



Digitally controlled generator tripping as an aid to power system stability
by Joseph Franklin Jolley

A thesis submitted in partial fulfillment of the requirements for the degree of Master of Science in
Electrical Engineering
Montana State University
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Abstract:

This thesis deals with a control processor that has been designed, built, installed, and operated on The Montana Power System to improve system stability by generator dropping. The power system stability problem is described, and various methods for strengthening power systems are compared. The effects of generator tripping are described, and a conceptual understanding of a processor that can be used to govern generator tripping is developed. The last section of the thesis contains descriptions of the actual operating history of the device.

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MONTANA STATE UNIVERSITY
Bozeman, Montana

December 1982

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APPROVAL

of a thesis submitted by

Joseph Franklin Jolley

This thesis has been read by each member of the thesis committee and has been found to be satisfactory regarding content, English usage, format, citations, bibliographic style, and consistency, and is ready for submission to the College of Graduate Studies.

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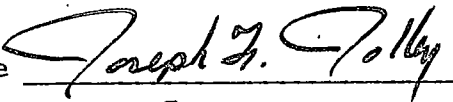
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ABSTRACT

This thesis deals with a control processor that has been designed, built, installed, and operated on The Montana Power System to improve system stability by generator dropping. The power system stability problem is described, and various methods for strengthening power systems are compared. The effects of generator tripping are described, and a conceptual understanding of a processor that can be used to govern generator tripping is developed. The last section of the thesis contains descriptions of the actual operating history of the device.

Chapter 1

INTRODUCTION

Problem Background

The development of the Acceleration Trend Monitor is strongly intertwined with the operating weaknesses of The Montana Power Company system. The weaknesses are, in part, due to gambles that were taken early in the development of the coal fields in eastern Montana. It was noted that much of the transmission that would be installed to transmit power from Colstrip Units #1 and #2 would become redundant after the transmission for Colstrip Units #3 and #4 was installed. Since Colstrip Units #3 and #4 and associated transmission were scheduled to be in place less than three years after Colstrip Unit #2 became commercial, and since generators are rarely capable of full output during the first several years, it was decided not to build the soon-to-be-redundant transmission lines. The resultant system had the capability (nameplate) to generate 720 MW of electrical power at Colstrip, and about 270 MW of electrical power at Billings. The local load at Colstrip (60 MW) and Billings (about 200 MW) could be subtracted from the total generation, but circulating flow (power that flows over a path on which none is scheduled -- up to 300 MW in this case) from Yellowtail to Billings must be added to the total generation. The result is that up to 760 MW must be transmitted over circuits west of Billings, Montana that are capable of transmitting only 572 MW. The flows on the circuits west of Billings have been kept below 572 MW by

reducing the generation at Colstrip. However, any reduction in the Montana generation simply causes more circulating flow to come from Yellowtail. The result is that Colstrip and Billings generation must be reduced by about 300 MW to reduce the flow on the circuits west of Billings by about 200 MW.

When Colstrip Units #1 and #2 were new, reduced generation was easy to obtain. The output of the plants was not curtailed substantially by the limitations of the system west of Billings. Most of the curtailments were due to problems with the units.

It was originally felt that by the time the plants became reliable enough to substantially stress the system, Colstrip Unit #3 and its associated transmission would be operational. However, since Colstrip Unit #3 has been delayed from June 1978 to January 1984, transmission imposed generation curtailments became common.

A one-line diagram of the Montana Power 230 kV system is on the next page.

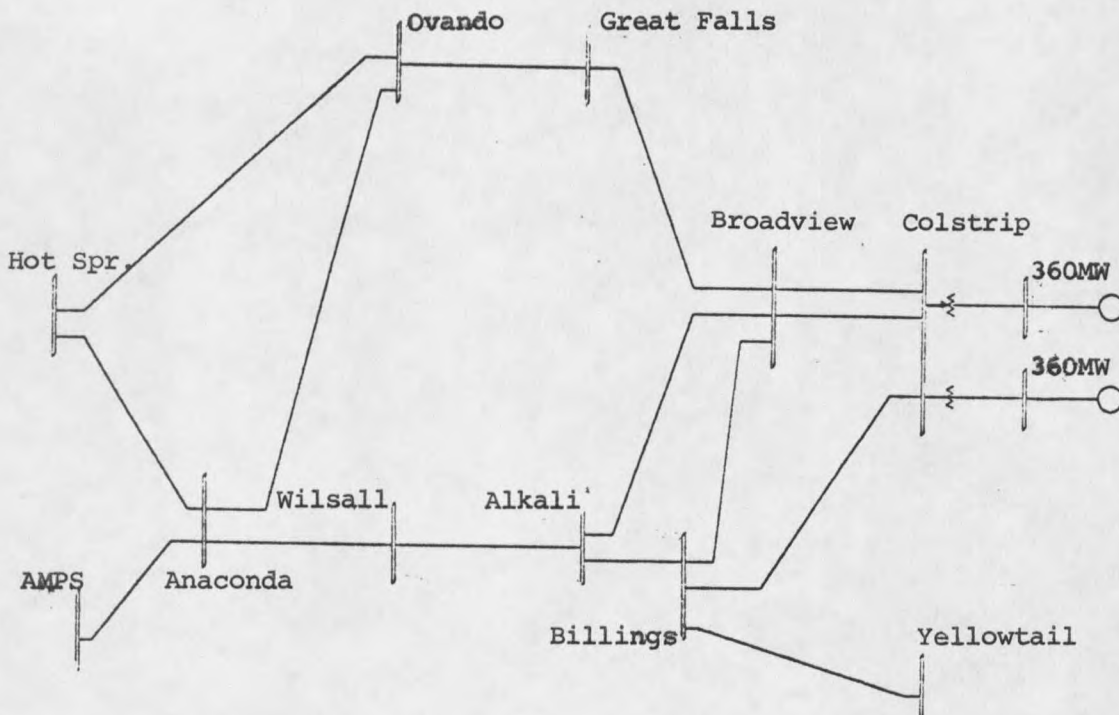


Figure 1.1: One-Line Diagram of the Montana Power Transmission System

The 572 MW limit is dictated by the system's ability to recover from a transient event (fault followed by circuit isolation). The 572 MW limit can be expressed as a limit of 400 MW total on the Broadview-Great Falls and Alkali Creek-Clyde Park 230 kV lines. A nearly constant 70% of the total power flowing west of Billings flows on the two 230 kV lines.

If transient events were not allowed to occur, the Montana system would be sufficiently strong to transmit all the power that could be generated by the eastern thermal plants plus accommodate all of the circulating flow that comes from Yellowtail. However, loss of the Broadview to Great Falls circuit, for instance, results in insufficient remainder system to transmit the power. The system collapses and a black-out results.

The black-out affects not only Montana, but the resultant power surges may cause the instability to cascade so far west as Washington, and so far south as Nevada. The entire power system of the Western United States might shatter into small shards of light surrounded by large areas of blackness.

The investigations described in this thesis were directed at preventing such cascading instability while allowing full generation in eastern Montana. The device that was developed is simply the most attractive of many methods available.

Research Objectives

The thrust of the entire study was to identify solutions that would take advantage of full generation from the eastern Montana thermal plants while not allowing the possibility of cascading black-outs subsequent to system disturbances. Many possible solutions were identified, and compared on the basis of effectiveness and cost.

The most attractive of all the alternatives was identified as generator tripping, and a new method for evaluating the viability of the power system was developed. A device capable of sensing imminent instability was specified, built, installed and operated on the Montana Power system.

Literature Review

This subchapter contains descriptions of the literature pertaining to electric power systems. The literature available is either general (applying to both power systems and electro-mechanical machines), or specific (applying only to electrical machinery). While many very astute volumes have been published since the New York black-out in 1965, the true classics in the field of electric power systems are about thirty years old.

General Literature

The Central Station Engineers of the Westinghouse Electric Corporation produced a book that has since become a classic¹. It contains engineering descriptions of nearly every aspect of power system operations. Very few facets of the power system escape the book's attention.

Byerly and Kimbark² edited a multitude of IEEE papers that describe many of the more recent developments in power system stability. Their book contains descriptions of the mathematical models available to define power system elements, a discussion of dynamic instability, a discussion of transient instability, and descriptions of some of the tools that can be applied to prevent power system instability.

Elgerd³ produced a text that contains descriptions of the mathematical tools and elements used in power system. Both electro-mechanical machines and integrated power systems are described in detail.

Electrical Machine Literature

Gourishankar⁴ wrote an excellent text on linear electrical and mechanical systems. His treatment of the elements that comprise an electrical power system is clear and complete.

Fitzgerald, Kingsley, and Kusko⁵ have produced a fine beginning text on electric machinery. It is a good place to start.

Concordia⁶ is probably the world's leading expert on synchronous machines. His book goes into sufficient detail to allow the solution to almost any type of machine problem. Long out of print, the book is again available through the efforts of the General Electric Company.

Concordia and Rustebakke⁷ produced a fine paper describing the induction generator effect that occurs when series compensated line is connected to a synchronous generator.

Torsional interactions are explained by Bowler, Ewart and Concordia⁸ in a fine descriptive paper.

Chapter 2

POWER SYSTEM STABILITY

System Model for Steady-State

Power system operation is limited by both steady-state and transient phenomenon. The problem, in its simplest form, may be understood by considering the simplest of power systems which consists of two busses joined by a line.

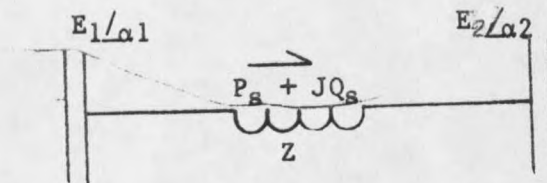


Figure 2.1: The Simplest Power System

The power transferred from bus #1 to bus #2 is:

$$P_s + JQ_s = E_1 |^*(1)$$

$$| = \frac{E_1 - E_2}{Z}$$

$$|^* = \frac{E_1^* - E_2^*}{Z^*}$$

$$P_s + JQ_s = \frac{E_1(E_1^* - E_2^*)}{Z^*}$$

$$= \frac{|E_1|^2}{Z^*} - \frac{|E_1||E_2|}{Z^*} \angle \alpha_1 - \alpha_2$$

$$= \frac{|E_1|^2}{Z^*} - \frac{|E_1||E_2|/\delta}{Z^*}$$

Where: $\delta = \alpha_1 - \alpha_2$

Recognize that the X/R ratio for a transmission line is large. The geometry dictates that the higher the voltage the larger the ratio. At 230 kV, the ratio is about ten to one. At 500 kV, the ratio is more than twenty to one. Consequently, the resistance portion of the impedance can be ignored without introducing much error. The numerator of the first term of the equation is clearly real. The denominator is imaginary. Consequently, the entire term is imaginary and can be eliminated.

$$P = \text{Re} \frac{|E_1|^2}{Z^*} - \frac{|E_1||E_2|/\delta}{Z^*}$$

$$P = \frac{|E_1||E_2|}{|X|} \sin \delta \quad (2)$$

Since the resistive component of the line impedance is ignored, transmission system watt losses are also ignored. The real power arriving at bus #2 equals the real power sent from bus #1.

Generally, the busses are assumed to be elements of a large power system. They are supported well enough to have the voltages remain at 1.0 pu regardless of how much power is transmitted between them. That is, the power transmitted between the two busses is a small percentage of power available at either. Having made the voltage assumption, Equation (2) can be reduced to the power-angle curve shown on the next page:

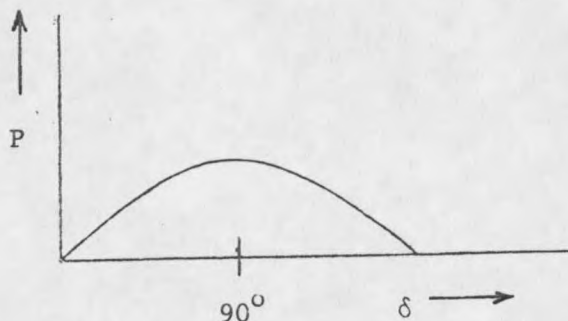


Figure 2.2: Power-Angle Curve

In the steady-state, the maximum power is transmitted when $\delta = 90^\circ$. Once the voltage assumption has been made, the maximum power is said to be 1.0 pu when the impedance is 1.0 pu.

Steady-State Computations

At maximum power transfer, the voltage at the center of the line can be computed.

$$E_c = \frac{PX_{lc}}{E_l \sin(\delta_{lc})} = \frac{.5}{2/2} = .707 \text{ pu}$$

If a load that is too small to upset the computations is served near the center of the line, the voltage is clearly too low.

The voltage can be corrected (in the steady-state) by adding shunt capacitors. If enough shunt capacitors are added at the center of the line to cause the current to substantially lead the voltage, the voltage

at the center of the line can actually exceed the sending-end voltage. A vector diagram illustrates the phenomenon.

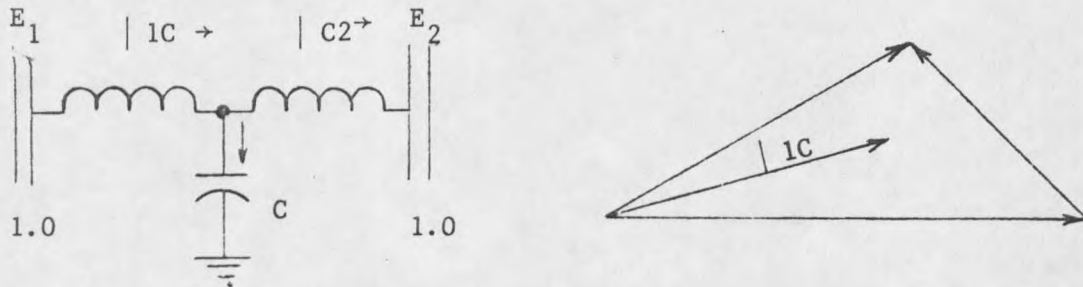


Figure 2.3: Voltage Boost Achieved by Shunt Capacitors

The voltage at the center of the line can be corrected to 1.0 pu even if the line is loaded to its power handling capability. The size of the capacitor that must be added to raise the voltage to 1.0 pu at the center of a line loaded to its capacity can be computed.

$$\text{First, compute } \delta_{lc}: P = \frac{|E_1||E_c|}{|X_{lc}|} \sin \delta_{lc}$$

$$1 = \frac{1 \times 1}{.5} \sin \delta_{lc}$$

$$\delta_{lc} = 30^\circ$$

Second, draw the vector diagram:

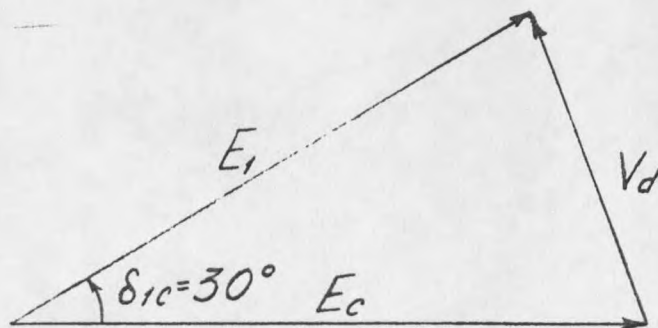


Figure 2.4: Vector Diagram of a System With the Center Voltage Corrected

Third, compute V_d :

$$\begin{aligned} V_d &= E_1 - E_c \\ &= 1 \angle 30^\circ - 1 \angle 0^\circ \\ &= -0.134 + j 0.5 \end{aligned}$$

Fourth, compute I_{1c} :

$$\begin{aligned} I_{1c} &= \frac{V_d}{X_{1c}} \\ &= \frac{(-0.134 + j0.5)}{j0.5} \\ &= 1 + j0.268 \end{aligned}$$

If the line ended at the center, 0.268 pu VARs would be needed to boost the voltage at the center to 1.0 pu. However, the line does not end at the center. It continues past that point. The entire system can be represented by a vector diagram.

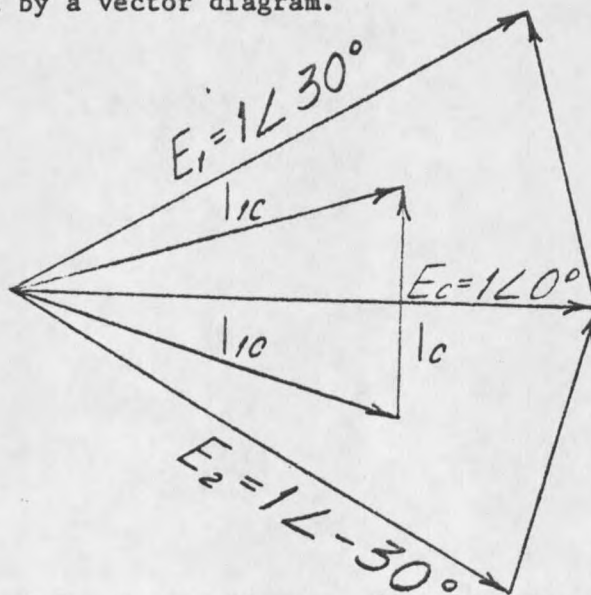


Figure 2.5: Vector Diagram of the Complete System With the Center Voltage Corrected

The capacitors at the center must supply $2 \times 0.268 = 0.536$ pu VARs.

Another expression of the power transfer equation is: $P = P_{\max} \sin \delta_{12}$. Since δ_{12} decreases as the center voltage is corrected, the capacity of the line increases.

$$\begin{aligned} 1.0 &= P_{\max} \sin 60^\circ \\ P_{\max} &= 1.155 \text{ pu} \end{aligned}$$

If the line is loaded to the increase capacity, the voltage at the center can be computed for that condition.

$$1.155 = \frac{1 \times E_c}{.5} \sin 45^\circ$$

$$E_c = .817 \text{ pu}$$

The points of minimum voltage have actually moved away from the center. The operating condition is shown by the vector diagram.

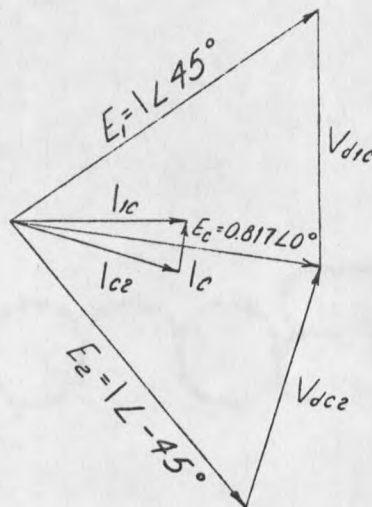


Figure 2.6: Vector Diagram of a System Loaded Beyond the Original Limit

The points of minimum voltage can be located by recognizing that there is no power loss in the system ($R = 0$) and that the power computed anywhere along the line must be 1.155 pu. The minimum voltage points must then occur where the voltage is in phase with the current. Alternatively, recognize that the shortest vectors from the origin to the voltage drop vectors are perpendicular to the voltage drop vectors. Either method will yield the magnitudes and locations of the voltage minimums.

The current can be computed:

$$\text{Re } [I_{1c}] E_c = 1.155$$

$$\text{Im } [I_{1c}] = .817 \times .268$$

$$\text{Re } [I_{1c}] .817 = 1.155$$

$$\text{Im } [I_{1c}] = .219$$

$$\text{Re } [I_{1c}] = 1.414$$

The angle of the current (θ_1) can be computed.

$$\theta_1 = \tan^{-1} (.219/1.414)$$

$$\theta_1 = 8.8^\circ$$

Similarly, $\theta_2 = -8.8^\circ$. The minimum voltages are 0.699 pu, and occur away from the center. The positions (in terms of impedance) can be computed.

$$1.155 = (1 \times .699/X) \sin(45-8.8^\circ)$$

$$X = .357 \text{ pu}$$

If the impedance is a linear function of distance, the points of minimum voltage occur 28.5% of the total distance from the center toward the terminals.

Steady-state considerations are that simple. The amount of power that can be transmitted over a circuit is defined by the impedance of the circuit, the magnitudes of the voltages at the terminals, and the angle between those voltages. More power can be transmitted between the busses by constructing more circuits (reducing X), boosting the operating voltage (reducing the pu value of X) installing series capacitors (effectively cancelling part of X), supporting the voltage along the line (installing shunt capacitors), or increasing (within limits) the angle.

Increased circuit capacity can be obtained by applying the less expensive (last three) solutions. However, if the load on the circuit continues to increase, one of the more expensive (first two) solutions must be applied to keep the line currents within the thermal capability of the circuit. Another possible solution to the loading problem (replacing the conductor with a larger size) is generally so expensive, and produces so few benefits that it is rarely applied.

System Model for Transient Events

Transient stability is the ability of a power system to recover from a disturbance without splitting into subsystems (whose frequencies might not be the same), and without loss-of-load. The types of disturbances that might cause a power system stability problem are: sudden increased in load, switching operations, and faults followed by switching of the faulted circuit.

The power-angle diagram, which was derived earlier in this thesis, can be used to analyze transient events. If area on the diagram is assumed to be equivalent to energy, the power-angle diagram becomes a very good tool. The equal-area criteria, even though only approximate, is an extremely valuable conceptual tool for the analysis of electrical power system performance.

Ignoring damping, the dynamic relation for each generator in the system may be written:

$$I d^2\theta/dt^2 = T_a \quad (3)$$

Where: I = inertia of the rotor

θ = total electrical angular displacement from a fixed reference axis

T_a = accelerating torque

If a synchronous machine is placed on each terminal of the simple system described earlier (2.1), the system represented by the following one-line diagram results.



Figure 2.7: Machines on the Simple System

The two (synchronous) machines must be coordinated if any useful electrical power is to be transmitted between them. The mechanical frequencies at which the machines rotate may be vastly different due to machine construction, but the average electrical frequency at each bus must be the same.

Following a transient event, the difference in velocity between the two machines must return to zero, or an unstable condition will exist. The difference in machine velocities that accompanies a transient event return to:

$$0 = \int \left(\frac{T_{a1}}{I_1} - \frac{T_{a2}}{I_2} \right) d\delta_{12} \quad (4)$$

Accelerating torques divided by inertias can be considered to be equivalent to accelerating powers provided the velocity of the system doesn't change too much. Equation 3 thus defines Figure 2.8.

If all the variables are referenced to bus #2, further simplification is possible.

Transient Computations

The following power-angle diagram shows the reaction of the system to a sudden increase (from .5 pu to .6 pu) in the power driving the machine at bus #1 if the pre-disturbance machine voltages are 1.0 pu, and the total impedance between the machines is 1.0 pu.

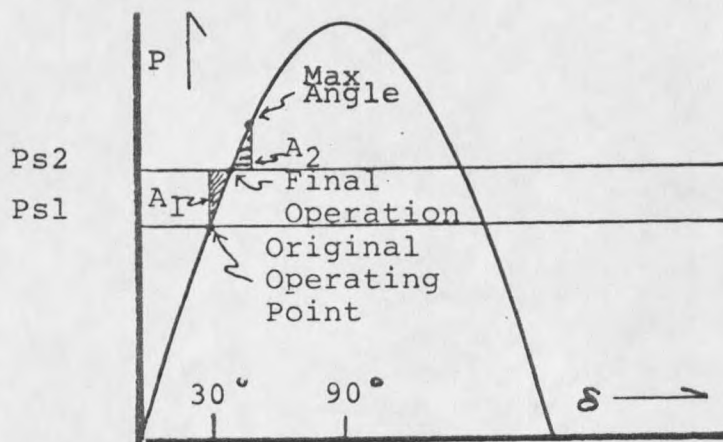


Figure 2.8: Power-Angle Diagram of the Reaction to a Sudden Increase in Driving Power

Since it is possible for A_2 to equal A_1 , the system is stable for the event.

The power-angle diagram can be used to analyze complex sequences of events once it is recognized that three-phase faults cause the electrical output to fall to zero so all the shaft power is available to accelerate

the rotor (increase δ), and that switching of faulted circuits simply diminishes the altitude of the curve (increases the impedance).

If the event is severe enough, the total area above the power input line might not be sufficiently large to equal the area accumulated beneath the input line. The situation simply means that the power system is not strong enough to transmit the excess energy (energy stored in the rotor during the disturbance in the form of increased velocity) to load before the relative angle between the generator and load increases enough to render the system incapable of transmitting even the power driving the generator. To stabilize the system, the total impedance can be reduced, the mechanical input to the generator can be reduced, or heroic measures can be applied.

The discussion has, so far, been limited to an extremely simple system. As the number of machines increased, and as loads are distributed throughout the system, the problem becomes extremely complex. The interactions between the system and the machines on that system rapidly become simply too much. In the past, it was common for a dozen engineers to spend months solving (using step-by-step methods) equations to compute the reaction of a simple two-machine system to a transient event.

The computations were so tedious, that they were rarely done. Most system design was accomplished through the application of rules-of-thumb. The maximum steady-state angle between major system busses was taken to be 30° . The minimum number of discrete circuits between major system

busses was taken to be three. The systems that resulted were often too strong, but it was cheaper to overbuild the systems than to perform the computations⁶.

The Multi-Machine System

The reaction of the interconnected Western power system to a disturbance at a specific bus could not be computed. An adequate model of the system must contain at least 1,500 busses, 2,000 lines, and 300 discretely modeled generators. To compound the problem, power system performance is governed by non-linear differential equations. The problem was complex enough to defy solution.

Digital computers have made it possible to store the (minimum) 1,500 x 1,500 complex matrices and to process enough data (error-free) to compute the system reaction to a transient event. Many stability programs, which generally use Newton's method to solve the non-linear system, are available. Two such programs, one maintained by the Western Systems Coordinating Council, and one created and maintained by Power Technologies, Inc. were used to evaluate alternative solutions to the stability problem in the Montana area. The programs are described (so much as the proprietary nature of the information allows) in the appendix.

The two following plots show the absolute rotor angles for the Kerr, Colstrip, and Corette generators subsequent to two different types of

system disturbances. The actual system events that cause the shapes of the two sets of curves are not important.

The important thing about the sets is that they are different. Figure 2.9 shows the generators' rotor angles (relative to a fixed reference) following an event for which the system is unstable. Figure 2.10 shows the rotor angles following an event for which the system is stable.

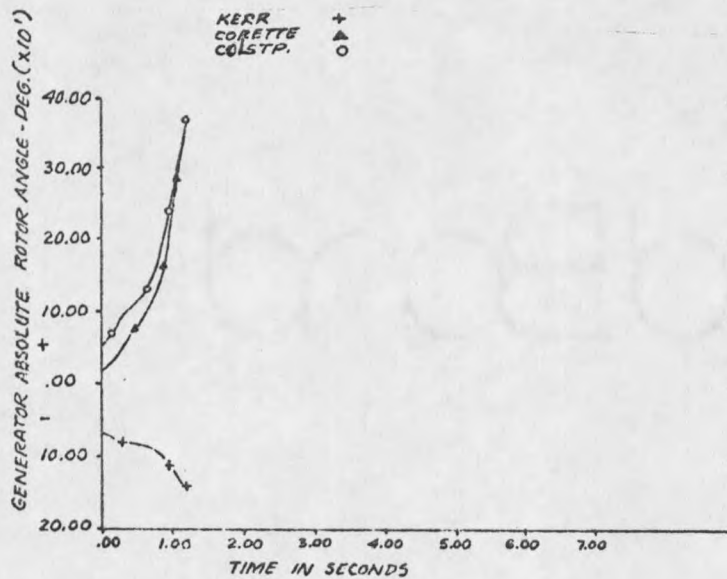


Figure 2.9: Absolute Rotor Angles for an Unstable Event

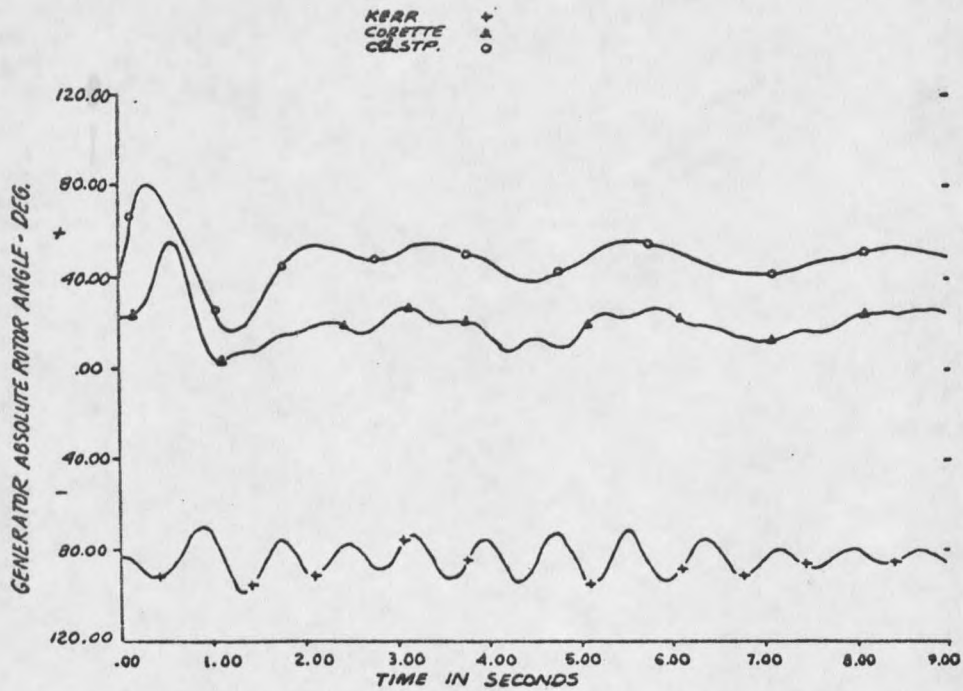


Figure 2.10: Absolute Rotor Angles for a Stable Event

A power system is unstable following a disturbance if there is simply too little system left to transmit the necessary power.

Chapter 3

STABILITY TOOLS

Alternatives

Many alternatives to limiting the eastern Montana thermal generation were investigated.

The alternatives fell into two categories:

1. Those more mundane solutions (transmission lines, series compensation, VAR support, sectionalizing, etc.) that are applied to system design.
2. Those solutions that can be called heroic actions (generator dropping, load shedding, islanding, etc.) that are last instant attempts to stabilize a system that would otherwise break.

In a series of studies, the effects of dynamic brakes, early valve action (EVA), series capacitors, transmission line upgrading, VAR support, phase shifting transformers (PST), and transmission line construction were evaluated. The power flow and stability programs described in the appendix were used to conduct the investigations.

Comparison Case

A one-line diagram of the Montana portion of the system modeled for the base power flow (with line flows, bus voltages, and thermal generation levels indicated) shows how stressed the system is.

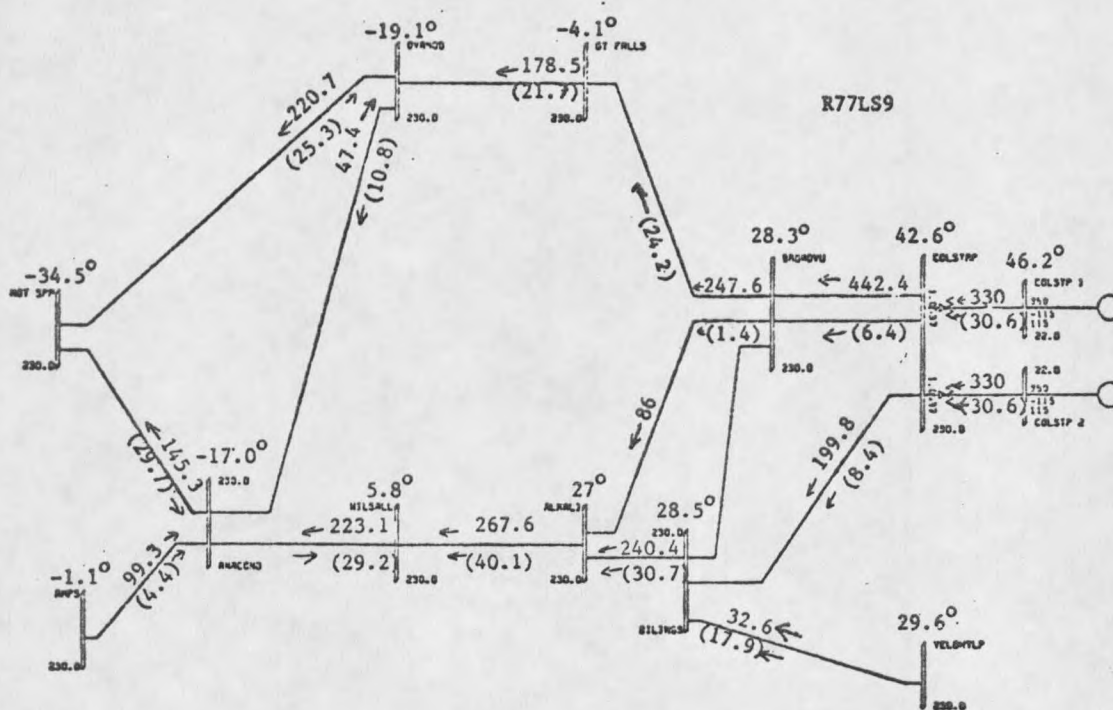


Figure 3.1: One-Line Diagram of Comparison Case

A stability simulation was run modeling a three-phase fault at Colstrip (3PHA FLT @ CS). The Colstrip generators advanced 360° beyond

the rest of the system in less than 0.8 sec. The fault, which was cleared after four cycles, caused the entire western system to break. No fewer than 14 islands were forming less than 0.8 sec. after fault inception.

The rotor angle plot below is from the simulation.

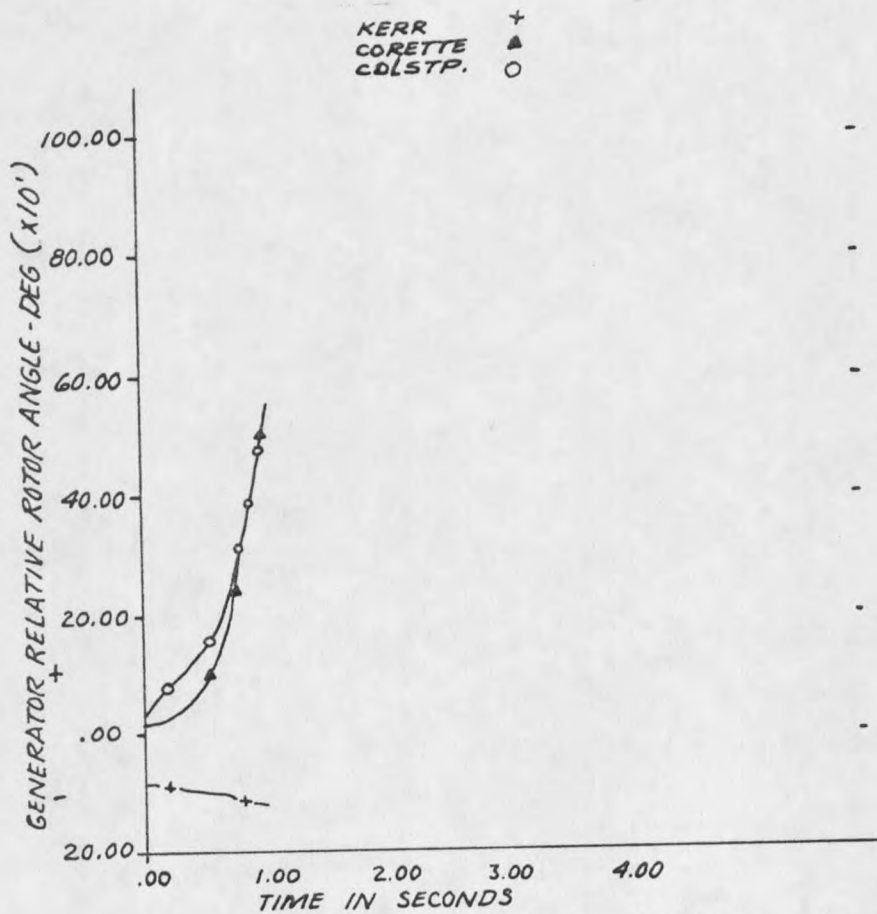


Figure 3.2: Plot From Comparison Case

The companion plots from the case are available from the author.

Dynamic Brake

Dynamic brakes are shunt resistive elements that are switched on to absorb power. Generally located near generators, they are connected when needed to dissipate excess rotor energy. Since the excess energy is consumed by the resistor, the transmission system is relieved from having to transmit the energy to load. The brake has the same effect as decreasing the mechanical power driving the generator during a disturbance. The power input line on the power angle curve is lowered allowing more area above the line.

Picking the proper size brake for a given installation can be difficult. Brakes must be close to the generator to be effective. They are most needed when δ is large, and the generator is accelerating. However, when δ is large, the generator's terminal voltage is low, and the brake is less effective ($P \propto V^2$). In addition, when the brake is switched on, the terminal current increases, and the terminal voltage goes even lower. The maximum size for a brake is realized when the brake's impedance equals the machine transient reactance. An even lower limit (less than 50%) is established by the generator manufacturer to protect the generator shafts from excessive torsional impacts. Conversely, a system so weak as Montana's needs the largest possible brake to dissipate excess rotor energy. Consequently, a 350 MW brake was picked for the studies ($50\% \times 2 \times 350 \text{ MW} = 350 \text{ MW}$). The two Colstrip machines are each 350 MW.

The brake can be connected to the system by a switch on the high voltage side of the generator's step-up transformer.

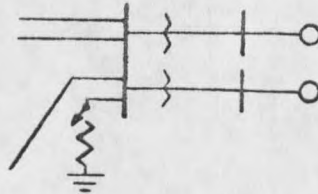


Figure 3.3: Resistive Brake Installed on the System

A stability simulation with a 350 MW optimumly switched brake at Colstrip, but otherwise exactly like the comparison case, was conducted. The rotor angle plot below show the results.

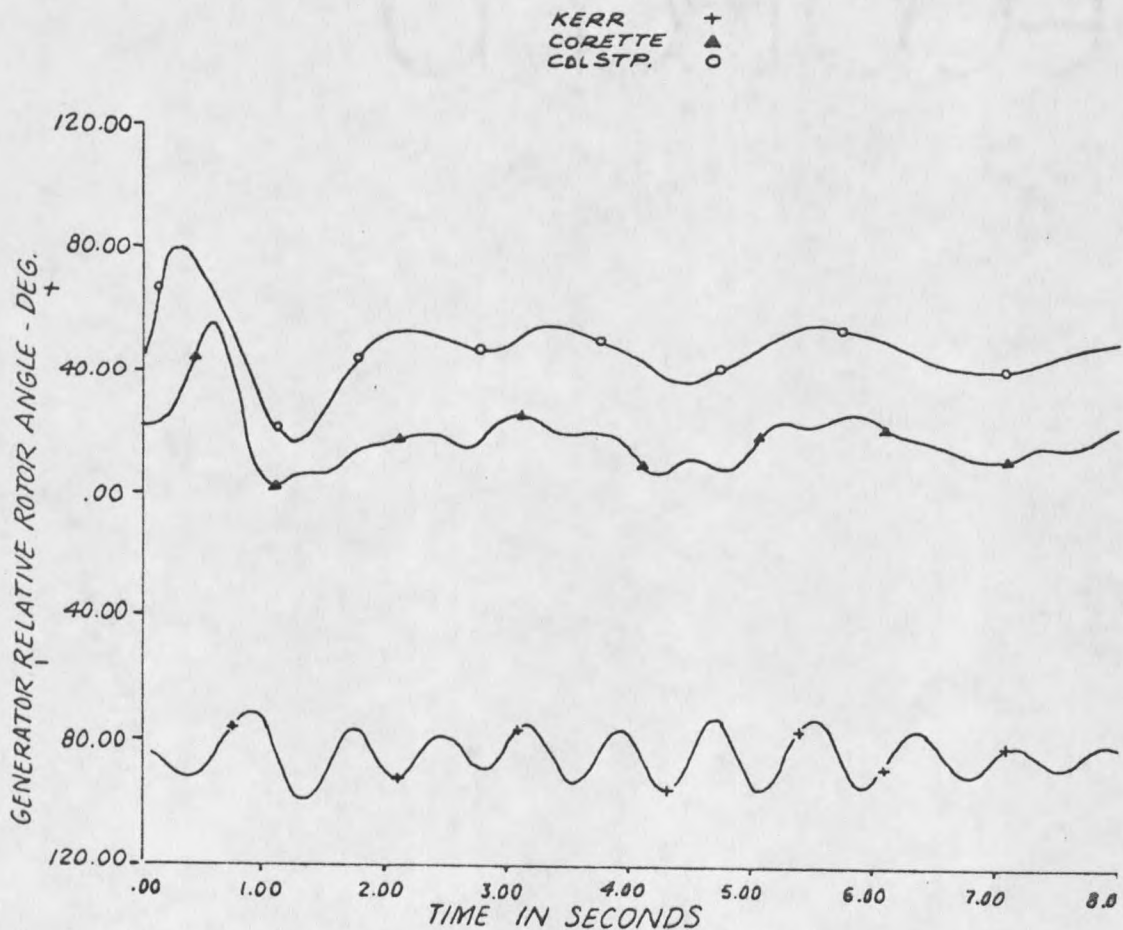


Figure 3.4: Plot From Brake Case

The companion plots are available from the author.

The optimum time to connect the brake is, of course, as soon as possible after fault inception. The best time to disconnect the brake is when the generator's angular velocity has returned to the system's base frequency. Such timing was used for the study. The system which was so wildly unstable before has been tamed by the addition of a simple resistor.

Early Valve Action

Early valve action (EVA) is the rapid closing of the generator's steam valves following a transient event. Mechanical input to the generator is thus reduced, and more area is available above the mechanical input line on the power-angle curve to synchronize against.

EVA is generally actuated by a step change in the electrical output of the generator. The generator owner specifies the minimum step change that is to activate EVA. The value is then entered into a watt relay. Any step change in generator output greater than the limit causes the rapid closing of the steam valves.

The Montana system cannot survive a three-phase fault at Colstrip even if Colstrip's generation is limited to 660 MW. EVA coupled with fast runback (closing of the throttle valve) can stabilize the system. The relative rotor angle plots on the next page show what EVA, coupled

with fast runback, can do for the system. Companion plots are available from the author. The mechanical input plot contains significant information.

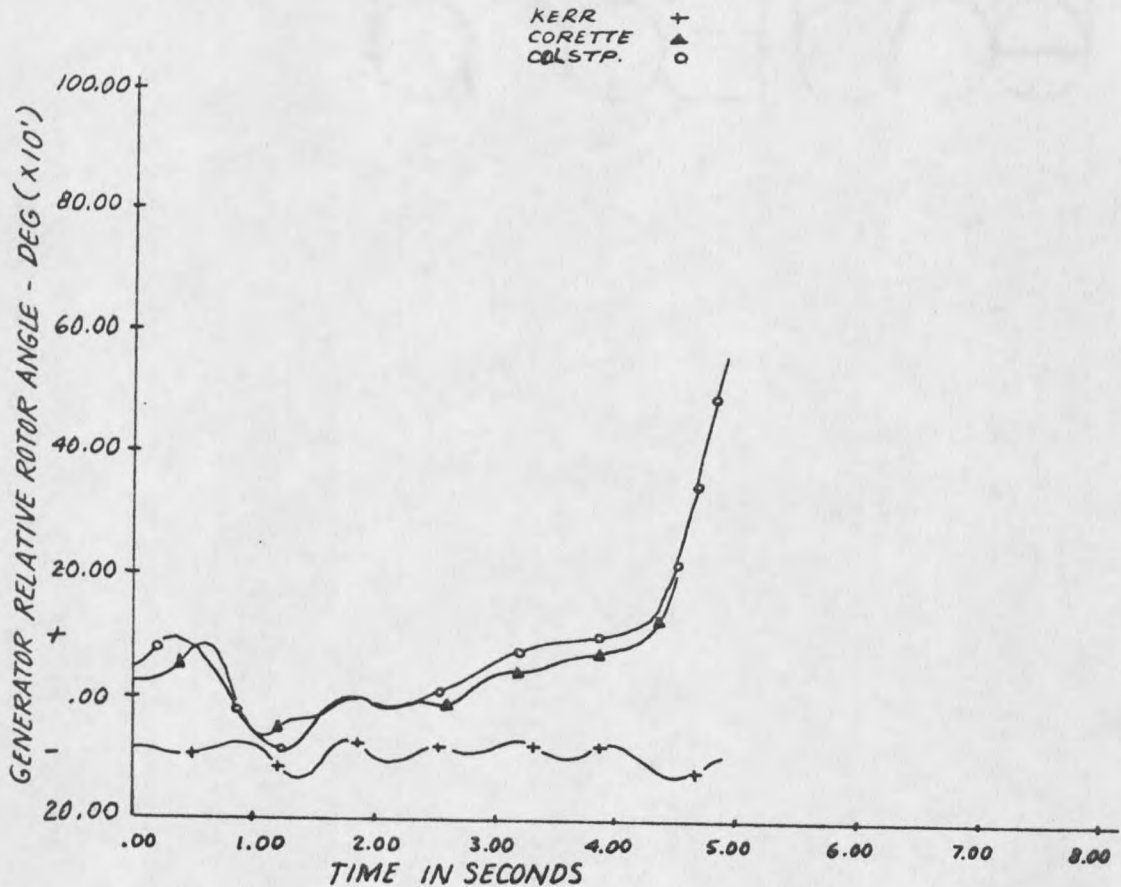


Figure 3.5: Results of EVA Coupled With Fast Runback

EVA can prevent transient instability but can do nothing to prevent steady-state instability. Several seconds after the valves have been closed, they are reopened. When the valves are reopened, the mechanical input raises to a higher value than it was at before the disturbance because of increased steam pressure.

Since the Montana system is steady-state as well as transiently unstable for the loss of some circuits, EVA is of little value unless coupled with fast runback (rapid closing of the turbine throttle valves).

Even with fast runback, EVA cannot always save the system from instability. The valves cannot be closed rapidly enough to save the system from instability following some types of events.

Static Synchronous Condensor

A static synchronous condensor performs the same function as the shunt capacitors discussed in Section 2.2. However, because the system is dynamic, a means is provided to vary (rapidly) the shunt compensation. Most static synchronous condensers (SSC) are composed of a variable reactance inductor in parallel with a static capacitor. The complex is connected shunt to the system. If the voltage at the point of attachment falls, the reactor is switched out of the complex, and the capacitor supplies supporting VARs. If the elements were large enough, and the switching rapid enough, any bus could be made to look like an infinite bus (constant voltage).

The inductor is switched by silicon controlled rectifiers (SCR) that short out parts of the winding. The inductance of the reactor can be changed every half cycle. Hence, the SSC can react very rapidly to changing system conditions.

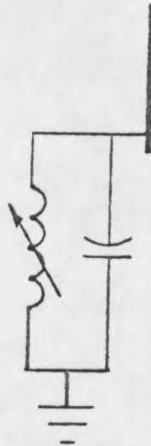


Figure 3.6: SSC Installed on the System

The WSCC program contains no specific SSC model. It was thought impossible to evaluate the performance of the SSC with that program. A SSC model was developed from the WSCC program's comprehensive load model. Loads can be modeled (for transient studies) as represented by the polynomial expression: $P = N_1 + N_2 * V + N_3 * V^2$. Separate polynomials are available for watts and VARs on any bus. The user specifies N_1 , N_2 , and N_3 . The only constraint is that $N_1 + N_2 + N_3$ must equal one. In addition, bus ties (zero impedance connections) are allowed. A bus with a constant impedance capacitor ($Q \propto V^2$) can be tied to a bus that supports an inductor with a strongly negative characteristic. The slope of the combined characteristics ought to be equivalent to $\partial Q / \partial V$ for the bus at near unity voltage. The resultant model does not account for the switching times for the SCRs, but that introduces a maximum of 1/2 cycle error.

The WSCC simulation proved an SSC could stabilize the system if connected to the Wilsall bus. The simulation, however, was later done on

the PTI program which does contain an SSC model. The relative rotor angle plot, which is below, is the result.

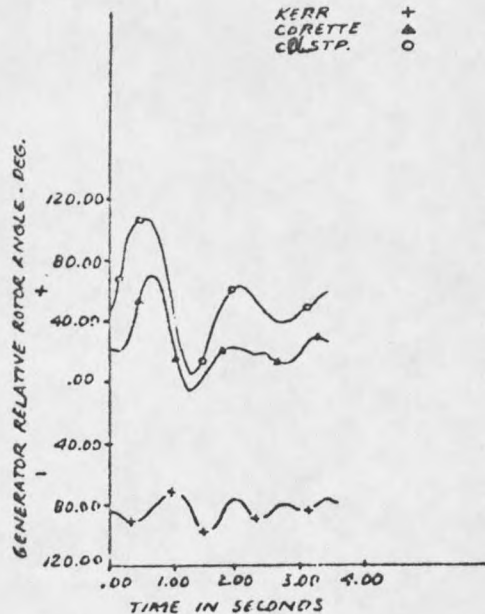


Figure 3.7: Results of Adding an SSC at Wilsall

The system can be stabilized for the test case if an SSC is added at Clyde Park.

Series Capacitors

Capacitors, if installed in series with a transmission line, cancel part of the 60Hz inductive reactance of the line. Theoretically, since the inductive reactance is reduced, the system is stiffer ($dP/d\delta$ is greater). The power angle curve is raised. The sketch on the next page shows how series capacitors can be placed in a system.

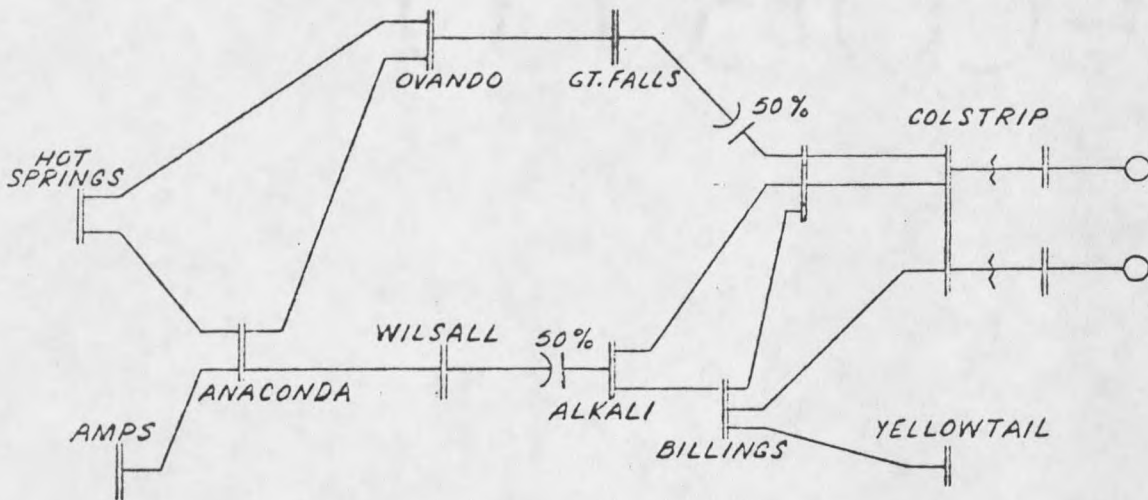


Figure 3.8: Series Capacitors Added to the System

The angle plot on the next page shows the reaction of the Montana machines to the test disturbance if the lines from Broadview to Great Falls and Alkali Creek to Clyde Park are 50% series compensated.

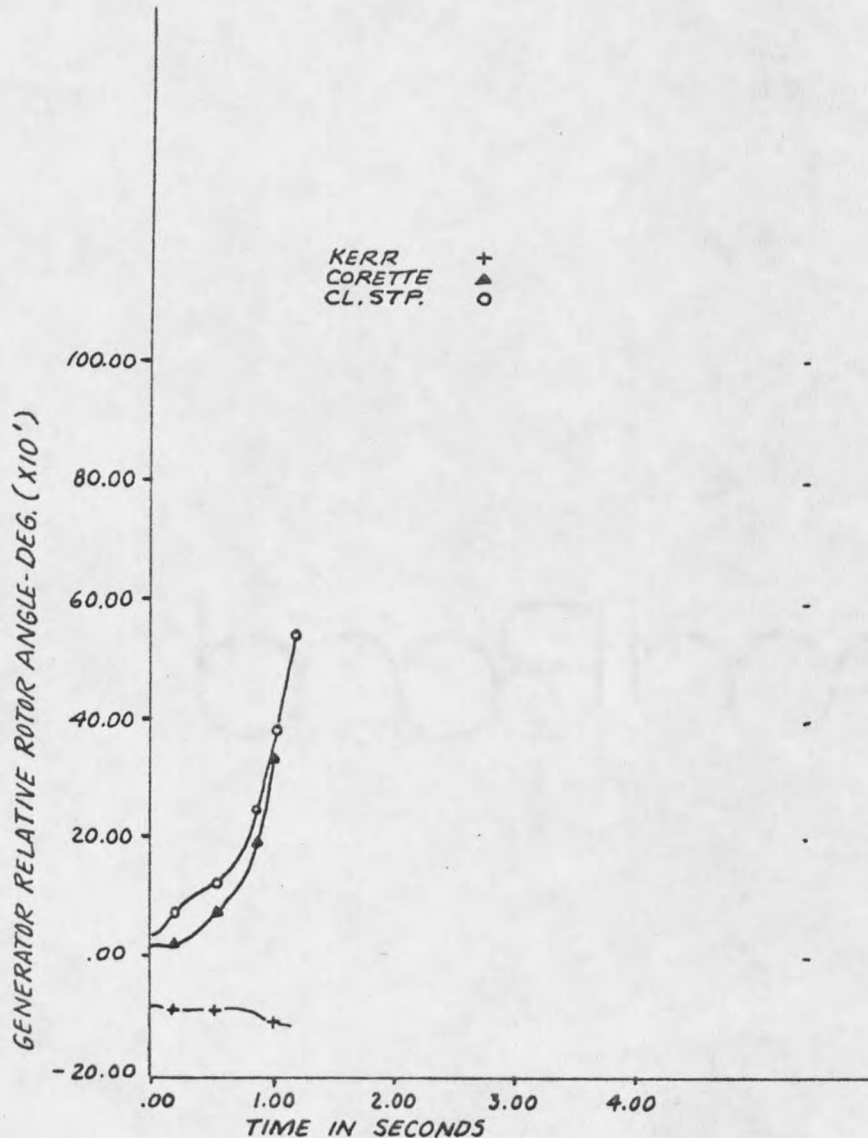


Figure 3.9: Results of 50% Series Compensation

The system is not stabilized with the compensation level at 50%. It should, however, be apparent that at some higher level of compensation the system would be stabilized. The higher levels of series compensation (above 50%) cause severe problems which generally dictate lower (below 50%) levels of compensation.

Capacitors do the most good for the Montana system if installed in the Broadview to Great Falls and Alkali Creek to Clyde Park (BV-GF&AL-CP) lines. If the Montana system were to be compensated, capacitors would be located at the AL, BV, and CP stations. However, faults in the Billings (BL) area (near BL, AL or BV) cause such high fault currents, that all three capacitor banks would have to be bypassed to prevent damage. Reinsertion of the capacitors is not certain. The problem is aggravated by the fact that Billings area faults are the most constraining to Montana system operation. They are the reason the capacitors would be installed in the first place.

Subsynchronous Resonance

When a capacitor is placed in series with an inductor, a harmonic circuit results. If the capacitors are sized so they tune out 100% of the inductance of the transmission system at 60Hz, the harmonic frequency is 60Hz. Lower levels of compensation result in lower frequencies. Once excited, the harmonics are limited only by system resistance. The synchronous generator has a negative slip relative to the harmonic frequency. Consequently, it is an induction generator at that frequency. The resonant currents are maintained by the induction generator effect. The resonance, in itself, is not particularly bad. The induction generator effect simply guarantees that the currents will exist.

Since the currents do exist (and are three-phase) in the armature of the generator, a rotating MMF results. Since the frequency is lower

than 60Hz, the MMF rotates more slowly than the rotor of the generator. Consequently, the poles of the rotor pass the poles of the more slowly rotating MMF at $60\text{Hz}-F$ where F is the electrical resonant frequency.

A predominately sinusoidal torque (at frequency $60\text{Hz}-F$) is imposed on the rotor of the generator. The torque also is not particularly bad unless the frequency happens to correspond to one of the rotor's natural modes of mechanical oscillation.

The rotor is composed of the generator's field structure, a low pressure turbine, an intermediate and high pressure turbine (possibly joined), and possibly an excitor -- all joined by shafts. The mechanical system has as many modes of oscillation as masses. One of the modes (Mode 0) is trivial, but the remainder, if excited, can result in oscillations severe enough to break shafts.

Mode 2 for the Colstrip Units is 33.6Hz. The electrical harmonic frequency of concern is then 26.4Hz. If the total inductance seen by the voltage behind $x'd$ is reduced by only about 20% at 60Hz by the addition of series capacitors, the harmonic frequency of the resultant series circuit is 26.4Hz. Fortunately, 50% compensation of the lines mentioned above does not compensate the total inductance to 20%. However, the levels of compensation required to stabilize the system for the test event certainly would.

Transmission Line Upgrading

Transmission line upgrading is the conversion of a circuit to operate at the next higher voltage level. The Montana system has a 161 kV line from Alkali Creek to Anaconda. A one-line diagram of the Montana system shows the 161 kV line.

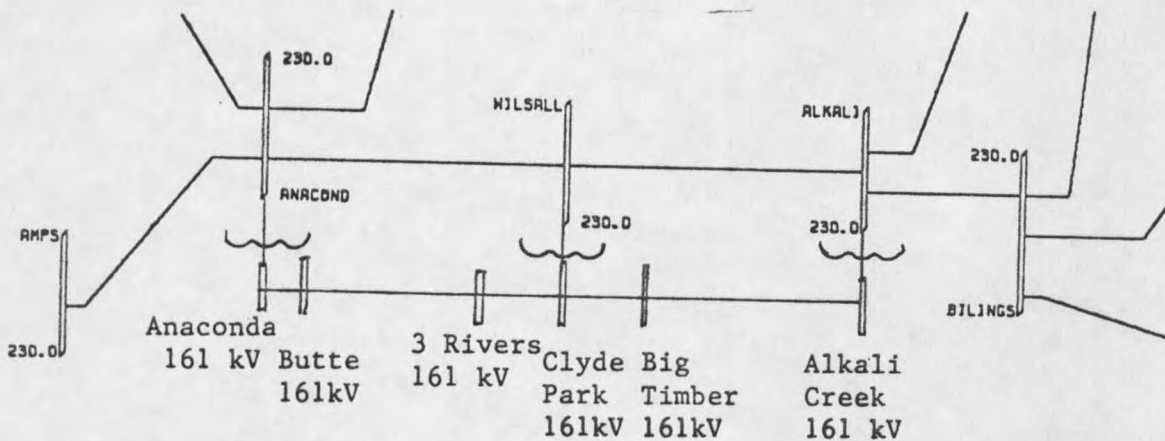


Figure 3.10: 161 kV Circuit From Alkali Creek to Anaconda

The capacity of the system could be increased if the line's effective (pu) impedance were reduced by converting the line to 230 kV operation. The construction methods that were used on the line would permit such conversion. The plot on the next page shows the results of the effort.

KERR +
CORETTE ▲
COLSTP. ○

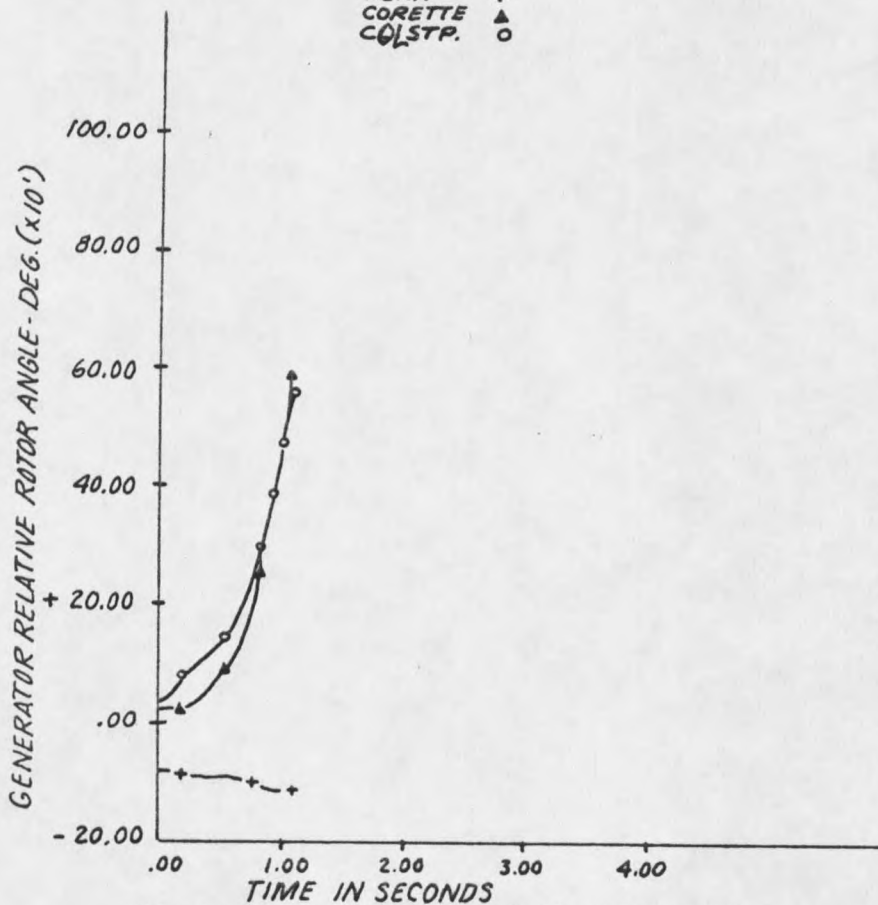


Figure 3.11: Results of Line Conversion

The line conversion does not stabilize the system for the test event.

Transmission Line Construction

Transmission line construction is the building of new circuits. The addition of enough lines ought to reduce the system's effective impedance enough to provide sufficient transfer capacity. The one-line diagram on the next page shows the Montana system with a new 230 kV line from Alkali Creek to Anaconda.

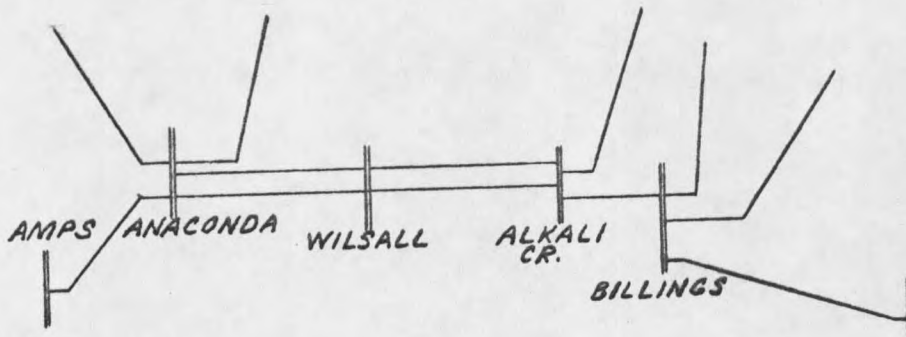


Figure 3.12: System With New Line

The system with the new line was subjected to the test event. As can be seen in the plot below, it failed.

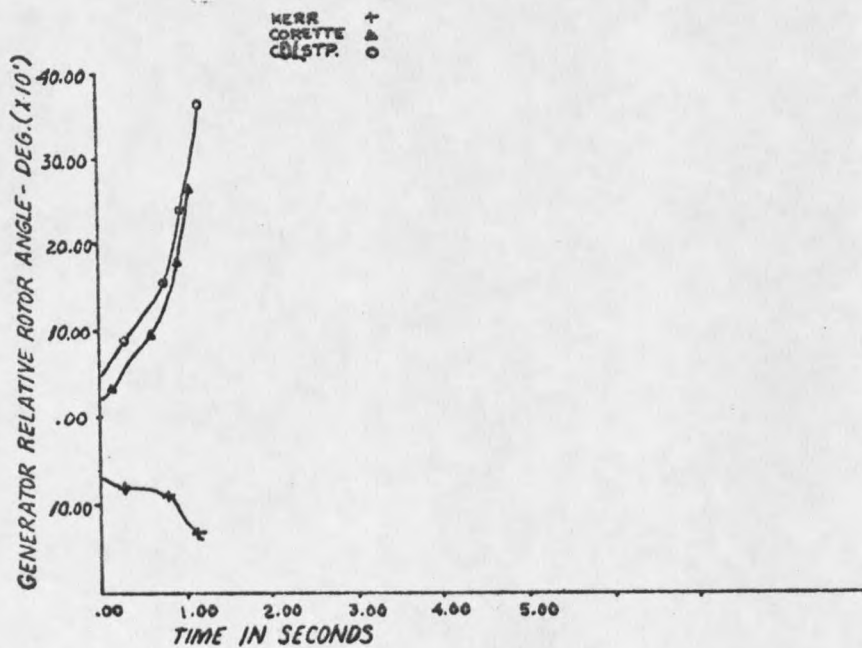


Figure 3.13: Results of Line Construction

More than one line must be constructed to stabilize the system for the test event.

Phase Shifting Transformers

Phase shifting transformers are multi-winding devices (generally adjustable) that control the amount of power that flows through the circuit of which they are an element by producing an apparent discontinuity in the voltage angle (δ). The drawing below shows a transformer that produces a fixed 30° phase shift.

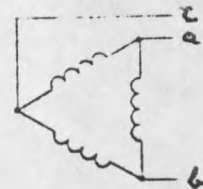
$$V_{na} = \frac{1}{\sqrt{3}} \angle 90$$

$$V_{nb} = \frac{1}{\sqrt{3}} \angle 330$$

$$V_{nc} = \frac{1}{\sqrt{3}} \angle 210$$



1: $\sqrt{3}$



Line in Vectors:

$$V_{ab} = V_{an} + V_{nb} = \frac{1}{\sqrt{3}} (\quad -J \quad) + \frac{1}{\sqrt{3}} \left(\frac{\sqrt{3}}{2} - j0.5 \right) = 0.5 - j \frac{\sqrt{3}}{2} = 1 \angle -60^\circ$$

$$V_{bc} = V_{bn} + V_{nc} = \frac{1}{\sqrt{3}} (-0.5 + j0.866) + \frac{1}{\sqrt{3}} (-0.5 - j0.866) = 1 \angle 0 = 1 \angle 180^\circ$$

$$V_{ca} = V_{cn} + V_{na} = \frac{1}{\sqrt{3}} (0.866 + j0.5) + j = \frac{1}{\sqrt{3}} \left(\frac{\sqrt{3}}{2} + j1.5 \right) = 0.5 + j \frac{\sqrt{3}}{2} = 1 \angle 60^\circ$$

Line Out Vectors:

$$V_{abs} = \sqrt{3} (-V_{na}) = \sqrt{3} \left(-\frac{1}{\sqrt{3}} \angle 90^\circ \right) = 1 \angle 270^\circ = 1 \angle -90^\circ$$

$$V_{bcs} = \sqrt{3} (-V_{nb}) = \sqrt{3} \left(-\frac{1}{\sqrt{3}} \angle 330^\circ \right) = 1 \angle +150^\circ$$

$$V_{cas} = \sqrt{3} (-V_{nc}) = \sqrt{3} \left(-\frac{1}{\sqrt{3}} \angle 210^\circ \right) = 1 \angle +30^\circ$$

Figure 3.14: Transformer Producing a 30° Phase Shift

Taps can be added to a phase shifter to make it adjustable as in Figure 3.15.

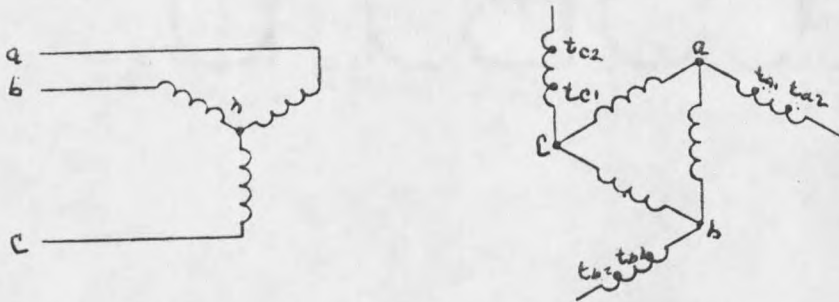


Figure 3.15: Taps Added to Phase Shifter

The winding that contains t_{a1} and t_{a2} is physically wound around the same core as the winding from b to c so the voltage induced in it is in phase with V_{bc} . If the output is connected across t_{a2} , t_{b2} , and t_{c2} , a phase shift of less than 30° results. A phase shift in excess of 30° can be produced if the tap windings are extended in the other direction for the nodes.

However, as the phase shift is moved from nominal, the magnitude of the output voltage changes. That is, the farther the shift is from nominal, the greater the magnitude of the output voltage. One way to counter this problem is by placing voltage taps on the primary winding.

Typically then, the whole unit is made automatic so that it maintains constant through power and constant output voltage regardless of power system conditions. The resulting tap mechanism is necessarily complex so a number of phase shifters have failed in service.

Perhaps the most spectacular failure was a unit that had been installed on the a-c Pacific intertie. The transformer destroyed itself, was repaired, and destroyed itself again. The original manufacturer removed itself from the phase shifter business so the replacement was purchased from a competitor.

Since power naturally flows on the lowest impedance path, phase shifting transformers must degrade the overall system performance since they force power to flow elsewhere. However, certain portions of the overall system can benefit.

As stated in the introduction, the Montana system is forced to accept as much as 300 MW of circulating flow from the ties between Billings and Yellowtail. The power then flows from east to west across the Montana system, reducing the system's ability to transmit the power from the

eastern thermal plants. If the system were to be relieved of transmitting the circulating power, more of the resource could be moved.

It would seem logical to simply open the ties, but it does not help. Opening the ties does eliminate the flow, but also significantly reduced the capacity of the system.

The ties serve to couple the eastern Montana system to many generators to the south. The ties provide a valuable source of synchronizing power. So long as the circulating flow is below 200 MW, the capacity to transmit Colstrip generation is actually higher with the ties closed.

What is really needed is a path that will allow the transmission of synchronizing power, but will not allow the transmission of circulating flow. If phase shifting transformers are added to the ties, they can be prevented from transmitting circulating flow while still providing a path for synchronizing power. The next drawing is a one-line diagram of the resulting system.

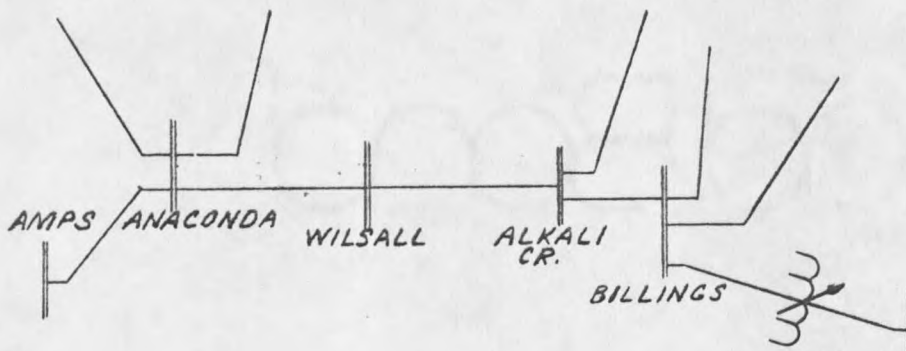


Figure 3.16: Phase Shifting Transformers in the System

The system with phase shifting transformers added to the 161 kV and 230 kV lines from Billings to Yellowtail was subjected to the test event. The plot below shows that it failed.

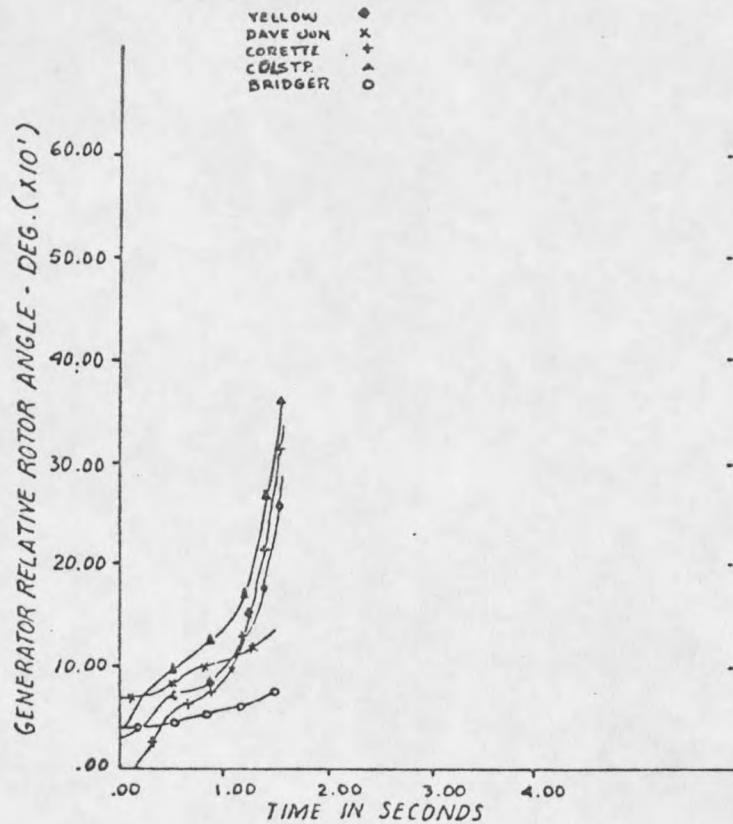


Figure 3:17: Results of the Addition of Phase Shifting Transformers

The phase shifting transformers do provide a reduction in the losses on the Montana system.

Any of the alternatives that serve to reduce the impedance across the Montana system failed. They failed because the reduced impedance simply attracts more circulating flow. Phase shifting transformers, by eliminating the circulating flow, make a reduction in the transfer impedance beneficial.

Generator Tripping

Generator tripping unloads the system. If one of the two Colstrip generators is tripped, the system is relieved of having to transmit the power from that generator. The power-angle diagrams below illustrate the benefits.

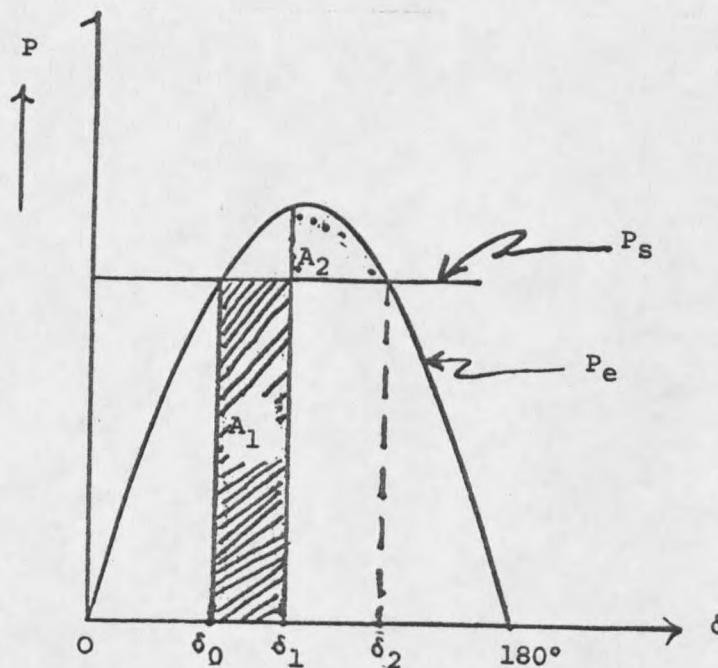


Figure 3.18: Power-Angle Diagram of System Without Generator Tripping

The power-angle diagram on the next page shows what happens if one of two generators is tripped subsequent to fault clearing. A_2 is substantially increased. It is apparent that if the unit were tripped early enough, the system would be stable for the event.

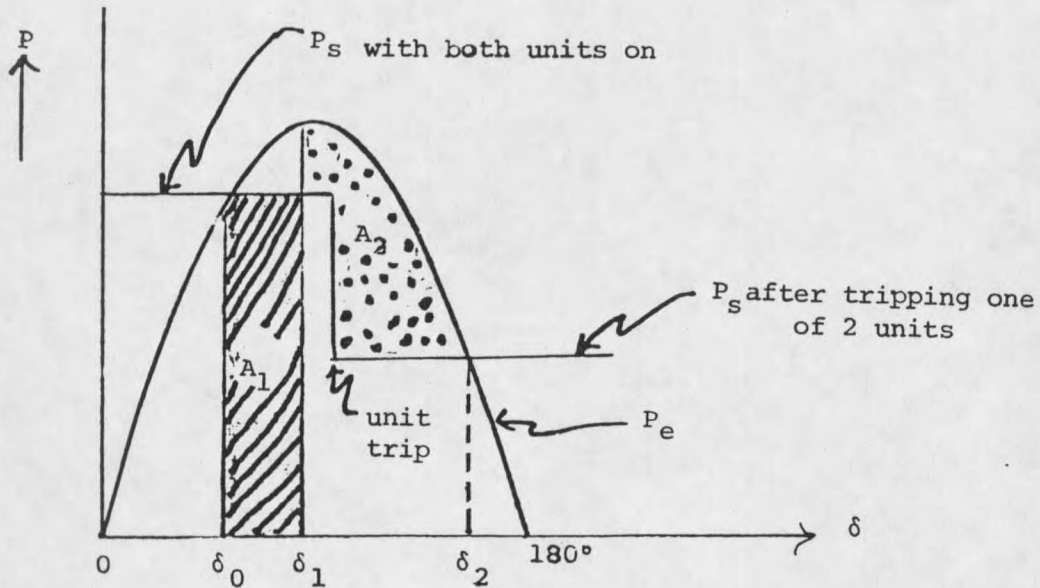


Figure 3.19: Power Angle Diagram of System With Generator Tripping

The plot on the next page shows the reaction of the system to the test event if one Colstrip generator is tripped.

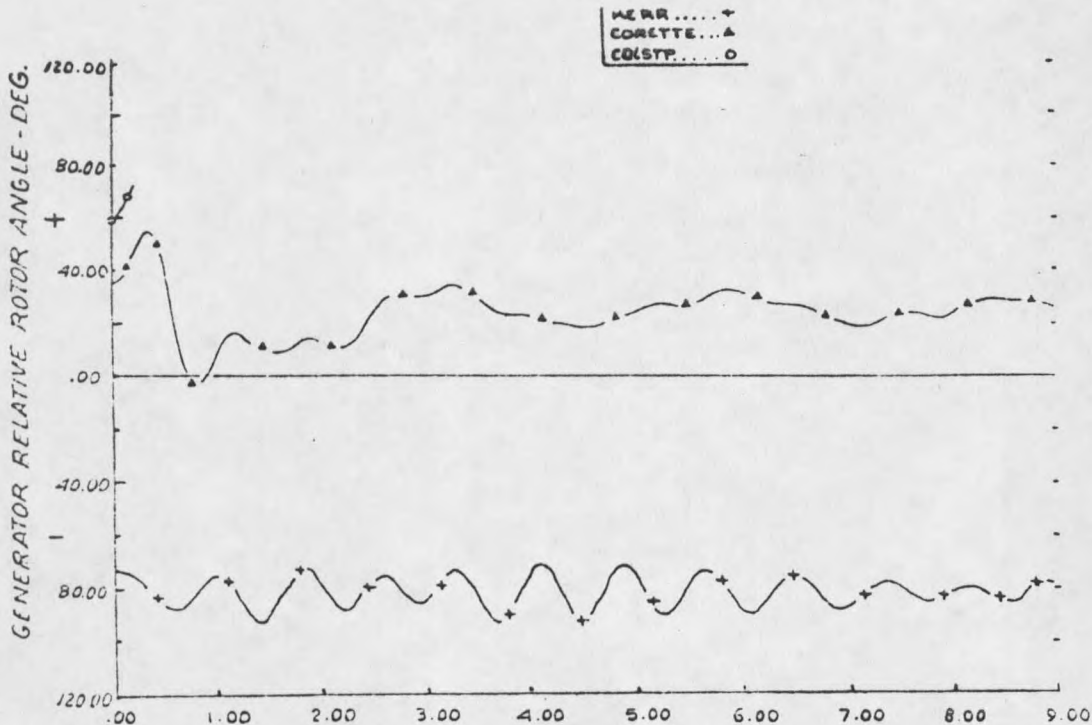


Figure 3.20: Results of Generator Tripping

The system is stable for the test event. Generator tripping is beneficial because the scheme does nothing to reduce the transfer impedance across the Montana system (thus attracting more circulating flow), and relieves the system from having to transmit up to 330 MW during times of stress.

The generator that is tripped will, of course, overspeed. It will be separated from its load. However, since it is separated from the system, the system will be spared. If the tripping is coupled with a full load rejection technique, the generator can be put back on-line in about ten minutes. If the system is broken, thermal problems with the boiler would

keep both machines down for about ten hours. Much can be gained from anticipating system break-ups and tripping generation.

Comparison of the Alternatives

The tools investigated, the results of the investigations, and the costs for the tools are listed in the table.

<u>Alternative</u>	<u>Result</u>	<u>Cost</u>
Dynamic Brake	Stable	\$ 700,000
Early Valve Action	Unstable	6,000
Static Synchronous Condensor	Stable	18,000,000
Series Capacitors	Unstable	3,000,000
Transmission Line Upgrading	Unstable	6,000,000
Transmission Line Construction	Unstable	15,500,000
Phase Shifting Transformers	Unstable	7,500,000
Generator Tripping	Stable	76,000

None of the alternatives that reduce the transfer impedance across the system is stable for the test event. The increased circulating flow offsets the benefits obtained by reducing the impedance. For these alternatives to be effective, phase shifting transformers must also be added to the system. The expense is prohibitive.

EVA is inexpensive. While it does not stabilize the test case, it does allow an increase in Colstrip generation of about 30 MW averaged throughout the year. The carrying charge on the \$6,000 was computed to be \$1,038. The carrying charge on an expenditure is composed of the interest that must be paid on the money that must be borrowed to make the expenditure, and the taxes that must be paid on the device that is

purchased with the expenditure. The extra generation allowed by EVA had an effective cost of \$0.021/MWh plus incremental operating costs. Since wholesale power is worth as much as \$70/MWh, it certainly made sense to activate EVA.

The next most expensive alternative, generator tripping, allows an increase of an additional 100 MW in Colstrip generation averaged throughout the year. The carrying charge on the \$76,000 was computed to be \$13,148. The extra generation had an effective cost of \$0.015/MWh plus incremental operating costs.

All of the other alternatives can be justified in a similar manner, but if generator tripping is applied first, the remaining available energy won't pay for any one of them. For the same reasons, combinations of various approaches were discarded.

Chapter 4

NEW SCHEME TO CONTROL GENERATOR TRIPPING

Introduction

Generator tripping has been applied to many plants. The schemes used have been transfer-trip, and out-of-step signals.

The transfer-trip signals are relayed to the generator's synchronizing breakers any time a critical circuit opens for any reason. The level of generation, and severity of any possible fault is not considered. Simply, if the line is lost, the plant is tripped. The scheme may accomplish some needed generator tripping, but might also generate unnecessary trips.

Out-of-step relays are nothing more than apparent impedance relays. They measure the voltage at a terminal of a line and the current flowing on the line. From these two quantities, the apparent impedance of the line is computed. If a fault occurs, the apparent impedance of the circuit decreases and the line is tripped. Since the voltage goes to zero at the center of a system that is going unstable (an apparent three-phase fault) the apparent impedance relay can be used to sense an out-of-step condition. The signal is generally produced too late to prevent instability, and is certainly produced too late to prevent dips below

0.8 pu voltage. In addition, a complex interconnected power system is likely to have a different center (swing node) each time it separates. Many out-of-step relays would have to be installed.

The two methods described above (transfer-trip, and out-of-step relays) share a common disadvantage. A signal available at some remote point in the system must be transmitted to the generator's location. The communications circuitry necessary to reliably transmit the signal would be very expensive.

Because the generator's speed reaction is different to an event for which the system is stable and to an event for which the system is unstable, the information necessary to govern generator tripping must be embedded in that speed. The device described in this section is located at the generating plant. By processing information embedded in the generator's speed, it has sufficient information to deduce the stability of the power system. If an unstable condition is developing, the device causes a generator to be tripped.

Special Problems Solved

It was recognized that studies had resulted in the values of acceleration that could be expected if the generators were assumed to be point masses. Generators are not, however, point masses. They are composed of several masses connected by shafts.

In the last eight years, at least four large nearly new turbine generator shafts have broken. In three of the cases, the generators were out of service for about a year each, and in the fourth case, the unit was completely destroyed. The ratings of the units average about 350 MW. Lost production for the units that were repairable amounts to about \$26,000,000. It is estimated that \$50,000,000 and two years were required to replace the unit that could not be repaired.

Since the impact torques that could be imposed on the shafts by a severe fault, clearing of that fault, and tripping of the generator are all substantial, it was decided that the phenomenon should be studied.

Simplified models were used to gain an understanding of the problem. Various switching sequences were analyzed, and equations were developed to describe the system. The complexity of the shaft-mass model was increased until a complete turbine generator could be analyzed.

Turbine generator shafts are fragile. Shaft bearings must be wide enough to support an oil film, but efficiency demands that the bearing surface area be as small as possible. Consequentially, the bearing's bore (hence the shaft) is small in diameter. Because the shaft is slender, it can be broken. Consider the simple two-mass system represented on the next page. Assume that it is being driven by the turbine, and supplying electrical power to a large system.

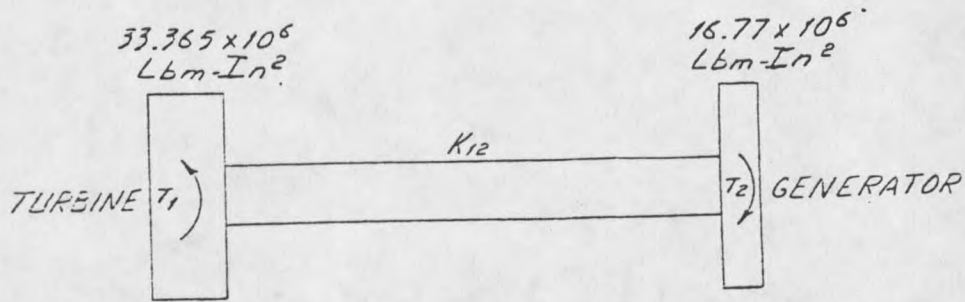


Figure 4.1: Simplified Spring-Inertia Model

T_1 is the mechanical torque delivered by the turbine. T_2 is then the electrical reaction torque produced by the generator. If the speed is to remain constant, T_1 (mechanical torque) and T_2 (electrical torque) must be equal in magnitude and opposite in direction.

Electrical power is being delivered to an electrical system. For simplicity, the system is represented by the drawing below.

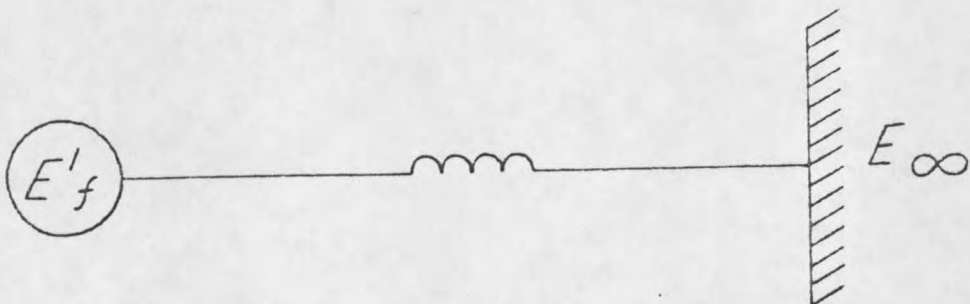


Figure 4.2: Simplified Power System

If the generator is delivering electrical power, the shaft of the machine will be twisted. The shaft will be said to have 1 pu twist when the generator is delivering 1 pu power.

A three-phase fault on the machine terminals causes the electrical power, hence, the electrical torque to drop to zero. If the generator does not accelerate, the shaft should untwist.

Since many electrical cycles must pass before the machine advances much, the assumption is not so revolutionary as it may sound. The assumption says that the driving torque is also removed. The shaft reaction is plotted below.

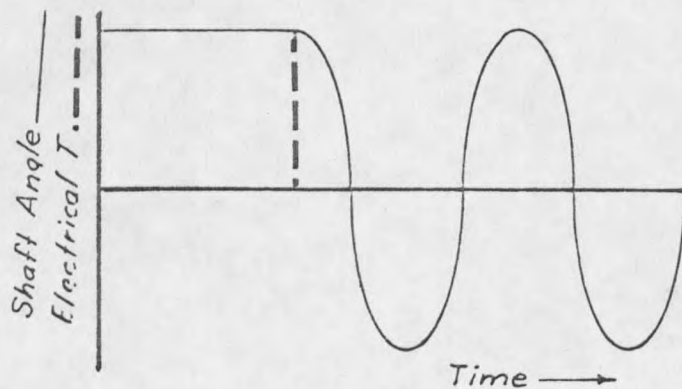


Figure 4.3: Shaft Reaction to a Three-Phase Fault

The instant after the fault is initiated, the shaft has 1 pu twist. However, the torque across the shaft is zero. The shaft will untwist. However, when the angular twist across the shaft reaches zero, the turbine and generator have angular velocity relative to each other, and the shaft

will continue to untwist. As the angular displacement becomes negative, restoring torques are developed. The torque stops the relative movement when displacement is -1 pu. However, at this point, the torque is in the opposite direction, and the masses move toward zero displacement again.

Suppose that two generators are located at the same station. In order to maintain system stability, it is planned to drop one unit subsequent to severe faults.

The unit that is not dropped suffers severe shaft stress. This is because the internal angle dictates that it pick up part of the load rejected by the dropped unit. If this remaining unit tried to pick up all the load ($X'_d = 0$), the shaft reaction could be so severe as that plotted below.

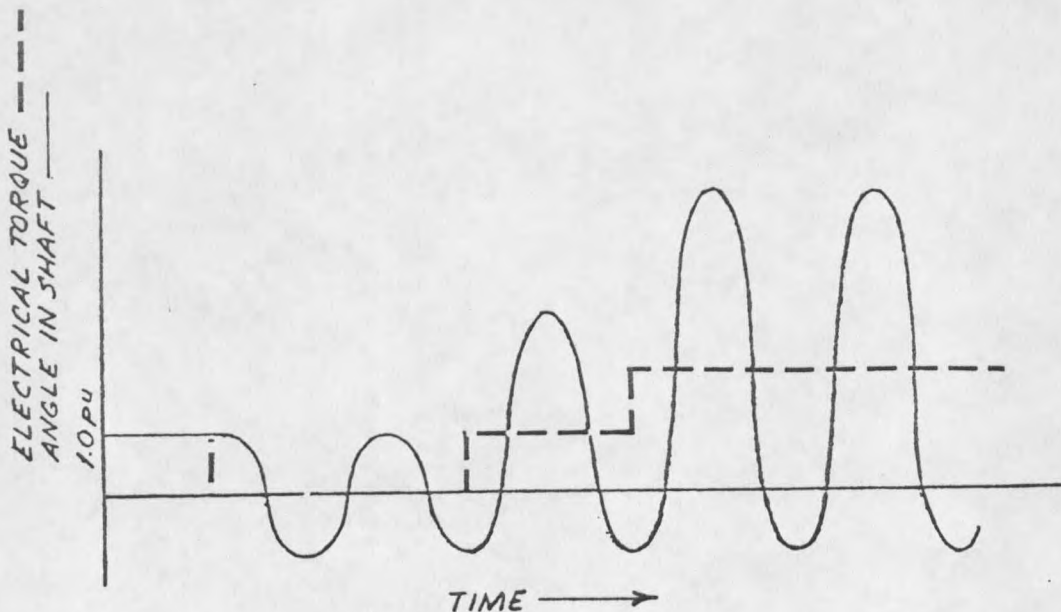


Figure 4.4: Shaft Reaction for Unit Remaining On-Line for a Fault-Clear-Trip Event

The maximum excursion is 5 pu. The low pressure turbine to generator shaft at Colstrip will tolerate only thirty cycles. One disturbance like that described above could break a shaft.

Caution must be used when dropping generators. Reclosing is not used near generator stations. Generators are carefully synchronized to the system before being connected.

The driving torque does not drop to zero when a fault occurs. It is more likely to remain at near 1 pu. Part of the torque accelerates the turbine; part is transmitted along the shaft to accelerate the generator. The portion of torque that is transmitted by the shaft is determined by how much of the total inertia resides in the generator.

For now, assume that the turbine inertia can be lumped at one location. The polar moments of inertia shown on the drawing below then represent the Colstrip units.

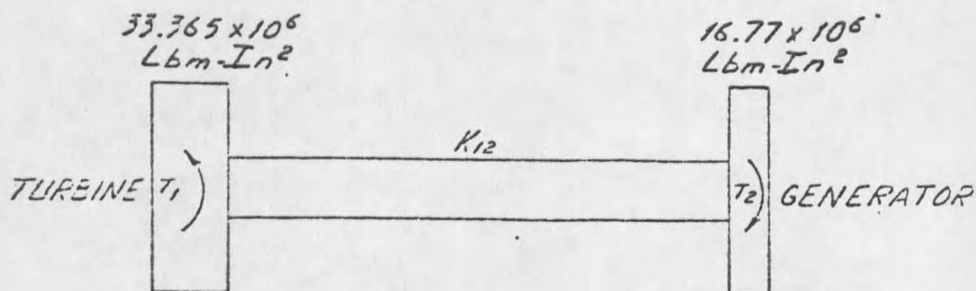


Figure 4.5: Level Two Spring-Inertia Model

The generator has only about 1/3 of the total inertia.

Returning to the simple intuitive approach with this information, one can see that a three-phase fault does not cause the torque to drop to zero. The turbine produces 1 pu torque of which about 1/3 is transmitted through the shaft to accelerate the generator. The shaft reaction is much less severe. The maximum excursion is still 1 pu, but the magnitude is reduced to 1.33 pu.

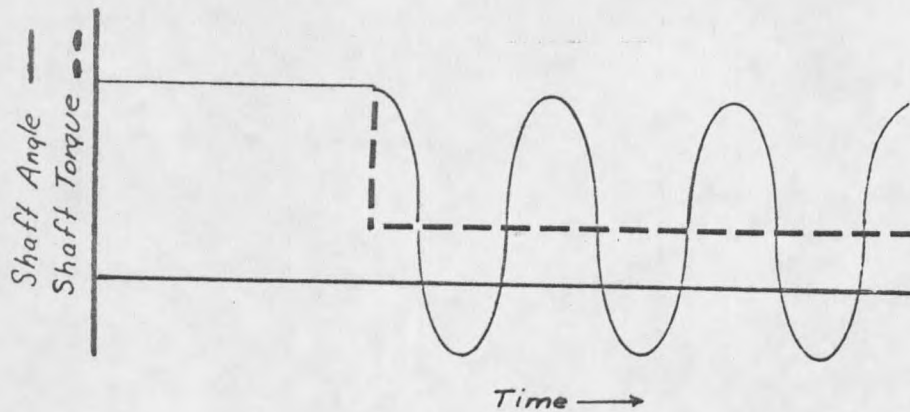


Figure 4.6: Reaction of Level Two Model to a Three-Phase Fault

The plot of the second approximation to the sequence that produced 6 pu magnitudes and 5 pu maximums is on the next page.

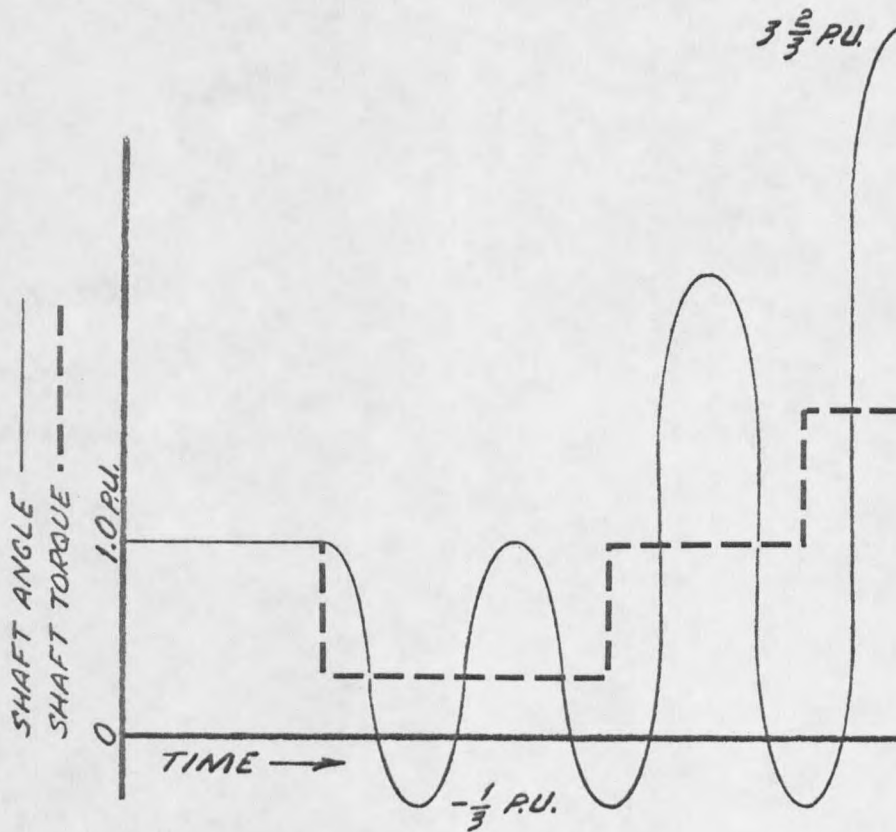


Figure 4.7: Level Two Model Reactions to Fault-Clear-Trip Event for Unit Remaining On-Line

The magnitudes have been reduced to 4 pu and the maximums to 3.67 pu.

Now that the intuition has been developed, it is much easier to write the formula that defines the reactions. Ignoring damping (which has already been said to be very small) the formula for the simple two-mass system is defined by Figure 4.5.

There are five torques of interest in the system. Two are imposed on the system by external elements; the remaining three are internal to the system. The torques are defined on the next page:

T_1 = Torque Developed by Turbine

$T_2 = K_t \phi f \phi_a \sin \delta_e$ = Electrical Torque

$T_3 = I_1 \alpha_1$ = Torque Required to Accelerate Turbine

$T_4 = I_2 \alpha_2$ = Torque Required to Accelerate Generator

$T_5 = K_{12} \alpha_m$ = Torque on Shaft

The torques must add to zero.

The summation of the torques results in two differential equations.

$$T_1 + I_1 \ddot{\theta}_1 = K_{12}(\theta_1 - \theta_2)$$

$$T_2 + I_2 \ddot{\theta}_2 = K_{12}(\theta_2 - \theta_1)$$

Coordinate transformation allows the creation of two different equations.

The variables for the new equations are developed below.

$$\mu = \frac{I_1 I_2}{I_1 + I_2}$$

δ_m = Twist Through Shaft

$\bar{\theta}$ = Position of Center of Mass

$M = I_1 + I_2$

$$\mu \ddot{\delta} + K \delta_m = 0; M \ddot{\bar{\theta}} = T_1 - T_2$$

The second of the formulae is the stability formula. The first formula is significant. The solution is of the form $\delta = \delta_0 \cos(\sqrt{K/\mu} t)$. This is the partial solution considered for the first intuitive approximation.

To improve the quality to that of the second intuitive approximation, a constant term must be added. The solution is then of the form $\delta = A \cos(\sqrt{K/\mu} t) + B$. It should be noted that $A+B=\delta_0$ and B is the residual twist in the shaft required to accelerate the generator.

If the turbines for one of the Colstrip Units are lumped, the turbine mass is $33.4 \times 10^6 \text{ Lb}_m \text{In}^2$. The stiffness is $61.2 \times 10^7 \text{ Lb}_f \text{In}^2$. The values result in the natural frequency computed below.

$$\omega_n = \sqrt{61.2 \times 10^7 \times 12 \times 32.2 / 11.09 \times 10^6}$$

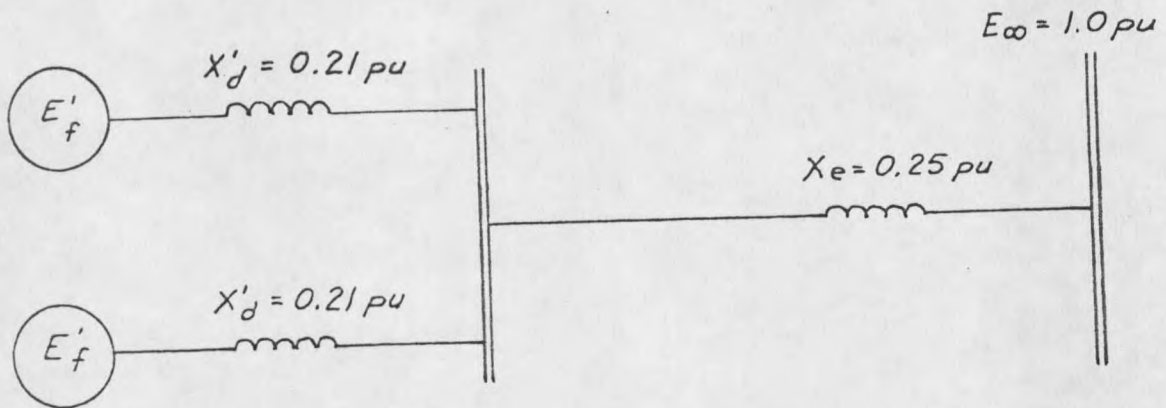
$$\omega_n = 146 \text{ Radians/Second} = 23.2 \text{ Hz}$$

The shaft between the turbines and the generator is twisted 5.21° at full load. The residual twist during a three-phase fault is 1.74° . Hence, the shaft twist for the unit remaining on-line after a fault-clear-unit drop disturbance can be roughly described by the formula below.

$$\delta = -10.42 \cos(23.2t) + 8.68^\circ$$

(t Measured From Unit Drop)

The expression derived for δ is still only an approximation. Since the subtransient reactances for the units are not zero, the remaining machine will not attempt to supply all the load rejected by its neighbor. The system could be represented by the drawing below.



Neglecting machine advance during the fault ($M_0 = T_1$), the post-drop system can be described by the drawing below.

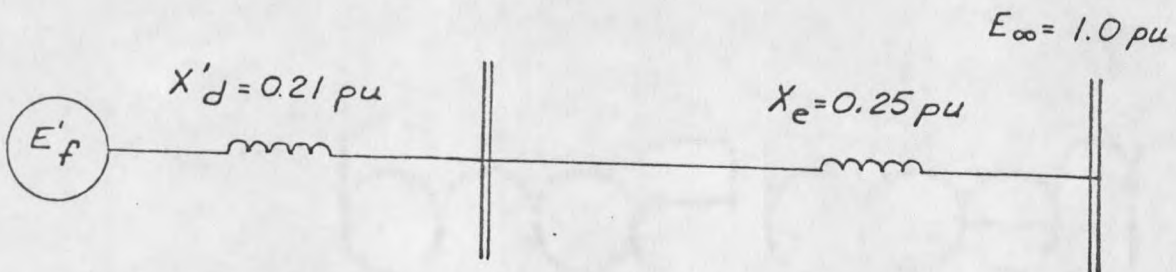


Figure 4.9: Post-Trip System Model

The power delivered to the infinite bus by the remaining machine is $(1.256/.46)\sin(34.4^\circ)=1.543$ pu. The excess power is 0.543 pu rather than 1 pu. Of the 0.543 pu only 0.361 pu is transmitted by the shaft. The resultant torque imposed on the shaft is 1.361 pu (provided the speed doesn't change much). The shaft will oscillate about $+7.09^\circ$ at 23.2Hz. The motion is described as $\delta = -8.815\cos(23.2t)+7.09^\circ$.

It might seem that lumping the two turbine inertias would introduce significant error in the frequency calculated for Mode 1. However, a three-body model developed by Montana Power Company indicates that the Mode 1 frequency is 22.4Hz, General Electric has given Mode 1 frequency to be first 24.4 then 22.4Hz, the frequency computed above is 23.2Hz, and the actual frequency measured subsequent to a unit drop at Colstrip is 22.97Hz. The approximate solution is closer to actual than the complete solution.

Before moving to the complete solution, one other aspect of the problem will be discussed. Electrical impact torques can be produced by synchronizing a unit out-of-phase. If a generator is brought to the proper speed, then connected to the system without matching the voltage angle, a step change in electrical torque results. Both Concordia and Cray describe the condition.

Transient electrical torque for a salient pole generator is described by the formula on the next page.

$$T = \frac{e'_q e_t}{X'_d} \sin \delta_e + e_t^2 \frac{(X'_d - X_q) \sin 2\delta_e}{2X'_d X_q} \quad (5)$$

The formula can easily be generalized to reflect the fact that there is normally impedance between the machine and the infinite bus.

$$T = \frac{e'_q e_\infty}{X'_d + X_e} \sin \delta_e + \frac{e_\infty^2 (X'_d - X_q) \sin 2\delta_e}{2(X'_d + X_e)(X_q + X_e)}$$

The angle at which the transient torque is the maximum can be found by finding the differential of T with respect to δ and setting the quantity equal to zero. (The second derivative is negative.)

$$0 = \frac{dT}{d\delta_e} = \frac{e_\infty^2 (X'_d - X_q)}{(X'_d + X_e)(X_q + X_e)} + \frac{e'_q e_\infty}{X'_d + X_e} \cos \delta$$

For the Colstrip units (slightly salient) against a system with $X_e=0.5$, the worst switching angle is below.

$$\delta = 114.8^\circ$$

The transient torque at that angle is computed.

$$T = (1/0.277+0.5) \sin (114.8^\circ) + \frac{(0.277-1.71)}{2(0.277+0.5)(1.71+0.5)} S_m (229.6^\circ)$$

$$T = 1.486 \text{ pu}$$

A plot of T vs δ_e is shown on the following page.

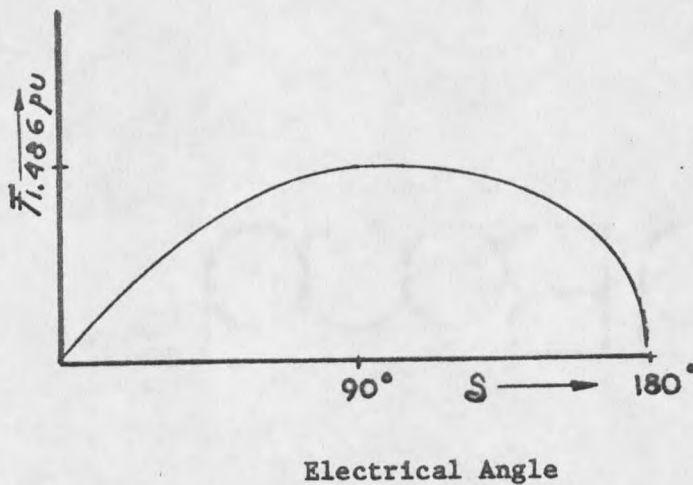


Figure 4.10: Torque Angle Diagram

If the machines had been serving load, e'_f would be greater than 1 pu, so the impact would be greater. Consider what could happen to a machine serving a load through a single path if it were subjected to the following sequence of events:

1. A three-phase fault is established near the machines terminals.
2. The line breakers open to isolate the fault.
3. The arc is extinguished.
4. After 30 cycles (required for arc extinction), the machine has advanced about 80° and the circuit is reclosed.

The generator might well be reduced to rubble.

The analysis has been limited to a two-mass system. Complete analysis required the solution to a three-mass system. Three-body problems require significant coordinate modification for solution. They are not

simple to solve. The Colstrip Units have no direct coupled exciters. They derive their excitation through subterfuge. Most modern units do have direct coupled exciters. They require the solution of a four-body problem.

For the complete solution, the Colstrip Units can be represented as shown.

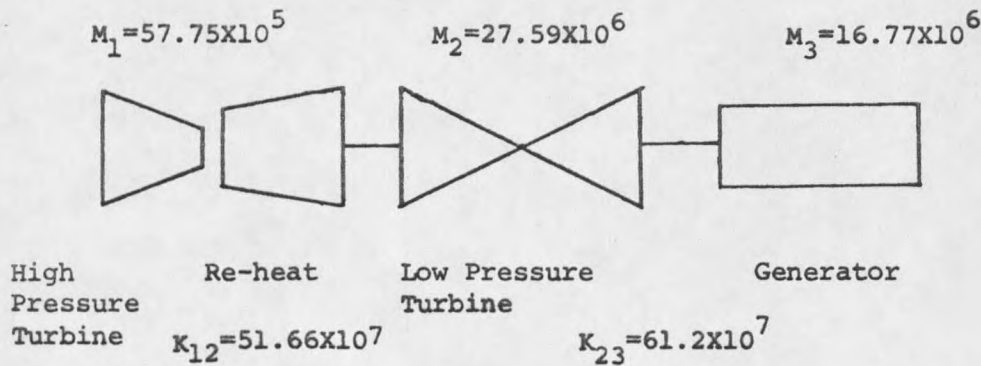
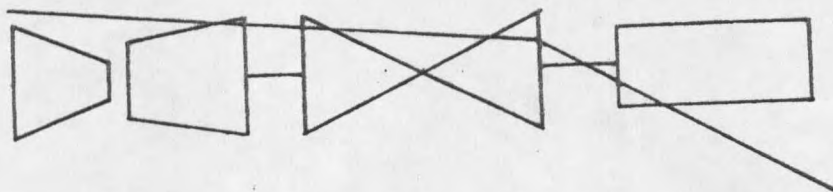
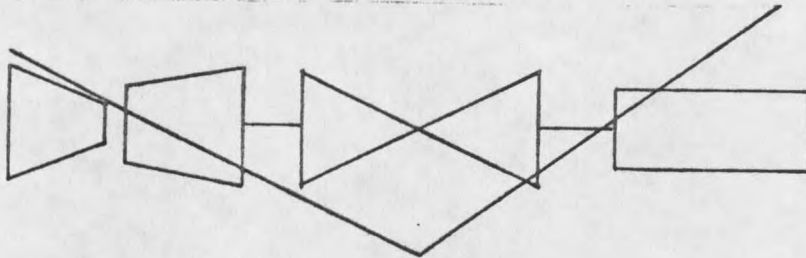


Figure 4.11: Level Three Shaft Inertia Model

For the three-body system there are two non-trivial modes of oscillation. Mode 1 is described by the generator oscillating against the two turbines combined (through K_{23}). In Mode 2, the HP turbine and generator oscillate against the LP turbine. The next two drawings show the approximate relative mechanical displacements of the two modes.



MODE I



MODE II

Figure 4.12: Modes of Oscillation

As stated before, there is very little damping associated with the natural frequencies. The logarithmic decrements are 0.0025, and 0.0012 for Colstrip Modes I and II, respectively. The definition of logarithmic decrement is below.

$$\text{Log Dec} = \ln(A_n/A_{n+1})$$

Where: A_n = Amplitude of n th cy
 A_{n+1} = Amplitude of $n+1$
 cycle

A logarithmic decrement of 0.0025 means that any cycle is more than 99.75% of its predecessor. It is not unreasonable to ignore damping.

The oscillators described by Mode I and II are coupled. The frequencies beat against each other. The displacement at any point along the shaft is a periodic, but non-pure function.

The equation for the system can easily be derived if one remembers that $\Sigma T=0$.

Equation of Motion

$$\ddot{\theta}_1 = K_{12} (\theta_2 - \theta_1)$$

$$\ddot{\theta}_2 = -K_{12} (\theta_2 - \theta_1) + K_{23} (\theta_3 - \theta_2)$$

$$\ddot{\theta}_3 = -K_{23} (\theta_3 - \theta_2)$$

Matrix Form

$$\begin{bmatrix} I_1 \\ I_2 \\ I_3 \end{bmatrix} \begin{bmatrix} \ddot{\theta}_1 \\ \ddot{\theta}_2 \\ \ddot{\theta}_3 \end{bmatrix} = \begin{bmatrix} K_{12} & -K_{12} & 0 \\ -K_{12} & (K_{12} + K_{23}) & -K_{23} \\ 0 & -K_{23} & K_{23} \end{bmatrix} \begin{bmatrix} \theta_1 \\ \theta_2 \\ \theta_3 \end{bmatrix}$$

Inertia Stiffness Matrix

Assuming a Harmonic Solution

$$\begin{bmatrix} 1/I_1 \\ 1/I_2 \\ 1/I_3 \end{bmatrix} \begin{bmatrix} \ddot{\theta}_1 \\ \ddot{\theta}_2 \\ \ddot{\theta}_3 \end{bmatrix} = \begin{bmatrix} K_{12} & -K_{12} & 0 \\ -K_{12} & (K_{12} + K_{23}) & -K_{23} \\ 0 & -K_{23} & K_{23} \end{bmatrix} \begin{bmatrix} \theta_1 \\ \theta_2 \\ \theta_3 \end{bmatrix}$$

$$\begin{bmatrix} A - I\delta & \omega^2 \end{bmatrix} \begin{bmatrix} \theta_1 \\ \theta_2 \\ \theta_3 \end{bmatrix} \equiv 0$$

Assuming a Harmonic Solution (Cont)

$$\begin{bmatrix} (A_{11} - \omega^2) & A_{12} & A_{13} \\ A_{21} & (A_{22} - \omega^2) & A_{23} \\ A_{31} & A_{32} & (A_{33} - \omega^2) \end{bmatrix} = 0$$

$$\begin{bmatrix} K - \omega^2 & -K & 0 \\ -K & 2K - \omega^2 & -K \\ 0 & -K & K - \omega^2 \end{bmatrix} = \begin{bmatrix} A \\ A \\ A \end{bmatrix} - \omega^2 \begin{bmatrix} I_\delta \\ I_\delta \\ I_\delta \end{bmatrix}$$

Examples I=K=1

$$\begin{aligned} |A - I_\delta \omega^2| &= 0 & = \omega^6 & -4\omega^4 + 3\omega^2 = 0 \\ \omega_0 &= 0 & , & f_0 = 0 \text{ Hz} \\ \omega_1 &= 1 & , & f_1 = 0.1592 \text{ Hz} \\ \omega_2 &= \sqrt{3} & , & f_2 = 0.276 \text{ Hz} \end{aligned}$$

For Colstrip Machines

$$I_1 = \frac{57.75 \times 10^5}{12 \times 32.2} = 1.495 \times 10^4, \quad I_2 = \frac{27.59 \times 10^6}{12 \times 32.2} = 7.23 \times 10^4$$

$$I_3 = \frac{16.77 \times 10^5}{12 \times 32.2} = 4.34 \times 10^4$$

$$I^{-1} = \begin{bmatrix} 6.69 \times 10^{-5} & & \\ & 1.383 \times 10^{-5} & \\ & & 2.30 \times 10^{-5} \end{bmatrix}$$

For Colstrip Machines (Cont)

$$\begin{aligned}
 K &= \begin{bmatrix} 51.66 \times 10^7 & -51.66 \times 10^7 & 0 \\ -51.66 \times 10^7 & 1.129 \times 10^9 & -61.2 \times 10^7 \\ 0 & -61.2 \times 10^7 & 61.2 \times 10^7 \end{bmatrix} \\
 I^{-1}K = A &= \begin{bmatrix} 3.46 \times 10^4 & -3.46 \times 10^4 & 0 \\ -7.14 \times 10^3 & 1.56 \times 10^4 & -8.46 \times 10^3 \\ 0 & -1.408 \times 10^4 & 1.408 \times 10^4 \end{bmatrix} \\
 A - \omega^2 I_\delta &= \begin{bmatrix} 3.46 \times 10^4 - \omega^2 & -3.46 \times 10^4 & 0 \\ -7.14 \times 10^3 & 1.56 \times 10^4 - \omega^2 & -8.46 \times 10^3 \\ 0 & -1.408 \times 10^4 & 1.408 \times 10^4 - \omega^2 \end{bmatrix}
 \end{aligned}$$

$$\begin{aligned}
 |A - \omega^2 I_\delta| &= (3.45 \times 10^4 - \omega^2) [(1.56 \times 10^4 - \omega^2)(1.408 \times 10^4 - \omega^2) - (1.408 \times 10^4)(8.46 \times 10^3)] \\
 &\quad + (3.46 \times 10^4) [(-7.94 \times 10^3)(1.408 \times 10^4 - \omega^2)] = 0
 \end{aligned}$$

$$0 = -8.82 \times 10^8 \omega^2 + 6.43 \times 10^4 \omega^4 - \omega^6$$

$$\omega^2 = 0$$

$$\boxed{\omega_0 = 0}$$

Trivial Solution

$$\omega_2 = \frac{6.43 \times 10^4 \pm 2.46 \times 10^3}{2}$$

For Colstrip Machines (Cont)

$$\omega_1 = 140.8 \text{ Rad/Sec}$$

$$\omega_2 = 211 \text{ Rad/Sec}$$

$$\underline{\underline{f_1 = 22.4 \text{ Hz Mode I}}}$$

$$\underline{\underline{f_2 = 33.6 \text{ Hz Mode II}}}$$

The effects of a three-phase fault on the terminals of the Colstrip Units were evaluated. If the fault were to be cleared at the worst possible time, and a generator tripped at the worst possible time, the loss-of-life for the low pressure turbine to generator shaft would be 2.5% for the generator remaining on-line, and 3.0% for the tripped unit. The shaft of the generator remaining on-line is actually subjected to mere severe initial torques, but the steam supplied to the turbines provides sufficient damping to substantially reduce the number of damaging cycles. The probability of significant loss of shaft life due to generator tripping was so small that development continued.

The knowledge gained about the generator's torque-mass characteristic did force changes in the logic applied to unit tripping. All logic had been developed around the generator's center of inertia characteristic. The facts learned during the shaft investigation led to a question

about the location of the toothed wheel. Depending on the location, one or both modal frequencies might be superimposed on the speed signal.

Investigations revealed that the wheel is located near the front standard (near the outboard side of the high pressure turbine). Both modal frequencies would certainly be present in any speed signal taken from that location. Further, the fundamental power frequency (60Hz) would probably be mixed with the speed signal.

A new algorithm to compute trips for type one instability could certainly be produced. The modal characteristics of a generator don't change. The reaction at the toothed wheel to a given fault cannot change. Consequentially, there was confidence that a solution could be found for the modal noise present during type one events. It would simply become part of the computations.

However, the method used to compute trips for type two events would have to change. The modal reaction to fault initiation was well defined, but it was known that the amount of time required to clear the fault is not constant. Since the fault could be cleared at any time, it is impossible to determine what the modal reaction might be past that time. Type two instability can only be sensed by monitoring the rotor's speed response after the fault has been cleared.

It is necessary to remove the modal frequencies from the speed signals for type two instability sensing. The beat frequency of the modes (mea-

sured) is 10.07Hz. The period is therefore 0.0993. The period is very close to the amount of time required for 477 teeth on the wheel to pass the probe when the rotor is turning at synchronous speed.

The input circuit could be modified to a divide by 954 circuit which would result in all samples being taken at 477 tooth intervals. The modal frequencies could thereby be filtered from the signal. However, the procedure would require that the 477 tooth counts also be used for type one events. The 477 tooth counts respond too slowly to type one events to allow generator tripping before type one instability has developed.

A second possibility would be to modify the input circuit into a divide by two circuit. The microprocessor could then keep running sums of the counts accumulated during the two previous 477 tooth intervals and update the sums each time a tooth passed. Also, the microprocessor could keep running totals for the counts accumulated during the two previous 80 tooth intervals on which to base type one event decisions. The process shows some merit, but requires more computations from the microprocessor than it can perform during the time available.

Fortunately, 477 is evenly divisible by 9, and 53. The input circuit was replaced by a divide by 18 circuit. The microprocessor keeps running totals of the counts accumulated during the previous two 81 tooth intervals to perform computations for type one events, and running sums of 477 tooth intervals to perform the computations for type two events.

The 477 tooth sums, however, are not adjacent. Adjacent 477 tooth sums define an acceleration that responds too slowly to a system event. The most recent 477 tooth total is compared to the 477 tooth total that was completed 720 teeth earlier. The time-line below shows how the sums are arranged.

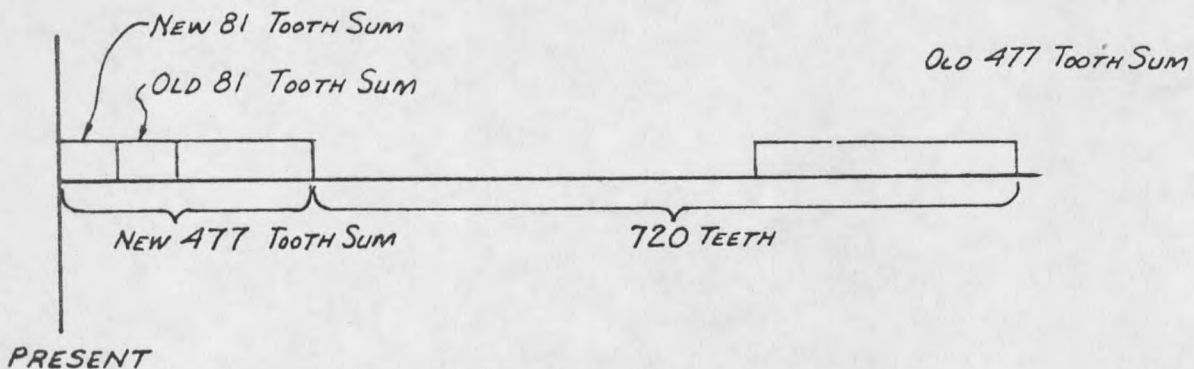


Figure 4.13: Time-Line

An acceleration (A_1) can be computed from the 81 tooth sums by subtracting the new 81 tooth sum from the old 81 tooth sum. Similarly, an acceleration (A_2) can be computed from the 477 tooth sums by subtracting the new 477 tooth sum from the old 477 tooth sum. The sums are updated and the accelerations are computed each time nine teeth pass. The 477 tooth sums are offset by 243 teeth so the A_2 values will be larger for any given amount of acceleration. Also, since the A_2 values are computed from sums that are separated by an integer number of electrical cycles (nine), the fundamental power frequency is removed from the acceleration.

Stability simulations were conducted to define the characteristic required of the device based on the two accelerations described. The A_1

acceleration is oscillatory since the modal frequencies are not filtered from the signal. The value used for A_1 is the maximum value reached during the first swing of the oscillation after the initiation of the disturbance.

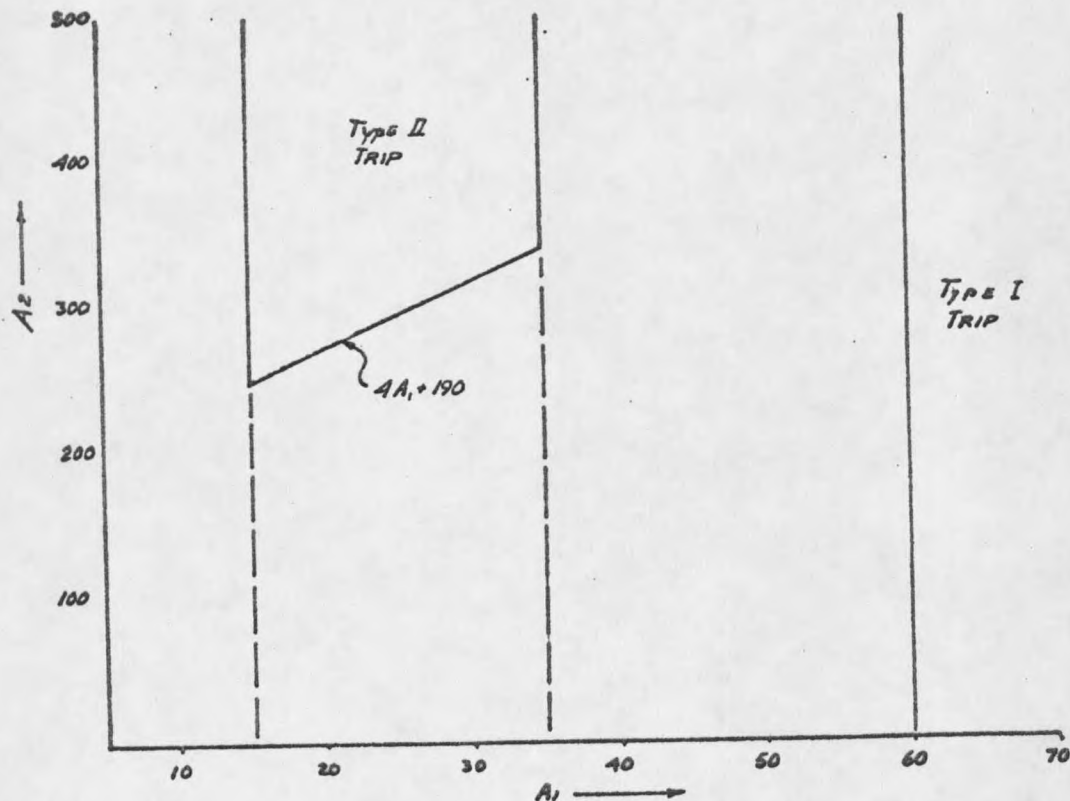


Figure 4.14: ATM Response

The Early Designs

System simulations have shown that the Montana system is vulnerable to instability following three distinct types of events. Type one instability results from severe faults near Colstrip that occur when the generators are loaded to a total of more than 550 MW. After the faults has cleared, there is simply too much excess energy stored in the genera-

tors' rotors for the power system to handle. Type one instability is characterized by a high rate of acceleration. Type two instability occurs when the generation at Colstrip is high, and a critical circuit is lost. The resultant system is too weak to transmit the power generated, so the excess is stored in the generators' rotors (as excess speed). Since the generators overspeed, sufficient angle eventually accumulates to prevent the transmission system from conducting power. Type two instability is characterized by more moderate levels of acceleration that are sustained. Type three instability results from a disturbance external to the Montana system. The loss of a circuit parallel to the Montana system, or the loss of generation west of the Montana system can cause large quantities of power to flow across the Montana system. The amount of power imposed can exceed the system's capacity, and cause the circuits connecting eastern Montana to western Montana to trip. A method has been developed to recognize type three instability, but it will not be used. The political implications of tripping a Colstrip generator to prevent an unstable condition which developed in another system from cascading are simply too heavy. Neighboring systems certainly should not plan on the sacrificial act. No effort has been expended to perfect the algorithm needed to deal with type three instability.

A very accurate speed signal is available from equipment already mounted on the Colstrip generators. Eighty teeth have been machined into steel discs that are mounted on the generators' rotors. Transducers consisting of coils of wire wrapped around permanent magnets are mounted very near the circumferences of the discs. When teeth are directly beneath

the magnet, a highly permeable path is available (through the steel disc) for the magnetic lines of flux. When gaps are directly beneath the magnet, the permeability is decreased. If the toothed wheel rotates, a waveform that has a frequency equal to 80 times the rotational velocity of the wheel results.

A device composed of discrete digital integrated circuit packs was actually designed and partially built, but it was soon recognized that design changes forced by changing requirements would become unwieldy. The requirements, at this stage in the development, were changing daily.

A microprocessor circuit was designed and built. As problems were identified that caused modifications in the logic, the microprocessor program could easily be changed. The waveform produced by the transducer on the toothed wheel was used to control the state of a Schmitt trigger. The output from the Schmitt trigger was processed by a symmetric divide by 18 circuit. The resultant waveform changed states every time the generator rotor turned one complete revolution. A high quality time base was supplied by a crystal oscillator. The output of the divide by 18 circuit controlled which of two registers would accept pulses (counts) from the crystal oscillator. The contents of the registers at the end of each counting period would then be a very accurate measure of the amount of time the rotor took to make that particular portion of a revolution. The drawing on the next page shows how the entire input circuit was designed.

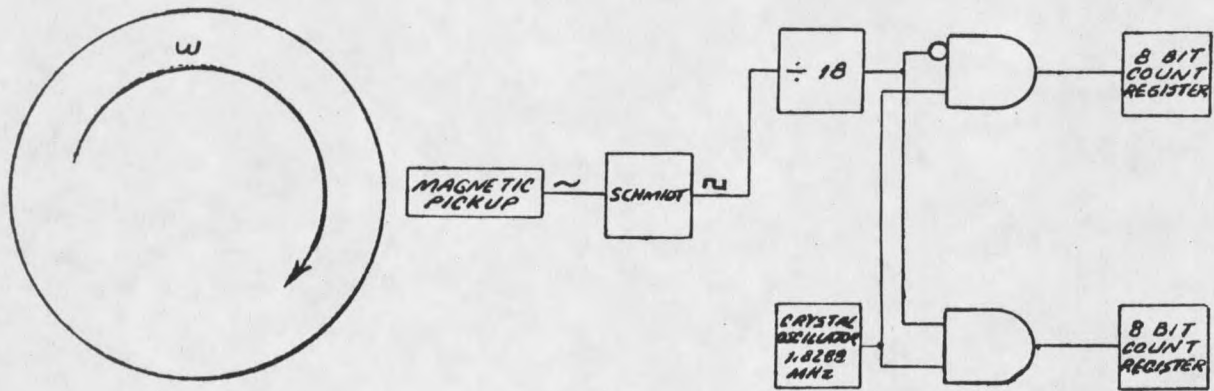


Figure 4.15: Block Diagram

The oscillator actually produced 2,304 counts during the passage of nine teeth. The number could be represented (in binary) by no fewer than 12 bits. However, the most significant bits would (even during the most severe system disturbances) always be the same. The pertinent data would be contained in the least significant eight bits.

Stability simulations, which were being conducted concurrently, indicated that the stability of the power system really could be evaluated using nothing more than rotor velocity and time derivatives of that velocity. The minimum rate of acceleration that preceded type one instability was defined, and the sequence of accelerations accompanying type two instability was found.

However, the counts contained in the registers define the period rather than the velocity of the rotor. A faster turning rotor would imply a smaller count; a slower turning rotor would imply a larger count. The count totals are proportional to a constant plus a second constant over the rotational velocity: $C=K_1/\omega+K_2$.

An approximation can be made to the acceleration simply by subtracting the counts accumulated during an interval from the counts accumulated during the preceding interval. The formula is: $C_\alpha=C_{I1}-C_{I2}$, i.e., an integer that is about representative of acceleration is computed by subtracting the counts accumulated during the second interval from the counts accumulated during the first interval. The approximation generates two questions:

1. Is much error introduced by the approximation?
2. Does it make any difference?

If the term α_c is used to describe Newtonian acceleration, the graph on the next page can be drawn. While the use of C_α for α_c does introduce some error, the nonlinearity over the range of interest is much less than 1%. (We trip a generator is $C_\alpha \geq 63$ over a cycle.) Also, since the trip limits are set empirically, nonlinearity would not matter so long as C_α is larger when α_c is larger. The error is insignificant.

Therefore, the acceleration and velocity used in the acceleration trend monitor (ATM) do not (in the strictest sense) conform to the clas-

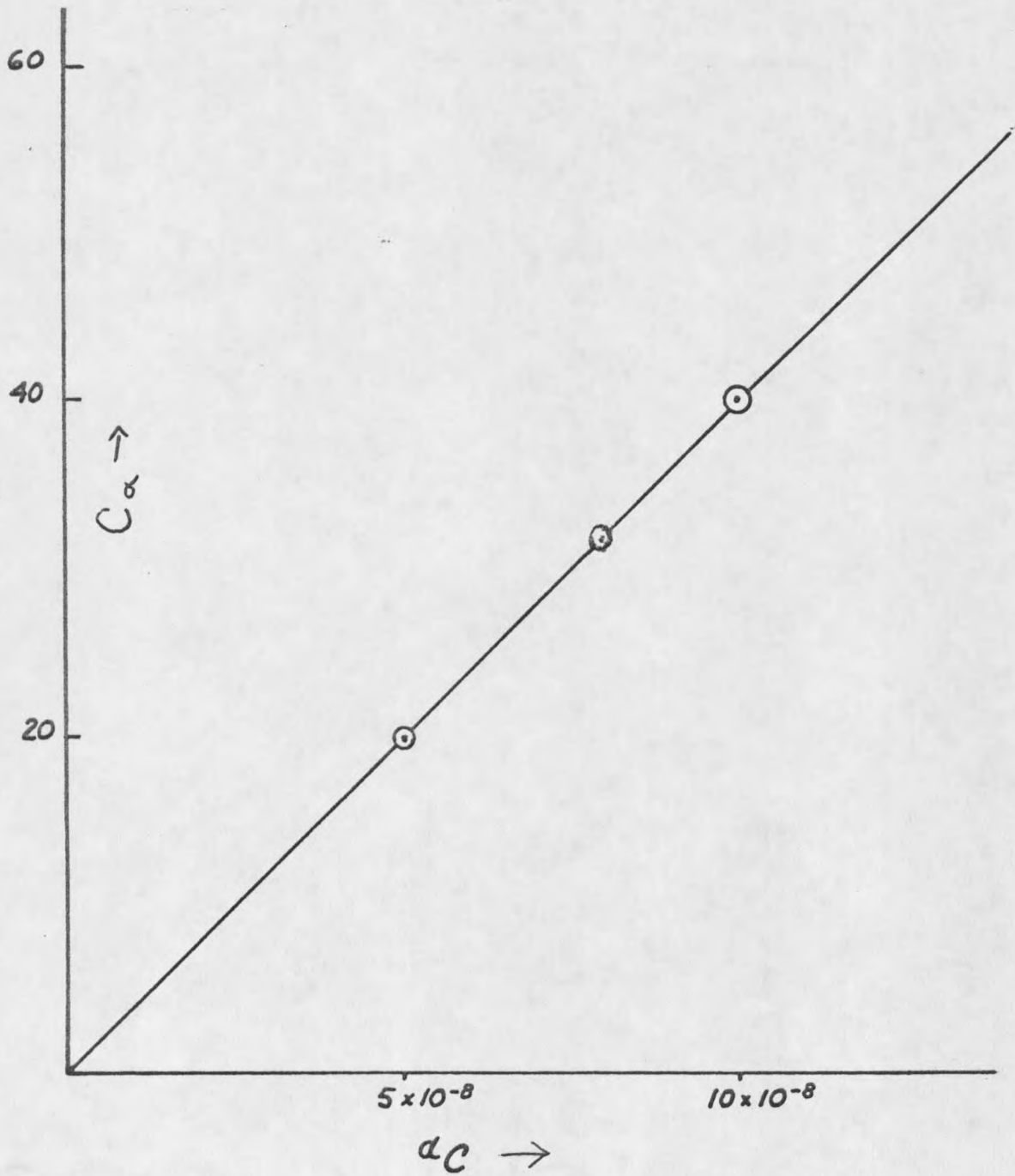


Figure 4.16: Period of Acceleration Versus Classical Acceleration

sical definitions of those terms. The quantities used in the ATM should more properly be called count velocity and count acceleration. They are the result of measuring the period required for certain events.

The counts, when processed properly, provided adequate definition of power system conditions. They could be used to recognize imminent instability, and control generator tripping.

Even during the early stages of development, it was recognized that the failure of any one of several components could cause an inadvertent generator trip. Consequently, the circuitry was duplicated from magnetic pickups to trip relays. The output register of each computer was fitted with a "dead computer relay". If the output register was not written into at least once every 20 milliseconds, the computer controlling the parallel system would be informed, it would halt, and a lamp indicating system failure would be energized. The same sequence could be initiated by the failure of the two systems to agree about the need for a generator trip.

The First Device

The 81 tooth sums, and 477 tooth sums would be about 1152, and 6784, respectively, and would require 16 bit registers. A_1 could be stored in an eight bit register, while A_2 would require 16 bits. The memory required (RAM) is very much less than 1K bytes. However, it was recognized that if the device were to have a large enough memory, it could

provide enough data subsequent to issuing a trip to justify the action, and provide a means to check the validity of the stability simulations. Two K bytes were specified.

A flow chart (on the next page) for the program shows that the logic is very simple.

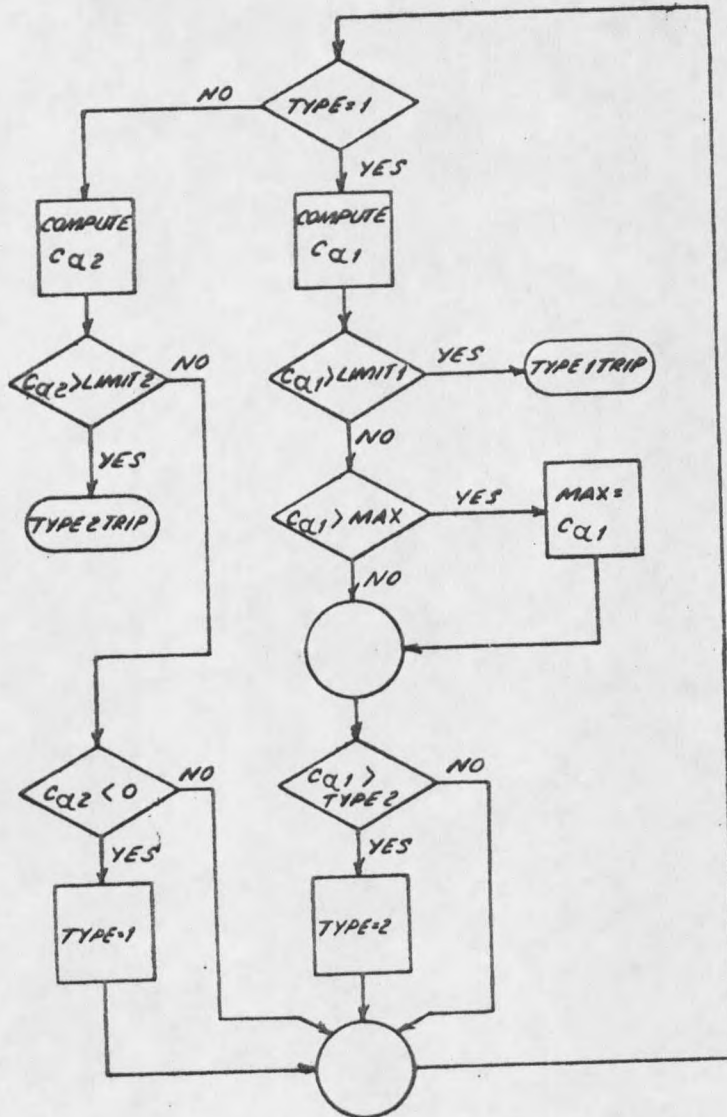


Figure 4.17: Flow Chart

The program would fit into 1K bytes of programable read only memory (PROM). However, to insure flexibility, the device was built with 2K bytes of PROM.

The device should operate only when the generator is synchronized to the system. Consequentially, a signal was provided to indicate that the

generator's synchronizing breakers were closed. The block diagram below provides a conceptual description of how the early device was constructed.

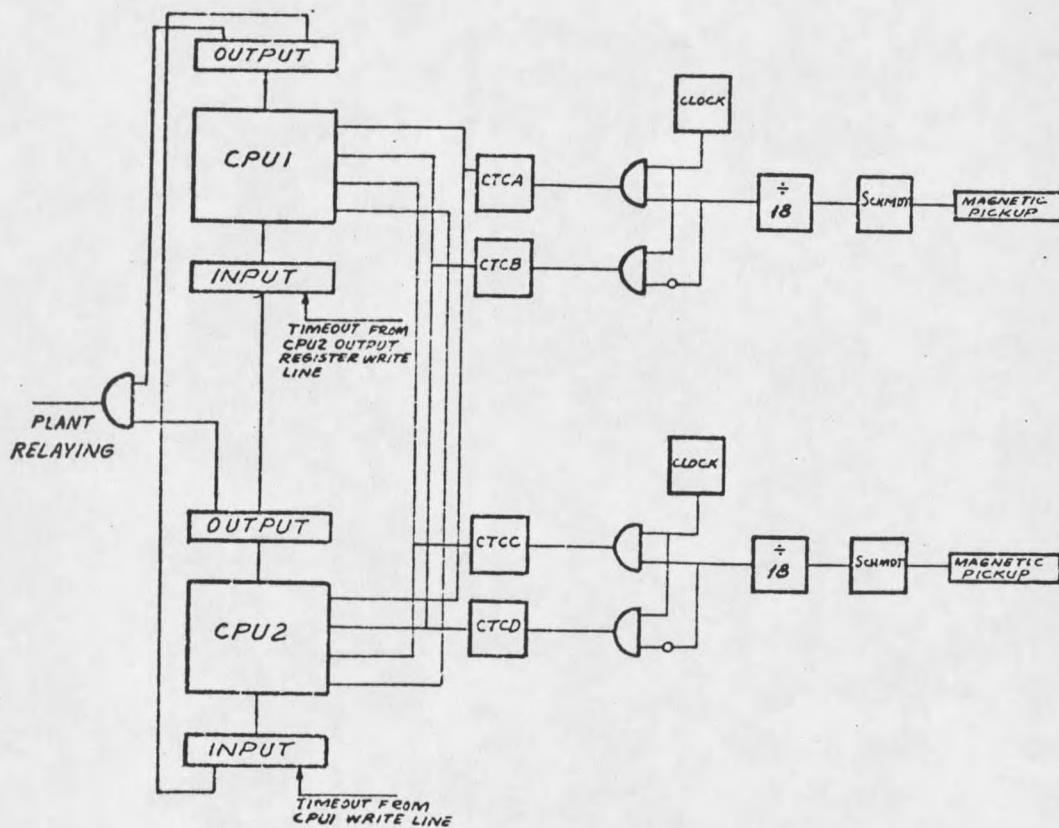


Figure 4.18: Block Diagram of the First Device

The diagram shows two identical circuits. The significant bits from the output registers (and time out circuits) from each half of the system are connected to the input circuits of the other half of the system. Each CPU then knows the status of the other. The outputs that control the

various plant actions are used to actuate relays that are wired in series. Both relays must be closed to cause the desired event. When one of the CPUs requests a trip, the other CPU is informed at the same time. If the second CPU does not agree within 17 milliseconds, the entire system deactivates. Generator trips that might be produced by equipment failure are thus avoided.

The first device was constructed and installed at Colstrip. It operated in the test mode for six months. All of the wiring for needed inputs was connected, but the trip leads were not. Miraculously, not one instance of power system instability occurred during the period. The test was inconclusive although the computers were still processing at the end of the six months.

The Second Device

The first device was retrieved from Colstrip and subjected to extensive bench testing. The CPU circuits proved extremely sensitive to noise. The switching of a soldering iron could produce enough noise to cause the microcomputers to stop processing. The device had not stopped while at Colstrip probably because it had been totally enclosed in a metal cabinet, and the CPU circuits had been powered directly from separate inverters connected to separate plant batteries. The system, even though in a very noisy environment, had been well isolated. However, a circuit that is susceptible to noise is not the proper type of device to use to control generator tripping due to transient events.

The entire device was scrapped and replaced with better equipment. The microcomputers were replaced with Control Automation minicomputers, and the input circuits were redesigned. Since none of the basic logic was changed, the new system was ready less than six weeks after construction began. The new device was installed at Colstrip in time for the full-load-reject test that had been scheduled to evaluate the generator's ability to accept a step-change from full load to about 10% load.

Chapter 5

TEST RESULTS

The full-load-reject test is significant because a generator's speed reaction to the test is nearly the same as the speed reaction to a three-phase fault near the generator. In both cases, the generator is separated from the electrical load. Still having full driving torque from the turbines, the generator accelerates. The full-load-reject test provided a means to test the type one instability logic without waiting for a type one event.

The generator was loaded to 312 MW net, then the synchronizing breakers were opened. The load served from the generator stepped from 312 MW plus plant burden (30 MW) to plant burden. The device recorded the resultant acceleration, properly decided that a type one event was in progress and issued a trip.

The speed data printed by the device subsequent to the trip was so close to the data expected that it was felt that the output could be used to calibrate the plant metering. The quality of the data was much better than expected. A copy of part of the speed data printed by the device subsequent to the trip is on Page 87. The first 55 lines contain nine tooth-sum residuals accumulated before the generator was tripped. If there were no digital noise, and if the generator's rotational velocity

were always exactly 3600 RPM, the pre-event residuals would all be 128. In line 56, the values start to decrease which indicates that the generator is accelerating.

A list of the A_1 counts from the event is on Page 88. The A_1 counts are from a program that was written to process the residuals in the same manner as the program in the device. The program stops processing as soon as a trip limit is reached. However, the A_1 counts continue to increase until the value is 106 at the first peak. A value of 106 at the first peak can be shown to indicate a step-change in the generator's load of 312 MW. The plant metering indicated 304 MW.

There being no method to test the device's performance for type two events (other than driving the input counters with a signal generator), the device was simply activated. Type two event testing would wait an actual system occurrence.

[illegible]

Figure 5.1: Velocity Counts

OK, R PROG1
 FREEZE 0/5/79 17:17:42:505 4068 0 1
 STATUS: ENAHLE SW
 CONTROL:
 LOCKUP 0/5/79 17:17:42:524 2934 3
 STATUS: ENAHLE SW
 CONTROL: IT INHIB

ALPHA COUNTS (9,9,81)

-1	-2	-4	-2	-2	0	0	2	2	-2	2	3	1	2	0	0	-1	-2	-1	-1
-1	0	-1	1	1	0	2	0	0	0	0	1	-2	-2	0	-1	0	0	1	1
-1	2	2	1	0	0	0	-2	-1	0	-1	-1	-2	1	1	1	2	1	1	1
1	2	-1	-1	-2	-1	-2	-2	-1	-1	-1	0	0	3	1	2	2	1	0	0
0	0	-2	-1	0	-1	-1	1	1	1	1	0	1	-1	1	0	-1	-1	-1	-1
1	-1	1	0	2	2	1	1	1	-1	0	0	-2	-3	-3	-1	-1	-1	1	1
-1	3	2	2	1	1	1	-1	0	0	-2	0	-1	-1	-1	-1	0	-1	1	0
-1	0	0	0	0	1	0	-1	1	1	1	1	1	2	0	1	1	0	-1	-1
-1	-1	-3	-2	-1	-1	-1	1	1	1	1	2	3	2	1	0	-1	-1	-1	-1
-1	-3	-2	-1	1	1	0	0	0	0	2	0	0	-1	-1	0	0	0	1	0
0	1	0	0	1	1	0	-2	-2	0	-2	0	-1	-2	-2	0	2	1	0	2
0	2	2	1	0	-2	-1	-1	-2	0	-3	-2	0	0	1	2	1	1	-1	3
1	-1	0	0	-2	0	0	1	-2	0	1	-1	0	1	-1	-1	-1	-1	-2	-1
1	-1	0	1	1	2	1	3	1	-1	1	0	-1	-1	-2	-1	-3	-2	0	-2
-2	1	0	0	1	2	2	1	2	1	-1	0	-1	-2	-2	-1	-2	-2	0	-1
0	1	1	0	-1	1	1	-1	1	0	-1	-1	1	2	0	0	2	0	-1	1
1	-1	-3	-2	-2	-3	-2	0	-1	-1	0	1	2	3	2	2	0	0	0	0
1	-2	-3	-2	-1	0	-1	-1	0	-3	1	1	0	-1	-1	0	0	-1	2	-1
-2	1	0	0	1	1	0	-1	0	1	-2	-1	-1	-2	-3	-1	-1	-1	0	1
2	2	1	3	1	1	1	-1	-1	-3	-3	-2	-3	-1	-1	-1	0	0	1	1
2	1	0	0	0	0	0	0	0	-1	0	-1	-1	0	-1	-1	-2	-2	0	-2
1	0	-1	0	1	1	2	2	3	-1	1	1	1	-1	-1	-1	-2	-3	0	-2
-3	-1	0	0	0	2	1	0	2	3	0	0	-1	0	-1	0	-1	-2	-1	0
0	1	0	-1	-1	1	1	-1	-1	-1	-1	-1	0	2	0	0	1	2	1	2
1	1	-2	0	-1	-1	-3	-1	-2	0	0	1	0	2	2	3	2	1	0	0
0	-1	-1	-2	-1	-1	0	0	0	-1	2	0	2	0	0	0	-1	0	2	-1
0	-1	0	0	1	2	1	-1	0	0	0	0	0	-2	-1	-2	0	0	1	1
1	1	3	1	3	2	1	0	-1	0	-1	-2	-1	-2	-2	0	-1	1	-1	1
1	1	1	1	0	1	1	2	1	0	1	0	1	1	1	-1	0	-1	0	-1
1	-2	-1	-1	1	-1	0	2	1	0	4	2	2	0	2	2	-2	0	0	-3
-2	-1	0	-2	-1	2	0	0	2	2	1	1	2	1	-1	1	1	-1	0	-1
0	0	0	1	0	0	1	0	1	-1	-1	-1	0	0	0	1	1	1	2	3
2	1	1	1	-1	1	-1	-1	-3	-1	-1	-1	-1	1	0	1	2	2	2	1
2	2	1	0	1	-1	1	-1	0	-2	-1	-1	0	-2	0	-2	-1	0	2	0
-1	0	2	0	2	2	1	0	1	3	1	0	0	-1	-1	-2	-1	-2	-1	-1
-1	1	-1	1	1	3	1	1	1	1	0	1	0	1	-1	0	0	0	0	0
0	0	-2	0	0	0	0	0	0	1	0	1	0	1	0	1	1	0	-1	0
1	0	-1	0	-1	0	0	1	-1	1	1	1	1	1	1	1	0	-1	1	-1
-2	-1	-1	-1	-1	0	0	-1	0	2	1	1	-1	1	1	1	0	1	0	-1
-1	2	-1	-1	-1	0	-1	-2	0	0	-1	0	0	0	1	0	2	1	0	0
0	0	1	-1	0	-1	-1	0	0	0	0	-2	-1	0	0	-1	0	0	0	0
1	1	0	0	2	0	0	0	-1	0	0	-1	0	-2	-1	-1	-1	0	1	-1
-2	0	0	1	0	0	1	-1	1	2	1	0	-2	0	0	-1	0	-2	-1	-2
0	1	0	0	-1	0	1	0	1	0	-1	-1	-1	1	-1	0	-1	0	-1	1
1	0	-1	0	-1	0	-2	0	-1	-1	0	0	1	0	1	0	1	0	0	0
0	-2	0	-3	-2	0	-1	-1	-1	-1	1	0	2	1	0	1	0	1	1	-1
-2	0	-1	-2	-2	0	-1	-1	0	1	0	0	2	0	-1	-1	0	0	-1	1
0	1	-2	0	1	1	-1	-1	0	-1	-1	0	-2	-1	-1	0	1	1	0	1
1	2	1	1	1	-1	-1	0	-1	-1	-1	-2	-2	-1	0	0	0	-1	1	0
2	1	0	0	0	0	-1	1	-1	-2	0	0	-1	0	0	1	-1	1	1	-1
-2	1	-1	-1	-1	1	-1	-1	1	3	0	1	0	1	-1	0	1	1	1	-1
-2	0	-1	0	0	0	0	1	1	2	0	-1	0	1	0	0	0	0	-2	0
1	0	-2	0	0	0	0	1	-1	0	-1	1	0	0	0	0	0	1	0	1
0	-1	-1	-1	-1	-1	-1	-1	-1	-1	1	2	1	1	1	1	1	1	1	-1
-3	-1	-1	-1	0	-1	-1	-1	-1	1	2	1	1	0	-1	0	1	0	1	1
3	8	11	17	22	33	42	53	67											

TYPE I TRIP

STOP PROCESSING AT I=1127

Figure 5.2: Acceleration Counts

Chapter 6.

OPERATING HISTORY

The test of the type two event logic came within a month after the device was activated. A lightning arrester in the Colstrip switchyard failed. The result was a single line-to-ground fault that lasted until a generator was shed. The ATM did not trip the plant because the output had been inadvertently connected to the wrong relay pole following the load reject test. It did, however, indicate that it would have shed a unit if connected properly.

As verified by the simulations, the power system did not suffer instability. However, the 100 kV voltage at Harlowton, and 230 kV voltage at Clyde Park did dip below 80%. A significant amount of motor load was lost. The ATM was installed to prevent such loss of load.

The next system events (Numbers 2 and 3) caused the ATM to trip a Colstrip generator when it should not have. Event Number 2 began with a relaying error that caused the Broadview to Great Falls 230 kV line to open for no apparent reason. The Colstrip generation was relatively low at the time, so the opening of the line should not have caused the levels of acceleration necessary for the ATM to issue the trip. A trip was not, in fact, issued by the ATM when the line opened. However, the Butte Dispatcher noticed the indicators on his panels change state and rushed

to close the line by supervisory control. When he closed the line, a Colstrip generator tripped. The ATM had initiated the generator trip.

The generator did slow (as expected) when the line was closed. However, when the rotational velocity rebounded, the accelerations were sufficient for the ATM to sense (mistakenly) a type two event and trip a generator.

The false trip was the result of an engineering judgment that had been made during the ATM development. The effect of line reclosing had been questioned, but it was decided that such an event would cause the generator to slow rather than accelerate and should be of no concern. Many engineering judgments were made during the development of the ATM in an effort to make it operational. This judgment proved false.

The Dispatchers were told to leave the ATM in service but to disable it before reclosing a line. No other type of event could be conceived of that would cause such a false trip, and the device had proven so valuable to system operation that it could not be removed from service.

Two days later, Colstrip Unit #1 tripped because of a coal mill problem. The ATM tripped Colstrip Unit #2. The event that could not be conceived of had occurred. The same error in the ATM logic had again caused a false trip.

The device was taken out of service until it could be fixed. The search for a method to prevent such false trips (which had begun subsequent to event Number 2) continued. Finally, it was decided to simply cause the ATM trips to be deactivated any time significant slowing occurred.

The device would monitor subsequent speed oscillations and reactivate after sufficient damping had occurred.

The software was modified, and the device returned to service. Two days later, Colstrip Unit #1 tripped because of boiler problems. The ATM did not improperly trip Colstrip Unit #2.

Several weeks passed before the fourth event occurred. A fire beneath the 100 kV line between the Billings Steam Plant Substation, and the Billings Rimrock Substation caused a fault that initially involved only one phase, but later developed into a multiphase fault. The breaker at Rimrock did not open, and back up relaying cleared all 161 kV, all 100 kV, and all 50 kV lines terminating at Rimrock. Substantial system was lost, and the ATM properly tripped a unit. Stability simulations later proved the unit trip saved the system from cascading instability.

Event number five also caused an improper operation. Colstrip Unit #1 was off-line for repair. The Buffalo Wyoming to Yellowtail 230 kV line was also out of service for maintenance. Upon completion of line maintenance, the line was to be reconnected at Buffalo; but since the angle across the open breaker at Yellowtail was nearly 60°, it could not be closed.

The Wyodak generation was reduced until the angle was reduced to 30° , and the breaker was closed. The resultant step-change in circulating flow across Montana caused sufficient acceleration for the ATM to trip Colstrip Unit #2.

The ATM should not have tripped the remaining unit. The fact that it did is due to a decision early in the project to minimize the equipment purchased until the device could prove itself, and incomplete operating instructions to the Dispatchers. The device could sense the speed of only one generator. The important quantity, so far as the power system is concerned, is the total generation at Colstrip, not the generation on one unit.

The ATM, in deciding if a condition at Colstrip is dynamic enough to cause system voltage to dip below 80%, always assumes that the generator it is monitoring is one of a pair of equally loaded generators. Thus, if the companion generator is loaded more lightly, or worse, off-line, the limits programmed into the ATM are conservative. This is, the unit might be tripped when not justified. However, so long as the ATM was connected to the most heavily loaded generator needed trips would always exist.

The Dispatchers had been told to keep Colstrip Unit #2 (which the ATM monitored) at least as heavily loaded than Colstrip Unit #1 when depending on the ATM for stability protection, but had not been told about the increasing sensitivity as the imbalance in generation increased.

The results were that the Dispatchers were given the plot on the next page, and a decision was made to modify the ATM to take information from both generators during the next year.

The fact that Colstrip Unit #2 always had to be at least as heavily loaded as Colstrip Unit #1 to guarantee necessary trips had proven constraining. A partial solution of modifying the device so it could process speed information from either generator was proposed. A simple switching scheme was installed to allow the device to take input from (and send output to) either generator.

The operating rule (Colstrip Unit #2 must always be at least as heavily loaded as Colstrip Unit #1 when depending on ATM protection) had been constraining because it is necessary to deslag the boilers every second day. Thermal efficiency is improved as input steam temperature is increased. The temperature is limited, in part, by the capability of the boiler tubes. These tubes, which are constructed of a high temperature alloy of stainless steel, produce a coating of slag when subjected to high temperatures. The slag protects the tubes from the extreme temperature. However, as the coating of slag gets thicker, it causes a reduction in steam temperature. After about 48 hours of operation, the boiler temperature must be decreased to allow the slag to slough off the tubes. The fact that the early ATM could take input only from Colstrip Unit #2, and that Colstrip Unit #2 had to be at least as heavily loaded as Colstrip Unit #1 to guarantee ATM protection dictated that Colstrip Unit #1 generation

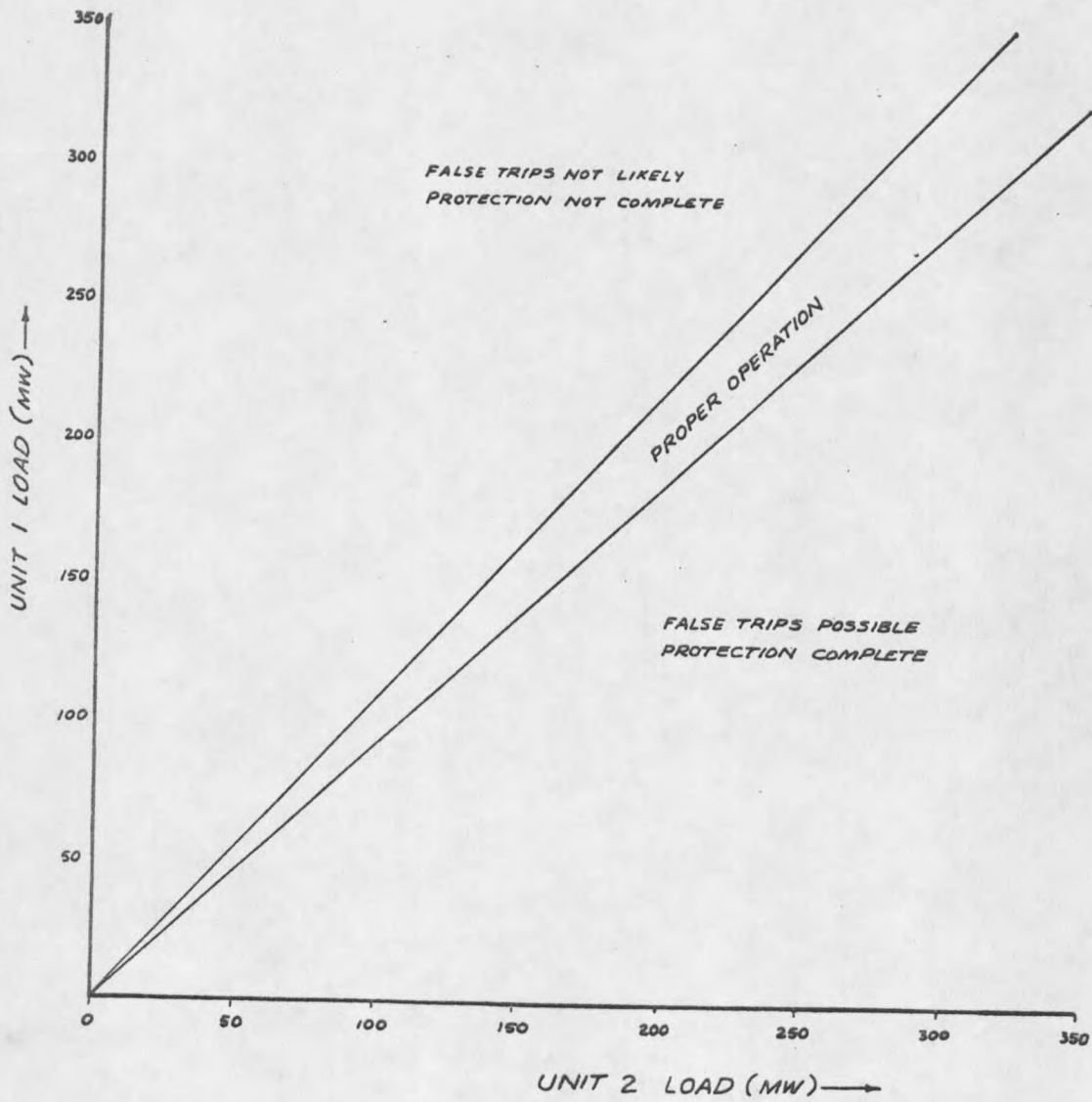


Figure 6.1: ATM Operation

had to be reduced whenever Colstrip Unit #2 generation was reduced to deslag. The operation costs about 400 MWh (\$10,800) every other night.

During the same period, concern about the shape of the ATM trip characteristic (plot below) was expressed.

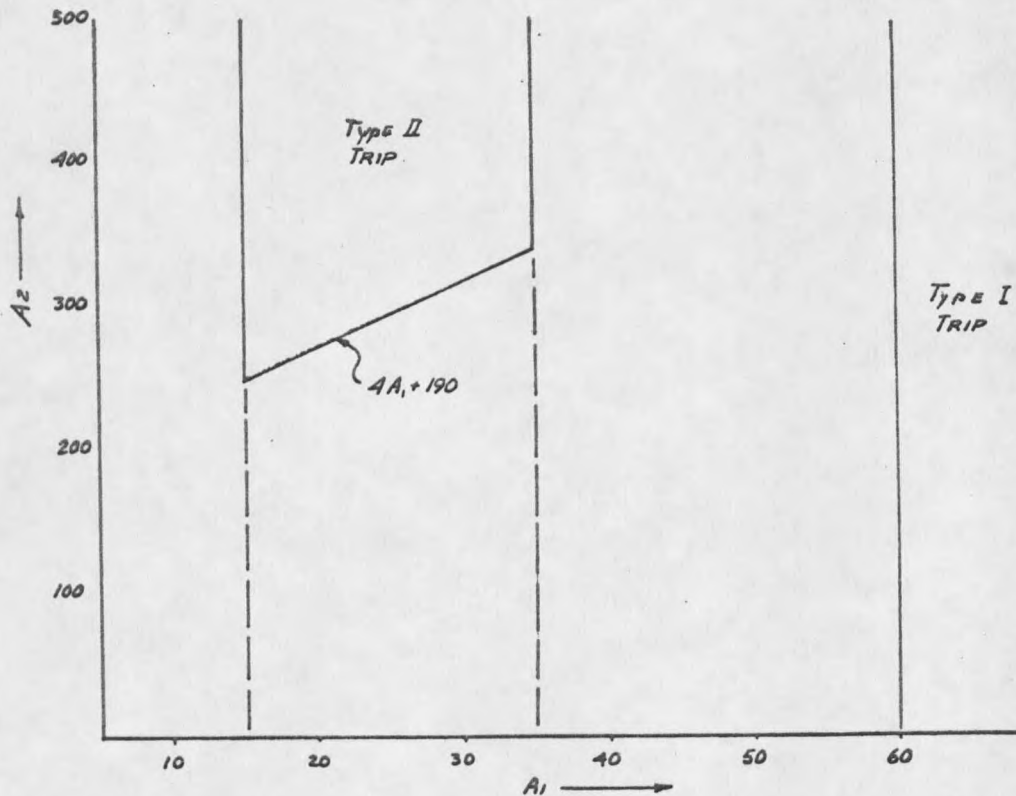


Figure 6.2: Trip Characteristic

The discontinuity at $A_1=35$ was of concern. Discontinuities of that nature should not exist in the real world. It is, after all, a continuous universe.

The discontinuity had originally been explained in the following manner. Faults at either Colstrip or Broadview cause a greater acceleration than faults on the lines between the two stations, because faults on the busses disable all the lines terminating on the busses. A type one trip is required for a severe fault near the Broadview bus because the resultant voltage swing dips below 80% too rapidly after the Broadview to Great Falls line is tripped to clear the fault to allow type two sensing. A severe fault was defined to be a double line-to-ground or three-phase fault occurring when the net Colstrip generation was above 540 MW. Severe faults on lines between Colstrip and Broadview would cause substantial though smaller rates of acceleration. Fault clearance, however, would result in the loss of one of the lines between Colstrip and Broadview. The loss of a Colstrip to Broadview line had proven to result in a much stronger system than the loss of the Broadview to Great Falls line.

The next most severe fault (line-to-line at Colstrip) did not cause the voltage to dip below 80% anywhere in the system because of the strength of the system remaining after the fault was cleared. A line-to-line fault at Broadview would, however, require ATM action. The loss of the Broadview to Great Falls circuit was simply too much to survive. Since faults

between Colstrip and Broadview could produce the same initial rate of acceleration, type two event logic had been produced to evaluate the strength of the system remaining after the fault was cleared. The dead-band between the logic for type two events, and the logic for type one events represented severe faults between Colstrip and Broadview. Since such faults would produce substantial values of A_1 , although fault clearance would have to result in a strong remainder power system, they are termed: "Too severe to worry about". Hence, the dead-band should exist.

Further reflection revealed that severe faults west of Broadview (on the Broadview to Great Falls line) could produce values of A_1 in the dead-band, yet would certainly cause instability. A whole class of events had been ignored.

Stability simulations were conducted to define the missing characteristic. However, when they were complete, a severe discontinuity existed between the old type two characteristic and the new section. The original characteristic had been defined with study results from the WSCC Program while the new sections had been defined with study results from the PTI Program. The PTI Program contains more refined generator models. Consequentially, a large number of stability simulations were conducted to redefine the entire characteristic with the PTI Program. The new trip characteristic is shown on the following page.

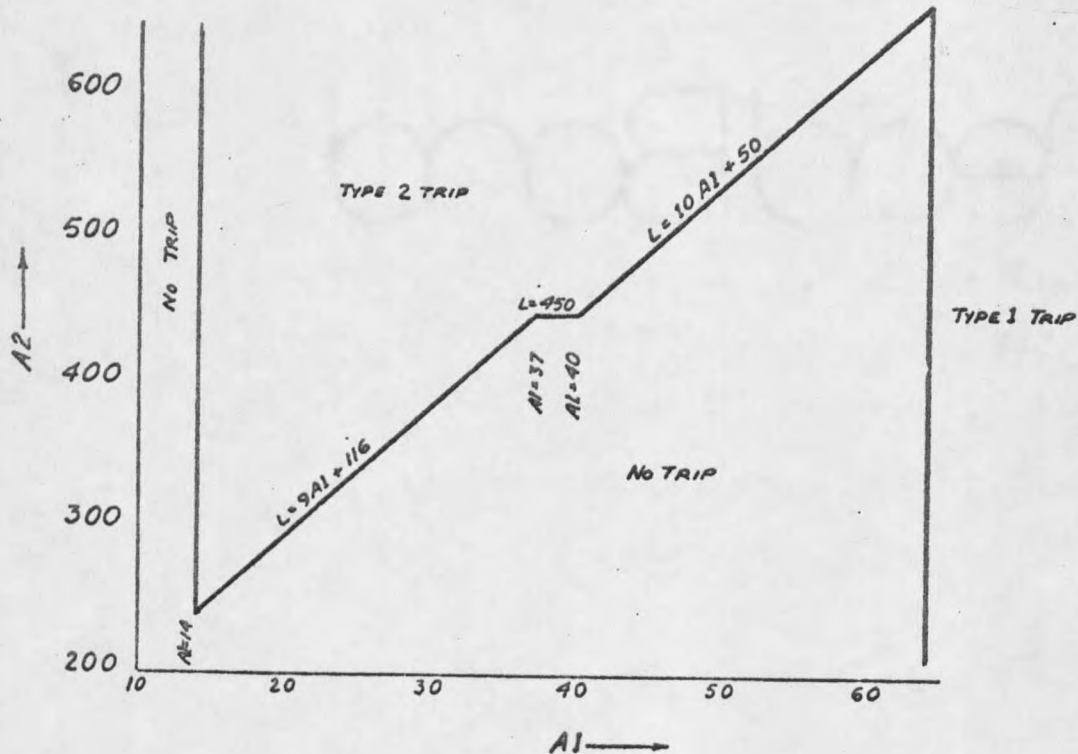


Figure 6.3: New Trip Characteristic

The study results were ready before the switching scheme was activated. Consequentially, the software changes were made at the same time that the switching scheme was installed.

Event number five occurred several months later. The Northwest to Southwest a-c intertie was out, and the Dworshak to Hot Springs 500 kV line was taken out for maintenance. The Pacific Northwest was left severely weakened with no 500 kV interties. A relay technician at the Grand Coulee generating station inadvertently cause the tripping of 800

MW of generation. The resultant instability cascaded throughout the Western system. The 230 kV ties from Anaconda to Hot Springs, and Ovando to Hot Springs opened since they were (in this case) the swing nodes. The ATM sensed the disturbance and tripped Colstrip Unit #1 thus preventing further loss of transmission, and stabilizing the Montana system.

A similar event that had taken place on July 2 of the previous year (before the ATM was in service) had shattered the Montana system, caused a state-wide black-out, and caused both Colstrip generators to be out-of-service for about 12 hours.

Simulations of the event proved the ATM should have tripped the generator. If the device had not tripped the unit, service to the entire state of Montana would have been interrupted.

Event number six followed within weeks and provided a long awaited opportunity to produce an accurate comparison simulation. A circuit switcher on the Bonneville Power Administration's capacitor bank in Anaconda failed resulting in a single line-to-ground fault that was not cleared until station differential relaying caused the switching of all the lines connected to the station seven cycles later. The ATM sensed the event and caused Colstrip Unit #1 to trip.

Since the Dispatcher had just completed the hourly report, a very accurate base power flow could be created. Also significant is the fact that the event had triggered the Anaconda oscillograph so the severity and

duration of the fault was well documented. The simulation was completed, and a plot of the expected values for A_1 and A_2 was produced.

The actual speed data from the ATM arrived several days later, and it was processed to obtain the actual values of A_1 and A_2 . The values were also plotted. The graphs below contain all four curves.

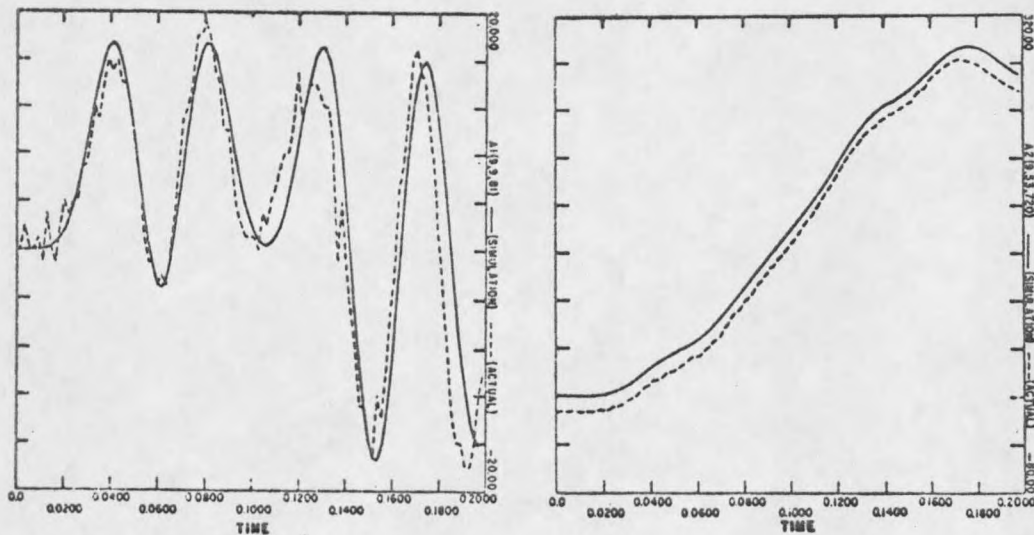


Figure 6.4: Comparison of Actual and Simulation

The difference between the first A_1 peaks is 1 count. The error could then be said to be 1 part in 16. However, the total number of counts required during the periods used to compute the value is 41,472. The overall error is therefore .002%!

The actual value of A_2 is not zero at time equals zero. This fact is because there was a slight increase in the electrical load on the generator and the governor had not yet responded to increase the input. The initial values of the actual A_2 indicate that the electrical power out of the 350 MW generator (plus loss) was 18 kW more than the mechanical power driving the generator! The significant A_2 value for ATM computations is the peak. As can be seen from the plot, the actual value is very close to the predicted value.

The next two pages contain the entire operating log for the device.

.....ATM LOG OF EVENTS.....

EVENT DATE	TRIP NECESSARY?	PERFORMANCE ACCEPTABLE?	EVENT CAUSE
08-05-79	YES	YES	LIGHTNING ARRESTER IN CS YARD BLEW UP. (TRIP COIL BAD ORDER.)
08-19-79	NO	NO	BROADVIEW-GREAT FALLS RECLOSED.
09-05-79	NO	NO	OTHER UNIT TRIPPED.
10-08-79	YES	YES	BILLINGS 100KV FLT-HUNG BREAKER.
10-23-79	NO	NO	LINE CLOSURE IN WYOMING AND ATM IN SERVICE WHEN ONLY ONE UNIT WAS ON LINE. (OVERSENSITIVE)
11-27-79	YES	YES	COULEE UNIT FAST RUN-BACK.
12-28-79	NO	YES	STATION FLT AT ANACONDA (BP4).
07-27-80	YES	YES	FLT ON BRIDGER-BORAH.
09-24-80	YES(?)	NO	PHASE SHIFTER INSTALLATION, BAD VOTE--PROGRAM MESSED UP. DYNAMIC-NOT TRANSIENT-INSTABILITY.
10-15-80	?	NO	UNKNOWN EVENT, BUT SAME PROBLEM AS ABOVE. --BAD VOTE.
11-18-80	YES	YES	BRIDGER TO GOSHEN FAULT NEAR GOSHEN WITH BREAKER FAILURE @ GOSHEN WITH 1600 GENERATION @ BRIDGER AND 1350 ON 345KV LINES WEST OF BRIDGER. (DEVICE REMOVED FROM TEST.)
12-12-80	YES	YES	LOSS OF HOT SPRINGS STATION ON DIFFERENTIAL.
01-09-81	YES	YES	CASCADING INSTABILITY INITIATED IN UTAH. UTAH, WYO, AND IDAHO BLACK; MONTANA LIGHT.
01-30-81	NO	NO	BV-GF LINE CLEARED ON RELAYING ERROR. BAD VOTE ON RECLOSE. BONA FIDE BAD VOTE.
01-30-81(A)	NO	NO	RELAYING ERROR CLEARED BV-GF. UNIT TRIP ON RECLOSURE. BACKED INTO SAME PROBLEM AS 08-19-79, AND 09-05-79. LOGIC MODIFIED TO HANDLE PROBLEM AND DYNAMIC INSTABILITY. (TEST PERIOD STARTED AGAIN.)

Figure 6.5: Page 1 - Log of Events

2-23-81	YES	YES	LOSS OF VERNAL-ASHLEY 138KV LINE CAUSED CASCADING INSTABILITY.
3-18-91	?	?	MYSTERY EVENT CAUSES LOST VOTE.
3-19-91	YES	YES	LOSS OF MOHAVE CAUSES B. C. HYDRO TO SEPERATE FROM NORTHWEST. NW THEN EXTREMELY DEFICIENT AND MT + WY STEAMERS TRIED TO PICK UP SLACK. VOLTAGE IN CENTER OF MT SYSTEM WENT TO NEAR ZERO.

Figure 6.6: Page 2 - Log of Events

Chapter 7

CONCLUSIONS

The ATM has proven to be an extremely valuable stability tool. It allows increased electrical production from Montana's thermal generators. The increase averages about 100 MW. The device has therefore proven to be worth \$2,700 every hour it operates. In addition, it has allowed Puget Sound Power and Light to serve customers that otherwise would have been without electricity due to severe resource shortages. It has also allowed coal generation of 1,008,000 MWh of electrical energy that would otherwise have been generated by burning oil.

The device has proven capable of the control job for which it was designed.

In addition, it has allowed validation of the models used to simulate system events. Since multi-million dollar decisions are based on the results of the simulations, it is important that they be accurate. A method has never before existed to make accurate comparisons between actual and simulated events. If the device had allowed nothing more than the validation, the development would have been worthwhile.

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APPENDIX

Two separate program packages were used to conduct the investigations described in this thesis. The first, which is the property of Western Systems Coordinating Council (WSCC) is composed of three separate batch-mode programs designed to be used to conduct power flow and transient stability studies. The package consisted (at the time of the studies described in this thesis) of a 2000 bus power flow program, a 2000 bus transient level stability program, and a plot program to allow graphical presentation of stability studies.

The second program package is the property of Power Technologies, Inc. (PTI). The package, in order to allow the user to conduct fault studies, is structured some what differently from the WSCC program. The basic power flow program is much the same except that it allows the representation of 4000 busses, and allows the user to add generator data for fault studies. The stability portion of the program plots state variables directly so magnetic tape interface and a separate plot program are not required. The package allows the representation of generators down to the subtransient level which produces a much better mathematical model. The PTI package is predominately interactive which enhances the engineer's productivity.



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Jolley, J. F.
Digitally controlled
generator tripping as
an aid to power system
stability

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