AN ABSTRACT OF THE THESIS OF

INGO PAUL THUREIN for the MASTER OF SCIENCE
(Name) (Degree)

Electrical and
in Electronics Engineering presented on May 8 1972
(Major) (Date)

Title: AUTOMATIC TIME CORRECTION FOR INTERCONNECTED POWER SYSTEM OPERATION

Abstract approved: Redacted for privacy
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The North American interconnected power systems continuously attempt to hold power system time as close to standard time as possible. All inherent problems associated with normal power system operation make this a difficult task. System time is presently allowed to deviate from standard time by up to two seconds before steps are taken to correct the time error. Present correction methods are manual, time consuming and add to existing operating problems which leads us to the conclusion that the advantages of power system interconnection impose more stringent requirements on load and frequency control. Without precise control of generation and frequency, undesired tie-line flows will result. The Tie-Line-Bias mode of control is examined in detail, with emphasis on present means of controlling system time error. A design concept for automatic system time correction is presented which if accepted by the utilities would eliminate manual initiation of frequency offset periods.

Automatic Time Correction for Interconnected Power System Operation

by

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A THESIS

submitted to

Oregon State University

in partial fulfillment of
the requirements for the
degree of

Master of Science

June 1972

APPROVED:

Redacted for privacy

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Date thesis is presented May 8 1972

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ACKNOWLEDGMENT

I wish to express my sincere and grateful appreciation to Professor John F. Engle for his assistance pertaining to this thesis and for constructive criticism in the preparation of the manuscript.

Appreciation is also extended to my associates at the Bonneville Power Administration for encouraging this work.

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AUTOMATIC TIME CORRECTION FOR INTERCONNECTED POWER SYSTEM OPERATION

I. INTRODUCTION

Scope

The power industry with all its plans to automate dispatch and scheduling functions still must develop standards and techniques to achieve automatic frequency and time-error correction. Such techniques will not only reduce time and effort required to coordinate manual time correction procedures in use today but it will also markedly improve the control of interconnected electric power systems. North American Power Systems Interconnection Committee (NAPSIC) recommendations and other standard procedures are included in the Appendices to complete the picture of current practices. A detailed needs analysis, design, and implementation plan for a synchronized frequency and time-error correction system will be presented.

Statement of Problem

Operating and controlling the interconnected power systems of the United States, Canada, and Mexico is becoming increasingly difficult because of more and heavier interconnections, larger single generating units and ever increasing size. More and more automation enters into the areas of generation control, stability security monitoring, and power scheduling. However, to this date the accumulated power frequency error or time error is still corrected manually. That is when the accumulated time error, as monitored by a designated utility, reaches a set limit, all interconnected systems offset frequency (60 Hz) by a predetermined amount in such a direction that time error will be reduced to zero. This offset period is initiated and terminated manually by a series of telephone calls. This method is not only slow and tedious but it also allows time errors to accumulate to up to plus or minus two seconds, the presently agreed to limit. Such a cumbersome method also contributes to the difficulty in controlling inadvertant power interchange between connected utilities.

Statement of Results

Today's power system time correction methods are reviewed in detail. Problems associated with interconnected power system operation due to today's methods are enumerated. These problems firmly establish the need for precise and more convenient methods for frequency and system time correction. The feasibility of implementing universal automatic time correction procedures is shown, and two conceptial designs for immediate implementation are proposed.

Discussion of Results

It is obvious that implementing an automatic scheme for power system time correction will not eliminate all problems of Tie-Line-Bias Control. Scheduling and telemetering problems will continue to plague the power system dispatcher. However, automating time correction procedures will not only reduce the work-load of the dispatcher but will also provide necessary experience with a tool that will be used simultaneously by all controlling areas. This would pave the way for further improving the control of bulk power transfers between interconnected systems by initiating system-wide automatic correction for inadvertent interchange, a logical step to follow automatic time correction.

Definition of Terms

POWER SYSTEM - A group of one or more generating sources and/or connecting transmission lines operated under common management or supervision to supply load.

INTERCONNECTED SYSTEM - Two or more individual power systems normally operating with connecting tie lines.

CONTROL AREA - A power system, a part of a system, or a combination of systems to which a common generation control scheme is applied.

TIE LINE - A transmission line connecting two or more power systems.

NET INTERCHANGE (Power and/or Energy) - The algebraic sum of the powers and/or energies on the area tie lines of a control area. Positive net interchange due to excess generation is out of the area.

NET INTERCHANGE DEVIATION - For a control area, the net interchange minus the scheduled net interchange.

SYSTEM FREQUENCY - The actual frequency of the power-system alternating voltage.

STANDARD FREQUENCY - A precise frequency intended to be used for a frequency reference.

SCHEDULED FREQUENCY - That frequency which a power system or an interconnected system attempts to maintain.

FREQUENCY DEVIATION - For a power system, system frequency minus the scheduled frequency.

SCHEDULED FREQUENCY OFFSET - The amount, usually expressed in hundredths of a cycle per second, by which the frequency schedule is changed from rated frequency in order to correct a previously accumulated time deviation.

FREQUENCY BIAS - An offset in the scheduled net interchange power of a control area that varies in proportion to the frequency deviation. This offset is in a direction to assist in restoring the frequency to schedule.

FREQUENCY BIAS SETTING - A factor with negative sign that is multiplied by the frequency deviation to yield the frequency bias for a control area.

TIME ERROR - For a power system, the integrated or accumulated difference between system frequency and rated frequency divided by the rated frequency.

TIME BIAS - An offset in the scheduled net interchange power of a control area that varies in proportion to the time deviation. This offset is in a direction to assist in restoring the time deviation to zero.

TIME BIAS SETTING - A factor with negative sign that is multiplied by the time deviation to yield the time bias for a control area.

AREA CONTROL ERROR - The frequency deviation of an isolated power system consisting of a single control area is the area control error. The area control error of a control area on an interconnected system is the net interchange minus the biased scheduled net interchange.

AREA LOAD-FREQUENCY CHARACTERISTIC - For a control area, the change in total area load that results from a change in system frequency.

AREA FREQUENCY-RESPONSE CHARACTERISTIC - For a control area, the sum of the change in total area generation caused by governor action and the change in total area load, both of which result from a sudden change in system frequency, in the absence of automatic control action.

STATION CONTROL ERROR - The station generation minus the assigned station generation.

INADVERTENT INTERCHANGE - For a control area, the time integral of the net interchange minus the time integral of the scheduled net interchange.

POWER CONTROL CENTER - The location where the area control error of a control area is computed for the purpose of controlling area generation.

SPEED-GOVERNING SYSTEM - The speed governor, the speed-control mechanism and the governor-controlled valves.

SPEED GOVERNOR - Those elements which are directly responsive to speed and which position or influence the action of other elements of the speed-governing system.

CONSTANT FREQUENCY CONTROL - For a power system, a mode of operation under load-frequency control in which the area control error is the frequency deviation.

HOLDING FREQUENCY - A condition of operating a generator or station to maintain substantially constant frequency irrespective of variations in load. A plant so operated is said to be regulating frequency.

CONSTANT NET INTERCHANGE CONTROL - For a power system, a mode of operation under load-frequency control in which the area control error is determined by the net interchange deviation.

BASE LOAD CONTROL - For an electric generating unit or station, a mode of operation in which the unit or station generation is held constant.

TIE-LINE BIAS CONTROL - For a control area, a mode of operation under load-frequency control in which the area control error is determined by the net interchange minus the biased scheduled net interchange.

TIE LINE BIAS REGULATORS - A controller that recognizes the location of load changes and automatically shifts the tie line schedule with changes in frequency.

PERMISSIVE CONTROL - Such a control system sends only Raise or Lower signals to the controlled plants, and blocks these signals if they do not contribute to the correction of an area control error.

MANDATORY CONTROL - In a command control system, any deviation from scheduled generation is immediately corrected, regardless of the existence or direction of a system deviation.

AUTOMATIC DISPATCHING SYSTEM - A controlling means for maintaining the area control error or station control error at zero by automatically loading generating sources, and it also may include facilities to load the sources in accordance with a predetermined loading criterion.

II. ANALYSIS OF FREQUENCY AND TIME ERROR CORRECTION

History of Power System Control

As power systems grew in size and complexity, control techniques had to change. The prime mover governor invented by James Watt, which matched machine output to load requirements was the first in a long list of developments. This list includes introduction of speed droop, to allow the operation of generators in parallel, supplementary frequency control, remote regulation, base load control and permissive or mandatory tie line bias control. In the present context power system control does not refer to the automatic techniques developed strictly for system security, such as, steady state and transient stability control which after a disturbance will return the system to a stable operating point. While system security is certainly considered to be the most important aspect of quality of service, it must be remembered that controls play an equally important role in frequency and voltage variations.

Today all prime movers are equipped with speed governors. The governors do not attempt by themselves to hold absolutely constant speed; instead they are designed to drop speed (system frequency) as the load increases. This speed regulation or speed droop is the difference between full-load and no-load speed and it is usually expressed as a percentage of full load speed. This speed regulation is necessary when two or more generators operate in parallel to assure stable load division between them. For the past 20 years, governors had a speed regulation of about five to six percent. Figure 1 shows a graph of frequency vs. load for this condition. This governor action as shown adjusts machine output so that the total generation is again matched to the load; but the system frequency is still either high or low. This describes the steady state speed regulation or speed droop, which is defined as the percent speed (frequency) change of the governed generator for a 100% change in load. Again since generation is always matched to load, there is no tendency for system frequency to change even though there is a deviation from 60 Hz. Supplementary frequency control equipment is needed to add power temporarily if frequency is low. This is called accelerating power, and is performed by changing the governor speed-changer position at the controlled machines. Conversely, applying decelerating power means the speed-changer position is adjusted to undergenerate, if frequency is high.

Numerous control methods have been proposed and tried and one of specific interest is frequency control. Under this control method one utility in a pool was designated as the frequency-holding system. The remaining connected systems, operating under constant tie-line control matched their generation to their load, while the designated frequency holding utility monitored system frequency.

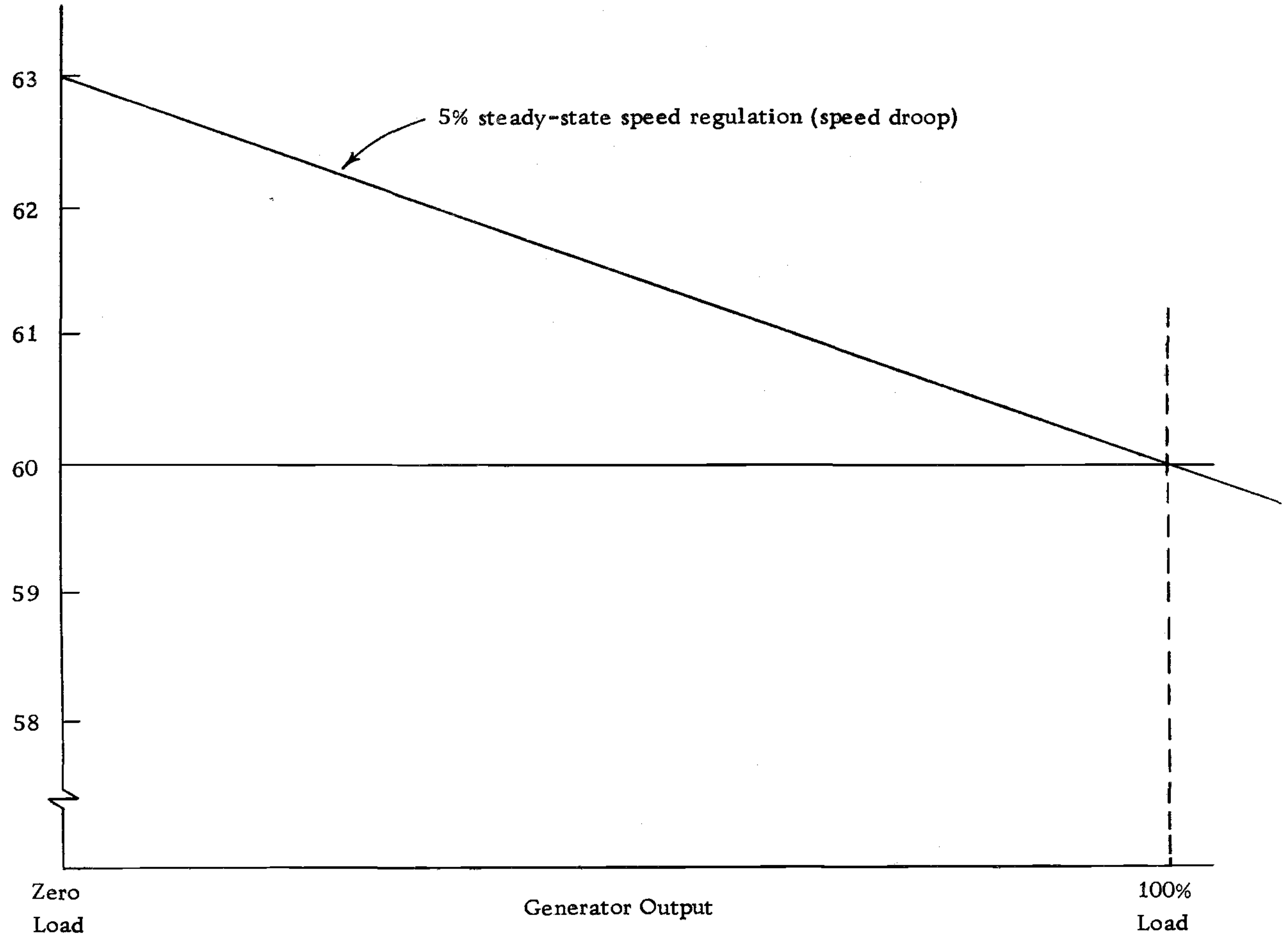

Figure 1. Steady-state speed regulation.

This utility then corrected any deviation for the whole interconnected system. Because of system size it is no longer possible for one utility to control frequency in such a manner. The risks of system outages involved would be too high. In case of large trouble in one system (loss of generation or load) interutility tie-lines could experience large power fluctuations with a possible breakup of the entire interconnected system. For this reason a closed loop, remote regulating scheme, monitoring net power interchange points, system frequency, and net interchange schedules, has been universally adopted. This control scheme is referred to as Tie-Line-Bias control.

Tie-Line-Bias Control

Tie line bias (TLB) control is the accepted control method of all interconnected power systems today; superseding all previous types of control such as constant-frequency control or constant tie-line control.

In this method each system in the interconnection operates with "tie-line-bias" control. This means that each utility area regulates its own load fluctuations and each makes its own proportionate contribution to the control of frequency; then for each control area of an interconnection the following equation applies:

$$ACE = (T_1 - T_0) - 10B(F_1 - F_0) \qquad [1]$$

where

ACE = area control error

T_1 = area net interchange, MW; power out of an area is considered positive

T_0 = area net interchange schedule, MW

F_1 = system frequency, Hz

F_0 = system scheduled frequency

B = area frequency bias, MW/0.1 Hz, considered to have a negative sign.

The TLB control equipment in each area acts to reduce its ACE to zero. When all areas accomplish this, the interconnection will automatically achieve its scheduled frequency F_0 and all net interchanges will be on schedule. Normally this works as follows in a power system: Power flow information from all of the tie lines is telemetered to the power control center. The Area Control Error (ACE) is computed as shown in Equation [1] by comparing the actually measured net interchange power against scheduled interchange and multiplying the frequency deviation by a factor B called the "area frequency bias." A block diagram of this control is given in Figure 2. The frequency bias is designated in megawatts per one-tenth hertz and is a negative quantity because the slope of the generator on governor control decreases as load increases. Frequency bias is a

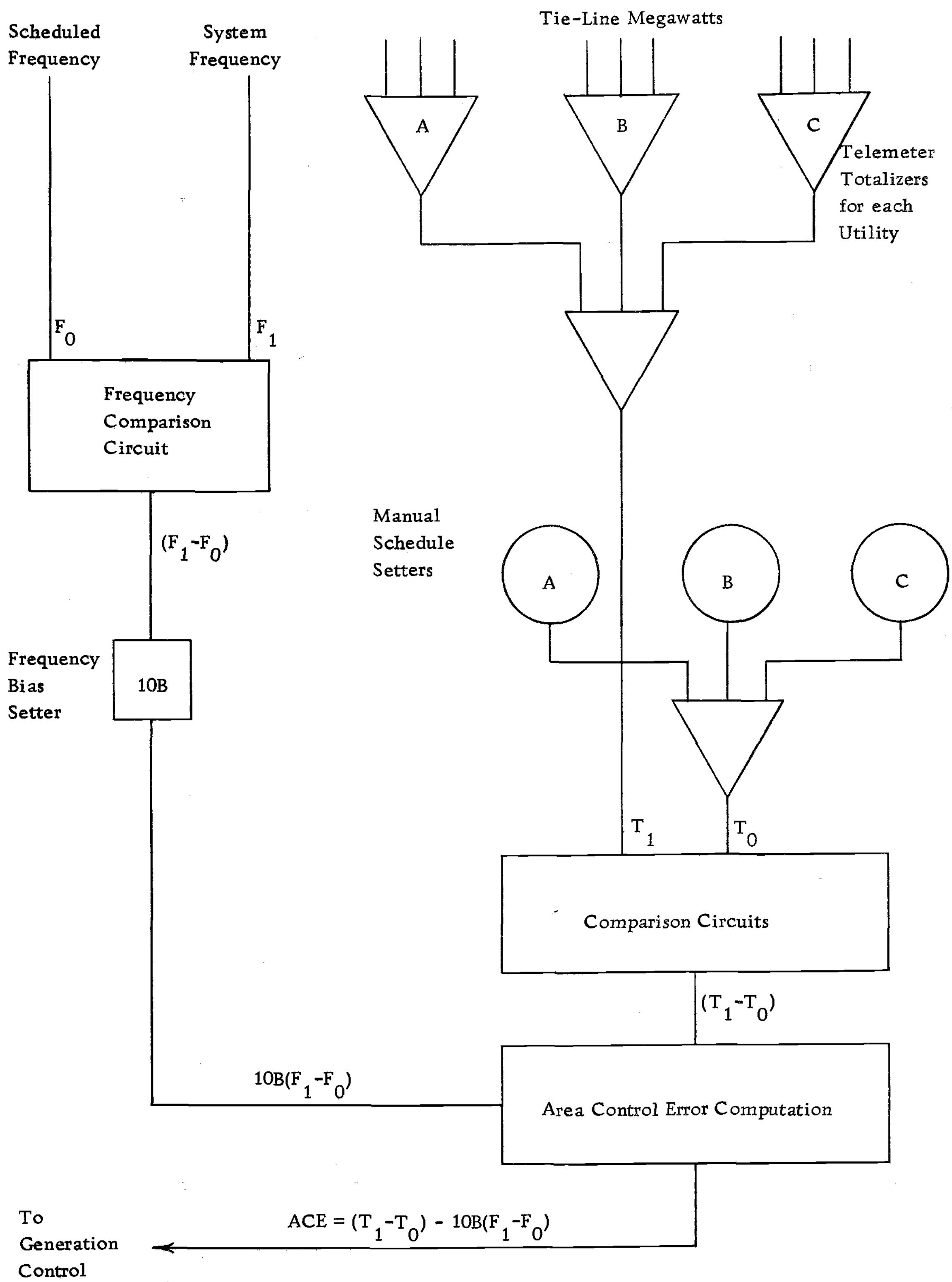

Figure 2. Tie-line bias control.

value set into a control area's automatic load control equipment to provide a quantity of power representing the responsibility of the control area to system frequency variations. The effect of this frequency bias control is to stabilize frequency in the interconnected systems and also assist other control areas in emergencies such as loss of generation or load. One can see that the frequency-bias setting must be reviewed from time to time, as the power system continuously changes and grows. For example, the addition of a large generating unit on a system would increase the inertia of the system and necessitate an increase in bias setting. If the bias is set too low, the system will not respond adequately to take its fair share of total interconnected system control during trouble conditions resulting in a control burden on other systems. A recent summary survey performed by the North American Power Systems Interconnection Committee (NAPSIC) of bias settings for the various power pools is given in Appendix A. The survey shows that the bias as a percent of peak load varies from 1.2 to 2.22 percent, which means that areas or power pools (made up of several systems) respond differently to emergencies.

From the above it can be seen that unless the bias is properly set to the natural load-frequency governing response of a system, it will put an excessive control burden on adjacent systems (inadvertent interchange will result). Current literature reveals quite a controversy with regard to what the bias setting should be (9, 16). We are interested here only in what effect the bias setting has on TLB control, i.e., reduction of inadvertent interchange and time error. NAPSIC recommendation No. 10, (17) indicates how the system frequency-response characteristic (bias) of control area shall be measured. The detailed procedure is given in Appendix B. Since a power system is constantly changing and the area frequency bias is reviewed only periodically (several months) it introduces certain inaccuracies in the control process. However, these are minor when compared to other influences in TLB. TLB attempts to control both frequency and power interchange, but permits deviations of both of them when they are opposite in sign. Figure 3 shows an actual System Time and Interchange deviation for the Bonneville Power Administration on April 7, 1971. Every controlling area keeps a similar log. From the graph it can be seen that system time deviated for this 24 hour period from -1.7 sec to +2.7. The chart further indicates other common problems associated with Tie-line-bias or normally referred to as Load Frequency Control (LFC). These are scheduling problems and telemetering troubles. Hourly schedules are set into the controller manually and naturally prone to human error. Problems can often occur in interchange telemetering equipment especially if a large number of quantities having a wide geographical range is involved. It is interesting to note that in both kinds

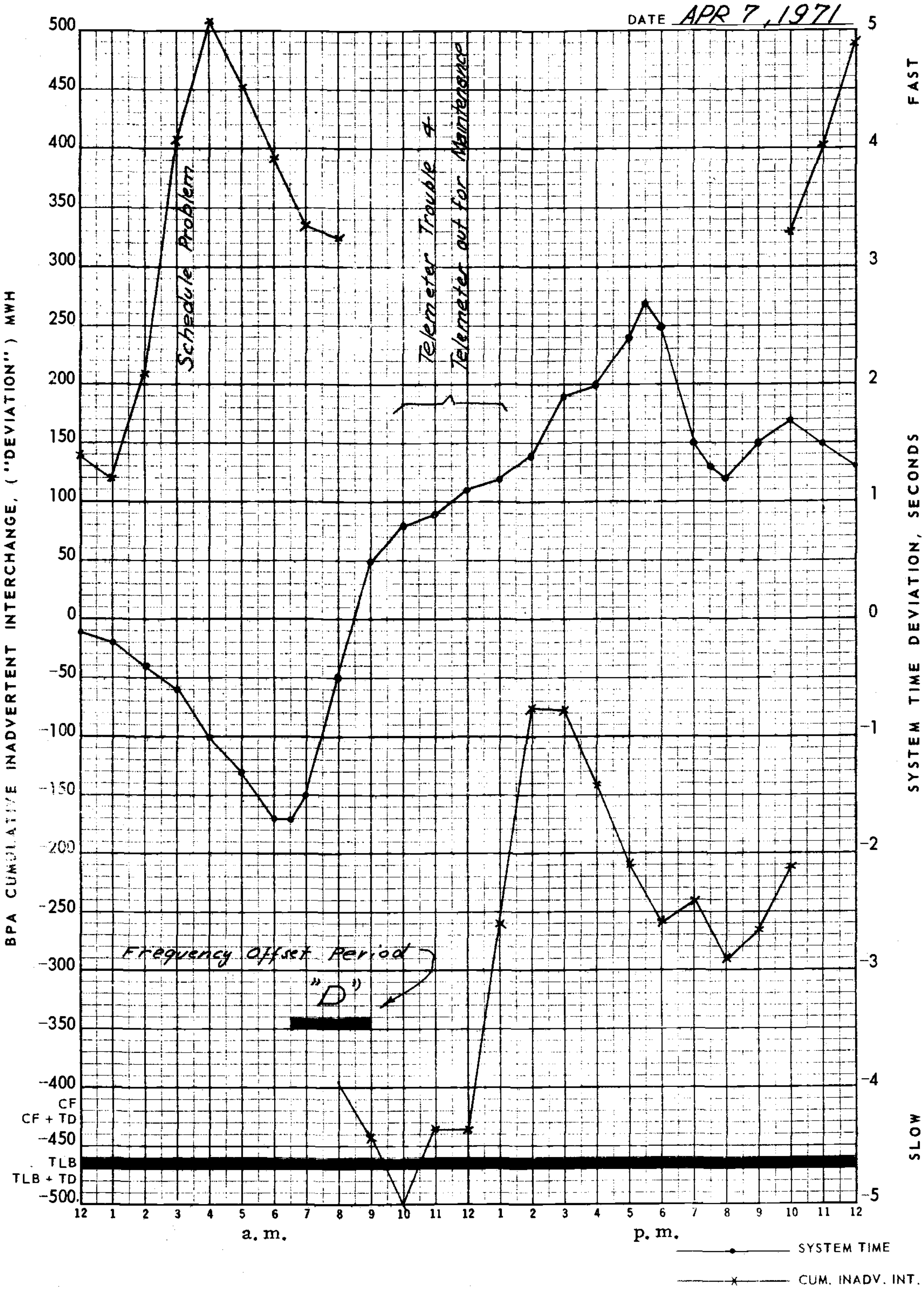

Figure 3. System time and interchange deviation graph.

of trouble the inadvertent interchange was affected more than the system time deviation.

Inadvertent Interchange Accumulations

If the algebraic sum of the interchange schedules around the interconnection is not zero, inadvertent interchange accumulates. The amount of accumulated inadvertent interchange depends in part on the design of each tie line bias control system, how many interconnections there are, and how accurate the telemetering is. (This paper does not intend to discuss all the problems of interconnected system operation; these problems are discussed in other papers ((2, 5, 6, 17).) Interchange telemetering is of particular importance where there are many interconnections. (The Bonneville Power Administration has about 150 such interconnections as shown in Figure 4.) Communication circuit problems have been numerous and individual quantities in error have sometimes not been discovered for relatively long periods of time. Due to the complexity of the interchange telemetering scheme, where the total net interchange quantity is derived from a great number of telemetered quantities, it is often difficult to determine the nature of the error.

The utilities bill each other for scheduled and not the actual power transfers, and each follows the same rules regarding deviations from schedule. For example overgeneration can be

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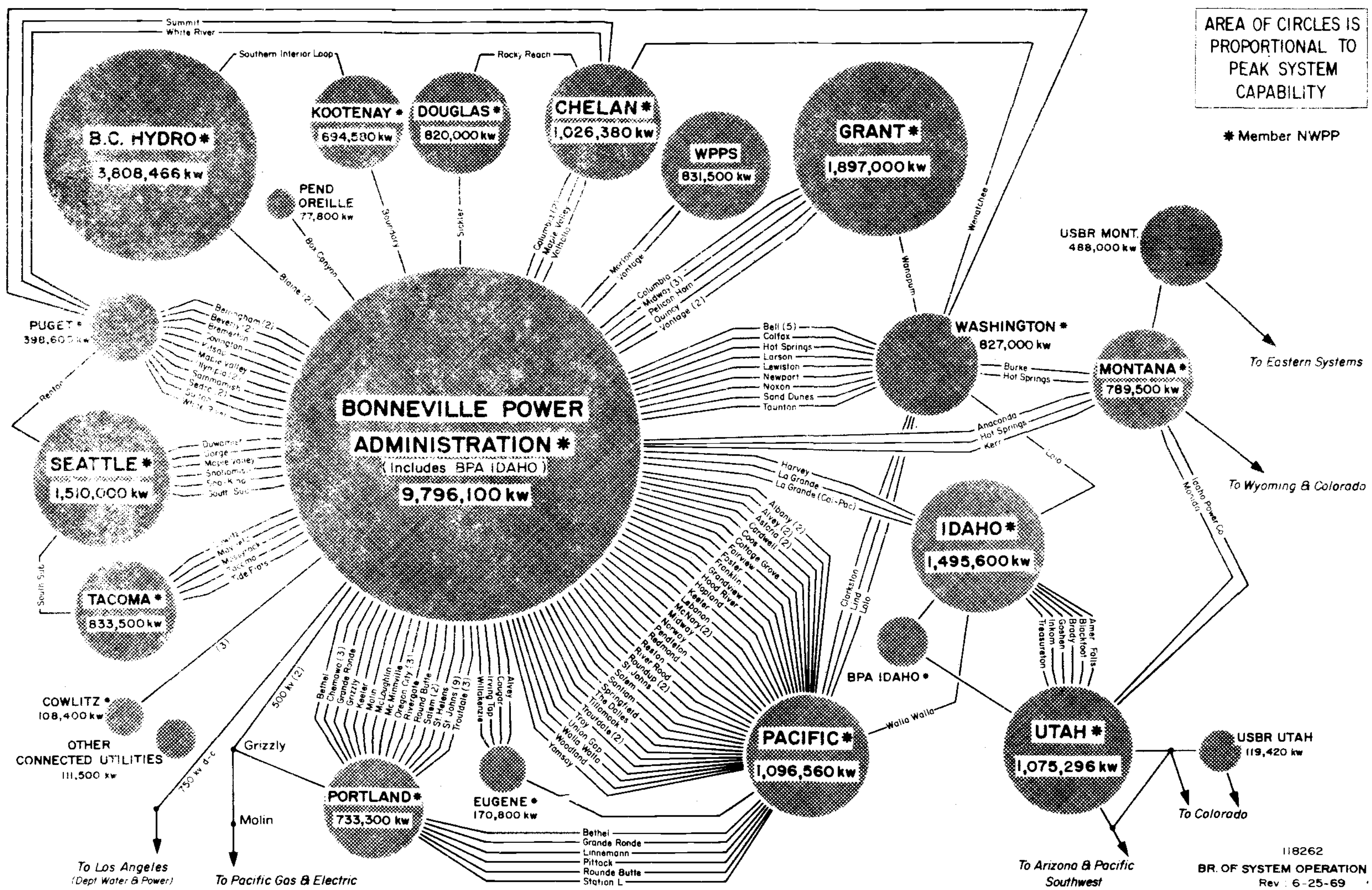

Figure 4. Northwest power pool interconnections.

accomplished whenever system time is slow and undergeneration by a utility is acceptable when system time is fast. However, contractual requirements dictate that energy supplied to a utility when it is under-generating must be repayed during a similar condition of system load. In other words, energy supplied in excess of schedule during a heavy load period must be paid back during a heavy load period. The discontinuities of the cumulative inadvertent interchange curve in Figure 3 identifies the heavy load period which runs from 8 o'clock in the morning to 10 at night.

System Time Deviation

A problem closely related to inadvertent energy accumulations is the accumulated time error. As was mentioned, commercially available LFC equipment does not provide exact control and as a result average frequency will deviate slightly from the desired frequency. Since all interconnected systems operate synchronously, any frequency error will be common to all the systems. The integrated frequency error then becomes the power system time deviation and is monitored and recorded by each utility.

Actually it turns out that system time deviation as monitored by each controlling area is not the same for each area. The reason for this is that the time and frequency standards used by each utility, against which power system frequency is compared, are not synchronized. Thus, since power system frequency is actually compared to different standards each area accumulates slightly different time errors. Figure 5 lists time standard checks as monitored by five different systems. This was accomplished by having each system record the time deviation accumulated on its equipment at exactly 2:00 a.m. Central Daylight Saving Time on the dates shown. The results are interesting, as they show differences between standards of over 200 milliseconds.

Time Error Correction Today

The North American Power Systems Interconnection Committee (NAPSIC) plays an important role in the time error correction technique used today. It should be pointed out here, that NAPSIC does not provide rigorous, technical, or scientific analyses of interconnected operations, but rather it provides guide lines and recommendations which individual systems may use in order to gain a higher degree of performance.

NAPSIC Operating Guide No. 4 entitles, 'Time Error Standard and Correction' provides detailed recommendations for time error correction. It recommends that the limit for the system time error should be plus or minus two seconds. Previously this limit was set at plus or minus three seconds, however, since control equipment performance has improved over the last years this limit was reduced

Mon.-Wed.-Fri.
2:00 AM CDT

Time in Seconds
For: September, 1971

Date	OPC Base	NSP Base	Diff.	CEC Base	Diff.	MS Base	Diff.	TVA Base	Diff.	Max. Diff. Any Two
9-3	-0.20	-0.24	-.04	-0.2	0	-0.3	-.10	-0.20	0	-.10
9-6	+0.76	+0.73	-.03	+0.7	-.06	+0.6	-.16	+0.70	-.06	-.16
9-8	+0.40	+0.41	+.01	+0.4	0	+0.3	-.10	+0.50	+.10	±.10
9-10	+1.17	+1.15	-.02	+1.2	+.03	+1.0	-.17	+1.20	+.03	-.17
9-13	+1.02	+0.99	-.03	+1.0	-.02	+0.9	-.03	+1.00	-.02	-.03
9-15	-0.29	-0.32	-.03	-0.2	+.09	-0.5	-.21	-0.30	-.01	-.21
9-17	-0.44	-0.48	-.04	-0.4	+.04	-0.5	-.06	-0.40	+.04	-.06
9-20	+1.51	+1.47	-.04	+1.5	-.01	+1.3	-.21	+1.49	-.11	-.21
9-22	+1.56	+1.52	-.04	+1.5	-.06	+1.6	+.04	+1.70	+.14	+.14
9-24	+0.35	+0.24	-.11	+0.3	-.05	--	--	+0.40	+.05	-.11
9-27	-0.84	-0.88	-.03	-0.8	+.04	-1.0	-.16	-0.80	+.04	-.16
9-29	-1.69	-1.75	-.06	-1.6	+.09	-1.7	-.01	-1.75	-.06	+.09

OPC = Ohio Power Company
NSP = Northern States Power
CEC = Commonwealth Edison Company

MS = Middle South System
TVA = Tennessee Valley Authority

+ = Fast Time
- = Slow Time

Figure 5. Time standard checks as monitored by five different systems.

to two seconds on an experimental basis. Furthermore, it is recommended that one system in each interconnected area shall be selected to monitor time error for that interconnection, and initiate time error correction notifications to designated control areas when the time error reaches the two second limit. Presently used time notification channels are shown in Appendix C. These time correction notifications, which are performed almost daily, are originated by the American Electric Power (AEP) System in Canton, Ohio, the designated time keeper for the North-American Interconnected Power Systems. The drawbacks of this manual procedure are evident. Not only is this cumbersome method used to inform other areas of impending frequency offset periods but the calibration of frequency meters and time error devices also depends on this same notification channel network. In other words, it is the duty of the designated time keeper to inform other control areas of the accumulated time error recorded on <u>its</u> instruments. The time error devices in all other control areas are then adjusted to agree with this reference. For this reason, the accumulated time error recorded by each utility (Figure 3) is adjusted periodically to agree with the time error measured by AEP.

Any time error notification consists of an alphabetic designator and the exact time at which the frequency offset period is to commence. An example of a frequency offset period is shown in Figure

3, designated by "D." At the agreed upon time every participating control area will offset its scheduled 60 Hz by 0.02 Hz. This offset is limited to ±0.02 Hz, due to changes in load and voltage with frequency. Normally system frequency is kept within plus or minus 0.03 Hz. A deviation of plus or minus 0.1 Hz is a signal that something is wrong somewhere in the system. After a two-second time error has been reduced to less than 0.5 seconds, or when the time error has not been reduced to 0.5 seconds in a five-hour period, the monitoring system shall initiate a notice of termination of the time correction in progress. Thus every frequency offset period or time correction period requires two series of telephone calls as outlined in Appendix C.

Another type of time error occurs when system separation occurs. Basically the same procedures as above are followed except that after reconnection the indicated time error of the previously separated area must match the time error of the agency having the time monitoring responsibility. This notification of the adjusted time error should be passed down through notification channels as soon as possible after the separated area becomes interconnected. This explains the discontinuities of the accumulated time error graph on Figure 6. This analysis would not be complete without a description of one regional automatic time error procedure being tested today. Details are given below.

Analysis of Inadvertent Interchange Accumulations Due to Frequency Scheduling Errors

All control areas must act continuously to decrease their respective ACE to zero. If the measurements used for control differ from interchange billing meters, inadvertent interchange will accumulate. Also, if the algebraic sum of the interchange schedules around the interconnection is not zero at all times, which includes periods of schedule change, inadvertent interchange will accumulate. These are important considerations but of interest here is the inadvertent interchange accumulation due to errors in the computation of frequency deviation. Theoretically, the frequency schedule set in all control areas should be identical. However, this is not presently done. Time or frequency standards used today may or may not be corrected to time signals sent out from a radio station such as WWVB. Manual and automatic frequency corrections are used today. As pointed out earlier this means that system time is compared to different frequency standards. Just what is the effect of such a frequency schedule error in an Area A assuming the the frequency schedule is 60 Hz and properly set in Area N?

For the Area N the following equation applies:

$$ACE = (T_{1_n} - T_{0_n}) - 10B_n(F_{1_n} - 60)$$

Whereas for Area A the equation becomes:

$$ACE_a = (T_{1_a} - T_{0_a}) - 10B_a(F_{1_a} - 60 - f)$$

The result is that each area now tries to regulate to a different frequency schedule. The resulting system frequency depends on two factors:

1. Magnitude of the setting error f.
2. Relative size of that area with respect to the size of the total interconnection.

If we let Y represent the ratio of the size of the area in error to the size of the total interconnection then the new steady state system frequency is given by:

$$F_1 = 60 + Y(f) \qquad [2]$$

This equation is derived in Appendix D [III]. The above equation shows that for a small Y (a small area) the corresponding effect on system frequency F_1, and time deviation is small. For example for $Y = 5\%$, $f = .001$, $Y(f) = .00005$ and the system time deviates by 3 ms per hour from standard time. For $Y = 50\%$ and the same schedule setting error as above:

$$Y(f) = .0005$$

and system time now deviates by 30 ms per hour. If many areas have errors in the same direction, the influence could be correspondingly larger. Errors in measuring system frequency have the same influence that a frequency schedule setting error has.

From actual experience on the BPA system, roughly a 10,000 MW area, system time changes quite frequently by 500 ms per hour (Figures 3 and 6). The amount attributed to the above mentioned errors cannot presently be established because no accurate statistical data is available. Getting back to the problem at hand, namely controlling to two different frequency schedules, let us determine what effect such an error has on inadvertent tie-line power flow.

From the basic modified equation:

$$ACE = (T_1 - T_0) - 10B(F_1 - 60 - f)$$

With the ACE = 0 and rewriting $T_1 - T_0 = 10B(F_1 - 60 - f)$ substituting [2] into this equation:

$$\begin{aligned} T_1 - T_0 &= 10B(60 + Yf - 60 - f) \\ &= 10Bf(Y-1) \end{aligned} \qquad [3]$$

Continuing with the above example, assuming a 200,000 MW system with a 10,000 MW area and a 2%/0.1 Hz frequency bias for the area and $f = .001$ Hz we have a 1.9 MW error. This error of course increases proportionately with Y and f. Example: A 40,000 MW area with $f = .05$ has an inadvertent tie-line flow of 320 megawatts.

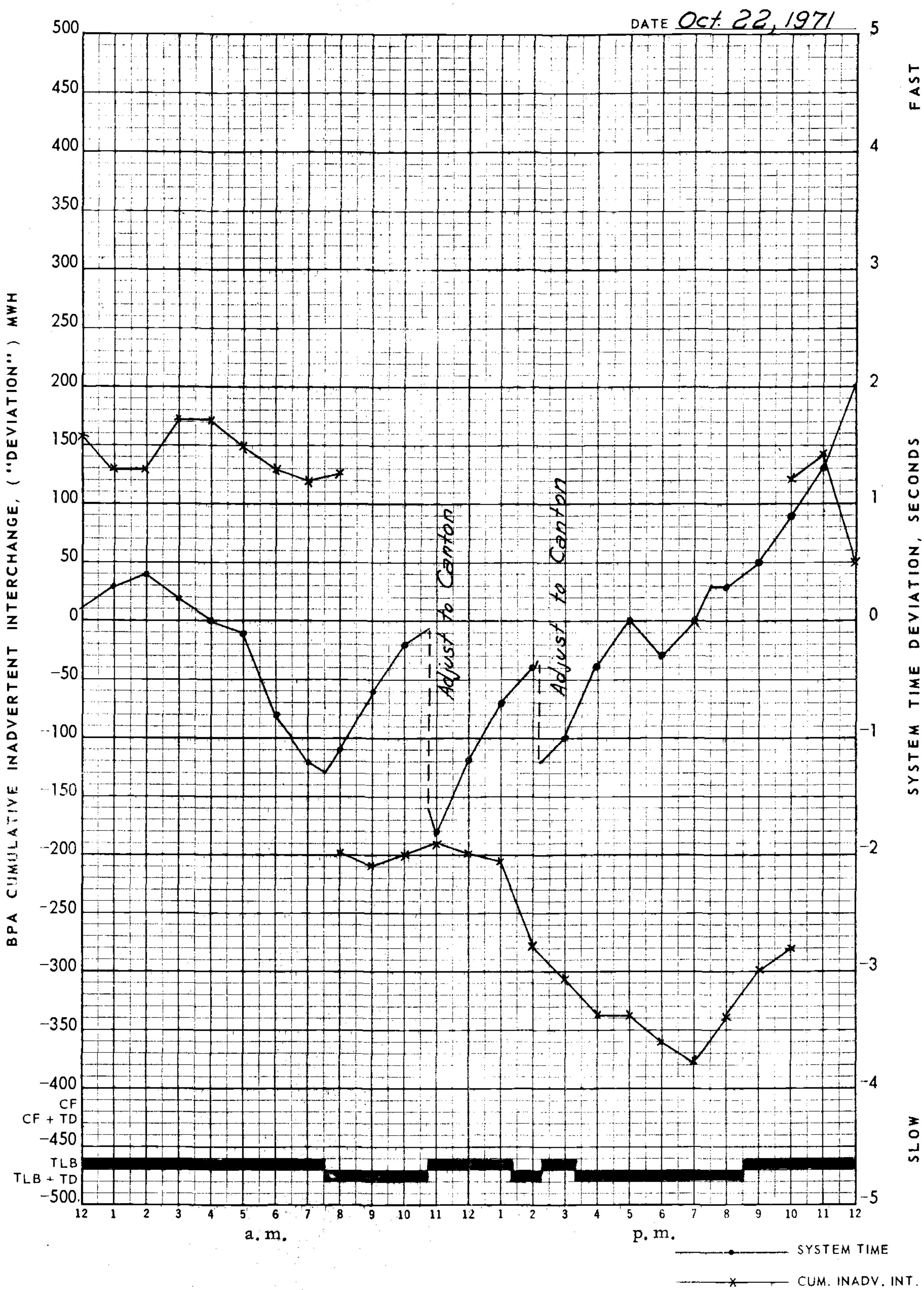

Figure 6. System time and interchange deviation graph.

If we take for the BPA system a 500 ms error as an average hourly error, this could be the result of an accumulated frequency scheduling error of only .008 Hz. Of course there are many other contributing factors such as inaccurate telemetering, and scheduling errors. Inaccurate telemetering is a particular problem in the BPA system, where the total net interchange quantity is derived from approximatly 150 telemetered quantities. If any quantity is missing due to a telemetry failure control is suspended and the power dispatcher estimates the missing quantity and restores control. Of course, any error in $T_1 - T_0$ will also cause an error in the ACE calculation which in turn has an adverse effect on system frequency, system time, and tie line interchange.

Analysis of Inadvertent Interchange Accumulation Due to a MW Scheduling Error

Let us examine just what effect a scheduling error has on system frequency. The conventional Equation [1] still applies. For area A with scheduling error t, Equation [1] becomes

$$ACE_a = (T_{1_a} - T_{0_a} - t_a) - 10B_a(F_1 - F_0)$$

Examining this special case of a t error only in area A and no other errors in the system we substitute zeroes for all f terms and all t terms except t_a in Equation [II] in Appendix D with the result:

$$F_1 = F_0 - \frac{t_a}{10B} \qquad [4]$$

What does Equation [4] mean quantitatively? For a system of 200,000 MW with a 2% per 0.1 Hz average bias (which corresponds to a total system bias of 4,000 MW), a 100 MW scheduling error in one area of the interconnection would cause a system frequency error of 0.0025 Hz, which is not particularly large.

Again assuming this to be a scheduling error, and also assuming area A to be a 10,000 MW system the load frequency control equipment would see the following (remember this to be a schedule setting error so that $T_1 - T_0 = 0$);

Then:

$$\begin{aligned} ACE_A &= -10B_a(0.0025) \\ &= -10(200)(0.0025) \\ &= -5 = -5 \text{ MW} \end{aligned}$$

The LFC equipment would interpret this to mean it is overgenerating 5 MW instead of the 100 MW it is actually overgenerating. Therefore, it is evident that a scheduling error shows up almost completely as a net interchange error for the area, and does not appreciably affect system frequency.

Effect on T_1 of Multi-Area f Errors

If we assume that all t errors are equal to zero, then from Appendix E Equation [IV_b] for area A is;

$$T_{1_a} = T_{0_a} - 10Ba(f_a - Y_a f_a - Y_b f_b - \cdots - Y_n f_n) \qquad [5]$$

The interesting point here is that if all f errors are equal, the last term of Equation [5] becomes zero. This means that no inadvertent interchange results from applying a universal frequency offset. This of course is the reason it is important that all controlling areas initiate and terminate frequency offset at exactly the same time.

Automatic Time Error Correction on a Regional Basis

On Dec. 2, 1969 the NAPSIC System Control Task Force requested that participating Western systems test their capability to control time error. All participating systems were requested to apply a linear time-error frequency offset ramp between ±1 second with a maximum frequency offset of 0.02 Hz (Figure 7).

For the Bonneville Power Administration, which has frequency bias of 180 MW/0.1 Hz the maximum accelerating or decelerating power is 36 MW for a ±1 second or larger time error. Ever since the NAPSIC request, the Western systems go to automatic time error correction when the East-West ties are open. This is a frequent

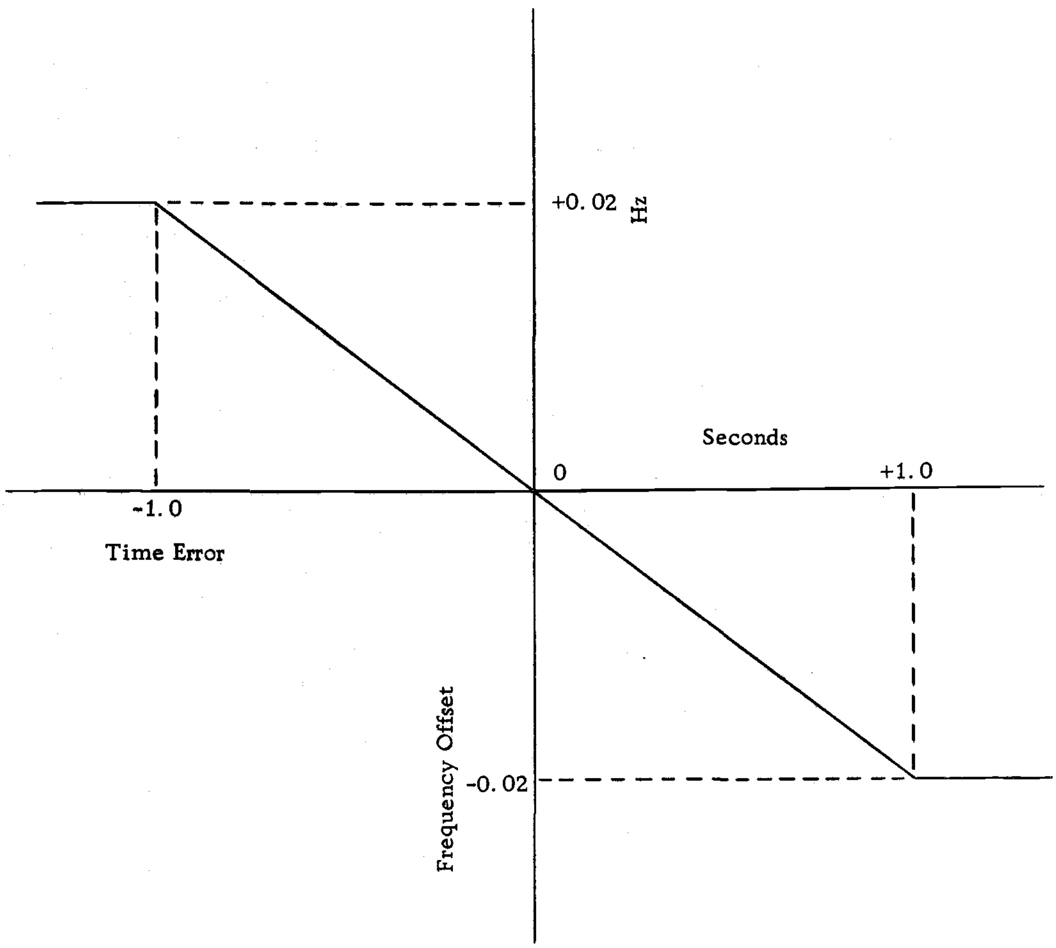

Figure 7. Time error frequency offset.

occurrence. The main cause for separation of the East-West ties, is attributed to inadvertent interchange. However, just recently it has been suggested that many of the East-West tie openings appear to occur from the development of inadvertent interchange buildup in one direction or the other during the few minutes before, to the few minuntes after an hour. This of course may be due to lack of coordination in shifting hourly schedules. In this automatic time correction scheme the participating controlling systems include Southern California Edison (SCE), Pacific Gas and Electric, and the Bonneville Power Administration. The notice to go to automatic frequency control is given by the SCE dispatcher, again using voice communications. This mode of operation is called Tie-Line-Bias and Time-Deviation (TLB + TD). Each system keeps a daily record of which mode of operation is used and when. Figure 6 shows the type of record kept by the Bonneville Power Administration. This System Time and Interchange Deviation Graph for Saturday October 22, 1971 shows several trippings of the East-West ties during a 24 hour period. These trippings are marked by breaks in the heavy line (TLB to TLB + TD) in the lower half of Figure 6. At approximately 7:30, on request from Southern California Edison, the BPA dispatcher switched his mode of control from TLB to TLB + TD. At this instant system time was slow by 1.3 seconds. The interconnected Western systems corrected for this error automatically without significantly affecting the cumulative inadvertent interchange. At approximately 10:45 the East-West ties were closed again. At that time the Western interconnected systems reached a zero time error, however, as mentioned previously, for the total interconnection there is only one national time keeper which is AEP in Canton, Ohio. During the time the East and West were separated, the East did not correct its time error since the two second limit had not been reached. Therefore, when the East-West ties were closed again the West had to adjust its time error to that of AEP, which at that instant of time was -1.6 seconds. Such readjustments occur almost daily. No accounting is presently kept of all these adjustments, which over the period of a year can amount to several minutes.

It has been suggested that before the East-West ties are closed, both interconnections first match their respective time errors; however in the interest of economics (inadvertent interchange) this idea was abandoned.

Manual Reduction of Time Error

In addition to simultaneous frequency offset by each controlling utility, to reduce time error each dispatcher also has the option of using a manual technique. However, this technique is utilized primarily to reduce inadvertent interchange accumulations, and is applied as follows: If time is slow and there is a negative accumulation of inadvertent interchange (under generation) the controller will be offset so that the system under control will overgenerate. Of course scheduling such a correction must be coordinated with another control area which has an accumulation in the opposite direction. Any amount of megawatts may be rescheduled in such a manner, provided that no other system is burdened. If however, time is slow and there is a positive accumulation the controller cannot be offset.

Summary

Todays method of correcting power system time to standard time is very cumbersome, requiring hundreds of telephone calls to initiate and terminate frequency offset periods. Furthermore, since such offset periods are now initiated if a ±2 second limit, rather than ±3 second limit, is reached, this has almost become a daily occurrence. This same notification network is also used to calibrate, periodically time deviation transducers and related equipment used by all controlling areas.

By analyzing frequency scheduling errors, it was determined that those errors not only contributed to the accumulation of system time deviation, but also added to the accumulation of inadvertent interchange. On the other hand, megawatt scheduling errors resulted almost entirely in inadvertent interchange with only a minimum affect on system time.

Manual adjustments by the power dispatchers are normally performed in conjunction with another area to reduce inadvertent interchange, any reduction in the time error is incidental.

The importance of the system frequency bias has been demonstrated. This bias which is different for each system, has been identified as a contributor to inadvertent interchange and time error, because of the difficulty in keeping it updated.

III. AUTOMATIC FREQUENCY AND TIME ERROR CORRECTION-BASIC DESIGN

Design Philosophies

The above points out the need for a better method of frequency and time correction than is presently used. But how should such an Automatic Time Correction (ATC) system be designed? The goal of such a system is to automate the following for each controlling area:

$$ACE = (T_1 - T_0) - 10B(F_1 - 60 - be)$$

where

b is system time error bias in Hz/second and

e is the system time error in seconds.

It was previously determined, that in order not to contribute to the inadvertent interchange, the time error, e, as determined in each area must be identical and the time error bias, b, as set in each area must also be the same in all areas. Thus, the term be introduced in each area's control error computation is identical in all areas, and by adding this term in all areas, universal automatic time error correction is provided without upsetting tie-line power flows.

There are two basic methods to implement automatic time error correction. In one the term be is calculated in one central location and transmitted to all controlling areas. In the other, each area individually calculates this term and applies it to the basic equation. In each case the first and foremost consideration must be given to an accurate standard which provides a continuous reference frequency. As far as the frequency standard is concerned, it has been fairly well agreed to utilize National Bureau of Standard references. So even if the term be is calculated by each area independently, time deviation $\dot{e}$ must still be obtained by comparing system frequency against a universal standard. This of course is done today to calculate the term $(F_1 - 60)$ during non-frequency offset periods. However, only very few areas automatically correct their local standards to the NBS standard. Using different references of course is not adequate for automatic time error correction.

The two methods of universal ATC are shown in block diagram form in Figures 8 and 9. Figure 8 shows the automatic time correction term be supplied from one central location to all controlling areas, whereas Figure 9 shows each controlling area computing this term independently, based only on standard time and frequency reference signals transmitted from NBS.

The disadvantage in method I is, that if a system separation occurs the transmitted be term applies only to that system which is supplying system frequency to NBS.

The disadvantage of method II is obvious. Periodic calibration would still be necessary for all frequency measuring and time

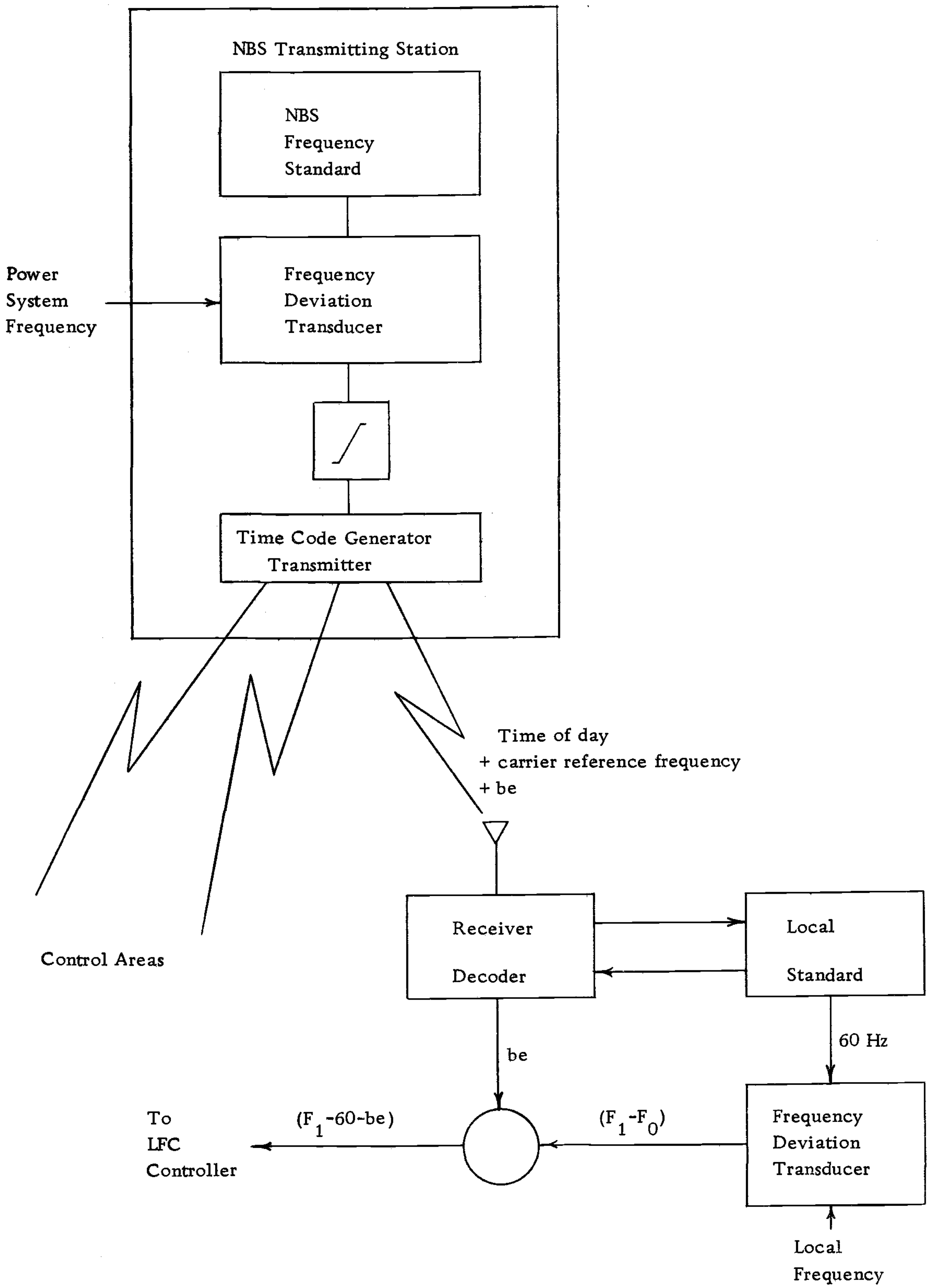

Figure 8. Automatic time correction system. Method I: Central deviation calculation.

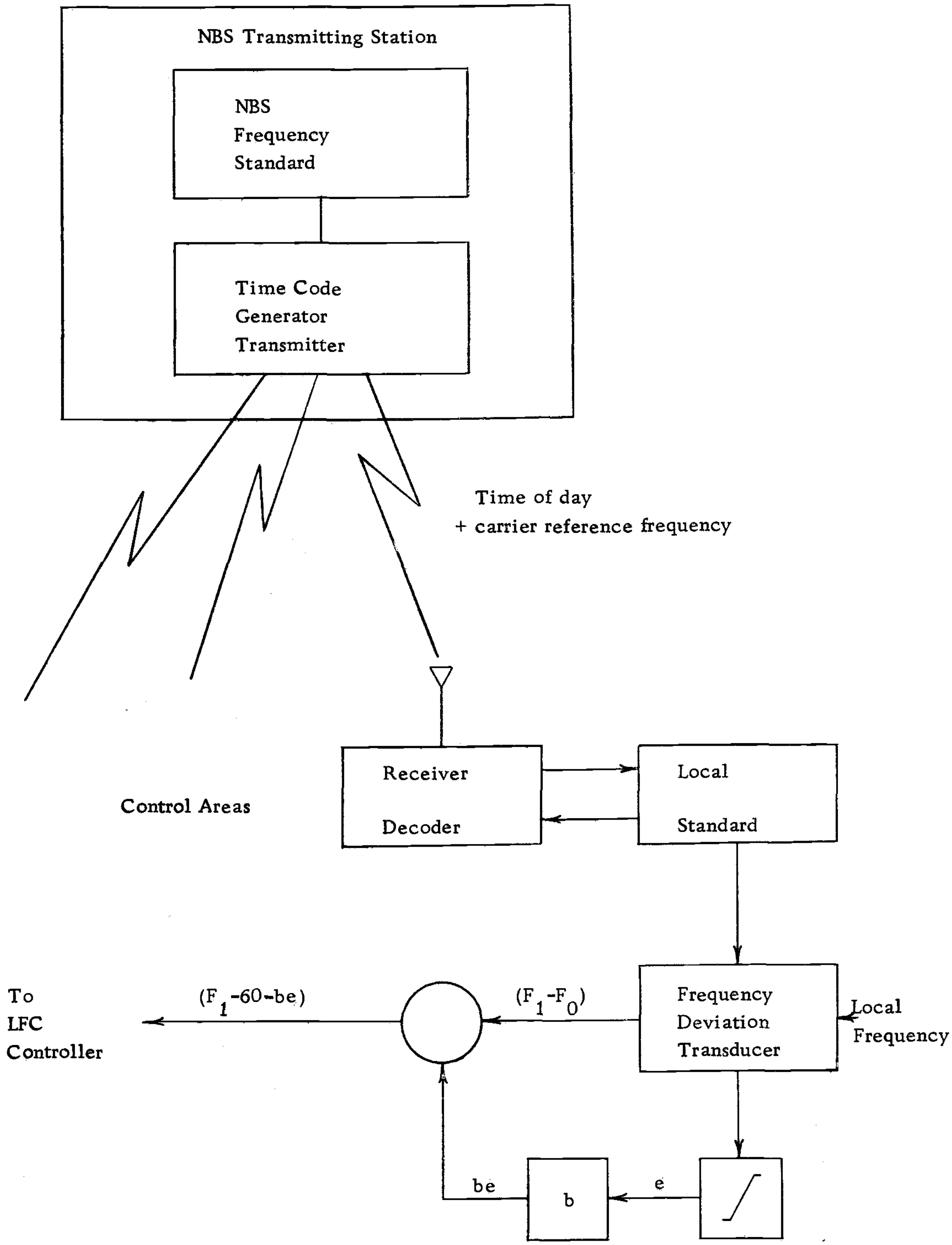

Figure 9. Automatic time correction system. Method II: Remote deviation calculation.

deviation equipment. However, from a reliability standpoint, method II has certain advantages. Loss of signal or receiver problems experienced by any one controlling area would not eliminate it from the automatic time correction scheme, i.e., this area would fall back to its local mode of control. It is for these reasons that a combination of the two methods should be utilized in order to provide a reliable universal time and frequency correction system.

Time and Frequency Standards

The heart of the ATC system is an accurate time and frequency standard which provides a continuous reference to all secondary standards. For all practical purpose we require that all power utility secondary frequency standards in the Continental U.S. are kept within 10 milliseconds of each other. It is also stipulated that initial synchronization of secondary standards by means of a portable clock is normally acceptable. However, any requirement for repeated visits is much less acceptable. Consequently, resynchronization capability, based upon signal reception alone is as valuable as initial synchronization capability itself.

The National Bureau of Standards has for a long time provided frequency and time broadcast services to the power industry and many other users. NBS Radio Stations WWV, WWVH, WWVB and WWVL provide the following services:

1. Standard Radio Frequencies
2. Standard Audio Frequencies
3. Standard Musical Pitch
4. Standard Time Intervals
5. Time Signals
6. UT2 Corrections
7. Radio Propagation forcasts
8. Geophysical alerts

The stations most often used by the utilities are WWVB and WWVL transmitting at 60 kHz and 20 kHz respectively. Both are located at Fort Collins, Colorado. WWVB provides the best service as far as time signal information is concerned. The other Fort Collins station WWV transmitting in the megahertz range transmits the time code only 10 times an hour; WWVL does not transmit time of day information. WWVB and WWVL frequencies are normally stable to better than 2 parts in 10^{11}; deviations from day to day are less than 1 part in 10^{11}.

Since WWVL does not transmit time of day information it is presently used only when WWVB is not available. (Every two weeks WWVB goes off the air for periodic maintenance.) As mentioned, the power industry has used the services of WWVB for some time. Its geographic location makes it ideal for the application. WWV, transmitting in the megahertz range with the same geographical location is less desirable, because it transmits time of day information only every 6 minutes; and until recently its carrier frequency was intentionally offset from standard frequency by a precise known amount to reduce departure between the time signals as broadcast and astronomical time. Rather than make a detailed comparison of High Frequency (HF) and Very Low Frequency (VLF) broadcasts, the adequacy of the present service must be determined for our new application. Generally, time synchronization utilizing VLF time services can probably be accomplished to no better than a few milliseconds. This is somewhat poorer than the use of HF time services where careful technique can yield time accuracies of 1 millisecond. For VLF broadcasts a quick calculation shows that a maximum delay of 10 ms can be expected due to propagation of ground-wave transmission of about 292,000 km/sec.

Even without the capability in the remote equipment to compensate for this propagation offset, it still meets the criteria of keeping all secondary standards within 10 milliseconds of the primary standard. It is therefore recommended that the power industry universally adopt the services of WWVB for ATC.

NBS Frequency Standard: Standard radio transmissions are held as nearly constant as possible with respect to the atomic frequency standards maintained and operated by the Time and Frequency Division of the National Bureau of Standards. Atomic standards have been shown to realize the ideal Cesium resonance frequency to a few parts in 10^{12}. The Cesium resonance frequency measured at 9 192 631 770 Hz is now defined as the exact value assigned to the atomic frequency standard to be used for the physical measurement of time. The present NBS standard realizes this resonance frequency to within 5 parts in 10^{12}.

WWVB Time Code: The WWVB time code is binary coded decimal (BCD), broadcast continuously and, synchronized with its 60 kHz carrier signal. As shown in Figure 10 the signal consists of 60 markers each minute, with one marker occurring during each second. Level-shift-carrier-keying is employed to generate the time code. Each marker is generated by reducing the power of the carrier by 10 dB at the beginning of the corresponding second and restoring it 0.2 second later for a binary "zero," 0.5 second later for a binary "one," and 0.8 second later for a 10 second position marker or minute reference marker. Each minute this code presents time of year information in day of the year, hour, minute, and an offset in milliseconds representing the difference between the time as broadcast and the best known estimate of universal time.

Stability of Secondary Standard: Per Section II, time standard checks have shown that any two secondary standards differ by over 200 milliseconds in only two days. This represents an accuracy of approximately 1 part in 10^5. In realizing the goal of automatic time

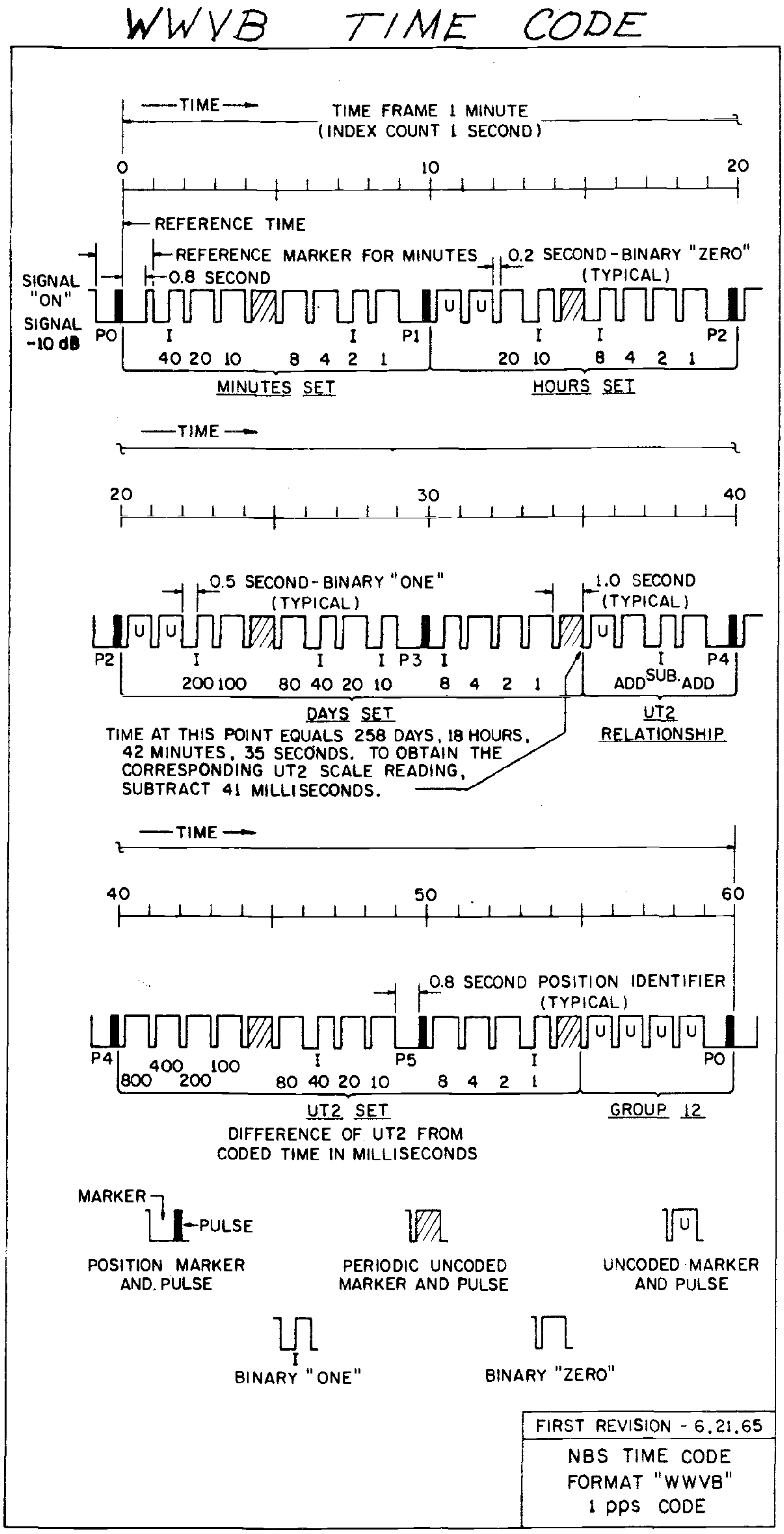

Figure 10. WWVB time code.

correction it was stipulated that any secondary standard should not deviate from the primary standard by more than ±10 milliseconds in any 24 hour period after loosing the reference signal. This requires a stability of 1 part in 8.65×10^{5} or in round figures 1×10^{-6} per day. This is certainly not a limiting requirement. Most present standards utilize piezoelectric crystal oscillators to provide a standard frequency reference. Improved performance can be obtained if the crystal and associated electronics are placed in an environmental oven. With such precautions it is possible to achieve long term stabilities of 1×10^{-10} per day. Higher stabilities can be achieved with cesium beam tubes, rubidium gas cells and hydrogen masers. However, the high cost of these standards, \$2,000 for crystal standards versus \$13,000 to \$15,000 for rubidium and cesium standards, does not warrant the additional higher stability.

Summary: Probably the most important component of the Automatic Time Correction System is the frequency standard. It has been determined that where accurate standard frequencies are required at a number of locations, it is generally advantageous to generate them in a central facility. Furthermore, it was determined that NBS station WWVB could best provide this service. Additionally each utility should utilize a local frequency standard, normally slaved to the WWVB carrier frequency, with a minimum internal long-term stability of 1×10^{-6}, which corresponds to a time deviation of less than

10 milliseconds per day.

Master Station Timing System

The proposed master station timing complex is shown in simplified block diagram form in Figure 11. In order to determine the power system frequency offset to be transmitted to each controlling area, power system frequency must be compared against a 60.000 Hz reference, frequency deviations must be integrated, and the current power system frequency offset calculated.

Frequency Counter and Frequency Deviation Unit: A frequency counter is an accumulator to which pulses are applied for a precise time period yielding a readout in events per time, which is frequency. Normally in modern frequency counters, this period of measurement is accurately provided by a crystal controlled oscillator. In this application of measuring power system frequency, a frequency derivative of the NBS frequency standard should be used as a time base. Output of this frequency digitizer should be a bus of 19 lines in BCD representing tens, units, tenth, hundredth, and thousandth of Hz. The frequency deviation unit will subtract this frequency measurement, which is taken once every second, from a fixed value of 60.0 Hz to obtain power system frequency deviation. System frequency deviation unit output should be 16 lines plus sign, in BCD, representing units, tenths, hundredths, and thousandths of hertz. Output of the frequency

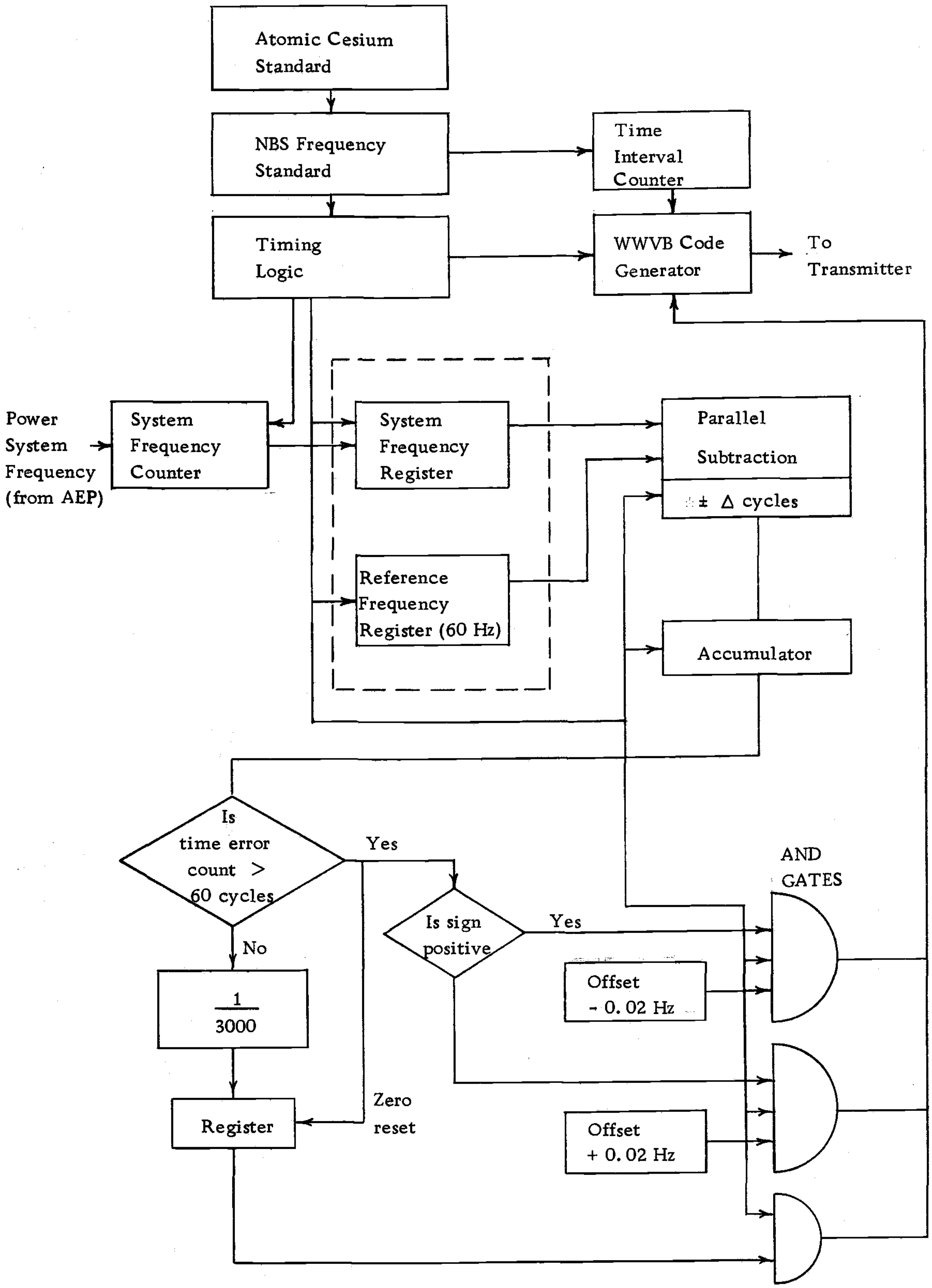

Figure 11. Master station timing system.

deviation digitizer is gated to the system time deviation accumulator, where the power system time error (e) is accumulated in cycles. (one cycle = one sixtieth of a second.)

Frequency offset transmissions: Every minute (the WWVB time frame is one minute) time deviation accumulator output is gated to a computor circuit which checks the total absolute accumulated time error in cycles against 60. As discussed in Section II, the present manual offset is limited to .02 Hz for any time error in excess of 1 sec therefore, if the time error is in excess of 1 sec (60 cycles) the frequency offset to be transmitted simultaneously to all controlling areas is .02 Hz plus or minus depending upon the sign of the time error. If the time error accumulation is less than 1 sec (60 cycles) the time error in cycles is multiplied by 1/3000 to obtain the scheduled frequency offset in hertz. It should be noticed that a linear relationship exists between the frequency offset and the time error from minus one to plus one second. In fact it is identical to the linear relationship shown in Figure 7. It is anticipated that with continuous ATC the time error accumulations will not exceed 1 second. Experience with ATC in the Western States, when the East-West ties have been open, has been encouraging. Figure 12 shows this operating mode for a 24 hour period in which system time did not deviate from zero by more than .4 seconds.

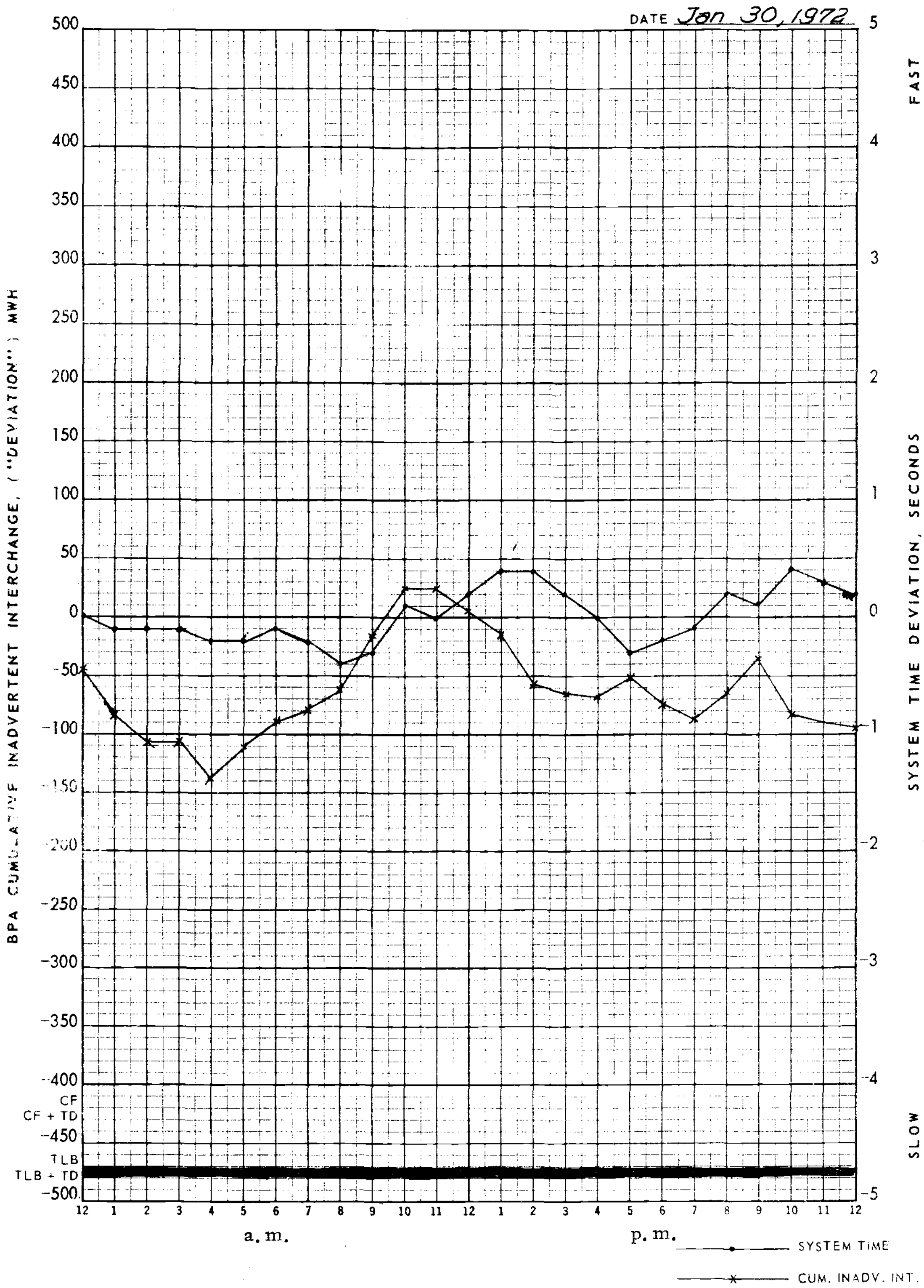

Figure 12. System time and interchange deviation graph.

Remote Station Timing System

Each controlling utility is considered a remote station. It is obvious from Section II that for successful ATC each utility must have identical timing capabilities in receiving and decoding WWVB, plus have the facilities to independently generate all ATC signals when necessary. This capability would be required during loss of NBS transmissions or when power system separation occurs. Figure 13 shows the major components needed at each remote station.

VLF Receiver: The VLF receiver must be capable of receiving the NBS 60 kHz transmissions from station WWVB, Fort Collins, Colorado. Furthermore, it must be capable of accepting a frequency input from the local frequency standard. An electronic error tracking system in the VLF receiver constantly compares the standard oscillator signal with the carrier signal frequency from WWVB. The error in the standard will be used as a feedback signal to correct any error in the local standard oscillator. A protective feature is needed which automatically returns the oscillator to unbiased operation if the VLF receiver is disabled for any reason. Furthermore, the receiver should be equipped with necessary carrier detection circuitry to prevent erroneous phase track signals due to noise, loss of NBS signal, or return of NBS signal. An indicator showing when the receiver is locked to the NBS signal, in addition to an electrical logic line (NBS

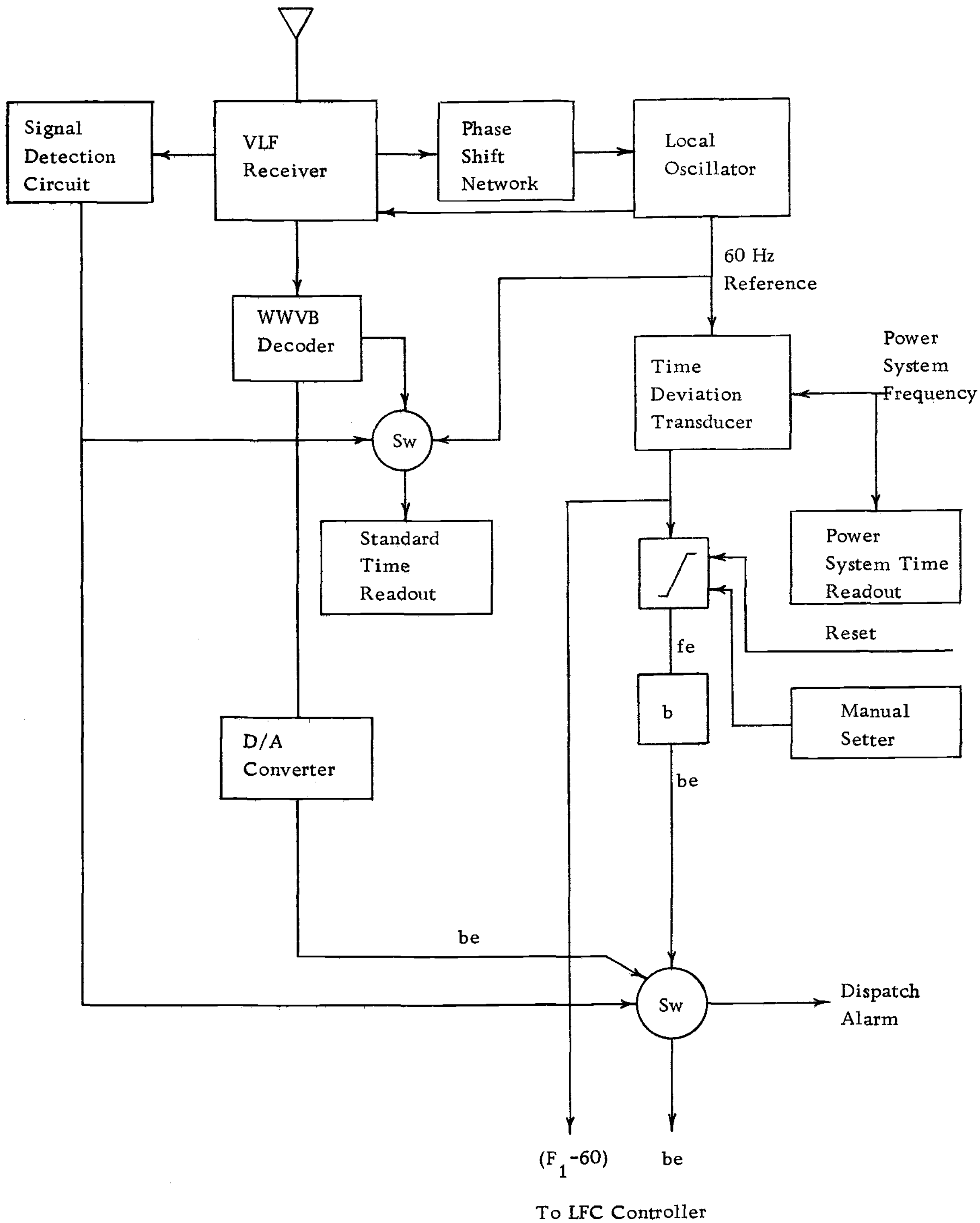

Figure 13. Remote station timing system.

carrier-on, NBS carrier-off) is also needed. This logic line, upon loss of carrier, automatically switches from remote to local time-correction bias signal.

WWVB Decoder: This unit decodes and displays the time code train modulated upon the 60 kHz carrier. The display showing days, hours, minutes and seconds is corrected every minute (one WWVB time frame) and updated every second, except during WWVB outages. The time error correction signal is updated once every minute and remains constant for this period of time. It is gated through the electronic switch directly into the LFC control loop.

Local Frequency Offset Determination: A 60 Hz reference signal is derived from the local phase locked oscillator. This reference signal is compared to the local power system frequency. This frequency deviation signal (F_1-60) is applied directly to the LFC control loop and also integrated to give the time error in cycles. The integrated time error is multiplied by b, the system time error bias, which is identical to the bias transmitted by NBS. The combined frequency offset, be, is input to the electronic switch which normally allows only the NBS transmitted signal to pass. Appropriate analog to digital or digital to analog convertors must be supplied depending upon the implementation of the LFC control loop, either in digital or analog form. Another way to determine frequency and time error is to perform these measurements digitally as was suggested for the NBS station. In fact, this would eliminate the need for a local oscillator, however since every utility still requires a display of standard time, and normally has many other (LFC unrelated) timing requirements, the analog determination is the preferred method. Switching from the remote to the locally derived frequency offset signal is done automatically upon WWVB carrier failure. Using this method no action has to be taken when system breakup occurs, since every utility is correcting by the same amount and no inadvertent interchange will result. Upon restoration of the tie-lines, there will be a discontinuity in time error in the separated systems, however, the 'adjustment' will be automatic and no voice communications are necessary. If the separation is expected to last for some time, the separated interconnection may elect to switch to local time error deviation. In either case manual resetting of time error is necessary upon restoration of the tie-lines. As long as provisions for visual or automatic comparison of the separately derived frequency offset signals are made, no periodic calibration checks are necessary.

IV. IMPLEMENTATION PLAN

The need and the feasibility of an automatic time correction system have been established in Section II and III of this paper. The most difficult task will be to implement this system on a universal basis. It must be accepted by every controlling utility or else the whole scheme fails. Aside from political problems considerable engineering will be required to successfully complete this effort. The total implementation phase should be initiated and directed by NAPSIC in cooperation with the National Bureau of Standards. It should be pointed out that automatic time correction has been a standing goal for NAPSIC. It is obvious from the foregoing that a maximum range of time error with this system cannot be predicted with a high degree of confidence, because of so many other factors involved in the Load Frequency Control process. However, from experience with the Western Systems automatic time correction procedures, during periods of isolated operation, it seems that an achievable goal for universal automatic time correction would be ±500 ms. That is, power system time should never deviate from the standard time by more than 500 milliseconds in either direction.

The cost for each utility is estimated to run approximately $20,000 for the VLF receiver, standard oscillator, WWVB decoder and time deviation equipment. This cost estimate does not include redundant equipment. For the approximately 75 controlling areas the total cost would approach 1.5 million dollars. When one considers that some major utilities spend upward of 10 million dollars for their dispatch control center facilities even this total compares favorably. The benefits derived from implementing ATC cannot be measured in dollars directly, making a cost benefit analysis impractical.

The steps towards implementation are simple, however, they require the cooperation of many utilities. To implement ATC the following must be accomplished:

1. A NAPSIC recommendation to implement and utilize ATC must be universally adopted.
2. A standard design for ATC must be accepted.
3. The National Bureau of Standards will have to redesign its facilities to disseminate frequency offset automatically to every area.
4. NAPSIC designates a trial period for ATC.
5. NAPSIC reviews all phases of ATC.
6. NAPSIC drafts and recommends final ATC procedures.
7. All utilities implement ATC.

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APPENDICES

APPENDIX A

Results of a Survey for Pool Bias Settings as of January 1, 1971

	Bias Settings January 1, 1971 MW/0.1 Hz	Estimated Peak Load for 1971, MW	Bias as Percent of 1971 Peak Load
CANUSE (1) (2)	733.0 (11.7)	45,970 (12.2)	1.60
PJM	340.0 (21.4)	28,091 (9.5)	1.20
East Central Systems	929.0 (7.9)	47,496 (8.2)	1.96
Southeast Region	952.0 (10.0)	61,675 (11.1)	1.54
North Central Region (3)	796.5 (17.3)	42,887 (15.9)	1.86
South Central System (3)	415.0 (0.5)	24,447 (-0.1)	1.70
RMPP	59.0 (5.4)	4,472 (5.9)	1.32
NWPP	574.0 (3.1)	25,865 (6.1)	2.22
Ariz. - N.M.	90.0 (6.7)	5,289 (5.3)	1.70
Cal. - Nev.	497.0 (8.5)	26,904 (9.1)	1.85
TOTAL	5,385.5 (9.7)	313,096 (9.6)	1.72

APPENDIX B

Instructions Survey of Area Frequency-Response Characteristic

1. Periodic surveys to determine the system frequency-response characteristic of generation and load of control areas shall be made. These frequency-response surveys will determine the combined adequacy of system controls with respect to the accuracy of adjustment and the response time of control telemetering, tie line load controllers including the frequency bias setting, turbine-governors and excitation systems.
2. It is recommended that at least one system frequency-response survey be conducted each month. A ten-minute period beginning with a large instantaneous loss of generation or load which does not cause a tie interruption is recommended for a response survey.
3. In determining Point A and Point B, Point A is designated as the midpoint of the frequency band immediately before the survey period starts, and Point B is designated as the mid-point of the frequency band immediately after the frequency stabilizes after the survey period starts but before any control action is initiated. Point C is the point of maximum deviation immediately after the disturbance.
4. The change in Interconnected System frequency or Control Area

frequency from Point A to Point B will always be considered positive in order not to change direction of Control Area response.

5. Frequency values (your chart) are for information only and are not used in any calculations.

REGULATION SURVEYS

Date ____________________ Time of Survey Period ____________________

Control Area ____________________

SURVEY OF AREA-RESPONSE CHARACTERISTIC

		Into My System (-)	Away From My System (+)	
Line 1.	Net Interchange of Control Area immediately before the survey period (Point A)	________	________	MW
" 2.	Net Interchange of Control Area immediately after the initial time of survey period (Point B)	________	________	MW
" 3.	Change in Net Interchange of Control Area (± Line 2) - (± Line 1)	________	________	MW
" 4.	Load (+) or generation (-) lost by Control Area causing initial deviation (leave blank if not applicable)	________	________	MW
" 5.	Control Area response (± Line 3) - (± Line 4)	________	________	MW
" 6.	Change in Interconnected System frequency from Point A to Point B (always considered +) as specified in letter of transmittal.		________	Hz
" 7.	Area Frequency-Response Characteristic of Control Area based on Interconnected System frequency (± Line 5) ÷ (Line 6 x 10)		________	MW/0. 1 Hz
" 8.	Frequency Bias setting of Control Area		________	MW/0. 1 Hz
" 9.	Control Area's net system load immediately before disturbance		________	MW

" 10. Frequency Values (Your chart):

Point A ________ Hz

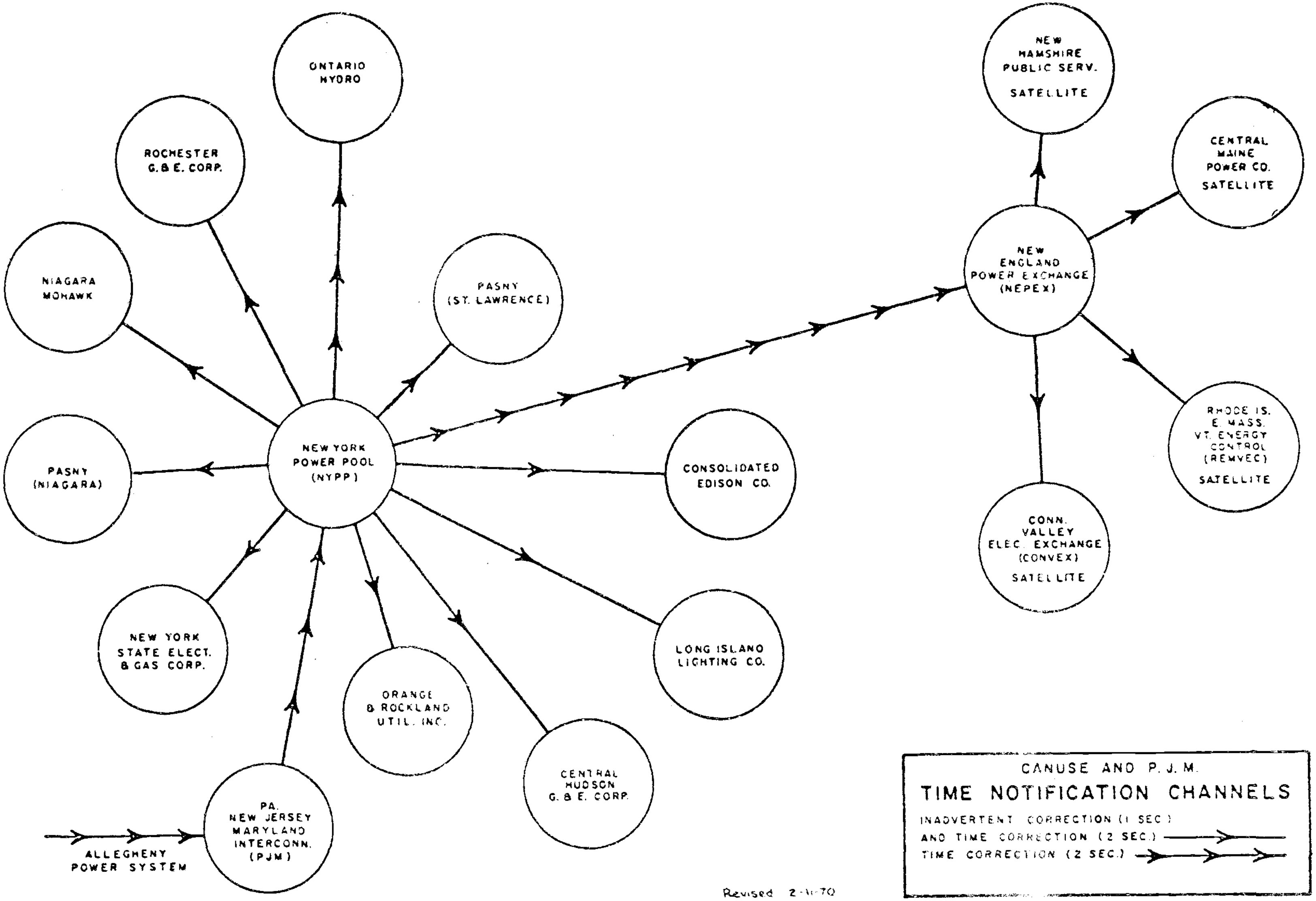
Point B ________ Hz

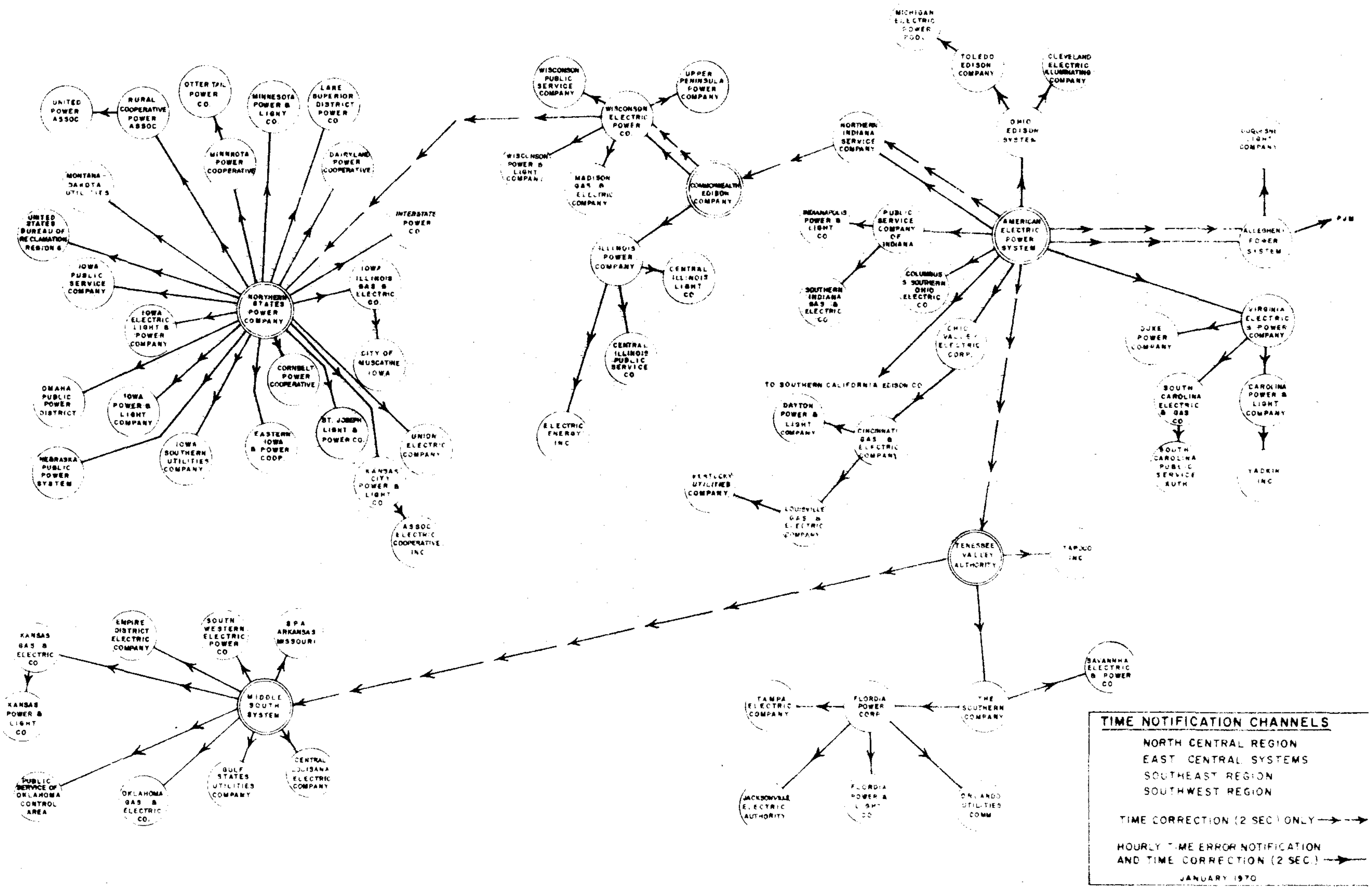
Point C ________ Hz

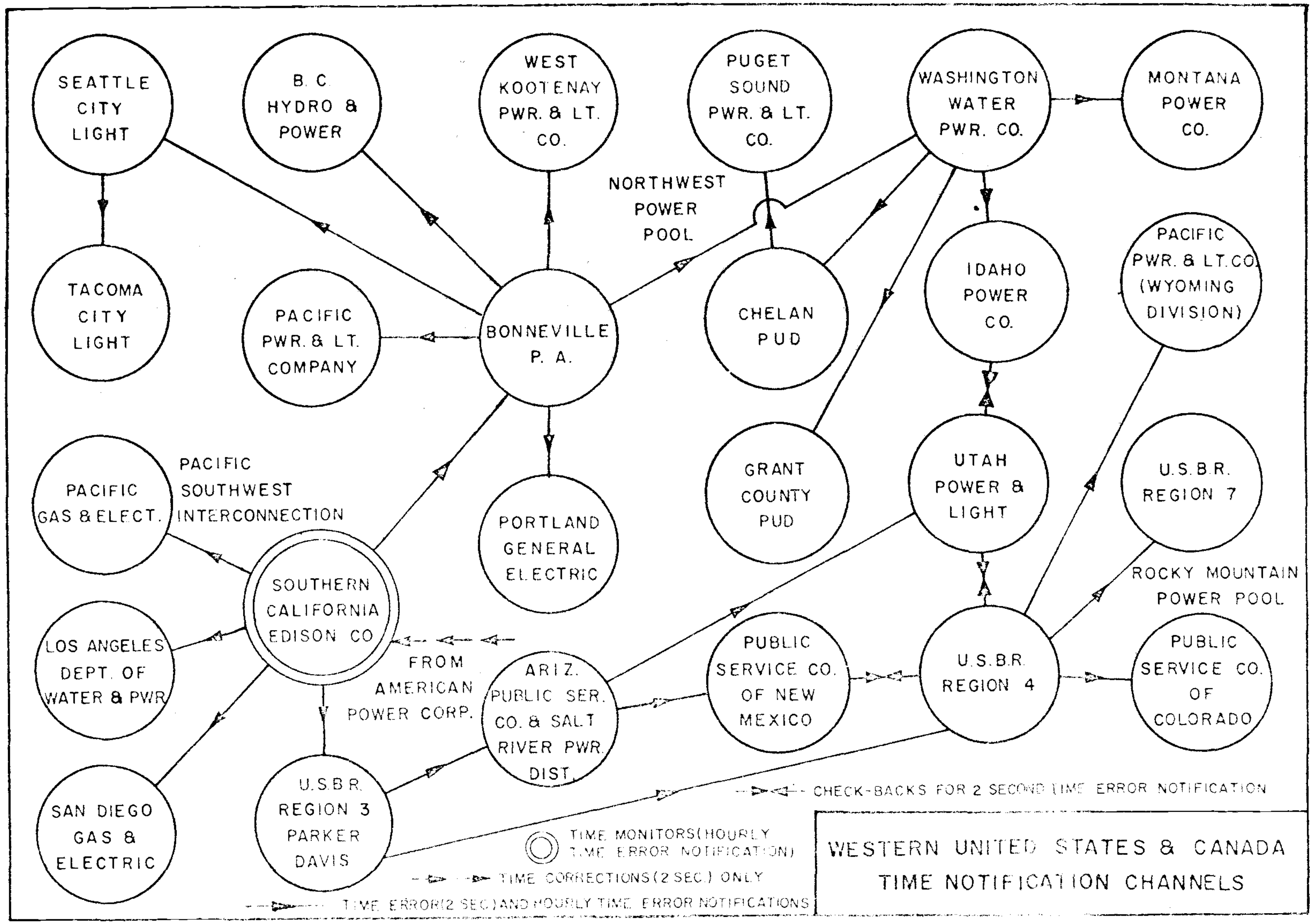
NOTE: Net power delivered out of Control Area (overgeneration) is (+), net power received into Control Area (undergeneration) is (-).

APPENDIX C

Diagrams of Time Notification Channels




UNITED POWER ASSOC
RURAL COOPERATIVE POWER ASSOC
OTTER TAIL POWER CO.
MINNESOTA POWER & LIGHT CO.
LAKE SUPERIOR DISTRICT POWER CO
MINNKOTA POWER COOPERATIVE
DAIRYLAND POWER COOPERATIVE
MONTANA-DAKOTA UTILITIES
UNITED STATES BUREAU OF RECLAMATION REGION 6
IOWA PUBLIC SERVICE COMPANY
IOWA ELECTRIC LIGHT & POWER COMPANY
OMAHA PUBLIC POWER DISTRICT
NEBRASKA PUBLIC POWER SYSTEM
IOWA POWER & LIGHT COMPANY
IOWA SOUTHERN UTILITIES COMPANY
EASTERN IOWA & POWER COOP.
CORNBELT POWER COOPERATIVE
ST. JOSEPH LIGHT & POWER CO.
KANSAS CITY POWER & LIGHT CO
ASSOC ELECTRIC COOPERATIVE INC
UNION ELECTRIC COMPANY
CITY OF MUSCATINE IOWA
IOWA ILLINOIS GAS & ELECTRIC CO.
INTERSTATE POWER CO
NORTHERN STATES POWER COMPANY
WISCONSIN PUBLIC SERVICE COMPANY
WISCONSIN ELECTRIC POWER CO.
UPPER PENINSULA POWER COMPANY
WISCONSIN POWER & LIGHT COMPANY
MADISON GAS & ELECTRIC COMPANY
COMMONWEALTH EDISON COMPANY
ILLINOIS POWER COMPANY
CENTRAL ILLINOIS LIGHT CO
CENTRAL ILLINOIS PUBLIC SERVICE CO
ELECTRIC ENERGY INC
MICHIGAN ELECTRIC POWER POOL
TOLEDO EDISON COMPANY
CLEVELAND ELECTRIC ILLUMINATING COMPANY
OHIO EDISON SYSTEM
NORTHERN INDIANA SERVICE COMPANY
INDIANAPOLIS POWER & LIGHT CO
PUBLIC SERVICE COMPANY OF INDIANA
SOUTHERN INDIANA GAS & ELECTRIC CO
COLUMBUS & SOUTHERN OHIO ELECTRIC CO
OHIO VALLEY ELECTRIC CORP.
AMERICAN ELECTRIC POWER SYSTEM
DUQUESNE LIGHT COMPANY
ALLEGHENY POWER SYSTEM
PJM
VIRGINIA ELECTRIC & POWER COMPANY
DUKE POWER COMPANY
SOUTH CAROLINA ELECTRIC & GAS CO
SOUTH CAROLINA PUBLIC SERVICE AUTH
CAROLINA POWER & LIGHT COMPANY
YADKIN INC
TO SOUTHERN CALIFORNIA EDISON CO
DAYTON POWER & LIGHT COMPANY
CINCINNATI GAS & ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS & ELECTRIC COMPANY
TENESSEE VALLEY AUTHORITY
TAPOCO INC
KANSAS GAS & ELECTRIC CO
KANSAS POWER & LIGHT CO
EMPIRE DISTRICT ELECTRIC COMPANY
SOUTH WESTERN ELECTRIC POWER CO
S P A ARKANSAS MISSOURI
MIDDLE SOUTH SYSTEM
PUBLIC SERVICE OF OKLAHOMA CONTROL AREA
OKLAHOMA GAS & ELECTRIC CO.
GULF STATES UTILITIES COMPANY
CENTRAL LOUISANA ELECTRIC COMPANY
SAVANNAH ELECTRIC & POWER CO
TAMPA ELECTRIC COMPANY
FLORIDA POWER CORP
THE SOUTHERN COMPANY
JACKSONVILLE ELECTRIC AUTHORITY
FLORIDA POWER & LIGHT CO
ORLANDO UTILITIES COMM
TIME NOTIFICATION CHANNELS
NORTH CENTRAL REGION
EAST CENTRAL SYSTEMS
SOUTHEAST REGION
SOUTHWEST REGION
TIME CORRECTION (2 SEC) ONLY
HOURLY TIME ERROR NOTIFICATION AND TIME CORRECTION (2 SEC.)
JANUARY 1970



REVISED 12-31-69

APPENDIX D

Effects of t and f on System Frequency

For an interconnected power system consisting of n areas, each operating on tie-line-bias control, a derivation of a general equation relating the effects on system frequency due to t and f errors in all areas is shown below.

The Area Control Error (ACE) for each of the areas is given by the following equations:

$$\begin{aligned} ACE_a &= (T_{1a}-T_{0a}-t_a) - 10B_a(F_1-F_0-f_a) \\ ACE_b &= (T_{1b}-T_{0b}-t_b) - 10B_b(F_1-F_0-f_b) \\ &\vdots \\ ACE_n &= (T_{1n}-T_{0n}-t_n) - 10B_n(F_1-F_0-f_n) \end{aligned} \qquad [I]$$

Adding the above equations:

$$\begin{aligned} ACE_a + ACE_b + \ldots + ACE_n = {} & (T_{1a}+T_{1b}+\ldots+T_{1n})-(T_{0a}+T_{0b}+\ldots+T_{0n}) \\ & -(t_a+t_b+\ldots+t_n)-10(F_1-F_0)(B_a+B_b+\ldots+B_n) \\ & + 10(B_af_a+B_bf_b+\ldots+B_nf_n) \end{aligned} \qquad [I_a]$$

If we assume all ACE's are equal to zero and also:

$$T_{1a} + T_{1b} + \ldots + T_{1n} = 0$$

and

$$T_{0a} + T_{0b} + \ldots + T_{0n} = 0$$

and since F_1 and F_0 are common to all areas, Equation $[I_a]$ then becomes:

$$F_1 - F_0 = \frac{-(t_a + t_b + \ldots + t_n) + 10B_a f_a + 10B_b f_b + \ldots + 10B_n f_n}{10(B_a + B_b + \ldots + B_n)} \qquad [I_b]$$

Let Y represent the "size ratio" of each area which is defined as the ratio of its bias setting to the sum of the bias settings of all areas so that:

$$Y_a = \frac{B_a}{B_a + B_b + \ldots + B_n} = \frac{B_a}{\Sigma B}$$

Equation $[I_b]$ now becomes:

$$F_1 - F_0 = \frac{-(t_a + t_b + \ldots + t_n)}{10(B_a + B_b + \ldots + B_n)} + Y_a f_a + Y_b f_b + \ldots + Y_n f_n \qquad [I_c]$$

or

$$F_1 = F_0 - \frac{t_a + t_b + \ldots t_n}{10 \Sigma B} + Y_a f_a + Y_b f_b + \ldots + Y_n f_n \qquad [II]$$

For the effect on system frequency in the special case of an f error only in one Area A, and with no other errors on the system the following equation results when substituting zeroes for all t and f terms except f_a:

$$F_1 = F_0 + Y_a f_a \qquad [III]$$

APPENDIX E

Effects of t and f on Net Interchange

For a system as in Appendix D, a derivation of a general equation showing the effect on area net interchange due to t and f errors in all areas is given below:

Substituting Equation $[I_c]$ from Appendix D for $(F_1 - F_0)$ into Equation [1] for area A:

$$ACE_a = (T_{1a} - T_{0a} - t_a) - 10B_a\left[\frac{-(t_a + t_b + \ldots + t_n)}{10(\Sigma B)} + Y_a f_a + Y_b f_b + \ldots + Y_n f_n - f_a\right] \qquad [IV]$$

with $ACE_a = 0$

$$T_{1a} = T_{0a} + t_a + 10B_a\left[\frac{-(t_a + t_b + \ldots + t_n)}{10(\Sigma B)} + Y_a f_a + Y_b f_b + Y_n f_n - f_a\right] \qquad [IV_a]$$

or:

$$T_{1a} = T_{0a} + t_a - Y_a(t_a + t_b + \ldots + t_n) - 10B_a(f_a - Y_a f_a - Y_b f_b \ldots - Y_n f_n) \qquad [IV_b]$$