

Topics for Today:

- Announcements
 - ASPEN software - run on MTU server via remote desktop, remote.mtu.edu
 - Office: EERC 614.
 - Recommended problems & all solutions: Ch.13 solns now posted.
- Chapter 12 - Power system operation, AGC, economic dispatch
 - System Operation Basics
 - Paralleling of Generators, droop characteristics
 - Frequency biasing - β and B.
 - Constrained optimization methods - LaGrange multipliers
 - Optimal Dispatch, Generator Scheduling
 - Economics
 - Other constraints - environmental, contractual, availability
 - System load characteristics
 - Application to lossless system
 - System including losses - use [B] loss coefficient matrix

LOAD FLOW Exercises

- Partnered assignment.
- System Parameters.
 - T-Lines
 - XFMRs
 - GENs
- Run "Base Case" to benchmark.
- Then ... do the planning study.
- Wed help session. - 2:05pm.

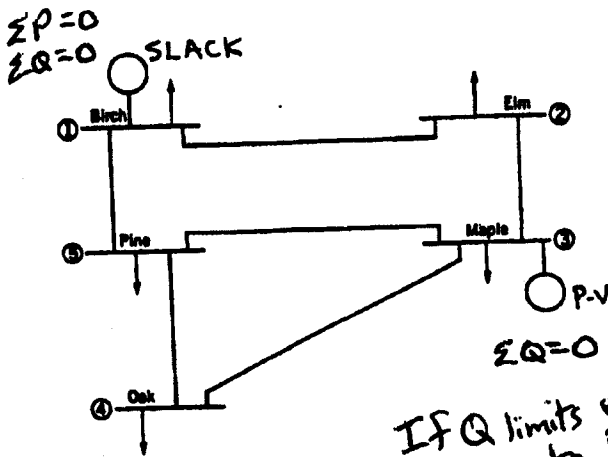
ASPEN (Loadflow) Exercise EES200

Note: Some delay in getting remote licenses. See e-mail for details on software & submission deadline.

The purpose of this laboratory is to gain insight into the operation of a utility power grid. A simple 5-bus system is to be analyzed using a Newton-Raphson power flow program. Operating problems are to be identified and various means of correcting them shall be explored.

The basic system is given as:

$$MVA_{BASE} = 100 MVA$$



If Q limits exceeded,
Change to P-Q bus
with Pfixed, Qmax.

Bus	Generation		Load		(INITIAL VALUES)	
	P, MW	Q, Mvar	P, MW	Q, Mvar	V, per unit	Remarks
1	65	30	1.04 pu	Slack bus
2	0	0	115	60	1.00 pu	Load bus (inductive)
3	180	70	40	1.02 pu	Voltage magnitude constant
4	0	0	70	30	1.00 pu	Load bus (inductive)
5	0	0	85	40	-1.00 pu	Load bus (inductive)

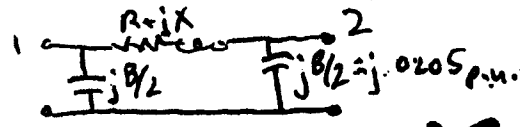
Gen Qmax/Qmin:
+1.2 / -0.6 p.u.

"FLAT" START

Line, bus to bus	Length		FULL LINE				Charging Mvar
	km	mi	R Ω	X Ω	R per unit	X per unit	
1-2	64.4	40	8	32	0.042	0.168	4.1 = 0.41 p.u.
1-5	48.3	30	6	24	0.031	0.126	3.1
2-3	48.3	30	6	24	0.031	0.126	3.1
3-4	128.7	80	16	64	0.084	0.336	8.2
3-5	80.5	50	10	40	0.053	0.210	5.1
4-5	96.5	60	12	48	0.063	0.252	6.1

Max Line Flow:
1.0 per unit

+ At rated (i.e. 1.0 p.u) voltage.



$$Q = V^2 B$$

SEE "AGC Notes"

From Gross, 2nd Ed.

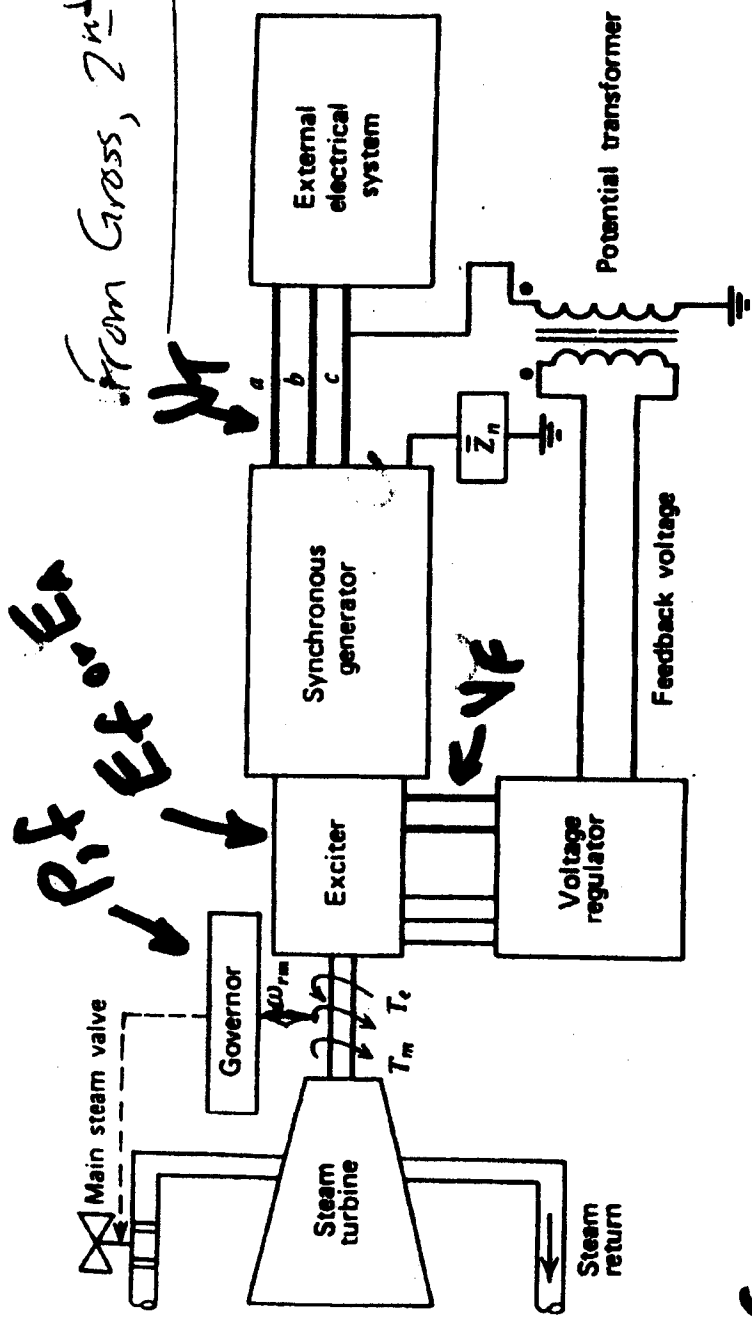
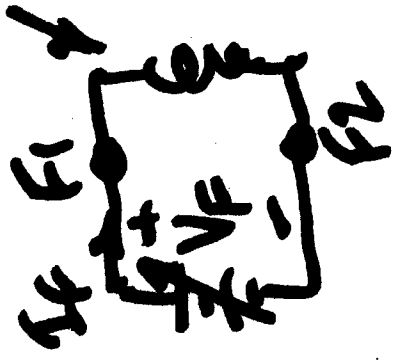
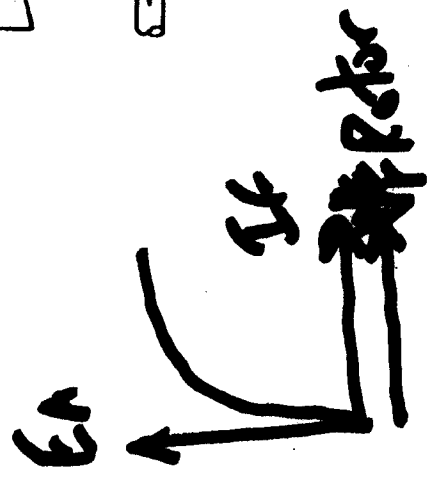


Figure 6.10. Turbine-generator-exciter system

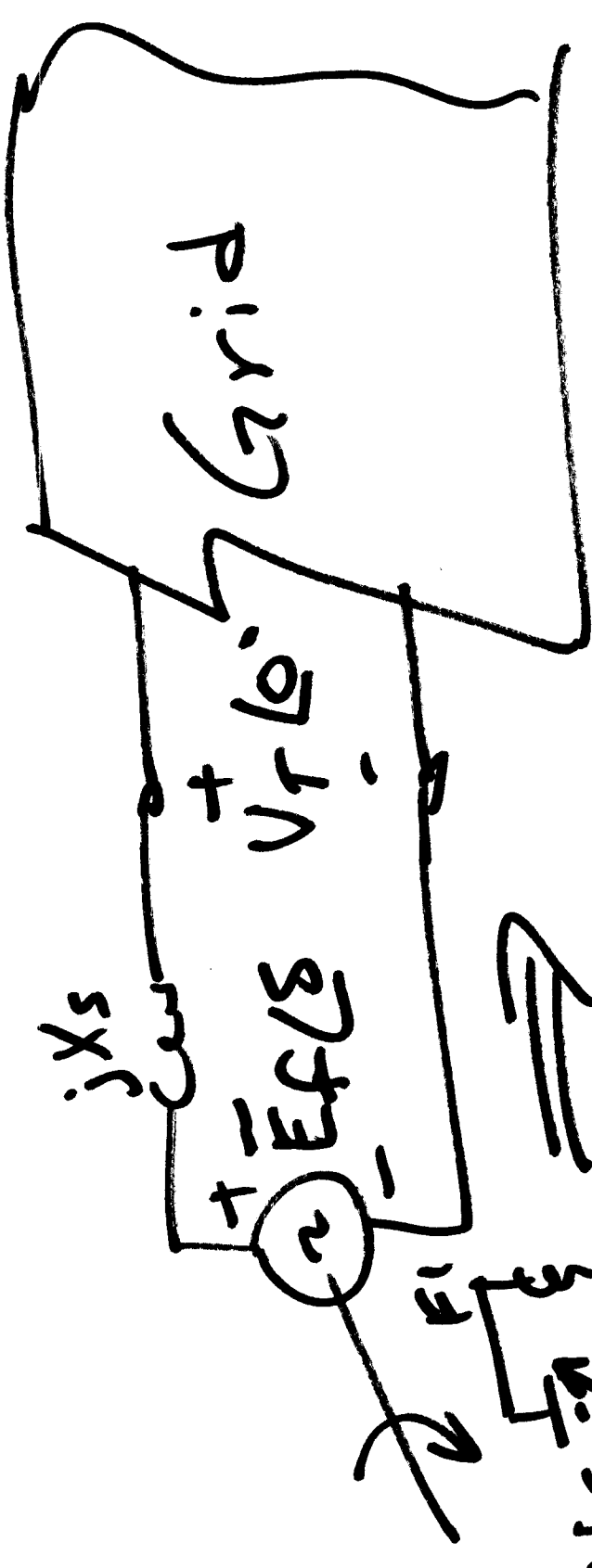


$$P = \frac{E_f V_t \sin \delta}{X_s}$$

$$Q = \frac{E_f V_t \cos \delta - V_t^2}{X_s}$$

$$Q =$$

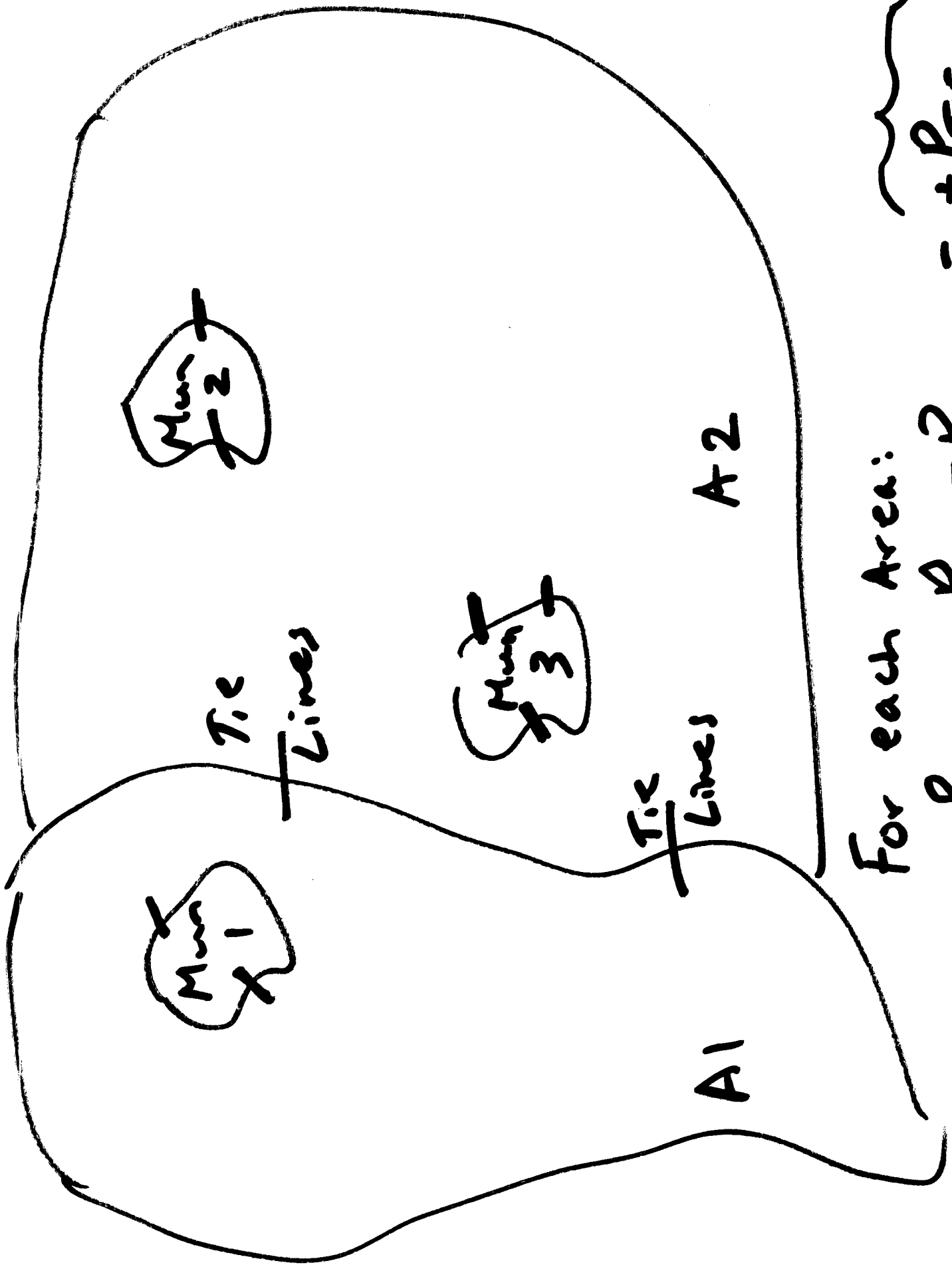
1a



$$P_E = \frac{E_f V_T \sin \delta}{X_s}$$

= Power of GEN
 increase torque \Rightarrow increases δ .

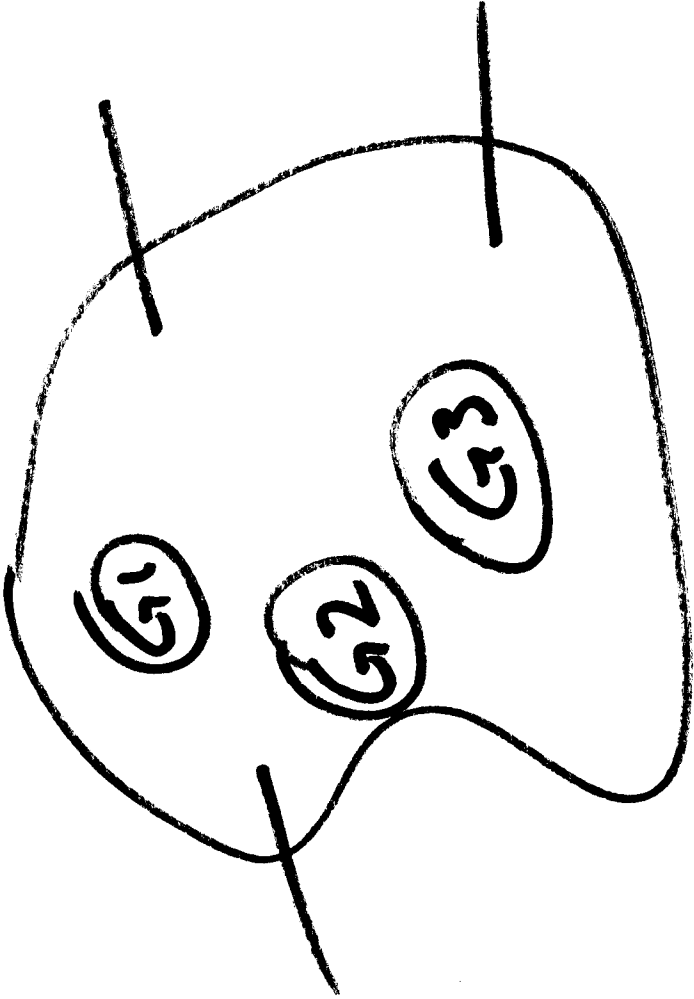
Governor:



For each Area:

$$P_{A_{TOT}} = P_{TOT} - P_{Loss_{TOT}} = + P_{TIE_{TOT}}$$

Scheduled
tie line
flows



$$P_{G1} + P_{G2} + P_{Loss} + P_{TIE} = P_{TIE} + P_{Sched} + P_{Tie} + P_{Gen.}$$

$P_{G1} + P_{G2} + P_{Loss} + P_{TIE} = P_{TIE} + P_{Sched} + P_{Tie} + P_{Gen.}$
Sched for Tie lines.

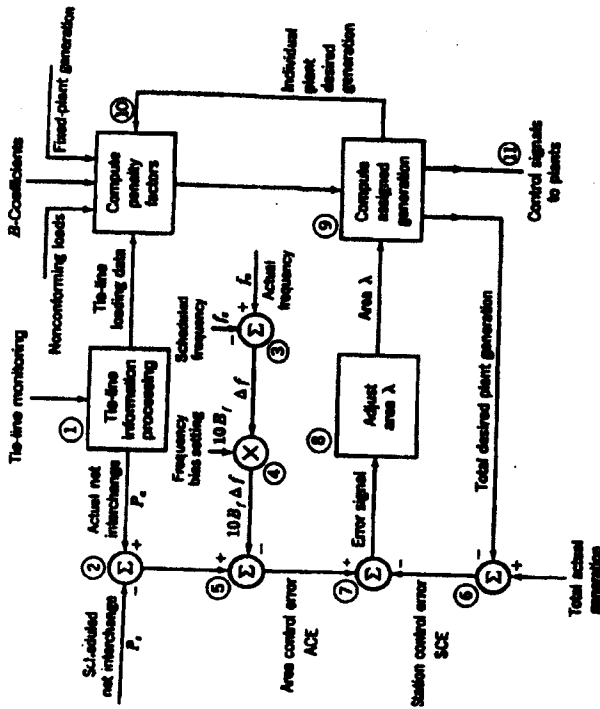


FIGURE 11.9 Block diagram illustrating the computer-controlled operation of a particular area.

symbols \times or Σ indicate points of multiplication or algebraic summation of incoming signals.

At position 1 processing of information about power flow on the lines to other control areas is indicated. The actual net interchange P_a is positive when net power is out of the area. The scheduled net interchange is P_s . At position 2 the scheduled net interchange is subtracted from the actual net interchange. We shall discuss the condition where both actual and scheduled net interchange are out of the system and therefore positive.

Position 3 on the diagram indicates the subtraction of the scheduled frequency f_s (for instance, 60 Hz) from the actual frequency f_a to obtain Δf .

¹Subtraction of standard or reference value from actual value to obtain the error is the accepted convention of power system engineers and is the negative of the definition of control error found in the literature of control theory.

the frequency deviation. Position 4 on the diagram indicates that the frequency bias setting B_f , a factor with a negative sign and the units MW/0.1 Hz, is multiplied by $10 \Delta f$ to obtain a value of megawatts called the frequency bias $(10 B_f \Delta f)$.

The frequency bias, which is positive when the actual frequency is less than the scheduled frequency, is subtracted from $(P_a - P_s)$ at position 5 to obtain the ACE, which may be positive or negative. As an equation

$$ACE = (P_a - P_s) - 10B_f(f_a - f_s) \text{ MW} \quad (11.68)$$

A negative ACE means that the area is not generating enough power to send the desired amount out of the area. There is a deficiency in net power output. Without frequency bias, the indicated deficiency would be less because there would be no positive offset $(10 B_f \Delta f)$ added to P_s (subtracted from P_a) when actual frequency is less than scheduled frequency and the ACE would be less. The area would produce sufficient generation to supply its own load and the rearranged interchange but would not provide the additional output to assist neighboring interconnected areas to raise the frequency.

Station control error (SCE) is the amount of actual generation of all the area plants minus the desired generation, as indicated at position 6 of the diagram. This SCE is negative when desired generation is greater than existing generation.

The key to the whole control operation is the comparison of ACE and SCE. Their difference is an error signal, as indicated at position 7 of the diagram. If both ACE and SCE are negative and equal, the deficiency in the output from the area equals the excess of the desired generation over the actual generation and no error signal is produced. However, this excess of desired generation will cause a signal, indicated at position 11, to go to the plants to increase their generation and to reduce the magnitude of the SCE; the resulting increase in output from the area will reduce the magnitude of the ACE at the same time.

If ACE is more negative than SCE, there will be an error signal to increase the λ of the area, and this increase will in turn cause the desired plant generation to increase (position 9). Each plant will receive a signal to increase its output as determined by the principles of economic dispatch.

This discussion has considered specifically only the case of scheduled net interchange out of the area (positive scheduled net interchange) that is greater than actual net interchange with ACE equal to or more negative than SCE. The reader should be able to extend the discussion to the other possibilities by referring to Fig. 11.8.

Position 10 on the diagram indicates the computation of penalty factors for each plant. Here the B -coefficients are stored to calculate $\partial P_i / \partial P_{ei}$ and the penalty factors. The penalty factors are transmitted to the section (position 9), which establishes the individual plant outputs for economic dispatch and the total desired plant generation.