Topics for Today:

- Announcements
  - Software: online students - apply for ATP/ATPDraw license, verify licensing when you receive it by e-mail, and we will mail you the install CD.
  - ASPEN software - run off of MTU server via internet, see e-mail instructions.
  - Office: EERC 614. Phone: 906.487.2857
  - Recommended problems & all solutions: 13 solns now posted.

- Chapter 13 - Power system operation, AGC, economic dispatch
  - System Operation Basics
  - Paralleling of Generators, droop characteristics
  - 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
Automatic Generation Control (AGC)

For equilibrium (constant speed) generator operation, or constant system frequency,
\[ P_{G\,\text{tot}} = P_{L\,\text{tot}} + P_{\text{loss\,tot}} \]

If tie lines are included,
\[ P_{G\,\text{tot}} = P_{L\,\text{tot}} + P_{\text{tie\,tot}} + P_{\text{loss\,tot}} \]

The portion of the overall power system under a given utility's control is a "control area".

A group of utilities under collective control is called
- A power pool - If tie lines not controlled
- An interconnected system - If tie line flow is controlled

ACE (Area Control Error) is a measure of the difference between scheduled and actual tie-line interchange. ACE is "biased" to include effect of actual system freq vs. \( f_{\text{synch}} \).

Consider operation of an individual turbine-generator set. For a given throttle valve setting,
- Steam flow and resulting torque depend on \( P_{\text{mech}} = T \omega_{\text{mech}} = P_{\text{elec}} \).
Figure 6.10. Turbine-generator-excitation system

\[ P = \frac{E_F \sin \theta}{X_s} \]

\[ Q = \frac{E_F \cos \theta - V_F^2}{X_s} \]
Exciters

- Old - Aux gen connected on shaft
- New - Static w/slip rings
  - **Brushless** - inverted gen - field in stator
  - Arm in rotor, rectified for field
  - No slip rings or brushes req'd.

**General Idea:**

\[ \frac{K_s}{s^2 \alpha^2 + 1} \text{ regulator} \]

\[ \frac{1}{s^2 \beta^2 + 1} \]

\[ \frac{1}{s^2 \gamma^2 + 1} \]

\[ \frac{1}{s^2 \delta^2 + 1} \]

SE used to provide stability. (Stabilizing Compensator)

**Terms:**

\[ V_{ref} \]

\[ V_{error} \]

\[ V_R \]

\[ V_F \]

\[ V_e \]
Any change in $P_c$ will affect the speed and torque of the so-called prime mover, (i.e. constant torque cannot be assumed).

First order responses are assumed for the turbine and governor.

\[ \frac{1}{\tau_g s + 1} \]

Turbine/Gov as a whole:

\[ \frac{1}{(\tau_g s + 1)(\tau_v s + 1)} \]

"Commanded" change in generation due to $ACE$

The effect of these 2 controllers in steady state operating point results in a "droop characteristic"
At position 1 processing of information about power flow on tie lines to other control areas is indicated. The actual net interchange 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.\footnote{Subtraction 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.} 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 $\Delta f$, 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

$$ACE = (P_a - P_s) - 10B_f(f_a - f_s) \text{ MW} \tag{13.68}$$

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 prearranged 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 one area 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 decrease 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 $A$ 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. 13.8.

Position 10 on the diagram indicates the computation of penalty factors for each plant. Here the $B$-coefficients are stored to calculate $\delta P/P_a$ 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.
One other point of importance (not indicated on Fig. 13.8) is the offset in scheduled net interchange of power that varies in proportion to the time error, which is the integral of the per-unit frequency error over time in seconds. The offset is in the direction to help in reducing the integrated difference to zero and thereby to keep electric clocks accurate.

Example 13.6. Two thermal generating units are operating in parallel at 60 Hz to supply a total load of 700 MW. Unit 1, with a rated output of 600 MW and 4% speed-droop characteristic, supplies 400 MW, and Unit 2, which has a rated output of 500 MW and 5% speed droop, supplies the remaining 300 MW of load. If the total load increases to 800 MW, determine the new loading of each unit and the common frequency change before any supplementary control action occurs. Neglect losses.

Solution. The initial point of operation on the speed regulation characteristic of each unit is shown in Fig. 13.9. For the load increase of 100 MW, Eq. (13.66) gives the per-unit frequency deviation

\[
\Delta f = \frac{-100}{\frac{600}{0.04} + \frac{500}{0.05}} = -0.004 \text{ per unit}
\]

Since \( f_0 \) equals 60 Hz, the frequency change is 0.24 Hz and the new frequency of operation is 59.76 Hz. The load change allocated to each unit is given by Eq. (13.67)

\[
\Delta P_1 = \frac{600}{0.04} \left( \frac{600}{0.04} + \frac{100}{0.05} \right) = 60 \text{ MW}
\]

\[
\Delta P_2 = \frac{500}{0.05} \left( \frac{500}{0.04} + \frac{100}{0.05} \right) = 40 \text{ MW}
\]

and so Unit 1 supplies 460 MW, whereas Unit 2 supplies 340 MW at the new operating points shown in Fig. 13.9. If supplementary control were applied to Unit 1 alone, the entire 100-MW load increase could be absorbed by that unit by shifting its characteristic to the new 60-Hz position at point c of Fig. 13.9. Unit 2 would then automatically return to its original operating point to supply 300 MW at 60 Hz.

The large number of generators and governors within a control area combine to yield an aggregate governing speed-power characteristic for the area as a whole. For relatively small load changes this area characteristic is often assumed linear and then treated like that of a single unit of capacity equal to that of the prevailing on-line generation in the area. On this basis, the following