformers are used to step-down transmission level voltages to the distribution level. Transformers are normally equipped with an automatic voltage load tap changer (LTC) which operates to maintain voltages at the load within desired limits, especially when the system is under disturbances. In other words, LTCs act to restore voltages by adjusting transformer taps, as a result the voltage level will progressively increase to its pre-disturbance level.

Dynamic characteristics of the LTC's logic can be modelled in different ways, as described in CIGRE Task Force 38-02-10 [1]. In this study, a discrete LTC model is chosen, its behavior is to raise or lower the transformer ratio by one tap step. The tap changing logic at a given time instant is modeled by [7]:

$$r_{k+1} = \begin{cases} r_k + \Delta r & \text{if } V > V^0 + d \text{ and } r_k < r^{max} \\ r_k - \Delta r & \text{if } V < V^0 - d \text{ and } r_k > r^{min} \\ r_k & \text{otherwise} \end{cases} \tag{3}$$

where Δr is the size of each tap step, k is the tap position, and r^{max}, r^{min} are the upper and lower tap limits, respectively.

The LTC is activated when the voltage error increases beyond one half of the LTC deadband limits (d). To this aim, a comparison between the controlled voltage (V) and the reference voltage (V^0) is performed by the LTC's logic.

$$k = 0 \quad \text{if} \quad \left|V(t_0^+) - V^0\right| > d \quad \text{and} \quad \left|V(t_0^-) - V^0\right| \leq d \tag{4}$$

Moreover, the tap movement can be categorized into two modes which are: *sequential*, and *non-sequential* [9]. In this study, the sequential mode is adopted here the first tap position changes after an initial time delay and continues to change at constant time intervals. If the transformer ratio limits are not met, the LTC will bring the error back inside into the deadband.

1.6 Load restoration model

Loads are modelled in different ways, many of which are described in IEEE Task Force on Load representation [10]. Load representation can be accomplished by self-restoring load generic models in which load dependencies on terminal voltages exhibit power restoration characteristics. Generic load models can be categorized into two types which are *multiplicative* and *additive*, in these models the load state variable is multiplied and added to a transient characteristic. In this study, a multiplicative generic load model is selected, the load power is given by [7]:

$$P = z_P P_0 \left(\frac{V}{V_0}\right)^{\alpha_t} \tag{5}$$

$$Q = z_Q Q_0 \left(\frac{V}{V_0}\right)^{\beta_t} \tag{6}$$

where z_P and z_Q are dimensionless state variables associated with load dynamics and z_P = z_Q = 1 in steady state.

Moreover, the dynamics of the multiplicative model are described by:

$$T_p \dot{z_P} = \left(\frac{V}{V_0}\right)^{\alpha_s} - z_P \left(\frac{V}{V_0}\right)^{\alpha_t} \tag{7}$$

$$T_Q \dot{z_Q} = \left(\frac{V}{V_0}\right)^{\beta_s} - z_P \left(\frac{V}{V_0}\right)^{\beta_t} \tag{8}$$

where T_P and T_Q are restoration time constants for active and reactive load, respectively. Table 5 contains a listing of parameters for the load model used in this study [11].

Table 5: Load model parameters

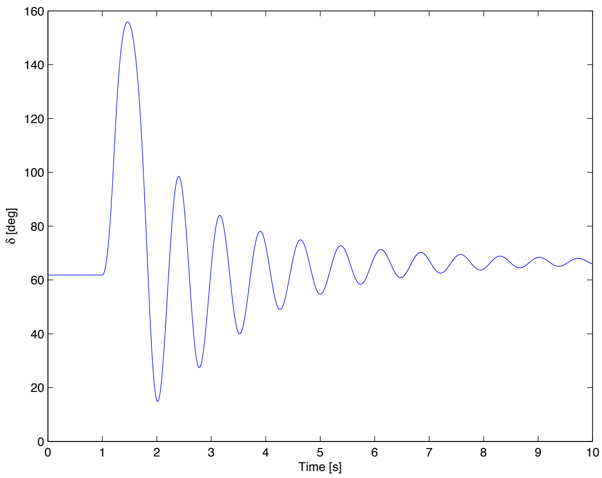
Load type	Parameters	Value
Active load	α_s, α_t, T_P	1.5, 2, 0.05
Reactive load	β_s, β_t, T_Q	2.5, 2, 0.05

2 Simulation results

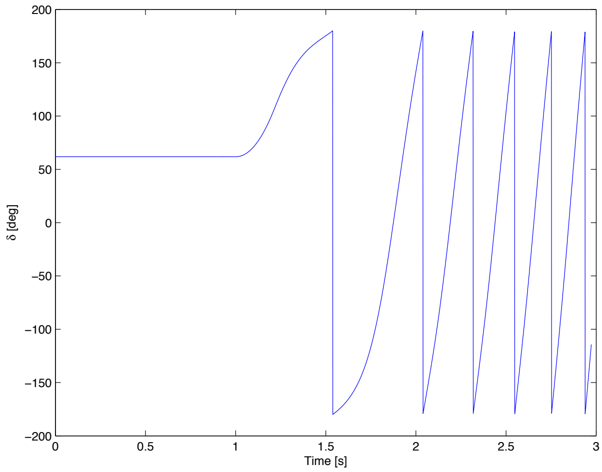
In this section we present simulation results for different instability scenarios that can be observed in the "All-in-one" system by setting different parameters and load flow conditions.

2.1 Transient (angle) instability

Transient angle instability is defined by the IEEE/CIGRÉ joint task force on Stability Terms and Definitions [12]. It refers to the ability of synchronous machines of an interconnected power system to remain in synchronism after being subjected to a disturbance. In other words, it is the ability of each synchronous machine in the system to maintain an equilibrium between electrical torque and mechanical torque. In this study, transient angle instability is simulated by applying a short-circuit on line L1-3, near Bus 3 at $t = 1s$. Afterwards, the fault is cleared by tripping one of the transmission lines between Bus 1 and Bus 3.
There are two cases for fault clearing: at time *(i)* $t = 1.20s$ and *(ii)* $t = 1.21s$. A plot of the generator's rotor angle for *(i)* and *(ii)* are shown in Fig. 9a and 9b, respectively.



(a) $t = 1.20s$



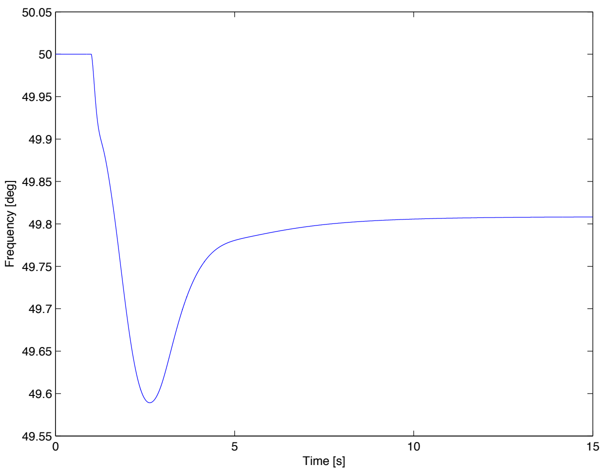
(b) $t = 1.21s$

Figure 9: Rotor angle of generator G2

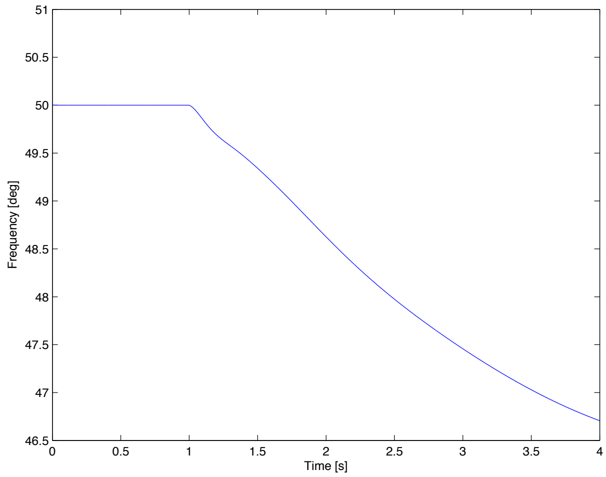
In Fig. 9a, the fault duration is short enough to preserve stability and the system returns to a new equilibrium. In Fig. 9b, the fault lasts too long and the generator looses synchronism.

2.2 Frequency instability

Frequency instability deals with the ability of a power system to maintain steady frequency following a severe system upset which results in a significant imbalance between generation and load [12]. In these cases, simulations are conducted by tripping two transmission lines between Bus 1 and 3. As a result, the generator and load are islanded from the infinite bus. The power consumed by the load is 400 MW while the generator capacity is 450 MW. The governor is able to restore the frequency close to its nominal value, allowing islanded operation.
In a second case, the load is increased from 400 MW to 500 MW, and the same disturbance is applied. This load increment cannot be supplied by the generator. Hence the frequency decay cannot be stopped, resulting in frequency instability. Figure 10a depicts the case of frequency restoration by the governor, whereas Fig. 10b shows how the governor attempts to overhaul the frequency but it fails. In addition, Fig. 11a and Fig. 11b shows the power mismatch between electrical power and turbine mechanical power in the case when the load equals to 400 and 500 MW, respectively.

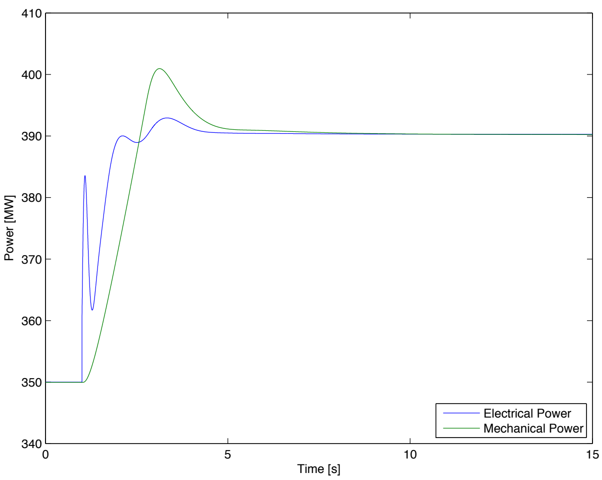


(a) Load = 400 MW

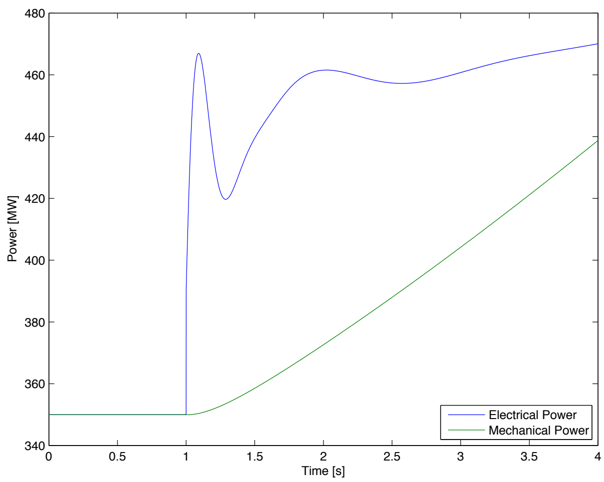


(b) Load = 500 MW

Figure 10: Generator Frequency



(a) Load = 400 MW



(b) Load = 500 MW

Figure 11: Generator Electrical and Mechanical Power

2.3 Voltage instability

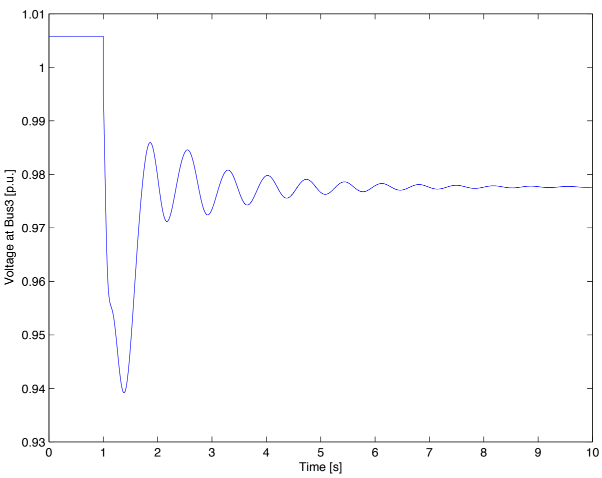
Voltage stability is defined by the System Dynamic Performance Subcommittee of the IEEE [13] as a system's ability to maintain voltage under increased load admittance. Power increases in conjunction with the raise of load admittance, hence, both power and voltage are adjustable. Meanwhile, CIGRÉ report 38.02.10 [14], defines voltage stability as the resiliency of a power system under disturbances to drive voltages near loads to a stable post-disturbance equilibrium value. In other words, the disturbed state is within the attraction region of the stable post-disturbance equilibrium. From the discussion above it can be realized why voltage instability is categorized in two groups, which are *(i)* short-term voltage instability and *(ii)* long-term voltage instability.

Short-term voltage instability

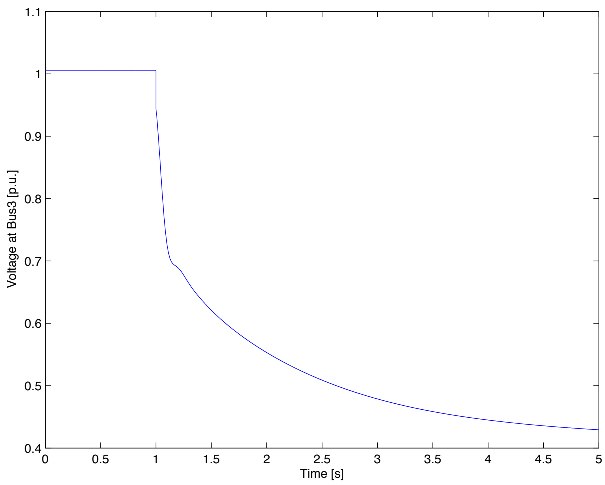
In this system, there are several cases where short-term voltage instability conditions can be observed.

- **Case 1: One of the transmission line between Bus 1 and 3, and the generator at Bus 2, are disconnected at t = 1 sec**

  The voltage at Bus 3 drops to acceptable levels as well as the motor speed, if there is only one line trip (see Fig. 12a and Fig. 13a). However, the disturbance is too severe for the system to remain stable when both components are tripped. This leads to a dramatic drop in the motor voltage and speed (see Fig. 12b and Fig. 13b). In addition, Fig. 14a and Fig. 14b show the power consumed by the motor for both situations.

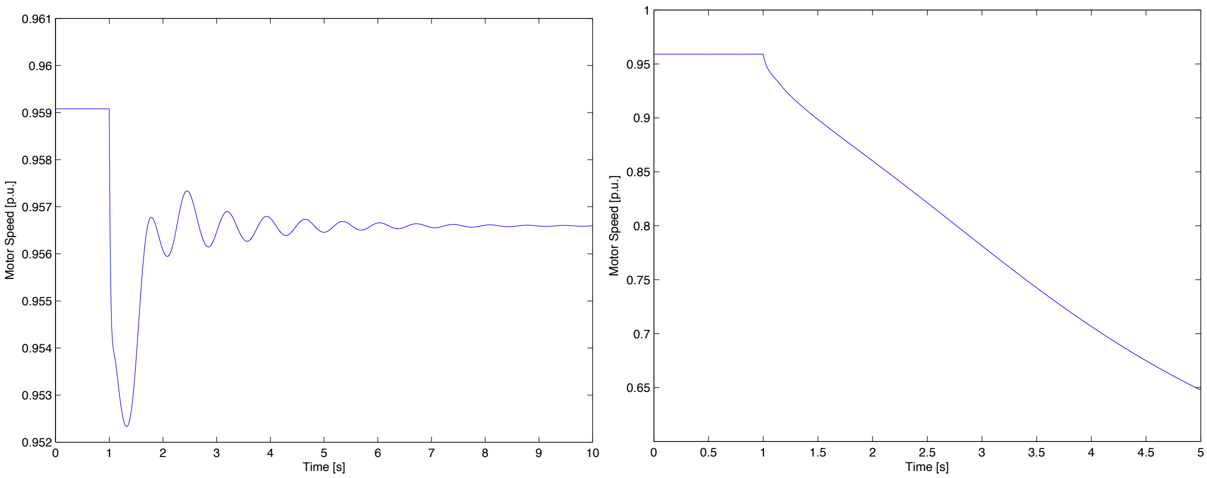


(a) Only L1-3 is tripped



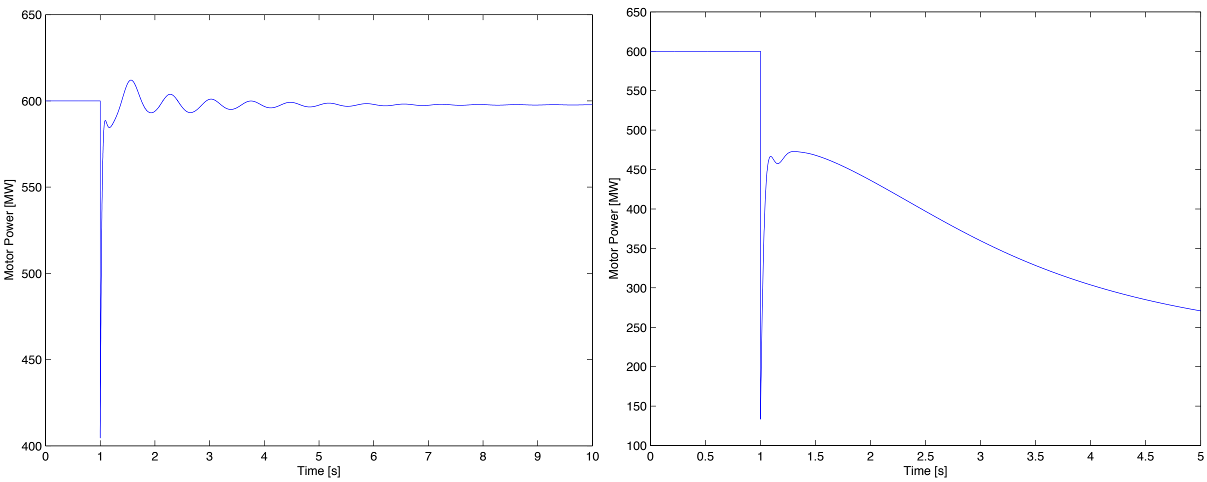
(b) Both L1-3 and Generator are tripped

Figure 12: Voltage at Bus 3



(a) Only L1-3 is tripped (b) Both L1-3 and Generator are tripped

Figure 13: Motor speed

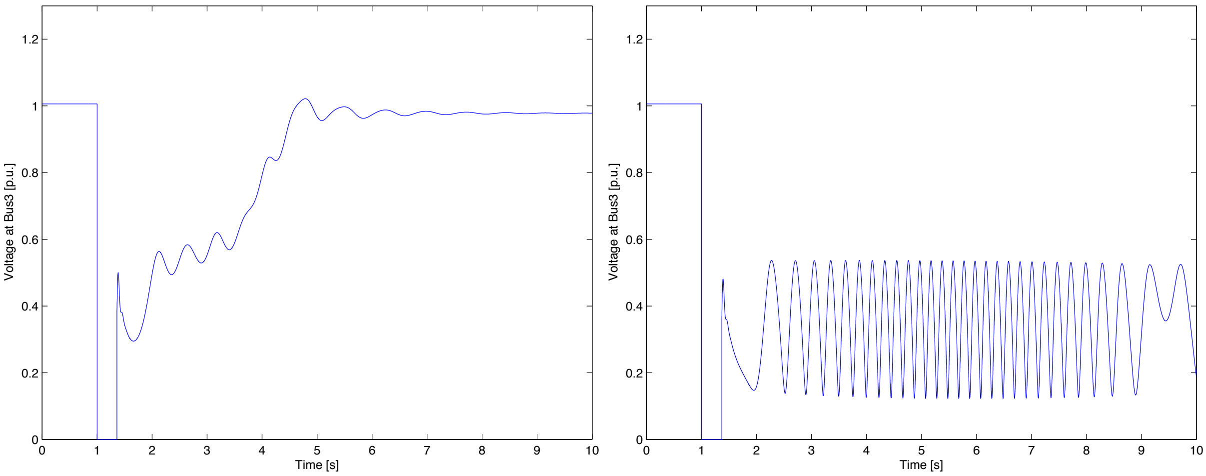


(a) Only L1-3 is tripped (b) Both L1-3 and Generator are tripped

Figure 14: Motor Power consumption

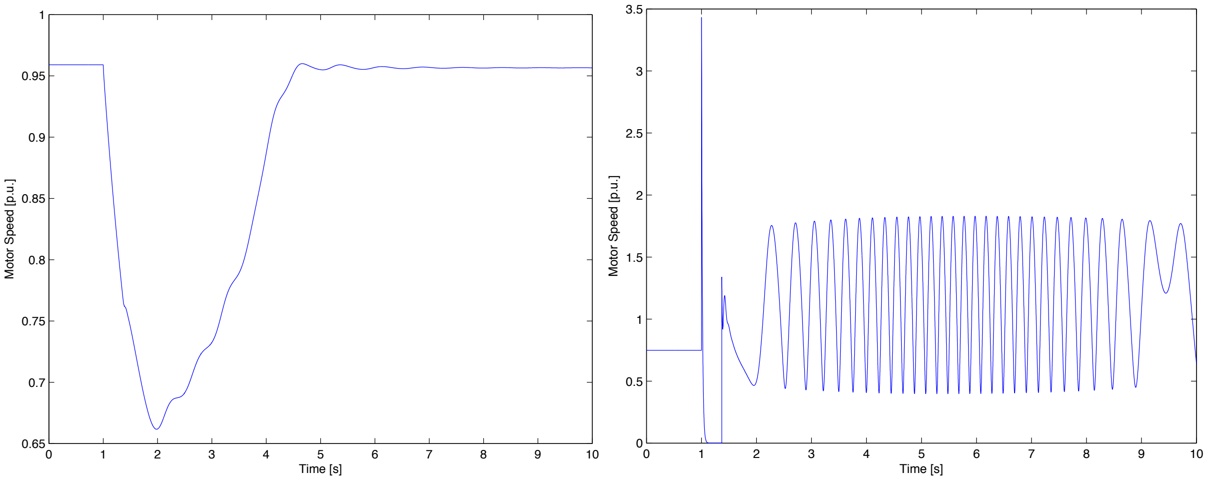
- **Case 2: Three-phase fault at t = 1 sec near Bus 3 and clearing by the trip of Line L1-3**

  A fault is cleared at different times: *(i)* $t = 1.36s$ and *(ii)* $t = 1.37s$. For clearing time $t = 1.36s$, the fault lasts for $0.26s$, which is short enough to preserve stability and hence the system returns to a new equilibrium. Meanwhile, for clearing time $t = 1.37s$, the fault lasts too long and the motor (load at Bus 4) stalls, causing voltage collapse. Figure 15 and 16 show a comparison of the voltage at Bus 3 and the motor speed for the two fault clearing time cases, $t = 1.36s$ and $t = 1.37s$, respectively.



(a) $t = 1.36s$ (b) $t = 1.37s$

Figure 15: Voltage at Bus3



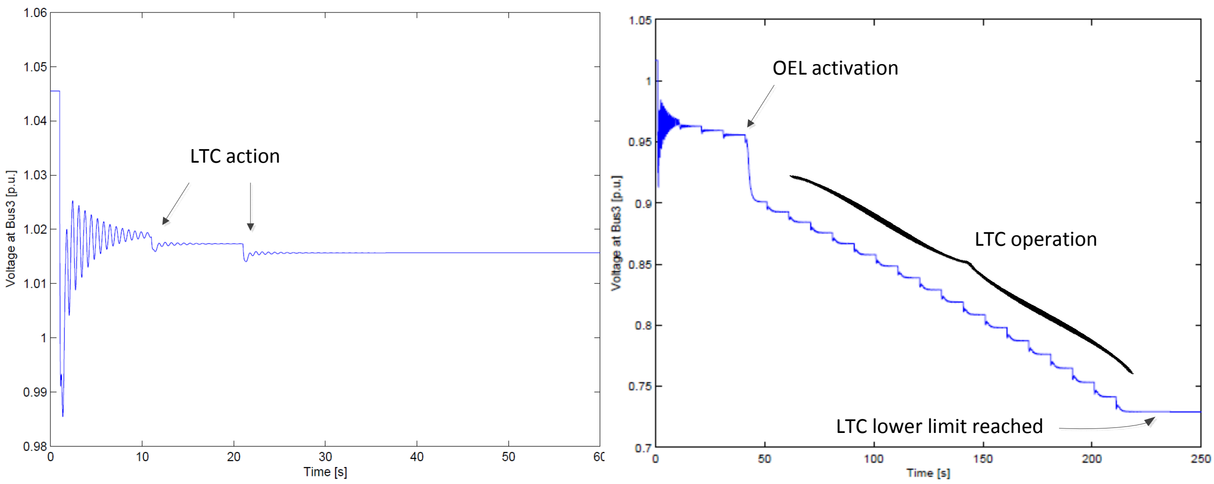
(a) $t = 1.36s$ (b) $t = 1.37s$

Figure 16: Motor speed

Long-term voltage instability
Similar to short-term voltage instability, there are several ways to observe long-term voltage instability conditions in this system.

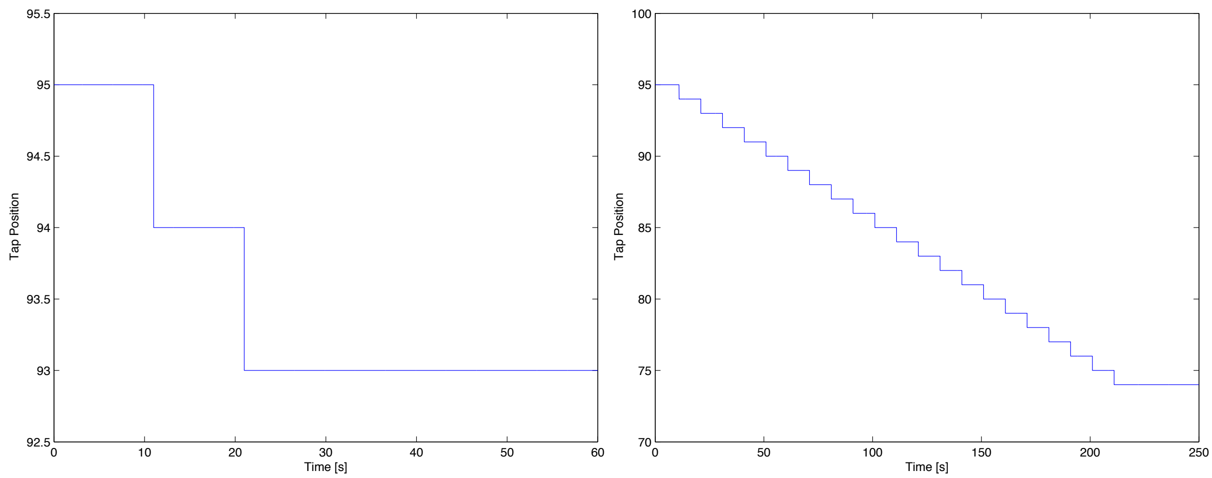
- **Case 1: Higher load consumption at Bus 5**

  In this case, one of the transmission lines between Bus 1 and 3 is tripped at $t = 1s$. The load tap changer (LTC) restores the voltage at the load bus within its deadband (see Fig. 19a). This forces the power system to operate at a new equilibrium point. However when the load is increased from 1200 to 1500 MW and 150 MVAr, the overexcitation limiter (OEL) at the generator is triggered, thus generator voltage is no longer controlled. Consequently, the LTC unsuccessfully attemps to restore the load bus voltage, until reaches its lower limit. The load bus voltage then decreases stepwise accordingly (see Fig. 19b). In addition, Fig. 18 and 19 show the transformer tap position and field current of the generator at different load levels, respectively.



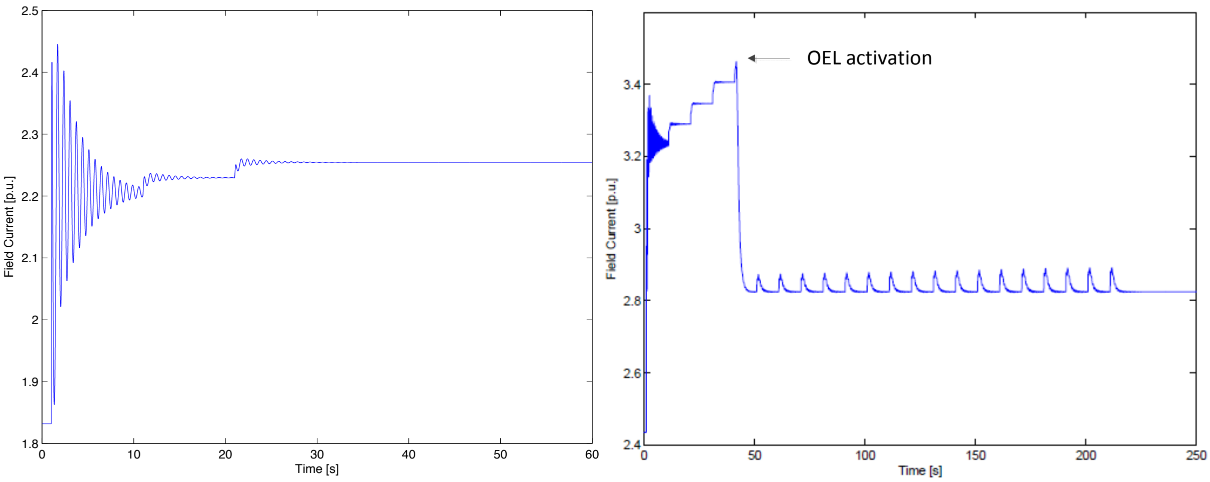
(a) Load = 1200 MW and 0 MVar (b) Load = 1500 MW and 150 MVar

Figure 17: Voltage at Bus 3



(a) Load = 1200 MW and 0 MVar (b) Load = 1500 MW and 150 MVar

Figure 18: LTC Transformer tap position



(a) Load = 1200 MW and 0 MVar

(b) Load = 1500 MW and 150 MVar

Figure 19: Generator field current

- **Case 2: Higher Power generation**

  This case is similar to Case 1 (which is a line trip at $t = 1s$) however, here power generation is changed from 300 MW to 450 MW. In this case, long-term voltage instability triggers an instability of the short-term dynamics in the form of a loss of the generator's synchronism. Figure 21 shows the dynamic response of the system from which it can be observed that the generator looses synchronism at $t = 110s$. Short-term dynamics are triggered about $t = 100s$ when the machine is forced out of equilibrium.

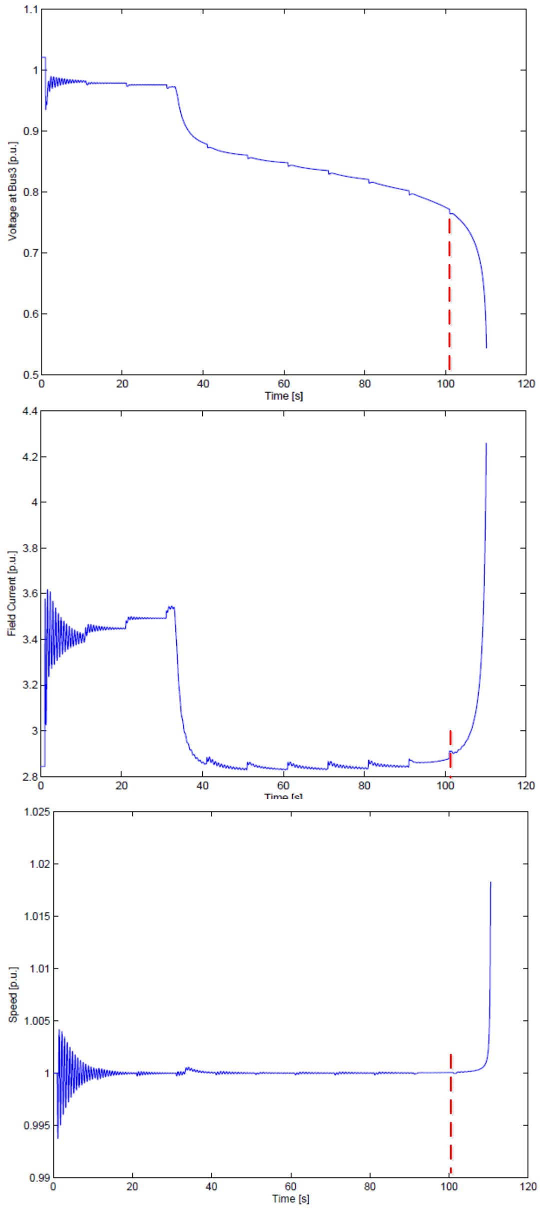


Figure 20: Voltage at Bus 3 (top), Field current (middle), Gen-Speed (bottom)

- **Case 3: Higher Motor Load**

  This case is similar to Case 2, however, part of the load at Bus 5 is shared with the motor load at Bus 4 while power generation is kept at 300 MW. In this case, long-term voltage instability triggers an instability of the short-term dynamics resulting in both loss of generator's synchronism and motor stalling at $t = 47s$. Short-term dynamics are initiated about $t = 27s$ when the OEL is activated. This results in an uncontrolled field voltage which is not able to restore the voltage at Bus 3. Finally, the lack of reactive support prompts short-term angular instability at $t = 35s$ which initiates the final system collapse.

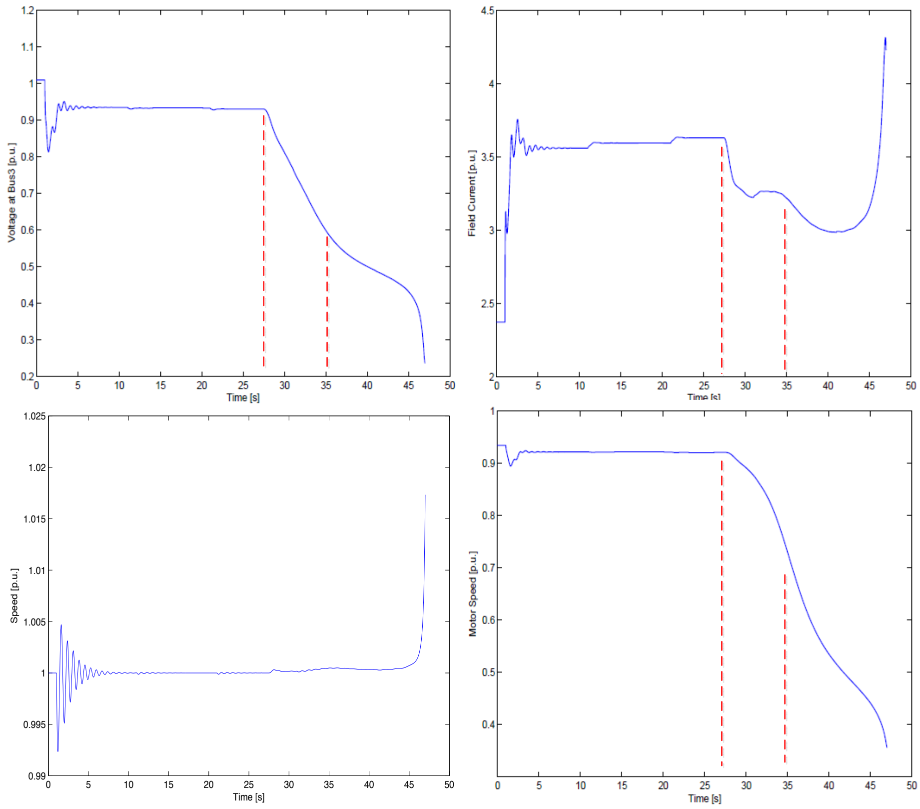


Figure 21: Voltage at Bus 3 (top-left), Field current (top-right), Gen-Speed (bottom-left) and Motor-Speed (bottom-left)

This short-term angular instability is confirmed as shown in Fig. 22 where the angle different between Bus 1 and 3 increases abruptly from $t = 27s$ to $t = 35s$ and onwards.

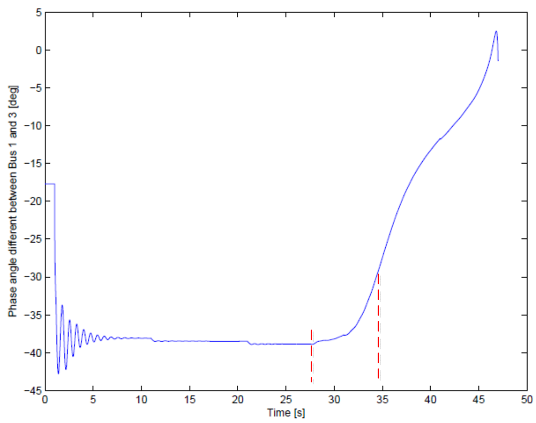


Figure 22: Phase angel between Bus 1 and 3

Summary

This report presents "All-in-one" test system that can reproduce different instability scenarios. A comprehensive modelling and setting are key requirements for accomplishing instability simulations. The authors would like to acknowledge Prof. Thierry Van Custem for making available the original Simulink files from [15]. These files were used as a staring point for the model represent in this report, which is made in the PowerFactory simulation software [16].

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A Load Flow Calculation

This part of the report shows the load flow calculations necessary for initializing the instability cases simulated in Section 2.

A.1 Transient instability

```
bus 1         :         V= 1.0600 pu    0.00 deg        402.80 kV
        > 1-3           P= -175.0      Q=   -8.3      > 3
        > 1-3b          P= -175.0      Q=   -8.3      > 3
    gener 1             P= -350.0      Q=  -16.7     Vimp= 1.0600

bus 2         :         V= 1.0400 pu    8.76 deg         20.80 kV
        > 2-3           P=  450.0      Q=   98.6      > 3
    gener 2             P=  450.0      Q=   98.6     Vimp= 1.0400

bus 3         :         V= 1.0683 pu    4.90 deg        405.94 kV
        > 1-3           P=  175.0      Q=   23.4      > 1
        > 1-3b          P=  175.0      Q=   23.4      > 1
        > 2-3           P= -450.0      Q=  -67.2      > 2
        > 3-4           P=    0.0      Q=    0.0      > 4
        > 3-5           P=  100.0      Q=   20.4      > 5

bus 4         :         V= 1.0078 pu    4.90 deg         15.12 kV
        > 3-4           P=    0.0      Q=    0.0      > 3
    gener 4             P=    0.0      Q=    0.0     Vimp= 0.0000

bus 5         :         V= 1.0675 pu    4.70 deg        405.65 kV
        > 3-5           P= -100.0      Q=  -20.0      > 3
     load               P=  100.0      Q=   20.0
```

A.2 Frequency instability

Load at Bus 5 = 400MW

```
bus 1         :         V= 1.0600 pu    0.00 deg        402.80 kV
        > 1-3                      P=   25.0    Q=   30.3       > 3
        > 1-3b                     P=   25.0    Q=   30.3       > 3
    gener 1                        P=   50.0    Q=   60.5     Vimp= 1.0600

bus 2         :         V= 1.0100 pu    2.45 deg         20.20 kV
        > 2-3                      P=  350.0    Q=   46.7       > 3
    gener 2                        P=  350.0    Q=   46.7     Vimp= 1.0100
```

```
bus 3        :        V= 1.0443 pu   -0.72 deg        396.84 kV
       > 1-3                   P=  -25.0    Q=  -29.5       > 1
       > 1-3b                  P=  -25.0    Q=  -29.5       > 1
       > 2-3                   P= -350.0    Q=  -27.1       > 2
       > 3-4                   P=    0.0    Q=    0.0       > 4
       > 3-5                   P=  400.0    Q=   86.1       > 5

bus 4        :        V= 1.0041 pu   -0.72 deg         15.06 kV
       > 3-4                   P=    0.0    Q=    0.0       > 3
    gener 4                    P=    0.0    Q=    0.0     Vimp= 0.0000

bus 5        :        V= 1.0411 pu   -1.56 deg        395.62 kV
       > 3-5                   P= -400.0    Q=  -80.0       > 3
     load                      P=  400.0    Q=   80.0
```

Load at Bus 5 = 500MW

```
bus 1        :        V= 1.0600 pu    0.00 deg        402.80 kV
       > 1-3                   P=   75.0    Q=   32.7       > 3
       > 1-3b                  P=   75.0    Q=   32.7       > 3
    gener 1                    P=  150.0    Q=   65.3     Vimp= 1.0600

bus 2        :        V= 1.0100 pu    1.02 deg         20.20 kV
       > 2-3                   P=  350.0    Q=   50.3       > 3
    gener 2                    P=  350.0    Q=   50.3     Vimp= 1.0100

bus 3        :        V= 1.0437 pu   -2.15 deg        396.61 kV
       > 1-3                   P=  -75.0    Q=  -29.4       > 1
       > 1-3b                  P=  -75.0    Q=  -29.4       > 1
       > 2-3                   P= -350.0    Q=  -30.7       > 2
       > 3-4                   P=    0.0    Q=    0.0       > 4
       > 3-5                   P=  500.0    Q=   89.5       > 5

bus 4        :        V= 1.0036 pu   -2.15 deg         15.05 kV
       > 3-4                   P=    0.0    Q=    0.0       > 3
    gener 4                    P=    0.0    Q=    0.0     Vimp= 0.0000

bus 5        :        V= 1.0404 pu   -3.20 deg        395.37 kV
       > 3-5                   P= -500.0    Q=  -80.0       > 3
     load                      P=  500.0    Q=   80.0
```

A.3 Short-term voltage instability

For both Case 1 and 2

```
bus 1        :        V= 1.0400 pu    0.00 deg        395.20 kV
       > 1-3                   P=  400.0    Q=  107.1       > 3
       > 1-3b                  P=  400.0    Q=  107.1       > 3
    gener 1                    P=  800.0    Q=  214.1     Vimp= 1.0400
```

```
bus 2        :         V= 1.0000 pu   -9.35 deg        20.00 kV
        > 2-3                    P=  300.0    Q=  212.9      > 3
    gener 2                      P=  300.0    Q=  212.9     Vimp= 1.0000

bus 3        :         V= 1.0058 pu  -12.20 deg       382.21 kV
        > 1-3                    P= -400.0    Q=  -19.5      > 1
        > 1-3b                   P= -400.0    Q=  -19.5      > 1
        > 2-3                    P= -300.0    Q= -191.2      > 2
        > 3-4                    P=  600.0    Q=  140.0      > 4
        > 3-5                    P=  500.0    Q=   90.2      > 5

bus 4        :         V= 0.9930 pu  -15.87 deg        14.90 kV
        > 3-4                    P= -600.0    Q= -100.0      > 3
    gener 4                      P= -600.0    Q= -100.0     Vimp= 0.0000

bus 5        :         V= 1.0024 pu  -13.34 deg       380.92 kV
        > 3-5                    P= -500.0    Q=  -80.0      > 3
     load                        P=  500.0    Q=   80.0
```

A.4 Long-term voltage instability

Case 1: Load at Bus 5= 1200 MW and 0 MVar

```
bus 1        :         V= 1.0800 pu    0.00 deg       410.40 kV
        > 1-3                    P=  450.0    Q=  117.6      > 3
        > 1-3b                   P=  450.0    Q=  117.6      > 3
    gener 1                      P=  900.0    Q=  235.2     Vimp= 1.0800

bus 2        :         V= 1.0100 pu  -10.01 deg        20.20 kV
        > 2-3                    P=  300.0    Q=   36.9      > 3
    gener 2                      P=  300.0    Q=   36.9     Vimp= 1.0100

bus 3        :         V= 1.0455 pu  -12.72 deg       397.29 kV
        > 1-3                    P= -450.0    Q=  -15.1      > 1
        > 1-3b                   P= -450.0    Q=  -15.1      > 1
        > 2-3                    P= -300.0    Q=  -22.6      > 2
        > 3-4                    P=    0.0    Q=    0.0      > 4
        > 3-5                    P= 1200.0    Q=   52.8      > 5

bus 4        :         V= 1.0053 pu  -12.72 deg        15.08 kV
        > 3-4                    P=    0.0    Q=    0.0      > 3
    gener 4                      P=    0.0    Q=    0.0     Vimp= 0.0000

bus 5        :         V= 1.0445 pu  -15.24 deg       396.90 kV
        > 3-5                    P=-1200.0    Q=    0.0      > 3
     load                        P= 1200.0    Q=    0.0
```

Case 1: Load at Bus 5= 1500 MW and 150 MVar

```
bus 1        :         V= 1.0800 pu    0.00 deg       410.40 kV
        > 1-3                    P=  600.0    Q=  216.7      > 3
        > 1-3b                   P=  600.0    Q=  216.7      > 3
```

```
   gener 1                        P= 1200.0    Q=  433.5     Vimp= 1.0080

 bus 2         :         V= 1.0100 pu  -14.79 deg         20.20 kV
        > 2-3                     P=  300.0    Q=  212.6      > 3
   gener 2                        P=  300.0    Q=  212.6     Vimp= 1.0100

 bus 3         :         V= 1.0166 pu  -17.58 deg        386.30 kV
        > 1-3                     P= -600.0    Q=  -23.9      > 1
        > 1-3b                    P= -600.0    Q=  -23.9      > 1
        > 2-3                     P= -300.0    Q= -191.4      > 2
        > 3-4                     P=    0.0    Q=    0.0      > 4
        > 3-5                     P= 1500.0    Q=  239.3      > 5

 bus 4         :         V= 0.9966 pu  -17.58 deg         14.95 kV
        > 3-4                     P=    0.0    Q=    0.0      > 3
   gener 4                        P=    0.0    Q=    0.0     Vimp= 0.0000

 bus 5         :         V= 1.0089 pu  -20.93 deg        383.37 kV
        > 3-5                     P=-1500.0    Q= -150.0      > 3
    load                          P= 1500.0    Q=  150.0
```

Case 2: Higher Power generation

```
 bus 1         :         V= 1.0800 pu    0.00 deg        410.40 kV
        > 1-3                     P=  525.0    Q=  186.5      > 3
        > 1-3b                    P=  525.0    Q=  186.5      > 3
   gener 1                        P= 1050.0    Q=  373.0     Vimp= 1.0800

 bus 2         :         V= 1.0100 pu  -11.10 deg         20.20 kV
        > 2-3                     P=  450.0    Q=  197.6      > 3
   gener 2                        P=  450.0    Q=  197.6     Vimp= 1.0100

 bus 3         :         V= 1.0205 pu  -15.26 deg        387.81 kV
        > 1-3                     P= -525.0    Q=  -39.5      > 1
        > 1-3b                    P= -525.0    Q=  -39.5      > 1
        > 2-3                     P= -450.0    Q= -159.7      > 2
        > 3-4                     P=    0.0    Q=    0.0      > 4
        > 3-5                     P= 1500.0    Q=  238.6      > 5

 bus 4         :         V= 1.0005 pu  -15.26 deg         15.01 kV
        > 3-4                     P=    0.0    Q=    0.0      > 3
   gener 4                        P=    0.0    Q=    0.0     Vimp= 0.0000

 bus 5         :         V= 1.0129 pu  -18.59 deg        384.90 kV
        > 3-5                     P=-1500.0    Q= -150.0      > 3
    load                          P= 1500.0    Q=  150.0
```

Case 3: Higher Motor load

```
 bus 1         :         V= 1.0800 pu    0.00 deg        410.40 kV
        > 1-3                     P=  600.0    Q=  226.7      > 3
        > 1-3b                    P=  600.0    Q=  226.7      > 3
   gener 1                        P= 1200.0    Q=  453.3     Vimp= 1.0800
```

```
bus 2         :         V= 1.0000 pu  -14.84 deg         20.00 kV
        > 2-3                      P=  300.0    Q=  177.3      > 3
    gener 2                        P=  300.0    Q=  177.3     Vimp= 1.0000

bus 3         :         V= 1.0117 pu  -17.67 deg        384.45 kV
        > 1-3                      P= -600.0    Q=  -31.8      > 1
        > 1-3b                     P= -600.0    Q=  -31.8      > 1
        > 2-3                      P= -300.0    Q= -157.9      > 2
        > 3-4                      P=  600.0    Q=  139.5      > 4
        > 3-5                      P=  900.0    Q=   81.9      > 5

bus 4         :         V= 0.9990 pu  -21.30 deg         14.99 kV
        > 3-4                      P= -600.0    Q= -100.0      > 3
    gener 4                        P= -600.0    Q= -100.0     Vimp= 0.0000

bus 5         :         V= 1.0091 pu  -19.69 deg        383.46 kV
        > 3-5                      P= -900.0    Q=  -50.0      > 3
     load                          P=  900.0    Q=   50.0
```

“All-in-one” test system modelling and simulation for multiple instability scenarios

Internal Report

Report # Smarts-Lab-2011-002

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