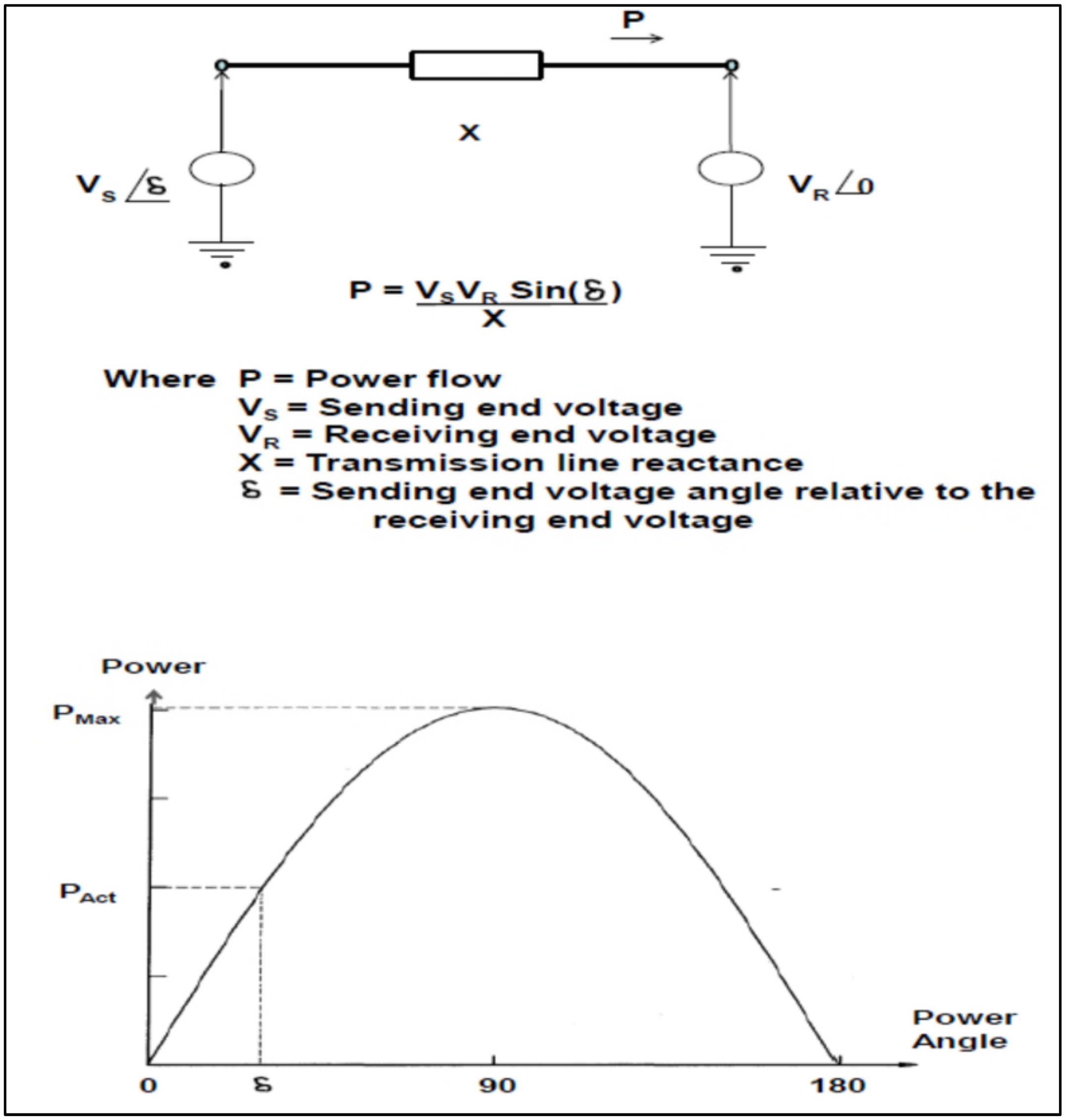
APPENDIX A

ATTACHMENT A - STABILITY OF POWER SYSTEMS

1. Power systems have multiple generators and loads that are constantly changing. How generators respond to these small perturbations is considered **dynamic stability**. The generators and loads are connected together by transmission lines that are open to the environment and subject to various natural events that can cause elements of the system to fail. Lightning strikes, tree contact, ice storms, animals causing short circuits as well as failure of insulating materials are some examples. All power systems are designed to be able to transition from one stable state to another stable state following the contingent loss of any one piece of equipment. This is **transient stability** and the maximum power flow at which the system can safely recover is referred to as the **transient stability limit**.

2. To begin, it is useful to describe the elements of power flow across a transmission line. In a power system the amount of power that can flow across a transmission line is dependent on the voltage at each end of the line, the impedance of the line and the sine of the angle between the voltages (the Power Angle). By ignoring the resistance of the line which is small relative to the reactance the impedance reduces to the reactance X. Consider the diagrams and Power equation below:

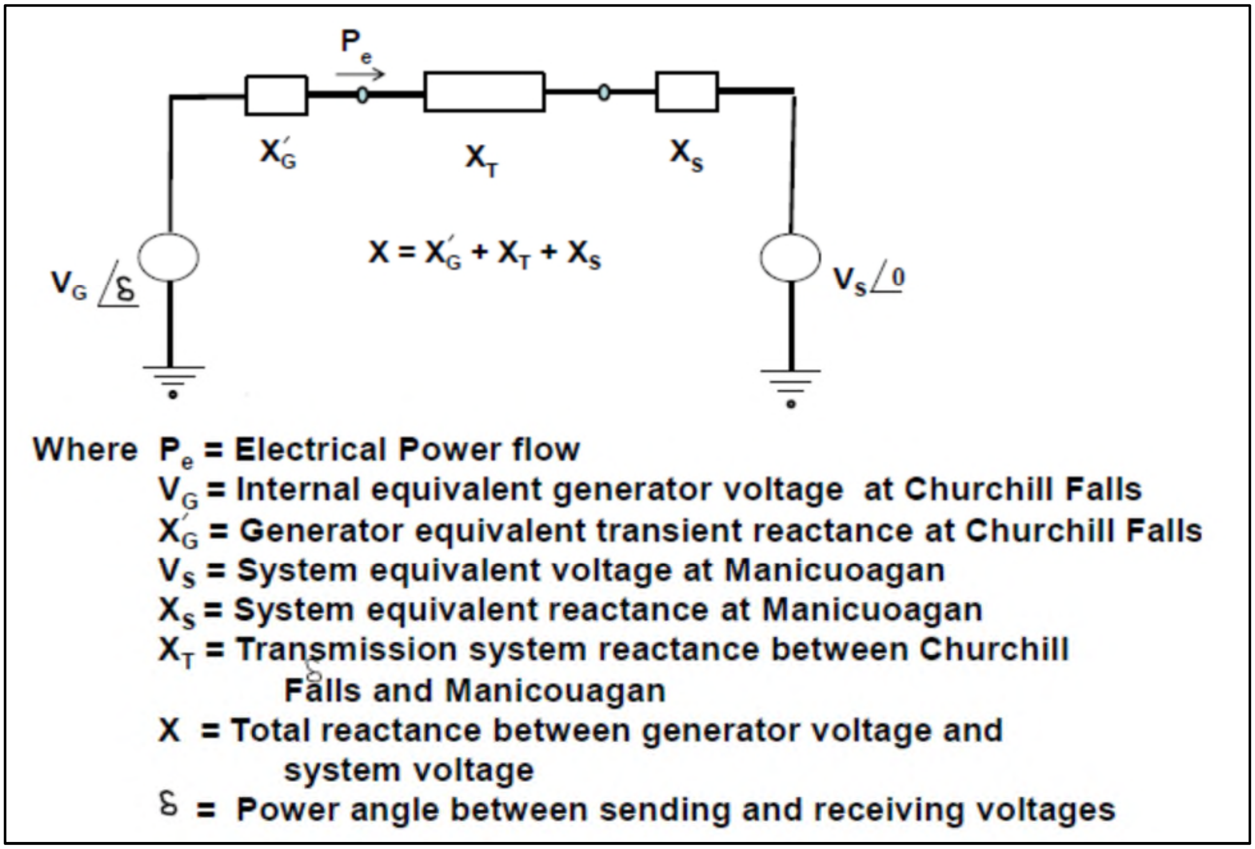


3. This introduction reveals several points. A power system normally operates at the design voltage with per unit values of 1.0 so the most influencing variable is the transmission reactance X. A small value of X causes a large amplitude P_{Max} (which is desirable) and consequently a small initial power angle δ (which is also desirable).

4. As you can see the amplitude of the sine function $V_S V_R/X$ is the maximum amount of power that can flow and it would be at a power angle of 90 degrees. This is the **steady state stability limit**. It is dangerous for power systems to be operated near the steady state stability limit because it leaves little opportunity for recovery should a contingency occur.

Transient Stability

5. Let us consider the system from Churchill Falls to Manicouagan/Micoua as an example to consider transient stability. It can be reduced to the simplified equivalent circuit by adding a classical equivalent made up of a voltage behind a reactance at each end of the transmission. One represents Churchill Falls generators plus their power transformers and the other represents the HQT system beyond Manicouagan/Micoua.



6. Because the voltages in a power system are always maintained near the rated values on all system equipment we can assume that the per unit voltages are 1.0 so that the Power flow P_e before and after a fault is cleared is dependent on the sine of the power angle divided by the total reactance X. Before the fault, X is small because all three transmission lines between Churchill Falls and Manicouagan/Micoua are in service. This makes P_{Max} large which is good.

7. If there is a fault on one of the transmission lines near Churchill Falls, protective relays will sense the fault and send signals to open the transmission line breakers. This takes the transmission line out of service and increases X so P_{Max} is reduced. During the fault P_e is zero because of zero voltage at the fault. With the imbalance between P_m and P_e the generator rotor accelerates and the power angle increases. It can go beyond 90 degrees, and the system will attain transient stability if the power angle recovers to a steady state value well below 90 degrees. The transient stability limit that provides enough post fault restraining power to pull the generator back into a stable synchronous state is illustrated by the diagram[1] below.

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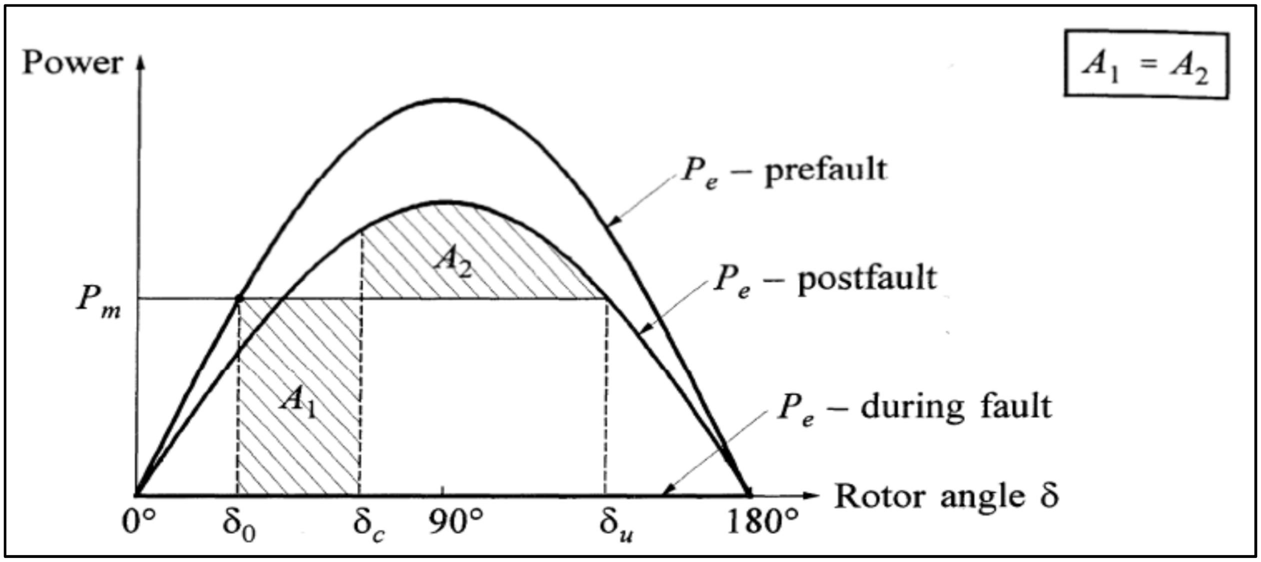
1 Diagram from **Power System Stability and Cont**rol by P. Kunder, Figure 13-60 (b), page 944



8. Area A_1 represents the imbalance accelerating power equal to the mechanical input power P_m during the fault which increases the rotor power angle. When the fault is cleared electrical power P_e is greater than mechanical power P_m by area A_2 and the rotor angle is pulled back. Stability will be maintained if area A_2 is greater than or equal to A_1. If it is not, the Power angle will increase beyond recovery and the system will go unstable.

9. Large single contingencies for the LAB-HQT path could be a three phase fault to ground at the Churchill Falls end of a transmission line from the plant or a three phase fault of a 230/735 kV transformer that connects two generators. Either of these faults would reduce the Churchill Falls bus voltage to zero and the electrical power delivered from the plant to zero as well. Such a contingency makes accelerating area A_1 have the largest possible value. This would cause the Churchill Falls generators to accelerate rapidly because of the imbalance between the electrical output power (which is zero) and the mechanical input power. This acceleration would increase the power angle and move the generators toward instability.

10. Fortunately power systems utilize sensitive protective relay equipment that would detect the fault and send signals to open the breakers to isolate the faulted equipment so that the fault would be cleared. This action is done in about a tenth of a second or less and it acts to make the accelerating area A_1 as small as possible.

11. It also takes the faulted equipment (the transmission line or transformer) out of service which will increase the reactance X_T of the transmission system and consequently the total X as well. In order for the system to remain stable the electrical power must be able to increase sufficiently to offset the generator acceleration and bring each generator back to a stable state. For this to happen, the decelerating area A_2 must be at least as large as accelerating area A_1. When the power system is operated at rated voltage, when the worst possible single contingency (N-1) is considered, and when the circuit breakers operate at the fastest speed possible, then the transient stability limit is determined exclusively by the strength of the electrical system which remains after the failed component transmission equipment is removed. A post-fault reactance X which is as small as possible means a large post-fault P_{Max} and a large A_2.

12. More simply, the transient stability limit provides enough power transfer margin to be able to withstand the worst single contingency (N-1) and return the system to a safe steady operation

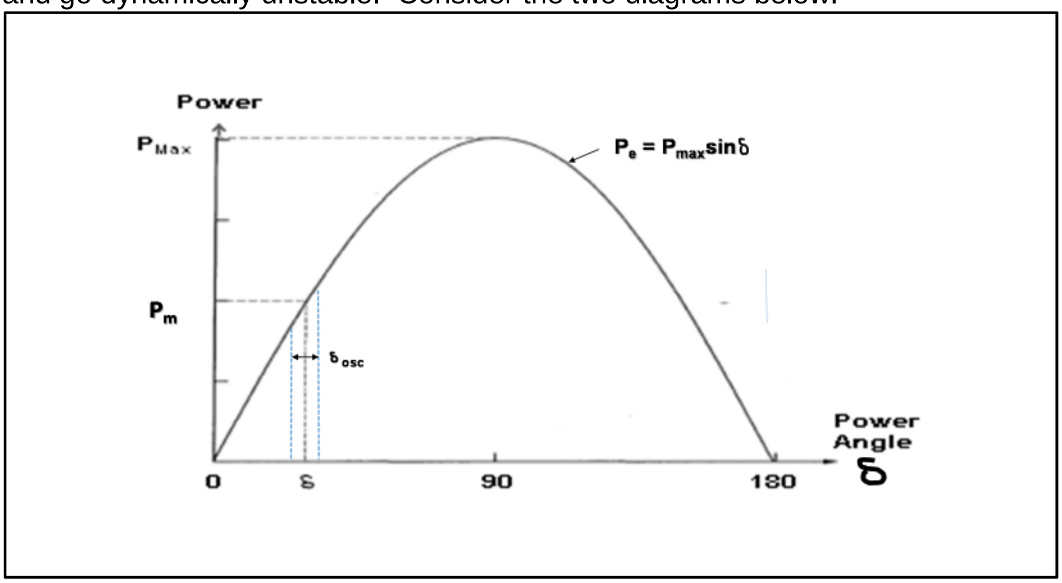
should such a contingency occur. This stability limit value is also referred to as the Total Transfer Capacity or Total Transfer Capability ("TTC") for an interface between two sub-areas of a transmission network. For the corridor between Churchill Falls and Manicouagan/Micoua the transfer capacity has been determined by HQT to be 5200 MW.

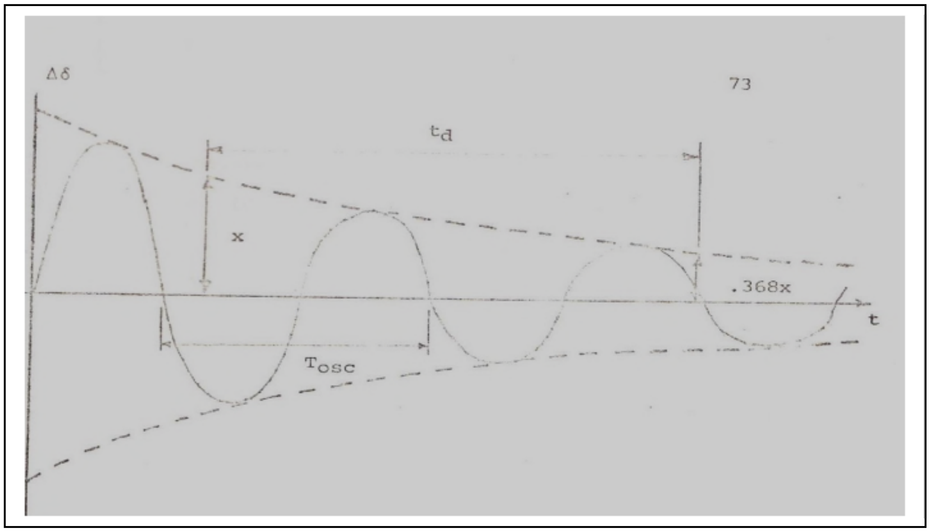
13. HQT would not use this simplified transient stability analysis to determine the Transfer Capacity for the LAB-HQT path. HQT would undertake a detailed computer simulation of the system that would model in real time all system variables (voltages, currents, power flows and phase angles) prior to the fault, during the fault and after the fault is cleared.

14. This simplified transient stability analysis is not as extensive as a complete real time stability model of the HQT system but is informative for us to understand why transfer capacities are different for different conditions. From the analysis we can see that there are three key variables related to transient stability (and therefore transfer capacity determination) as follows:
    a) Initial power at the generator and its starting power angle;
    b) The duration of the fault before it is cleared; and
    c) Most importantly the magnitude of the reactance X between the generators at Churchill Falls and the system at Manicouagan/Micoua.

Dynamic Stability

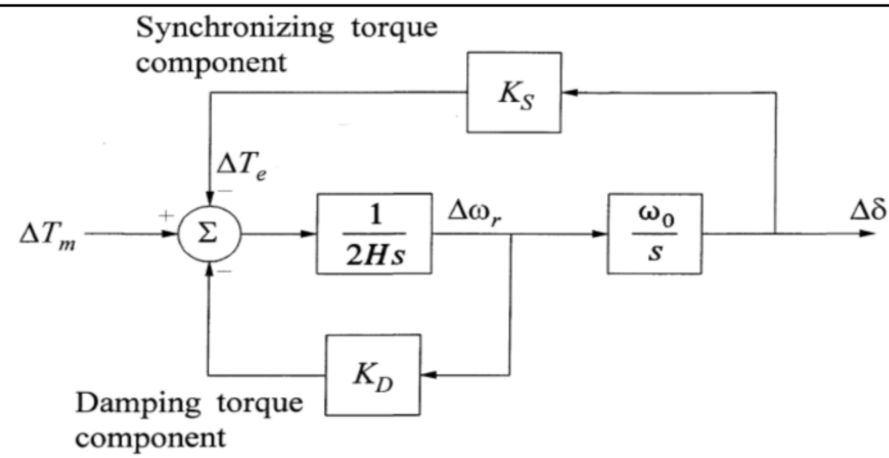
14. Power systems are never stationary in a specific steady state. They are continuously subject to small perturbations that cause the rotor angles of generators to oscillate around its equilibrium point where mechanical input power P_m is equal to the electrical output power P_e. After any small disturbance the oscillations may be damped back to the equilibrium point or may get larger and go dynamically unstable. Consider the two diagrams below.



16. 

The diagrams illustrate a small perturbation that is dynamically stable as the oscillations reduce in magnitude. The period of the oscillation frequency T_{osc} can be measured by field tests and determine the natural oscillating frequency as $1/T_{osc}$ and the damping time constant is the time in seconds for oscillation amplitude to reduce by 63.2%. Note that T_d is the time in the diagram for the amplitude to reduce from x to 0.368x.

17. For a single generator connected to a large system the oscillation of the power angle can be modelled according to the diagram below.



K_S = synchronizing torque coefficient in pu torque/rad
K_D = damping torque coefficient in pu torque/pu speed deviation
H = inertia constant in MW·s/MVA
$\Delta\omega_r$ = speed deviation in pu = $(\omega_r - \omega_0)/\omega_0$
$\Delta\delta$ = rotor angle deviation in elec. rad
s = Laplace operator
ω_0 = rated speed in elec. rad/s = $2\pi f_0$
= 377 for a 60 Hz system

Figure 12.5 Block diagram of a single-machine infinite bus system with classical generator model [2]

17. The natural frequency of the oscillations and the rate at which they are damped are dependent on the synchronizing torque coefficient (K_S), the damping torque coefficient (K_D) but **most importantly on the generator inertia constant (H)**. Note below Kundur's equations and comments.

Therefore, the undamped natural frequency is

$$\omega_n = \sqrt{K_S \frac{\omega_0}{2H}} \quad \text{rad/s}$$

and the damping ratio is

$$\zeta = \frac{1}{2} \frac{K_D}{2H\omega_n}$$

$$= \frac{1}{2} \frac{K_D}{\sqrt{K_S 2H\omega_0}}$$

[3]

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[2] Diagram is Figure 12.5 of "***Power System Stability and Control***" by P. Kundur as published by McGraw-Hill, Inc.
[3] Ibid, page 731

As the synchronizing torque coefficient K_S increases, the natural frequency increases and the damping ratio decreases. An increase in damping torque coefficient K_D increases the damping ratio, whereas an increase in inertia constant decreases both ω_n and ζ. [4]

18. If the external system, to which the generator is connected, is not an infinite bus then H must be adjusted to include the system inertia (H_s) and the generator inertia (H_g). This enables the performance of a remote generator to be analysed in a similar manner. The adjustment to H is given as follows.

$$H = \frac{H_g H_s}{H_g + H_s}$$

19. Dynamic stability problems in a power system may be local to a single area of the system or global in nature. Note comments of Kundur at page 817 and pages 821-22.

Local problems involve a small part of the system. They may be associated with rotor angle oscillations of a single generator or a single plant against the rest of the power system. Such oscillations are called *local plant mode oscillations*. The stability problems related to such oscillations are similar to those of a single-machine infinite bus system as studied in Sections 12.3 to 12.6. Most commonly encountered small-signal stability problems are of this category.

Local problems may also be associated with oscillations between the rotors of a few generators close to each other. Such oscillations are called *intermachine or interplant mode oscillations*. Usually, the local plant mode and interplant mode oscillations have frequencies in the range of 0.7 to 2.0 Hz.

Global small-signal stability problems are caused by interactions among large groups of generators and have widespread effects. They involve oscillations of a group of generators in one area swinging against a group of generators in another area. Such oscillations are called *interarea mode oscillations*.

The characteristics of interarea modes of oscillation are very complex and in some respects significantly differ from the characteristics of local plant modes. Load characteristics, in particular, have a major effect on the stability of interarea modes. The manner in which excitation systems affect interarea oscillations depends on the types and locations of the exciters, and on the characteristics of loads [23].

Speed-governing systems normally do not have a very significant effect on interarea oscillations. However, if they are not properly tuned, they may decrease damping of the oscillations slightly. In extreme situations, this may be sufficient to aggravate the situation significantly. In the absence of any other convenient means of increasing the damping, adjustment or blocking of the governors may provide some relief [26].

Analysis of interarea oscillations requires detailed representation of the entire interconnected power system. Models for excitation systems and loads, in particular, should be accurate, and the same level of modelling detail should be used throughout the system.

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[4] Ibid, page 732

19. As stated by Kundur, modelling of interarea oscillations is very complex and requires detailed computer simulation of all elements of the power system and this would be done by HQT. While there are ways to increase damping using power system stabilizers the main system components that limit oscillations are the inertia constants of generators and the characteristics of loads.

20. The inertia constant H is defined as *"the megajoules of stored energy of a machine at synchronous speed per megavolt-ampere of the machine rating."* [5] Typical values for different types of generators are also provided.

Large nuclear turbo generator	4.1
Large steam turbo-generators	
1800 rpm condensing	6
3600 rpm condensing	4
3600 rpm noncondensing	3
Large vertical shaft hydraulic generators	
450-514 rpm	4.5
200-400 rpm	4.0
138-180 rpm	3.5
80-120 rpm	3.0
Combustion turbine generators	4.7
Wind turbine generators	2.0

21. The amount of inertia constant H retired by Hydro-Quebec was about 20 in 2011 at Tracy, 13 in 2012 at La Citiere and 4.1 in 2012 at Gentilly. The total retirement is about 35 to 40 MWs/MVA.

22. Inertia is also provided by certain types of loads, especially industrial motor loads as they would contain kinetic energy that would tend to keep them rotating.

[5] W.D. Stevenson, ***"Elements of Power System Analysis"***, Second Edition, McGraw-Hill, Inc., 1962, page338