References:

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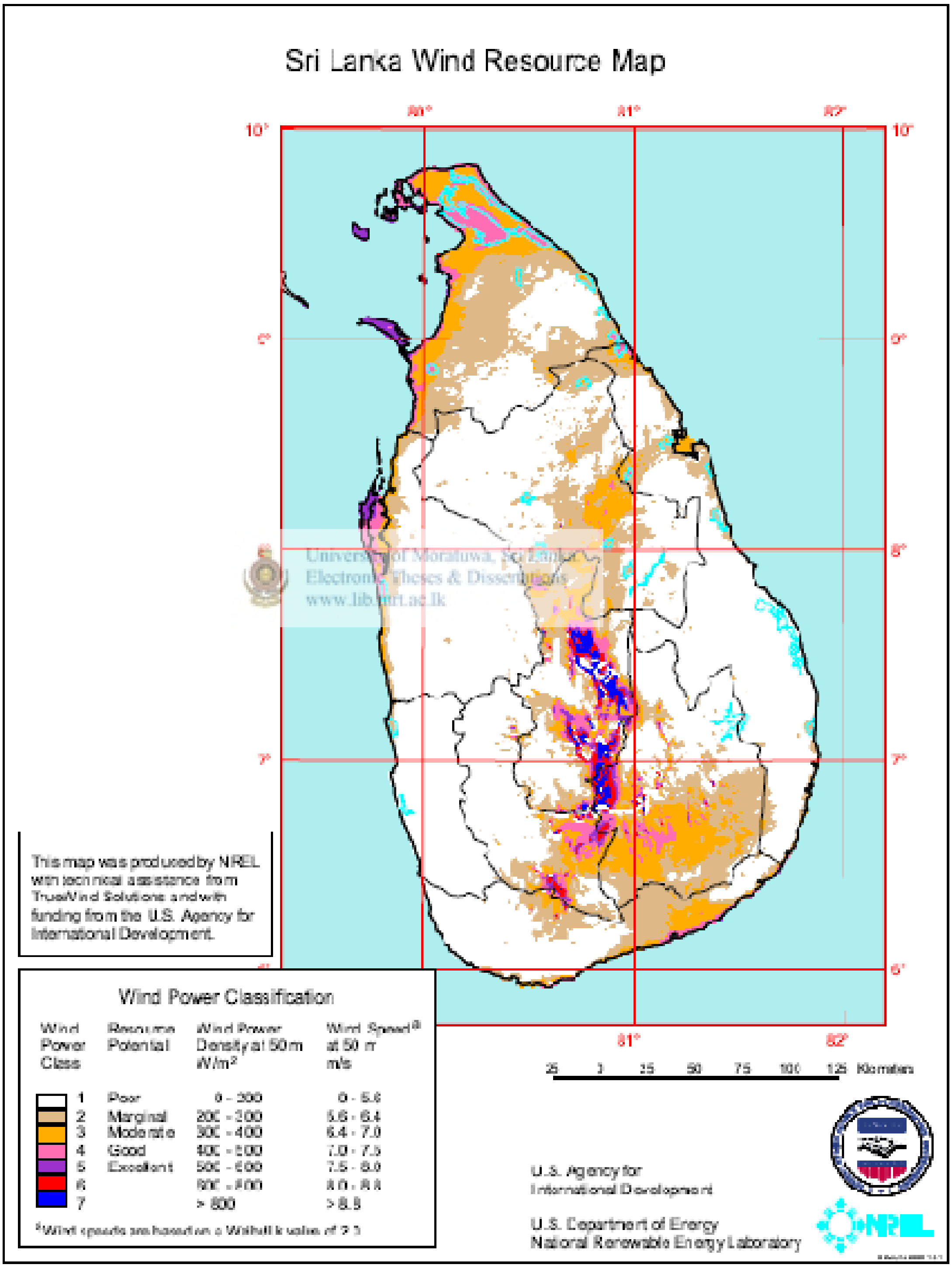
Appendix A: Sri Lankan Wind Resource Map

Following figure shows the wind resource distribution in Sri Lanka based on the study done by National Renewable Energy Laboratory in 2003.



Appendix B: Wind Power Variations in 1 Minute Interval

Following figures shows the wind power variations in 1 minute interval at Seguwanthive and Widatamuni wind plant

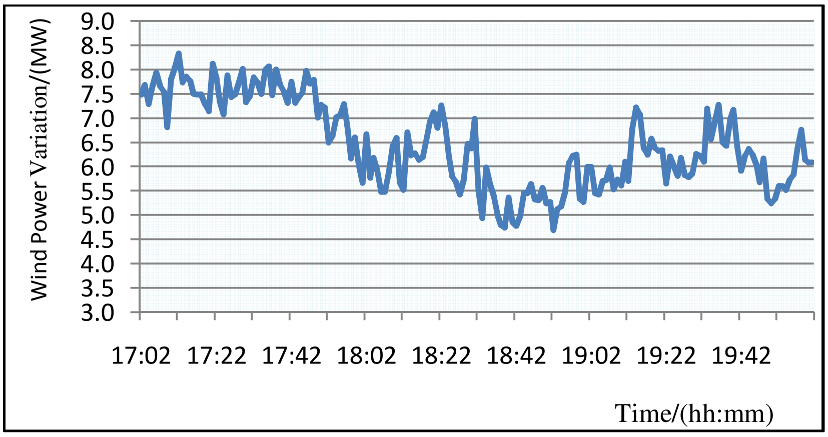


Figure B1: Wind power variation on 17/08/2010 at Seguwanthive wind plant

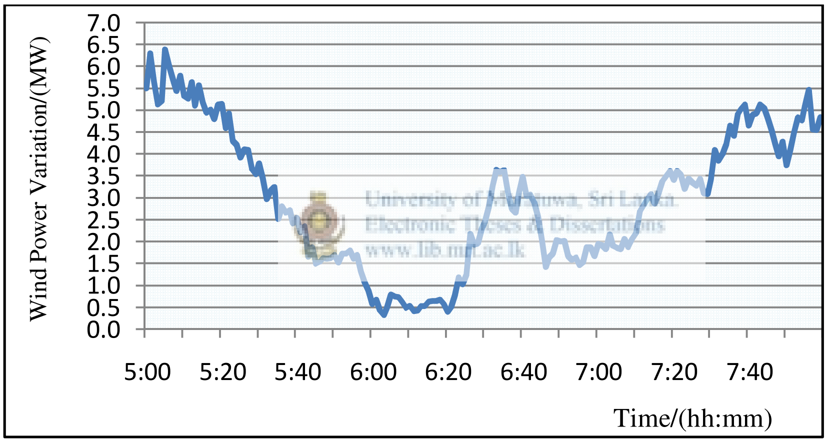


Figure B3: Wind power variation on 18/08/2010 at Senox wind plant

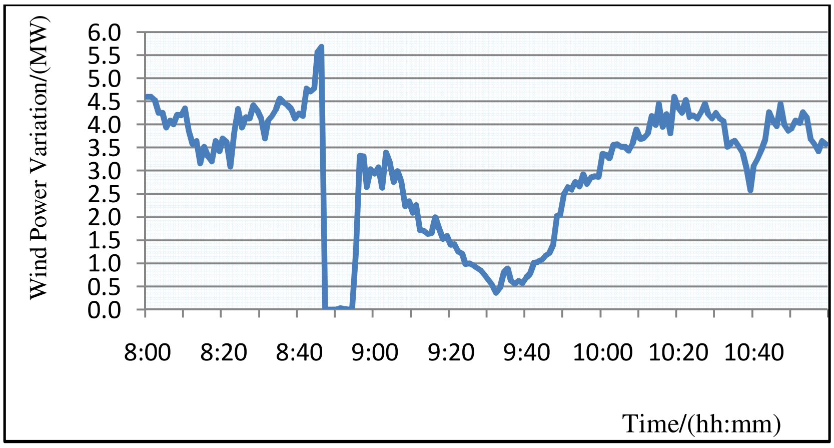


Figure B4: Wind power variation on 18/08/2010 at Senox wind plant

Appendix C: Wind Speed Variations in Uddapuwa Area

Following figures shows the typical wind speed variations in one minute interval

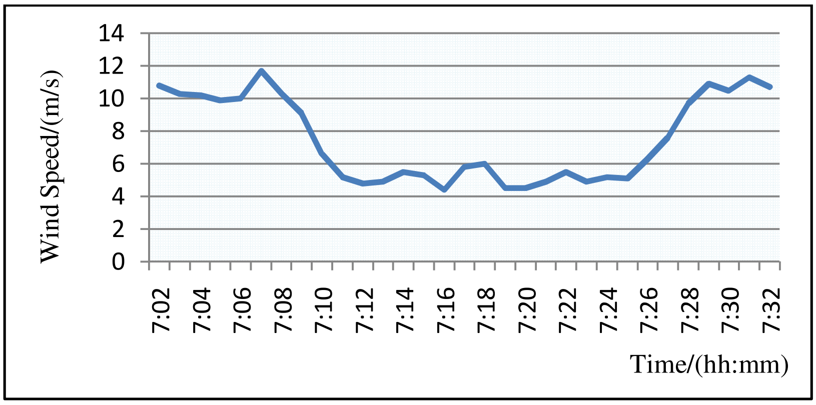


Figure C1: Wind speed variation on 18/05/2010

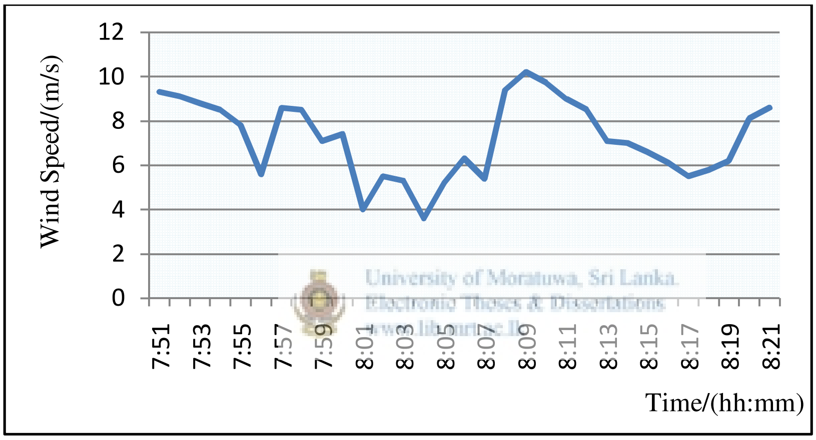


Figure C2: Wind speed variation on 17/06/2010

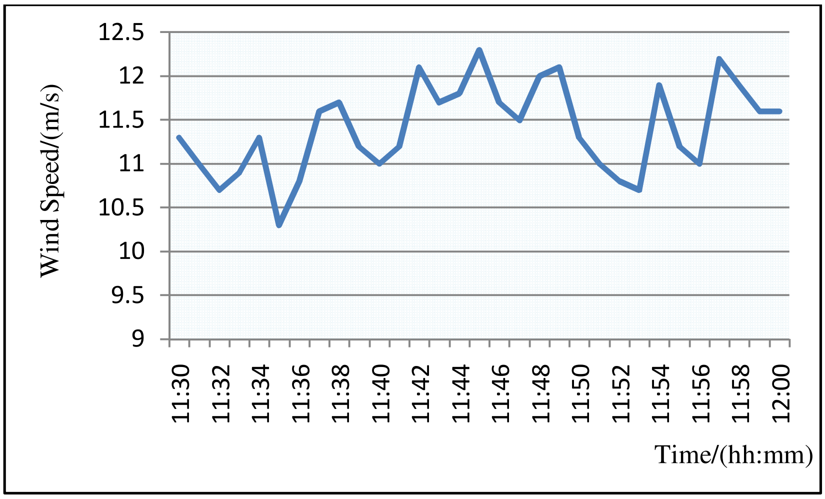


Figure C3: Wind speed variation on 20/07/2010

Appendix D: Power System Modeling Fundamentals

D.1. Frequency Stability and Control

This chapter deals with the active power control of the power system in order to keep the system stable under steady state condition. In general power system experiences the excess or deficiency of its generation due to the load changes and generator output variations (due to uncontrollable prime mover power or generator trippings). This leads to a power imbalance between electrical power and mechanical power of the generating units. This power imbalance is initially covered from the kinetic energy of rotating rotors of turbines, generators and motors and, as a result, the frequency fluctuations appeared in the network. That reflects the rotor angle deviation due to power imbalance. To maintain the system frequency at the desired value there should be a mechanism to control the active power delivered by the generator to the system. Basically the power delivered by a generator to power system is controlled by the controlling the mechanical power output of the prime mover such as gas turbine, steam turbine, hydro turbine and diesel engines etc. The frequency deviations from its nominal value are used as feedback controls signal for governor who is responsible for initiate the action of prime mover power change. Frequency will become stable at new steady state level after the governor action. This control scheme which provided by the governor control mechanism is referred as primary frequency control. In addition, secondary frequency control scheme provided by Automatic Generation Control is used to restore the frequency to the nominal value. To understand the primary and secondary frequency control phenomena it is required to consider the turbine governor characteristics of the generator. Primary and secondary frequency control collectively referred as load frequency control.

D.2. Load Frequency Control

D.2.1. Speed droop characteristics

The function of the speed governor is to monitor the turbine speed continuously and control the gate positions in case of hydro turbines which adjust the water flow into the turbine in response to changes in speed or frequency. The speed versus power output governing characteristic of each unit has a droop.

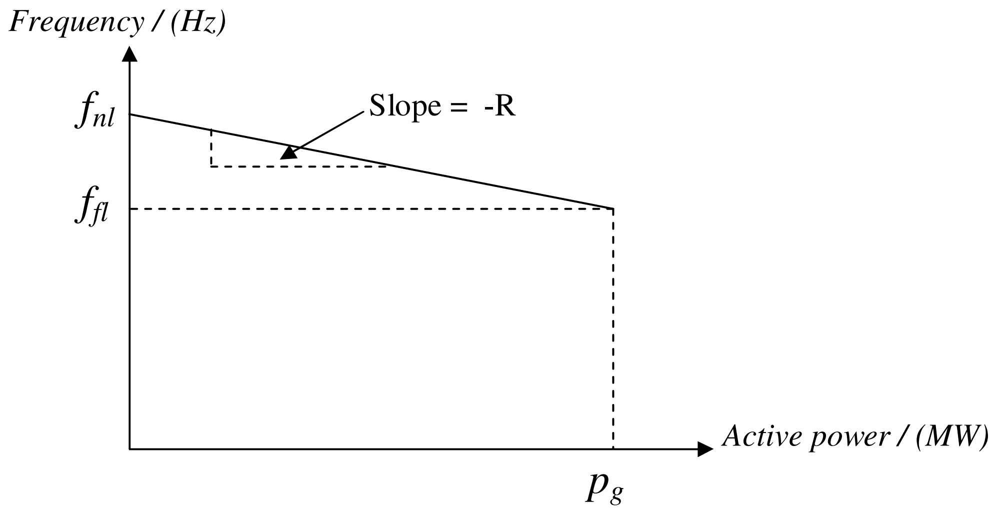


Figure D.1: Speed droop characteristics of a governor

Physically per unit droop can be interpreted as the percentage change in speed with respect to rated speed , when the output of the turbine is gradually change from hundred percent of rated power to zero.

From figure E.1 per unit speed droop can be expressed as

$$R_{pu} = \frac{(f_{nl} - f_{fl}) / f_o}{p_g / p_r} \quad \textit{Per unit} \qquad \text{(D.1)}$$

f_{nl} - frequency in Hz at no load

f_{fl} - frequency in Hz at full load

f_o - rated frequency in Hz

p_g - full load of the turbine in MW

p_r - rated power of the turbine in MW

$$R = R_{pu} \times R_{base}$$

$$R_{base} = \frac{f_o}{p_r} \qquad \text{(D.2)}$$

$$R = \frac{\Delta f}{\Delta p} \quad \text{Hz/MW}$$

D.1.1. Primary and secondary frequency control

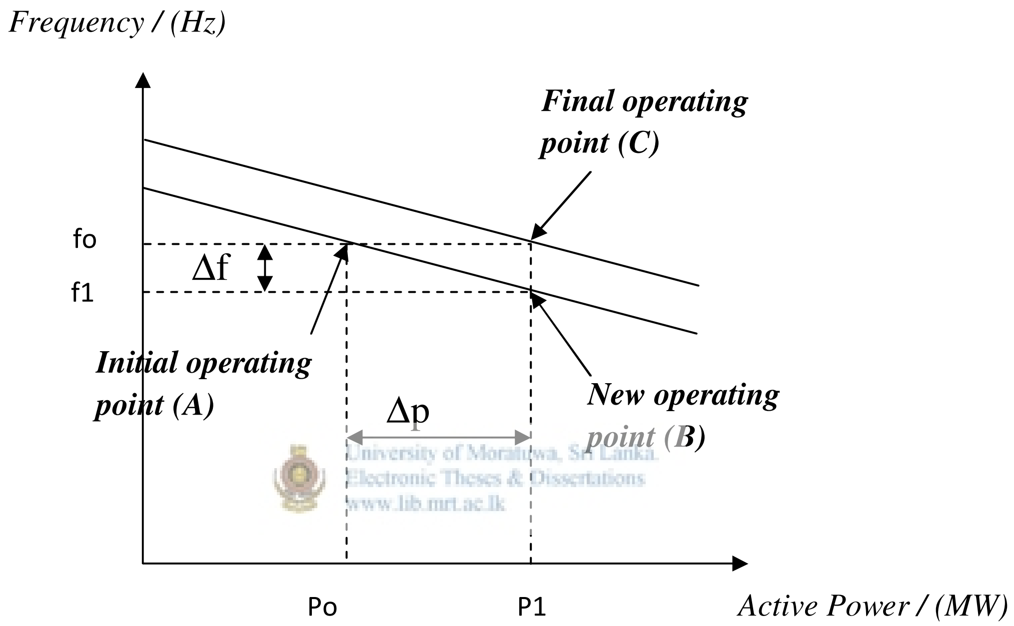


Figure D.2: Primary and secondary speed control representation in droop curve

Suppose that the machine supplying P_0 power (reference power) at nominal frequency, *f*o. As load increased from ΔP as shown in figure D.2 frequency of the machine decrease hence governor allows more prime mover by opening gates or valves depending on the turbine type (hydro/Gas/Steam).When equilibrium between input and output power occurs, frequency stabilized at new frequency which is equal to $f_1=(fo - \Delta f)$ as shown in the figure D.2. This response of the governor is called as primary frequency control. Frequency deviation from the nominal value can be expressed as

$$\Delta f = - R \times \Delta P \qquad \text{Hz} \qquad \text{(D.3)}$$

To normalize the system frequency should be raised to nominal value (fo). In order to do that the droop curve should be parallely shifted to new operating point (C) as shown in the figure D.2. The speed changer supplements the action of the governor by changing the speed setting to allow more prime mover power to increase kinetic energy of the generating unit and so that it can again operate at the nominal frequency to which providing the new power P_1 [9].This is called the supplementary frequency control.

When multiple no of generators operating in parallel on the system, speed droop characteristics of individual generator determine the load sharing among them in the steady state. Since all generators are interconnected by the transmission network, they are operated at common frequency. The contribution of each generator at the steady state equilibrium after initial governor action with respect to ΔP load change in the system can be expressed as follows.

$$\Delta p_{,1} = \frac{1}{R_{,1}}\Delta f$$
$$\Delta p_{,2} = \frac{1}{R_{,2}}\Delta f \qquad \text{(D.4)}$$
$$\Delta p_{,n} = \frac{1}{R_{,n}}\Delta f$$

Adding all these equations together gives the total change in power

$$\sum_{i=1}^{n}\Delta p = \left(\frac{1}{R_{,1}} + \frac{1}{R_{,2}} + ... + \frac{1}{R_{,n}}\right)\Delta f \qquad \text{(D.5)}$$

$$\Delta f = \frac{-\Delta p_{\text{tot}}}{\left(\frac{1}{R_{,1}} + \frac{1}{R_{,2}} + ... \frac{1}{R_{,\text{n}}}\right)} \qquad \text{(D.6)}$$

Where

$$\frac{1}{R_{,eq}} = \left(\frac{1}{R_{,2}} + \frac{1}{R_{,2}} + ... + \frac{1}{R_{,n}}\right) \qquad \text{(D.7)}$$

D.2.3. Speed governor/ turbine model

The output of each unit at any given system frequency can be varied only by changing its' reference power, which in effect moves the speed droop characteristic up and down[10]. The governor action is modeled based on the steady state equation of frequency power relation for turbine governor control.

$$\Delta P_g = \mathrm{P}_{ref} - \frac{1}{R}\Delta f \qquad \text{(D.8)}$$

ΔP_g	= Change in mechanical power	MW
P_{ref}	= Reference power set point	MW
Δf	=Steady state frequency deviation	Hz
R	= Governor Droop setting	Hz/MW

The required change in mechanical power delivered from the turbine after complying the response time of the governor and the turbine itself based on the commanded signal (ΔP_g) by the speed droop characteristics.

Simply assuming linear relationship, governor model can be represented by using governor lag time constant. This consideration is to comply the response time of the governor speed control to compensate the sudden imbalance power between mechanical and electrical power.

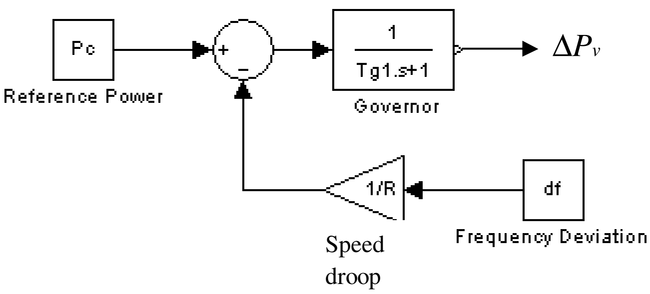


Figure D.3: Block diagram representation of speed governor model

ΔP_v = Valve position_or gate of the turbine.

Tg = Governor lag time Constance.

S- domain above can be expressed as follows.

$$\Delta P_v = (\frac{1}{1+sT_g})\Delta P_g \tag{D.9}$$

$$\Delta P_v = (P_{ref} - \frac{1}{R}\Delta f)(\frac{1}{1+sT_g}) \tag{D.10}$$

Derivation of the above model obtained from the “Power System Stability and Control” by P.Kundur [10].

Mechanical power output of the turbine with respect to the its’ value position can also be simply represented using a time constant by assuming linear relationship.

$$\Delta P_m = (\frac{1}{1+sT_t})\Delta P_v \tag{D.11}$$

$$\Delta P_m = (P_{ref} - \frac{1}{R}\Delta f)(\frac{1}{1+sT_g})(\frac{1}{1+sT_t}) \tag{D.12}$$

T_t - Time constant of the turbine

D.3 Swing Equation

The swing equation is a fundamental importance in the study of power oscillations in power systems. In steady state operation, all synchronous generators in the system rotate with the same electrical angular velocity. But during a disturbance one or more generators could be accelerated or decelerated according to the newton’s second law due to unbalance between the electromagnetic torque and mechanical torque of the individual generators.

The combined inertia of the generator and prime mover is accelerated by the unbalance in applied torque [10].

$$T_m - T_e = J\frac{d\varpi_m}{dt} \tag{D.13}$$

J - Combined moment of inertia of generator and turbine Kgm^2

ϖ_m - Angular velocity, mechanical rad/s

T_m - Mechanical Torque Nm

T_e - Electromagnetic Torque Nm

If equation is multiplied with the mechanical angular velocity ϖ_m

$$P_m - P_e = J.\varpi_m \frac{d\varpi_m}{dt} \quad (D.14)$$

$P_m = T_m.\varpi_m$ Mechanical power on rotor

$P_e = T_e.\varpi_m$ Electrical power on rotor

D.3.1 Generator load model

The increment in power input to the generator-load model is $\Delta Pm - \Delta Pe$

ΔPm = Incremental mechanical power

ΔPe = incremental electrical power

This increment in power input to the system is accounted in two ways

1. Rate of increase of stored kinetic energy in the generator rotor. At rated speed (ωo), the stored kinetic energy is

$$Wo = HxS \quad VA.S \quad (D.15)$$

Since kinetic energy being proportional to square of the speed (frequency), the kinetic energy at a frequency of ($\omega o+\Delta\omega$) is

$$W_k = Wo(\omega o + \Delta\omega)/\omega o)^2 \quad (D.16)$$

$$W_k \approx HxS(1 + (2\Delta\omega)/\omega o) \quad (D.17)$$

Rate of change of kinetic energy is therefore

$$\frac{d(W_k)}{dt} = \frac{2Hs}{\omega o}\frac{d(\Delta\omega)}{dt} \quad (D.18)$$

2. As frequency changes, some equipments change its load with respect to the change in frequency due to being sensitive to speed. Load change for $\Delta\omega$ frequency change is

D. $\Delta\omega$. Now power balance equation can be written as follows

$$\Delta P_m - \Delta P_e = \frac{2Hs}{\omega o}\frac{d(\Delta\omega)}{dt} + D.\Delta\omega \quad (D.19)$$

Dividing both sides from S in equation D.19 and taking per unit of angular velocity

$$\Delta P_{m(pu)} - \Delta P_{e(pu)} = \frac{2Hs}{} \frac{\mathrm{d}(\Delta\omega_{pu})}{dt} + \mathrm{D}_{(\mathrm{pu})}.\Delta\omega_{(pu)} \tag{D.20}$$

$$\Delta\omega_{(pu)} = \Delta f_{(pu)}$$

Taking Laplase transformation, Δfpu can be expressed as

$$\Delta f(s) = \frac{\Delta P_{m(S)} - \Delta P_{e(S)}}{D + 2Hs} \tag{D.21}$$

H - Combined Inertia constant of the generator and turbine MW-S/MVA

S - MVA rating of the generator

D - Power system damping constant[1]

Equation D.21 can be rearrange as

$$\Delta f(s) = \Delta P_{m(S)} - \Delta P_{e(S)} \left[\frac{K_{ps}}{1 + T_{ps}(s)} \right] \tag{D.22}$$

K_{ps} $= 1/Dpu$, Power system gain

T_{ps} $=2H/Dpu$, Power system time constant

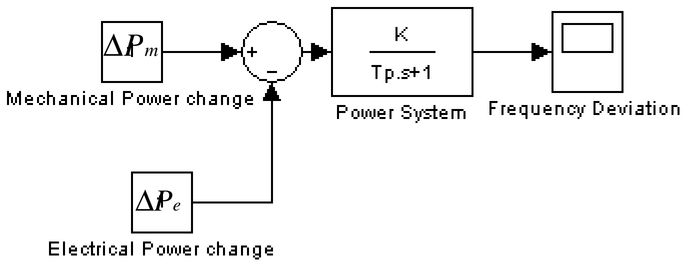


Figure D.4: Block diagram representation of the generator load model

Complete block diagram representation of an isolated power system comprises turbine, governor, generator and load. The complete block diagram can be obtained through the equation D.12 and D.22.

[1]Percentage change in load per 1% change in system frequency

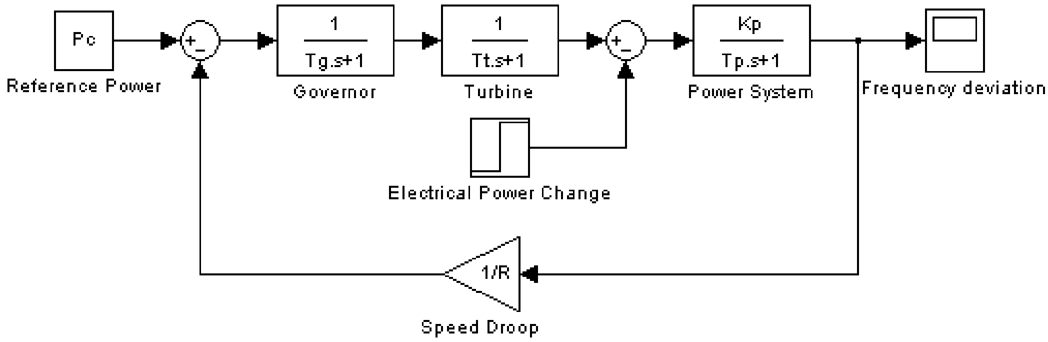


Figure D.5: Block diagram representation of Load Frequency Control

D.4 Automatic Generation Control

AGC provide the secondary control which is superimposed on the primary control that has been discussed in previously in section D.2.2. This secondary controller action is much slower than the primary speed control action as it takes effect after the primary speed control has stabilized the system frequency. Then AGC adjust the load reference of selected units and hence their output power, to override the effect of the composite frequency regulation characteristics of the power system [11]. Restoring the frequency to the specified nominal value is accomplished by adding a rest or negative value of integrator gain control that acts on the load reference settings of the governor model as shown figure D.6 (a). The negative integral gain will force the steady state frequency error to zero by adjusting the load reference set point.

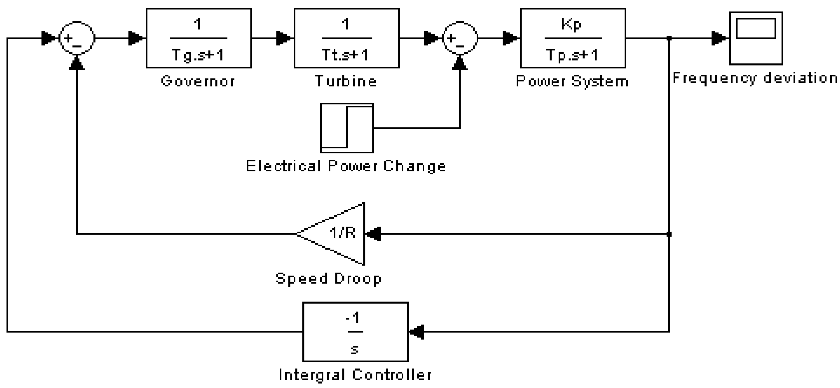


Figure D.6 (a): Block diagram representation of LFC model with Integral controller

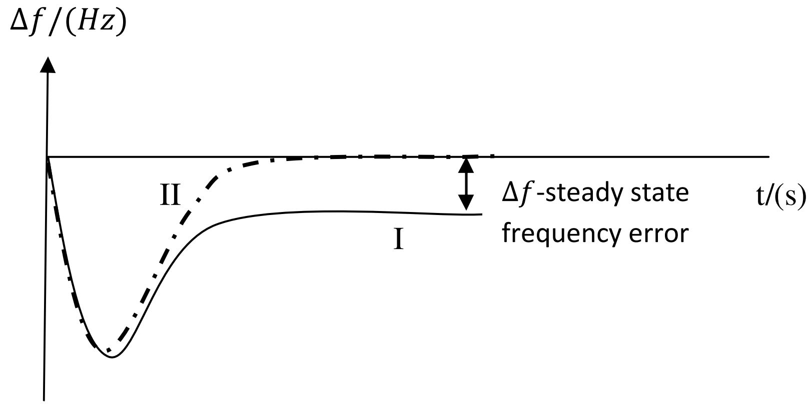


Figure D.6 (b): Frequency response of LFC model with integral controller

Figure D.6 (b) graph I Shows the steady frequency error in absence of integral gain ie only having primary frequency control. Graph II shows frequency error becomes zero in the presence of integral controller.

D.5. Multi Machine in Isolated Power ystems

In the analysis of whole power system we are interested in the collective performance of all the generators in the system. The inter machine oscillations therefore not considered [11]. We implicitly assume the coherent response of all generation to changes in system load and represent them by an equivalent generator. The equivalent generator has an inertia constant, which represents equivalent kinetic energy stored in the all generators at their rated speed and is driven by the combined mechanical outputs of the individual turbines as illustrated in the figure E.7. Similarly the effects of all loads are lumped into a single damping constant.

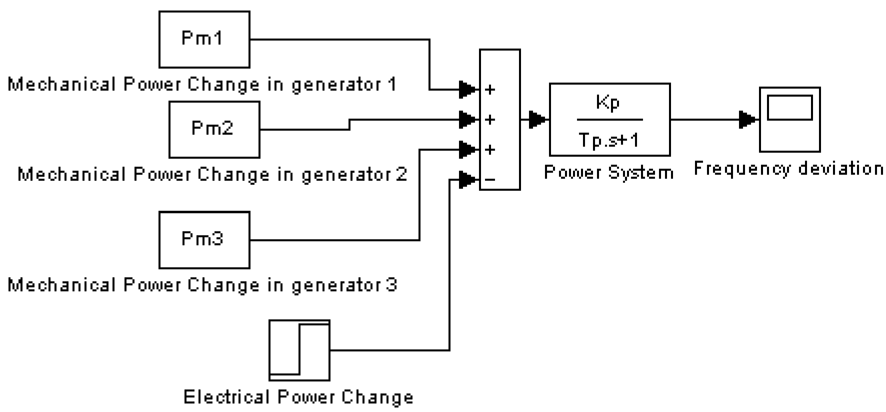
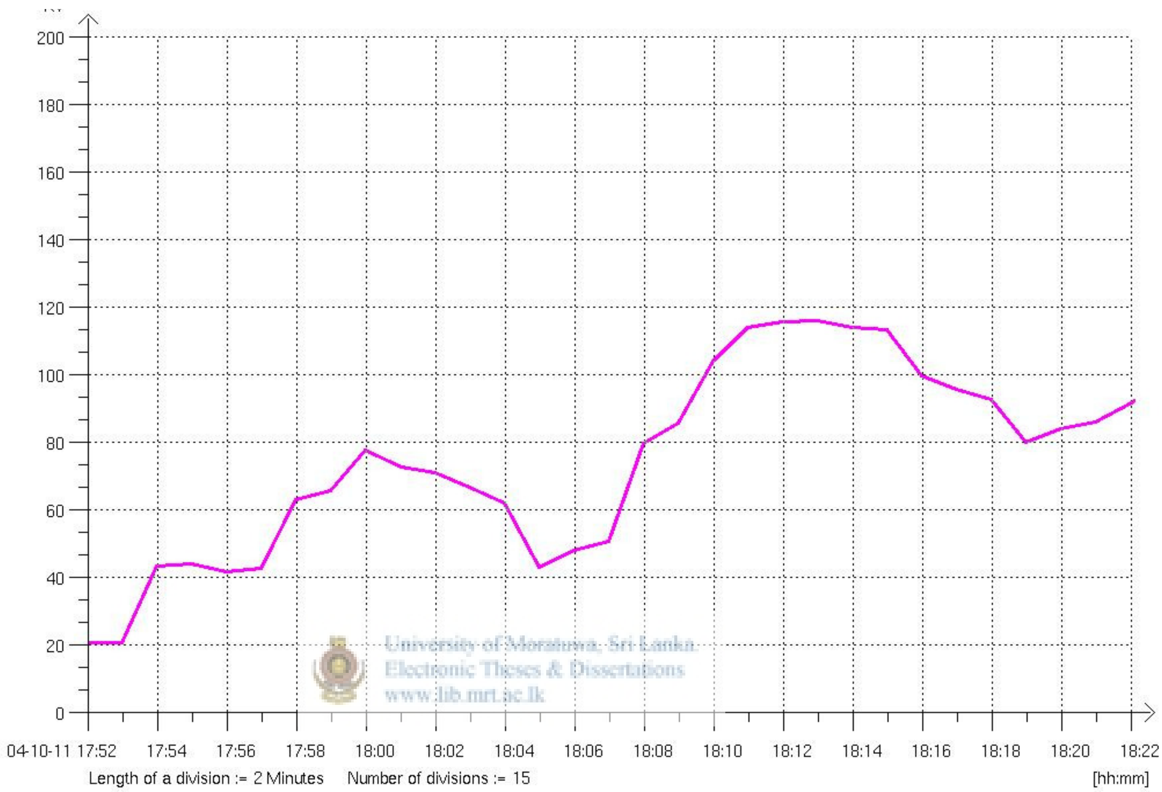


Figure D.7. Equivalent generator representation for multi machine system

The composite power frequency characteristic of a power system thus depends on the combined effects of the droops of all generators speed governors. It also depends on the frequency characteristics of the loads in the system.

Appendix E: Scada Plot of the Response of Frequency Controlling Station

Following plot illustrates the active power variation of the frequency controlling station in one minute sampling rate.



This plot shows how frequency controller responses with system load changes from 17:52 hrs to 18:22 hrs. No disturbances experienced during this period. Frequency controller contribution remained unchanged during 18:11 hrs to 18:15 hrs since system load change during that period catered by the other machines in the system as per instruction of system operator.

CALCULATION OF INITIAL CONDITIONS OF THE POWER SYSTEM

Station	No of Units Available	Fre control	Unit Loading (MW)	Unit Capacity (MW)	Total Station MVA Rated (Pr)	Spining	Droop Settin g %	1/R (K)	K on System MVA base	K
O/Lax I	3		12	8.3	24.9	12.9	5	20.00	0.37	0.37
O/Lax II	2		12.5	12.5	25.0	12.5	5	20.00	0.37	0.37
N/Lax	2		100	50	100.0	0.0	5	20.00	1.49	0.00
WPS	0		0	25	0.0	0.0	5	20.00	0.00	0.00
Canyon	0		0	30	0.0	0.0	5	20.00	0.00	0.00
Polpitiya	2		60	37.5	75.0	15.0	5	20.00	1.12	1.12
Kotmale	1	1	42	67	67.0	25.0	2	50.00	2.50	2.50
Victoria	1		40	75	75.0	35.0	5	20.00	1.12	1.12
Randenigala	0		0	60	0.0	0.0	5	20.00	0.00	0.00
Rantambe	1		15	25	25.0	10.0	5	20.00	0.37	0.37
Ukuwela	0		0	20	0.0	0.0	5	20.00	0.00	0.00
Bowatanne	0		0	40	0.0	0.0	5	20.00	0.00	0.00
Samnalawewa	0		0	60	0.0	0.0	5	20.00	0.00	0.00
Kukule	1		30	40	40.0	10.0	5	20.00	0.60	0.60

KPS Small GT	0		0	20	0.0	0.0	4.2	23.81	0.00	0.00
GT 7	0		0	115	0.0	0.0	5	20.00	0.00	0.00
KCCP GT	1		115	115	115.0	0.0	4	25.00	2.15	0.00
KCCP STG	1		60	60	60.0	0.0	4	25.00	1.12	0.00
Sapu A	4		58	20	80.0	22.0	4.2	23.81	1.42	1.42
Sapu B	5		45	10	50.0	5.0	4.2	23.81	0.89	0.89
AES GT	0		0	112	0.0	0.0	4	25.00	0.00	0.00
AES ST	0		0	53	0.0	0.0	4	25.00	0.00	0.00
ACE Horana	0		0	24	0.0	0.0	5	20.00	0.00	0.00
ACE Matara	0		0	24	0.0	0.0	5	20.00	0.00	0.00
Barge	1		60	60	60.0	0.0	5	20.00	0.90	0.00
Asia Power	1		48	48	48.0	0.0	5	20.00	0.72	0.00
Heladhanavi	1		80	100	100.0	20.0	5	20.00	1.49	1.49
ACE Embilipitiya	1		40	100	100.0	60.0	5	20.00	1.49	1.49
Lakdhanavi	0		0	23	0.0	0.0	5	20.00	0.00	0.00
WCP GT	1		90	90	90.0	0.0	4	25.00	1.68	0.00
WCP ST	0		0	90	0.0	0.0	4	25.00	0.00	0.00
Coal plnt	1		230	300	300.0	70.0	5	20.00	4.48	4.48

Appendix G: Power System Data Utilized for the Study

Pilot Servo Time Constant for Hydro / Th1	0.05	s
Reset Time / Tr1	5.2	s
T1 (rTr1/R)	31.20	s
Steam Chest Time Constant / T6	0.5	s
Fraction of total turbine power generated x Reaheater Time Constant /T4	2.66	s
Main Servo Time Constant for Hydro / Th2	0.7	s
Water Starting Time for Hydro / Twh1	-1.3	s
Twh2	0.65	s
Thermal Governor Time Constant / Tg1	0.6	s
Fuel Combustion Time Constant / Tg2	0.5	s
Tg3	0.3	s
Thermal Spiing / UL	0	pu
Pilot Servo Time Constant for Fre Controller / Tf1	0.05	s
Reset Time / Tr2	5.2	s
T2(rTr2/R)	78	s
Reheater Time Constant / T5	8	s
Boiler Storage Time Constant /Tb	100	s
Main Servo Time Constant for Fre Controller / Tf2	0.6	s
Water Staring Time for Fre Controller / Twf1	-1.3	s
Twf2	0.65	s
Frequency Controller Gain / Gainfr	2.50	pu
Thermal Gain for UF / Gainth1	0.00	pu
Thermal Gain for OF / Gainth2	3.83	pu
Hydro Gain for UF / Gainhy1	2.99	pu
Hydro Gain for OF / Gainhy2	4.86	pu
Dead Band Hydro / db1	0.005	pu
Dead Band Thermal / db2	0.01	pu
Power System gain / K	1.38	pu
Power System Time Constant / Tp	21.85	s
Nominal Frequency / fo	50	Hz
Ramp Rate for Fre Controller / slope	0.001	pu/s
Coal Gain / gainco	4.48	pu