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WELLHEAD CONTROL DISPATCHED FROM ONE CONTROL CENTER

By

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Panhandle Eastern Pipe Line Company has long been aware of the advantages of being able to remotely control the flow of natural gas from various fields to meet sudden demand changes in our marketing areas. Transmission systems are designed and constructed to provide the required volume of gas demanded at any time, regardless of the weather or sudden changes therein, even though the peak domestic and industrial loads may occasionally be many times the average load. In order to meet peak demands the system makes use of its auxiliary facilities, such as storage fields that during the periods of slack demand have been filled with gas. High transmission line pressures also help to fulfill the peak demands, resulting from the high degree of compressibility of the gas itself. A sudden change in the weather in the marketing areas is not the only reason for a sudden need for additional gas volumes. The temporary loss of a compressor unit or a section of the pipeline can result in the sudden demand for more gas from another area. Unfortunately, the additional amounts of gas that can be obtained from these aforementioned facilities is limited and additional gas must be obtained from the producing areas if the peak demand persists.

Under present operations when a gas well is to be turned on or shut-in, this must be done manually by a fieldman. For the most part, demands for sudden increased volumes occur in the winter months when a sudden drop in the ambient temperature in the marketing areas is more likely to occur. Several times, because of severe snow storms, it has been impossible to get to the individual wells. In order to improve our operating efficiency it was decided to investigate the feasibility of wellhead control of several selected wells in the Camrick Field located in the eastern half of Texas County, Oklahoma.

This particular field was selected because the wells have a high wellhead working pressure and are capable of producing at large flow rates. It was estimated we could realize an increase of about 30 MMCF per day from the five "pilot" wells selected. Additionally, the field is located approximately 35 miles from our Liberal Compressor Station, which is the beginning of our main transmission system which terminates in the Detroit, Michigan area, and the gas flowing from the Camrick Field area reaches Liberal Station in about 20 to 30 minutes.

The basic design was premised on the need for a supervisory and telemetering control system which would allow the selected wells to be remotely controlled from a Central Control Station located in Panhandle Eastern's Pressure Control Dispatcher's office in Liberal, Kansas. Remote control of these wells thus gives the Dispatcher an immediate source of additional gas to meet sudden changes in the main line demands, irrespective of local weather conditions, or having to call a fieldman and wait for him to drive to the field and turn on the wells. The control system selected was an all-electronic, solid state, digital-pulse-code system supplied by Motorola Instrumentation and Control, Inc. of Phoenix, Arizona, a division of Motorola, Inc.

Before I describe the physical facilities we have installed, it might be good to briefly review some of the general theory, techniques, and typical circuits employed in a supervisory and telemetering control system. The control system (Figure 1) must be able to control and monitor the required number of remote points.

The remote equipment receives and decodes messages transmitted by the Central Station for: (1) controlling and reporting the position or status (on or off, opened or closed) of devices and (2) acquiring and reporting quantitative information (pressure, flow rate, etc.). Automatic alarm provisions can be included for detecting abnormal conditions.

The central or command equipment includes control and display facilities for controlling and monitoring the remote equipment. To perform a change-of-status at the remote station, the Central Station Dispatcher first selects the desired operation to be performed and initiates a command. This results in the transmission of an encoded message to the remote station where the message is decoded and applied to a suitable interpose relay which performs the commanded operation. Following the completion of this operation, the remote station encodes a status message and automatically transmits this message to the Central Station. Here the status message is decoded and displayed, providing the operator with a visual indication of the change-of-status operation.

Acquisition and digital display of quantitative data is accomplished manually by selecting the data through switch controls. A supervisory and telemetering control system can be programmed to operate in a quiescent (non-scanning) or in a dynamic (scanning) operation mode. We chose the quiescent mode, therefore, no information is transmitted from the Remote Station to the Central Control Station unless a change has occurred or a status check requested by the operator.

A digital system handles information in some form of numeric coding, with binary coding being the most common form used in digital control and telemetering systems. Binary coding has two characteristic states, the binary digits "0" and "1". There are many advantages in binary coding, foremost being that it has only two states for encoding a message, only the "0" or a "1" is used. Another advantage is the simplicity of the digital circuits; either the circuit is energized or de-energized to represent one of the states. There are no precise voltage controls required.

The control and acquisition of information is accomplished by arranging the binary bits into a message group. The intelligence is determined by the position of the "0" and "1" bits within the message group. A "1" in a particular bit position has an entirely different meaning from a "1" bit in another position, even though they are electrically identical.

The control system we selected uses three different codes for encoding the desired control commands and data into digital form. These codes are: (1) 2/5 Code, (2) Unitary or Discrete Bit Code, and (3) Binary Coded Decimal. All of these codes are handled identically in the transmission and reception phases of the system. Each of the three codes is described briefly below.

2/5 Code

The 2/5 notation indicates that the code message group consists of FIVE bits, TWO of these bits always being binary "1". For example, the 2/5 code structure has 10 possible combinations of two "1" bits and three "0" bits. The following table shows the 10 valid 2/5 code combinations and their decimal equivalents.

VALID COMBINATIONS	DECIMAL EQUIVALENTS
00011	0
11000	1
10100	2
01100	3
10010	4
01010	5
00110	6
10001	7
01001	8
00101	9

Thus, when an incoming 2/5 message is checked, if there are more or less than two "1" bits or three "0" bits, the equipment may recognize an invalid message structure and no control action is taken. The system uses the 2/5 code for command functions (open/close valves, trip/close circuit breaker, etc.), station addressing, and message identification.

Unitary or Discrete Bit Codes

Most of the data returned from remote stations to the central station is inherently binary in form. That is, a circuit breaker is either open or closed, etc. Accordingly, this binary information is inserted into the message structure in its original form. For example, a circuit breaker may be assigned to a certain bit position in a message. If this breaker is open, the bit is encoded as a "0" -- if the breaker is closed, the bit is encoded as a "1". Such a code format is called unitary or discrete bit coding; each bit stands on its own, regardless of the over-all message length.

For the 2/5 code described above, it is necessary to examine all bits simultaneously to determine one of 10 possible valid combinations. In the unitary code, each bit contains the complete on-off, open-closed status of its associated equipment without regard to the other message bits.

Binary Coded Decimal (BCD)

The third type of coding encountered in control systems is associated with the telemetering of quantitative data and involves assigning a numerical "weight", or value, to each bit relative to its position within a group of bits. A common weight used in digital applications is the base "2" raised to some power; e.g., 2^0, 2^1, 2^2, 2^3, etc. The power (exponent) determines the numerical "weight" assigned to the bit location. If the bit is a "1", the numerical weight of that bit is the base to the assigned power. If the bit is a "0", the numerical weight of that bit is zero.

Bit weighting is based on the technique of binary counting, i.e., establishing a decimal equivalent for each binary code. The following table shows the binary coding for the decimals 1 through 10.

BINARY	DECIMAL
0000	0
0001	1
0010	2
0011	3
0100	4
0101	5
0110	6
0111	7
1000	8
1001	9
1010	10

Careful examination of the binary numbers reveals that numerical weights have been assigned to each vertical column. From right to left the numerical weight of each column is as follows:

1st column	$2^0 = 1$
2nd column	$2^1 = 2$
3rd column	$2^2 = 4$
4th column	$2^3 = 8$

When the bit is a "1", the numerical weight of that bit is the base 2 to the power indicated for the column in which the bit appears. For example, the binary number 0010 has a decimal equivalent of 2. Notice that the bit in 2nd column ($2^1 = 2$) is a "1"; therefore, the decimal equivalent is 2 ($1 \times 2^1 = 2$). Notice also that the decimal equivalent 3 is written as 0011 in binary. In this case both bits assume the assigned numerical weight, and the decimal equivalent is obtained by adding horizontally; i.e., $1 \times 2^0 = 1$; $1 \times 2^1 = 2$; and $1 + 2 = 3$.

The technique of utilizing a group of binary numbers or bits to encode a decimal number (i.e., some number 0 through 9) is referred to as binary coded decimal (BCD). The encoding process, i.e., converting the quantitative information to BCD, is referred to as digitizing. The BCD format is compatible with most automatic logging devices and modern computers.

Message security is an inherent feature of digital systems since the digital codes can be easily checked for complete validity or invalidity. Digital message codes are checked by (1) dual message transmission, (2) bit counting, (3) timing, and (4) a controller to prevent the energizing of more than one interpose relay at any given instant.

The messages transmitted from central-to-remote and remote-to-central may differ in both length and structure. All messages are based on five bits per digit for each of the three codes previously described. To the four bits of the binary coded decimal system a fifth bit ("0") is added to fill out the five bit message.

The control system will operate over all of the commonly used transmission systems such as teletype and telegraph channels, telephone voice lines, VHF and UHF radio, microwave, or power line carrier. We have utilized forty miles of open wire telephone line as the primary communication channel.

Basically the system at the Remote Station can be divided into two parts: (1) flow measurement, and (2) the control system for turning on or off the individual wells. In order to measure the flow rate from the area, a 12-inch orifice meter was installed on the main trunk line. Measurements of the static and differential pressures at the orifice plate are fed to transmitters which convert the pressure in pounds per square inch gauge to a corresponding output signal of 4 to 20 milliamps. The flow rate in MMCF per day is computed by an Analog Computer using the outputs of both transmitters, manually adjusted for the correct gas flowing temperature and fixed orifice constant.

A two pen recorder-controller provides a continuous record of line pressure and flow volume. The desired flow rate is selected at the Central Control Station and a digital to analog converter is used to interpret this information and actuate the electrically set point to the flow controller. The output signal from the flow controller operates an electro-pneumatic transducer whose pneumatic output regulates or positions a high flow regulator valve located immediately downstream of the 12-inch orifice fitting.

The regulator valve is positioned so as to maintain a back pressure on the field gathering system at all times during normal operation. Four of the five "pilot" wells are equipped with pressure controllers which monitor the line pressure continuously and with control valves acting as wellhead regulators installed upstream of the wellhead separation equipment. These controllers have what you could call "high and low" set points. When the line pressure is reduced, this is accomplished by the Dispatcher initiating a signal to the flow controller to increase the flow rate resulting in a signal to the main regulating valve which causes it to open further, decreasing the line pressure to the lower pressure level set on the controller. At this point the controller sends a 3 to 15 Psi signal to the control valve allowing the valve to start opening and the well to start producing.

When the line pressure reaches the wellhead controllers "high" set point, the signal pressure to the control valve is decreased and the valve starts to close.

The fifth well is controlled directly from the Central Control Station over three miles of buried cable extending from the Remote Station to the wellhead. An electro-pneumatic transducer is located at the wellhead along with the same type of control valve as is installed at the other four wellheads. A 4 to 20 milliamp signal from the Remote Station is converted to a pneumatic output signal of 3 to 15 Psi by the transducer, positioning the wellhead control valve allowing the well to start producing at a predetermined flow rate. To shut-in this well a command is simply initiated at the Central Control Station. The big advantage of this system is no back pressure must be maintained on the entire system for operation.

High and low pressure alarms continually monitor the pressure in the pipeline. These alarm set points are manually set and can be changed at any time. A deviation flow alarm continuously monitors the difference between the corrected flow rate and the flow set point. Remote Station alarms are automatically reported to the Central Station and are indicated by visual display and audible alarm.

A bank of nickel cadmium batteries and charger for operation during a commercial power failure are located at the Remote Station, battery ampere-hour capacity is sufficient for a minimum of eight (8) hours operation.

The Central Control Station equipment includes control and display facilities for controlling and monitoring the Remote Station equipment. The Central Station control console (Figure 2) includes control and display of the following:

1. Station Selector
2. Command Selector Group
3. Set Point Selector Group

A rotatable drum type selector with visual display permits the Central Control Station Dispatcher to select the remote station to which commands may be transmitted. Another similar rotatable drum selector provides selection of commands to be transmitted. A single pushbutton is provided that when depressed causes the encoding and transmission of information derived from the Station and Command Selectors.

The following commands can be selected for transmission:

1. Status Check - The receipt of this command by the Remote Station results in the transmission of a message indicating the true status of all monitored qualitative status points.
2. Remote controlled well - off
3. Remote controlled well - on
4. Pressure, Psig
5. Actual Flow, MMCF/D
6. Set Point Flow, MMCF/D

The Set Point Selector Group consists of a set point identifier, a quantitative selector and a single pushbutton actuator.

The Central Station qualitative status display consists of one lamp display to indicate the station originating the status message and lamp display to indicate the actual status of the monitored equipment. Whenever a qualitative status message is received by the Central Station, a single stroke gong is sounded and the lamp displays the informational content of the message.

The qualitative status display includes the following:

1. Remote Controlled Well - off
2. Remote Controlled Well - on
3. Pressure Low Alarm
4. Pressure High Alarm
5. Flow Deviation Alarm
6. Remote Controlled Well Circuit

In addition to the above tabulated qualitative status display stations, two on-off alarm signals have recently been installed on two field engine-compressor units, and connected into the telemetering alarm system. The Dispatcher can tell immediately if either unit suddenly goes down because the alarm signal is automatically received at the Central Station.

Quantitative information from the Remote Station is received only as a result of operator action at the Central Station. This information is displayed on a single in-line three digit indicator. This includes display of set point volume, actual flowing gas volume, and operating pressure.

The system has been in operation for almost two years and we are still learning and modifying the equipment. Ultimately, it is hoped all five "Pilot" wells can be controlled directly from the Central Station utilizing a 960 mc microwave channel. Additionally, plans are to install control systems on remote field compressors, allowing the Dispatcher at the Central Station to automatically start and load or stop the units. The advantages of such a system are self evident and have a definite place in the producing and transporting of natural gas from gathering areas.

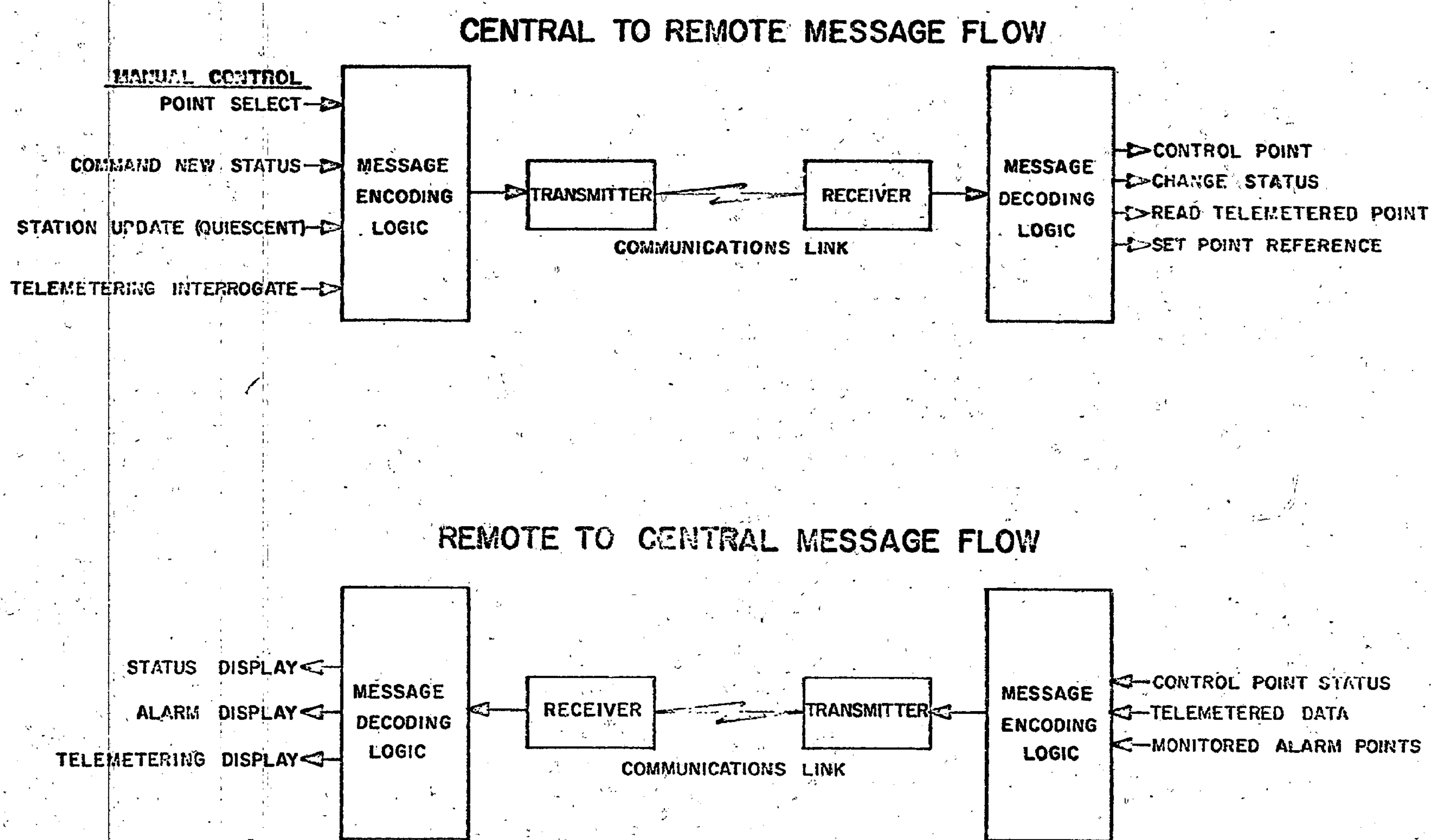

FIGURE 1
TYPICAL CONTROL SYSTEM

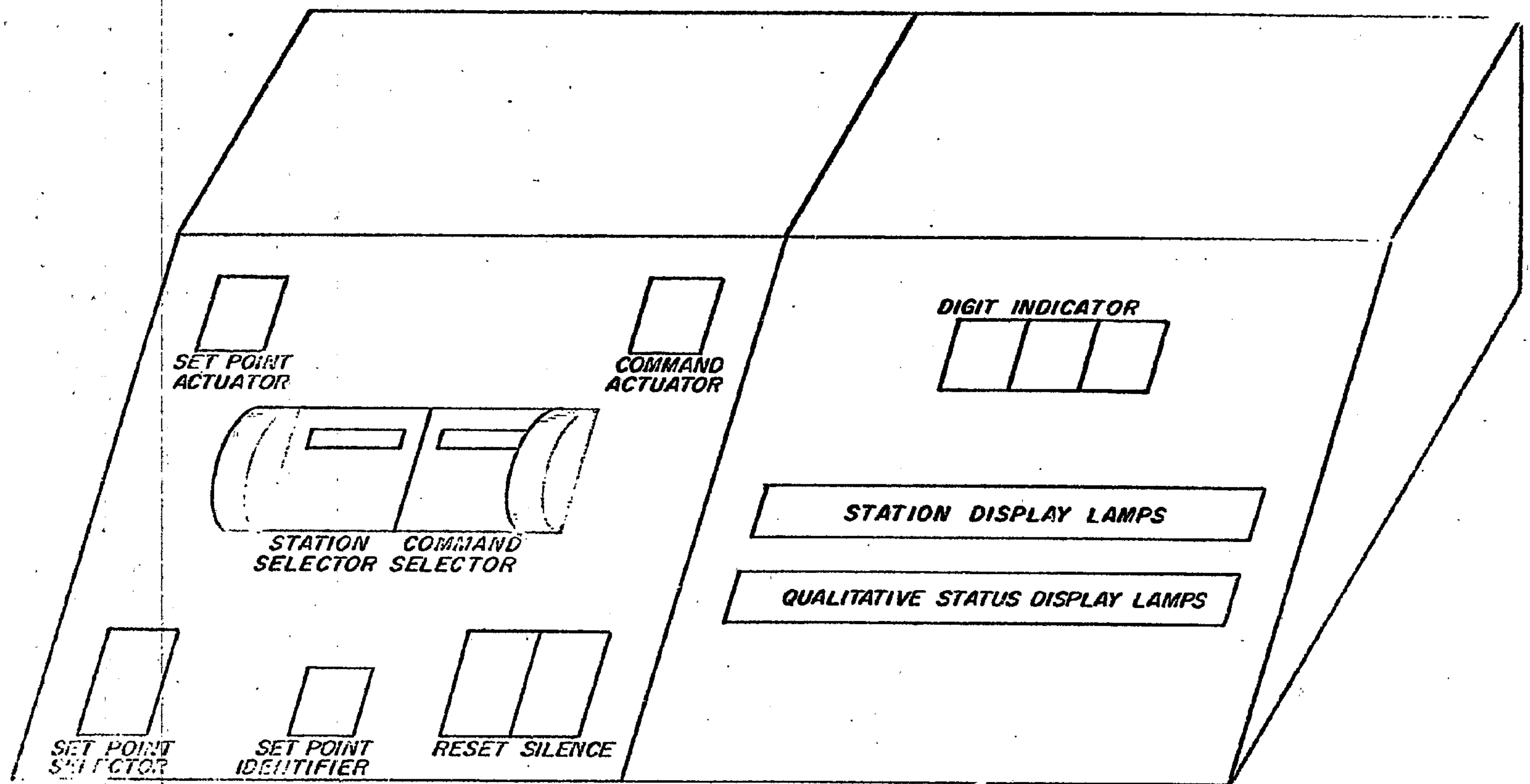

FIGURE 2
CENTRAL STATION CONTROL CONSOLE