INTEGRATING MICROELECTRONICS INTO GAS DISTRIBUTION

Edited by
WILLIAM F. RUSH, JR.
JAMES E. HUEBLER
JARED R. W. SMITH

ELSEVIER APPLIED SCIENCE PUBLISHERS
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INSTITUTE OF GAS TECHNOLOGY

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PREFACE

This volume contains papers presented at the first and second IGT symposia on microelectronics in the gas industry. The first was held November 18–20, 1985, in Orlando, Florida. The second symposium was held September 8–10, 1986, in Fontana, Wisconsin.

The purpose of these symposia was to disseminate information on the rapidly evolving topics of gas distribution automation. Speakers included manufacturing, utility, and R&D personnel. The papers considered technical, economic, and policy aspects of the application of microelectronics to gas distribution problems. The major topics included—

- Technology overviews
- Commercially Available Systems
- Emerging Technologies and New Directions
- Utility Experience with Microelectronic Automation
- Related Developments

Comparing the papers from the two symposia illustrates the speed at which this field changes. Products being designed or available only as prototypes during the first symposium were commercially available during the second. Several had already been reduced in cost and improved in reliability as manufacturers gained experience. The rapid technical and economic changes complicate automation-related decisions for both utilities and manufacturers. If these papers help to improve and simplify these decisions, our efforts will have been justified.

William F.Rush
James E.Huebler
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Institute of Gas Technology

TABLE OF CONTENTS

Symposium Papers

INTEGRATING MICROELECTRONICS INTO GAS DISTRIBUTION I

Presented
November 18–20, 1985
Orlando, Florida

FUNDAMENTAL CONCEPTS OF MICROELECTRONICS AUTOMATION

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ABSTRACT

This paper addresses fundamental applications of microelectronics to automation systems used in the gas industry. The information focuses on terminology used in microelectronics automation and presents an overview of automation processes.

FUNDAMENTAL CONCEPTS OF MICROELECTRONICS AUTOMATION

INTRODUCTION

Microelectronics dominates today's automation applications in the gas industry with miniature circuit and semiconductor technology. Microelectronic's hardware decline in cost and improved reliability makes automation a buzz word in the gas industry. Economics is the primary force driving automation decisions, especially considering the increasing operation and maintenance costs associated with personnel and regulatory activities. Significant incentives exist to automate information gathering and control activities to avoid adding personnel and create improved productivity of existing personnel. For discussion purposes in this material, automation will be considered the application of electronics to replace or speed up human activities.

AUTOMATION CONSIDERATIONS

The use of microelectronics broadens the application base for automation. The vast technology available today may seem overwhelming, but there are some basic considerations that will simplify evaluating automation.

Identify the Objective

The foremost consideration is identifying the information needed and the process you want to automate. Automation can be confusing unless it is clear in your mind what you want to accomplish. The motives for automation are primarily economic; however, some subjective parameters like security, peace of mind and status also enter into the decision.

Other considerations include the response time of an automated system along with reliability requirements.

A State of Mind

One mental characteristic needed to make automation easier is that decision makers and gas system operators may need to rethink the way they work or gather information. For example, are you able to use a portable computer terminal for field data gathering instead of using the trusty clipboard and pentel pencil? Or when you want a data file are you comfortable going to a computer terminal and calling the information up on a screen instead of going to the nearest file cabinet? It soon becomes apparent that when considering automation that an open mind and flexible work methods are invaluable.

Since automation often involves leading edge technology a reasonable expectation is to experience problems introducing new technology along with some hardware and installation problems. Prepare for obsolescence, today's technology may only be state of the art for one year before a new technology is available. However, don't be discouraged by potential obsolescence as long as your automated system still performs its intended function. Financial treatment of microelectronic systems is different than many other gas system components. Life cycles and obsolescence for microelectronics is closer to 5–10 years versus 30 or more years for distribution mains.

Gas industry leaders in automation are the type of people that are not afraid to risk problems or mistakes and forge ahead into leading edge technology.

Specialized Skills

Automation and microelectronics is a highly specialized occupational field making training and experience invaluable in implementing a successful automation project. For example, design of a complicated automation system might involve up to three specialists, a hardware/computer specialist, a communications specialist and a software programmer. These specialists often make the critical difference between realizing the economic benefits projected in a feasibility study or having a project cast as the latest management fiasco. Fortunately, there are many skilled professionals serving the gas industry as consultants, vendors, and gas company employees.

Site Environment

The availability, reliability and cost of utility services at sites where microelectronic equipment is to be installed is a critical consideration. often telephone lines and electrical power are required to collect data and operate control equipment. Reliability plays a part in determining if backup power supplies or alternate communication systems are required.

Environmental conditions are also important from the standpoint that some electrical equipment is not designed to operate at temperatures below zero degrees Fahrenheit (°F), while other equipment can operate properly at −40°F. Humid or corrosive environments can be very destructive to electronic equipment.

Gaseous atmospheres may be encountered at some gas facilities due to bleed type control equipment. This often requires intrinsically safe or explosion proof equipment to avoid explosion or fire.

Transient upsets can also damage microelectronics equipment. These are often in the form of voltage spikes, over/under voltage conditions, radio frequency interference (RFI), static electricity, and lightning. A variety of mitigative techniques and equipment exists to control these problems common in some parts of the United States.

Security considerations also play a part in automation systems as equipment and data can be easily destroyed by uninformed or malicious individuals.

AUTOMATION SYSTEM ELEMENTS

Before discussing different types of automation systems, it is important to understand the three primary elements of an automation system. The three elements include input devices, output devices, and communications links.

Input Devices

Input devices change some physical function or value into a form (electrical signal) used by a data acquisition or control system. The hardware commonly used are transducers or computer peripherals. They can be as simple as an on/off switch or as sophisticated as a computer. Transducers and other input devices are described in more detail on Page 4.

Output Devices

Output devices display the output from a transducer, computer or communication device. An output device provides a signal for a control system to control a process or activity or to provide a human interface such as a video display, indicator, or alarm. Table 1 lists general types of output devices.

Table 1. GENERAL TYPES OF OUTPUT DEVICES

Output Devices	
Type	Kind
Optical	LED, Video, LCD
Indicator	Pointer, Chart Gauge
Magnetic	Computer Disk/Tape
Audio	Buzzer, Tone
Electrical	Current, Voltage, Resistance

Communication Links (Telemetry)

Communication links transfer a signal or information from one location to another. The type of link is dictated primarily by the distance the information needs to travel. Short distances (less than 10 ft) are commonly wired directly from one point to another. Longer distances (miles) usually require some sort of communication link to get data from one location to another. Common types of communication links include direct wire, telephone, radio, microwave and fiberoptics.

SYSTEM FUNCTIONS

Automated systems perform two primary functions: data acquisition and control. A system combining both functions is called SCADA, Supervisory Control and Data Acquisition.

Data Acquisition (DA)

A data acquisition system collects status or control information and either stores it at the site or transmits the data to another location. The information is recorded or used for decision making. The upper half of Figure 1 illustrates a data acquisition system.

Control

Control systems monitor an activity and then take action to control a process or activity. There are two primary types of control systems: open loop and closed loop.

Open loop systems monitor an input value and initiate action (output) dependent only upon the input variable. No feedback action is possible. The lower half of Figure 1 illustrates an open loop control system.

Closed loop systems monitor an input value and initiates action as an open loop system does and in addition the closed loop system modifies the control system through a feedback process. Figure 2 illustrates a closed loop data acquisition and control system.

SYSTEM RESPONSE

System Response is commonly classified into two categories: real time and batch/exception.

Real Time

Real time is “right now” processing where information acquired by the system is received in time to be used in controlling the system. Real time systems predominantly have response times less than one second and commonly in the fractions of a second.

Batch/Exception

Batch or exception systems are systems where the system information is not readily available without going through the intermediate process. An exception process occurs where a system does not indicate any information to the operator unless the process falls outside of described limits; for example, an alarm might sound if an unusually high pressure occurs in a gas pipeline system, or a remote terminal device would dial you up on the telephone and announce in an electronic voice that an upset condition has occurred.

AUTOMATION PROCESSING

Automation frequently involves computer applications. There are two major categories of processing: remote and central.

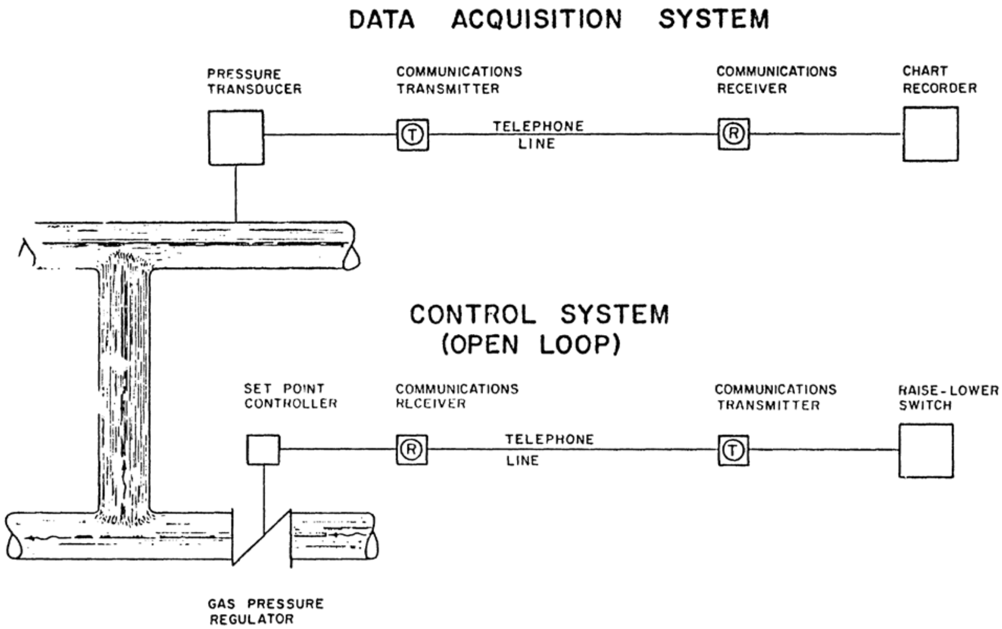

FIGURE 1

Central Processing

This type of processing collects raw data from remote locations and processes the information for recording or control at a central location (computer). This type of system was common a few years ago where computers were expensive and required substantial environmental treatment. Central processing units are commonly referred to as CPU’s. Figure 3 illustrates a central processing real time gate station data acquisition system.

Remote Processing

This type of processing includes a remote terminal (RTU) or remote processing unit (RPU) to store or process raw data on site and then transmit reduced data or send a control signal from that location. This is also known as distributed processing. With the dramatic reduction in costs of microcomputers, distributed processing is receiving increasing attention. Figure 4 illustrates a distributed processing real time gate station data acquisition system. Figure 5 illustrates a distributed processing dial up data acquisition system.

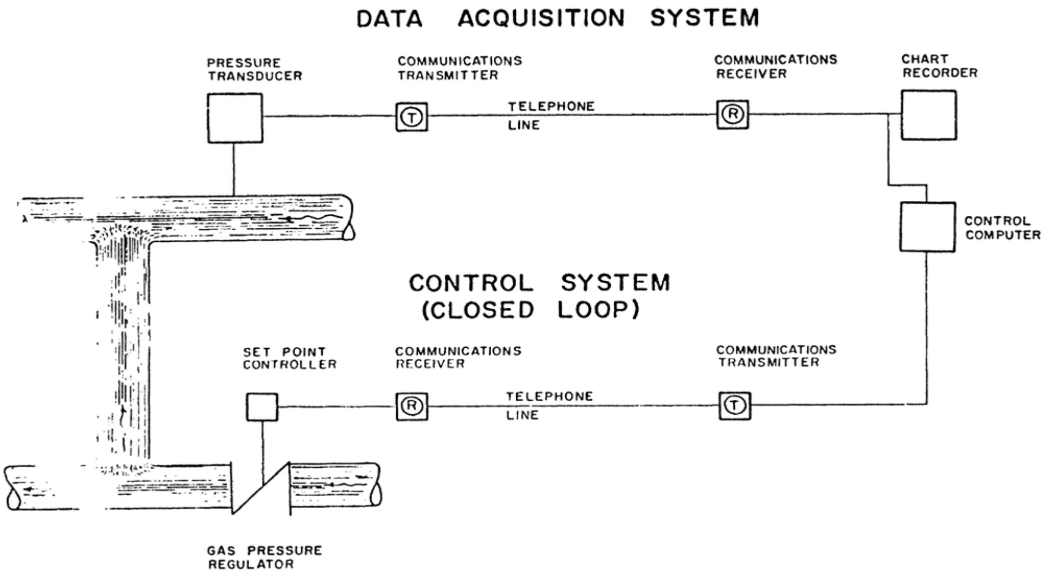

FIGURE 2

TRANSDUCERS

Except for the common on/off switch, transducers are by far the most common input device used in the gas industry. These devices convert one physical quantity into another physical quantity. For example, a pressure transducer would sense a pressure variation and output a voltage proportional to the input pressure. (This decision will be limited to the case where the output quantity is electrical.) A transducer consists of two components: a sensor and compensation circuitry. The compensation circuitry corrects sensor instabilities, sensitivity, zero balance, and environmental conditions. Table 2 lists several styles of transducers.

Table 2.. SEVERAL STYLES OF TRANSDUCERS

Transducer Inputs	
Physical Property	Type
Pressure	Static, Diffrential, Vacuum
Temperature	RTD, Thermocouple, Thermistor, IC
Frequency	Analog, Digital
Voltage	Analog, Digital
Current	Analog, Digital
Resistance	Analog, Digital

Transducer Inputs	
Physical Property	Type
Optical	LED, Bar Code, Infrared
Displacement/Rotation	Magnetic, Contact & Proximity Switch
Specific Gravity	Gravitometer
Gas Composition	Chromatograph, Chemical Titrator
Heat Content (BTU)	Calorimeter, Thermal Titrator
Humidity	Humidistat
Hydrocarbon	Resistance Bridge (CGI), Flame Ionization
Electrical Transducer Outputs	
Analog	Current: 4–20 milliamp, 10–50 ma Voltage: 0–5 volts, 0–10 volts, 0–250 millivolt Resistance: Frequency
Digital	Voltage: mark/space Contact closure Frequency

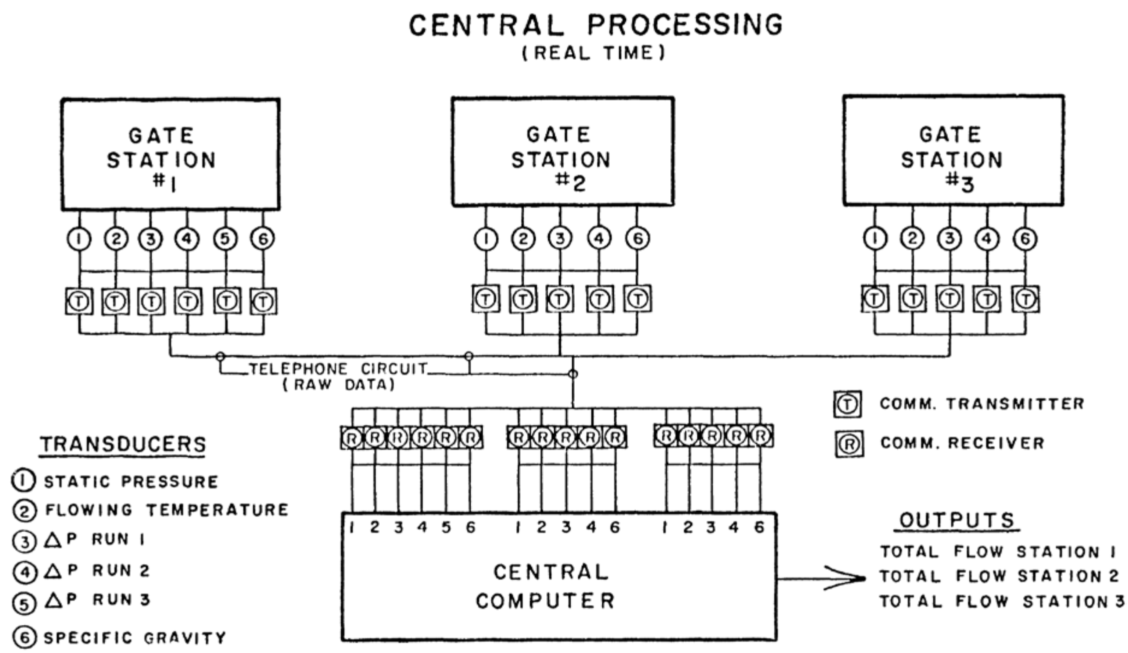

FIGURE 3

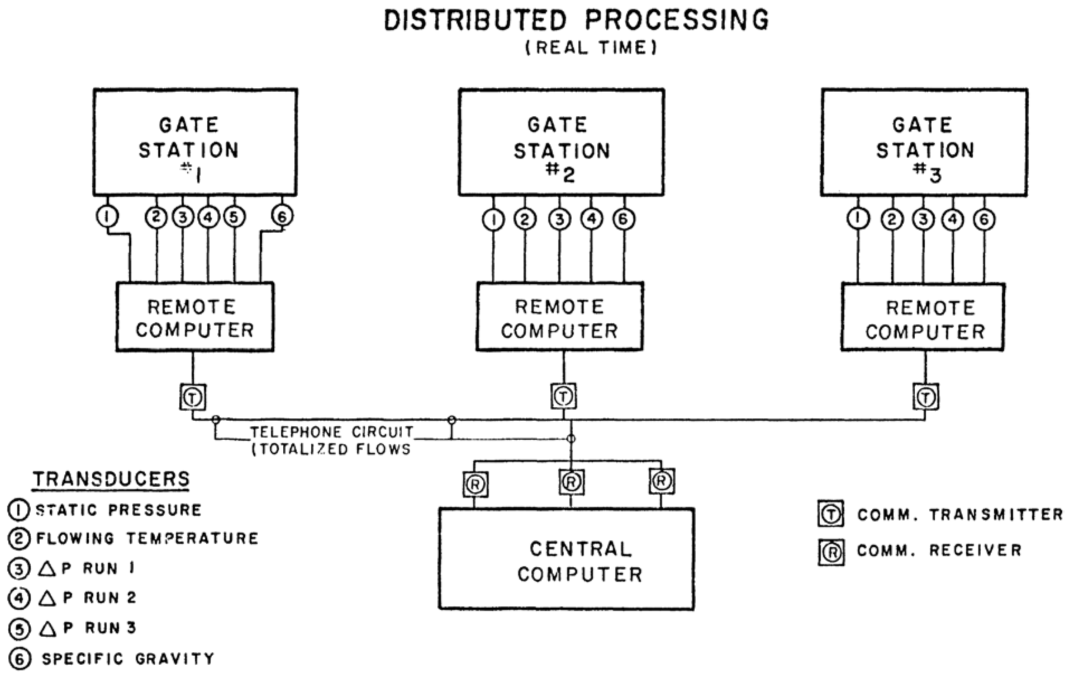

FIGURE 4

COMMUNICATIONS TECHNOLOGY

Telephone is probably the most common communication link used in the distribution gas industry. Telephone offers many advantages since telephone service is commonly available in most gas distribution systems. As illustrated in Figure 5, data acquisition and control systems communicate asynchronously on telephone systems through a modem. A modem is a modulator/demodulator where a signal is modulated into an audio signal for transmission over a telephone system and then demodulated back to an electrical signal.

Two types of telephone service are commonly purchased by gas companies: these are “dedicated” and “dial-up.” Dedicated lines, as their name implies, are dedicated to the sole use of the subscriber and consequently are relatively expensive. Dedicated lines are necessary for real-time systems since data is constantly transferred. Dial-up lines, on the other hand, are very similar to the common business telephone where data is transferred in batches after the transmitting and receiving locations have established a communication link.

In addition, there are two common grades of lines called voice grade and data grade. Lower cost voice grade lines are common telephone services and are limited to lower data transfer rates (300–2400 baud). Data grade lines are more expensive but are capable of transferring data at much higher transfer rates (300–19, 200 baud).

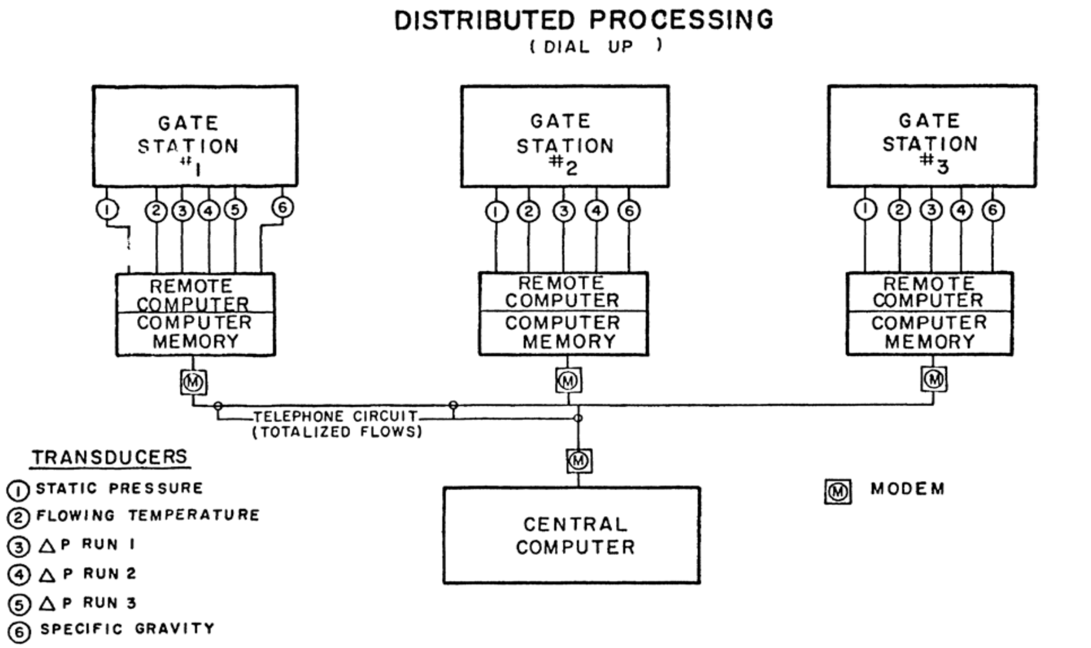

FIGURE 5

Other important communications terminology involves two types of data transmission methods. These are called synchronous and asynchronous. In synchronous communications there is no fixed time cycle for the data transfer operation. Asynchronous communications are prevalent in microcomputer (personal computer) applications whereas synchronous communications are common in large (mainframe) computers.

Asynchronous communications followed by most computer manufacturers is the Electronics Industry Association (EIA) standard RS-232C. This is commonly referred to as “serial” communication. The standard defines the interaction between data terminal equipment (DTE, typically a computer or terminal) and data communication equipment (DCE, typically a modem) employing a serial binary data exchange. This standard defines the methods of computers interfacing with communications equipment (modems), computer peripherals (printers, other computers), and the appropriate cabling methods.

MICROELECTRONICS

Microelectronics is an area of electronics that uses extremely small electronic components (transistors, resistors, capacitors, microprocessors) and combines them on a substrate or circuit board. Microprocessors are prevalent in many microelectronics applications today in the form of microcomputers.

Microcomputer

One of the most recent technologies applied in automation activities is the microcomputer. Let us discuss the components of a microcomputer to improve our understanding of the variety of applications possible today.

A microcomputer includes several components as described in Figure 6. The heart of the system is the microcomputer, that addresses read only memory (ROM), random access memory (RAM) interface circuits and permanent storage (e.g., disk drives). A real time clock synchronizes the microprocessor activities while a power supply provides electrical power to the system. The buss is the path for electrical power and data to travel. This hardware combined with state of the art software (computer instructions) creates a system to collect and display information, monitor processes and take action to control these processes.

An important concept in microcomputer and automation activities involves understanding the various types of electronic memory used in today's hardware. RAM is termed read/write memory where a microprocessor can retrieve or store information in memory. RAM is also considered "volatile" memory meaning that when power is turned off to the computer system the data is lost from memory and cannot be recalled.

ROM is memory that can only be read by a microprocessor. The information stored in ROM electronic memory is placed there by placing an electrical charge on the chip. The information is stored permanently on the chip and depending on the type of chip may or may not be over-written. Unlike RAM, ROM is "nonvolatile" meaning that data stored on the memory chip is not erased when power to the system is shut off.

There are several versions of ROM, these include programmable read only memory (PROM), erasable programmable read only memory (EPROM), and electronically erasable read only memory (EEPROM). Data may be entered on PROM chips once and cannot be erased and reprogrammed. EPROM chips are erased by exposure to ultraviolet light and may be reprogrammed. EEPROM chips function as EPROM chips with the exception that the erasing medium is electrical.

Another technology that is commonly heard in automation circles is metal oxide substrate (MOS) and complementary metal oxide substrate (CMOS). This transistor technology requires low power in relation to the silicon semiconductors commonly used in microcomputers. The lower power requirements for metal oxide technology makes it the choice for battery operated and portable devices. This advantage carries with it exposure to chip failure from static electricity charges which requires specialized handling procedures when installing or replacing chips on circuit boards.

GLOSSARY

Communication

ASCII — American Standard Code for Information Interchange. A seven-bit code used to represent aphanumeric characters. It is useful for such things as sending information between a computer and a peripheral, and from one computer to another.

Asynchronous — A communication method where data is sent when it is ready rather than waiting until the receiver signals that it is ready to receive.

Baud — A unit of data transmission speed most usually simply meaning bits per second: 300 baud=300 bits per second.

Handshake — An interface procedure that is based on status/data signals that assure orderly data transfer as opposed to asynchronous exchange.

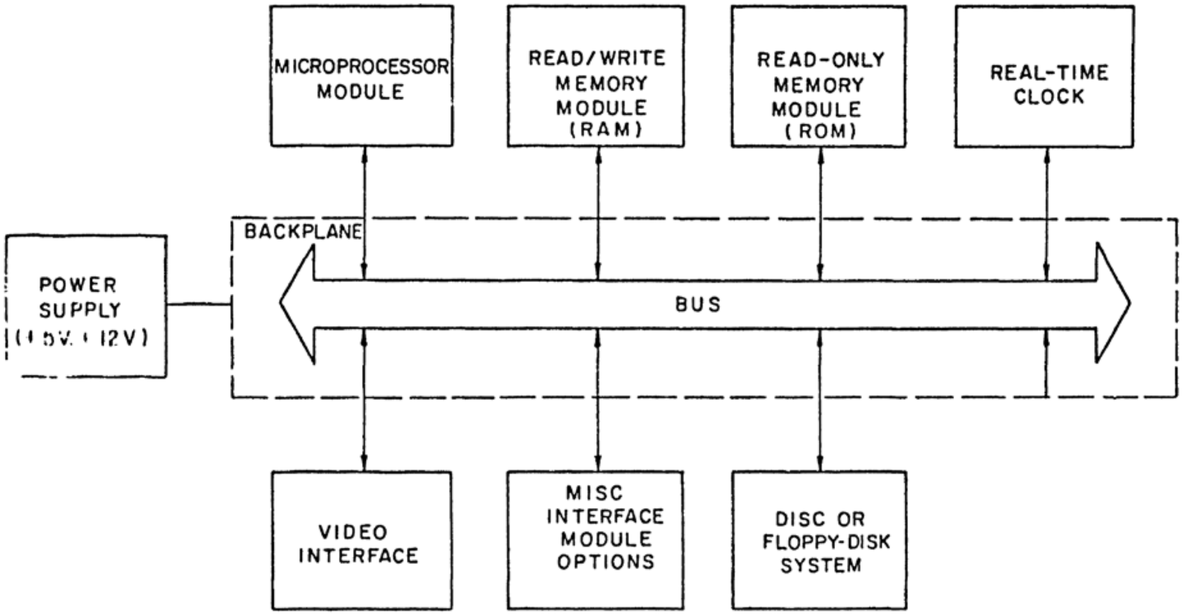

FIGURE 6

Modem — MOdulator/DEModulator. A device that transforms digital signals into audio tones for transmission over telephone lines, and does the reverse for reception.
Parallel Transmission — Sending all data bits simultaneously; one wire is needed for each bit. See serial transmission.
Parity — A one-extra bit code used to detect recording or transmission errors by making the total number of “1” bits in a unit of data — including the parity bit itself — odd or even.
Protocol — A formal definition that describes how data is to be exchanged.
Serial Transmission — Sending one bit at a time on a single transmission line. Compare with parallel transmission.
Transmitter — A device which translates the low-level output of a sensor or transducer to a higher level signal suitable for transmission to a site where it can be further processed.

Instrumentation

Analog-to-Digital Converter (A/D, ADC) — A device or circuit that outputs a binary number corresponding to an analog voltage level at the input.
Analog Output — A voltage or current signal that is a continuous function of the measured parameter.
Digital Output — An output signal which represents the size of an input in the form of a series of discrete quantities.
Digital-To-Analog Converter (D/A, DAC) — A device or circuit to convert a digital value to an analog voltage level.
Hysteresis — For a pressure transducer, the difference in output when the pressure value is first approached with increasing pressure and then with decreasing pressure. Expressed in percent of full scale during any one calibration cycle.
Input Impedance — The resistance measured across the excitation terminals of a transducer.

Life Cycle — The minimum number of pressure cycles the transducer can endure and still remain within a specified tolerance.

RFI — Radio Frequency Interference.

RTD — Resistance Temperature Device.

Microelectronics

Bus — Parallel lines used to transfer signals between devices or components. Computers are often described by their bus structure (i.e., S −100 bus computers, etc.)

CPU — Central Processing Unit. The part of the computer that contains the circuits that control and perform the execution of computer instructions.

EEPROM — Electrically Erasable Programmable Read-Only Memory. A field-programmable read-only memory in which cells may be erased electrically and each cell may be reprogrammed electrically.

EPROM — A PROM that can be erased by the user, usually by exposing it to ultraviolet light. See PROM.

Large Scale Integration (LSI) — The combining of about 1,000 to 10,000 circuits on a single chip. Typical examples of LSI circuits are memory chips, microprocessors, calculator chips and watch chips.

Microprocessor — A semiconductor central processing unit (CPU) and one of the principal components of the microcomputer. The elements of the microcompressor are frequently contained on a single chip or within the same package, but are sometimes distributed over several separate chips. In a microcomputer with a fixed instruction set, the microprocessor consists of the arithmetic logic unit and the control logic unit. In a microcomputer with a microprogrammed instruction set, it contains an additional control-memory unit.

PROM — Programmable Read Only Memory. A semiconductor memory whose contents cannot be changed by the computer after it has been programmed.

RAM — Random Access Memory. A semiconductor memory that can be both read and changed during computer operation. Unlike other semiconductor memories this one is volatile—if power to the RAM is cut off for any reason, all data stored in the device is lost.

ROM — Read Only Memory. A semiconductor memory containing fixed data—the computer can read the data but cannot be changed in any way.

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2WP/PAD/micro

MICROPROCESSORS APPLIED TO ECONOMIC AND OPERATIONAL CONTROL OF GAS SYSTEMS

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ABSTRACT

The explosive growth of the microprocessor in industrial control and in every other facet of life is a familiar story. Their great power and flexibility has led to a flood of products that solve various problems. Some of the applications of interest to the gas industry involve improved data acquisition, reduction and management; improved control in both the operational and economic realms. The ability to coordinate these realms is just coming into existence. The effect of this coordination is examined.

MICROPROCESSORS APPLIED TO ECONOMIC AND OPERATIONAL CONTROL OF GAS SYSTEMS

In 1976 I presented a paper titled "There is a Chip in Your Future", a microprocessor chip. The paper was designed to take a far reaching look into the future. The next paper presented covered the most far out application. Within six or seven years all the applications were for sale. More are announced everyday: Expert Systems, Intelligent Systems, Hueristic Systems to name a few. The original microprocessor developments efforts created discrete devices.

In the last three years, integrated systems have appeared that allow distributing these marvelous devices over a wide areas, to solve (system wide) problems.

Today gas company managers have a complicated decision pattern to go through in deciding how to run a particular company. They are moving from the "controlled monopoly" concept to the "free market" concept. They must operate somewhere along a continuum. The position on the continuum varies all the time. It is driven by a combination of economic, political, social, and physical forces. We can't reasonably discuss them here. We can discuss some tools to use on gas systems that make movement along the continuum more effective.

Let us examine some concepts that allow direct application of microprocessors, and produce a measuarable result. These concepts are related directly to human experience to emphasize that modern microprocessor systems can fruitfully aid human performance.

The first method a person uses to analyze a problem is to sense its characteristics. His idea of a problem is greatly influenced by the number of ways in which he can sense, and how he feels about the accuracy of his perception. We can coin some definitions to handle this:

"TRANSPARENCY" is a good word to describe the number of ways a problem is sensed, and the number of places it is sensed. Under present conditions two or three pressures and temperatures may be sensed to determine conditions at a site. Using a microprocessor it would be economic to sense more conditions and provide the operator with DECISION LEVEL INFORMATION, instead of raw measurements.

The purchase price of microprocessor based equipment is so low, that many sensing points and types of sensing are cost effective. The economics of this sensing makes it advantageous to go on a "whole problem" basis, instead of the present "knot hole" view of the system.

"UNCERTAINTY" is the result of the "knot hole" concept. If the system is sensing pressure, from which the operator is inferring flow and line pack, the operator will compensate for his uncertainty. This compensation will result in higher pressures, more use of supply resources or compressor time and fuel. He may also compensate with curtailments, loss of sales, or call out labor on overtime.

If you view a baseball game through a knot hole in the fence, your view may be limited to the pitchers mound, the batter's box or first base. Unless long experience from the grandstand allows your mind to fill in the actions of the other players, your idea of action on the field will be grossly distorted. Myths about the way the system (game) works arise to rationalize the action.

These myths applied to gas systems have proven to be expensive and dangerous.

"OPTIMIZATION" of system operation occurs when the best selections for operational criteria match the best possible financial criteria. This occurs where gas companies have happy customers buying fuel at an expected profit. Regulatory agencies are convinced that the best possible use is being made of your plant, and the environment is not being threatened. Optimization occurs when yesterdays planned thruput, is exactly on target today, when storage inventory is just sufficient for the season, and when your labor force is happily upgrading your system with no overtime.

"Optimization" in a mainframe computer has been tried and is a difficult concept to implement. In distributed microprocessors it is tackled one problem, one site, and one area at a time. Every Facit of every site operates at peak efficiency. Let's look at an example.

A large transcontinental pipeline had a labor problem. Many of its compressor station technicians were near retirement age. Stations were manually operated. The questions were: (1) Do we train new operators? (2) Do we automate the stations?

Economics and operations contend in these ways:

Training New Operators.

- Lower level of efficiency while new crews are trained.
-
- Continuing manpower replacement necessary because compressor operation is a <u>boring</u> job.
-
- Four shifts must be kept trained to man the station at $50,000 per man per year.
-

- Labor is not very productive since the technicians cannot sense many factors affecting the efficient
- operation of the engines.

Using Microprocessors to Control the Stations gives an immediate increase in efficiency of the compressor units:

- Starting sequences are short saving as much as $100 per start, per unit, in compressed air. To provide
- automatic start-stop sequencing for a human operator would cost an added $40,000 per unit. The same microprocessor while it is sequencing a unit can:
- Control Unit Torque to its most efficient level, saving around 10% of unit fuel gas.
-
- Control Unit Fuel to Air Ratio for a saving of 3 to 5% of unit fuel, with increased speed range. This helps
- for quick starts.
- Control of unit ignition timing for a saving of 1% or 2% of unit fuel, and increased speed range.
-
- Control of unit thruput.
-
- MEASUREMENT OF UNIT EFFICIENCY in the form of Specific Fuel Consumption.
-

Immediate increase in station efficiency thru:

- Incremental capacity control in which the station microprocessor calculates the most fuel efficient
- combination of engines to pump the stream.
- Reduction in manpower to one shift per day. These men work to upgrade the plant rather than operate it.
-

This is an example of tackling optimization one small concept at a time. The savings add up. A little arithmetic would show over $1,000,000 per year in fuel for a 12,000 horsepower station <u>and</u> over $1,000, 000 in labor. A saving of 10–15% quickly pays for application of microprocessor.

"DECISION LEVEL INFORMATION" is generated by microprocessors to destroy operational myths. Modern microprocessors have packaged gas programs that bring raw data (pressure, temperature, differential pressure, gas composition) to decision level (flow rate, BTU rate, line pack, pack trend, contract position) which are items that determine operator action. Certainly pressure is important as a sensing point; as a limit on system operations rather than a point of departure for making real decisions.

This decision level information also includes defined "relationships" he uses to make control judgements. In actual cases where control systems generated relationships among Load, Supply, Inventory (Line Pack) and Time to Displace, use of system horsepower was drastically reduced. The specific fuel consumption gives the operator immediate knowledge of the effect of his decisions.

In another case the relationships and controls among time of day, season, regulator discharge pressure, and low point pressure on many distribution grids in a major city reduced system seepage losses by over $1, 000,000 in one heating season.

In the grid pressure control above, the system gathered data for time sensitive load profiles. (See Figure 1) These profiles were put into an historic file, and retrieved on a "like day" basis. These represent the lowest level of system modeling. Other models used are line pack, pipeline flow rate, time to displace,

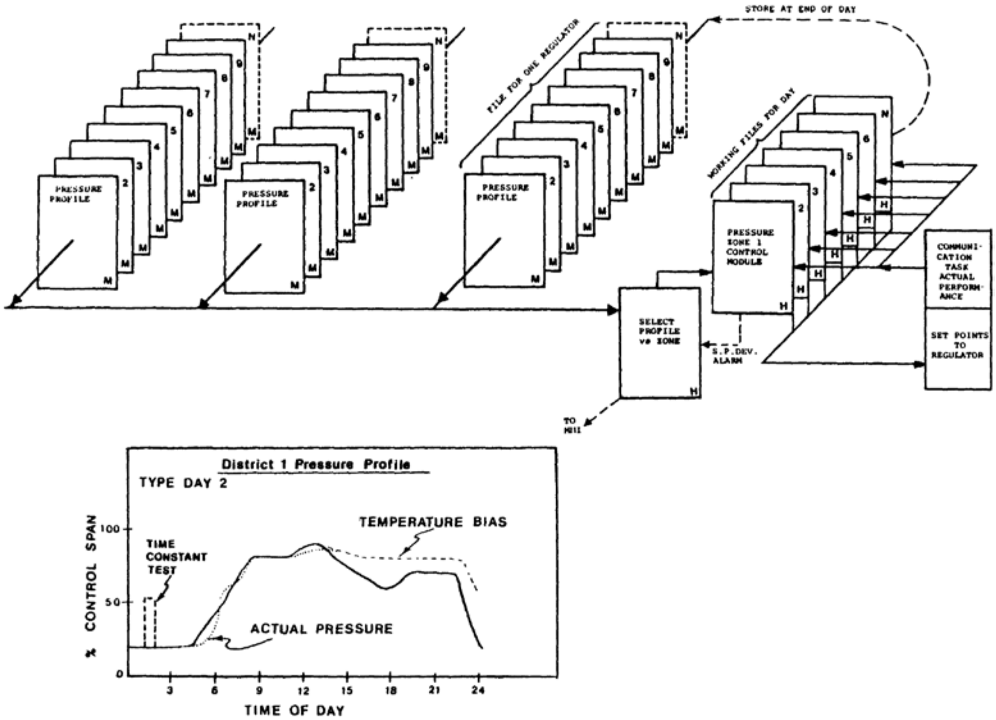

FIGURE 1

COMPUTER CONTROL PROGRAM

APP. DATA 4924•01•3300•01

horsepower requirements, etc. New instruments allow sensing in places, and under flow conditions impossible only a few years past making the models more accurate.

Generating these relationships involves some system mathematical modeling. This modeling takes advantage of the distributed microprocessor technique by modeling a local situation. These local problems have proven more managable, and accurate that system wide models. They are easily understood by operators, solve quickly, and can be used for closed loop controls. This results in operator "CERTAINTY" as opposed to "UNCERTAINTY" previously discussed.

An example of the economic effects of uncertainty will occur when there is a marginal possibility of a contract overrun. The system dispatcher must decide whether to start-up a peak shaving plant, or not. He may have decided to produce one percent of his MDQ.

For a medium size company this would be .01×182,000 MSCF/day or 1820 MSCF. At $5.00 per MSCF this would be $9100.00 plus plant startup costs.

With economic dispatch he may find that he can:

- Get the gas from Line Pack with no cost penalty
- Negotiate an overrun without cost penalty.

- Take a calculated risk that an overrun penalty would be less than startup and commodity cost for the peak shaving. For example:

  Penalty \$1.00/MSCF for 2% of MDQ, 02×182,000 MSCF×\$1.00=\$3640.00 cost of overrun.

CERTAINTY can be improved by "BIOFEEDBACK" which gives the operator an immediate appraisal of his operations. These appraisals may be such figures as:

- Average cost per MSCF sold
- Total curtailment volume
- Specific fuel consumption
- Predicted contract overrun or underrun

The various relationships are generated in realtime. "REALTIME" implies that the data measured, and the information generated will be related to actual conditions at any instant. The slower a system responds to changes, the broader the time span of "REALTIME".

"REALTIME CONTROL" is not a new term but is one that belongs in this discussion. We have seen that the operator's certainty concerning system operating conditions leads to more economic control. He can sense in realtime the conditions that must exist to get best performance from the system. He is notified of opportunities to increase system profitability and of opportunities to prevent or minimize financial losses. If he also can control the system in realtime, then the gain in profit, or stop loss, can be realized.

Most systems today operate on a historic basis. Data that was gathered is subjected to statistical analysis to gain knowledge of better control techniques. This a valid activity, however, the financial gains that could have occured, or financial losses that could have been stopped, are only reported, not achieved.

Mankind does not learn well from history. History requires study, and many of us are not students. Sensing, control, and feedback of results in realtime is the basis for most learning.

"TIME DISPLACEMENT OF INFORMATION" is another concept that needs attention. As sensing and control systems become more comprehensive a real possibility arises that the system will bog down in masses of data. The microprocessor in various ways minimizes this possibility. Some methods micros use to speed up telecontrol systems are:

- Reduction of raw data to decision level information and to statistical-historic level BEFORE it is transmitted. A typical process accomplished these days is metering and regulator station supervision and control. A five run meter station might have the raw data:

  - 3 Static Pressures
  - 5 Differential Pressures
  - 2 Temperatures
  - 4 Setpoints
  - 1 Level (Ordorant)

- 16 to 32 status contacts
-

Under conventional technique this data would be transmitted on every poll. Periodically the central computer would process the data to decision level information.

A microprocessor would:

- Compute the corrected flow rate and check it for alarm conditions.
-
- Compute the fuel value rate (MMBTU) and check it for alarm conditions.
-
- Check all contact closures for alarms and uncommanded changes.
-
- Control all meter runs on and off to achieve best flow accuracy.
-
- Totalize flow by volume and by MMBTU.
-
- Predict if the purchase contract will be met, overrun, or underrun, on a non-linear basis.
-
- Compute average differential pressure, static pressure, flowing temperature, BTU, Specific Gravity, Flow
- rates, Maximum flow and pressure, minimum flow and pressure.
- Put these valves in an array for efficient transmission at the end of the day. The microprocessor would
- normally transmit on the communications media a message that says "NOTHING TO REPORT". If any parameter is out of limits it will be reported, with the realtime of the alarm occurance sent from the remote.

  Any parameter or report that is "A MATTER OF INTEREST" is immediately reported. This is one technique used to keep the time displacement to a minimum.

Another technique used is the computer hierarcy. Using this method a number of small and medium size field stations are connected to a medium to large field station. The latter are then grouped and communicate with the central. Figures (2, 3 and 4) show such heirarchies. One company offers such a system with up to five (5) levels.

Each level is polled by its master. Data is automatically moved up and down the hierarchy as required. It moves much quicker than a large polling system where all stations are addressed in rotation.

These systems allow substantial savings on system software and communications.

The computer language used for this purpose is called a COMMUNICATIONS PROTOCOL. There are discussions in the industry on the need for a standard protocol for the gas industry. The International Standards Organization offers such a protocol, numbered ISO1745/21111/2629. It will be suggested as a candidate for the industry standard. A standard protocol would allow system expansion and update beyond the normal market life of the original system.

"RISK OF OPERATIONAL MISHAPS" is rarely assigned a dollar value by the gas companies. Much time and effort is spent on signs and meetings designed to create a "safety" mind set in employees.

A number of instances can be cited where risks were reported by telecontrol systems, then not acted on by companies. The resulting costs were in millions of dollars. Some of these were:

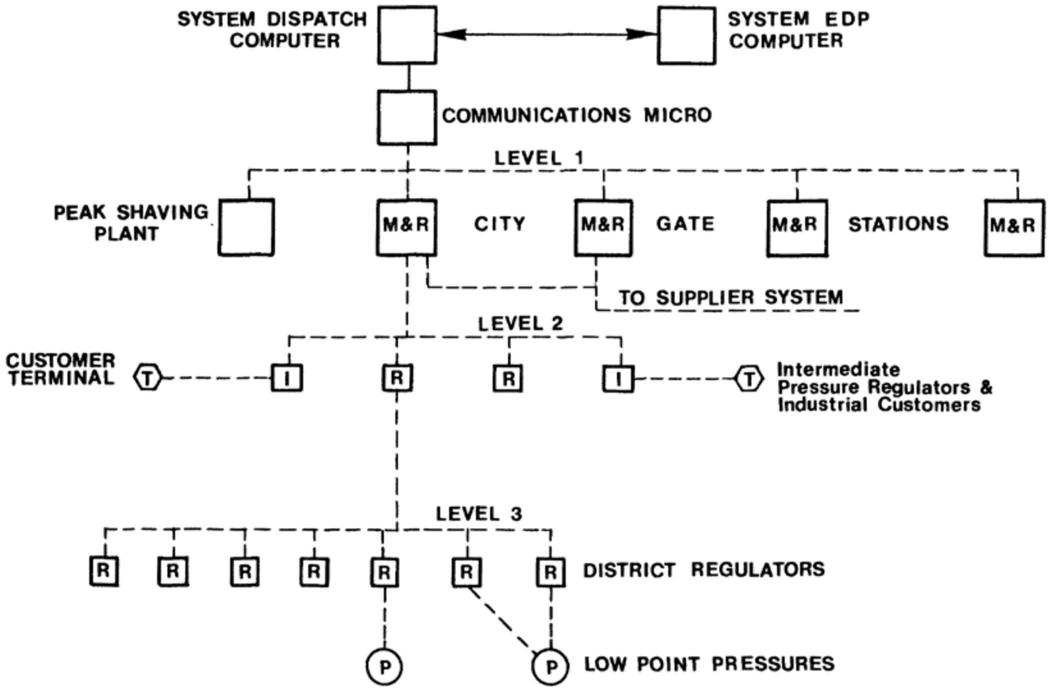

FIGURE 2

COMMUNICATIONS HEIRARCHY GAS DISTRIBUTION SYSTEM

- Loss of service to wide areas from valves being accidentally or maliciously shut.
- Line fractures from reported over pressures.

On the positive side, several instances have been reported where the telecontrol system correctly reported a fault which was acted on with very positive results:

- Two cases of construction damage reported within minutes of occurance.
- A broken impulse line to a transmitter was reported.

The serviceman was almost to the site when police reported the smell of gas in the area.

- A night dispatcher collapsed on the job. The system sensed his absence and called emergency personnel, possibly saving his life and a mishap on the system.

"PERSPECTIVE" of a company operations is usually different for various departments. Every industry has this problem. Communications among departments is often garbled by these different perspectives. "He heard what I said, did he hear what I meant?" is often heard. Modern microprocessor systems offer a powerful tool for resolving diverse perspectives into a more uniform one. It is relatively inexpensive to provide CRT Terminals to key people in various departments.

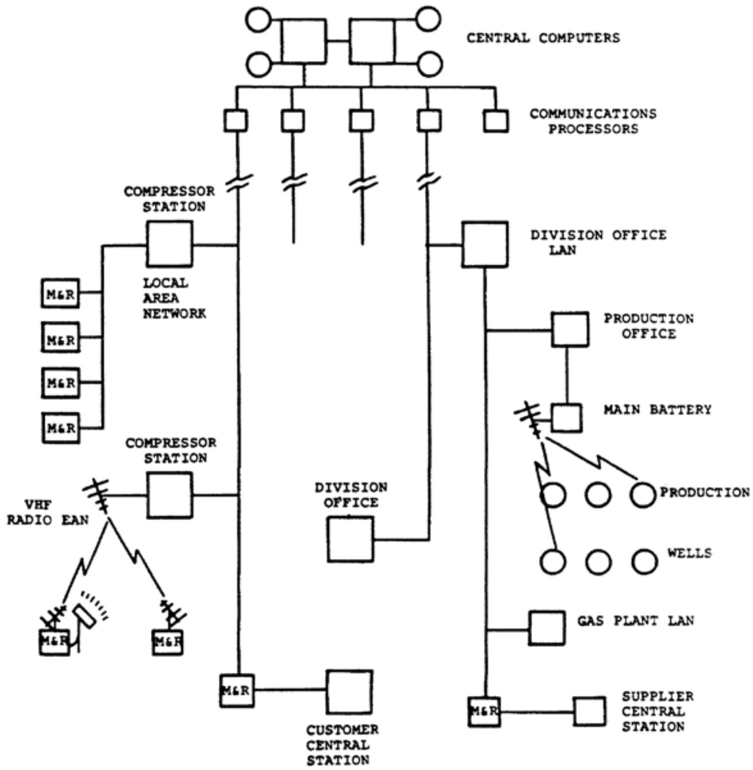

FIGURE 3

AN EXTENDED AREA NETWORK FOR TELECONTROL OF A PIPELINE SYSTEM

With these terminals they learn to interpret system response and capability in the same terms. Their access is limited to their particular needs and capability. Trainees also benefit from this technique, thru access to system models and observing techniques of systems operators.

SUMMARY:

In the short time allotted here we have examined some uses of microprocessors in the gas industry. I have attempted to place these units in philosophy of use, rather than discuss discrete applications.

Discrete applications need be limited only by the ability of the user to understand his own system. The knowledge of his most expert employees and consultants can be put into these units. Universally they are the most reliable devices made. With standard software, careful attention to internal construction standards, they are extremely cost effective. Often the payout is a matter of months.

We have seen that the microprocessor remote station can make your system transparent to the operator. Its diagnostic techniques build a high certainty that the system is sensing reliably. Operator confidence is the most important part of any system. The microprocessor systems can improve operator performance by allowing him to operate on decision level information instead of raw data. It establishes relationships among various data and information using models to relate economic and operations conditions. Immediate feedback of performance improved the operator's learning of system operation.

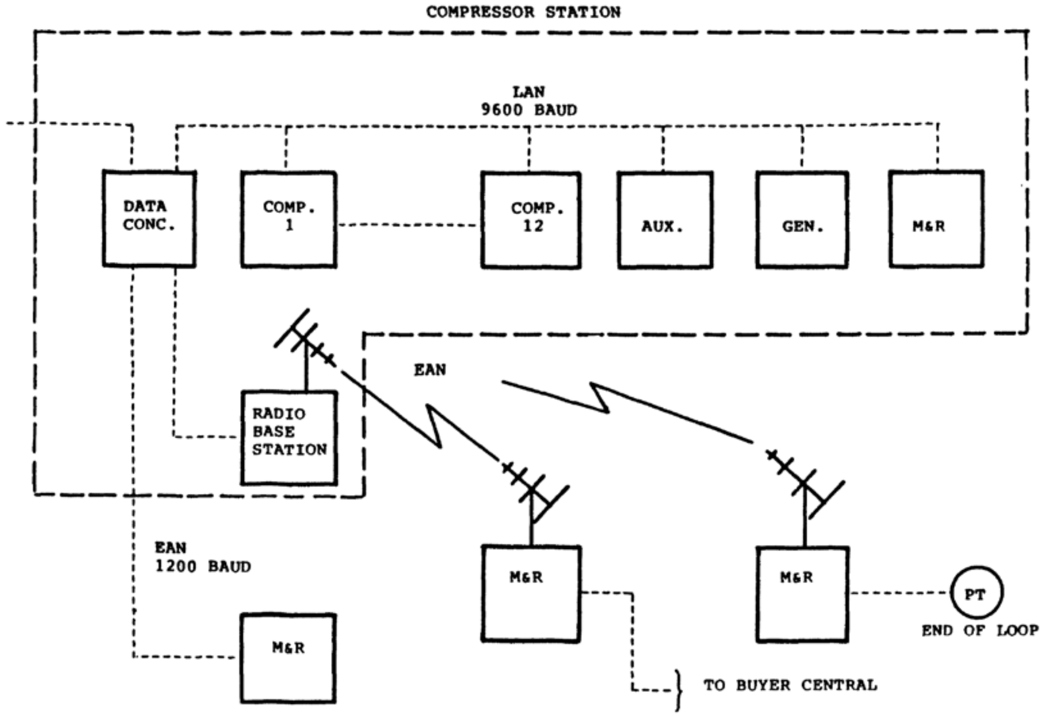

FIGURE 4.

LOCAL AREA NETWORK AS A CENTRAL FOR EXTENDED AREA NETWORKS

Realtime control allows the operator to prevent financial losses and to take advantage of opportunities for profit. Scheduled control activity is automatically accomplished by the microprocessor. Control requiring operator reaction is quickly accomplished.

A standard communications protocol allows the microprocessor systems to be assembled into heirarchies that minimize the time diplacement of data.

A uniform perspective of company operations can be developed using techniques available with microprocessor systems. This uniform perspective will smooth relations and allow more profitable operations by promoting realistic expectations.

The microprocessor is one of the most useful devices invented in many years.

INTEGRATING MICROELECTRONICS INTO GAS DISTRIBUTION

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ABSTRACT

American Meter Company, like other long time suppliers to the gas industry, has traditionally developed mechanical products to satisfy gas industry measurement and control needs. One of its first ventures into the world of electronics was the automatic prover introduced in 1965. While this was still more of a mechanical device than electronic, it was a start.

Today, American Meter is introducing three new microelectronic products that do more than simply replace existing mechanical products. The first is a remote reader for residential and industrial meters, the second is a meter mounted microprocessor based flow computer and, finally, a fully automated measurement and control station with a built-in calibration system. Each of these products was designed for the utmost in operating convenience and the highest levels of measurement accuracy and reliability.

INTEGRATING MICROELECTRONICS INTO GAS DISTRIBUTION

REDI/EDI/MEDI — ELECTRONIC REMOTE READERS

Remote reading volume counters are a simple but prime example of how microelectronics are displacing existing technology in the gas industry. Current models of residential remote readers consist of an electromechanical pulse generator and a remote counter. These pulse generators have mainsprings that are wound up by the meter and that spin a magnet within an inductive coil to create an electrical pulse. The pulse, usually representing 100 cubic feet, is transmitted via a two wire cable to the remote counter.

The electronic equivalent is much simpler and more reliable. An index mounted magnet and reed switch creates switch closures for each cubic foot of volume, Figure 1.

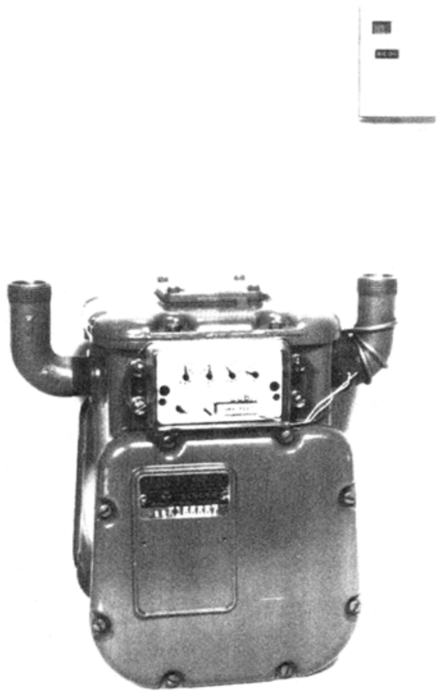


Figure 1. REDI RESIDENTIAL REMOTE METER

The remote receiver, containing CMOS integrated circuits and powered by a long life lithium battery, senses these switch closures and adds a count to a six digit liquid crystal display. The name of the residential remote reader is REDI™ for Remote Electronic Display.

The advantages of a microelectronic unit compared to electromechanical designs are numerous:

1. Imposes zero load on the meter because no work is done (like winding a mainspring).
2. Contains no moving parts to wear or break—and because it has no moving parts, it is perfectly quiet.
3. After installation, one revolution of the meter's proving circle adds a count to the register. With electromechanical models, it takes 100 cubic feet passing through the meter before the installer knows the system is working.
4. The magnet and reed switch fit on all popular gas meter models, making it universal in application. Electromechanical pulse generators are usually dedicated to a specific meter design.
5. Once installed, the remote counter can be set to agree with the meter index reading in less than a minute, using a PRESETTER. In mechanical models, it can be a nuisance to set the counter odometer wheels to the correct meter reading.
6. The electronic unit will only count forward, even if the meter is reversed to run backwards.
7. The circuitry of the receiver detects tampering. If the wiring is disconnected or shorted, the display goes to zero and will not resume counting even if the cable is reconnected or the short is removed. Only a PRESETTER will unlatch the circuit, allowing it to resume counting.
8. The reed switch has a life expectancy of at least 10 million cycles (roughly equivalent to 65 years of service).

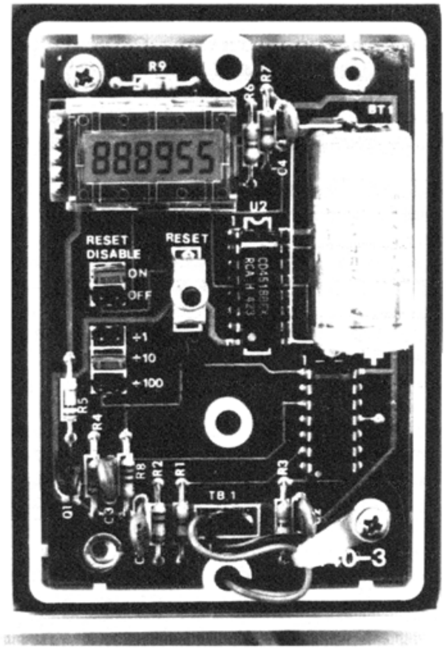


Figure 2. EDI REMOTE READER

9. The front cover of the receiver is protected by Seal Caps over the retaining screws.

The REDI remote reader is designed for use with residential meters up to and including the ANSI Class 400 with one or two cubic foot proving circles.

American Meter has also developed two companion products for use with commercial & industrial sized meters—large diaphragm, rotary and turbine meters. They carry the names EDI™ and MEDI™, Figures 2 and 3.

Like REDI, both are self-powered with a lithium battery. Both accept switch closures from the meter with values of 10, 100, or 1000 cubic feet per pulse (or in metric powers of ten) and add counts to a six digit liquid crystal display (LCD).

Each contains a reset switch that allows the count to be reset to zero. The reset function can be defeated if desired by moving a pin jumper on the circuit board. Another circuit allows incoming pulses to be divided by 1, 10, or 100 for applications where a high count rate would cause the counter to turn over too quickly.

The EDI and MEDI remote receivers can be located up to 1000 feet from the meter and will accept switch closures from any form A, B, or C switch.

The unique feature that distinguishes MEDI from EDI is its ability to fix-factor the incoming switch closures. Four BCD switches located on the circuit board allow it to apply a fixed factor from .0001 to .9999. The multiplier can be used for:

- Fixed factor pressure and/or temperature correction.
- Converting incoming counts from one set of units to another (such as cubic feet to BTUs or to dollars).
- To reduce the count rate by an additional 1/10th to 1/10,000th.
- Applying altitude correction factors.

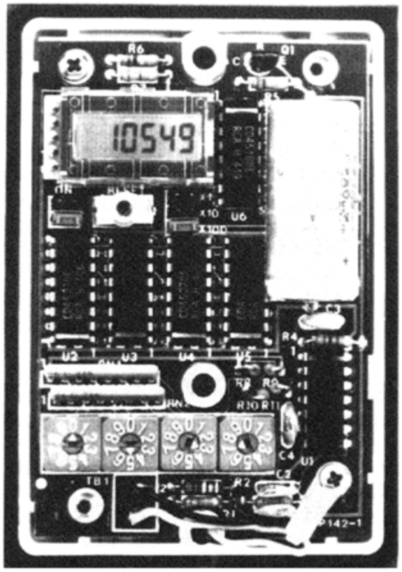


Figure 3. MEDI REMOTE READER

Both EDI and MEDI are ideal for commercial and industrial sized meters that are difficult or time-consuming to reach. Since they require no external power, they are easy to install.

ELSA — A MICROPROCESSOR BASED FLOW COMPUTER

The conversion of measured volumes to base conditions at the meter site has long been the exclusive domain of the mechanical correcting instrument. Until recently, electronics have been slow to penetrate this area of gas measurement, and for good reason. Mechanical correcting instruments must operate in a wide variety of climates, under severe temperature conditions and without any external source of power. These are stringent conditions for any product, especially for a device whose primary characteristic is accuracy. While digital computers and advanced transducer technology have made base volume computation not only feasible but highly accurate, their use has generally been restricted to protected areas and where electrical power is readily available.

The American Meter Company now introduces ELSA™ , a digital electronic flow computer developed specifically to operate in gas transmission and distribution systems with turbine, rotary and diaphragm meters, Figure 4.

Developments in semiconductor and battery technology have now made it possible to offer digital computer accuracy and reliability in all gas measurement environments.

This new electronic flow computer is a microprocessor based system programmed to solve the equations for standard volume, corrected to base conditions, with an accuracy not obtainable from mechanical correctors or from integrated chart recordings. Complete diagnostic routines incorporated in the computer program also make dramatic reductions in the time required to verify or adjust the calibration of the unit; a process that now takes minutes instead of hours.

The advantage of a microprocessor based design (computer) over one with circuits dedicated to a specific task (calculator) is application flexibility. The electronic flow computer software and data entry hardware have been structured to accommodate a wide range of application and operating conditions. Site specific

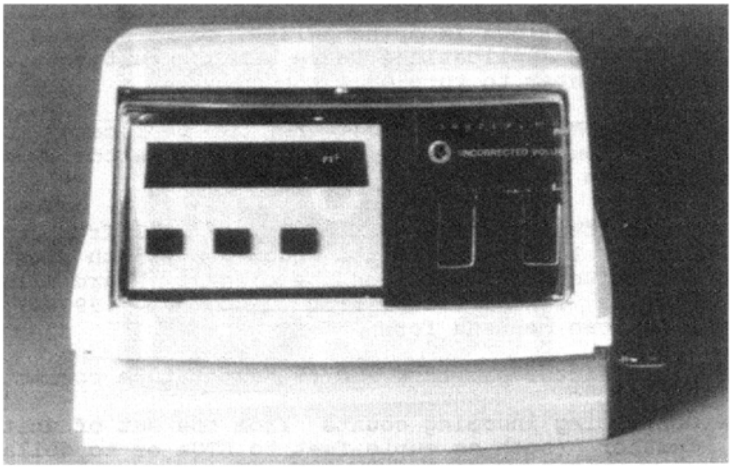


Figure 4. ELSA ELECTRONIC FLOW COMPUTER

variables can be entered into the computer by means of a convenient set of variable select DIP (dual-in-line package) switches located on the front panel of the computer cartridge. The operator may "program" the following variables.

units	English/metric (Kg/cm , kPa, Bars)
function	p/t/v correction
counter scaling	X1/X10/X100/X1000
meter drive	5 foot/other (decimal)
pressure type	gage/absolute
pressure range	to 1500 PSI
base temperature	60°F/50°F/70°F/other
base pressure	14.73/14.92/14.4/other
atmospheric pressure	14.4/14.73/14.74/other
supercompressibility correction	yes/no
	if yes, S.G./CO2/N2%
flow rate display	yes/no
volume retransmission	yes/no

As the list of input variables indicates, the computer can read in either English or metric units; and not just one metric scale—it will read in kilograms/cm^2 , kilopascals or Bars. It can be set to perform pressure correction only, temperature correction only, or pressure and temperature correction, all with or without supercompressibility correction (with dynamic P and t, and SG/N2/CO2). It can read in corrected volume, uncorrected volume, and flow rate, if desired. It will perform gage or absolute pressure correction to 1500 PSI and automatically compensate for variations in meter site altitude and barometric pressure. One computer cartridge will handle meters with 5 foot drive outputs or multiples of 10 cubic feet (or metres), as well as base and atmospheric conditions from 11.00 to 16.00 PSI, programmable in increments of 0.01 PSI. The user need only select one of two pressure transducer operating ranges for the specific application, 0–150 PSI or 0–1500 PSI as the computer continuously changes ranges to maintain maximum measurement discretion (commonly called “Auto Ranging”). In addition, the pressure transducer is temperature compensated (with a T-sensor) to reduce errors of measurement at temperature extremes. This demonstrates the overall flexibility of the computer, flexibility which can eliminate equipment dedicated to a specific set of operating conditions.

In addition to the primary advantages of improved measurement accuracy and reduced maintenance expense, the electronic flow computer has features and functions that go well beyond the capabilities of current mechanical correcting instruments.

- Digital accuracy
- Ease of calibration
- On-site programming of base measurement conditions
- On-site programming of gas composition
- Local display of corrected volume and flow rate
- Absolute pressure correction to 1500 PSIA
- Gage pressure correction to 1500 PSIA
- Diagnostic and measurement data display
- Automatic alarm indication
- Optional Remote Repeater
- Pulse output to remote counters
- Designed-in system security
- Broad operating temperature range
- Bi-directional volume counting

The ELSA Electronic Flow Computer is a complete system for use on all gas meters with an instrument drive output. ELSA is battery powered and completely self contained including the volume switching and transducers. The housing is cast aluminum, weather resistant, and secured with several tamper resistant features.

ELSA receives volume input directly from the meter via a rotating shaft or alternately will accept pulses from a user supplied contact closure. Meter shaft rotation can be either clockwise or counterclockwise. A four switch, magnetically operated pulser within ELSA supplies a volume signal and operates at torque levels that have no measurable effect on meter accuracy and rangeability. Having four volume input switches instead of one provides greater reliability while also allowing the microprocessor to detect dither, reverse flow and to update flow rate four times per meter shaft revolution.

Digitized volume is fed directly to the microprocessor which is simultaneously receiving pressure and temperature inputs from the transducers. The microprocessor digitally computes the corrected volume by applying the pressure, temperature and compressibility factors to the uncorrected volume and up-dates a digital display of corrected volume every 32 seconds.

Supercompressibility correction is an area where the microprocessor-based instrument has distinct advantages over its mechanical counterparts. In mechanical correcting instruments, Supercompressibility correction is performed using a variable pressure but a fixed temperature, usually the estimated average flowing temperature. This makes the Supercompressibility correction approximate since the Z factor is a function of both P and T.

The ELSA Electronic Flow Computer performs a Supercompressibility correction using dynamic pressure <u>and</u> dynamic temperature inputs and uses programmable values for specific gravity and diluents (carbon dioxide and nitrogen). The use of a dynamic temperature input becomes increasingly more important at higher pressures as indicated by Chart A below. For example, at 1500 PSI, a change in flowing gas temperature from 60°F to 40°F results in a 5% change in the compressibility of 0.60 S.G. Gas.

The computer is powered by <u>two separate</u> 6-volt battery sources. The batteries offered are lithium and/or a combination of lithium and rechargeable batteries, each with its own application advantages. This is another redundancy feature to insure the highest reliability.

One of the major features of the elecronic flow computer is its ability to display measurement information in user friendly form. ELSA has an eight (8) character alpha-numeric LCD that displays other measurement data such as pressure and temperature plus cites specific variables and alarm conditions. This capability allows a a serviceman or technician to check the system and verify analog input signals in a matter of minutes. The computer program lists 30 types of measurement information in menu form that can be sequentially displayed on the LCD.

Three push-button switches on the face of the cartridge are employed to access the data. The “mode” switch indexes from one menu item to the next and displays the basic function; i.e., “press”, “temp”, etc. The “display” switch causes the LCD to indicate actual values; e.g. “72.4 PSI”, “39.4 F”. The “set/clear” switch enters data (such as base conditions) or clears transient alarm conditions (such as pressure over-range alarm).

The computer program contains a priority system which causes the LCD to automatically switch from corrected volume to an alarm indication if an off-normal condition exists. An alarm indication could be related to low battery voltage, pressure and/or temperature overrange conditions or a defective uncorrected volume input switch. Under these conditions, the LCD will display one of the following indications:

B-l Lo	SW 1,2,3 and/or 4
B-2 Lo	
P Hi	T Hi
P Lo	T Lo

Any one of the above indications requires the reader to report the off-normal condition, thus prompting a service call. Alarm indications are one more example of the capability of the computer’s microprocessor based system.

ELSA’s alpha-numeric display normally reads in corrected volume to eight digits. Actuating an external pushbutton switch causes the computer to display uncorrected volume to seven digits (for correlation to the mechanical uncorrected counter). Actuating the external switch again causes the computer to display current flow rate in standard cubic feet per hour. A typical flow rate indication would read “FLO 1234”. Actuating the switch again causes the display to revert back to corrected volume.

For those installations where a remote indication of corrected volume or flow rate is required, the computer has an optional remote repeater. The repeater, also containing an 8 digit LCD, is hard wired to the computer and can be located within a 1000 foot radius. Corrected volume is normally displayed in the LCD. When a push-button switch on the repeater is actuated, the LCD indicates flow rate, updated every quarter revolution of the meter output shaft. The repeater requires no external power; it operates from the computer power supply.

SIGMA (Sonic Integrated Gas Measurement Assembly) A Real Time Measurement and Control Station

SIGMA™consists of a skid mounted Measurement Assembly and a Control Station. The Measurement Assembly is prepackaged and ready to attach to the pipeline; it contains two transfer meters, a meter calibration loop, a unique experiment to continuously determine the compressibility factor Z, and all necessary sensors, controls, valves and piping. The operation of the station is fully automatic; measurement data collection, station outlet pressure, meter and transducer calibration and communication to and from the station are controlled by a touch screen CRT master communications computer, two meter data terminals and a station controller.

The measurement assembly is a dual flow metering and pressure control station with an integral test loop for the American® GT™ turbine meters. Refer to Figure 5.

Each turbine meter is equipped with an ELSA™ flow computer and a high density pulser. The ELSA flow computers provide totalized base volume utilizing meter volume, pressure and temperature sensors and programmed constants for gas composition, i.e., specific gravity and N2/CO2 content. The ELSA computers are battery powered (rechargeable) to provide local corrected measurement in the event of an electrical power interruption.

The meter test loop provides a number of meter calibration points, using Sonic Monitors™ . A Sonic Monitor is a unique mounting and valving arrangement for a Sonic Flow Nozzle™ where the nozzle is mounted coaxially within a special Axial Flow® valve. By using these and other Axial Flow valves under computer control, these in-situ sonic flow standards can be placed in series with either custody transfer meter. The nozzles, based on a modified Smith-Matz geometry, are normally sized at about 10, 20, 40 and

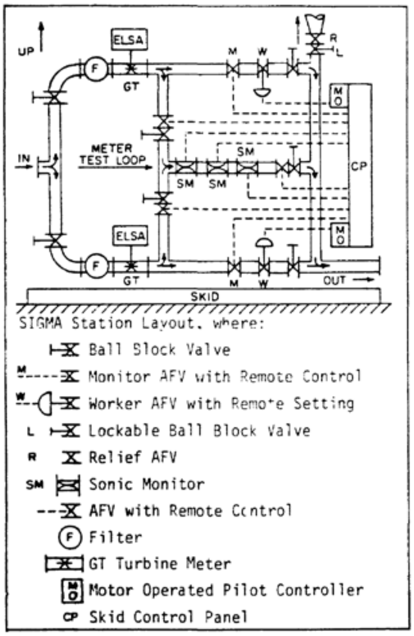


Figure 5. MEASUREMENT ASSEMBLY SCHEMATIC

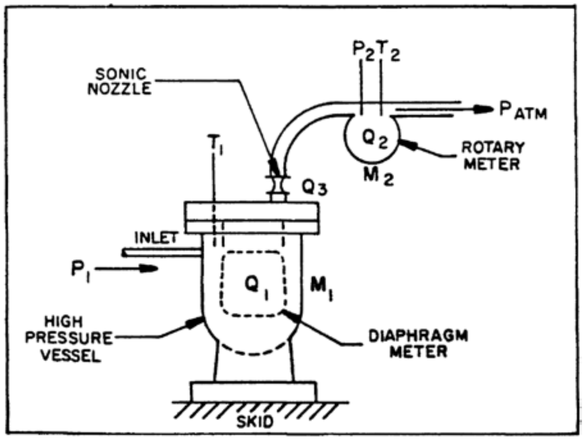


Figure 6. GAS COMPOSITION SENSOR SCHEMATIC

80% of the maximum meter capacity and have a certified accuracy traceable to the United States Bureau of Standards of ±0.15%

SIGMA also contains a unique gas composition effect sensor; a sensor that is able to measure the compressibility factor (Z) and a critical flow factor C* in real time. Refer to Figure 6.

The compressibility factor Z is determined by very accurately measuring the flow rates of a diaphragm meter (Ql) at station pressure (P1) and temperature (T1) and comparing these conditions to that of a Rotary Meter (Q2) at near atmospheric conditions (P2) and the resultant temperature (T2) after flowing through a

$$Vb = \text{Pulses}\left(\omega\right)\left(\frac{Pf}{Pb}\right)\left(\frac{Tb}{Tf}\right)\left(\frac{Zb}{Zf}\right)$$

Figure 7. ACCURACY CURVE OF A GAS TURBINE METER PLOTTED AGAINST ACTUAL FLOW RATE IN ATMOSPHERIC PRESSURE AIR

Sonic Flow Nozzle (Q3). After correcting for the ideal gas laws, the calculated difference of flow rates is the compressibility Z. Since meter flow rates are used instead of volumes, the determination of the factor is continuous. The significance of employing a live Z factor in the base volume can be seen in Charts B and C which show how the compressibility factor varies as a function of Specific Gravity and CO2/N2 content versus line pressure.

Performing a sonic nozzle calibration of the station meters would normally require a knowledge of the gas composition. In SIGMA, the critical flow factor is determined by very accurately measuring the flow rate of the diaphragm meter (Ql) compared to the calibrated flow rate of the critical flow Sonic Nozzle (Q3). After determining the prevailing meter flow rate on the gas currently flowing through the station, it is possible to ratiometrically determine a critical flow factor and, thus, the precise flow rate of each sonic nozzle in the calibration loop. This experiment is also continuous. Since it measures the effect on sonic velocity caused by 100% of the gas, this method is more reliable than trying to compute the factor from gas analysis (not all gases are detectable in a gas chromatograph, for example).

These experiments, Z and C*, eliminate the need for auxilliary equipment such as gas chromatographs and eliminate the manpower needed in gas sampling methods. The results of the experiments are fed to the station's Meter Data Terminals for computation of standard volume and flow rate.

Normally, the equation for base volume is expressed as:

$$Vb = Vf\left(\frac{Pf}{Pb}\right)\left(\frac{Tb}{Tf}\right)\left(\frac{Zb}{Zf}\right)$$ Equation #1

Where Vf is volume in actual cubic feet at flowing gas conditions. In practice, the Vf term is expanded to:

$$Vf = \text{pulses}\left(\frac{1}{K}\right)$$ Equation #2

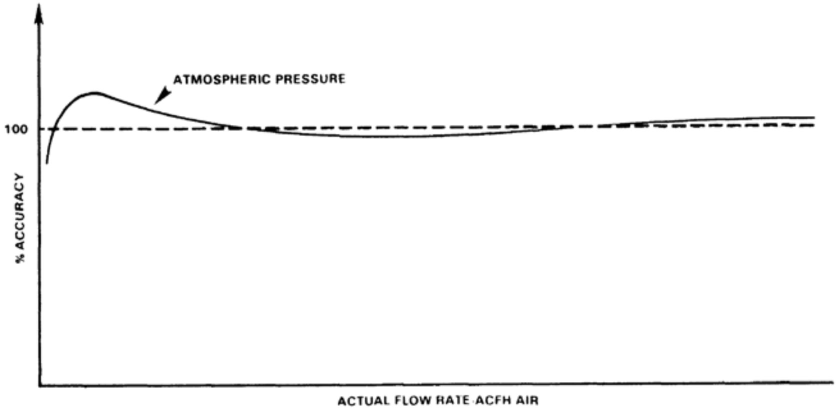
where the number of pulses is related to whole or partial revolution of the turbine meter rotor and the K factor is a fixed value in pulses per cubic foot determined during calibration at some point on the calibration curve.

The SIGMA station recognizes that the K factor for a turbine meter is not a constant, that it can vary as a function of:

1. Flow Rate — The calibration curve of a turbine meter is not a perfectly flat, horizontal line over the total flow range of the meter, as shown in Figure 7.
2. Density — The accuracy of a turbine meter can vary slightly between atmospheric and high pressure calibration tests.
3. Piping Effect — Pipe bends, pipe fittings and obstructions such as regulators, valves or even foreign matter ahead of a turbine meter can cause severe changes in the K factor due to gas jetting, swirl turbulance, or pulsing.

4. Service Condition — Friction, wear or rotor damage may affect turbine meter calibration, particularly at the lower end of the meter flow range.

To insure the accuracy of the uncorrected volume term (Vf) in the base volume equation, the SIGMA calibration loop tests the turbine meter at several flow rates while operating at line pressure, under actual inlet piping conditions and in its current service condition. This allows the station to compute base volume using a modified volume term:



Equation #3

where the term replaces the fixed K factor and accounts accounts for the four operating variables listed above.

In effect, SIGMA extends the concept of real time measurement beyond the inclusion of a dynamic Z factor by automatically correcting for any possible errors in the meter factor, Vf. The result is base volume computation, in accordance with Equation #1, where all the factors in the equation are measured on a real time basis.

THE FUTURE

Like other businesses, the gas industry can expect to see more and more use of technically advanced electronics in all aspects of its operations from SCADA systems to meter reading. The days of the mechanical pressure compensated index is already numbered. When cost justified automatic meter reading arrives—and it will not be long—even the standard meter index will be replaced.

Electronics will find its way into such things as vandal detection devices, portable meter and instrument calibration and, who knows, perhaps even into a 21st century version of pre-payment meters to solve the difficult accounts-receivable problem faced by metropolitan utilities. What we have seen thus far is the tip of the proverbial iceberg. Lots of exciting new products are in the offing.

None of what has just been described would be possible without microelectronics. For instance, the Sigma Station Controller (Figure 8) orchestrates the operation of the calibration loop and the Z and C* tests as well as controlling station pressures and flow rates. The Meter

Data Terminals (microcomputers) accept data in digital form from several sources to compute and display base volume and flow rate in addition to other information. The station's Master Communications Computer facilitates local or remote control of station set pressure, flow rate, alarm values, and test cycles; it also displays, records and prints any history (for instance, P, t, flow rate, Z and C* history).

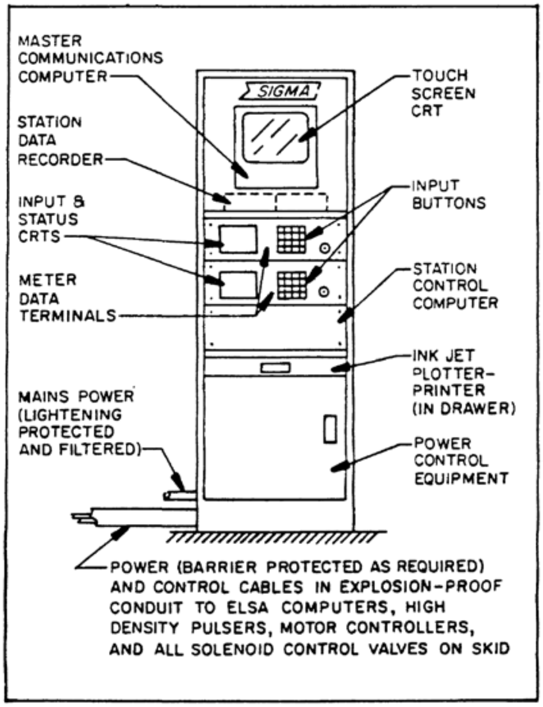


Figure 8. STATION CONTROLLER LAYOUT

REMOTE DATA COLLECTION SYSTEM AND COMMUNICATION WITH A CENTRAL COMPUTER

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ABSTRACT

Microelectronics, microprocessors, state-of-the-art, high-tech, are some of the new “buzz” words reaching into gas distribution. The introduction of intelligent flow computers, electronic volume temperature and pressure correctors along with fully automatic communication and alarm systems, at an affordable price, automates distribution This holds true also in production and transmission.

A gas utility having the ability to remotely calculate consumption and with accurate communications, transmit the data, opens up new avenues for creative rates. This is becoming more visible in the interruptible, transportation or carriage, and peak demand billing accounts. Cash flows are enhanced by the ability to read and bill the same day with total accuracy.

Alarm capabilities which will notify the gas company immediately for such non-standard conditions as: energy diversion, intrusion, tampering, regulator failure, compressor failure, leak detection, and low pressure, to name a few, also help justify this new technology.

The following paper introduces a system which allows a utility to incorporate the above benefits and maintain control of its destiny. The system is solely owned and controlled by the distribution company without third party interface.

REMOTE DATA COLLECTION SYSTEM AND COMMUNICATION WITH A CENTRAL COMPUTER

Introduction

In today’s changing world, it is necessary to have more and more information available to adequately manage any business. Certainly, this is no less true for a gas utility than it is for any other commercial business. Until recently, however, it has been uneconomical for the utility to obtain all of the information it needs for efficient system operation because of the diversity of its customers. Now, because of recent advances in technology, it is becoming more and more feasible to collect the information needed. Several different communication technologies are currently maturing into economically justifiable systems. Today, I will concentrate on a means of communication that has been in existence for quite awhile, but has only recently become viable for widespread application. I will be talking about using existing telephone lines for automatically reporting information about the gas consumption back to the utility from the customer's meter site.

The recent deregulation of telephone service has made such use of customer's phones possible. Essentially, deregulation means that the customers now own the wiring within their structures and therefore can attach any approved device to these lines that they wish. Later, I will discuss the economic impact of this change and what it can mean to you—the utility. I will also explain the process used for communicating between the customer site and the utility's central location. Obviously, sharing the customer's phone requires special equipment so that the customer will not be inconvenienced or have his normal use of the telephone curtailed.

First, I will briefly describe some potential applications for this data collection technology. Included will be meter reading, load management, and alarm reporting.

Applications

Everyone would like the ability to remotely gather consumption data, rather than having to send someone to each site to collect it manually. Although this is a desirable goal, the reality of the situation is that electronic meter reading alone is just not cost effective at this time. The decrease in price of electronic component parts and the increase in cost of the American labor force are bringing this reality closer each month. However, in any service area, pipeline or distribution, a certain percentage of meters are significantly more expensive to read than those in the average residential sub-division. Remote data collection systems can read such hard-to-access accounts effectively. Automating the meter reading process for the ten to fifteen percent of your accounts that are hard-to-read is normally very easy to cost justify. In addition, using such a process significantly lowers your average meter reading cost throughout the system.

Lets look at what types of meters or accounts we would want to read and why:

A. Large Industrial or Commercial
B. Transportation or Carriage Accounts
C. Interruptable Accounts
D. Purchasing Points or Town Border Stations
E. Firm Accounts
F. Multi Rate Accounts
G. Remote Accounts
H. Residential Accounts

1. Hard-to-read
2. High Crime Areas
3. Inaccessable
4. Transient
5. Bi-monthly Average Billing
6. Rate Studies, Load Profiles

Justifying the Application

Industrial and Commercial Accounts. A significant amount of revenue is generated from these accounts. Many types of instruments and chart recorders are placed at these sites. An automatic metering system with full programmable communication placed at these sites will allow you to monitor uncorrected and corrected gas consumption on an hourly basis. The central computer will provide you with gas consumption profiles and monitor, from the uncorrected and corrected reads, the pressure factor. This will enable you to ascertain the accuracy of your mechanical instrument and the pressure regulators. Many gas utilities are also researching a potential "peak demand rate structure".

Transportation or Carriage Accounts. Some large industrial accounts purchase gas direct from the producer and only pay the gas company a transportation fee. Since gas, a commodity, is purchased on a twenty-four hour period, it is beneficial to monitor the consumption in this same period. Profiling these accounts and their demands offer the utility the opportunity for creative and competitive rates and possibley win back the account as a full customer.

Interruptible Accounts. An automated monitoring system is almost a must for utilities who not only have interruptible customers, but actually interrupt then. If timing and penalty billing is important, a system that will monitor time, meter reading, and consumption during the curtailment period is a must.

Purchasing Points and Town Border Stations. This is an important point in gas transmission and distribution where monitoring is necessary. Monitoring the flow and pressure is important for the gas control function in a distribution company.

Firm Accounts. Where a customer agrees to purchase a certain quantity of gas for a specified period, the quantity very often dictates the rates. Did that account meet his contract requirements? After the contract amount is he on interruptible rate or another metered rate? Remote metering of these accounts enables the utility to answer these questions and address control.

Multi Rate Accounts. Much like the above scenario, many accounts are or could be utilizing multi rates. This allows the utility, in many cases, to be more competitive against other fuels. The problem is monitoring with accuracy the various rates and the consumption in each rate. Obviously, the problem compounds when there are multi meter runs and the total consumption versus time must be measured.

Remote Accounts. The expense of reading a meter or changing out a chart compounds with the remoteness of the accounts. These remote accounts are a primary target for the new automated meter reading and alarm systems.

Residential Accounts. Automating meter reading for residential accounts, in general is NOT justifiable yet. The row houses in a community, if the meters are accessable, are not too costly to read. The hard-to-read meters stated previously are of first concern. Call backs, for instance, in order to obtain a meter reading are very expensive to handle.

Manual meter reading costs, as you know, are highly labor intensive, and this is one of the considerations which make an automated system highly desirable. On the other hand, electronic cost trends are downward and substantially less labor intensive. If we could accurately define these two costs and plot them on a graph, we would find the cross-over point closer than most people would predict.

There are many cost considerations for automatic meter reading and many variables. Some of these considerations and variables are as follows:

The cost of:

- Meter Reading Operations
- Customer Accounting Operations
- Customer Relations Operations

– Credit and Collection Operations
– Data Processing Operations
– Meter Department Operations
– Service Operations
– Mail-room Operations

Communication Process

Now that we have discussed the necessity and applications for the first part of this paper, 'Remote Data Collection', lets proceed with 'Communication with a Central Computer'.

I mentioned in the introduction that I will concentrate on using the existing telephone network as the means of communication.

How would you actually use these telephone lines to communicate information to a central computer? Probably the best mode of operation for this type of data collection is to allow the remote unit to dial the central computer— as apposed to having the central computer dial out (that is, poll) the remote sites. The typical process that would be used is as follows:

1. The remote data-collection device would decide for some reason, whether at a pre-scheduled time or because of some alarm condition, that it is time to call the central computer.
2. The device first looks at the phone line to determine whether or not the customer is currently using it. If the customer is using the phone line, the device must recognize this and not attempt to use the phone at the same time. Typically, the device would then go into a retry mode so that it will check periodically (for example, every five minutes) until the phone line becomes available.
3. If the line is available, the device will pick up the line and dial the number of the central location.
4. The central location will detect that its incoming line is ringing and pick up the phone. When this happens, an identifying signal is sent down the line to the remote site that a communications link has been established. If, for some reason, the central site does not pick up the line (for example, the line is busy) the remote site would have to be smart enough to recognize that it did not get an answer, then hang up the line and try again later.
5. Once the communications link has been established, the data is transferred as appropriate to that particular data collection device and the call is terminated by each end hanging up the line. At that point, the unit at the central end is available to receive another call from a different device and the customer line is once again available. Also, the central end can be equipped so that it can process calls from more than one data-collection device at a time.
6. A key ability, which is provided only when the remote site can initiate calls to the central computer, is reporting alarm conditions. Via alarms, company personnel can be notified immediately whenever the remote device detects that soemone is tampering with the meter. A wide variety of tamper-detecting sensors can trigger alarm calls based on almost any conceivable type of tampering that is attempted. In addition, this same alarm reporting capability allows the utility to offer additional services to its customer base—such as fire, burglar, or health emergency alarms.

   An interesting extension of this alarm reporting ability is that it provides a fairly low-cost automatic fault-isolation system, where the computer system could simply detect where the fault in the network exists. This is an example where using the telephone lines, which operate completely independently, is a great advantage.

It is important to note that, throughout this data-transmission process, the customer might pick up the phone line to use it. If this occurs, the device at the remote site must recognize that the line has been picked up and immediately abort its call. In this way, customer inconvenience due to the data-collection device is minimized. Just as important to the utility, of course, is to prevent information to creep into the data base at the central computer if the customer does interrupt a call.

Conclusion

Using state-of-the-art technology to remotely collect data for many various reasons is becoming very cost justifiable because of immediate fault condition alarms, and also an increase of cash flow.

Using dial-up telephone lines is not necessarily the answer to all data-communications requirements a utility will have, but it does provide a solution that is currently feasible in many cases. In addition, since it requires additional equipment beyond the data-collection device and the central computer, it is frequently the least expensive and cost effective system available.

WATER METER TECHNOLOGY AND THE GAS INDUSTRY: AUTOMATED METER READING SYSTEMS HAVE BECOME MARKET DRIVEN

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ABSTRACT

This paper outlines a basic introduction to the central meter reading (CMR) system for gas, water and electric utilities as produced by Neptune Information Systems, an Allied-Signal company. Covering the history, origin of the system and features of CMR, it gives the reader reasons as to why this technology is emerging at a rapid rate and what some of its far reaching applications will be. The appendices further explain the functions of the systems and how they would integrate into an existing phone or cable TV communications network.

WATER METER TECHNOLOGY AND THE GAS INDUSTRY: AUTOMATED METER READING SYSTEMS HAVE BECOME MARKET DRIVEN

Introduction and History

Thank you for inviting me to speak at this conference on the integration of microelectronics in the gas industry. You may wonder first why a representative from a company that originated from water metering would speak at a conference supposedly related only to gas metering. NIS was formed to meet the needs of more than just the water metering industry. Our base in water metering has shown that there are commonalities among all the utility industries in the need for concise metering information. Both gas and water meters are traditionally located indoors, making reading difficult and sometimes near impossible. Most have few tools at their disposal for detecting system leakages ouside of customer calls. There is also a real need for increased accuracy and immediacy in the readings obtained. The faster you know the readings, the faster a bill can be generated. And the better the cash flow situation is within the user utility.

So as you can see there are some good reasons why I'm here to talk about our company, our product and our commitment to this concept of automatic centralized meter reading. First though I would like to give you a brief history of our company and some of the things we've accomplished so far.

Neptune Water Meter Company was founded in 1892 and has been a leader in the water meter industry for almost a century. With a complete line of both residential and industrial meters to meet a variety of customer needs, Neptune has remained in the forefront of technological advances in the art of metering. Over 20 years age, we pioneered the development of encoders and an integrated Automatic Reading & Billing (ARB) system. An encoder is a simple device that turns the hard geared registration on a meter into electronic impulses that can be read and transmitted over a communications network. This development was undertaken to differentiate the Neptune product line from other manufacturers and to establish the foundation for future automatic reading systems. The ARB encoder is now used in over two million customer locations.

In 1976, Neptune Water Meter deployed their first Central Meter Reading (CMR) system. This system differed from the ARB system in that data gathering was performed automatically from a central station over some carrier's lines to the customer installation. The utility initiated the call to interrogate the meter data from their office and the data was returned automatically, without requiring a site visit. Systems can use either cable or existing telephone lines for the data transfer.

Neptune Water Meter Company became the market leader in CMR technology, with eight CMR programs in progress. These programs aided the development of CMR to meet the needs of not only the utilities but also the telephone and cable TV carriers.

These included needs such as the ability to read meters without having to enter the customer premises; obtaining accurate meter information in a timely manner; reducing cash flow by speeding up the billing process; eliminating estimated billing; and giving the utility a tool for detecting leaks and theft of service.

Neptune Information Systems (NIS) is one of the Allied-Signal Companies. With the progressive backing of this high technology company, NIS is set up as a division that concentrates its efforts on CMR, expanding beyond the basic charter of water metering. In March of this year, NIS was started with the sole purpose of becoming a leading information systems provider in the water, gas and electric utility industries.

NIS is headquartered in suburban Atlanta, Georgia in one of the fastest growing high tech areas in the country. Our location houses all engineering, research and development, marketing and production facilities. Although a new company, our employees are seasoned professionals from the telecommunications, data processing and utility industries.

With Allied-Signal's philosohical and financial support, NIS is continuing to develop CMR to meet the present and future needs of the utilities industry. NIS is dedicated to providing the design, technology and continued improvement of affordable CMR systems for utility management. I stress the word "affordable" because we believe this is crucial to the future success of CMR type systems. The vast majority (95%) of customer locations (especially residential) only require a simple meter reading function and not an elaborate high tech electronic box that can do many functions. Our goal is to provide a simple, reliable, economic unit that can be deployed today and also meet the needs of tomorrow. As more sophisticated systems are justified, NIS will be ready to meet the need.

CMR Efforts Today

NIS is concentrating its CMR efforts in two areas that are related to the carrier used: (1) a telephone polling or dial-up system and (2) a cable TV based system. Both systems offer utilities automatic meter reading capabilities. A choice is offered because the implementation of a CMR system requires coordination with the carriers, and at times the service area of one carrier is more in line with the area the utility wants to monitor than the other one is. NIS can also provide a complete turn-key system, with full support from system analysis and design to financing to on-going agency services.

The telephone system design has evolved from the early scanning type systems to a more cost effective dial-up system which uses the existing remote testing equipment in the telephone equipment offices. The dial-up system simplifies the installation process and eliminates the wiring congestion which had resulted with the scanning system.

This new phone system design has been customized to fit within the Bell Company divestiture guidelines for services they can offer. Telephone company reaction to the dial-up system has been very positive. They were often reluctant to get involved with CMR programs in the past because of the headaches it created for them. Now the BOCs and other phone companies are very interested, not only because the equipment is much simpler for them but primarily because of their new entrepreneurial attitude towards new service offerings. In many cases, they are now taking the lead in an effort to offer the service within their territory.

Utilities have also responded favorably to the concept of CMR. Especially in the more northern areas of our country, metering for both gas and water is located indoors. Due to the fact that more women are entering the workforce and there often is no one at home during the day, obtaining accurate and verifiable meter readings is proving to be a difficult task. CMR eliminates this problem because the readings are obtained directly over the phone or cable TV wire without actually having to see the meter.

This brings up another interesting point: CMR is very much a market driven concept. You might ask why this is. Well, CMR is something that certain customers have been requesting for years. AS the technology has advanced to the point where the CMR concept is economically feasible, more and more user utilities have seen the advantages of using such a system in place of and as an addition to their current meter reading programs. CMR may appear to be more expensive on the front end than a body of meter readers, but when you consider the difficulty of reading the meters, the frequency of inaccurate readings and requests for verification, and the need to eliminate estimated billing, the economics are beginning to fall in place.

CMR is becomming the first affordable tool that utilities can use to check up on what is going on in their systems. Not only can you verify customer usage right at the meter location, you can also put monitoring equipment at main feeders and valving points to frequently monitor usages there. Leaks can be quickly detected by adding and subtracting meter readings taken at the same time in different areas of the same feeder system. Since the meter readings are recorded by computer, an exact visual and permanent record of consumption results. Finally, the CMR concept is designed to fit in with a utility's existing billing and computer procedures. Data obtained from the meters can be directly input into your exising routines for fast and automatic bill generation. This eliminates the trouble associated with the transcription of meter reading data from the route logs.

All this of course is made possible by advancements in technology. Without the advent of microelectronics, a concept such as CMR would not have been affordable for most utilities. But using computers, microprocessors and the like, automatic meter reading is both affordable and easy to use. A typical system would include one transmission unit, called an MIU, per installation with encoders on each meter to be monitored. Hardware located in the carrier's office, and by carrier I mean either the phone or cable company, transmits the readings over a phone link to the user utility, where they are input into a computer for further processing and bill generation.

I mentioned that encoders would be required on each meter to be monitored. Each MIU will communicate with up to four different encoding devices. These can include gas, water and electric meters. Additionally each user utility can interrogate their own meters without receiving the readings for the others. This feature can help utilities justify the purchase of a CMR even more easily by allowing them to purchase it as a group for more than one application. Each user utility would have their own computer at their office for collection of the readings and would maintain their own customer list, but all would use the same communications links and the same MIUs.

Future expansion is something that this system is well suited to. In the CMR market, the active promotion of the concept of inexpensive and cost effective information transfer is key. This could include many varied enhanced services. Making it possible for your customers to use these enhanced services without a high initial cost will benefit utilities in the long run by creating a more positive company image.

CMR can't and won't happen without your support. Your request and those of other utilities like yours for a meter reading system that would eliminate and reduce many of the headaches associated with the traditional way of doing things is exactly why we are in this market today. This morning I've given you an overview of where NIS originated, our corporate committment to this marketplace, a description of the functionality of our system and some of the benefits you will derive from its use. I invite you to speak with us further about using CMR in your specific applications. We also invite you to visit our offices in Atlanta and see CMR in action for yourselves.

I thank you again for the opportunity of speaking at this meeting and if there are any questions at this time, please feel free to ask.

FUNCTIONAL OVERVIEW

CMR is a computerized data collection system developed by NEPTUNE INFORMATION SYSTEMS and is designed for efficient, cost-effective central meter reading. Utility (gas, water, electric) usage information is transmitted over the customer's existing telephone line to the utility's computer for billing and other administrative functions such as leakage detection and tampering control. It will also improve customer service as it will allow the utility to respond quicker to customer inquiries regarding utility usage or billing problems.

The CMR telephone system is made up of five main components:

1. Utility meter with compatible 3-wire encoder
2. Meter Interface Unit (MIU) at customer's premises
3. Subscriber Line Access Controller (SLAC) at the telephone central office
4. Protocol Converter at the utility's premises
5. Communications Control Unit (CCU) software for utility

The Subscriber Line Access Controller (SLAC) is located at the telephone company and uses a dial-up arrangement to access the customer's meter to gain meter reading information. The CMR telephone system does not ring the customer's telephone nor does it interfere with the customer's telephone service.

The CCU directs the SLAC to dial-up the customer's working telephone line and to interrogate the MIU for utility usage data. Once the MIU identifies a valid tone, it uses the telephone line power to activate the meter encoder and transmit the utility usage data to the MIU, through the SLAC, to the Protocol Converter. The Protocol Converter reformats the data from the meter encoder format to the proper CCU format. (The CCU software is run on a utility owned computer.)

Both the MIU and SLAC transmit the data as received without storing it. They are transparent to the system and allow for different meter encoder formats without changing out either the MIU or SLAC. To accommodate different meter encoders changes are made in The Protocol Converter.

CMR provides a solution to many of the meter reading problems utilities face today. The system employs several key elements of Neptune's advanced patented central meter reading technology. Central meter reading systems from NIS are the answer to security, access, and accuracy concerns as well as the increasingly high cost of manual methods used to measure and manage utility resources. Only NIS can offer the depth of experience, the technical innovation, and long-term support that have made NEPTUNE INFORMATION SYSTEMS the market leader in central meter reading.

SUBSCRIBER LINE ACCESS CONTROLLER (SLAC)

The SLAC provides dial-up access to any working telephone line in the appropriate serving central office by using the test trunk equipment at the telephone company. (The test trunk facility allows for use of the telephone line, without ringing the customer's telephone, to transport meter-reading data.)

The SLAC directs the central office test trunk to provide access to subscriber loops for the purpose of obtaining data from meters at the subscriber's premises.

The SLAC is rack mountable, 3 1/2 inches high, 19 inches wide, and with adapter provided, can be installed in 21 inch racks. A key switch, access counter, keypad, and display are provided on the front panel.

Power for the SLAC is supplied by the central office battery. An internal modem enables the SLAC to communicate with the Protocol Converter and the Meter Interface Units (MIU). Two internal counters record day/night usage and an external counter also records total usage.

A real-time clock, built into the system, controls the incrementation of the internal counters. These counters record each successful access in accordance with the time of day and enables the customer to be billed on a peak and off-peak rate schedule. The clock has a built-in battery back-up.

Security is provided by an internal auto-dial modem. Upon receiving a request and a proper log-in sequence from the utility's remote terminal, the modem breaks the connection and dials a pre-programmed telephone number for a specified user's terminal. Once the SLAC is reconnected to the utility's terminal, the Communications Control Unit (CCU) communicates with the SLAC and proceeds with dialing up the individual customer telephone lines. The telephone company controls the SLAC programming of telephone numbers and log-on passwords.

The SLAC provides for connection to the central office alarm system. If the unit malfunctions, camps on a customer's line, and is unable to restore the test trunk to its idle state, the unit attempts to free itself and, if unsuccessful, signals the alarm.

PROTOCOL CONVERTER

The Protocol Converter is a device that hooks up to the incoming telephone line from the SLAC via a standard RJ11 jack. The Protocol Converter then reformats the data received from the MIU into a format acceptable to the Communications Control Unit (CCU) software package.

The Protocol Converter allows for the efficient conversion of different meter encoders at a centralized point just before the CCU. If different formatted meter/encoders are deployed in the future, they can also be protocol converted to be compatible with the existing SLAC and CCU.

The Protocol Converter is connected to the CCU computer by means of a standard RS232 link. A 212A compatible modem connects the Protocol Converter with the telephone network. It handles data up to 1200 BAUD.

COMMUNICATIONS CONTROL UNIT (CCU)

The CCU is a software package (based at utility) that can be run on a compatible personal computer (e.g., IBM-AT model) or on the utility's mainframe computer.

The CCU stores customer information including meter identification number and telephone number. It can be programmed to contain the operating system that schedules and directs the SLAC to read selected customer meters on certain days. This enables the utility company to control the meter reading schedule.

The CCU is a user-friendly system which allows the utility to easily update the data tables for such things as customer's name, telephone number, meter identification, etc. The CCU can also provide meter reading data on demand, as well as generate various analytical reports to assist the utility in managing their customer accounts.

METER INTERFACE UNIT/(MIU)

The MIU is customer premises equipment (CPE) owned by the utility. It connects the customer's working telephone line to the meter/encoder. The MIU measures 6 inches, wide, 7 inches high and two inches deep, and can be wall mounted. It is connected to the meter/encoder by a three-wire hook-up.

Each MIU can accommodate up to four meters. The total system time to read four meters is approximately sixteen seconds. The MIU is FCC registered with a . 5Z ringer equivalent. In its active state, the MIU draws 5 milliamps and operates on 44–56 volts DC. It has an on-hook impedance of 2.2 megaohms in its idle state. It uses a two wire (tip and ring) connection to the telephone network by attachment to the telephone protector block. It is not polarity sensitive, is powered by the telephone line (48 volts), and operates in the standard voice frequency range.

FUNCTIONAL OVERVIEW

CMR is a computerized data collection system developed by NEPTUNE INFORMATION SYSTEMS and is designed for efficient cost-effective central meter reading using two-way cable TV networks. The heart of the system is a Communications Control Unit (CCU) which collects and stores meter reading data from remote terminals (utility customers) throughout the network. The CCU is a dedicated, embedded computer coupled to the cable plant through a cable data interface (CDI/receiver). (The accompanying sketch illustrates the system component relationships and operation.) A unique feature of the system architecture permits the system to operate in an unpolled mode. That is, communications between the remote terminals and the CCU are upstream only. Unlike more complex polled systems, CMR does not consume any of the valuable downstream cable channel space for polling signals. This proven feature makes it more economical to acquire, install, operate, and maintain.

The system consists of the head end equipment, a CCU, and cable data interface(s) located at the cable plant, and remote meter interface units (MIU) located at the utility customer's premises. From the meter registers to the head end computer output, the system is entirely digital. The MIU terminal interrogates digital utility meter registers such as the Neptune ARB, reformats the reading information into a data packet and then transmits this via the cable to the communications control unit. The CCU in turn evaluates the data and performs error checking routines. If the meter reading data is accepted by the CCU, it is stored in memory and made available for use by the utility company. If the data is not accepted, the fault condition is noted and the information is discarded. The CCU operating system software provides a wide range of information for the user utilities and the cable operator. Operation of the CCU is controlled by a series of three letter commands. These include the ability to display and print information for a single or a range of sites, a check for error conditions, and an evaluation of the overall operational status of the system. The system is designed to operate completely unattended. Interaction with the CCU can be accomplished through the local on-site port, or remotely by using a password protected data communications feature. The data communications feature is typically used by the user utility to monitor system operation and extract meter reading data.

CMR provides a solution to many of the meter reading problems utilities face today. The system employs several key elements of NEPTUNE'S advanced patented central meter reading technology. Central meter reading systems from NIS are the answer to the security, access, and accuracy concerns as well as the increasingly high cost of manual methods used to measure and manage utility resources. Only NIS can offer the depth of experience, the technical innovation, and long-term support that have made NEPTUNE INFORMATION SYSTEMS the market leader in central meter reading.

METER INTERFACE UNIT (MIU)

The MIU is a microprocessor controlled terminal unit designed for remote data acquisition. It is customer premises equipment (CPE) owned by the utility. In the CMR system, it accesses meter reading data and sends the information to the Communications Control Unit (CCU) at the utility company. The MIU is designed for indoor or outdoor mounting and is powered by a small plug-in transformer.

Up to four (4) CMR compatible meters may be read by each MIU. The entire data acquisition and transmission process is digitally encoded for maximum reliability. Each unit is assigned a unique identification code which is transmitted with the meter reading data packet. The complete data packet consists of the site ID, an MIU status indicator, and the four most significant digits of meter reading data from each meter port, encoded in a proprietary format. A 16-bit cyclic redundancy check character is appended to the data packet to assure reliable transmission results.

MIU SPECIFICATIONS

Physical:	
Enclosure:	6.75" H×6.00" W×2.13" D
	17.1 cm×15.2 cm×5.4 cm
	Sliding cover for connection access
	2 grommeted cable entry openings
	Provision for cover tamper seal
	Gray polymer weather resistant design
	2 #8 clearance mounting holes inside the cover
Connections:	Power — screw type terminals
	Meters — screw type terminals

	RF Output — type ‘F’ female coaxial
	RF Test Port — RCA phono jack
Environmental:	
Operating:	0 to 70 degrees Centigrade
	0–100% relative humidity, non-condensing
Storage:	−40 to 90 degrees Centigrade
	0–100% relative humidity, non-condensing
Electronic:	
Input Power:	5ma @ 115 VAC nominal to power module
	30 ma @ 9 VAC nominal to MIU
Output Power	30–50 dBmV ajustable into 75 Ohm impedance

METER INTERFACE UNIT (MIU) (continued)

Spurious Emmissions:	Suppressed greater than 55 DB
Modulation:	4800 baud PCM
Frequency:	T-10 band, 16 MHz nominal
Meter Ports:	5 volt CMOS compatible*
RF Test Port:	75 Ohm data sampling port*

NOTE: To assure compatibility and reliability, only NIS approved meter encoders and test sets may be connected to the MIU ports.

Status Indicator:	Flash rate of internal LED indicates status
Site ID:	Strappable from 0 to 65535

METER WITH ENCODER

The utility (gas, water or electric) meter must be equipped with a compatible 3-wire electrical encoder. The encoder is mounted on the meter housing and usually has the following features:

- Six digit visual register
- Quick indexing mechanism
- Corrosion resistant materials
- Weatherproofed and sealed unit
- Three terminals for electric connection to MIU

The encoder contains micro-circuitry which reads the registers and transmits the register reading in serial format. If the CMR system were to be temporarily disconnected, the register would continue to record accurate customer usage and would transmit accurate data once the CMR system was back in operation. Meters in varying sizes, from small residential customers to large commercial customers, can be equipped with encoders.

COMMUNICATIONS CONTROL UNIT (CCU)

The CCU is an embedded computer sub-system programmed to analyze and store meter reading data packets as they are received from the remote Meter Interface Units (MIUs) via the cable network and the cable data interface (CDI). It functions as a completely unattended processor using a real time operating system with the necessary software and hardware to recover from power failures and system faults.

Physically, the CCU consists of:

The Controller:

A processor and data storage unit available in either rack-mount or desktop enclosures.

The Console:

A standard video display terminal with keyboard for communicating with the controller and displaying system operating and diagnostic information.

The Printer:

A dot-matrix printer to provide listings of meter reading data and operating information.

The Modem:

A standard asynchronous 300/1200 baud modem to permit remote access and control by a dial-up telephone link.

Interaction with the CCU is accomplished by entering three letter commands via the console or from a remote site via the remote access modem port. The command set includes functions to display or print a wide variety of system operating parameters, meter reading data, and exception reports. In addition, a data transfer communications routine provides the means to send all or part of the meter reading data file to the user utility's computer for bill processing. For security, access to the CCU through the modem port is restricted by multiple levels of password protection.

As reading data is received by the CCU, it is checked for errors either in the data itself or inaccuracies caused by communications faults. Good data is then stored in memory with the date and time it was received at the cable data interface. Incomplete or erroneous data is noted in the system's error log and then discarded. Thus, the CCU retains only accurate data while noting error conditions for analysis and maintenance action.

CCU STRUCTURE AND OPERATION

The CCU contains:

CPU

Processor
Operating System Memory
Program Memory
Realtime Clock

I/O Ports

Console
Printer
Remote Access
Cable Data Interface

Data Storage

Mass Memory For Readings

Command Set:

MON	Monitor system activity and display incoming data
SST	Display active/inactive site status table
DSD	Display site data for remote MIUs
ALM	Display system and communications activity and errors
DTG*	Display or set system realtime clock
PSW*	Display or set passwords
DTX*	Data communications routine to transfer readings

Since the data file and operating system queues are quite large, displays and listings can be delimited for a range of entries and the results can be stopped, restarted, or terminated with single keyboard entries.

Commands marked with an asterisk (*) require a password to execute. Many display commands provide for optional printed report output listings. Refer to the current system manuals for a complete list and operating description of available commands.

METER MOUNTED INSTRUMENTS

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ABSTRACT

Turbine meters, like all other metering devices, measure natural gas at line conditions. Gas volumes vary with changes in temperature and pressure following the well known Boyle's and Charles' Laws. Base conditions provide a common reference for measuring gas at an inlet pressure of 4 oz. and a temperature of 60°F. Any variance in these parameters requires a calculation to correct the gas line volume to base volume. A number of ways have been evolved by the industry to obtain this base volume.

METER MOUNTED INSTRUMENTS

METER MOUNTED INSTRUMENTS

Chart recorders were developed in the early 1920s. Mounted on a Turbine Meter, this meter-driven device provides a record of volume and pressure by scribing lines on a circular chart. Periodically, the charts are collected and taken to a central facility to "integrate" the pressure and volume, to obtain base volume. These recorders are still used today as shown in Figure 1.

In the late 1920's, meter mounted mechanical instruments were developed to automatically correct gas volume for varying pressure. A change of pressure is translated into a change of position of a linkage within the instrument. Gas volume is then determined by an odometer which counts revolutions of the mechanical output shaft.

In the 1950s, meter mounted instruments began applying both gas temperature and pressure corrections. During calibration, a nominal compressibility ratio could be set into the instrument. Figure 2 illustrates a typical installation.

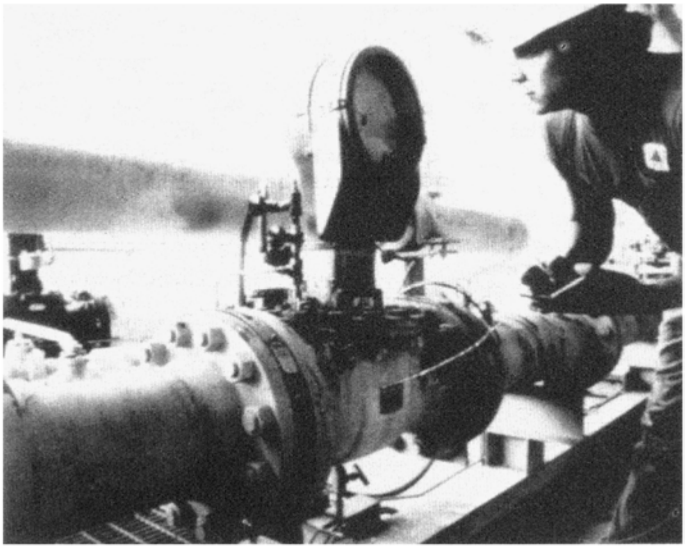

FIGURE 1

Meter Mounted Mechanical Chart Recorder

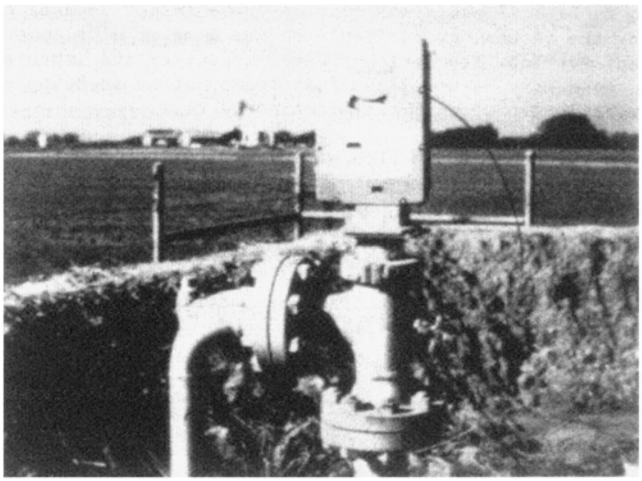

FIGURE 2

Mechanical Temperature/Pressure Corrector

Mechanical instruments have provided a means to obtain base volume for many years. Since they are driven by the meter's output shaft, (require no external power) they are still used in numerous applications today.

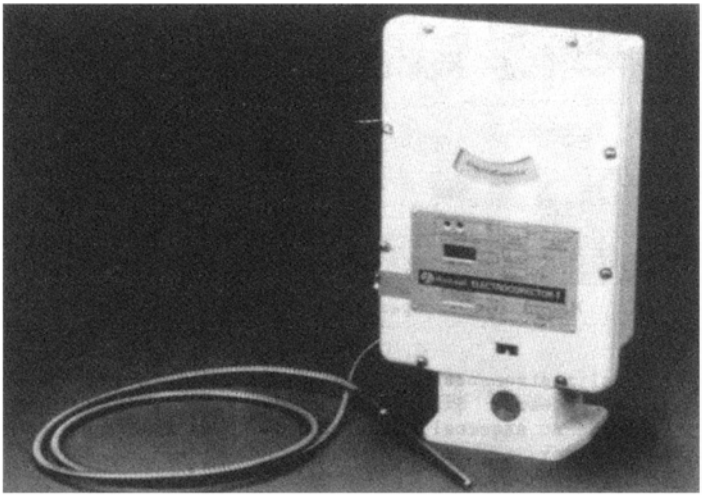

FIGURE 3

Electrocorector T temperature transducer is prewired and connected with an armored cable. Base volume is determined by the measured temperature and a fixed factor pressure.

ELECTRONIC BASE VOLUME INSTRUMENTATION

Analog and sequential logic electronic instruments began to appear in the 1960s. Due to the requirement for electrical power, these instruments could not be located close to the meter for safety reasons. The sensitivity of the instrument's accuracy to varying ambient temperatures necessitated the device being mounted in a "controlled" area, typically indoors.

The microprocessor revolution of the 1970s provided digital computational accuracy and flexibility in a relatively small size. The industry responded by developing base volume computers, which are capable of handling virtually any measurement condition. Instruments can calculate compressibility ratio, handle multiple meters, accept energy inputs and telemeter the data to other locations.

"ELECTROCORECTORS"

Both mechanical and electronic instrumentation designs have been driven by the technology available at the time of development. With the recent availability of low powered circuitry and improvements in battery technology, a new line of instrumentation is being developed by Rockwell International—the Electrocorectors.

Electrocorectors (Figures 3 and 4) are battery powered instruments designed to take advantage of the latest in low power circuitry and transducer techniques yielding both high accuracy and low maintenance. The Electrocorectors provide the sophistication and performance of base volume computers in a package that can be installed like mechanical instruments. Mounted directly on the index plate of a meter, the Electrocorectors obtain volume input via the meter's mechanical output shaft.

The temperature input is obtained from a temperature transducer which is prewired to the Electrocorector. It is connected with an armored cable and treated exactly like the temperature compensating instruments.

The pressure input is also obtained exactly as with the mechanical instru- ments. Only the connection of a capillary tube to a pressure tap on the Turbo-Meter body is required, since the pressure transducer is mounted in the Electrocorector's case.

Batteries are contained within the Electrocorector. No external power connections are required.

There are three versions of the instrument; the Electrocorector T, The Electrocorector P, and the Electrocorector P/T.

The Electrocorector T calculates base volume using a measured temperature and fixed factor pressure. The Electrocorector P calculates base volume using measured pressure and a fixed factor temperature. The Electrocorector P/T uses both measured temperature and measured pressure, to calculate base volume.

ELECTROCORECTOR T

With current emphasis on greater measurement accuracy, temperature correction is an important factor. On positive displacement (diaphragm) meters, a mechanical temperature compensating tangent is available. However, turbine meters, due to their construction, cannot be fitted with a built-in temperature compensating element.

Temperature correction is often complemented by the use of fixed factor pressure correction. By operating the meter at a constant regulated line pressure, the effects of pressure on the gas volume can be included using a fixed factor multiplier. Fixed factor measurement is gaining widespread acceptance with gas companies.

The Rockwell Electrocorector T (Figure 3) provides on-line measured temperature correction and the ability to set in a fixed pressure multiplier, giving greater correcting accuracy than can be provided by mechanical instruments. Since actual volume is measured by the meter itself, the electronic function is to correct for gas temperature variations by calculating the ratio of the absolute base temperature and the measured gas absolute temperature.

Accuracy. Tests to determine the Electrocorector's overall accuracy were conducted using two sets of conditions: 1) To determine accuracy of the temperature transducer, the temperature of the transducer was varied while holding the Electrocorector's temperature constant and 2) To determine the effect of the summer sun and winter cold on the Electrocorector's accuracy, the gas temperature was held constant while varying the ambient temperature.

The first of these tests (varying gas temperature) provided impressive results with about a±0.1% deviation over a 150°F range. In the second test, an ambient temperature variation from −30°F caused approximately a 0.07% devia- tion in accuracy. Based upon these results, the error specification for all effects can be conservatively set as±0.35%.

Pressure Multiplier. A fixed factor pressure multiplier can be set into the instrument with easy-to-use switches. Pressures from atmospheric to 1,500 psia can be accommodated using multipliers ranging from 1. 000 to 99.99. By building the pressure correction function into the instrument, the need for specially geared indexes is eliminated. Also eliminated is the after-the-fact application of a multiplier during bill processing, where the possibility of applying the wrong factor may exist.

Calibration. An essential element of any instrument is the ability to retain its initial performance characteristics through the use of an easy calibration method. The Rockwell Electrocorector Calibrator (Figure 4) provides this.

The Calibrator performs a complete check of the Electrocorector T by providing a transfer calibration; from the temperature transducer to the totalizer, in a matter of minutes. The calibrator has its own independent temperature trans- ducer. This transducer can be put into the thermo-well near the Electro-

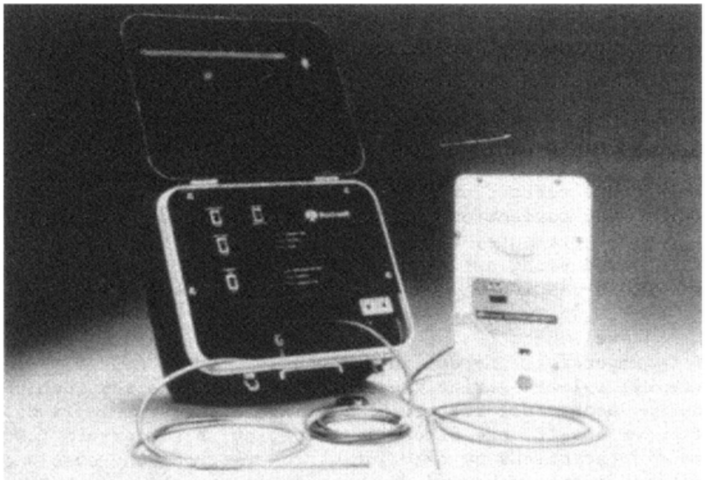

FIGURE 4

Electrocorector Calibrator perfoms a complete check of the Electorcorector T in the field. Any temperature deviation is corrected with one adjustment

corector's transducer to allow calibration under actual operating conditions. Or, an isothermal block, supplied as part of the calibrator, can be used to force both transducers to the same temperature. If any deviation is found during the calibration process, a correction can be made, in the field, by making only one adjustment in the Electrocorector.

In addition, the Field Calibrator checks the fixed factor multiplier switch setting by reading and displaying the value. It also provides three checks of battery condition and verifies proper operation of the corrected totalizer.

<u>Battery Powered.</u> A replaceable battery pack provides a nominal two years' operation under normal situations. A battery status indicator is incorporated which, when actuated, provides a warning of low battery condition. This check is performed by touching an area of the instrument case with a magnet. The status is immediately displayed without having to open the instrument's case.

An alternative to disposable batteries consists of a rechargeable battery system with a solar cell array. This solar panel power system can be expected to extend battery life to five years or more.

ELECTROCORECTOR P

The Electrocorector P is similar to the T with the exception of the measured gas parameters. As the letter P in the name implies the Electrocorector P calculates base volume using measured gas pressure and a fixed factor for scaling gas temperature and compressibility ration. This unit is meter mounted, taking its volume input from the meters mechanical output shaft.

Since the pressure transducer is contained within the instrument, it is treated exactly like a mechanical instrument requiring only the connection of the capillary tube. A series of pressure transducer ranges is available to handle a wide range of applications. This battery powered instru- ment can be calibrated with the same calibrator as the Electrocorector T.

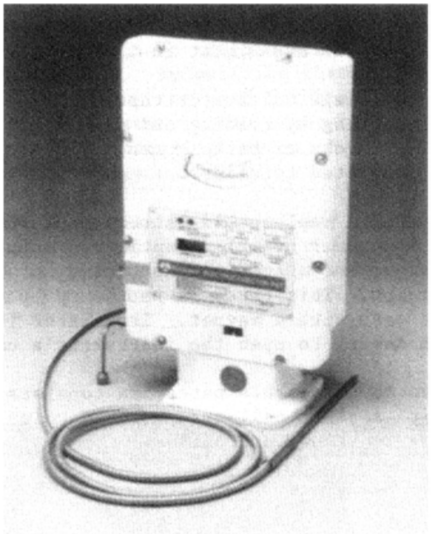

FIGURE 5

Electrocorector P/T measures both pressure and temperature to provide base volume.

Capillary tube connects pressure transducer in the case with the meter's pressure tap.

ELECTROCORECTOR P/T

The Electrocorector P/T measures both pressure and temperature and applies these measurements to the base volume calculation, including compressibility ratio. Physically, the Electrocorector P/T (Figure 5) is meter mounted on the meter index plate and includes a temperature transducer, identical to the Electrocorector T. The most notable difference is a capillary tube which transfers gas pressure from the meter's pressure tap, to the pressure transducer located within the Electrocorector P/T.

A series of pressure transducers are available to span applications from low pressures to 1500 psig. As with the Electrocorector T, the front panel displays include the uncorrected output (by a gear-driven odometer) and the corrected volume via an electromechanical totalizer.

Ease of initialization and calibration are important considerations in the choice of an instrument. By removing the Electrocorector's front panel, a connector is exposed which allows the connection of the Hand Held Terminal. This pocket calculator sized terminal allows for the entry of data such as specific gravity, mole % CO2 and N2, base pressure etc. The terminal is also used to calibrate the Electrocorector P/T, eliminating the need for transducer adjustment. Flow data which occurred over the previous 30 days can be easily collected with the terminal.

As with the Electrocorector T, a replaceable battery pack is available providing nominal one-year operation. The solar rechargeable power system can provide five years' operation.

Both the Electrocorector P/T and the Hand Held terminal have been designed to the specifications governing instrinsic safety.

Safety Considerations. The inherent nature of a meter mounted electronic instrument such as the Electrocorector T and P/T necessitate a design which is safe for use in a potentially explosive atmosphere. Of the various techniques (explosion-proof housings, purging, etc.) for attaining a safe design, intrinsic safety is the most practical. Therefore, the Electrocorector T and P/T have been designed to the specifications governing intrinsically safe equipment.

ELECTROCORECTOR FEATURES CHALLENGE MECHANICAL INTEGRATORS

- Accuracy — Measurement accuracy approaching that of the base volume computers is obtained.
- Calibration — The Electrocorectors have been designed to provide effortless calibration which can be performed by field personnel in a matter of minutes. No specialized technical training is required.
- Mounting — The Electrocorectors are installed exactly like a mechanical instrument -- no new procdures are required. Fewer precautions are required.
- Self-Contained — The battery powered Electrocorectors require no additional external connections.
- Safety — The Electrocorectors are designed to conform to the specifications of intrinsic safety to allow meter mounted convenience.

REAL TIME MEASUREMENT OF NATURAL GAS METER STATIONS

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ABSTRACT

Natural gas measurement as we have known is changing. Measurement used to be considered an art, now it has become a science. Also the natural gas industry has changed into a more competitive market. Gas distribution companies need to know how much gas they are purchasing and selling instantly. The advent of new technology and the need for immediate gas flow information has fostered the use of microelectronics by gas distribution companies. This paper will address the use of real time measurement equipment and how it is being integrated into a gas distribution system.

REAL TIME MEASUREMENT OF NATURAL GAS METER STATIONS

Entex, Inc. serves over 1.25 million customers in three states (Texas, Louisiana, and Mississippi). In these areas we purchase natural gas from suppliers, which we resell to our customers. Recently, we acquired a new supplier that would be used to supply gas to five different distribution systems. We determined that it would be advantageous to monitor the amount of gas we are using at each location. After evaluating several different methods of monitoring the gas flow we selected real time measurement (Figure 1).

Real time measurement is the means by which a microprocessor is used to analyze actual natural gas measurement data as it occurs (real time). The data is used by the microprocessor to calculate the flow and store it for retrieval at a later date. At the same time the unit has the ability to control any number of operations based on the calculated gas flow.

Before deciding to use real time measurement equipment, we looked at our current methods of monitoring natural gas meter stations. We use chart's and telemetry at our city gate stations (custody transfer sites). If we had used charts to receive the information, we would have had to send an individual to the sites each day to remove and calculate the charts. This method would be too time-consuming for personnel and at the same time, it would not allow us to constantly monitor the gas flow. A telemetry system would allow

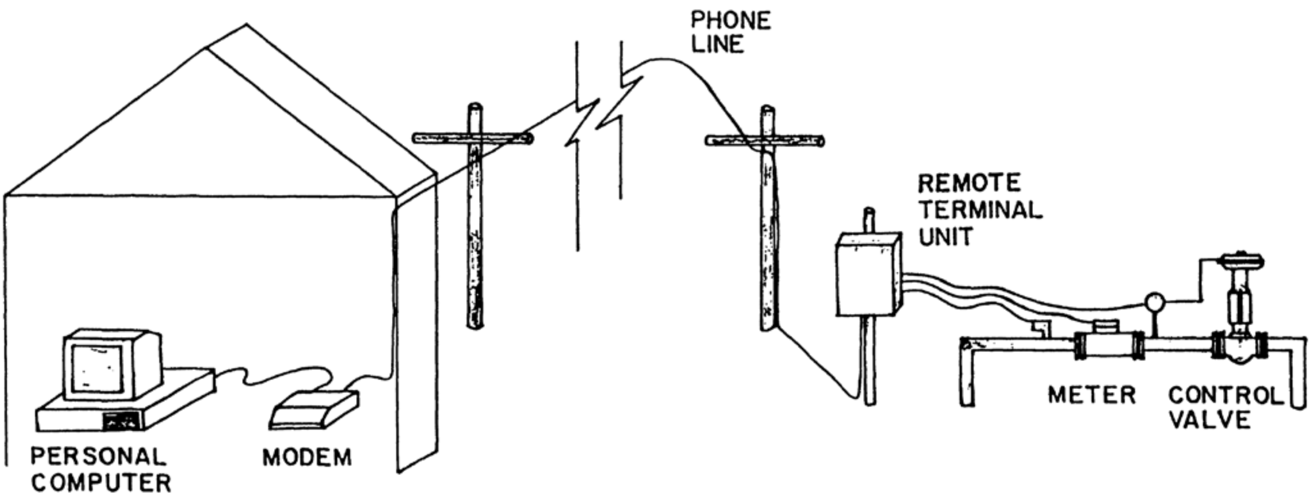

Figure 1. REAL TIME MEASUREMENT SYSTEM

us to monitor the flow continually. However, the cost of leasing phone lines between the distribution systems would be quite costly.

We began by setting up specifications for a real time measurement system and evaluating equipment currently on the market. Our basic specifications were:

Host Computer:	IBM PC; the computer must not be dedicated to the system.
Communication:	Dial up phone lines.
Remote Terminal Unit	
Power:	Must be able to use AC, solar or thermoelectric generator.
Inputs	2-meter pulse, 4-analog, 2-status.
Outputs:	2-relay, 2-analog
Software:	Must use a language that allows us to reprogram the remote terminal unit (RTU). Must be able to do close loop control. Must be able to call out if an alarm condition occurs.
Data:	Store data on the hour for 31 days.

After evaluating 10 different systems, we decided that the Key Telemetering GA-8052/EGM was best suited for our specifications. Real time measurement equipment is constantly changing with today's technology. Therefore, we will continue to monitor the new equipment as it becomes available.

COMPUTER

Entex has standardized on the IBM PC computer. These computers are utilized to do odorization reports, warehouse inventory and other bookkeeping and office functions. We did not want to dedicate a computer solely to a real time measurement system. The specifications required that the computer be configured to talk to the remote terminal units (RTU) when information is needed, and then be reconfigured for other functions. This adds to the versatility of the computer allowing far more efficient use. We also wanted the ability to format reports based on the data received from the RTU. The key units communicate in an ASCII format. Lotus 1–2–3 or dBase III can then be used to create such a report. This way we can be self-sufficient and do not need to hire a software consultant.

MODEM

One of the important specifications was for the RTU to initiate a call if an alarm condition occurred in the field. Since the computer is not dedicated to the system, a call could come into the host computer but it would not answer. We found a communication modem with a built-in buffer (memory storage) that could be used to answer the alarms and record them. The ProModem 1200 is an intelligent 300/1200 baud telephone modem with a buffer and an alphanumeric display. This device allows us the freedom to choose not to dedicate the computer to the real time measurement system. The modem display will alert us to any incoming calls that have been received. The computer can then be reconfigured to read the alarm messages. Also, if any calls come in during the night, the modem will record them for playback at a later time.

COMMUNICATION

Entex does not operate a microwave system or a long distance radio system. Therefore, the best most efficient and economical means of communicating with the RTU is through a dial up telephone line. The RTU is able to initiate a call when an alarm condition occurs or answer the phone if the host computer calls.

REMOTE TERMINAL UNIT

The Key GA-8052/EGM is an RTU. Inputs are provided for eight analog transducers (4–20mA), eight status signal and output signals to drive eight relays (12Vdc). Two of the eight status inputs and configured as 16 bit pulse count inputs, that may be used for turbine meters. The data input/output signals include one RS-232 terminal port, RS-232 printer port, and a 300/1200 baud modem. The complete system is on a single printed circuit board requiring a single 12 Vdc power source. The heart of the microprocessor is the Intel 8052AH central processor unit (CPU). It is supported by 24K of random access memory (RAM) and 16K of erasable programmable read only memory (EPROM). The Intel CPU has a BASIC interpreter occupying 8K in the chip. The RTU is programmed in BASIC, with the program residing in the EPROM. This feature permits a program to be modified and then burned into the EPROM for permanent storage. If the unit were to lose all power, it would automatically start execution when power is reapplied.

POWER

The Key unit can work off of AC, solar, or thermoelectric power. Besides the primary power source there are two back ups. One is a 12-volt gel cell battery which allows the unit to continue operating. The second is a nickel-cadmium battery used to keep the data from being lost.

ALARMS

We have programmed the unit to call the host computer when the following alarms occur: high/low flow rates, high/ low pressures and loss of our primary power source (AC). Additional alarms can be programmed into the unit, since the software can be reprogrammed.

CONTROL

Currently the units are not programmed to do any type of control. However, we plan on reconfiguring the units to do flow control based on the corrected gas flow. The unit could also be used to control pressure, an injection odorizer, meter tube switching or a gas sampler.

CONCLUSION

We believe that Entex has selected a piece of equipment that is versatile enough to meet our current and future requirements. At the same time, we have based our specifications on realistic values that are becoming the standard in the personal computer and gas industries. We will continue to monitor the new generation of electronic equipment because we believe that real time measurement is here to stay.

AUTOMATION OF FACILITIES INFORMATION

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ABSTRACT

Wisconsin Public Service Corporation has implemented a corporate data base that integrates all corporate data needs into one system. This results in significant savings in data maintenance and new application development while better serving the ultimate users. Uses of this system range from automated mapping to network analysis to cathodic protection to property accounting.

The migration from "islands of automation" to full "integration" of systems is providing benefits well beyond those originally projected.

AUTOMATION OF FACILITIES INFORMATION

Wisconsin Public Service Corporation is a combination electric and gas utility serving 10,000 square miles of northeastern Wisconsin. Two hundred ninetyseven thousand electric and one hundred fifty-seven thousand gas customers are served by two thousand four hundred employees in nineteen operating districts. The gas operation is limited to distribution with the exception of a few short intercity transmission lines.

Every industry has its buzzwords and the gas industry is no exception. Rather than spend time on all the familiar ones, I would like to concentrate on two new ones —"integration" and "islands of automation".

The first is built into the title of this conference while the second might be considered its antithesis. "Islands of automation" has become the catch term for stand-alone solutions in the computer realm. In the 1960's and 70's, technology dictated very specific solutions to data problems. Each problem was analyzed and very unique programs were written to solve that problem. A good example of this might be system valves.

The problems and solutions might have a split like this:

Problem	Solution
valve location	maps

valve inspection	valve cards/inspection system
valve flow control	maps/network analysis program
emergency valving procedures	maps/emergency books

Now each of these problems has a workable solution. It should be noted, however, that each time a valve is installed, removed, or replaced, each of these systems requires updating. Every “island”, whether automated or manual, must be visited to assure up-to-date information to solve each problem. Automation of any one of these solutions (such as automated mapping) may streamline the effort to the particular problem. This creates the “islands of automation”—stand-alone computer systems that speed a particular work process.

Technology of the 80’s has offered an alternative to this—“fully integrated systems”. These may be thought of as single source data supporting multiple functions.

Returning to our valve example—a fully integrated system would consist of a valve record. This record would support each of the application solutions I have outlined. When a valve is removed from this one record, it therefore ceases to exist on the map, in the emergency valving plan, and in the valve inspection schedule.

This integrated approach has been implemented at Wisconsin Public Service with significant benefit. Let me first detail integration:

An Information Architecture is the basis for integrating data management. It is the framework used to relate data to each of the business processes or groups of business processes that support the Company. The Information Architecture is the vehicle for understanding the basic data which must be managed to operate the business successfully.

For the architecture to support the entire business, it must include all data in the Company, both computerized and non-computerized. By using it as a framework for the management of all data and for all project development, it is ultimately possible to develop uniformity of data throughout the company. This concept is fundamental to the successful management of data.

A data dictionary for the company will satisfy this requirement for data management. It will be used to define the data, its definition, location, where it is used, security and privacy considerations, and the individual or department responsible for the data. Naming conventions and standards are important parts of its implementation.

As data class detail is defined during new development or as existing data is documented, the data dictionary becomes a more valuable tool. Ultimately, computer services and the user will be aware of all data available in the Company.

The Information Architecture diagram on Attachment #1 provides a medium for understanding the basic data which must be managed to operate the business successfully. It outlines for each business process (1) the information areas supporting each process, (2) the data created, controlled or used, and (3) the relationship between information areas. Collectively, the information areas, which are made up of data classes and business processes, are grouped and called information categories.

The seven boxes in the diagram represent information categories. The arrows show which categories provide input and which categories are dependent. As can be seen by the diagram, there is an intricate flow of data between all processes taking place in the company.

The Information Architecture provides a basis for initiating future data management; a broad structure which is sufficiently accurate to satisfy current needs, and yet is flexible enough to meet changing requirements.

All existing systems supporting the proposed architecture must be defined. Their interrelationship to the architecture must be intricately understood. The implementation of future systems must be incorporated, whenever appropriate, into the Information Architecture.

Detailed use of the Information Architecture by data administration personnel will require expansion and specific definition of the architecture as well as regular periodic updating to insure its continued usefulness.

The Information Architecture illustrated supports understanding of the creation, use and flow of data within and between the various processes. A detailed analysis of the interaction was made and is illustrated by the C's (creator) and the U's (user) on the Data Class/Business Process (Attachment 2) . This matrix may be employed to assure that future computer projects involve each of the processes affected when developing or modifying data files. During the procedures of new project development, refinements to the business processes and data classes defined must be made by the computer services department.

Now, let me apply this directly to gas distribution facilities.

In 1981, Wisconsin Public Service Corporation committed 23 people full time to develop a mechanized model of all real property owned, leased, or used by the corporation. These people represented gas and electric distribution engineering, accounting, administration, and computer services. The result of this effort is a functional data base system that effectively models the entire corporation.

While the system produces automated maps, it also supports all engineering and accounting applications of the company. There is currently a multitude of applications from each of these disciplines running against the data base.

All utilities spend a lot of money each year on their equipment and facilities. Keeping track of the massive amount of facilities related data has been a difficult process. Recording the on-going maintenance, access, and utilization for each piece of equipment you use is a time and resource consuming project. Over the past two to three years, it has become popular to talk about AM/FM systems, facilities systems, automated mapping, facility information, and other such buzz-words that deal with methods of mechanizing these facility related records of a company.

Because of the scope of these projects, budget constraints, lack of personnel, vested interest of a sponsoring department, or other influences, most of these projects have resulted in a computer mapping system, very few of which have reached a successful conclusion.

As we studied these problems at Wisconsin Public Service, we came to a slightly different conclusion. Facility information is not owned or maintained by only one department. Taking a very simple example, a valve, we found that for any given valve, numerous departments were keeping some duplicate and some unique information.

- street crews and field clerks had maps with location dimensions and valve number.
- plant accounting had a more generic location plus cost, valve number, size, material, and manufacturer
- planning had valve number, location, plus relationships to other facilities.
- operations had valve number, material, vintage, and inspection record.

The list goes on and on but I think you get the idea. When that pole was replaced, removed, or retired, many records were updated, not always simultaneously, and frequently, one or more records were missed completely in the updating. Our conclusion was that mapping was a symptom—not the problem. Facility information needed to:

1) reside in only one place.
2) be updated with only one transaction.
3) be available to all users.
4) be available in a meaningful way.

This conclusion led to the development of our Integrated Facilities Model. A quick explanation of terms:

Facilities—all real property of the corporation.

Model—a representation of the facility as it exists in the field including geographic and network relationships.

Integrated—one definition that meets all users needs and allows cross exchange of information with other corporate data bases.

To insure that the model functions correctly, it must support the full range of applications for all users in an efficient manner. As we began to test the actual data base that evolved from the model, it became quickly apparent that, because the system could produce a map (a graphic report), it did not follow that it could evolve to support other functions. As a result, we defined seven test applications to finalize the data base design and worked through numerous iterations of the data base to support these applications.

As of today, we are well beyond the original seven applications used for testing, have our first two divisions functional, are projecting our third division for shortly after the first of the year, and will have all seven divisions operational by the Fall of 1986. With this background, I would like to review the applications supported by the system, what they do, how the system supports them, and the benefits to Wisconsin Public Service of this approach. I will divide these into two groups—those we have operational today, and those scheduled for implementation over the next year and one-half.

Starting with those that are operational now:

1. Gas Load Analysis

   A) Loads are accumulated from CIS billing information.
   B) Lengths, accumulated loads at nodes, assignment of nodes, assignment of node loads, and diameters are fed directly into the analysis programs from the data base.
   C) Analysis results are displayed graphically.
   D) A load analysis that used to take six months can be done in 15 minutes.

2. System Planning

   With the ability from number 1, the system can do an infinite number of what-if's and store alternate solutions until such an answer is implemented.

3. Gas Service Restoration

   A) The location of the appropriate valves to close for any emergency.
   B) A listing of all customers shut-off during that emergency.

The electric area is very similar to the gas:

1. Electric Feeder Load and Voltage Analysis

   A) Loads from the customer billing system.

B) Nodes, lengths, material, diameters, and nodes assigned to analysis program from the system.
C) Analysis results displayed graphically.

2. Capacitor Spotting
   With the infinite ability to do the what-if studies, ultimate capacitor spotting can be accomplished.
3. Transformer Load Management
4. Service Restoration
   This includes the capability to predict the most likely outage point.
5. Area Load Forecasting
6. Feeder Switching
7. Substation One-Line Diagrams

   A) Multiple views and displays schematically of the same substation.
   B) Inventory and spare parts records including common analysis between substation.
   C) Maintenance scheduling for substations.
   D) Failure analysis.

The mapping applications cover the whole range of maps. For example:

1. Pole Maps
2. Primary Maps
3. Secondary/Service Maps
4. Duct and Duct Occupancy
5. Analysis and Planning Maps
6. Gas System Maps
7. Detailed Gas Area Maps
8. Land Use Maps

These maps are all nothing more than multiple views of the data base. As a result, a change on any map changes all maps accordingly. Maps are nothing more than a graphic report and, therefore, can be any combination of data desired. Since the system deals with a global data base, problems such as map boundaries disappear. Between increased productivity and decreased number of maps to be drawn, the mapping function results in a close to 5 to 1 savings. With this information, the system also supports a number of marketing applications:

1. End Use Maps—with ties to census data, end-use analysis and system end-use can be clearly studied.
2. Saturation Studies
3. Development of Targeted Marketing Programs

A significant benefit of the system lies in the financial area. Traditionally, the accounting records, the operation records, and the engineering records were all separate and never guaranteed to match. Specific examples in this area include:

1. Determination of Tax Liability

A) System includes all facilities relational to governmental boundaries.
B) System includes depreciation codes and initial cost.

2. Cost of Service Studies

A) Customers are linked within a network all the way back to the substation.
B) Each facility carries cost.

3. Work Order Drawings

A) While thought of as an operations or engineering function, this also directly relates to the financial area.
B) Preposted and even planned work orders can be stored in the system for recall and updated as engineering or approval statuses change.
C) Bills of material can be automatically generated from the work order.

The list of additional applications completed or under development is too long to go through in detail, but very quickly:

1. Cathodic Protection

A) Inspection, maintenance, and test reports
B) Cathodic protection maps

2. Valve Inspection and Maintenance

A) Scheduling
B) Record-keeping
C) Generation of forms showing valves to be inspected
D) Special Maps

3. Equipment Maintenance and Inspection

A) Regulator light maintenance scheduling
B) Station Equipment maintenance scheduling
C) Leak Surveys
D) Odorant Saturation

4. Emergency Valving

A) Tie to Customer System for Address/Phone # of Affected Customers
B) Relight Maps
C) Optimization of Valving
D) Systems Impacts

5. Computer Output on Microfilm

   A) All trucks will be equipped with a complete set of maps on microfilm cards.
   B) Microfilm copies are approximately one-sixth the cost of paper maps.
   C) Microfilm is produced for the computer directly eliminating photographic step.

For a project cost of approximately five million dollars, Wisconsin Public Service will realize an annual benefit of over two million dollars while eliminating conflicting information, updating all facility records, improving customer service, and improving productivity of its employees. To date, no facilities related application has been beyond the technical capabilities of the system and the time of development for new applications has been reduced significantly because the data and data structure are already in place—only the actual reports and algorithms need to be developed. Our computer services department is maintaining one system rather than a number of small systems, frequently with the same basic data in them —freeing resources for additional development. The ability to use fourth generation languages for many report oriented applications, and removing these applications from the control of computer services, plus the capability to use data from other systems that also run on the mainframe directly (materials, customers, etc.) rather than maintaining duplicate, redundant out-of-date copies of these for each application have significantly benefitted the corporation.

This integration approach has moved WPS from our old direction of “islands of automation” and set a direction of providing timely, correct information to the ultimate user in a cost effective, efficient manner.

AUTOMATING CORROSION CONTROL

Ron J.Grozelle, P.Eng.
Corrosion Control Engineer
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Chatham, Ontario N7M 5M1

ABSTRACT

The development and introduction of small, rugged and reliable microprocessors for field use over the past few years has greatly changed the day to day operation of gas utilities.

These units have been introduced in the areas of meter reading, telemetering, alarm systems and for a variety of other applications.

The use of microprocessors has also expanded into the Corrosion Control areas of the gas utilities. Since a successful cathodic protection program requires the need for frequent surveillance and monitoring, the field microprocessors have greatly benefited the Corrosion technicians in doing their jobs and provided the Corrosion Engineers and Corrosion Supervisors with improved capabilities of reviewing and assessing system status as well as solving problems.

This paper is intended to provide a general discussion on the introduction of microprocessors into the area of Corrosion Control at Union Gas. The overall system which was implemented in the spring of 1985 will be reviewed with a brief discussion of the various components used and the benefits achieved.

AUTOMATING CORROSION CONTROL

INTRODUCTION

Union Gas Ltd. is engaged directly in the production, purchase, storage, gathering, transmission, distribution and sale of natural gas to just over half a million residential, commercial and industrial customers in Southwestern Ontario.

CORROSION INFORMATION REGISTER PAGE 706

WATERLOO HANOVER BENTINCK T 07-03-04 SEPTEMBER 1985

	PIPE DESCRIPTION						ANODE INFORMATION				ADDRESS INFORMATION								PIPE TO SOIL READINGS		
GRP	JB M KY-CT	JOB NO	METRES	SIZE	T	A I	JB AN KY-CT	JOB NO	NO	T	A I	MAP NUM	AD CT	STREET	TD	ADDRESS	READ LIMIT	85-2	85-1	84-2	84-1
001	01-01	64-504478	181.4	1.00	1		01-01	64-504478	1	1		26Q2	01	HWY 4		GROCERY STORE	1.00		*1.26	*1.18	1.33
	02-01	66-508942	163.4	1.00	1		01-02	65-500008	2	2											
	03-01	71-518249	21.3	1.00	7		02-01	83-900008	1	4											
002	01-01	67-510716	80.8	1.00	1							26Q2	01	HWY 4	K	J GARDINER	1.00		1.45	1.39	1.43
003	01-01	70-516026	67.1	1.00	7		01-01	70-516026	1	4		26Q2	01	HWY 4		BRICK HSE BROWN	1.00		1.54	1.39	1.54
004	01-01	70-516407	153.3	1.00	7		01-01	70-516407	1	4		26Q2	01	HWY 4		BRUCE DAY H1W CREEK	1.00		1.53	1.50	1.52
005	01-01	70-516156	78.3	1.00	7		04-01	74-524599	1	4		26Q3	01	HWY 4		LOUS SERVICE CENTER	1.00		1.41	1.42	1.43
	02-01	70-516562	94.5	1.00	7																
	03-01	74-524599	29.9	2.00	7																
	04-01	74-524600	116.1	1.00	7																
	05-01	77-532507	85.3	2.00	7																
006	01-01	72-519709	388.0	2.00	7		01-01	72-519709	1	4		26Q2	01	ALLEN PARK		405 BROWNS	1.00		1.53	1.58	1.58
007	01-01	69-514397	495.3	2.00	7		01-01	69-514397	1	2		26P3	01	IRE HANOVER		CEMENT PLANT	1.00		1.51	1.52	1.51
							01-02	69-514397	1	4											
							02-01	85-900008	1	4											
008	01-01	72-520043	57.9	2.00	7		01-01	72-520043	1	4		26P3	01	7TH	A	1153	1.00		1.19	1.20	1.29
009	01-01	72-520175	180.7	2.00	7		01-01	72-520175	1	4		26P3	01	8TH	A	865	1.00		1.59	1.58	1.60
	02-01	73-522618	30.5	2.00	7																
010	01-01	71-517422	278.3	4.00	7		01-01	71-517422	2	4		26P3	01	10TH	S	754	1.00		1.37	1.38	1.45
	02-01	65-507251	403.9	4.00	1		02-01	65-507251	2	4											
	03-01	75-525417	157.0	2.00	7		04-01	71-517423	2	4											
	04-01	71-517423	353.6	4.00	7																
011	01-01	71-518627	146.3	4.00	7		01-01	71-518627	1	4		26P3	01	07 TH	A	HANOVER HOSPITAL	1.00		1.20	1.07	1.27
							02-01	77-900008	1	4											
							03-01	79-900008	1	4											
012	01-01	73-522543	69.2	2.00	7		01-01	73-522543	1	4		26P3	01	HWY NO 4		J H FLEMING LTD	1.00		1.38	1.38	1.42

FIGURE 1

The Company owns and operates 400 kilometres of gathering and storage lines, 3,000 kilometres of transmission lines, ranging up to 42 inches in diameter, 14,000 kilometres of urban and rural distribution lines.

In addition, the Company also operates numerous gas wells, and eight compressor stations (total of 147, 000 horsepower) for the transmission and storage of gas and ten underground storage pools with a working capacity of approximately one hundred billion cubic feet.

The total franchise area is covered by eight major divisions with twenty-two offices, employing approximately 2,250 employees. The Corrosion Department includes 15 full time technicians, located throughout the division offices who are responsible for all aspects of the Corrosion program within their geographic areas. Each technician has approximately 1,000 kilometres of pipeline for which he is responsible for conducting surveys, troubleshooting and maintaining department records.

Union Gas has an effective Corrosion Control Program which has been in existence since the late 1950's. In the early days the process for conducting surveys was tedious, cumbersome and generated mounds of field notes and reports. Manually generated reports and statistics often turned the Corrosion technicians into "accountants" as they tried to balance pipe footage statistics for protected and unprotected plant, etc., for month end information summaries.

This situation was greatly improved in 1970 with the development and introduction of computer programs which provided all the necessary statistics and data required for management summaries and reports. The following represents a couple of examples of the types of reports which are available. The first (Figure 1) is a sample of our Distribution System Register which provides key Corrosion related information and historical data on specific sections of pipeline.

Figure 2 shows a sample of a summary report which outlines the status of the Corrosion Control Program at a particular point in time. In addition to the Summary Report, numerous sub-reports are also available which give further details by division, branch and town levels.

In completing the required scheduled surveys of the Company's cathodically protected systems, approximately 55,000 survey readings are taken annually. The Corrosion Department's computer data base system used to be updated using mark sense computer cards until 1984. With the introduction of data entry display terminals (Video 370) and an ever increasing number of P.C.'s or Personal Computers throughout

OD-C04200XD-01 DISTRIBUTION CORROSION SYSTEM - 55 BUSINESS MO 09 RUN 1985-10-02-16:55

CORROSION CONTROL REPORT PAGE 1

	WESTERN REGION		CENTRAL REGION		NORTHERN REGION		EASTERN REGION		
	WINDSOR	CHATHAM	SARNIA	LONDON	BRANTFORD	WATERLOO	HAMILTON	HALTON	COMPANY TOTAL
***** SURVEY STATUS *****									
TOTAL KM OF C.P. PLANT	1602.07	859.56	818.91	2518.33	1539.26	1820.70	1407.38	1060.47	11626.68
KM OF PLANT SURVEYED	1589.56	851.40	791.73	1900.97	1188.65	1292.00	1319.17	1057.89	9991.37
% SURVEYED TO-DATE	99.21%	99.05%	96.68%	75.48%	77.22%	70.96%	93.73%	99.75%	85.93%
KM PLANT BELOW PROTECTION									
PRIORITY A .85 OR LESS	33.43	4.87	12.01	26.38	16.51	63.59	45.21	9.14	211.14
B .86 - .99	20.71	1.81	2.60	18.72	15.23	82.53	27.99	14.98	184.57
TOTAL	54.14	6.68	14.61	45.10	31.74	146.12	73.20	24.12	395.71
% PLANT BELOW PROTECTION	3.37%	.77%	1.78%	1.79%	2.06%	8.02%	5.20%	2.27%	3.40%
***** FAULT SUMMARY REPORT *****									
YTD FAULTS FOUND	193	28	55	70	25	73	161	36	641
YTD FAULTS REPAIRED	170	22	31	54	23	36	106	32	474
YTD-OUTSTANDING	23	6	24	16	2	37	55	4	167
TOTAL-FAULTS-OUTSTANDING	34	6	61	18	4	42	56	4	225
***** PLANT BELOW PROTECTION - STATUS *****									
KM PLANT BELOW PROTECTION	54.14	6.68	14.61	45.10	31.74	146.12	73.20	24.12	395.71
PLANT NOT TROUBLESHOT	46.24	5.57	7.33	41.94	29.63	119.6J	63.07	23.58	336.96
PLANT TROUBLESHOT									
A. - ANODES REQUIRED	2.09		.79	.19	.39	3.20	6.00		12.66
B. - OTHER	5.81	1.11	6.49	2.97	1.72	23.32	4.13	.54	46.09
TOTAL	7.90	1.11	7.28	3.16	2.11	26.52	10.13	.54	58.75

FIGURE 2

the Company's Head Office, the computer card system and related equipment was replaced with the new technology for communicating with the mainframe computer.

In the spring of 1985 the Corrosion Control Department installed a new data gathering system which utilizes a microprocessor called MICAPS (Microcomputerized Cathodic Protection Surveys) produced by Pathtechnics Ltd. of St. Catharines, Ontario, Canada. Figure 3 shows a system concept drawing and outlines the various components which will be described in more detail. Basically, two methods of data capture are used to process data for the department's various computer records. The first method utilizes a data entry terminal (Video 370) which is used to process the set-up transactions, deletions and modifications needed for the base data updates. The second system, which is the topic of this particular paper, incorporates the use of a microprocessor for the capturing and data transmission of survey results from the field office back to the central Head Office computers.

MICAPS FIELD UNIT

One of the key components of this automated data gathering system is the Micaps Field Unit. This high impedance voltmeter with microprocessor and solid state memory is a lightweight, handheld unit with internal programming. The unit can be used as a basic data acquisition and storage unit using specific key sequence operations.

In the overall development of this system for Union Gas a number of specific programming changes were incorporated into the field unit by the supplier, which allowed us to tailor the system specifically for our particular application. Some of these items

1) Unique field unit identification codes

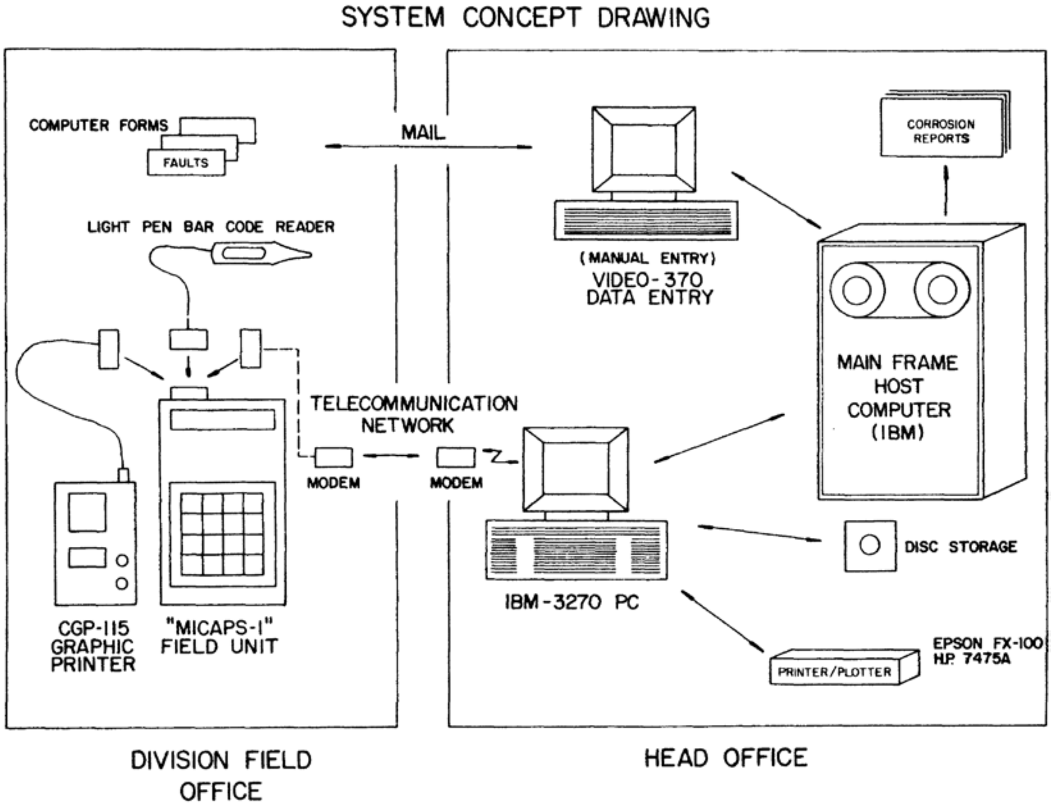


FIGURE 3

2) Special bar code programming
3) Manual as well as auto data entry in the field of voltage reading or identification codes

The field unit has basically four operational modes:

1) Voltage reading and entry
2) Code entry
3) Auxiliary modes ie. recall, scan, cancel, timed program, etc.
4) Data transfer—to EPROM, to printer, to modem, to a computer

The field units were programmed to accept either manually or automatically (ie. through the voltmeter) pipeline potentials and location codes. This gives the technician increased flexibility to add data, either voltages or codes in the event that they were not entered while at the site and eliminates the need for returning to the reading location to re-enter the data. Manually entered potentials are easily identified on a printout which would discourage anyone from considering conducting their entire survey from one location!

Each field unit has a unique identification number which automatically is logged into the memory every time the unit is turned on. This I.D. number is also transmitted whenever data is downloaded from the unit.

This information is helpful not only in identifying the source of the incoming data but also allows for tracking the amount of data sent in by each unit.

The field unit can be programmed with an unlimited number of unique identification codes which can be used to identify specific pipeline and terrain features while conducting a survey. Examples of such codes could be, Foreign Line Crossing, Casing, Road Crossing, Fence Line, Test Box, Chainage, etc.

In addition to conducting routine test station location readings, the field unit can be utilized for data logging with special time reading programs. Delayed entry readings, ON/OFF surveys, and high, low average readings can be automatically recorded over operator selected time spans. Features such as these eliminate the need for the technician to record in field notes which allow him to be more productive and accurate with the completion of special type surveys.

Some of the basic features of the field unit are listed below:

Display	8 Digit LCD
Input Resistance	10 Megohm
Voltage Ranges	−10 to +10V
	−100 to +100V
Data Storage	C.M.O.S. Ram
Keyboard	4×4 Alpha-Numeric 0–9
	A–F
Internal Power	6 Volt Sealed Rechargeable Cell
Memory Capacity	Approx. 4000 Voltage Reading (4 digit)
Data Transfer	300 Baud

Data which is stored in the field unit's memory remains in the unit even after the data has been transferred, until a special initialization sequence is performed by the technician. In order to avoid the possibility of missing any of the data in storage the technician does not initialize the unit until authorized to do so by the P.C. operator at Head Office. A record audit system was implemented which ensures that the number of records in the field unit matches with the number of records received by the P.C.

DATA IDENTIFICATION

In designing the overall system, one of the concerns was to avoid the need for having to modify any of the existing Corrosion data files and programs. Therefore a data coding scheme was developed which utilized the existing Corrosion Department system and location codes in addition to identifying "Production" vs "Non-Production" data.

Production codes identify data which must be processed and transmitted to the mainframe computer to update the computerized Corrosion Record System. This information is required to update the statistical reports and summaries mentioned earlier, as well as provide essential historical data.

Non-Production codes identify data which is not to go to the mainframe. This could be special surveys and other routine tests which do not form part of the statistical reports. This type of data can be stored on floppy disks at the P.C. for future reference if required.

In order to minimize the need for key entering the survey location codes into the Micaps Field Unit, a Bar Code System was introduced along with a light pen reader. Figure 4 shows an example of the Distribution Location Catalogue containing the bar codes used for identifying the system and location codes

OD-C05500XD-03 DISTRIBUTION LOCATION CATALOG - 55 DATE 85-08-09
PAGE 2

DIVISION WINDSOR BRANCH WINDSOR W TOWN WINDSOR W

9910101

---STREET----TD--------ADDRESS------		---STREET----TD--------ADDRESS------	
HARRIS S 3431 MAP 06A6 LIMIT 0.85 SURVEY 1 2 3 4 5	*0101601*	CONNAUGHT R 03861 MAP 06A6 LIMIT 1.00 SURVEY 1 2 3 4 5	*0101701*
CONNAUGHT TB WSD OPP 3811 MAP 06A6 LIMIT 1.00 SURVEY 1 2 3 4 5	*0101801*	PRINCE R 1505 Y DENTAL BLDG MAP 06A6 LIMIT 1.00 SURVEY 1 2 3 4 5	*0101901*
VAUGHAN R 3733 MAP 06A6 LIMIT 1.00 SURVEY 1 2 3 4 5	*0102001*	VAUGHAN R 03865 MAP 06A6 LIMIT 1.00 SURVEY 1 2 3 4 5	*0102101*
VAUGHAN R 03876 MAP 06A6 LIMIT 1.00 SURVEY 1 2 3 4 5	*0102201*	BIRCH A 03844 MAP 06A6 LIMIT 0.85 SURVEY 1 2 3 4 5	*0102301*
BIRCH A 3865 TW MAP 06A6 LIMIT 0.85 SURVEY 1 2 3 4 5	*0102302*	CHAPPELL A 01319 MAP 06A6 LIMIT 1.00 SURVEY 1 2 3 4 5	*0102401*
MATCHETTE R 3866 MAP 06A6 LIMIT 1.00 SURVEY 1 2 3 4 5	*0102501*	MATCHETTE R 4579 MAP 06A6 LIMIT 1.00 SURVEY 1 2 3 4 5	*0102502*
MATCHETTE R CLARK RD STN OUTLET MAP 06A6 LIMIT 1.00 SURVEY 1 2 3 4 5	*0102503*	COLLEGE A REG INLET AT PRINCE MAP 06A6 LIMIT 1.00 SURVEY 1 2 3 4 5	*0102601*
REDWOOD C 01377 MAP 06A6 LIMIT 1.00 SURVEY 1 2 3 4 5	*0102701*	REDWOOD C 01519 MAP 06A6 LIMIT 1.00 SURVEY 1 2 3 4 5	*0102801*

FIGURE 4

The Field Unit's original Bar Code programming, U.P.C., (Universal Product Code) was modified to accept "3 of 9" Bar Code symbols. There were two main advantages to using the "3 of 9" system.

1) This particular system allowed for greater flexibility in generating codes vs the U.P.C. (Universal Product Code) system which was originally available with the Micaps unit.
2) By obtaining the "3 of 9" Bar Code programming, Union Gas can produce inhouse, its own bar code catalogue using an IBM 3800 Printer System which has been recently installed to support the billing system. This high speed printer (20,000 lines per minute) can generate the bar code catalogues consisting of over 45,000 bar codes in well under an hour. With the implementation of this particular system, new codes or complete catalogue updates can be generated at anytime.

As mentioned earlier, location codes can be entered automatically (ie. using the light pen attachment) or manually through the keyboard functions. This allows the technician to still enter the appropriate location code in the event that the light pen may not accept the bar code in his catalogue. It also allows him to create a new location at any time and enter the appropriate voltage reading while in the field.

PRINTER/PLOTTER

Upon completion of his days activities the technician can produce a printout as well as a graph (depending on the type of survey) of any portion or all the data that is contained in his field unit. Figure 5 shows an example of the type of printout which can be produced.

Figure 5 also shows an example of the type of graphical data which can be produced on an inexpensive graphic printer (CGP-115 Printer) which can be connected directly to the Micaps Field unit. Data outside pre-set criteria and rectifier readings are automatically computed and flagged. The micrographie printer, controlled by the filed unit C.P.U. performs various functions including:

1. Print out all or any selected section of data in the field unit memory.
2. Print out the preselected lower and upper limits.
3. Compute and print out the number of data entries more positive than −1000mV.
4. Compute and print out the number of data entries more negative than −2000mV.
5. Flag with +++ all data printed out that is more positive than −1000mV.
6. Flag with ––– all data printed out that is more negative than 2000mV.
7. Automatically assign a data entry number to each potential stored.
8. Graphically plot all or any selected section of data in the field unit memory.
9. Draw ‘y’ graph axis 0 to −4000mV in 1000mV marked scale or +8000mV to −8000mV in 1000mV marked scale.
10. Draw ‘x’ graph axis 0 to 4000 readings.
11. Identify −850mV criterion with dotted line.
12. Plot all data more negative than −1000mV in black (or other selected pen colour).
13. Plot all data more positive than −1000mV in red (or other selected pen colour).
14. Print out all codes at respective locations.

The graphic printer can be operated wherever power is available and can even be operated in the technician’s vehicle in the field if required, through a special connection with the vehicle’s cigarette lighter.

At the end of each day the technician is required to produce a printout of his days survey results. A quick review of the printout alerts him to any problems with the data, if any, which in turn can be communicated to the P.C. operator in Head Office where corrections or missing codes/data can be edited. This information also provides the technician with an immediate and permanent record of his days survey results.

MODEM

Data transfer from the Micaps field unit is accomplished using an auto answer modem system. This data transfer system utilizes the Company’s existing SL.1 Telephone System using dedicated extensions which are connected by existing dedicated digitized voice service (Teleroute 200).

In each of the division offices a Novation J-CAT Modem, which has a transmission data rate of 300 bits per second, is connected to a dedicated extension. Connected to the Head Office P.C. is a Hays Smartmodem which was selected because of its compatibility with the particular communication package used called Crosstalk.

In order to provide maximum automation of the data retrieval, an auto-dialing system was introduced which would automatically call each of the division offices, after hours and download data from any Micaps field units which were connected.

MICAPS

SURVEY BY :
UNION GAS LTD.

CATHODIC PROTECTION SURVEY TABULATION

COPPER/COPPER SULFATE ELECTRODE

TABULATION FROM 0001 TO 0042

0000 READ. < -2.000V
0004 READ. > -0.850V
0000 RECTIFIER READINGS

0001	1000250	
0002	7000005	
0003	-0.880	
0004	-0.902	
0005	-0.905	
0006	-0.892	
0007	-0.880	
0008	-0.867	
0009	-0.852	
0010	-0.825	+++
0011	-0.820	+++
0012	-0.812	+++
0013	-0.827	+++
0014	-0.857	
0015	-0.867	
0016	-0.885	
0017	-0.900	
0018	-0.915	
0019	-0.927	
0020	1000500	
0021	-0.940	
0022	-0.952	
0023	-0.970	
0024	-0.967	
0025	-0.980	
0026	-0.995	
0027	-1.010	
0028	-1.007	
0029	-1.025	
0030	-1.037	
0031	-1.040	
0032	-1.060	
0033	-1.065	
0034	-1.090	
0035	-1.090	
0036	-1.065	
0037	-1.060	
0038	-1.090	
0039	-1.090	
0040	-1.105	
0041	-1.125	
0042	7000006	

MICAPS

SURVEY BY :
UNION GAS LTD.

CATHODIC PROTECTION SURVEY PLOT

COPPER/COPPER SULFATE ELECTRODE

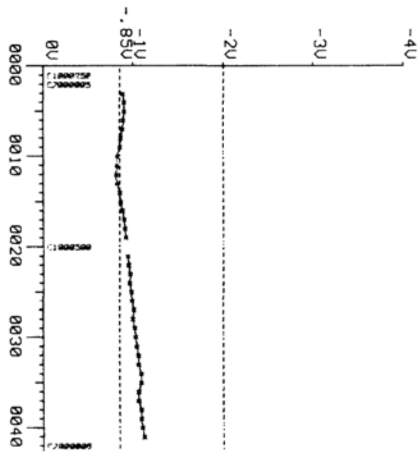


FIGURE 5

Figure 6 illustrates a Data Transmission Schematic which shows the various offices involved, the technicians located there, as well as the identification number of the various field units.

In those areas where more than one field unit is located, data transmission is completed on alternate days in accordance with the technicians local schedule. During major survey periods the field unit is capable of storing up to a weeks worth of data, therefore transmitting daily is not absolutely necessary.

Data can also be downloaded at any time of the day by having the P.C. operator initiate the appropriate extension number to a division office where the field unit has been connected and ready for transmitting data.

IBM 3270

An IBM 3270 P.C. along with disk storage, an EPSON FX-100 printer and a Hewlitt Packard 7475 plotter, make up the balance of the key components of the system. Once the field data has been received by the P.C. a variety of functions and activities can occur. Audit trails, backup and data recovery systems, editing and formatting features have all been incorporated by our Systems Department for managing the Corrosion data.

Production type data can be forwarded on to the mainframe computer for updating the Corrosion records and reports. Non-Production or special survey data can be stored on floppy disks for future reference.

Printouts and graphical analysis of specific survey data such as transmission test station surveys, close-spaced ON/OFF potential surveys, data logging, etc., can be generated for specific analysis.

Figure 7 shows an example of a graph produced using the H.P. 7475 plotter which contains the test station survey results for one of Union's transmission lines known as the 16" Panhandle Line. Information, such as this allows for a quick review of the overall status of the cathodic protection system as well as identifying potential problem areas which may require further investigation.

SYSTEM BENEFITS

Some of the benefits of implementing this "automated" approach to handling field data within the Corrosion Control Department at Union Gas can be listed as follows:

1) Maximum Productivity — Implementation of this system has greatly reduced the administrative overheads (by the Corrosion Technician in the division and by Head Office Corrosion personnel) which was previously required to capture, transmit and data enter survey results. In the case of special surveys the elimination of manual data logging has resulted in increased productivity.
2) Minimize Existing System Impact — The department's existing mainframe computer system and status reports were unaffected by the implementation of this new system. As a result of co-operation and co-ordination with the equipment supplier we were able to custom tailor the Micaps field unit and related equipment to suit our specific needs.
3) Provides Flexibility — The system allows for more frequent and special surveys to be completed and analyzed in the field.
4) Improved Accuracy — Since manual data entry is minimal, the microprocessor approach to data capture offers the least possibility for data errors.
5) Improved System Turnaround Time — The delay of mail/courier services between offices is eliminated by the use of the existing telecommunication network. In addition delays in data entry at Head Office are also eliminated.

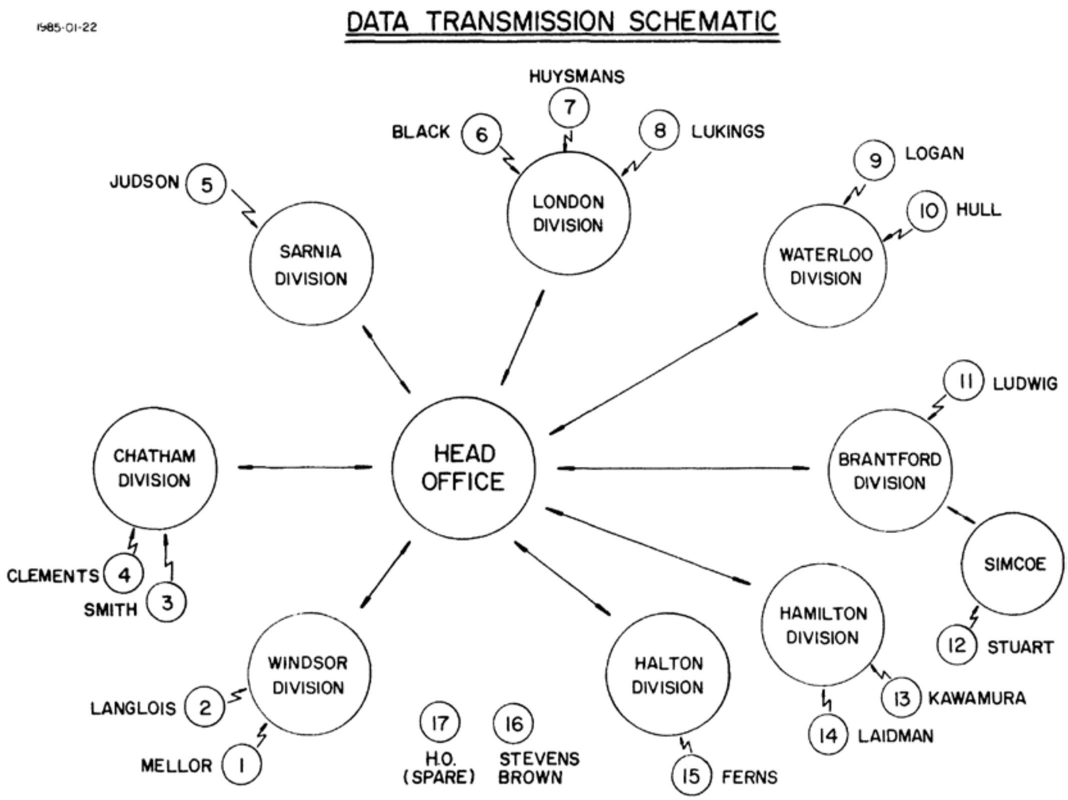


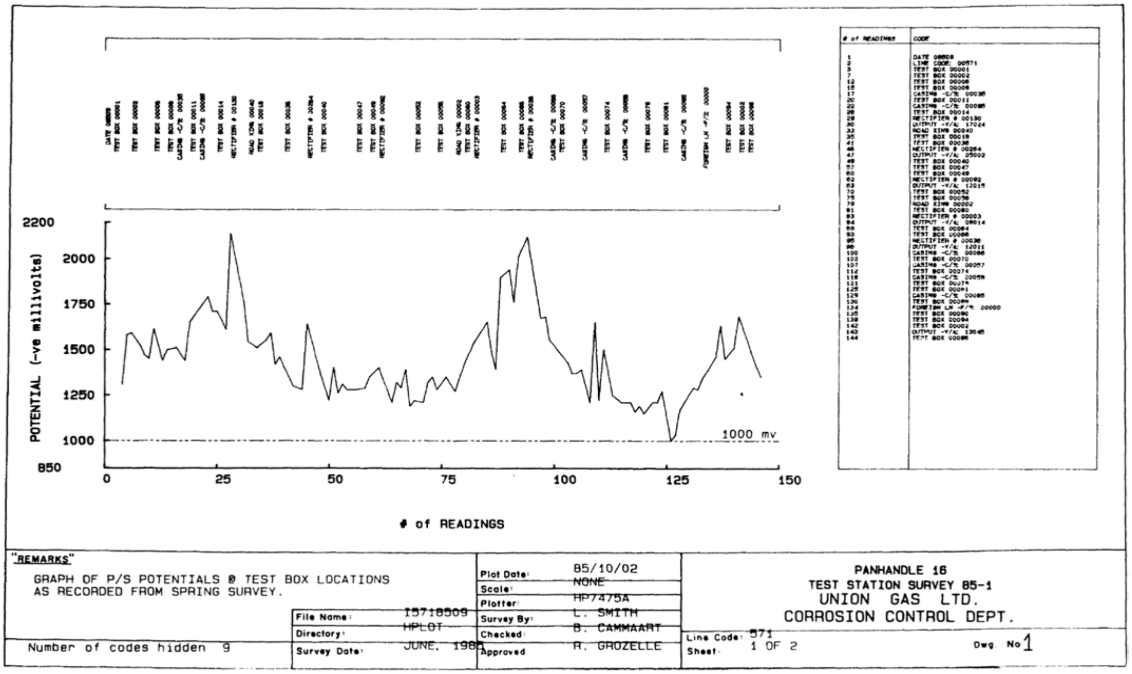
FIGURE 6

6) Corporate Data Entry Objective — The concept of the introduction of new computer base technology which captures and records data in the field which results in minimum administrative involvement is achieved through the use of the Micaps field unit .
7) Graphical Analysis — With the introduction of this system, the capability for computerized graphical analysis of special Corrosion survey data now exists (both in the field and Head Office).

SUMMARY

The rapidly evolving microcomputer technology has made major advances in data collection, record storage, interpretation, data analysis and design optimization.

By incorporating and utilizing the enormous potential of microprocessor technology within the Corrosion Control Department at Union Gas, I feel that we can continue to provide an effective Corrosion Control Program for extending the life of our pipeline systems and continue to provide a safe distribution network for our customers.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1500
1250
1000
850
1000 mv
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AS RECORDED FROM SPRING SURVEY.
Number of codes hidden 9
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Survey Date: JUNE, 1984
Plot Date: 85/10/02
Scale: NONE
Plotter: HP7475A
Survey By: L. SMITH
Checked: B. CAMMAART
Approved R. GROZELLE
PANHANDLE 16
TEST STATION SURVEY 85-1
UNION GAS LTD.
CORROSION CONTROL DEPT.
Line Code: 571
Sheet: 1 OF 2
Dwg. No 1

FIGURE 7

INTEGRATING RF ELECTRONICS INTO GAS DISTRIBUTION

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ABSTRACT

Accuracy, productivity, flexibility, and quality of service are objectives that the gas industry strives for in this new era of deregulation and competition. It was with these objectives in mind that DEI made a long-term commitment to develop a technology that could help gas utilities improve their performance in the meter reading and customer billing process. As the owner of a major U.S. gas distribution utility, we realized that the costs and problems of maintaining a system based upon manual data collection had to be improved.

At the onset of the program, we evaluated several basic technologies to select the one that could provide the best balance in meeting the gas industry's needs. The scope of our technology evaluation was quite broad including hardwired systems such as telephone, cable TV, and power line carrier as well as radio technology could provide the best balance in meeting the utility's needs. With recent advances in microelectronic technology, a system could be offered at a competitive price.

INTEGRATING RF ELECTRONICS INTO GAS DISTRIBUTION

SYSTEM DESCRIPTION

The DEI Remote Meter Reading System (RMR) is a derivative of land mobile radio technology. The same technology which most utilities use today for dispatching service vehicles.

The RMR system hardware consists essentially of two parts. A remote device and a mobile data acquisition system. The remote device is retrofitted on an existing meter by simply removing the existing meter index and index cover and replacing it with a new index and cover which is equipped with a micro electronic assembly, shown in Figure 1 This device performs three essential functions, encodes gas consumption data, receives radio activation signals from a mobile data acquisition system (MDAS) and transmits data to the MDAS.

Power is supplied to the remote encoder receiver transmitter (ERT) through a self-contained lithium battery with a life expectancy roughly equal to its shelf life which is 7–10 years. Installation of the ERT can readily be performed with only a standard screw driver in minutes. As can be seen from Figure 2, the ERT packaging is small and unobtrusive to the consumer.

Gas consumption is measured through a reed switch mounted on the meter index test hand. Meter tamper is monitored through a sensor which detects movement or tilting of the index or meter set. Normally the ERT is operated in a passive state in which only the encoder and RF receiving circuitry are active. This is done to conserve power and prolong the battery life. When activated by the MDAS, the ERT will turn on its radio transmitter and initiate data transmission to the MDAS.

The heart of the DEI system is the mobile data acquisition system (MDAS). In the standard configuration, the MDAS is installed into a utility vehicle or in a mini-van as shown in Figure 3. The MDAS consists of three components: an activator transmitter which is used to “awaken” the ERTs; a high speed radio receiver and data controller used to collect and sort ERT transmissions; and a data computer which is a ruggedized IBM compatible PC in rack mount configuration which is used to store ERT readings and support operator interface peripheral equipment.

SYSTEM OPERATION

From the utility billing computer a file is created with the accounts to be read for a particular billing cycle. This file is transcribed onto a streaming tape cassette. The cassette is then loaded into the MDAS data computer. The operator then drives to the beginning of the route, enables the MDAS activator transmitter and begins driving the route at normal street and highway speeds.

As the operator drives the route, the system will display the ERT identification numbers and actual addresses from which the data has been received. At any time during the route the operator can check to see what data has been received, what accounts are left to be read and if any accounts have been missed. The system has the capability to easily read and store up to 16,000 read/8 hour day.

Once readings have been received by the MDAS receiver controller, they are passed to the data computer where they are stored on non volatile memory until they can be transferred to the billing computer via the streaming cassette tape. Figure 4 shows the data flow of the system.

KEY DESIGN FEATURES OF THE DEI RMR SYSTEMS

~ Virtual 100 percent accurate, timely reading of all meter sets including indoor meters.
~ Capable of demonstrating 30 to 50 fold increases in meter reading productivity on a system-wide basis and substantially improve productivity of downstream operations.
~ Ability to detect tampering at the meter set.
~ Installation is quick, simple, with minimal disruption to the customer.
~ System is field retrofittable to most common meter sets.
~ Remote units have self-contained, long life power supply requiring no external hardwire connections.
~ Remote units have hard back up feature to verify gas consumption.
~ System has no interference with customer lifestyle and does not require the involvement of a third party (i.e., common carrier) to perform meter reading and customer billing.

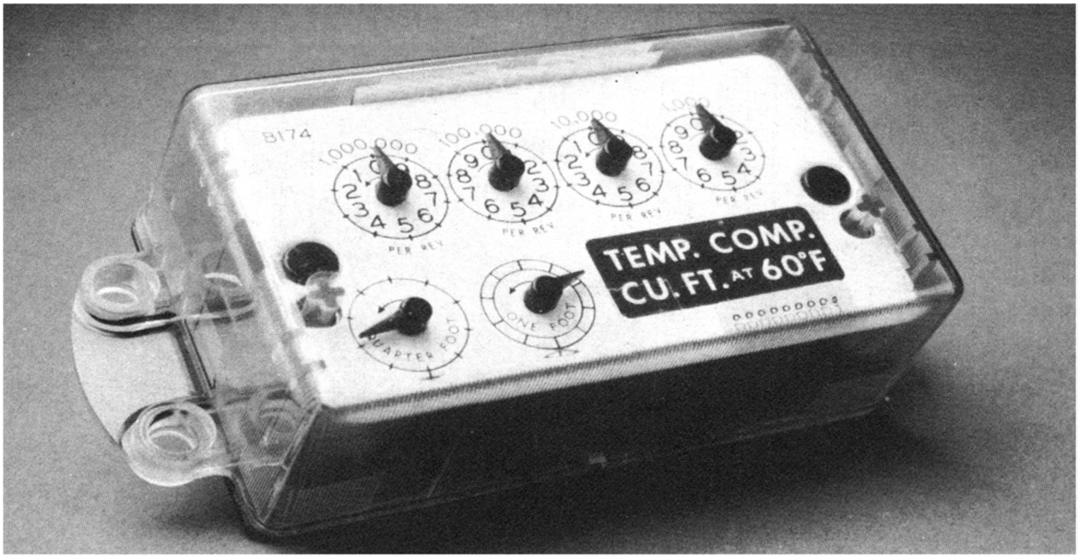

FIGURE 1 —DEI ENCODER RECEIVER TRANSMITTER

CONCLUSION

~ Accuracy
~ Productivity
~ Flexibility
~ Quality of Service

These were the objectives we had in mind as we developed the DEI RMR system. The ability to read every meter accurately on a timely basis. The ability to drastically reduce, if not eliminate, estimated billing to the customer. The ability to demonstrate dramatic improvements in productivity and operational effectiveness. Flexibility in route and billing cycle design, and most importantly, provide the highest quality of service to the customer at an acceptable cost. In this new era of deregulation and competition these objectives may soon become requirements. We think the DEI RMR system can go a long way to help the industry realize these objectives.

FIGURE 2 — ERT SMALL PACKAGE SIZE

FIGURE 3 — DEI MOBILE DATA ACQUISITION SYSTEM

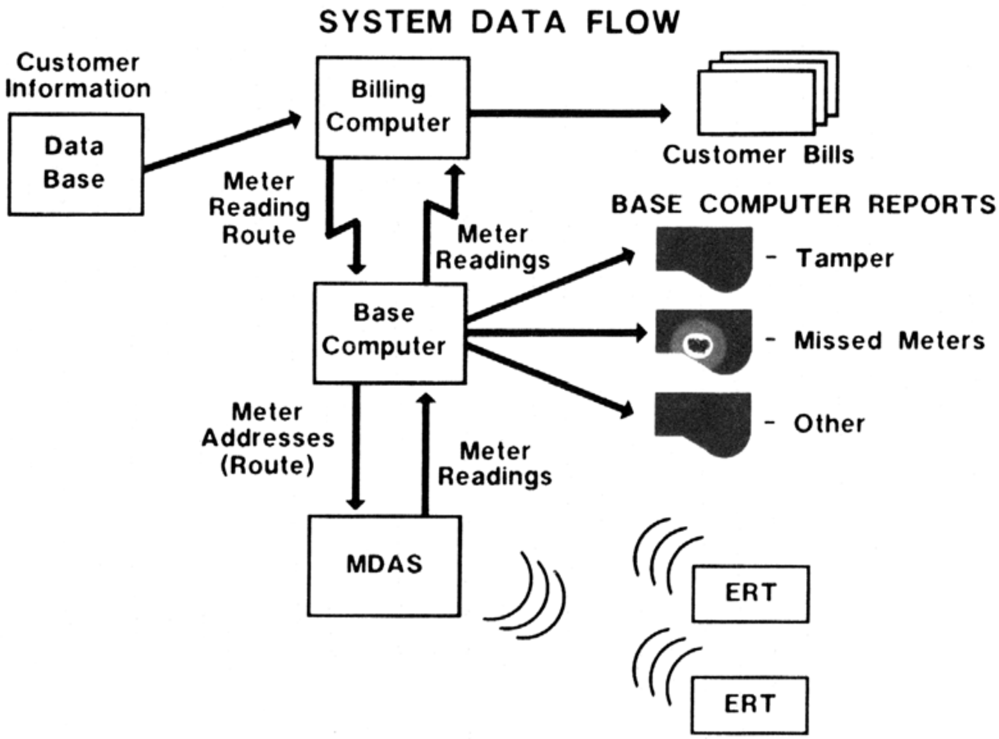

FIGURE 4 — SYSTEM DATA FLOW

ON THE CONCEPT OF A TOTAL SYSTEM APPROACH TO DISTRIBUTION AUTOMATION

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ABSTRACT

The gas distribution industry is automating more and more operating features to improve efficiency and service to customers. Remote meter reading is one feature currently receiving much attention. The automation of any single feature requires hardware to automate the feature, a communication link, hardware to receive the data, and a power source. The incremented cost of automating a second feature can be made quite small if the second feature uses the same power source, communication link, and electronic hardware. This paper presents a total system approach to automating gas distribution. The key concepts of any such approach are: 1) automating many features together, 2) establishing a set of industry-wide stable standards, 3) making components modular and interchangeable, and 4) the use of distributed intelligences.

The paper gives an example of a totally automated system as a basis for discussing the benefits of the total approach. It also describes the difficulties of estimating the value of automating a feature, describes retrofitting problems that must be solved, and provides strong arguments for the development of stable standards in communication protocol, power supply, and interconnection of hardware.

ON THE CONCEPT OF A TOTAL SYSTEM APPROACH TO DISTRIBUTION AUTOMATION

INTRODUCTION

During this symposium, we have been treated to papers on topics including automating city gate stations and remote meter reading technologies. For convenience, we view automation within a conceptual framework that divides automating gas distribution systems into two approaches: top-down and bottom-up.

The top-down approach begins by automating city gate stations and odorizers first, followed by district governors. Historically most of the automation has been top-down. The bottom-up approach starts by automating remote meter reading and continuing the automation towards district governors. Utilities using the bottom-up approach have typically dealt with only remote meter reading. Of course, both approaches can be used simultaneously. This paper substantially expands the concept of the bottom-up approach. A gas distribution system using the total bottom-up automation will have many other capabilities in addition to remote meter reading.

The total system approach was developed in the process of our efforts, based on conventional cost-benefit analyses, to find economical solutions to individual gas distribution operating problems. Several of these problems were quantified in GRI requests for proposals. For some problems we were able to envision a solution that was technically possible, but not economically acceptable. In other cases a technical solution could be made only if some missing piece were present. As an outgrowth of these efforts the question was asked "How could a gas distribution system be structured to permit economical solutions to the problems of pipe location, third party damage prevention, and remote meter reading?" We believe that the concept of a total approach that evolved can lead to an economical solution to many operating problems, and provides several other capabilities as added benefits. A comprehensive bottom-up approach is valid for retrofitting to existing systems as well as new systems.

IGT has recently begun a funded, multi-year project to develop the total system approach into a practical system with many features and options for automated distribution. This paper is an overview of the potential of the total system approach and the problems that need to be solved to make it practical. A logical and necessary part of the total approach, the need for gas industry wide standards, is also important for meter reading only approaches.

KEY CONCEPTS OF THE TOTAL APPROACH

The total approach to automating gas distribution systems has four key concepts:

1. A Total Approach to the System

   Automation of any one of several functions would be of great aid in operating a gas distribution system. Automating them sequentially is not cost effective. However, combining several features can make the combination cost effective. Technical synergies produce additional features at no increase in cost. The total approach is to solve many problems together rather than one at a time.
2. Standardization

   A set of gas industry standards followed by all manufacturers will more quickly result in a larger market for automation. These standards must encompass a large number of technologies so that a utility has choices in selection of automated features, the method of implementing those features, and compatible equipment from several manufacturers. Scrapping all existing automation hardware each time a feature is added or a manufacturer is changed will severely impair the market. Because equipment installed today normally need to last a minimum of 50 years, the standard must be very stable yet capable of incorporating future technical developments. Detailed arguments for standardization are given in the last section of this paper.
3. Modularity

   Even though all utilities have similar operating problems to solve, opportunities and priorities are different. Any universally acceptable automation system must be flexible enough to permit each utility to solve its own special set of problems. Components should be developed in modular form so that a utility can select one or more alternatives to solve its problems. For example, a variety of communication modes is possible. A utility could select one method such as, telephone and later replace it with radio, wires, and fiber optics depending on its needs. With modularity, any communication mode could be selected, based on price or features. Alternatively the utility should be able to use telephone communication in part of its system and radio in the rest without making any other changes in equipment.

4. Distributed Intelligence

   The use of many low cost microprocessors throughout the system (distributed intelligence) permits a variety of tasks to be performed without requiring a single, large, expensive computer capable of handling all the details at every meter. Many tasks could be performed automatically or upon system wide command without constant supervision. Other tasks require some communication with a "centralized authority". A "centralized authority" can be a computer(s) monitored by a per son(s) at one main control point or several control points. The use of distributed intelligence permits all of the tasks to be done economically and provides the utility flexibility on how "centralized" it desires to be.

GENERIC AUTOMATION PARTS

Part of the technical and economic benefits of the total approach occur because any automated function providing information feedback to an "operator" must have several generic key parts.

By definition an automated function with information feedback must have some method of communicating with the operator. This may be as simple as a meter readout or a chart recorder, or more complex, such as, encoding of the data to a digital stream and transmission of that data to a satellite and back to earth. In order for the operator to understand the data, hardware to decode and display the results is needed. It is often useful to record the data for future reports. The hardware to perform the automation to obtain the data is required or nothing happens. And of course, some type of power supply is needed to operate all of the hardware.

Thus, there are four key, generic parts:

1. a method of communication
2. a source of power
3. hardware to perform the desired function (read a meter or pressure and to control pressure set points etc.)
4. hardware to receive, record, and/or relay informa tion to an operator.

No matter which technologies are utilized, automation of a function will not be made if it is not cost-effective. Thus, automation costs must be recouped quickly in benefits to the utility and its customers. Automation that can perform just one function (e.g., remote meter reading) must obtain payback based on that function alone. The cost/ benefit ratio can be improved by increasing the number of automated functions. Because any automated system with information feedback must have at least four key parts, independent automation of two functions requires duplication of those four key parts. However, combining the two functions into one automated system obtains the cost savings of both without the duplication of components. Several gas distribution automated functions can be obtained by adding a few components to a remote meter reading system. The total approach takes advantage of the technical and economic synergies that occur when functions are increased by adding a few components.

There are many ways of performing each of the key parts, each with advantages and disadvantages. Methods of communication for automating gas distribution systems include telephone lines, cables, radio waves, microwaves, wires and fiber optics inside or next to the piping, and acoustic and vibrational transmission in the piping.

Sources of electrical power include batteries, the customer's electrical service, gas utility supplied over a low voltage system, telephone company supplied, and on-site power generation from natural gas. Thermoelectric generation is an example of the latter. Assuming a 2.5% efficiency, 0.01SCF/hr of natural gas will supply 0.08 watts of power; enough to power CMOS electronics.

Examples of hardware include meter electronics to collect and encode a meter reading, to recognize an address and command and then respond with the proper action; inexpensive, remotely controlled valves and regulators; cathodic protection voltage measuring devices; pressure sensors, etc.

It is possible to envision situations where any combination of communication mode and power source would be the most appropriate. Given the diversity of gas utilities it would be inappropriate to eliminate any combination. This paper advocates a total system approach that permits the use of all possibilities.

ONE POSSIBLE SYSTEM CONFIGURATION

Thus far, the discussion of the total bottom-up approach has been in general terms. Consider one possible system configuration. This example is not the only system nor is it necessarily the best. In fact the key concepts of the total approach demand that many other power supplies and communication modes can and should be used as appropriate. However, this example does describe the many distribution operating functions that can be automated.

Our example system can be composed of any generally accepted materials and operating philosophies. (Practical and retrofitting problems and trade-offs between other modes of communication and power will be discussed later in the article.)

The following components have been selected to automate our example total system:

1. Wire and fiber optic communication system with the wires/fiber optics located in or near the main and services
2. Low voltage power supplied by gas utility over the same wires used for communication
3. "Smart" meter — addressable meter plus other addressable functions
4. Remotely controlled service valve located on the service at the main
5. Flow reading device also located at service tee, or alternatively, a pressure sensing device just upstream of the smart meter
6. Sensors for cathodic protection monitoring capable of being read by its own addressable reader or by the meter electronics
7. Pressure sensors and governor control devices
8. Distributed intelligence substations
9. Global commands for obtaining simultaneous meter readings, or the shutting of all valves, etc.
10. A meter tamper alarm.

In this example, communication and power are supplied by the gas utility via the wires and fiber optic cable buried along or in the piping. This provides complete gas utility control, security from power and communication losses in severe weather storms, and aid in pipe location/ third party damage prevention.

The location of a remotely controlled valve on each gas service at the main combined with a device capable of monitoring service integrity provide several operating functions and safety features.

The amount of gas lost through leaks is a function of the operating pressure in the mains. The amount of gas that can be supplied to the consumer is also a function of operating pressure. Gas demand is much greater during cold weather than warm weather. The operating pressure is controlled at regulator stations and is usually set manually a few times each year. Automated pressure regulators and governor control devices connected to the communications network can be adjusted quite often as a function of weather (gas demand). This minimizes the amount of gas lost with a potential savings of millions of dollars per year.

An array of sensors capable of monitoring cathodic protection, basically a voltage reading, can automatically alert the system operator when the cathodic protection of metal piping is no longer adequate.

BENEFITS OF THE TOTAL SYSTEM APPROACH

The benefits occurring from such a total bottom-up system can be divided into two parts: 1) those benefits accruing from only remote meter reading and 2) the additional benefits possible from the rest of the automated system.

As discussed in earlier papers in this symposium, remote meter reading is seriously being pursued by several utilities and manufacturers. In most cases the goal is to obtain the monthly meter reading remotely, eliminating estimated bills and the “intrusion” of a meter reader into homes. The benefits of monthly remote meter reading include:

1. Improved cash flow because of more rapid billing
2. Automatic billing reduces cost of billing
3. Elimination of special meter rereads because of errors

Better customer relations and response to customer needs are also benefits of remote meter reading.

1. No estimated billing
2. No unknown meter reader entering the house
3. No potential “bogus meter reader” trying to enter home disguised as a gas man

A system capable of multiple meter readings per month or day provides additional advantages. Frequent simultaneous meter readings in neighborhood size areas add the benefits:

1. Improvements in system design due to more accurate load, utilization, and friction factor data
2. Better analysis of unaccounted for gas
3. Better analysis of leakage from leak prone areas
4. Detection of gas theft by monitoring gas usage patterns
5. Determination of compliance by interruptible customers
6. Variable rate pricing becomes possible as a means of peak load shedding (Reduction of peak loads can be very cost effective in meeting gas contracts, in reduction of peakshaving costs, and in planning spot market gas purchases.)
7. Minimizes cost of final meter reads when customer moves

The addition of a few other components to the system can substantially increase benefits of the total approach.

1. Pressure sensors and remote regulator controls: Reduction in gas loss through automatic feedback pressure control
2. With known, continuous, unique (non −60 Hz) signal on piping:

   A. Better pipe location
   B. Third party damage prevention by using automatic alarms on digging equipment

3. Voltage measurement sensors: Remote or automatic cathodic protection monitoring
4. New customer convenience features:

   A. Display of gas usage in cubic feet per time unit or dollars via LCD displays, etc., rather than difficult to read meter mechanisms
   B. Using his own computer, customer can monitor his own gas usage, including effectiveness of new energy saving devices

5. Automatic tamper detection
6. Potential of reading other utility meters
7. Remotely operated valves:

   A. Rapid service termination in case of emergency (e.g., Gas flow to a burning house is stopped even before fire department arrives.)
   B. Remote service termination
   C. Reliable excess flow protection based on metered gas flow or pressure drop measurement, with definition of excess as function of season and individual customer load.
   D. Provides effective enforcement of interruptible customers

8. Knowledge that the gas utility is doing a great job in keeping gas prices down and keeping safety up.

DETERMINATION OF ECONOMIC BENEFITS

Determination of the economic benefits of bottom-up automation is difficult. The value of intangibles, such as safety and customer goodwill, are particularly hard to quantify. Intangibles can strongly affect PUC (public utility commission) decisions on rate hikes, directives on how utility money is spent, and the requirement of and/or the rate of installation of special capital intensive projects (e.g., cast iron replacement and installation of excess flow protection).

Even the seemingly straightforward task of determining costs of meter reading is not simple. The average cost to read a meter is not simply the meter readers wages divided by the number of meter reads. Employee supervision, training, and benefits, the cost of a vehicle to get him to and from his route, the cost of transferring readings from a card to the computer, and maintenance of personnel departments and building facilities add to the per meter reading cost. Customer complaints result in extra meter reads, requiring a special trip and vehicle to read individual meters, as does the final meter reading when a customer moves (an average customer moves once every 7 years). A special reading can cost $25. The cost of money incurred because of the time lag between meter reading and customer payment can be substantial at today’s interest rates.

Most of a customers dollar (70–80%) is spent for the gas itself. What impact could the automation of a distribution system have in that area? Several automation features have a direct impact on the cost of gas purchased by a distribution company. Currently utilities contract with major gas suppliers for a fixed amount of gas. If the utility's gas usage exceeds the contracted amount a penalty is paid to the gas supplier. In addition to the major contract(s), utilities may now purchase gas on the spot market. Weather conditions can force heavy usage for short periods of time. During such time peakshaving facilities are required to make up the difference. Underground storage SNG plants, and propane/air plants are expensive secondary supplies. Automated meter reading can measure unaccounted for gas in each area of the system, help identify its causes, and monitor the effectiveness of gas loss reduction methods. Automated governor pressure control can reduce leakage substantially. Variable rate pricing could load shed during weather extremes and/or permit the customer using the high cost gas to pay for it.

These brief observations on the economic benefits of automation indicate that the "true" cost of operating must be carefully determined.

RETROFITTING POTENTIALS AND PROBLEMS

There are many problems that must be addressed before bottom-up automation of gas distribution systems can be installed on a large scale basis. Many of these issues are independent of whether the system is meter reading only or a total approach.

Important communication concerns are cost, reliability, security, and rate of data transmission. Security from data tampering will require special attention, especially if physical access to the communication path is possible. For example, telephone lines may be vulnerable to unauthorized tampering because of easy connection to personal computers.

Power supply concerns include cost, long term reliability and availability, back-up during power loss, and maintenance. If the power comes from either the electric utility or telephone power grid, will power outage stop the supply and metering of gas? What happens if a consumer disconnects the power supply? How often would batteries need to be replaced? How will a gas utility respond to supplying electrical power itself?

Examples of hardware concerns include the development of 1) electronics to collect and encode a meter reading, 2) electronics to recognize an address and command and then respond with the proper action, 3) inexpensive, remotely controlled valves and regulators, 4) cathodic protection voltage measuring devices, and 5) pressure sensors, etc. Hardware concerns also include ownership of the hardware, both in the consumers home and at the data collection end if a third party is collecting the data.

The installation of a total system in a new neighborhood is the easiest and most cost effective case. Even a wire communication system can be easily installed as the new pipe is laid. While the U.S. gas distribution system is currently growing at a relatively slow rate of 1–2% per year, the growth still represents an important opportunity to introduce automation. A new housing development with a totally automated gas distribution system, plus new ideas in interior gas plumbing and gas appliances, represents an exciting marketing opportunity and tool. Added incentives to manufacturers of automated systems are the countries who are in the process of installing natural gas systems for the first time. These countries include Sweden and Greece. New foreign systems are a potentially large market for equipment manufacturers.

Renewals and pressure upgrades (currently proceeding at 1–2% of the system per year) offer another automation opportunity.* The use of distributed intelligence subcenters to collect data from a street or small neighborhood area would permit efficient use of the new features as they are added. While such approaches to retrofitting a total system would require several years to convert the entire system, it does have some practical advantages to the utility and manufacturer. With current regulations on utilities, a massive installation of a complete system within a few years might be unacceptable to the public and PUC's. The gradual, but steady, installation of such systems would not tax the economic and manpower resources of a utility. It would also provide a steady, predictable market for the manufacturers for many years.

One of the major problems to be solved in automating a distribution system is developing a cost effective method (s) for retrofitting the automation. This is true for meter reading only or for the total bottom-up approach. Over 50% of the U.S. gas distribution system has been installed since 1950 and should have many decades of useful life remaining. Thus a method of retrofitting automation to existing systems is vital if automation is to make an important impact. Retrofitting the total approach can be performed in a variety of ways because of two of its key features: modularity and a set of stable standards. By making the communication mode one interchangeable module and the power supply another module, a great retrofitting flexibility results. For example part of the system could be installed for meter reading only using telephone or radio as a communication link. Then additional features can be added at a later time. Remotely controlled valves could be added when services are renewed. Wire/fiber optic communication and power modules could easily be added at such a time.

It may be possible to develop methods for economically retrofitting total bottom-up automation rapidly. One possibility is to pull a small wire/fiber optic cable inside a main using variatons of plastic pipe insertion techniques. Small acoustic transceivers would be spaced along the wires, providing two-way acoustic communication with the individual meters. This procedure eliminates the difficult problem of installing wire through a service.

The use of modular components and a well thought out set of standards will be vital for an economic retrofitting solution acceptable to the industry.

THE NEED FOR STANDARDIZATION

The requirement faced by a few utilities to solve a specific problem on a short term basis (e.g., remote meter reading) plus the general market of other utilities and countries should provide the incentive and initial impetus to develop automated systems. Adherence to stable, carefully designed standards is vital to the development of a strong automation market.

The experience of some utilities with top-down automation makes them hesitant to automate. Too many utilities have purchased a newly designed system and helped the manufacturer debug the equipment only to see the manufacturer drop the product or leave the market. The gas utility is "stuck" with an "obsolete" product and salesmen explaining that an all new product is needed to perform the desired automation. Because the expertise of most gas utilities is not in electronic systems, such experiences make distribution companies very reluctant to purchase new systems, and very careful in their selection process. All of which delay the sale and add to the manufacturers cost because a sales force must be maintained a long time before substantial sales begin. This raises the cost of the product further delaying the purchasing decision. Knowledge of an industry wide standard permitting the utility to obtain help from more than one company without discarding all the equipment will aid producing sales base more rapidly.

The usefulness of standards can be itemized as follows:

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* Utilities constantly renew services as a safety precaution on a 30 to 50 year cycle. This renewal is often performed on one street or small neighborhood at a time. Pressure upgrades are sometimes made to replace aging pipe and/or to increase the amount of gas available to an existing neighborhood because of increased demand. Increased demand can occur when a highrise building is added to an old neighborhood.

1. Gas utilities are much more likely to purchase a standardized system with several potential suppliers of components than for a non-standard system. Judging from some experiences in automating various parts of current systems, the selection of a single manufacturer's system is risky because there is NO guarantee that the system will remain available and/or well serviced by the manufacturer. The newly purchased system may be obsolete in a few years or the manufacturer suddenly drop out of the market, leaving the utility "holding the bag" for a non-working system.
2. Standards can simplify manufacture and permit economy of scale. The cost of a individual solid state electronic component decreases rapidly with volume. A set of standards will permit manufacture of fewer individual chips, with many more of each chip produced sold. Thus the manufacturing cost would be less for all manufacturers.
3. Several manufacturers making interchangeable equipment gives a utility choices in how to solve which problems and how to expand in the future.
4. Insure compatibility of top down and bottom up system interface.

SUMMARY

The automation of any single feature of gas distribution operation requires four basic parts: a communication mode, a source of power, hardware to perform the automation, and hardware to receive the information. The incremental cost of automating a second feature can be made quite small if the second feature uses the same power source, communication link or electronic hardware. With a small amount of additional hardware, several operating problems can be automated together. The basic tenet of the total system concept to automation is that the added benefits of the additional hardware far outweigh the added cost.

Four key concepts are important to making a total approach viable. These are: 1) the solution of many problems together, 2) establishment of gas industry wide standards for communication, power, and interconnection of components, 3) modularity of components, and 4) the use of distributed intelligence. By integrating all technologies into a standardized, modular system, gas utilities are given the maximum flexibility to choose the problems they want to solve, using the technologies they desire, and with interchangeable products from many manufacturers. A carefully designed total approach will allow the utilities to modify and/or add to their system without losing the initial major investment.

Determining the cost saving benefits of automating the gas distribution system is not easy. There are many hidden expenses that can be alleviated by automation. Many of these are currently itemized in categories where the impact of automation is not obvious. Intangible safety and customer relation benefits are hard to quantify, and yet can have a major impact on a utility's business. These include improving PUC relationships, thereby easing the acceptance of rate increases and lessoning the impact of unfavorable rulings, improving the effectiveness of spot market purchases of gas, reducing peak shaving expenses, reducing unaccountable losses, and developing new marketing tools and concepts.

Of course, many problems must be solved and issues resolved before the automation of any feature becomes successful on a large scale. These include technological problems of power sources, communication, optimized hardware, retrofitting, and security. They also include ownership of equipment in a home, ownership of equipment and data collected through a third party, and policy decisions on remote shut-down, tamper detection, and enforcement of interruptible service. Practical solutions to these problems and issues can be envisioned. The potential benefits to the utilities and their customers are much greater than the cost of solving and implementing them. Automation of many operating problems may be necessary to keep natural gas a viable energy product.

The issue of standardization is critical for automating any operating problem. This includes meter reading only, as well as, a total system approach. The key to a strong, viable automation market is a set of products assuring gas utilities purchasing and installing automation that those products will be supported by more than one manufacturer. These standards must be stable, that is, they must be capable of lasting 50 years without limiting technological advancement. The utilities must also be assured that their investments will not be wasted by the change in plans of one manufacturer. They must also be confident that their purchased hardware can be expanded to include other features at a later date without having to duplicate power supplies and communication hardware. Only with these assurances will the market be strong enough to permit the economies of large scale production of electronic components and the maximum benefit to the gas customer, the utilities, and the manufacturer.

Carefully defined standards for bottom-up automation should be made as soon as possible, before substantial investments in development and hardware.

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THE GRI PERSPECTIVE ON ADVANCED GAS DISTRIBUTION SYSTEMS RESEARCH

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ABSTRACT

A brief review is given of GRI projects in the gas distribution area where microelectronics are playing a major role. GRI's overall service to the gas industry is to sponsor research and development which will lead to improvements in supply, transport and end-use technologies. The technologies in distribution which are discussed here include pipe location and underground mapping, flaw detectors, metering, and computerized data bases. Some examples of cost reduction through microelectronics are given.

THE GRI PERSPECTIVE ON ADVANCED GAS DISTRIBUTION SYSTEMS RESEARCH

THE ROLE OF GRI IN GAS DISTRIBUTION R&D

Introduction

Gas Research Institute (GRI) is a not-for-profit membership organization of natural gas pipeline and distribution companies. GRI plans, manages and develops financing for a research and development (R&D) program designed to advance gas supply options, end-use and operations technologies and to conduct related basic research. The funding mechanism for the program is based on the volume of interstate and intrastate sales by GRI member companies and is subject to annual review and approval by the Federal Energy Regulatory Commission and, where appropriate, by state regulatory agencies.

The program includes over 300 individual projects that are performed by leading R&D organizations under contract to GRI. The flow of new products, processes and information resulting from GRI's R&D investments provides substantial benefits for the gas industry and its ratepayers.

Background

The gas distribution system currently in place in the U.S. provides gas—reliably, safely, and efficiently—to residential, commercial and industrial customers, and it is expected that this distribution system will continue to serve gaseous fuel end-users into the next century. If the gas industry is to remain responsive to the needs of its customers over the coming years, however, several issues will have to be addressed. These include (1) the costs of operating and maintaining the nation's distribution systems; (2) the longevity of both metal and plastic underground gas piping systems; (3) the expenditure on main extensions and service connections to new customers; (4) the cost of installing or retrofitting interior gas piping systems in homes, multifamily dwellings, and commercial buildings; and (5) the provision of ample and reliable supplies of gas on demand to all end-use sectors. GRI's Transport and Storage subprogram is addressing these needs with two major initiatives. The subprogram's first initiative is directed toward reducing costs and improving techniques for maintenance, operation, and preservation of the existing gas distribution system. The subprogram's second initiative focuses on (a) the development of modified materials, advanced technologies, and new modular systems to decrease costs of main and service extensions to new customers and to meet future needs of gas distribution companies; (b) decreased costs of interior (building) piping in new and retrofit applications; (c) low-cost, alternative storage options; and (d) ensuring safe, ample, and reliable delivery of natural gas to the customer.

APPLICATIONS OF ADVANCED ELECTRONIC SYSTEMS

The primary emphasis for this paper is the application of microelectronics to the gas industry and GRI's role in the development of specific new products and services. In this brief overview, a few selected projects will be described to show how advanced computational systems and microelectronics are benefiting the gas industry.

Pipe Location

In the broad area of construction and maintenance for the gas industry, the problems of accurately locating underground facilities (e.g., pipes, electrical cables, water conduits, TV cables, etc.) are still unsolved. GRI has sponsored research on a plastic pipe locator for several years applying pulsed radar wavelength signals as the sensing energy. One of the simple examples of electronic advances here is the replacement of the original source unit which used a spark discharge tube for the microwave energy. Currently, a solid state source is used to generate the initial energy pulse.

The major difficulty in achieving reliable performance from a radar system is the wide variability in soil parameters—conductivity and dielectric constant—across the U.S. Our original objective of having a simple pipe locator instrument with a visual, real time, readout is being replaced with a more sophisticated, on board, near real time data acquisition and processing system. We expect the application of microcomputers to be especially valuable here. In a separate project completed last year, GRI evaluated underground radar mapping systems which could be used to locate complex systems of pipes and/or cables at street intersections. Figure 1 shows the typical strip chart image from an off-the-shelf underground radar system. This type of visual image is quite sufficient for isolated steel pipes, but when two or more pipes are installed close to each other the location becomes much more uncertain. A GRI contractor applied special imaging techniques to the received signals and reconstructed the images of Figure 2 showing much better resolution and some depth data. Two years ago, the hardware required to accomplish this processing retailed for about $100,000. Currently, we are estimating that the cost of specialized electronics would be $25,000. Once the

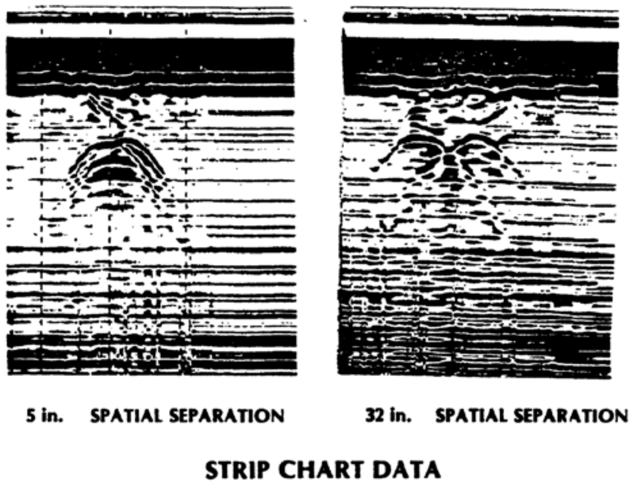


FIGURE 1. Strip Chart Data from Ground Penetrating Radar Showing Resolution of Two Four-Inch Steel Pipes Installed at a Depth of Four Feet.

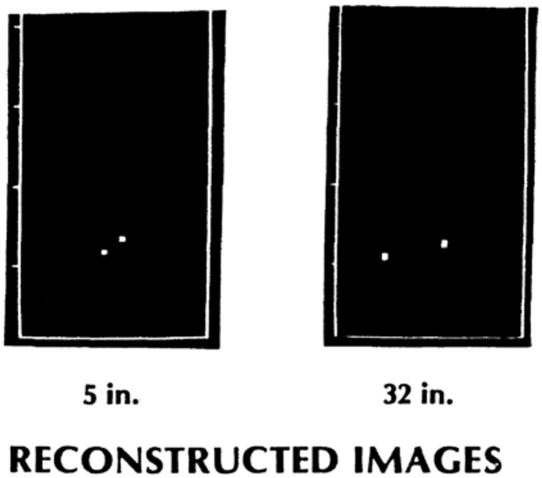


FIGURE 2. Reconstructed Images of Two Four-Inch Steel Pipes Installed at a Depth of Four Feet. Laterial Separation is Five inches and 32 inches, Respectively

hardware for this imaging system reaches about $10,000, we believe that a marketable mapping system will be used by the gas industry.

Flaw Detectors

Another application of microcomputer systems is in the development of a nondestructive testing device for heat-fused, butt-joints in polyethylene plastic gas pipes. In order to complement the current techniques of specialized crew training and careful visual inspection, GRI has sponsored two R&D projects to develop ultrasonic flaw detectors—primarily to identify "cold welds" in butt-joints where visual inspection is not effective.

The original data acquisition system used by the first manufacturer was a special purpose computer with automated learning networks which sold for about $50,000. The research which GRI supported led to a simplification of the design and permitted the application of an IBM PC in place of the special purpose computer (Figures 3 & 4). Further miniturization and simplification has led to a semi-rugged, portable PC unit which has the capability to record field test data on discs and be reprogrammed for specific pipe material and defect discrimination levels (Figure 5).

GRI has recently initiated a second contract with another manufacturer to develop a field-hardened unit. This device was originally developed with GRI funding for the inspection of two- to four inch diameter joints. It is microprocessor-controlled and programmed to require minimal operator instruction. The operator need only select the appropriate pipe size and material. The operating parameters of the inspection device are then set automatically. The technique used in this NDT device has been demonstrated to be capable of detecting the type of defects that can occur in polyethylene pipe joints. The final inspection system is expected to be have several applications: routine field inspection of butt-fusion joints before pipe installation, random field inspection to verify fusion crew performance, and extensive field inspection for critical installations (e.g., under roadways). The device is likely to be purchased by gas utilities and contractors who conduct construction and maintenance for the gas industry. Applications may also be found in other areas, such as water pipelines, where plastic pipe and the heat-fusion joining process are used.

A photo of the initial, non-hardened prototype is shown in Figure 6. Further advances in hardening the design and reducing electronic component costs are expected in 1986. Clearly, the application of microelectronics is having a significant effect on flaw detector design for plastic pipes.

Metering

In the area of custody transfer metering, GRI has several projects underway which rely heavily on microelectronic systems. GRI has sponsored research on the development of an energy flowmeter since 1982. The current gas industry practice for determining energy flow rate is to combine independent measurements of volumetric flow rate with energy content. These independent measurements are often taken at different times and in separate locations leading to greater uncertainty. The Precision Machine Products (PMP) organization has developed an energy flowmeter concept which withdraws a sample gas flow from the main pipeline and measures the Btu content of that sample using on-line combustion calorimetry and a very precise mass flow measurement of the small sample. The key to this design is a restriction placed in the main gas line (a splitter plate) which maintains the ratio of main gas flow to sample flow at a constant value over a certain range of main line flow rates. If the split ratio is maintained at a constant value, the main line energy flow rate is a simple multiple of the sample line value. Figure 7 shows a schematic of this concept. After initial tests in a two inch industrial burner supply line, a field prototype is now being tested in an eight inch, high pressure gas line feeding a gate station near the city of Bryan, Texas. Thus far, this test unit has proved to be at least as accurate as an adjacent, on-line system using a combination of an orifice meter, flow computer, and combustion calorimeter. Future field tests at other sites are planned for 1986. Again, this type of on-line field usable instrument would not be economically feasible without low cost, microelectronic data collection and processing techniques.

For longer term applications of new concepts in non-intrusive metering, GRI initiated a project in 1985 to evaluate laser velocimetry and infrared spectroscopy as sensing techniques for custody transfer measurements. A schematic of the laser geometry is shown in Figure 8.

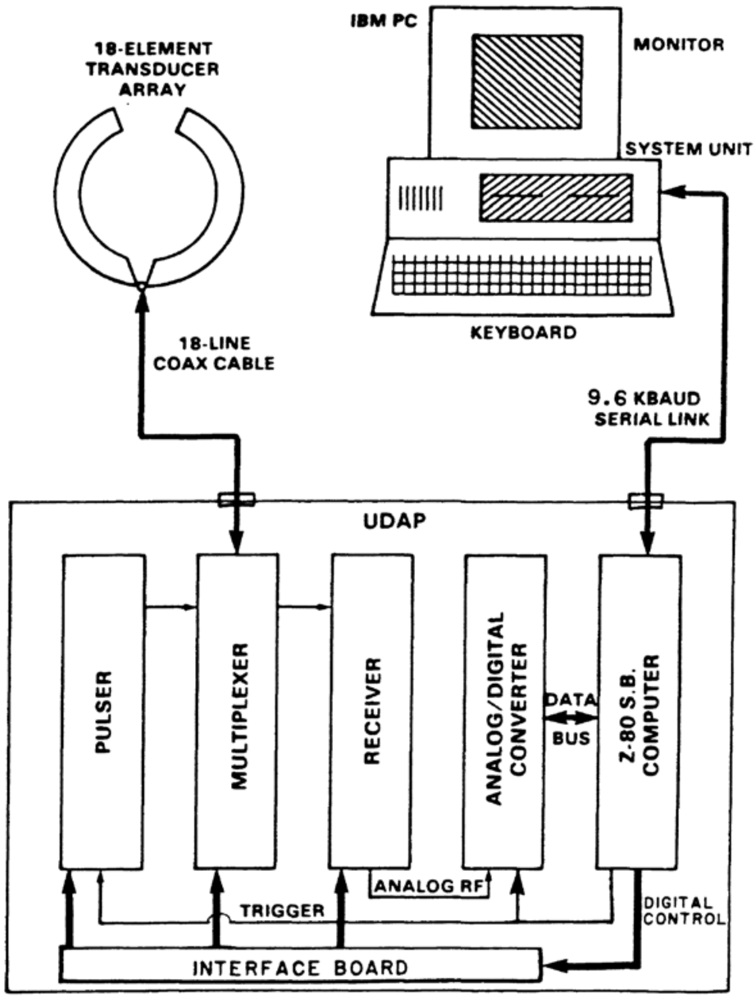


FIGURE 3. Schematic Diagram of Flaw Detector Using 18-Element Array and Phase I Computer Hardware.

In areas closely related to metering, GRI has sponsored work at the University of Oklahoma where a new correlation method for calculating supercompressibility factor has been developed by Dr. Kenneth Starling. The A.G.A. Transmission Measurement Committee (TMC) has recently issued a draft standard (TMC Report No. 8) based on this Starling correlation which will replace the existing tables of supercompressibility factor published as Report No. NX19. GRI is currently considering whether or not to develop specific computer discs or hand-held calculator chips which will make this new computer model readily available to field measurement people.

Lastly, in an area related to custody transfer measurement calibration, one piece of instrumentation which has been receiving more acceptability by gas utilities is the gas chromatograph. This instrument will give good results on gas composition, and therefore Btu content, when accurately calibrated. In early 1983, GRI responded to an A.G.A. request to develop uniform calibration standards for gas chromatographs which could be used as references in any field location. IGT has developed such standards under the direction of Dr.

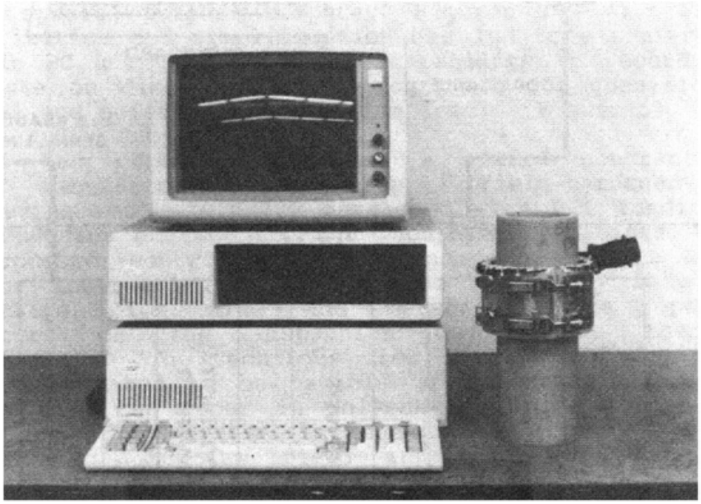


FIGURE 4. Laboratory Prototype System Showing Phase I Computer Hardware

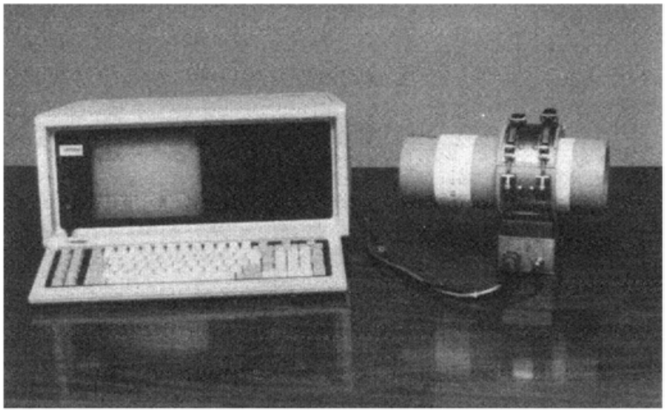


FIGURE 5. Photograph of Semi-rugged Flaw Detector with 18-Transducer Array and Portable Computer for Data Collection and Analysis.

Amir Attari, and these new calibration gases will be available to the gas industry early in 1986. Figure 9 shows the sophisticated reference laboratory which IGT has established to provide these services.

In the area of residential metering, many manufacturers, gas utilities and research organizations are working on small, accurate residential meters. Several concepts for automatic meter reading have been presented at this conference. While GRI is not currently sponsoring any R&D in automatic meter reading, we are following several pilot projects now underway across the U.S. We do have plans for work on compact gas meters—primarily for multifamily residence applications. We have initiated one such project in mid-1985 with the primary emphasis on a mechanical design which does not require electrical power. For 1986, we expect to be funding R&D which focuses on other sensing concepts—such as hot film anemometry, fluidic devices, and mini-turbines—which require battery or AC power. These latter concepts

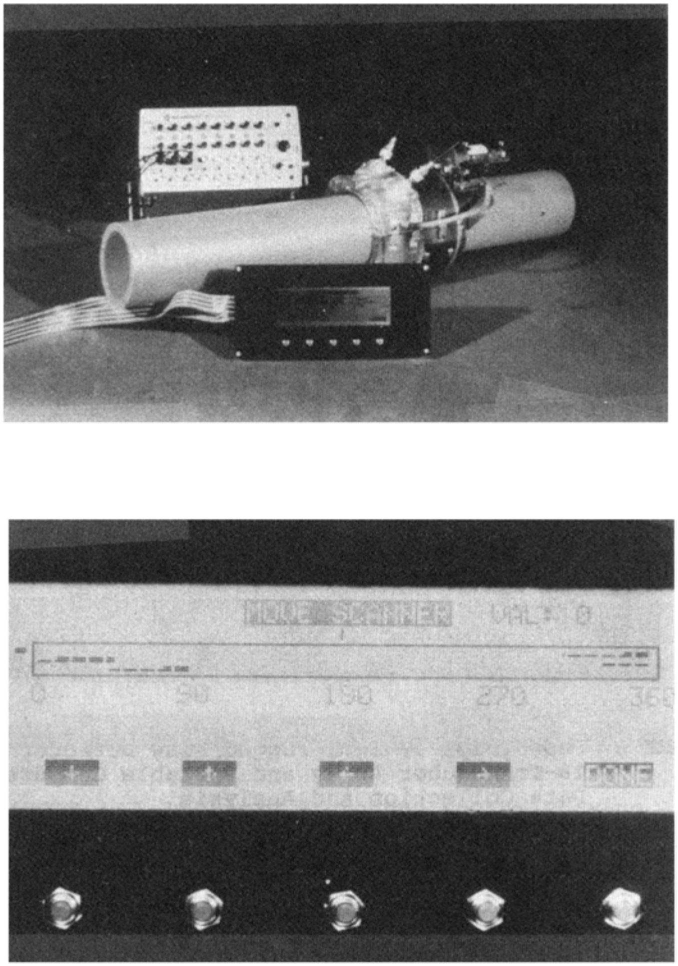


FIGURE 6. Photographs of Prototype Field Unit Flaw Detector and LCD Readout Showing Joint Condition as a Function of Circumferential Position.

will, of course, lend themselves to automatic meter reading since electrical power will already be present at the meter.

Automated Mapping/Facilities Management (AM/FM)

A technology which is rapidly emerging as a valuable tool for gas distribution systems is in computer mapping and facilities management. A few gas utilities have made corporate decisions to convert system maps and drawings into multiple, overlaid, computer files so that system operations, modifications, repairs, and expansions can all be analyzed and performed using an extensive computer data base. Once such a data base is established, the potential increases in efficiency are substantial—especially for combined utilities where electric and gas systems can be referenced. Also, municipalities can achieve great operational efficiency by combining gas, water, and electric facility features.

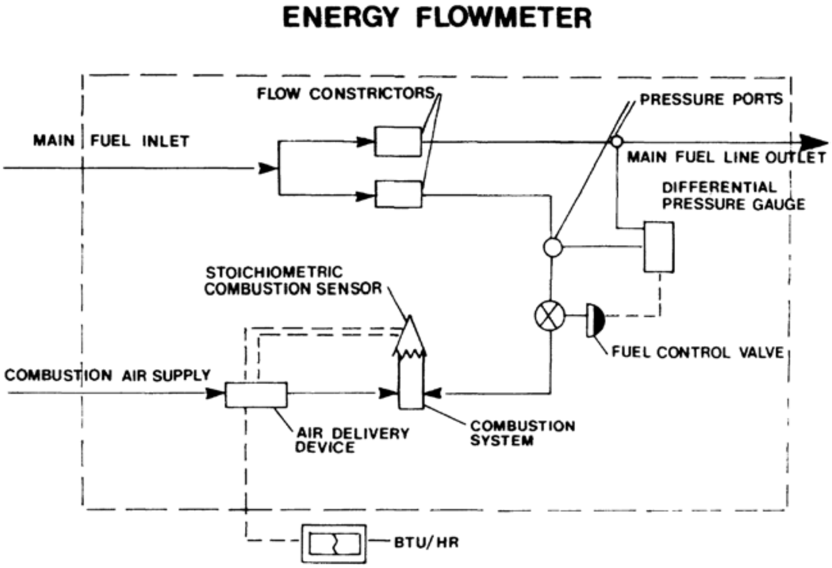


FIGURE 7. Schematic of Energy Flowmeter Installed at Field Test Site.

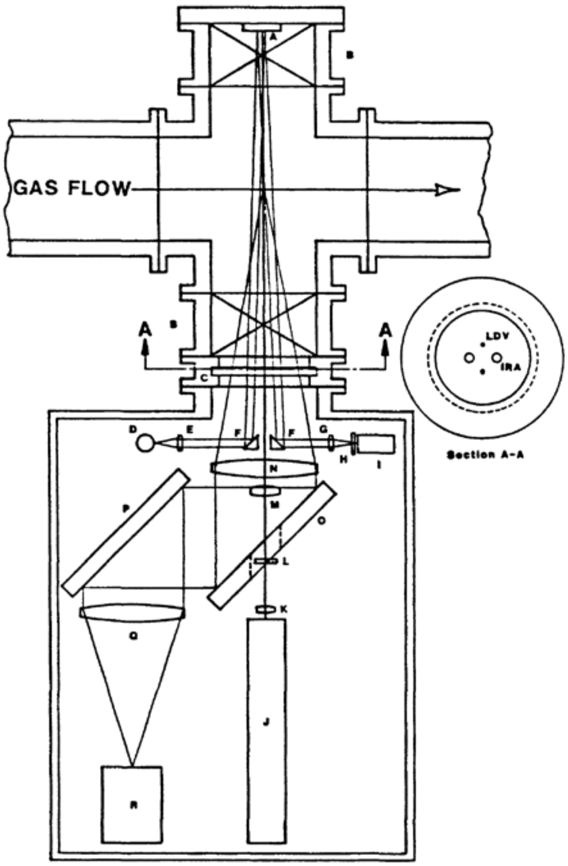
GRI believes that this AM/FM technology will eventually be used by many gas utilities. One of the greatest hindrances at this point in time is the cost of converting historical maps and records into the computer data base. While techniques and organizations have improved the conversion efficiency through special hardware and mass production methods, it still may cost a utility between $5.00 and $35.00 per customer for the conversion process. This exceedingly wide range shows that key cost factors are:

1. The condition of current maps and drawings,
2. The amount of data which is to be stored,
3. The number of reference files which must be accessed in order to develop input data, and
4. The relative amount of in-house expertise versus outside service organization usage.

Consequently, GRI is formulating a plan over the next six months to develop contracts, workshops, literature, technology centers, etc. which will be used to assist the gas industry in utilizing AM/FM technology.

CONCLUSIONS

In this brief review of only a sampling of GRI projects, we have seen the strong impact of microelectronics into gas distribution. Over the next few years, this impact will manifest itself in new products, instruments, and operational techniques which will help the gas industry maintain its record of low cost, reliable, and safe energy service to U.S. residential, commercial, and industrial customers.



A] Infrared Reflecting Mirror
B] Isolation Valves
C] Pressure Window
D] Infrared Broad Band Light Source
E] Infrared Collimating Lens
F] Infrared Output/Receiving Mirrors
G] Infrared Collecting Lens
H] Infrared Filter Matrix
I] Infrared Quadrant Detector
J] Helium Neon Laser
K] Focusing Lens
L] Diffraction Grating
M] Collimating Lens
N] Output/Receiving Lens
O] Trepanned Mirror
P] Plane Mirror
Q] Photodetector and Aperture

FIGURE 8. Schematic Diagram of Advanced, Nonintrusive Energy Flowmeter.

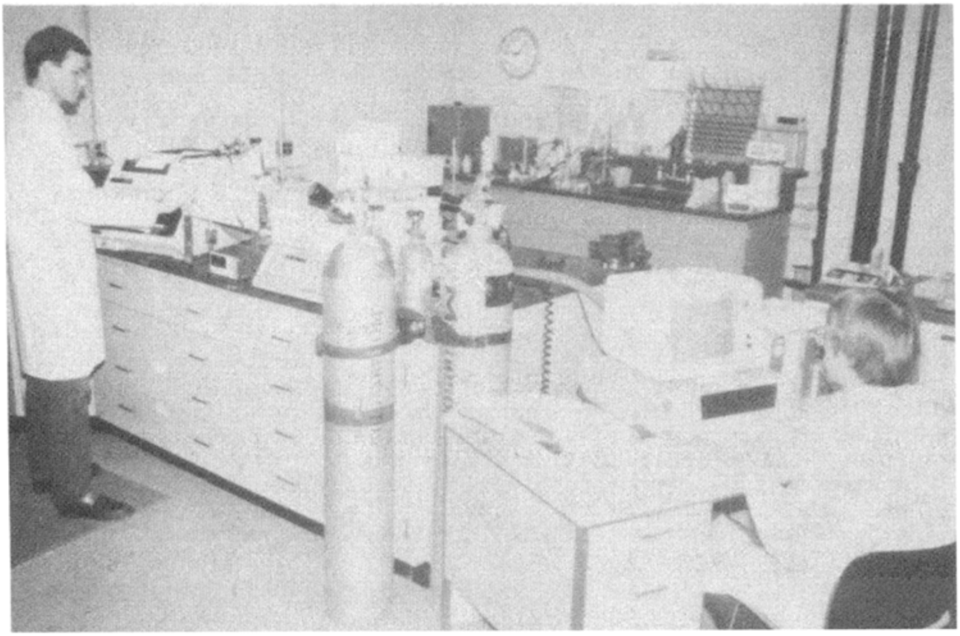


FIGURE 9. Photograph of IGT Laboratory Apparatus used to Analyze Calibration Gases.

AUTOMATION OF WASTE HEAT RECOVERY PLANT FOR COMPRESSION OF NATURAL GAS

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ABSTRACT

Natural gas Pipeline Company of America (NGPL) has designed and installed a waste heat recovery plant, as a demonstration project, at its compressor station in Beatrice, Nebraska. A programmable controller and a professional computer comprise the control system for the plant.

The plant recovers energy from the exhaust gas of two four thousand horsepower compressors, and using an expander/compressor turbine, converts thermal to mechanical energy to provide additional horsepower for the compression of natural gas. The experimental nature of the plant, makes it necessary to be able to change the control sequence and operating parameters easily. Additionally, reliable data acquisition and logging are important considerations. The programmable controller is particularly well suited to this type of application.

This paper discusses the operation of the heat recovery plant and design of the hardware and software systems required to control it.

AUTOMATION OF A WASTE HEAT RECOVERY PLANT FOR COMPRESSION OF NATURAL GAS

INTRODUCTION

Natural Gas Pipeline Company of America operates forty four transmission compressor stations throughout its system. The engines at all but two of these stations are fueled by natural gas. Less than 40% of the energy contained in the fuel is used to compress natural gas. The remaining 60% of this energy is wasted thermal energy lost through engine cooling jackets, the lubrication system and the exhaust gas. Over 5 trillion Btu is lost in this manner annually. Obviously, any process that would capture some of this wasted energy for some useful application would be of great benefit. To that end, NGPL designed and installed a waste heat recovery plant to recover the energy from the exhaust of two four thousand horsepower compressors. The control system for this plant employs a programmable controller, interfaced to a professional computer.

DISCUSSION

Process Description

The plant uses a process called the Rankine cycle to recover the energy from the exhaust gas. This process was chosen because it represents the potential for increasing the available horsepower by 10 to 15 percent without the burning of any additional fuel. Furthermore, virtually no additional pollutants are produced by this process.

A schematic of the Rankine cycle is shown in figure 1. A brief explanation of the process follows. Supercritical isobutane at approximately 700 psia enters each of the two heat recovery units where it is heated at constant pressure to a temperature of 500 deg. F using engine exhaust gas from the two Clark TCV-12/16 engine compressors. The exhaust temperature leaving each heat recovery unit will be approximately 300 deg. F. Both working fluid streams are combined before entering the turboexpander, where the thermal energy in the isobutane is transformed to mechanical energy and its temperature and pressure are reduced. The power, 1300 to 1500 horsepower, is absorbed by a centrifugal compressor. This compressor horsepower is utilized to compress natural gas in parallel with other compressor station horsepower. The working fluid leaving the expander is now a superheated vapor at approximately 385 deg. F and at 54 to 100 psia, depending on ambient temperature. Next the working fluid enters the hot side of the shell and tube heat exchanger (economizer) where its superheat is removed and used to preheat low temperature, high pressure isobutane prior to the high pressure fluid entering the heat recovery units. After the working fluid leaves the hot side of the heat exchanger, the fluid is condensed and cooled a small amount. The condenser is an air cooled, finned tube unit designed for a 20 deg. F approach. From the condenser, the subcooled working fluid enters a 10,000 gallon surge and storage tank. It then enters one of two parallel electric circulating pumps, each designed for one half of the system flow, where it is compressed to 710 psia (supecritical pressure). A third pump is available as a spare. The high pressure fluid then enters the cold side of the heat exchanger where it is preheated by the superheated stream entering the expander. Finally, the supercritical fluid enters each heat recovery unit to repeat the cycle.

Control System Hardware

The control system consists of two main sub-systems, the programmable logic controller (PLC) and the professional computer (PC). The PLC provides sequential logic processing, mathematical calculations, conversion functions, timers and counters. Through its input/output (I/O) system, it monitors and controls the operation of the plant. A diagram of the control system is shown in figure 2.

The PC serves as the operator interface to the control system. Total monitoring and control of the system is possible from the computer console. The PC provides color displays of operating data, generates reports and serves as a control panel.

Central Control Unit. The heart of the control system is the Texas Instruments PM550 programmable controller. It has 7K of battery backed up RAM memory and dual 16-bit microprocessors. One processor executes only the sequential logic, timers and counters. Sequential logic is in ladder logic form, which resembles electrical contacts and coils and is easily understood by technicians and field personnel. An example

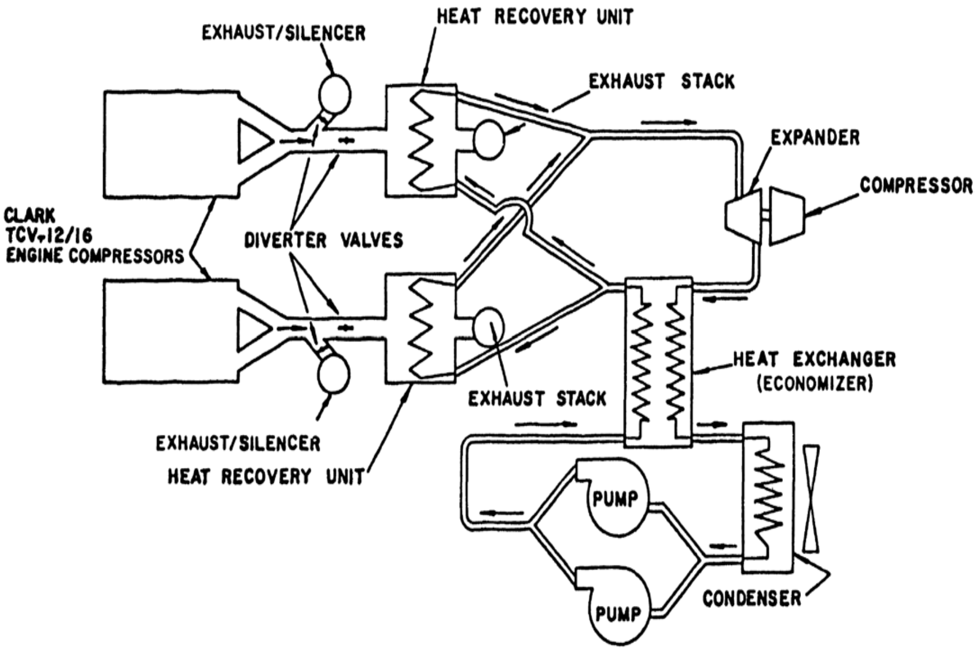


Figure 1. SCHEMATIC DIAGRAM OF STA. 106 WASTE HEAT RECOVERY FACILITIES

of ladder logic is shown in fiqure 3 The other processor handles mathematical calculations, conversion functions and control loops. This arragnement ensures that logic update will be kept to a minimum because the first processor is not slowed down by lengthy mathematical computations. The controller has three communication ports for communication with the professional computer, diagnostic equipment and for loading of programs. Figure 3, Cont. LADDER LOGIC EXAMPLE

Programs are written using a video programming unit which consists of a c.r.t., keyboard and floppy disk drive. Programs can be downloaded from the unit to the controller, or from a cassette tape loader. Diagnostics, calibration and minor programming changes are accomplished using a read/write programmer, which resembles a desk-top calculator.

Loop Controllers. Four dedicated proportional, integral, derivative (PID) electronic controllers by Robertshaw, are used to control the expander/compressor and heat recovery units. These PID controllers receive setpoints from the programmable controller, when they are in remote mode. In local mode, the setpoint is entered from the front panel of the PID controller.

Input/Output System. The input/output (I/O) system interfaces the controller to the various end devices throughout the system. Analog data from temperature, pressure, and flow transmitters are sent to the analog input modules in the form of 4–20 milliampere signals. These input modules are analog to digital converters that convert the 4–20 mA signal to a 12 bit number.

Analog outputs are 4–20 mA signals sent to the PID controllers and panel meters. The analog output module takes a 10 bit number from the controller and coverts it to a 4–20 mA signal.

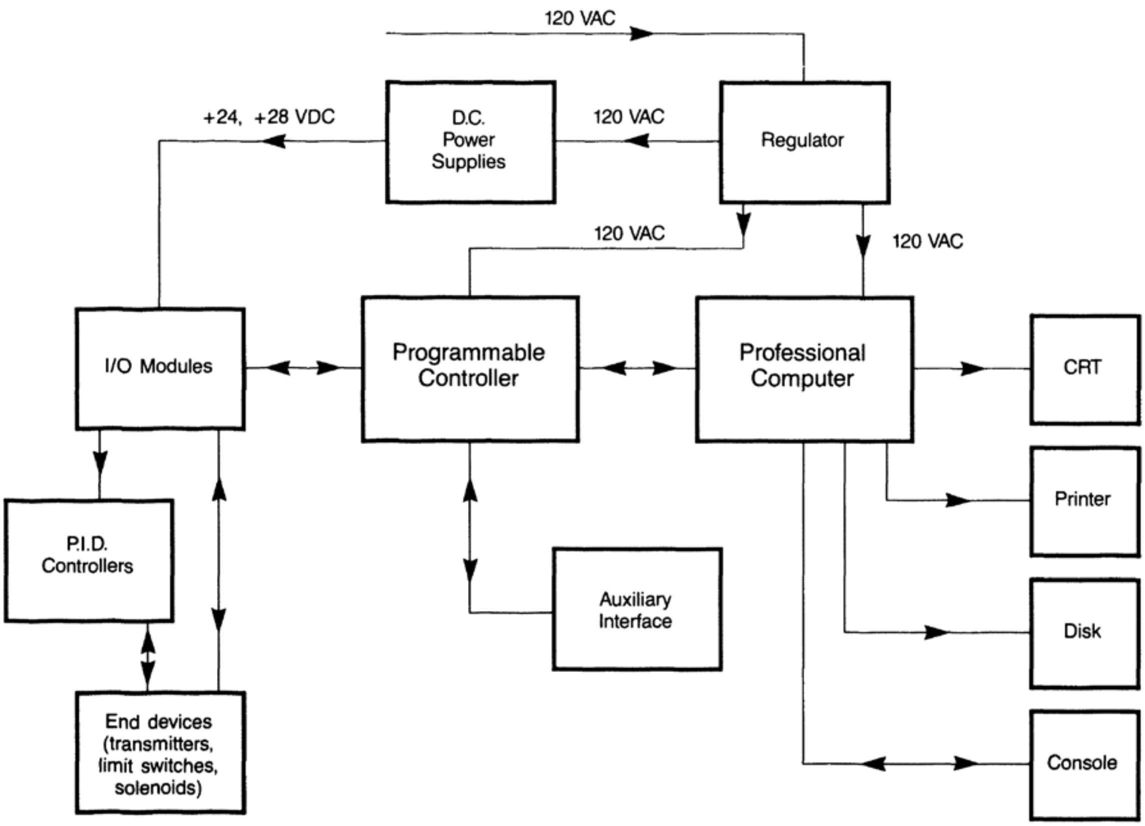


Figure 2. WASTE HEAT RECOVERY PLANT CONTROL SYSTEM

Discrete input modules accept 24VDC signals from pressure, temperature, and limit switches, providing alarm and status information. Solenoids that operate valves, and motor starters on pumps are controlled by 24VDC signals from discrete output modules.

Operator Interface. The primary operator interface is a CVU5000 by Texas Instruments. It consists of a T.I. professional computer with a color c.r.t., a floppy disk drive, a special keyboard and a software package. From the keyboard, the operator can select up to 25 different display screens, initiate control functions and generate reports.

Programming of the operator interface is menu driven. Displays showing data, status and alarms are constructed by filling in tables. Data are displayed in logical groupings on various pages, and are color coded for easy identification with all isobutane data in blue, lube oil data in green, etc… In addition to numberical form, some critical information is also displayed in bar graph form. The status of equipment such as valves and pumps is also displayed and color coded, with green signifying on or open, and yellow signifying off or closed. The color red is reserved exclusively for alarm and shutdown conditions.

Keys on the operator console are programmed to provide such functions as start, stop and control of pumps and valves.

Auxilary Operator Interface. A backup operator interface is provide for use in the event of a failure of the primary interface. It was also used in the initial startup of the plant because the primary operator interface was

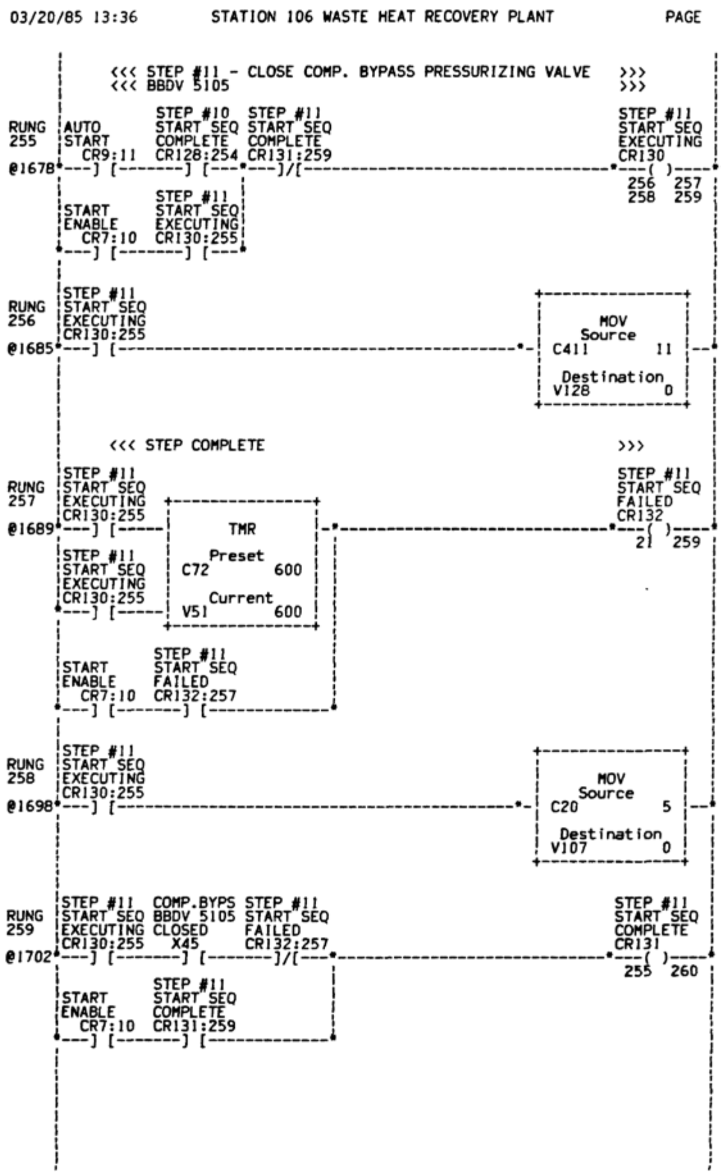
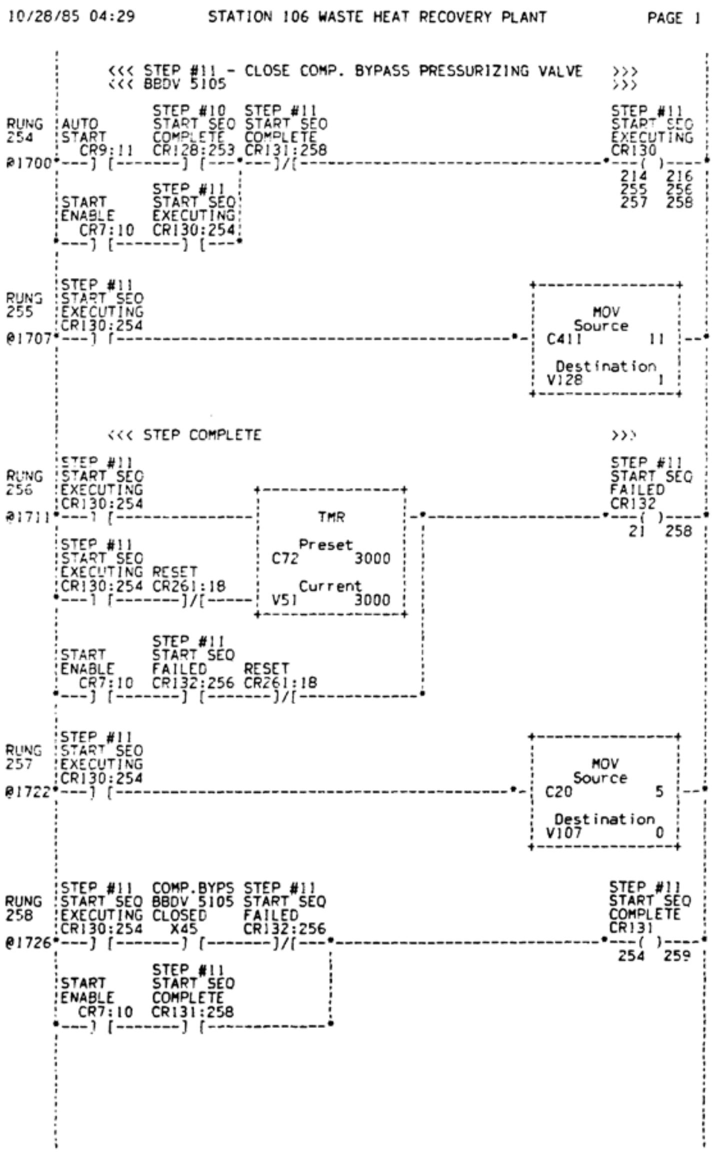


Figure 3. LADDER LOGIC EXAMPLE

not yet installed. This interface consists of pushbuttons mounted in a panel to provide start, stop, emergency stop and reset functions. Two thumbwheel switches and two LED current meters are provided to select and display data, and annunciator lights are provided to display alarms. A timer/counter access module gives access to the controller memory to enable other control functions.

Power System. The control system is powered by 120VAC commercial power. A regulator is used to protect the controller and computer from dips and spikes in the power.



Two d.c. regulated power supplies provide power to the I/O system.. Analog and discrete I/O are powered by separate supplies to prevent noise on the analog channels. A third d.c. power supply automatically takes over if either of the primary supplies fail.

Software

Sequencing. The most important function of the PM550 is controlling the automatic plant startup and shutdown sequences. The sequence is a series of steps programmed in the ladder logic section of the PM550 memory. Confirmation of the successful completion of each step is necessary before the next step can be executed. For this reason, each step has a timer associated with it. The timer is started at the beginning of the execution of the step, and if it expires before the step has completed, the start sequence is suspended and an alarm is generated. Additionally, a master timer is started at the beginning of the start sequence and if it expires before the sequence is complete, the start sequence is aborted and the normal shutdown sequence is initiated. A similar procedure is followed in monitoring the normal shutdown sequence. If this sequence fails, the emergency shutdown sequence is initiated.

Start Sequence. The PLC control program features two variations of the startup sequence. Depending on the conditions in the system, a warm start or a cold start sequence may be selected from the keyboard of the operator interface.

The following is a brief description of the start sequence. The first step in the sequence is to set all valves in their initial positions, issue the initial setpoints and to verify that all shutdown conditions have been cleared. If any shutdown conditions are present, the PLC will inhibit the start sequence. The second step involves a timed sequence in which valves are operated to purge the gas piping. Upon completion of the purging sequence, a start signal is issued to the turboexpander and setpoint ramping begins. The next step involves starting the four condenser fans and two isobutane pumps to establish isobutane flow. If one of the fans fails to start, an alarm is issued and the sequence continues, but if two or more fans fail, an alarm is issued and the sequence is aborted. If a pump fails to start within twenty seconds after the start segnal is issued, the PLC will attempt to start another pump. If the minimum number of pumps cannot be started, the sequence is aborted, once isobutane flow is established, diverter valves are operated to send exhaust gas through the heat recovery units and setpoints to the temperature controllers are ramped to bring the isobutane up to operating temperature, valves are sequenced to begin loading the compressor. Following this, valves are sequenced to establish isobutane flow through the expander. When the turbine has reached 50% of its rated speed, valve sequencing takes place to complete the loading of the compressor and the unit is on line. Once the unit is on line, any shutdown protection which was locked out for startup, is enabled.

Setpoint Control. Another important function of the controller is issuing setpoints to the four Robertshaw PID controllers. Two of these controllers on the heat recovery units are used to control the temperature of the isobutane. The other two controllers are used as pressure controllers, to control the operation of the turboexpander In all cases, these setpoints must be ramped at a rate which gives optimum response yet minimizes overshoot and oscillation. This is especially critical in the operation of the turboexpander.

The PLC provides several functions and routines for the manipulation of data. The following is an example of how one of the functions (correlated data table) was applied to implement the setpoint ramping described above, (fig. 4) When the value of the input word is greater than or equal to a particular value in the input table, the corresponding value in the output table is sent to the output word. In this case, a timer is used as the input word and the times at which the setpoint is to change are entered in the input table. The corresponding setpoint values are entered in the output table, and the analog output channel tied to the PID controller is used as the output word.

This approach allows variations in the time intervals and the size of the increment. It is useful because in some cases, the setpoint is ramped to a certain value and remains there for an extended period of time before ramping is resumed. Changing the rate of the ramping function is then accomplished by simply changing the values in the table.

Online Operation. Once the plant is on line, the controller must monitor the operation of the system and alert the operator to any alarm conditions that may occur. It monitors analog points and issues an alarm if a predetermined warning limit is reached. If the shutdown limit is reached, an alarm is issued and a plant shutdown sequence is initiated. Discrete alarm points such as pressure switches and fire alarm contacts are

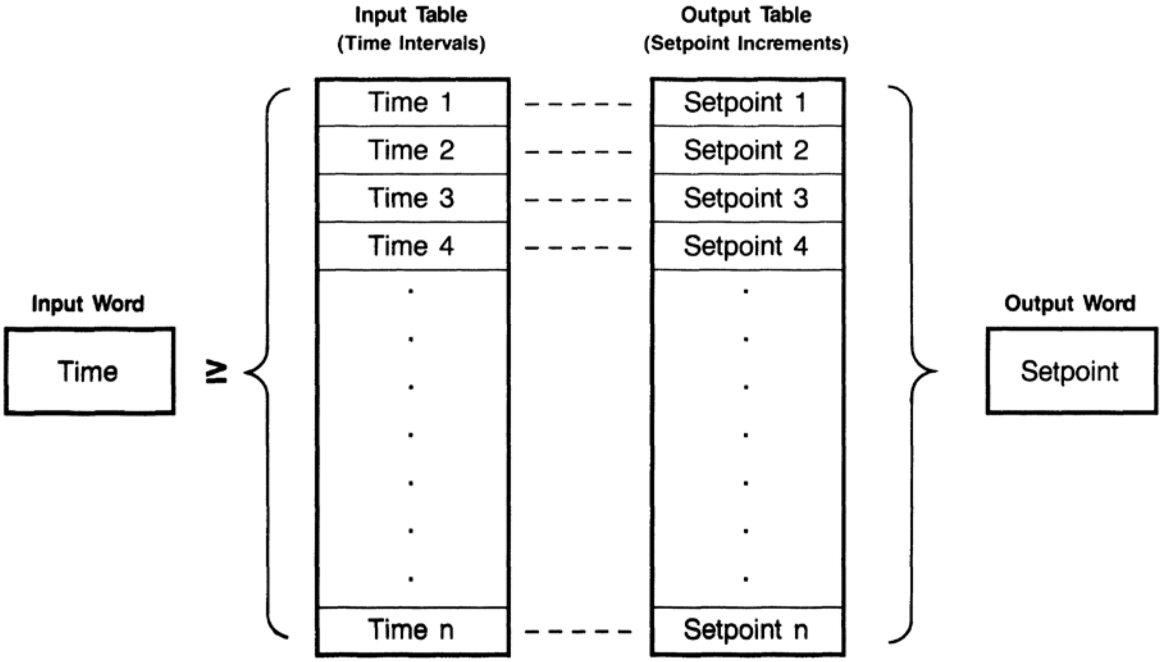


Figure 4. CORRELATED DATA TABLE FOR SETPOINT CONTROL

also monitored for alarm reporting and safety shutdowns. Each analog and discrete alarm is filtered to eliminate false alarms. This is done by means of timer on each alarm point which requires the condition to be present continuously for at least 3 seconds before any action is taken.

Another on line function is the starting of backup equipment in the event of a failure. If an isobutane pump fails for any reason, a reserve pump will be automatically started within 20 seconds.

Mathematical and scaling functions are also programmed in the controller to allow monitoring of system parameters and to compute flow and horsepower values.

Shutdown Sequences. There are basically two types of shutdown sequences programmed into the PLC, a normal and an emergency shutdown sequence. The normal shutdown sequence is basically the reverse of the startup sequence, with the plant being shutdown one step at a time in an orderly fashion. This would be caused by some unacceptable operating condition such as a high temperature or low flow which poses no immediate safety hazard.

The emergency shutdown sequence is triggered by a fire or gas detection somewhere in the plant. In this case all control outputs are turned off causing all equipment to shutdown and all valves to go to their fail safe positions A failure of the PLC will cause all D.C. power to be shut off, having the same effect as an emergency shutdown.

Keyboard Control Mode. In addition to the fully automatic mode of operation, a semiautomatic mode is also provided. In this control mode, each pump valve and piece of equipment is controlled by its own individual function key on the operator console, independently of the automatic control sequence. This feature is useful in an experimental plant such as this because it provides flexibility of operation by allowing variations from the programmed sequence.

Hardcopy. In addition to the display screens, data and status information are also output to a printer. Alarms are printed out as they occur, with the time and date at which they occured. Reports are printed hourly, showing critical data and plant operating conditions. These reports can be generated on demand at any other time from the keyboard. Additionally, the operator can dump any display screen to the printer with the push of a key.

System Upgrades

Two of the principal reasons for choosing a programmable controller/professional computer system were flexibility and expandability. Upgrades for both the controller and computer are currently under development.

To allow the computer to run more programs and to improve reliability, a 10 megabyte winchester hard disk is being installed. A graphics upgrade which will display process flow diagrams of the plant will be added soon. Another addition to the system is a feature that will plot selected analog points on the screen or the printer, in graph form. In addition to hourly hardcopy reports, data will also be logged onto a floppy disk for archival and further analysis on other computer systems.

Additions to the controller program will include surge and efficiency computations.

CONCLUSION

The programmable controller system installed at NGPL's waste heat recovery plant has proven to be an effective means of controlling and monitoring a complex system. Features can be added by simply changing a program, rather than rewiring a control panel. When an equipment failure does occur, the modular design of the system allows a technician to replace the faulty module from a stock of spares and have the system back up in a short time.

The same type of controller is being used to control various types of plants and compressor stations that NGPL operates. NGPL currently has programmable controllers at 15 of its sites, either in service or under developement. Many of these systems include five or more programmable controllers.

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ON-SITE ENERGY MEASUREMENT

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ABSTRACT

Recent advances in measurement, communications and microprocessor technology can be brought together to form an energy measurement information system that can offer a cost-effective alternative to traditional methods of measuring and billing energy usage for large volume customers.

At SoCal, a program is underway to implement such a system for about 35 of our largest customers. The system will employ gas chromatographs and flow computers at each customer location along with communication links to a central data acquisition and reporting system. The system is being developed, in part, to meet increasing information needs, reduce error opportunities in the data reduction process, reduce operating and maintenance costs and evaluate the concept for possible future expansion.

ON-SITE ENERGY MEASUREMENT

INTRODUCTION

Those of us involved in the measurement end of the gas distribution business are to a large degree, also in the information business. We have an on-going responsibility not only to pursue more cost effective and accurate methods of gas measurement, but to meet the increasing information needs created by a number of factors both internal and external to our operation.

All of the gas we sell and more and more of the gas we purchase is billed as energy rather than volumes which requires more accurate and timely methods of identifying the commodity we buy and distribute to our customers.

Recent technological advances in gas chromatography, flow computers and communication systems have opened the door to opportunities for improved measurement accuracy, reduced operating and maintenance costs and reducing the time required to get the bill in the customer's hands.

The purpose of this paper is to describe how SoCal plans to apply this technology in a number of high volume custody transfer applications over the next two years.

DISCUSSION

Traditional Measurement Methods

The orifice meter has long been the standard of large volume gas measurement in the industry. While rotary and turbine meters are finding their way into some of these applications I think its safe to say that orifice meters are going to be with us for some time to come.

The accuracy of orifice meter measurement is a function of many factors: the recording of the variables at the measurement site, the recording media (paper charts), the gas sample collection, the gas analysis and the data reduction process required to bring all the variables together in order to establish billable energy units. The process is complex in the sense that it is labor intensive. There are many steps in the process and there are numerous opportunities for human error requiring many checks and balances along the way. This process is also time consuming —typically three days from chart collection to the determination of the final result.

The Concept of On-site Energy Measurement

Simply stated, on-site energy measurement is the determination of the end result, billable energy units, at the point of measurement including a means of transmitting that information to the ultimate users whether it be gas accounting, gas dispatching, the billing computer or the customer.

This concept has also been referred to as "chartless billing." In recent years the concept has seen increasing application in the gas transmission area but has not been applied extensively to customers of distribution companies. At SoCal we feel the timing is right for selective implementation—the technology and the need have arrived at about the same time and the economics are beginning to make sense.

Site Selection

The initial implementation will involve SoCal's six utility electric generating (U.E.G.) customers comprising 24 plant locations spread throughout our southern California service territory. These sites were selected for first phase installation because of some immediate and unique information and billing requirements.

- In 1984 SoCal's U.E.G. customers accounted for 248 billion cubic feet or 30% of total gas volumes sold and 1.2 billion dollars or 27% of total gas sales revenue. System implementation is expected ultimately to reduce the time required for bill preparation with the potential for a positive impact on cash flow.
- Current tariffs for these customers provide for different rates under the air pollution episode requirements established by the South Coast Air Quality Management District. This requires the ability to apply episode or non-episode rates, many times after the fact, to prior periods of usage -difficult at best under current manual data reduction procedures.

- Several of these customers have indicated need for real-time energy usage data to be used for energy management programs. In lieu of installing their own measurement equipment, and the inevitable finger-pointing that would result, SoCal has agreed to make this data available to the customer through our on-site measurement equipment.
- U.E.G. customers are likely to be the first to come under a proposed "transportation" tariff. Under this tariff, filed recently with the California P.U.C., SoCal would provide to qualified, large-volume users a service of transporting customer-owned gas requiring unique energy accounting procedures to comply with contractual obligations.

System Configuration

The system consists of two major parts, the on-site measurement station for each customer and a centralized data acquisition computer. The measurement station configuration, shown schematically in figure 1, employs high accuracy pressure and temperature transducers at the orifice meter, a gas chromatograph for determining heating value and specific gravity of the gas, a remote terminal unit (RTU) and a modem for linking the RTU to the central data acquisition computer via telephone line.

The RTU is the "brain" of the measurement station and is essentially a flow computer with added features that permit energy and flow data to be combined, local data storage in the event of temporary power or communication failure, communication links for transmitting data, and local process control capability that can perform orifice meter tube-switching functions where multiple orifice meter runs exist. The RTU and transducers must provide wide rangeability to accurately measure igniter fuel loads of about 40, 000 cfh at the low end and full boiler fuel loads of about 25 million cfh at the high end.

The central data acquisition computer (figure 2) communicates with each on-site measurement station, obtains the data, performs edit and verification checks on the data and directs the information to the appropriate users via remote terminals, either printers or CRT's. Mass storage permits access to customer data, either detailed or summary, when requested by authorized users, and provides a historical data base to meet operating, accounting and regulatory requirements.

Communication with each measurement station is accomplished by the data acquisition computer "dialing-up" each station over standard telephone lines, eliminating the need for expensive, leased dedicated lines to each site. This automatic polling will be performed during off-hours, typically midnight to six A.M., which further reduces communication costs. The data thus obtained will reflect the customers energy usage over the preceding 24 hours in total and in increments of 15 minutes over the same 24 hour period. Individual data elements such as heating value, specific gravity, temperature, pressure, chromatograph calibration results, etc., are also available on request.

To facilitate maintenance and minimize downtime, alarm conditions and diagnostic information on malfunctioning components are communicated by a reverse dial-up procedure. Out-of-tolerance parameters or equipment malfunctions will cause the RTU to automatically dial-up the data acquisition computer and log the alarm condition. Remote diagnostic capability is provided to determine the nature and location of the malfunction at the measurement site to assist maintenance personnel in predetermining the likely corrective action needed prior to visiting the site.

Measurement Accuracy

There are approximately 50 variables in a conventional orifice meter measurement system with the potential error contributed by each variable ranging from ±0.1% to ±1.0%. By "conventional" system, I'm referring

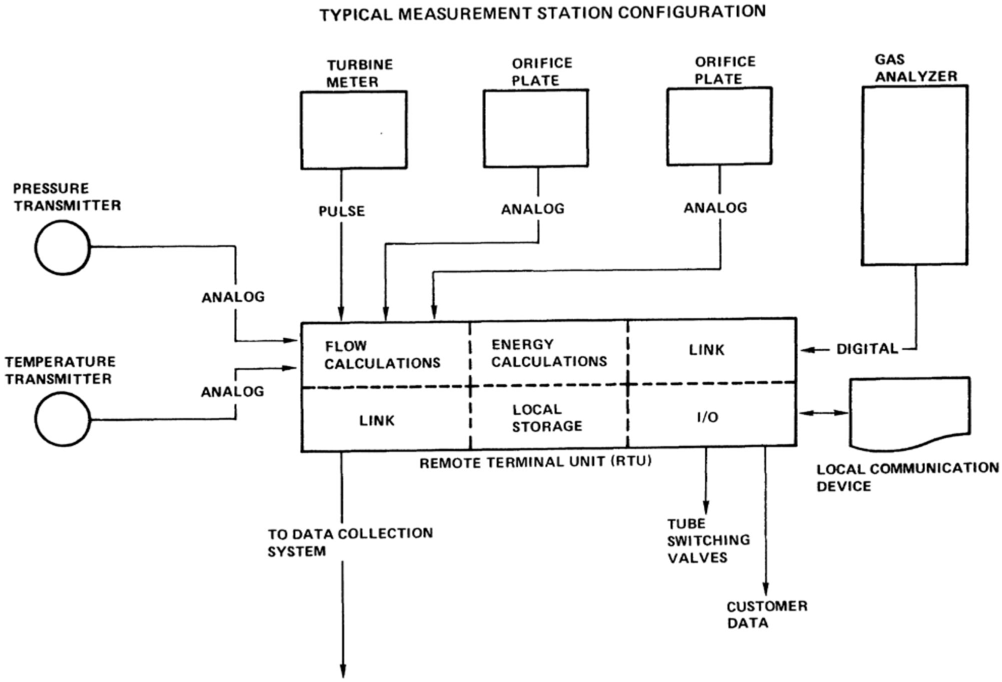

FIG. 1

to the use of chart recorders using both mechanical integration and electronic scanning methods, gas sampling using calorimeters and gravitometers, and coefficient calculations performed by computer.

In any system with a large number of independent variables that can be both plus and minus, the composite error will average out to some degree even though some individual errors may be quite large. The large number of variables in an orifice meter measurement system make it highly unlikely all errors will go in one direction and reach the maximum additive error limit. Another factor to consider is not all orifice meter variables are independent. In some cases an error in one variable introduces an opposite or compensating error in another variable. For example, a plus error in specific gravity produces a minus error in supercompressibility and a plus error in static pressure produces a minus error in the expansion factor.

The above discussion would lead us to the conclusion that the overall accuracy of an orifice meter system is a function of off-setting or compensating errors, and that would appear to be the case. So how do we improve on measurement accuracy by automating the system? I suggest there are two factors to consider: (1) minimizing or eliminating the opportunity for human error and (2) reducing the number of variables and dealing with variables which we can better control. In automating the system as discussed earlier, we reduce the number of variables from approximately 50 to about 20. Half of the twenty are variables that are a function of the mechanical design, construction and maintenance of the orifice tube and plate. What remains

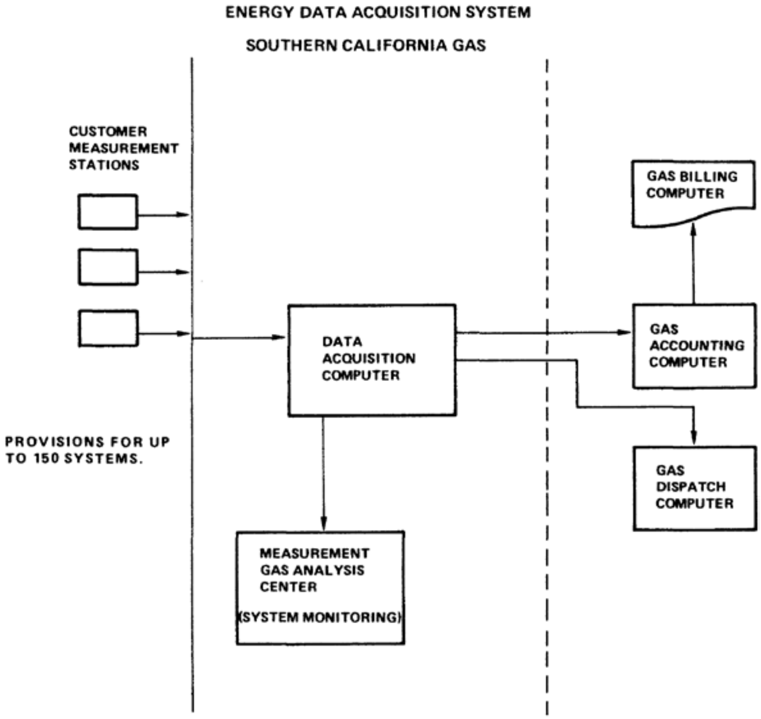

FIG. 2

are inaccuracies associated with the chromatograph, reference gas, pressure and temperature transducers, ambient temperature effects, calibration instruments and computer calculated coefficients. The individual error contribution can be held to ±0.25% with ±0.1% achievable for the most critical elements.

System Economics

While there are a number of benefits that are difficult to quantify in dollars, the primary goal when the system was conceived was to reduce operating and maintenance costs associated with orifice meter measurement. This objective took us in two directions: replacement of orifice meters with rotary or turbine meters where customer volumes and the economics proved feasible, and automating the measurement function where conditions offered no practical alternative to the orifice meter.

During 1984, SoCal's average annual cost to operate and maintain a typical U.E.G. orifice meter installation was $13,100. The costs break down as follows:

Orifice meter & gravitometer maintenance	30%
Chart collection	15%
Gas sample collection & testing	15%
Chart processing	40%

With the automated measurement system we expect the average annual O&M cost to drop to about $2500 or 20% of current costs. Capital investment for each site is planned at $70,000 including purchased equipment, engineering, construction and installation. Assuming 20 year equipment life and including a provision for investment tax credit, the annual cost of capital is $13,000. Also assuming a 5.5% annual inflation rate for O&M costs on both the existing and proposed system, we reach the breakeven point in the fourth year of operating the new system.

The remote terminal units and gas chromatographs used in the initial installations account for 50% of total expenditure. As the cost of this equipment decreases in the future, and presumably it will, the economics will be more attractive.

Data Protection

Data protection addresses two areas: protection from unauthorized access to the system and protection of data in the event of equipment failure.

Although electronic systems are quite reliable they are not infallible. A backup system must be in place to insure customer measurement is not lost in the event of system malfunction due to equipment failure or loss of power or communication. Redundant or duplicate hardware is one approach but is very costly and doesn't address loss of power or communications. We have incorporated into the system several features to minimize the effects of malfunctions:

- RTU internal memory with battery backup stores up to 72 hours of data in the event of communication failure.
- In the event of transducer or chromatograph failure an alarm condition is transmitted and the last valid data values may be used.
- An uninterruptible power supply capable of maintaining the system for at least four hours during power outages.

Until such time as reliability and confidence in the system are well established a minimum chart recorder configuration will be maintained. As a last resort, estimating procedures already in place for the existing system can be utilized, if necessary.

SoCal Gas has established very specific policies and procedures governing data security for all EDP systems and the OSEM system must comply with those requirements. Access to the system by company personnel is limited through the use of multi-level access codes. User access codes are assigned to personnel depending upon authorized need such as limited access to data, full access to data and those authorized to change data. Since the measurement sites are polled over the "dial-up" telephone network, there is the risk of unauthorized access by outsiders or "hackers." Communications protocol, hand-shaking routines and unique algorithms have been incorporated to minimize this risk.

Making the Transition

In planning the transition from chart measurement to electronic measurement perhaps the single biggest issue that must be dealt with is acceptance—acceptance by our own people and acceptance by our customers.

The relatively high degree of accuracy and reliability that we've been able to maintain over the years with chart measurement systems is due to the interest, skills and experience of our employees. Unless we plan the transition carefully and assist our people in making the change we run the risk of lacking the expertise to operate and maintain the new measurement systems. The pace of the transition should not exceed our ability to provide training, procedures, tools and equipment.

Customer confidence in the measurement system is critical and they must be satisfied that the quality of measurement is as good as or better than the chart systems. The problem is that “better” may translate to “different” so the utility must be prepared to defend the accuracy of the system—and know up front if it’s going to be different and why. Customers targeted for electronic measurement systems are large volume users, many of whom employ specialists in measurement and instrumentation to develop and administer in-house energy management programs. They’re apt to know as much about measurement systems as we do.

SUMMARY

The OSEM project was conceived to meet increasing customer and operating measurement information needs created by customer energy management programs, air pollution episode billing requirements, gas purchase contracts based on heating value content, and shorter time frames to meet gas accounting requirements. In addition, implementation provides opportunities for more accurate and reliable measurement and a reduction in operating and maintenance costs over current gas analysis and data reduction methods.

The application of technology provides real benefits but also presents new challenges to all of us. Hi-Tech firms that once ignored the gas industry are now viewing it as an untapped market opportunity and are jumping at the chance with guns blazing.

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PEOPLES GAS TAKES ANOTHER STEP INTO THE COMPUTER AGE

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ABSTRACT

Peoples Gas recognized that in order to compete in today's marketplace it needed to know more about its industrial customers, their changing demand requirements, and their past usage patterns. Information was previously retrieved from historic pressure and volume recording charts and analyzed by hand, taking many hours to consolidate into reports. Realizing the need to speed up the information gathering process, Peoples' management last year gave approval to have a committee investigate state-of-the-art computerized technology to generate data that could be utilized by various departments throughout the Company for load analysis, rate design, trending, billing, and facility analysis. The committee researched various systems on the market and recommended the Metretek Advanced Instruction System, which is an automatic data accumulation and transmission system. The Metretek System was chosen because of its:

Unique remote dial-up capabilities;
Ability to share existing telephone lines, eliminating the need for dedicated facilities;
Low equipment and operating costs; and
Ease and flexibility of operation.

This system consists of three main components: (1) a remote gas monitoring recorder called a Survey Instrument Point (SIP); (2) a telecommunications link; and (3) a central office computer. It is designed so that data can be collected and stored at remote locations and then transmitted via standard telephone lines to the central computer.

PEOPLES GAS TAKES ANOTHER STEP INTO THE COMPUTER AGE

SIP: Data Collection and Storage

The SIP is a remote microprocessor-based module powered by 24 volts AC that collects either analog or pulse data from up to four inputs; stores it as a function of time; and at a predetermined time transmits the data via existing telephones.

Peoples' industrial customers with actual measurement pressure at 1 psig or higher are equipped with a Mercury Instruments mechanical integrator (MERCOR), a pressure and volume correcting device. To adapt to the SIP, each MERCOR is retrofit with a 3-wire FORM C pulse initiating device on both the corrected and uncorrected meter index. The SIP's microprocessor provides the control logic to collect and transmit data to the central computer. As each meter index revolves, a magnetic reed switch initiates a pulse that is collected by the SIP. Pulses are continually collected and are stored as a function of time. Should a power outage occur, each SIP is supplied with a backup battery that will allow the module to continue to collect and store data. Each SIP has the capacity to store up to 41 days of data with all inputs utilized.

Peoples collects both corrected and uncorrected meter data and stores it hourly. Knowing both the corrected and uncorrected meter readings allows the data analyst to take full advantage of the software flexibility and calculate an average service pressure per measurement site. Minimum and maximum flow parameters can be established for each meter. Should actual flows exceed these boundaries, alarms can be established to alert the user that a nonstandard condition has been recognised. Widespread variances in the calculated service pressure could indicate a meter failure or pulse initiator failure. Having access to this information allows for an immediate investigation of a probable malfunction. Previously, this type of malfunction normally would have taken days or weeks to discover.

Telecommunications Link; Data Transmission and Communication

Communication between the SIP remote module and central computer is accomplished through existing voice grade telephone lines. The SIP contains its own internal modem and telephone interface hardware that is registered with the FCC; therefore, the SIP can be connected directly to the telephone system through a standard plug-in RJ-11C telephone jack. Since the SIP checks whether the phone line is in use before placing a call to the computer, it can share the customer's phone line and does not require a dedicated telephone line.

A unique feature of the system is the automatic remote dial-up capability. A PROM (programmable read only memory) provides the SIP with an identity number and instructions for remote call-up. It also allows the user to easily make changes to the SIP operation without modifying the hardware. Information contained in the PROM consists of the following:

AIS NUMBER	—	Advanced Instruction System identification number.
TELEPHONE NUMBER	—	Telephone number, including area code, that the remote module is to call.
DIAL TYPE	—	Type of dialing system that the customer utilizes.
NUMBER OF SIP INPUTS	—	Informs central computer of the number of active data inputs.
CALL RETRY STRATEGY	—	In the event of an aborted call, the information tells the SIP the retry interval and number of retry attempts.

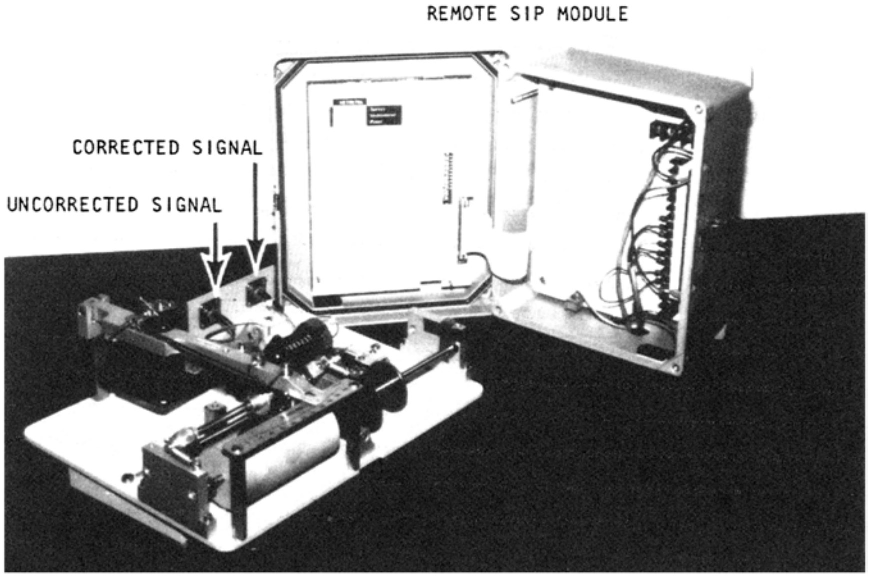

Figure — REMOTE SIP MODULE WITH MECHANICAL INTEGRATOR, DATA COLLECTION AND STORAGE

At a predetermined time, the SIP remote module dials the central computer and transmits the data stored in its memory. At Peoples, the SIP modules have been programmed to call the central computer once a day to transmit the past 24 hours of measurement data. When the SIP places a call, the central computer accepts the data and checks it for accuracy. If the data is unacceptable or incomplete, the computer informs the SIP and terminates the call. The SIP will sense an incomplete call and, based upon the call retry instructions programmed into the PROM, will initiate another call to the central computer. If the data received is accurate, then the data is stored in the computer and new instructions are transmitted back to the SIP. New instructions include real-time clock synchronization, setting new callback times, and any other functional changes. Transmission time between the SIP and the central computer is approximately 10 to 15 seconds, depending upon the amount of data that is stored in the SIP.

The Central Computer; Data Storage and Processing

The central computer system consists of a micro-processor-based receiver hosted by an IBM PC-XT, which receives, stores, and processes data transmitted from the remote sites, required modems, a matrix printer, and a fully functional utility software package. When the data collection system is fully implemented, the central computer will receive and process data from over 200 industrial customers per day.

The system's software package facilitates manipulation of the customer-specific data stored in the computer and can generate various reports. In addition, the computer will generate a report of nonstandard conditions detected by the SIP, such as loss of AC power, input malfunctions, and tampering. When the alarm condition is sensed, the SIP immediately places a call to the central computer; therefore, the system is located in the Gas Dispatch Control Center so that all alarms can be monitored 24 hours a day.

System Implementation

Peoples Gas divided its industrial class of customers into large- and small-volume users. The large-volume users, which account for nearly 80 percent of the total revenue, were completed in Phase I of the system implementation. Phase I involved a group of 26 customers and required the installation of 35 SIP modules to collect data from 60 individual meters. MERCOR's from each facility were removed from service and returned to Mercury Instruments for installation of a pulse initiator. This activity required considerable time and coordination, and after completion of Phase I, Peoples and Mercury Instruments worked cooperatively to reduce the time of this activity. Within weeks, a kit was made available that allows field retrofit without physically removing the MERCOR from service.

To keep costs at a minimum, Peoples contacted each customer to gain access to their telephone system. Since the SIP can share an existing telephone line, a dedicated telephone installation is not required; therefore, expensive installation costs and monthly billing costs can be eliminated. All calls by the SIP are made to an "800" Watts line connected to the central control system. This eliminates any telephone billing costs to the customer. Each customer was also asked to provide an electrical power supply for the SIP.

Peoples' costs for Phase I, excluding the central control system, ranged between $2,000 and $2,500 per installation depending upon the location of the measuring facility. Monthly operating costs are approximately $130, or $5 per customer, and include the rental cost of the Watts line.

System Benefits

Being competitive in today's environment makes gathering as much information as possible about customer requirements of prime importance. Benefits gained from a system of this nature, therefore, are numerous. But the primary benefits are the ability to have immediate access to customer-specific load characteristic data, allowing Peoples Gas to efficiently and effectively manage its gas load requirements; analyzing load profiles by customer or by groups of customers, thereby contributing to better rate designs; and analyzing facilities to evaluate their performance on peak-day conditions.

Access to such measurement data can also assist in detecting meter failures almost immediately, eliminating the need to estimate gas usage over long periods of time. Peoples Gas is also able to look at specific industrial accounts and determine where existing meters are sized too large to measure low flow consumption. In addition, this system could be used as an automatic billing system. This automated process could shorten the Company's read-to-bill cycle by as much as two days, thereby producing cash flow gains.

Customers can also benefit from the data generated from the various reports. The data will permit the customer to effectively manage its natural gas requirements and assist in future usage projections.

Although it is early in the program, Peoples is quite satisfied with the availability and accuracy of the data and with the capability to generate various types of reports for load analysis. Beacuse of the ability to collect and transmit data, future plans will include the installation of SIP modules at gas storage stations to collect measurement data during storage and withdrawal operations. Modules will also be installed in major purchase and exchange facilities and at other customer locations throughout the distribution system to collect gas flow data.

Table — CALENDAR REPORT
MONTHLY CONSUMPTION

As the program matures, additional benefits will surely be realized by various departments throughout the Company.

ELECTRONICS AT UNION GAS

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ABSTRACT

At Union Gas, the department that repairs and supports electronics within the company is presently involved with the design, development and construction of electronic circuits.

The following gives reasons why this group exists within Union Gas, along with four (4) specific microelectronic projects we have designed, constructed, installed and field tested.

The microelectronic projects are as follows:

1. Turbine Meter Correction Micro, which corrects a turbine meter for its over spin on an abrupt turn on/turn off type of process.
2. Turbine Meter Test Loop Micro is for the testing of turbine meters against standards.
3. Micro Odourant Injection System accurately calculated correct gas flow and controls the volume of odourant injected. It also allows for off site monitor of odourant rates.
4. Distribution Alarm System provides a low cost alarming at sites that have no physical room and no hydro (ie. on side of buildings) back to an office with an annunciator panel. This system distinguishes between Bell Telephone problems and alarm conditions.

ELECTRONICS AT UNION GAS

REASONS FOR ELECTRONICS AT UNION GAS

Why does Union Gas have an Electronic Department that develops specialized electronic equipment? The Electronic Department designs and develops electronic circuits for the following reasons:

1. Specialized requirement in small numbers, ie. one of a kind;

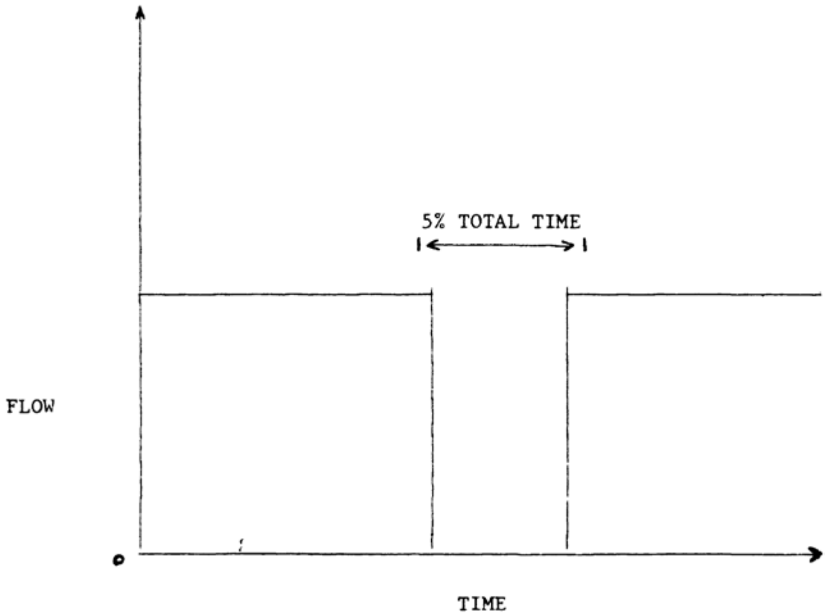

FIGURE 1

2. Interface required between two pieces of equipment;

   a) old to new equipment;
   b) different manufactured equipment;

3. There is a requirement but there is no commercially available solution.
4. There is an item commercially available but it does not fulfil the requirement or it is an overkill and very expensive.

Additional benefits from the electronic groups are as follows:

1. It becomes a support group for field problems involving electronic equipment;
2. It provides expert evaluation of new electronic devices, including considerations of field environment and interfacing with existing equipment;
3. It becomes a support group for new installations.

TURBINE METER CORRECTION MICRO

Union Gas has a customer whose flow is based upon his process and will shut off entirely for 5% of the time. Below, see Figure 1 which illustrates the customer's flow, as it relates to time.

The occurring problem is, that there is a turbine meter measuring this flow and turbine meter requires time to slow down and time to speed up. The spin down time versus the spin up time for turbine meter varies drastically, hence there is an error of approximately 3/4% on volume of gas measured. There are three possible solutions:

1. customer changes process;
2. mechanical;
3. electronics.

The customer could not change his process, so this method was eliminated. The mechanical method is very expensive, which left this alternative: electronics.

We have designed and constructed a micro, which will do the following items:

1. In 1/10 of a second, it will detect the slow down or speed up of the meter;
2. It will verify that it is slowing down or speeding up through smart decisions;
3. There is an electronic totalizer for uncorrected volume. This uncorrected volume takes in account of the slow down and speeding up of the turbine meter.
4. It is battery backed up and will not lose D/C power to the micro.
5. There is a separate hardware section that constantly monitors the health of the micro and will report on the validity of data.

The micro itself consists of an eight-bit micro processor chip the 8085, 1K of Ram memory and 4K of EPROM memory. The signal from the turbine meter is conditioned to eliminate noise. An additional feature of the micro, is that it has an alpha/numeric character included in the display indicating the following:

The micro is totalizing the volume, verifying the slow down, not totalizing or verifying the speeding up. This assists in troubleshooting and testing the turbine meter correction micro.

The turbine correction meter is not approved by the Department of Consumers and Corporate Affairs but is considered to be valid information, as long as both the customer and Union Gas agree to its results on a month to month basis. The Turbine Meter Correction Micro has been built and fully tested in our shop and will be installed within the next few weeks.

TURBINE METER TEST LOOP

The Turbine Meter Test Loop is authorized by the Department of Consumers and Corporate Affairs for the verification and reverification of turbine meters. The loop itself operates at atmospheric pressure; however, the micro in electronics was designed to operate at high pressure. Over the past year, we have sealed our own meters and other manufacturer's meters on the turbine meter test loop and have found that the loop itself is repetitive of less than 1/10%. We have a probable accuracy of ±3/10%, which includes the provers from Rockwell of ±1/4%.

The turbine test loop uses two provers, being a T18 and T140, which allows us to test flow ranges from 2 mcfh to 140 mcfh.

The turbine meter test loop has been used for other applications, being as:

1. meter accuracy dispute with customers;
2. evaluation of new meters and equipment;
3. test facilities for ourselves and other companies.

The operation of the turbine meter test loop is as follows:

1. The meter to be tested is installed in the setup.
2. There is a valve that controls the volume of air flow. This is turned and a remote display from the micro feeds the percent flow of the meter.
3. When the test condition is obtained, the operator goes over to the micro and pushes the start button.
4. At that instant, the micro will then read the thumbwheel inputs into the micro, being barometric pressure, test meter capacity, volume per revolution, the meter to be tested and the number of revs for the test.
5. The micro will show, continuously the status of the setup; whether it is running or not; if there is a meter overranged and will give an alarm; if the test has failed, it will give an alarm and let it show; if the printer is available or not with alarm.
6. It will also select, which prover is being used, either the T18 or the T140, and it will indicate whether it is Imperial or metric testing. The selection from Imperial or metric tests is via the switch.
7. The micro will constantly display the standard meters percent capacity.
8. The micro will take control of the complete test, reading the various pressures and temperatures throughout the turbine test loop using Rosemount transducers.
9. After the test is completed, the micro will give a printout indicating test number, whether it's the first, second, third, fourth or fifth test (this is automatically started every time a new meter is put in).

The results consist of the following:

It will indicate the percent capacity at which the meter is running for both the standard and the test meter; the average pressure in Kpa; the average temperature during the test; and the cumulative volume. It will also indicate the percent registration for the test meter. The standard meter's percent registration is incorporated in the micro, with a corrective curve to make it appear like a perfect meter.

Each time a new meter is installed, the micro will present a header for the test, which includes a location for identification of the test meter serial number, the date, the time, signature, as well as serial numbers of the two provers built into the system. Should we want to calibrate the turbine meter test loop, the switch indicating revs is turned to 0 and the printer will print out every two seconds the current value of the pressures, temperatures, and accumulated turbine pulses.

The micro itself consists of an 8085 with RAM and EPROM and has signal conditioning inputs for pulses from both standard and test meters. Also, it has 4 to 20 inputs from Rosemount transducers for pressure as well as temperature. It has a built-in audible alarm functions which flags up if an alarm situation occurs (ie. capacity of any meter is exceeded or a test fails). It has a start push button into the panel, a printer as an output, and a remote output showing meter capacities.

To date, we have found the complete setup repeatability within 1/10% and have found this to be very satisfactory for any application. This is the only turbine meter test loop in Canada that is computer controlled and gives printout. The advantages of the computer controlled printout is that it eliminates operator error and inaccuracies, due to mechanical readings.

MICRO ODOURANT INJECTION SYSTEM

The Micro Odourant Injection System uses a micro computer to inject odourant at a preset rate based on corrected flow. The inputs into the micro odourant system consist of the following:

– Analog:	Pressure; Temperature; Differential (if orifice measurement).
– Turbine	Pulses

The micro odourant injection system corrects the flow through the station for temperature, pressure and supercompressibility. The measurement of the amount of odourant being pumped is also an input. The micro takes the volume of odorant pumped and the corrected flow and controls a Williams odourant pump.

The operator dials in via thumbwheels the required rate of odourant to be injected. As the micro odourant injection system is a closed loop control system, the micro will compensate for any error in the Williams pump, based upon the calculated flow and the measured odourant volume. The advantages of the micro odourant injection system are as follows:

– accurate flow calculation;
– accurate odourant volume calculations and outputted to SCADA system;
– precise control of a Williams odourant pump;
– once a day the system does a test of leaking solenoids;
– self-diagnosis of integrity and output alarms into a SCADA system;
– automatic shutdown on low pressure or low flow;

The micro odourant injection system also allows the technician to go in and view the inputs or calculations via a display. This includes the input pressure, differential, uncorrected flow, corrected flow, odourant injection rate, and the volume sent to the SCADA system.

By utilizing micro control in a close looped system on site, along with off site monitoring and alarming, we hope to reduce all unnecessary odourant call outs.

A prototype has been built and has been in service for six months. To date, we have determined the accuracy of the complete micro odourant injection system to be in the order of 1% to 2% and has had one failure since installation. This was in a solenoid seat, due to wrong type of seat installed by manufacturer for odourant.

DISTRIBUTION ALARM SYSTEM

The Distribution Alarm System is not to be confused with a SCADA System. There is no history, no calculations, and no conversions done at the display location. The reasons for the Distribution Alarm System are as follows:

1. the function does not require a full SCADA System;
2. discrete (pressure switches) alarms are required from sites with no hydro, and no physical room.

The present system consists of pressure switches going in to dedicated Bell Telephone lines and going back to our office onto an annunciator panel. This is very susceptible to Bell Telephone noise and this creates false alarms.

With this new alarm system, we are putting electronics at the pressure switch location in our station in a small explosion proof box and Bell Telephone will terminate in that same box. The electronic circuits use Bell Telephone power and will generate a square wave signal over Bell Telephone of 1.2 seconds for an alarm condition, 2.0 seconds for an OK. This is brought into a central location in what we refer to as a communication micro.

The communication micro has a digital filter to eliminate noise of 2/10 of a second duration. In addition, there are two levels of statistics to determine whether the pressure switch is closed, or if there is communication problems with the station. The discrete information is updated once a minute.

The discretes are dedicated lines from the communication micro to the station. In addition to discrete information, there are analog inputs into the system, which are updated approximately every A seconds. At each site, there is an analog micro.

The analog micro has an input of 4–20 milliamps into a 12 bit A-D. The micro has a scale selection, which is built into the EPROM. By switch selecting one of sixteen preset scaling units, the micro display in engineering units will transmit via Bell Telephone the information in a very secure format. The analog micro has switch selectable addresses and may be used interchangeably with any other analog micro. There is a switch for calibration.

In the calibrated mode, the micro will not transmit the information to the communication micro but will update the information on the display. There is a display on the analog micro which will update continuously, as information is available. For each analog input, there must be one analog micro; however, as the analog micros have addresses, they may be on a party line arrangement or may be on dedicated lines back to the communication micro. Therefore, if more than 1 analog is required from a site, it only requires 1 Bell Telephone line.

The communication micro can talk to a maximum of A communication micros or a display micros. The communication micros may be in any design configuration possible and may consist of star arrangements or a chain arrangement or any combination thereof.

The display micro is the interface to the operator and shows him the present state of the system. The discretes are displayed for two situations: alarm or equipment failure. The analog values are displayed and are shown either for a fixed input or are sequenced through a preset table. The names for the analogs are in alpha/numeric format. In addition, there are alarms on the analog: being high or low limit, and equipment has failed. There are additional alarms displayed on communication failure between display micros or communication micros. There is provision for a printer to print out the time of the alarm, the description of the alarm, and the value. This incorporates a real time clock on the display micro. There are additional special requirements, ie. local remote switch.

The system we have in place has two display micros. The Brantford centre is in the location of the alarms with Waterloo being a distance off. During normal working hours, Brantford monitors the alarm; however, at night, they throw the local remote switch into remote and the alarms are automatically redirected to the Waterloo display.

The total capacity of the systems are as follows:

1. 128 discretes;
2. 64 analogs
3. 8 specials.

The number of communication micros and display micros are unlimited. The information between communication micros and display micros is updated entirely within six to seven seconds and is done through 300 Baud telephone lines. There is additional security with each transfer to ensure integrity of data. At present, we are planning to install the first alarm system in July and a second system in September of 1985.

CONCLUSION

In the past, we have designed and built many specialized electronic circuits that are performing well across our company.

With the introduction of new technology, we are very excited about future projects and continued electronic support to our company.

AUTOMATIC CALL-BACK ALARM SYSTEMS

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ABSTRACT

This paper discusses the use of automatic call-back alarm devices in an integrated natural gas system (gathering, transmission and distribution). The paper will concentrate on actual experiences in designing, installing, troubleshooting and operating an automatic call-back alarm system. The use of the term automatic call-back alarm system in this paper refers to a microelectronic device(s) which can be designed and programmed to sense an alarm condition (e.g., low pressure) and respond by dialing/calling a programmed list of telephone numbers to notify appropriate personnel of the alarm location and condition.

AUTOMATIC CALL-BACK ALARM SYSTEMS

INTRODUCTION

This paper discusses actual experiences designing, installing, troubleshooting, operating and maintaining automatic call-back alarm systems on natural gas systems. The primary case study used as an example in the discussion is the automatic call-back alarm system installed in the Lamar, Colorado District of Peoples Natural Gas Company. Other applications within PNG will also be discussed.

The remainder of this paper will describe in more detail our following experiences:

- Why automatic call-back alarm systems were chosen.
- Installation considerations and problems.
- Operating/Maintenance considerations and problems.
- Future considerations.

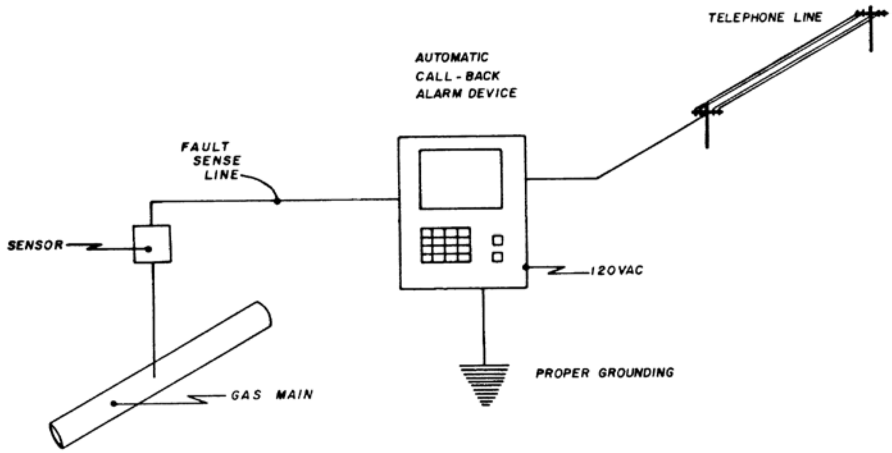

FIGURE 1

The automatic call-back alarm device that will be described in most detail in this paper is the ADAS IX unit manufactured by Butler National Corporation. The emphasis given to the ADAS IX in this paper is not meant to be an endorsement, but it is what PNG selected and consequently its capabilities and features will be discussed. Other automatic call-back alarm options, besides the ADAS IX are mentioned in the conclusion of this paper.

An automatic call-back alarm system can be best defined or described by referring to Figure 1. The basic components of this system are:

– Sensor
– Fault/alarm sense line
– Automatic call-back alarm device
– Telephone line
– AC power

The sensor is merely a set of contacts (e.g., normally closed). Examples are pressure and temperature switches whose contacts open and break the alarm circuit when a pre-set pressure or temperature is reached. The fault sense line is simply a pair of wires completing the alarm/fault circuit between the sensor and the call-back device. The automatic call-back alarm device in most PNG applications is the ADAS IX. The telephone line is a standard voice-grade line and can even be an existing phone line.

DISCUSSION

The following discussion will provide an overview of the projects where Peoples Natural Gas has installed automatic call-back alarm systems. The largest application was in our Lamar District, however, several other smaller scale installations throughout the PNG system will also be discussed.

Lamar District Gas System Monitoring

The impetus for installing an automatic call-back alarm system in Lamar resulted from PNG's decision to consolidate the gas system monitoring and dispatching of the Lamar District with that of the PNG KPL District in Cheney, Kansas, about 250 miles away (refer to Figure 2). Lamar originally had its own 24 hour a day system monitoring personnel responsible for the entire 5,000 square mile district. After the consolidation, the Lamar District was monitored from Cheney where they also had 24 hour a day staffing. Because the Lamar data acquisition information would now be routed to Cheney over leased telephone lines, a back-up system was deemed necessary in the event the leased phone lines became inoperable. The back-up system chosen was the placement of ADAS IX (automatic dialing alarm system) devices at critical/ strategic locations in the district. These locations were:

- Lamar Town Border Station—low inlet pressure alarm
- Springfield Town Border Station—low inlet pressure alarm
- Kendall Compressor Station—compressor outage alarm
- Johnson Compressor Station—compressor outage alarm

These locations are also monitored through the data acquisition system at Cheney with the ADAS IX units providing an independent back-up. The automatic call-back alarm system was chosen for our gas system monitoring/dispatching back-up for the following reasons:

- Similar equipment had been successfully used by our sister company, Northern Natural Gas
- Relative low cost
- Ease of installation/set-up and flexibility to move to other locations

The capabilities of each ADAS IX unit are the following:

- Monitor/sense up to 4 alarm channels.
- Sequentially dials 4 user-programmed phone numbers upon an alarm condition and keeps dialing until a positive receipt of the alarm call is acknowledged.
- Precise verbal description of alarm location and condition when alarm calls are made.
- The status/condition of the ADAS IX can be interrogated at any time from any telephone.
- Battery back-up in event of AC power outage.

The installation of the ADAS IX units at each location was relatively easy with only 120 VAC power and a standard pulse-type telephone line required. Only one unit was not located inside a heated building so it was placed in a thermostatically controlled heated cabinet. As the manufacturer's installation instructions suggested, particular attention was given to proper electrical grounding of the ADAS IX units. This was to ensure maximum effectiveness of the ADAS IX built-in transient and surge protection for the telephone, fault (alarm)-sense and power lines. The compressor station installations required some special consideration. A deactivating or disarming circuit was designed to allow the ADAS IX's to be disarmed when the compressors were shut-down manually under normal operation. This capability was necessary to prevent "false-alarm" dial-out calls from the ADAS IX's during normal manual shut-down.

Once installed, the ADAS IX's operated with few problems and without much attention. The most significant problem encountered was with the dial-out phone lines at the Kendall and Johnson, Kansas locations. These two areas are served by a different telephone company than the rest of the district. Out-

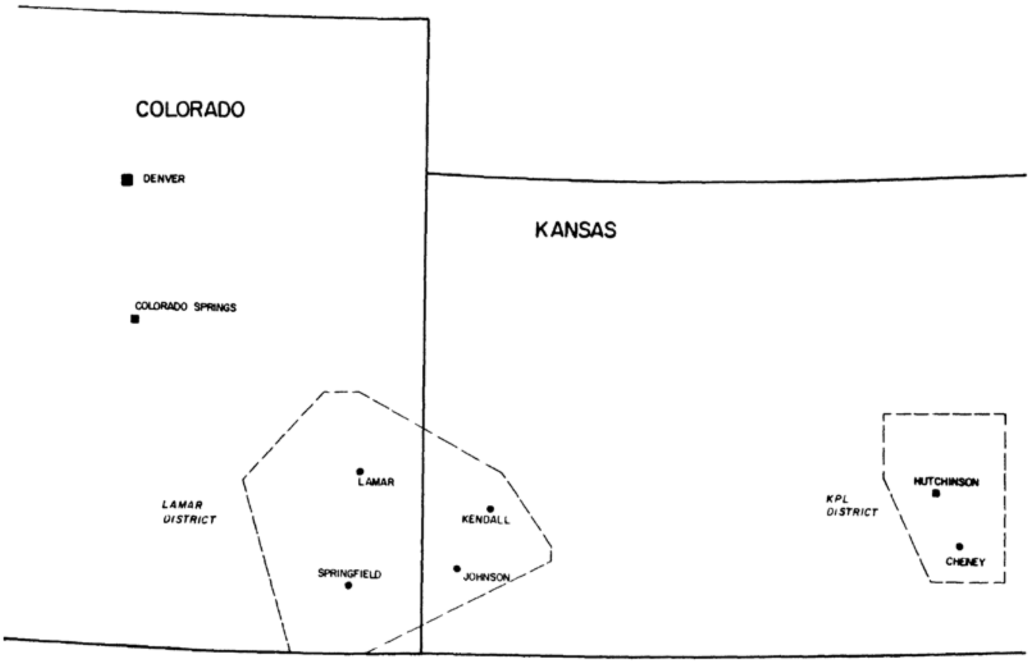

FIGURE 2.

going calls from the ADAS IX units that went outside the local phone company's service area were not getting through. Incompatible switching gear was identified as the problem and was quickly resolved. Automatic dialing devices are much more sensitive to the quality of the phone lines than the human ear is. Other problems that can effect this microelectronic equipment are:

- Additional transient and surge protection may be needed in areas where lightning strikes are frequent or power fluctuations are common.
- Electromagnetic interference (EMI), radio frequency interference (RFI), and static electricity can all either damage components or alter what is stored/programmed into memory.
- Improper electrical grounding, this is usually caused by too high a resistance to earth ground (> 25 ohms).
- High voltage power lines in the vicinity of the fault (alarm)-sensing lines can result in induced current problems.

Once installed, the ADAS IX's need very little attention. However, an on-going preventative maintenance/ check-up program is recommended. Since an ADAS IX is designed to work (i.e., go into an automatic dialing mode) only when a fault or alarm condition exists, a unit could go months without being activated. To better assure that the systems are functioning properly, we periodically (3–4 times a year) activate each ADAS IX by simulating an alarm. This tests each component of the system, the alarm/fault sensor (e.g., pressure switch), the ADAS IX itself and the phone lines. We also recommend to our field people that they periodically (2–3 times a year) discharge the internal battery by taking the ADAS IX off AC power for a few hours. This helps lengthen the life of the rechargeable battery. The ADAS IX can also quite easily be monitored remotely merely by dialing into the phone line it is connected to and listening to the status message.

Other Applications

The ADAS IX unit has proved valuable in other applications to PNG. Typical PNG applications are remote facilities where manual monitoring is expensive and the cost of having the facility abnormally out-of-service is great. A good example of this is a remote measurement/exchange station where PNG takes custody of the gas from a transmission pipeline. This station is the sole feed to several towns and consequently the loss of its service would be extremely costly. An ADAS IX at this location sensing for low pressure is a very inexpensive insurance policy. Remote, unmanned compressor stations are also frequent applications for an automatic call-back alarm system.

CONCLUSIONS

Automatic call-back alarm systems have worked well for Peoples Natural Gas. They are a reasonably priced alternative when the cost of a sophisticated data acquisition system or SCADA system is not warranted. The ADAS IX units we have used are quite flexible and adaptable as they can be relocated and reprogrammed (by the user) as needs change.

Even though the price of an ADAS IX is quite reasonable ($1150–$1700) for what they can do, PNG has still experimented with an even lower priced automatic call-back alarm device. Radio Shack markets a unit called a Home Monitor, which provides many of the same capabilities as the ADAS IX for less than $200. Although the Home Monitor is not marketed as an industrial type device, it has worked well in two separate locations (compressor station and fuel cell). The Home Monitor has two built-in sensors, a microphone and a temperature sensor, plus two open channels for external sensors. The Home Monitor's case is plastic and therefore lacks the ruggedness of the ADAS IX's aluminum case. The longevity of the electrical components in the Home Monitor compared to the ADAS IX is uncertain at this time. The Home Monitor does appear to be an extremely low-cost way of installing an automatic call-back alarm system for the proper application.

Symposium Papers

INTEGRATING MICROELECTRONICS INTO GAS DISTRIBUTION II

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OVERVIEW OF GAS AUTOMATION

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ABSTRACT

The automation of gas distribution is occurring in several areas at ever increasing rates. It is difficult to keep track of the developments and their interrelationships. This paper offers a conceptual framework within which to view and understand the rapidly developing automation of gas distribution systems. This framework relates the forces driving automation, general approaches, key trends, and features common to automation systems. It also discusses practical design considerations along with automation potential and challenge.

OVERVIEW OF GAS AUTOMATION

INTRODUCTION

This paper is intended to provide a conceptual framework within which to view and understand the rapidly developing automation of gas distribution systems. This discussion focuses on automation benefits and potential, driving forces, problems that must be solved, and the ongoing work. Metaphorically, this paper is a road map so that the forest of gas distribution automation will not be "lost" for all the trees of individual papers.

Before describing the conceptual framework, the definition of several terms should be given. Any new application of technology develops its own jargon and definitions. There are a few definitions/distinctions that are useful in discussing gas distribution automation.

<u>Automatic.</u> Capable of producing a desired response to certain predetermined conditions without direct human intervention.

<u>Remote.</u> Capable of producing a desired response over distance without physical contact.

For example, a meter equipped with electronics that initiates a telephone call every week to report its readings would be both automatic and remote. On the other hand, driving a van through a neighborhood to collect gas meter readings via radio is remote automation, but not automatic.

Top-Down Approach to Gas Distribution Automation. The "top-down" approach to automation starts at the city gate station(s) and adds remote and/or automatic features to the system until district regulator vaults are added and continues until individual household meters are automated.

Bottom-Up Approach to Automation. The "bottom-up" approach starts with the individual customer's meter and continues adding remote and/or automation features until the city gate(s) stations are automated.

Both the top-down and bottom-up approaches can function in a single utility, hopefully meeting and interfacing at some point. However, even if they never meet at a common point nor even progress further than the initial steps, we refer to the general starting point as the main criterion of the definition.

Centralized Intelligence. In a system using centralized intelligence, all of the data collection and control functions at all levels of detail are controlled by a single (usually a large mainframe) computer.

Distributed Intelligence. A distributed intelligence system contains a large number of microprocessors and/or computers physically separated. Each microprocessor collects data and controls functions with at least some decision making authority without consulting the main computer. Each distributed computer passes processed and/or raw data to the main computer and receives instructions from it.

Islands of Automation. Islands of Automation are formed when isolated functions are automated with no preplanned avenue of expansion. They also tend to be able to transfer information to other units where it could be utilized. (This was well described in Jack Bernard's, "Automation of Facilities Information" at last year's symposium.)

Bridges of Automation. Attempts to connect the islands with add-on equipment not provided for in the original designs are defined as bridges of automation.

Given that automation is not just coming, but has arrived and is growing rapidly, a conceptual vantage point is needed to aid in understanding the developments in distribution automation, we have developed a conceptual framework that we find useful in "forest viewing." The framework includes several components: 1) the general forces driving gas distribution automation, 2) philosophical approaches, 3) key trends, 4) features common to all automated systems, and 5) practical design considerations.

GENERAL FORCES

There are several general "forces" that are driving the integration of electronics and automation into gas distribution. The existence of these forces and the changes they are causing in the gas industry are the reasons for this symposium and why we are all here. The rate of progress being made is illustrated by a comparison of the talks given less than one year ago at the first symposium (Orlando, Florida, November 18–20, 1985). Several potential products discussed last year are commercially available this year and at prices less than projected a year ago.

Although individual forces overlap categories, the general forces driving automation of the gas industry can be broadly typed into 3 categories: economic, regulatory change, and technological.

Economic Forces: 1) Increased competition from alternative fuels and rising costs are driving utilities to reduce their operating costs as the price of gas increases. 2) Labor costs continue to be a major cost component. 3) In contrast, the cost of electronics continues to drop steadily, even as capabilities increase dramatically. That automation is cost effective and is attested to by the presence of the most of the symposium speakers, several of whom represent companies with commercial products in this area.

Forces Due to Regulatory Changes: 1) Changes in the regulations governing transportation, purchase, and sale of natural gas have created a need for faster flow of information regarding the amount, time, and source of gas purchases. 2) Some PUC's are urging utilities under their jurisdiction to carefully investigate the benefits of remote/automatic meter reading, etc. 3) Recent court decisions requiring restructuring of the telephone company have changed the competitive structure of the communications industry. 4) Further changes may be anticipated as questions are resolved concerning the amount of data processing communications companies can legally do. As communication and computer companies begin to seek new markets in which to compete, the gas industry is likely to see a variety of new concepts and products offered.

Technical Forces: 1) Perhaps the most obvious development is the sheer number and capability of the new high tech devices. Products that were unheard of 10 years ago are major industries today. The rapid development of these markets is often followed by fierce competitive struggles for market share that reduce prices and increase the variety of options. 2) These obvious changes are accompanied by more subtle, but equally important, modifications. For example, the integrated circuits of today require far lower power than their predecessors, making possible long-life operation with existing batteries. The circuits themselves are smaller, more reliable, faster and better able to withstand temperature, humidity, and electrical interference. 3) The advances in integrated circuits are also driving improvements in related fields, such as sensors, motors, and other mechanical systems. The trend is to make all of these components smaller, more efficient, and less expensive. 4) One of the most important changes these technological developments create is a shift in perceptions and expectations. The initial fear of the new technologies, especially of computers, can lead to denials that such automation is needed on more than a very limited scale. These same people, after becoming accustomed to modest levels of automation, quickly ask why more features cannot be automated. On the other hand, employees and customers who have grown up with the electronic revolution expect rapid availability of information and automated operations.

GENERAL APPROACHES

There are several general approaches or philosophies to applying the new technologies to the automation of the gas distribution system. One is the starting point for doing the automation.

Single Item Versus Expandable Approaches

Automation can be approached one item at a time as an end in itself with no provision for expanding or integrating the automation features. The expandable approach is to plan for the automation of additional features, even though only one is being installed initially. Admittedly, the latter approach requires more planning, discipline, and initial expenditure. However, the payback can be much greater.

As an illustration, at last year's symposium, Don Diel of Niagara Mohawk discussed the installation of a SCADA system and the benefits it was bringing. This year Don will discuss why it is being replaced: not because it didn't work, but because they found additional features are desired and economically justifiable.

Top-Down Versus Bottom-Up Approaches

In the "top-down" approach, automation starts at the city gate station(s) and adds remote and/or automatic features to the system until district regulator vaults are added, continuing until individual household meters are automated. The economics for automating at the top have been easier to recognize and quantify than for most other parts of the system. City gate stations, while few in number, process large quantities of gas. In addition, operations at city gate stations have been affected the most by new regulations. The relatively small number of items to be automated and the ease in quantifying payback have made this a very active area of automation with utilities.

The "bottom-up" approach starts with the individual customer meter and continues adding remote and/or automation features until the city gate station(s) are automated. The "bottom-up" approach includes reading the meters of individual customers. The need for economies of scale in production are an important consideration in this area, with several companies developing different methods of automatic meter reading (AMR). We believe it is important to realize that many more features can be automated for small incremental cost increases over AMR.

KEY TRENDS

Even though the automation of gas distribution is relatively new, there are several key trends emerging.

1. The forces driving automation are decreasing costs while, at the same time, increasing capabilities.
2. There is a trend to demand more after a system is installed.
3. The efficiencies and synergies inherent in the system at small marginal cost increase are beginning to be exploited. This trend is increasing.
4. Compatibility is becoming more desirable as utilities and manufacturers try to build bridges between "islands of automation."

EDITORIAL COMMENT

We view it as vital for gas utilities to see the trends in and the potential for automation and to ask manufacturers to supply expandable, compatible systems. Manufacturers are market driven. They will provide cost effective equipment that is expandable and compatible with other manufacturers if that is what the gas industry wants. Manufacturers will also provide lowest first cost, limited capability, unexpandable, incompatible equipment if that is what utilities wish to purchase.

FEATURES COMMON TO AUTOMATION SYSTEMS

All of the gas automation technologies and products have several general features in common. They must have methods to:

1. Collect and encode the desired information.
2. Communicate the data to a place or places where it is needed.
3. Provide "intelligence" for initiating data collection, transmission, and interpretation. In some applications the "intelligence" could be a single chip microcomputer; in other applications it could be circuitry that recognizes an address and responds appropriately.
4. Power the instrumentation.
5. Decode the transmitted data and provide the information in a useful format.
6. Install the instrumentation and communication system.

Many of the talks will describe the automation of one or more utility operations. In the design of the equipment, each common feature had to have been addressed.

PRACTICAL DESIGN CONSIDERATIONS

The previous section outlined the features common to all automation systems. This section looks at several options that might be used in a practical automation design. The purpose of this section is to identify many of the possible solutions and to broadly describe their advantages. It also describes problems that must be overcome. It must be emphasized that there has been no attempt or desire to advocate any potential solution over any other. Clever systems could be built using most or all of the possibilities.

Method of Communication

An automated system implies transfer of information from one place to another. Thus a communication method is required.

1. Telephone lines have several pluses. They are in place, widely distributed, and well supported (at least in most places). Potential drawbacks include remoteness from some locations, a traditional perception as expensive (although technology can change this) and data security problems. There are two approaches to using telephone lines: 1) data collection with active aid of a telephone company and 2) data collection independent of the company.
2. Radio transmission pluses include ease of retrofit, a well developed technology, and active competition among manufacturers. However, there are a limited number of available frequencies and strict regulations on power and/or licensing. There are three approaches to using radio: 1) a central radio station with direct communication between all units (areas of concern: range/power tradeoffs, licensing of all transmitter/ receivers), 2) a central radio with communication to a small number of substations, with substations having “short range” (1 mile) communication with all subunits. Subunits send data to substations which collect, compile, and send it to the master station, and 3) short range receiver/ transmitters (hundreds of feet) responding to a mobile station. The last two are commercially available.
3. Wires can be located anywhere but have security versus cost of installation issues (If strung on poles, wires are less expensive but more vulnerable. If buried or strung inside mains, wires are more secure, but may cost more to install.) Wires inside mains could supply low voltage power, as well as, communications; but this raises safety design issues.
4. Fiber optics have a very large data bandwidth, are inherently safe, and have interesting options for non-gas revenue. As examples, fiber optics can be used in mains and transmission lines for communication for major long distance telephone users and for a communication network to individual customers. There are unanswered questions about costs of the fiber optics and retrofitting costs.
5. Acoustic data transmission inside mains and services offer the advantages of ease of retrofit, security, and gas utility control. However, this is a still an undeveloped technology.

Power Supply

Power is vital to automation. There are several issues that must be addressed in this area. The first is the source of power. There are several potential sources of power, each with its own strengths and weaknesses. These include: 1) batteries, 2) customer supplied power, 3) thermoelectric generation, etc., using gas at the site of the automated feature, 4) telephone supplied power, and 5) gas utility supplied power.

There are several issues related to power supply: 1) How long will the batteries last? 2) Can the customer disconnect the supply? 3) What happens during electrical power failure? 4) Can capacitor storage be used as a backup? 5) Can thermoelectric power generation be made small enough and inexpensively and 6) If utilities supply power over a wire system, how much experience in power supply must utilities have?

Safety Concerns

Electronic components in or near natural gas must satisfy stringent safety requirements in terms of actual safety, liability potential, and public acceptance.

Installation

The cost of installing an automated system also depends on the application and whether or not it is for a new installation, renewal, or retrofit.

1. New — A brand new system has the fewest installation problems and costs because all power and communication can be included initially.
2. Renewal — When part of a distribution system is being renewed for other purposes, part of the installation costs of power and communication problems are borne by the renewal.
3. Retrofit — Highest installation costs occur in retrofitting an automation system. The method of communication and power supply will strongly affect the cost of installation, and can make a difference in the cost effectiveness of the automation.

Long Life Criteria

Any automation regardless of the technologies used must be reliable, require little or no maintenance, and have a long lifetime (as much as 40 to 50 years).

AUTOMATION POTENTIAL

The following is a partial, yet impressive list illustrating that it is possible to automate "virtually everything" in gas distribution operations. Work to automate most of these is being performed at one place or another. It can be argued that the thought and planning process is the limit, not the technology.

The partial list of features that could be automated includes:

1. Measurement of gas transfer at city gate stations
2. Odorization of gas
3. Monitoring of odor content throughout a system
4. More accurate load management
5. Industrial and/or interruptible customer monitoring
6. Waste heat recovery for compression of natural gas
7. Pressure monitoring
8. District governor control

9. Meter reading of gas and other utilities
10. Tamper detection
11. Corrosion control
12. Load shedding via variable rate billing
13. Improved system design based on comprehensive load data
14. Mapping of systems and improved pipe location
15. Third party damage monitoring and protection
16. Remotely or automatically operated valves (remote service termination and reliable excess flow protection)
17. A whole set of features become possible with robots or “mice” in the mains.

COMPATIBILITY AND MODULARITY

While the general automation needs of each utility are similar, the differences among them in climate, soils, history, and philosophy of operation yields a surprising diversity of automation goals. Obviously there are a large number of features that could be automated and a large number of ways to automate them. In terms of the bottom-up approach, the cost per individual meter is reduced if economies of scale in manufacturing electronics can be applied. The combination of these factors argues for compatibility and modularity in the design of the automation components. There is no reason that compatibility and modularity should cramp anyone’s “style.”

SUMMARY OF CONCEPTUAL FRAMEWORK

In summary, the rapidly increasing pace of gas distribution automation requires a conceptual framework within which to view and understand the changes. The conceptual framework given in this paper describes the driving forces, general approaches, key trends, and features common to automation systems. It also discusses practical design considerations along with automation potential and challenge.

Economic, regulatory, and technological forces are driving two general approaches to automation; the “top-down” starts with city gate stations while the “bottom-up” starts with individual homes. Regardless of the philosophical approach, the short term goals, and the technical design, there are features common to all of the automation: 1) collection and encoding of data, 2) communication, 3) “intelligence,” 4) power supply, 5) decoding of data, and 6) a method of installation.

Even though the automation of gas distribution is relatively new, there are several key trends emerging: 1) automation costs are decreasing, while capabilities are increasing, 2) increased demands for more after a system is installed, 3) inherent efficiencies and synergies are beginning to be exploited, and 4) the desirability of compatibility is increasing.

Because manufacturers are market driven, we view it as vital for gas utilities to see the trends in and the potential for automation and to ask manufacturers to supply expandable, compatible systems.

AUTOMATION CHALLENGE AND OPPORTUNITY

During this symposium we will hear about many examples of the opportunities and challenges presented to gas utilities, transmission companies, and manufacturers and how they are being met. Many of the speakers will be describing the opportunity to minimize operating costs, improve operations through increased knowledge, and/or how their product(s) will help meet these goals, other speakers will discuss the technical and economic challenges of solving the technical problems and demonstrating the economic benefits. Many of these efforts center on utilizing the microelectronics revolution to read meters and to distribute gas from the city gate stations.

I would like to suggest an even larger opportunity and challenge; one that IGT has been advocating since our first article was published in February, 1982. The current and emerging technologies present the gas industry with the rare opportunity to rethink how natural gas is delivered to its nearly 50 million customers and the challenge of making major changes in that process, over the decades the gas utility industry has utilized the available technology to solve difficult practical problems in the management of the delivery of gas. Clever solutions to practical needs have led to organizational structures within the utility. To a large degree these structures, solution, and thought processes were determined by economics and the available technology.

The new technologies provide an information revolution. To obtain maximum advantage, utilities must rethink their entire structure and method of operation. The operative question should be “in the best of all worlds, how would I like to deliver gas to my customers through the existing pipe and what information and control would I like to have?” In the difficult day-to-day running of a utility, such questions may seem to be a waste of time, or at best, pie-in-the-sky thinking. However, current and near term technology will take such “dreams” and turn them into a practical and economic realizations much sooner than many believe. The time scale for the technology is shorter than the planning process can prepare for and make maximal use of. The challenge is to be ready! And the biggest challenge of being ready is the recognition of the possibilities and the careful selection and justification of those most desirable.

AN OVERVIEW OF MICROELECTRONICS

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ABSTRACT

Microelectronic devices are finding their way into a wide range of applications, including many in the gas industry. In order to apply this technology to the industry properly, a basic knowledge of device features and limitations is required. The most commonly encountered devices in gas distribution control systems are memories and microprocessors, and it is on the properties and applicability to the gas industry of these devices that I wish to focus attention.

The wide variety of memory devices on the market allows us to match the device to our needs. High speed, low power dissipation, and high packing density are all available in today's memory devices, but there are trade-offs to be made among device types and features. It is important that we are cognizant of the trade-offs when we are evaluating microelectronic devices for a particular application.

Microprocessors (and their closely related relatives, single-chip microcomputers) are advancing to the point where a very sophisticated system can be constructed from one integrated circuit chip and a handful of discrete components. This single-chip solution could provide communication, sensor interfacing (analog and digital), decision making and data collection capabilities, and all system memory.

What makes these devices so attractive for gas industry applications is that these powerful devices are constructed using a technology, CMOS (Complementary Metal Oxide Semiconductor), which seems to be perfectly suited for gas industry applications. CMOS technology requires low power, has excellent noise characteristics, and is a pleasure to work with.

AN OVERVIEW OF MICROELECTRONICS

INTRODUCTION

For the past twenty years we have seen a tremendous expansion in the design and fabrication of integrated circuits. These devices are finding their way into a wide variety of new applications.

The expansion so far is only a preview of things to come. Electronics products for the past twenty years have been decreasing in price by a factor of 10 every five years, and this trend is expected to continue for another 10 years. Consequently, as more features are added to auto-mobiles, televisions, radios, telephones, etc., an ever increasing selection of integrated circuits is becoming available. This, in turn, generates the possibility of new or improved applications, including the automation of gas distribution and transmission systems.

Any technology soon develops a jargon of its own. To those unfamiliar with it, it may seem that the sole function of that jargon is to confuse and bewilder the neophytes and glorify the practitioner. The gas industry has several sets of jargon as does the microelectronics industry. This paper focuses on microprocessors and the many types of memory devices that are finding their way into more and more applications in the gas industry. Each type of device has its advantages and disadvantages depending on the application. It is important for gas industry personnel to have a general knowledge of the most common devices and their properties.

One application area, the automation of gas distribution and transmission requires the interaction of several electronic subsystems. These subsystems include: encoders to obtain data, electronics to process data and control the system, communication links to transmit data and system status, power supplies to drive the system, and displays to interface with operators. (See Figure 1.)

In particular, the data processing and control electronics consist of two distinct parts: a microprocessor and a memory. The microprocessor functions to provide intelligence in the system, to perform computations, manage data, make decisions based on comparisons of data, and manage communications. To carry out these duties, the microprocessor requires memory.

Microprocessors require memory to store two types of information. The first type is the program, which is the actual sequence of instructions that the microprocessor follows. In this type, program information consists of several sequences of instructions telling the microprocessor how to calculate readings, convert sensor voltage signals to flow rates, react to abnormal readings, communicate with peripherals, etc. The second type is data, which the program stores and uses to make decisions. “Data” includes histories of pressure, temperature, flow, meter readings, normal operating ranges, prices, etc.

Memory

Memory consists of individual cells. Each cell is an electronic circuit capable of storing a 0 or a 1, also called a Binary digIT, or bit. For ease of use by the microprocessor, these cells or bits are grouped into units called bytes and words. A byte is generally understood to be a group of 8 bits. Historically, 8 bits have been used because they have enough memory to store one character or number from a keyboard. A memory that has the capacity to store 2^{10}=1024 bytes is said to be a 1K memory (for approximately 1000 bytes or 1 kilobyte), enough to store 1024 keyboard characters. A 2K memory has 2^{11}=2048 bytes of storage space, a 64K memory has 2^{16}= 65,536 bytes (enough to store about 30 pages of text), etc. Although a byte is always composed of 8 bits, the definition of a “word” depends on the microprocessor using the memory. A word generally consists of an integer number of bytes, common values being 1 to 4 bytes (8 to 32 bits). A word is actually not a memory organization term, but a microprocessor operational term. For a system that contains

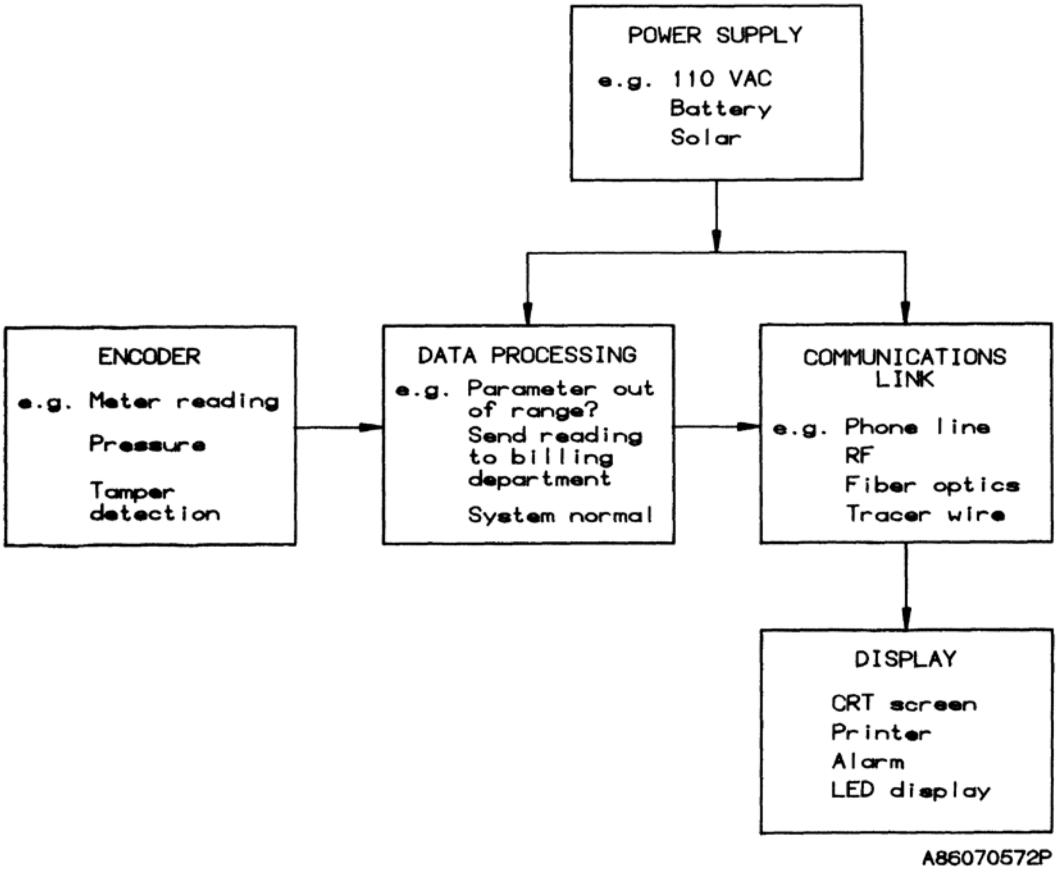


Fig. 1 — GENERIC CONTROL SYSTEM

a microprocessor, a word is the smallest possible number of bytes (or bits) that the microprocessor will recognize as forming a valid instruction. The following are examples of word lengths of frequently encountered computers: 8 bits for the Apple II series, 16 bits for the IBM AT series and the Apple Macintosh, and 32 to 64 bits for mainframe machines.

The ability of a memory to retain its information during a power failure is very important in gas industry automation applications. In electronics, this ability is known, as nonvolatility. A nonvolatile memory retains its information when power is discontinued. A volatile memory loses its information when power is discontinued. Initially, it may seem that one would never want to use a volatile memory, when nonvolatile devices are available. However, as we will see below, it is generally true that nonvolatile memories are incapable of having data written to them by the program.

Memory may be divided into two general categories: random-access memory (RAM), and read-only memory (ROM). Each of these categories consists of several sub-categories or types. (See Figure 2.)

Computers and microprocessors store a great deal of unchanging information such as operating systems and look-up tables. This type of information can be stored in a memory which does not have the ability to change its contents on command—a read only memory (ROM). Strictly speaking ROMs are intended to be

Device	Technology	Power	Speed	Volatile/ Nonvolatile	Acronym	Reprogrammable?
Mask	Bipolar	High	Extremely Fast			
Programmable ROM	MOS	Moderate	Fast	Nonvolatile	ROM	NO
	CMOS	Very Low	Moderate			
Programmable ROM	Bipolar	High	Extremely Fast			
	MOS	Moderate	Fast	Nonvolatile	PROM	NO
	CMOS	Very Low	Moderate			
Erasable	MOS	Moderate	Fast	Nonvolatile	EPROM	YES
Programmable ROM (UV)	CMOS	Very Low	Moderate			(Must remove from ckt.)
Electrically	MOS	Moderate	Fast	Nonvolatile	EEPROM	YES
Erasable	CMOS	Very Low	Moderate		E÷PROM	(Limited)
Programmable ROM						
Static	Bipolar	High	Extremely Fast			
RAM	MOS	Moderate	Fast	Volatile	SRAM	YES
	CMOS	Very Low	Moderate			
Dynamic RAM	MOS	Low	Fast	Volatile	DRAM	YES

Fig. 2 — GENERAL PROPERTIES OF MEMORY DEVICES

programmed only once—at the time of manufacture. In fact there are various degrees to which ROMs may be programmed. What follows is a brief description of the most common types of ROM.

A simple ROM contains a pattern of bits which is fixed in the memory at the time of manufacture. In its very simplest form a connection between two wires indicates a binary 1, the absence of a connection indicates a 0. This type of ROM is manufactured by creating a custom photolithographic mask which will produce the required bit pattern as submitted by the circuit designer. This procedure is costly because the manufacturer charges the circuit designer a special fee for custom masking a ROM. For this reason, mask programming is economical only if large quantities (greater than 5000) of the same ROM configuration are required. The word "same" must be emphasized here, any change in the ROM configuration (program) requires a new mask, and another masking fee (approximately $10,000). However, for very large quantities this is the most economical permanent memory device.

For smaller quantities, a more economical approach is the use of a second type of ROM called programmable readonly memory or PROM. Initially, PROM units contain all 1's (or all 0's) in every cell. The user "burns" away (breaks) connections in some locations by passing a strong pulse of electrical current through them. A broken connection defines one binary state, and an unbroken connection defines the other. This allows the user to program the ROM at his own site to produce the desired bit pattern. Commercial units called PROM programmers are available to facilitate this procedure.

The procedure for programming ROMs or PROMs is irreversible. Once a bit pattern is established, it cannot be changed. A third type of device which is available is called erasable PROM or EPROM. EPROMs can be reinitialized to all 1's (or all O's) even though a bit pattern has been previously established. When an EPROM is placed under a special ultraviolet light for a specified period of time, the radiation returns the ROM to its initial state (all 1's or all 0's), and it can be reprogrammed. This device is very useful for field testing of prototype units, where there is a high probability that changes in the program will be desired. Some ROMs can be erased using electrical signals instead of ultraviolet light, these are known as electrically erasable programmable ROMs or EEPROMs. EEPROMs can be reprogrammed while still included in an electronic circuit. This type of device can be used to maintain data at an installation (pressures, temperatures, flow rates, prices, etc.) so that they are completely unaffected by power outages. EEPROMs do have a limited lifetime in terms of the number of times a particular cell may be written to. Although this lifetime has yet to be fully characterized, it is greater than 1000 write cycles. In fact, EEPROMs are not read-only at all, but they possess the one characteristic common to all ROMs: nonvolatility.

RAM is a read-write type of memory, which means that a computer or similar device may store (write) data at any selected location (address) and, at any subsequent time, retrieve (read) the data. Because the locations in memory may be accessed in any order, this is a random-access memory. (Originally RAM meant random-access memory, but now it is interpreted as read-and-write memory.)

Semiconductor RAMs can be divided into two major types: static and dynamic. The distinction between the two is very straightforward. Static RAMs retain their information as long as power is applied to them, and require no attention from the microprocessor. Dynamic RAMs, on the other hand, require continuous attention from the microprocessor (or specialized support circuitry) in order to maintain their information. The process of continuously maintaining dynamic RAM information is known as refreshing the RAM. Both static and dynamic RAMs are volatile.

Static RAM cells consist of circuits known as flip-flops. There are two different types of transistors which may be used to construct the flip-flops: bipolar-junction (bipolar or BJT), and metal-oxide semiconductor (MOS). Bipolar memories are extremely fast, but they suffer from large power dissipation and require a relatively large area on a memory chip (thus severely limiting the number of cells which can be placed on one chip). MOS cells are somewhat slower than bipolar cells, but they have a higher packing density (more cells can be put on one chip) and much lower power dissipation. Bipolar memories are therefore appropriate only for applications that require extremely high operating speed and that can afford the penalty of high power dissipation and low packing density (e.g., the main memory of a central computer, that handles a very large amount of data and needs to do so at very high speed). The device of choice for most field applications is a hybrid MOS device known as a complementary MOS (CMOS) memory. The penalty for using this device is a slightly lower packing density. The advantage is a large decrease (factor of 50 to 100) in power dissipation. The power consumption of this device is so low, in fact, that it can be made to function as a nonvolatile device for a period of up to ten years with the addition of a small battery as a backup energy supply.

Dynamic RAMs do not utilize flip-flops as storage cells. Instead, the cells consist of a very simple circuit, containing one transistor and one capacitor. A logic 1 or 0 is stored as a high or low voltage on the capacitor. The problem with this dynamic storage system is that the charge eventually leaks off the capacitor, and with it goes the stored information. In order to preserve the data, most typical dynamic memory devices require the microprocessor examine (sense) the data and restore the original voltage levels every 2 milliseconds. Since the circuitry required for dynamic RAMs is so simple, they are able to achieve a very high packing density, while dissipating only about half the power of a MOS static RAM (but still using many times the power of a CMOS static RAM). Dynamic RAMs are useful in applications where packing density (space) is at a premium, and power is only a secondary concern.

The dynamic behavior of the dynamic RAM can be a useful characteristic. The capacitor in a dynamic cell, when exposed to light, will discharge at a rate proportional to the light intensity. This opens up the possibility of using a RAM chip (which is modified to include a window which exposes the circuitry) as a camera to obtain and record images which have been focused onto it. Such a camera is, in fact, already commercially available, complete with software.

A memory device that deserves mention is the bubble memory. It is a sequentially (as opposed to randomly) accessed device, which means that the locations must be accessed in a specific order. Bubble memory does have its advantages: it is very rugged (e.g., withstands vibration, radiation, humidity), has a large capacity (1 million bits or more), and is nonvolatile. Its main drawbacks are its dependence on old-fashioned, difficult to automate production techniques, and its lack of an efficient means to interface with other logic devices. Currently, these drawbacks are severe enough to render the bubble memory noncompetitive in todays market for gas system automation.

Considering our initial example of a gas distribution and transmission system, the following is a likely scenario for memory selection. At the central office level, where system-wide billing and maintenance of records takes place, we would require a computer and memory capable of handling large amounts of data at high speeds with little concern for power dissipation. A large bipolar RAM would be a logical choice for such an application. At the city gate station, where relatively large amounts of data are to be collected, and power dissipation is not the primary concern, a logical choice would be a MOS RAM for data collection along with an EPROM for program storage (which facilitates changes in the program) and a limited amount of EEPROM for “semi-permanent” data storage (for data that changes infrequently). A CMOS RAM for data collection could be substituted in many applications without hindering the data sampling rate. At the district and individual service level (household gas meter) data volume is relatively small, and power dissipation is the primary concern. Here the logical choice for memory would be a CMOS RAM for data storage, EPROM for program storage, and a limited amount of EEPROM for “semi-permanent” data storage. In all applications, the ROM should be chosen with the previously mentioned guidelines of quantity and certainty of the program in mind. Also, most types of ROM are available in either bipolar, MOS, or CMOS versions. Generally the ROM is chosen to be the same type as the RAM (e.g., CMOS ROM with CMOS RAM).

Microprocessors

Undoubtedly the most important integrated circuit (IC) package in production today is the microprocessor. A microprocessor combined with memory and interface modules is called a microcomputer. The prefix “micro” is used to indicate the small physical size of the devices involved. The roots of the words “microprocessor” and “microcomputer” are what sets them apart. “Processor” is used to specify the section of the system which performs the functions to execute instructions and process data as specified by the program. “Computer” indicates a system consisting of three basic units: central processing unit (CPU), memory, and input/output (I/O) interface. A microprocessor is enclosed in one IC package. A microcomputer generally consists of several interconnected packages. There are, however, microprocessor chips which contain memory and I/O circuitry. Such a device is called a one-chip microcomputer. As we will see shortly, the one-chip microcomputer shows great promise for gas industry applications.

A microprocessor consists basically of an arithmeticlogic unit (or ALU, which is simply a complex electrical circuit that is designed specifically to perform logic and arithmetic operations) whose operation is controlled by a program consisting of an ordered set of coded instructions to which the components of the ALU respond. Each instruction is retrieved (fetched) from memory in turn, following completion of the activity produced in the ALU by the preceding instruction. Besides simply adding or subtracting two numbers, it is possible for the ALU to make logic decisions on the sign or zero value of the result. Such decisions are the basis for a branch in a program; a change in the sequence of instructions that depends on the data provided. As an example, the system may compare a sensor reading to limits it has stored in memory, and proceed to execute one of two sets of instructions depending on whether the reading was or was not within limits.

In order for data to be stored and manipulated during processing, memory must be present. The memory may be in the form of registers or RAM. Register memory is special purpose RAM memory which is part of the ALU, so it is more easily accessible than conventional RAM. Register memory often times has special capabilities, such as the ability to act as a counter or to shift data. RAM, on the other hand, provides a large amount of data storage which is both convenient and economical. Every word in RAM or ROM is assigned a unique address, and is accessed using a special register, the address register. The content of the address register may originate either in a stored instruction, or as the result of a computation. The ability to compute an address provides a great deal of flexibility in micro-proccessor systems.

To round out our discussion of microprocessors, a brief look at I/O devices is in order. While many approaches to I/O are available, all implement the equivalent of memory, writing to which provides output and reading from which provides input.

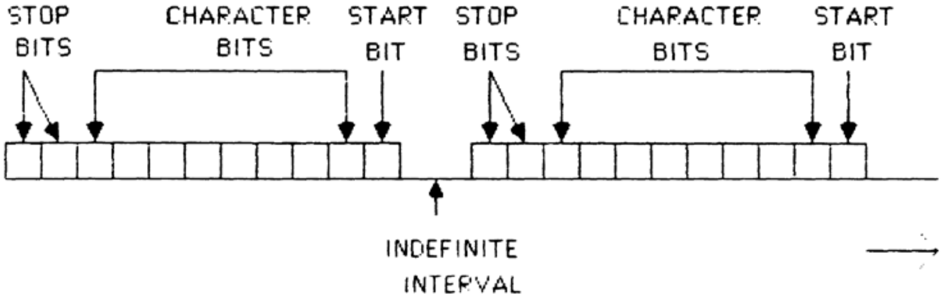
For a microprocessor with a word length of 8 bits, I/O ports called parallel are also 8 bits long. To save pins on the IC, the input and output ports may be combined or multiplexed, the eight leads being used for input or output based on the state of a ninth control line. If pins are extremely limited, I/O may be carried out using only two pins, where data is sent one bit at a time, or serially. Parallel transmission obviously increases the speed at which data can be sent. Because of this it is a technique generally used to further increase the effective speed of high-speed lines, rather than enhance the speed of lines that are used for applications where speed is not a vital factor. However, its uses are limited because:

1. The lines and receivers are comparatively expensive;
2. It is difficult to synchronize the parallel signals. Parallel transmission is not practical over long distances because synchronization cannot be maintained.

Serial transmission is the more common form. There are two major types of serial transmission: asynchronous, and synchronous. (See Figure 3.) Asynchronous transmission is a form of transmission in which the transmitting and receiving devices are not synchronized to receive data at fixed intervals. Instead, data is transmitted and received when and as it becomes available. Each byte transmitted is preceded by a start bit (to signal the receiver that a byte is on the way) and followed by a stop bit (to signal the end of the byte). Synchronous transmission handles data differently. The transmitting and receiving devices are synchronized by the initial transmission of a set of bits to receive data in a fixed form at a fixed rate. The data is then sent in a continuous string with no control characters. This allows for fewer control characters per byte transmitted, and therefore a faster exchange of information. The disadvantages of synchronous transmission are higher equipment cost, and difficulty in detection of transmission errors.

One additional very important type of input is often available on a microprocessor, the interrupt. Upon reception of a signal by this input, normal processing is interrupted, and special processing is performed. This allows the processor to turn its attention to a problem which demands immediate attention (e.g., fire, loss of pressure, excess flow).

Members of the new generation of one-chip microcomputers include many subsystems which make them attractive for gas industry applications. (See Figure 4.) Features such as a multi-channel analog to digital (A/D) converter, synchronous serial communication port, asynchronous serial communication port, parallel



b) SYNCHRONOUS

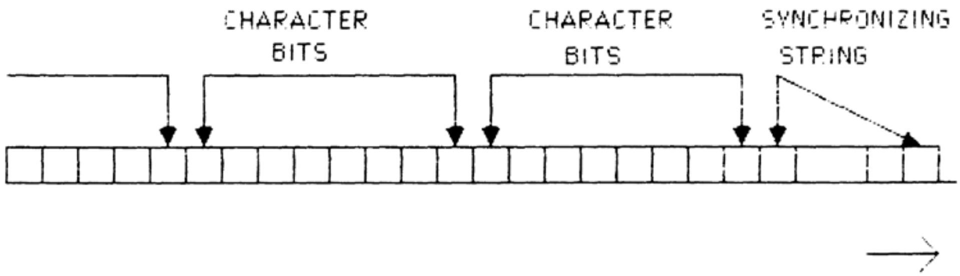


Fig. 3 — SERIAL TRANSMISSION

communication port, pulse accumulator, timer system, RAM, ROM, EEPROM, low power operation modes, with CMOS technology used throughout, can all be found on one IC.

On board A/D conversion allows “real-world” voltage/ current level signals to be interfaced to the microcomputer with the only additional circuitry required being a voltage reference. This allows the use of the full range of sensors currently on the market.

The availability of three types of communications interfaces on one IC allows communication with the majority of systems and peripherals that are currently available. This eliminates the need for selecting and using additional circuitry for communication purposes, including greatly simplifying hardware and software design.

A pulse accumulator is a special register which is incremented automatically, requiring no immediate software attention, upon reception of a pulse. The processor can therefore spend more time attending to other duties (e.g., monitoring sensors, detecting tampering) or hybernating in a low power mode, while the meter proving hand revolutions are being counted.

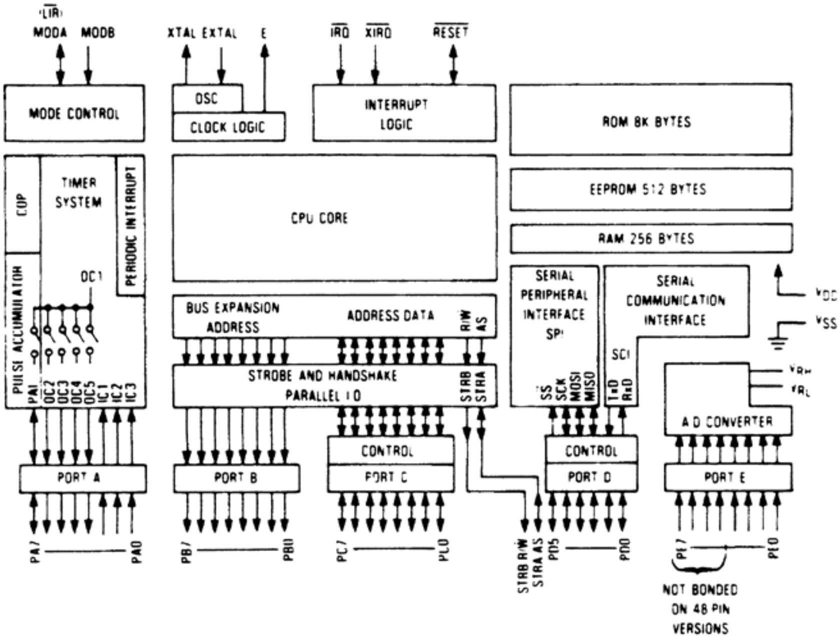


Fig. 4 — BLOCK DIAGRAM OF MOTOROLA MC68HC 11A8 MICROCOMPUTER

On board memory allows the program and data to be stored and run without the need for external memory. Along with the elimination of external memory goes the elimination of supporting hardware, such as decoders and latches, which reduces both cost and size.

A single-chip computer with the capabilities described here is both powerful and flexible, and seems to be very appropriate for gas industry applications. However, it is the availability of these capabilities in a device which incorporates CMOS technology that makes it particularly appealing for widespread (i.e., down to the residential meter level) use in gas distribution and transmission systems.

Why is CMOS such an appealing technology? As stated earlier, CMOS has ultralow power requirements. In fact it uses essentially no power when the state of the outputs is not changing. But low power dissipation is not the only claim that CMOS can make. This technology also boasts of noncritical power requirements (many devices can operate with a supply voltage range of 3–15 V), and excellent noise performance (CMOS actually eliminates, rather than perpetuates system noise, while producing very little powerline noise during output switching). This facilitates easy, inexpensive, compact, medium to long term energy source backup at even the lowest levels of a distributed intelligence system.

CMOS does, of course have its limitations. It is sensitive to outside world loading and static electricity during handling, and has only moderate operating speed. The first two problems can be avoided by the strict adherence to a simple set of design and handling guidelines, once properly soldered onto a board, CMOS devices are relatively immune to static electricity. The third limitation, relatively slow operation, actually does not prove to be a problem for gas industry applications. High computing power is not important in that type of application. Low cost, low power dissipation, ease of use, and good noise performance are much more important, and CMOS delivers these desirable features.

CONCLUSION

The microelectronics industry has grown and matured a great deal during the past 10 years. Devices that are reliable, compact, inexpensive, sophisticated, and require little power, are now available from many highly competitive sources. The technology is in place for the gas industry to economically extend its range of services to the customer, while implementing a system that will operate reliably long into the future.

THE FUTURE ROLE OF SENSOR TECHNOLOGY IN GAS DISTRIBUTION OPERATIONS

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ABSTRACT

There are many areas in gas distribution operations where sensor technology and automation can be applied. This paper describes some of the advanced sensor technology that Gas Research Institute is sponsoring at research institutions and manufacturers to help gas utilities reduce the cost of owning and operating a gas distribution system. The descriptions concentrate on technology that should be available within the next five years. Specific sensors are described that can be applied for pipe inspection and location, proximity devices, navigation and guidance, non-destructive evaluation, automatic controls, and intelligent machinery.

THE FUTURE ROLE OF SENSOR TECHNOLOGY IN GAS DISTRIBUTION OPERATIONS

INTRODUCTION

In the past 10 years, advanced technology has greatly affected the operation of gas utilities. Several utilities are now using microelectronics, sensors and advanced communications in their every day activities. As you look around your operation, there are automated systems in use for inventory control, facilities management, meter reading, quality control, dispatching, billing, system design, one-call systems, load management, and many more. However, we are just beginning to see the application of automated systems in the repair, replacement, renovation and construction of gas distribution systems. In 1985, approximately $3.6 billion was spent on these critical activities of gas utilities. In this area, the industry has not yet really begun to take advantage of the potential in automation and sensors brought on by the computer and electronics industry. The methods used for digging holes, repairing leaks, and installing new pipe have not greatly changed in the past 25 years.

There are many reasons for the reluctance to incorporate sensor-based equipment, materials and methods in the daily routine of gas utilities. They include an emphasis on low first cost, industry conservatism, regulations and unions. In order to overcome these barriers of acceptance to new technology, the innovations must offer significant cost and performance advantages, proven reliability and durability, acceptance by gas utility crews and contractors, and compatibility with existing techniques.

This paper will focus on some of the advanced sensor technology that Gas Research Institute (GRI) is sponsoring to help gas utilities reduce the cost of owning and operating a gas distribution system. We continue to see advances in reducing the cost and increasing the application for microelectronics and sensors. The technologies vary from fiber optics to ultrasonics to radar. The descriptions will concentrate on technology that should be available within the next five years.

The strategy of GRI's research program in sensor technology is to apply or adapt developments in this area to traditional gas operating problems. To carry out this strategy, GRI is sponsoring research in many different fronts. The potential application and benefits of sensor technology to gas distribution operators is tremendous. The GRI projects to develop sensors for application to the gas industry can be divided into four general categories: (1) Mechanical sensors; (2) Electromagnetic sensors; (3) Wave and radiation sensors, and (4) Optical sensors. Mechanical sensors have the ability to measure displacements, velocities, strains, pressures, leaks, vibrations and angles. Mechanical sensors could be used to better control the movements of large excavation equipment and for robotic applications. Electromagnetic sensors can be used for detecting metal pipelines and for navigating excavation equipment. Uses for wave and radiation sensors include the inspection and detection of pipe; while optical sensors can be used for locating leaks and for guiding machinery. In the following sections, several types of the above-listed sensors will be described including how they might be implemented into the construction and maintenance operations of gas utilities. This is not an inclusive list, but a sampling of some of the technologies that will be available soon.

PIPE INSPECTION AND LOCATION

Two major time, cost and safety factors in the maintenance of gas distribution systems are the difficulty in precisely locating the specific pipe section in need of repair and the potential hazard and high cost to the utility and community from damaged or leaking pipe that is not detected. Approximately 850,000 main and service leaks are repaired annually by the gas industry at an approximate cost of $850 million. Accidental damage due to outside forced such as excavation and earth moving equipment is estimated to account for over 60% of gas leak incidents. Methods presently used by gas utilities to locate damaged or leaking buried pipe are sometimes imprecise. These methods include gas detectors and pipe locating instruments. Even with the use of these methods there is the potential that after a contractor or utility crew has excavated a buried pipe he may find that due to false detector readings, the exposed section of pipe is not leaking or he may not find the pipe at all.

Autonomous Robotic Mouse

The development of an autonomous robotic "mouse" that will precisely locate and assess the condition of underground gas distribution pipe without the need for excavation could be of substantial benefit to the industry. The Mouse system will internally inspect distribution mains for leaks, corrosion, cracks, and flaws. Information on the pipe will be communicated back to utility personnel at a central office. Conceptually, it is envisioned that the mouse will consist of the following subsystems: (1) sensors and intelligence, (2) navigation, communication and control; (3) power and propulsion, see Figure 1. The Mouse will use sensors

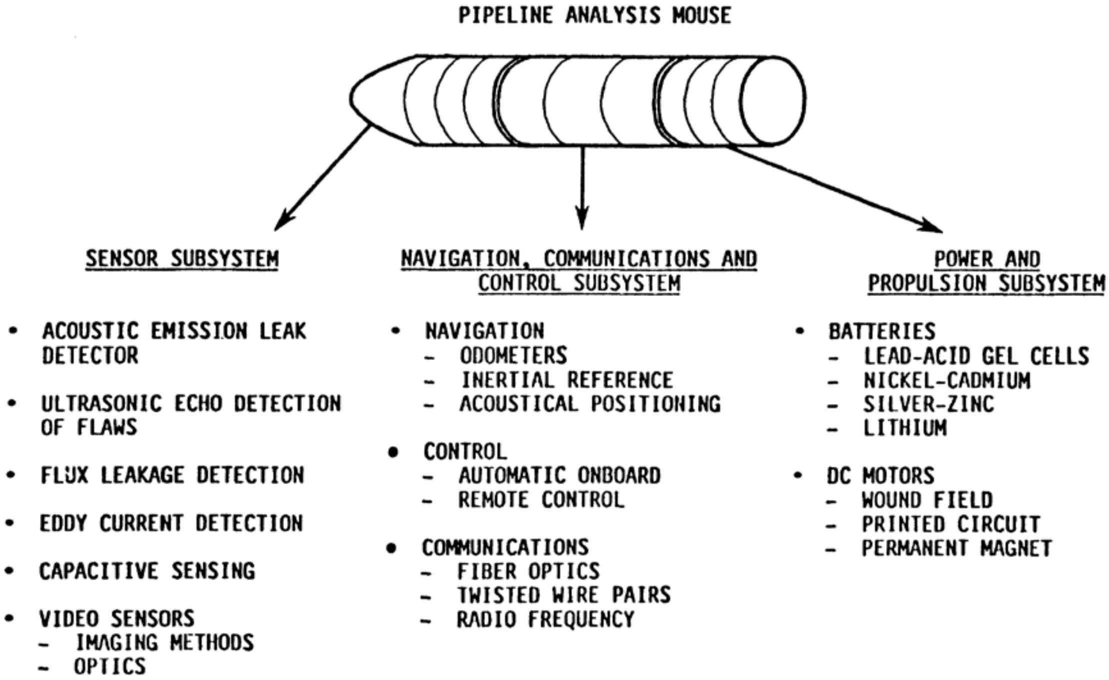

Figure 1. Robotic Mouse System Technology Options.

to investigate and interpret information on corrosion, fractures and pittings. Use its navigation, communication and control subsystem to identify the exact position of the pipe, and use the propulsion subsystem to move through the piping network. Some of the technologies that can be used in a mouse system include:

- Detection of active leaks through acoustic emission (noise from leaks detected with ultrasonics) and thermal imaging (local changes in the temperature of a pipe detected with infrared devices).
- Ultrasonic echo detection of flaws in materials
- Video inspection
- Navigation in pipes through odometers and inertial reference units
- Communication through fiber optics and radio frequency.

Electromagnetic Pipe Locators

Electromagnetic pipe locators have been available to the gas industry for decades. Basically, there exist two types of magnetic field locators. The first type is a passive locator. These devices locate underground structures by detecting existing or natural signals which exist on them. The second type of locator is active. It consists of a transmitter which applies a signal to a utility line through induction or by a connection to the pipe. A receiver is set to the same frequency and can then trace the pipe. Currently, many manufacturers are selling these devices. However this technology has a critical limitation. It is unable to detect plastic pipe. About 18% (157,860 miles of mains) of the present gas distribution piping system is plastic pipe, most of it

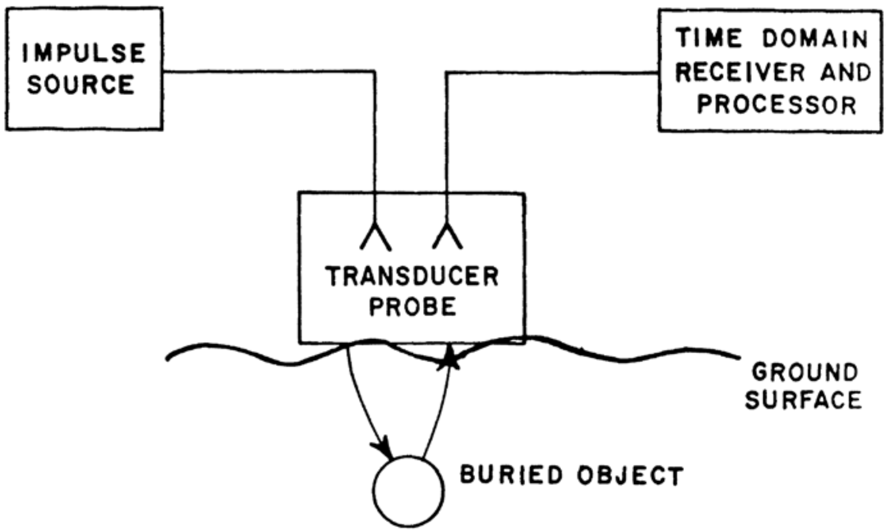

Figure 2. Block Diagram of Ground Penetrating Radar System for Plastic Pipe Detection.

polyethylene. In 1985, 24,500 of the 31,500 miles of distribution piping installed were plastic. Obviously a need exists for equipment that will detect plastic. Copper tracer wires or metallic tape adjacent to the pipe cannot always be detected.

For several years, GRI has sponsored research on alternative pipe locating techniques. These include ground penetrating radar, pulsed eddy currents and acoustic methods. Each of these technologies has limitations. It appears that an optimum system may contain several types of pipe sensing devices.

Ground Penetrating Radar Technology

Ground penetrating radar is similar to conventional radar in that both use a pulse echo technique where a pulse is transmitted and objects in its path reflect a portion of the pulse, see Figure 2. Conventional radar looks into the atmosphere, where as ground penetrating radar uses soil as the transmission medium. Any changes in the electrical properties of the soil, such as from a buried pipe, cause part of the signal to reflect back to the surface. Plastic pipe represents a change in the dielectric constant when compared with the surrounding soil. The research to locate plastic pipe has concentrated on the development of TERRASCAN. The TERRASCAN contains a specially configured antenna designed to recognize long, thin cylindrical objects, such as pipe and cables, from all other signals.

Acoustic/Seismic Sensors

Research has also been conducted on the use of acoustic/seismic sensors for detecting utility lines. The acoustic sensors transmit an elastic wave propogation into the soil. The waves reflect from the pipe and send a return signal through the earth which can be detected above the ground. Radar and acoustic sensors may complement each other because radar performs better in dry soils, whereas acoustic energy will propogate with less attenuation in wet soils.

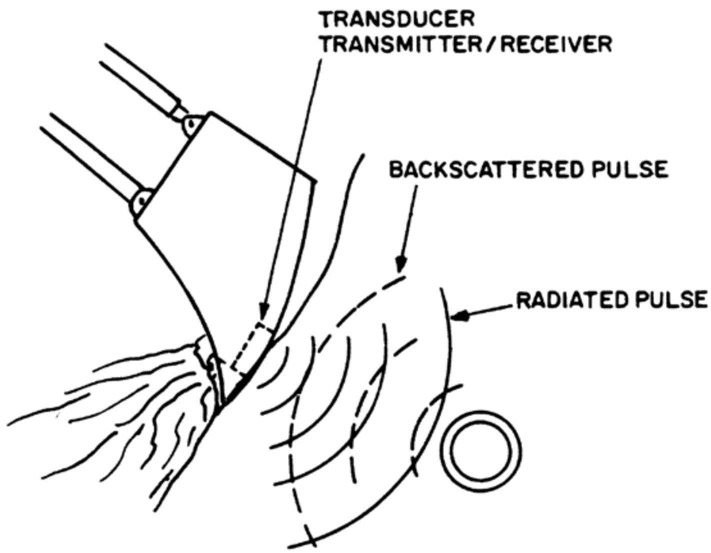

Figure 3. Proximity Device Mounted on Backhoe Bucket,

PROXIMITY SENSORS

Work has been conducted to attach a proximity type device to backhoes or other excavation equipment. Excavation equipment is the leading cause of gas pipe failures. A proximity device could warn the operator or automatically stop the digging equipment before hitting an underground structure.

Pulsed Eddy Currents

A pulsed-eddy current technique was investigated for attachment to a backhoe bucket, see Figure 3. This technique uses a pulsed magnetic field to induce eddy current in nearby conducting objects, such as pipes. The delay of the induced current is dependent upon the objects shape and magnetic characteristics. Objects such as metallic gas pipes exhibit a longer delay time than rocks or tin cans. The technique offers promise, however changes in the backhoe bucket are necessary for a commercial system.

Other techniques that are currently being investigated for use as a proximty warning device are electromagnetics and acoustics. An electromagnetic or acoustic device could include a transmitter to excite the underground structure and a receiver mounted in the digging equipment. A display would warn the operator when he is near a buried pipe.

NAVIGATION AND GUIDANCE

Research has been conducted to develop a “guided” horizontal boring tool. Existing boring equipment are typically adequate for boring distances up to 60 feet but cannot be controlled with accuracy over longer distances. If a tool deviates from a straight course there is no mechanism to correct it. Local soil conditions or rocks may cause a boring tool to follow a nonlinear path that cannot be detected from above the ground. A guided horizontal boring tool can potentially reduce the utilities cost of installation and restoration for underground gas distribution piping by at least 25%—up to 50% in urban areas when compared to trenching, backfilling and reinstatement costs.

The successful application of this tool requires a tracking or orientation system to monitor the tool's position. Several systems were investigated for tracking the boring tool. These were: conventional electromagnetic pipe locators, acoustical accelerometers and emplacement of coil(s) in the boring tool with surface and/or target receiving coils. The tracking system needs to provide the operator with X, Y, and Z coordinates and the orientation of the tool face, Figure 4. Three electronic instrumentation systems are being developed to meet these needs.

Magnetic Field Sensing System

A magnetic field attitude sensing system is used to track the subsurface position of the tool, see Figure 5. Magnetic fields generated by energized coils mounted on the boring tool are detected by three mutually orthogonal sensing coils located at a retrieval pit. The coils are energized by a low frequency 25 Hz amplifier. The data is processed to provide a graphical display to the operator that depicts the attitude of the tool.

Roll/Pitch Sensing System

The tool face sensing system uses two sensors for roll information and array of sensors for pitch information. The sensors are toroidal rings partially filled with a semi-conductive fluid. As the tool rotates or changes inclination angle, the impedance of the toroid changes in proportion to the angular difference.

Gyrating Fields

A three-dimensional gyrating field is being investigated that will provide data on position, roll, line of travel and inclination of a boring tool. A transmitter sends an electric field which is not only alternating in magnitude and direction at a specific frequency, but is also gyrating in space at a rate set by a synchronous motor. A data capture system is used to demodulate and decode the information conveyed by the gyrating fields and convert them into understandable information.

NON-DESTRUCTIVE EVALUATION

Ultrasonic Inspection

As previously mentioned, the majority of new gas distribution piping is made of polyethylene. Polyethylene pipe sections are joined by the quick and simple method of heat-fusion. Although grossly substandard joints are readily apparent through visual examination, joints of marginal quality are difficult to detect because critical defects are often internal to the joint. The use of automated ultrasonic test methods could greatly increase the capability of gas operation crews to determine the integrity of a heat-fused joint. An array of transducers are linked together in a ring that fits around the pipe. The transducers ultrasonically inspect the joint circumference. The transducers send a pulse of ultrasonic energy into the joint and receive back an echo signal which is automatically analyzed by a microprocessor based instrument to determine the joint's integrity. Waveforms showing a large reflection from the fusion area usually indicate a bad joint. Whereas waveforms showing little reflection from the fusion area represent properly fused joints, see Figure 6.

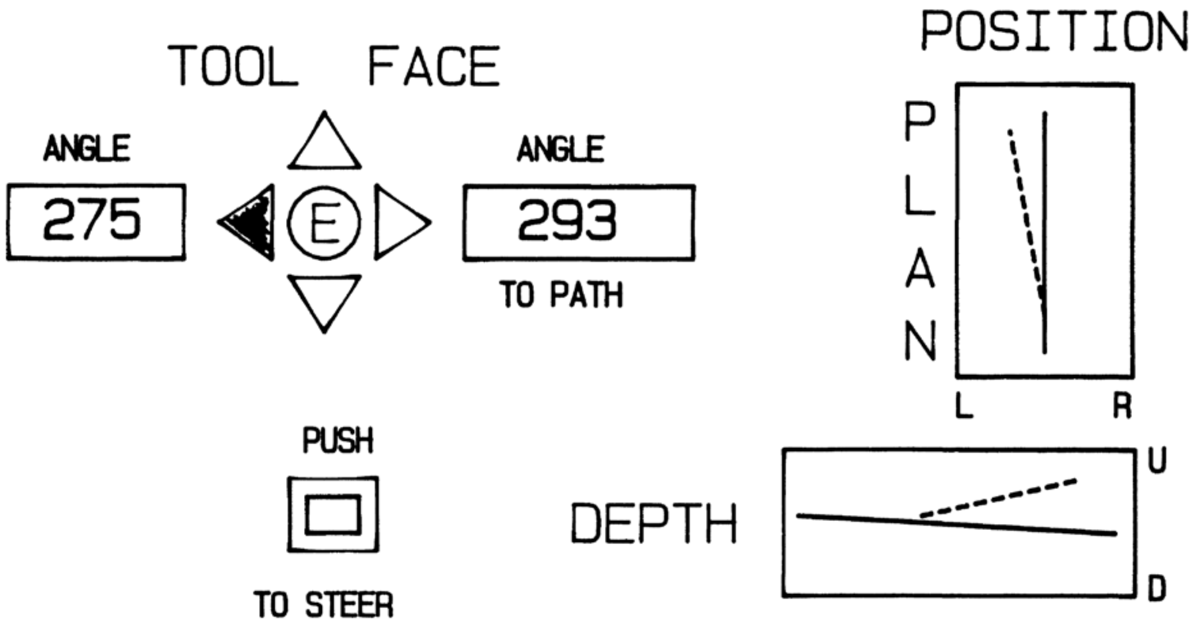

Figure 4. Illustration of Operator Display for Navigation/ Guidance System for Horizontal Boring Tool.

AUTOMATIC CONTROLS AND INTELLIGENT MACHINERY

The addition of intelligence to excavation equipment could improve operator and machine efficiency and provide greater safety. A robot controlled excavator is being developed to expose utility lines in need of repair. The system is designed to eliminate the need for a person to be located in the hole at a jobsite while soil is being removed. The robotic excavator is comprised of four major components: (1) sensing system to locate pipe and provide a map of the excavation area; (2) monitor/controller systems which receive input from the sensors and determine excavation strategies; (3) primary excavator that completes the major digging operations; (4) secondary excavator to perform “benign excavation,” (contact with the pipe will not damage underground utilities).

The robotic excavator integrates sensing, modelling, planning, simulation and digging action to unearth utility lines. In operation, the robot will gently clear the soil above the buried pipes until they are exposed or until a preset depth was reached without discovering pipe. There are sonar sensors (current design) on the excavator to create a map of the excavation. Imaging techniques are used to recognize pipes and other objects in the soil. The robotic excavator then uses the knowledge obtained by the sensors to map a digging course.

Microprocessor based electronics could also be added to excavation equipment such as backhoes and bulldozers to improve the control of hydraulic components, engines and valves. These additions would allow greater control and flexibility when digging. Researchers in the construction industry are developing sensors to monitor position and angle, and to measure pressure. For example, by using sensors to measure displacements and angles, it is possible to closely monitor the position of a backhoe’s arm and bucket.

Both of the above-described systems are aimed at developing machines to function semi-automatically or with full autonomy.

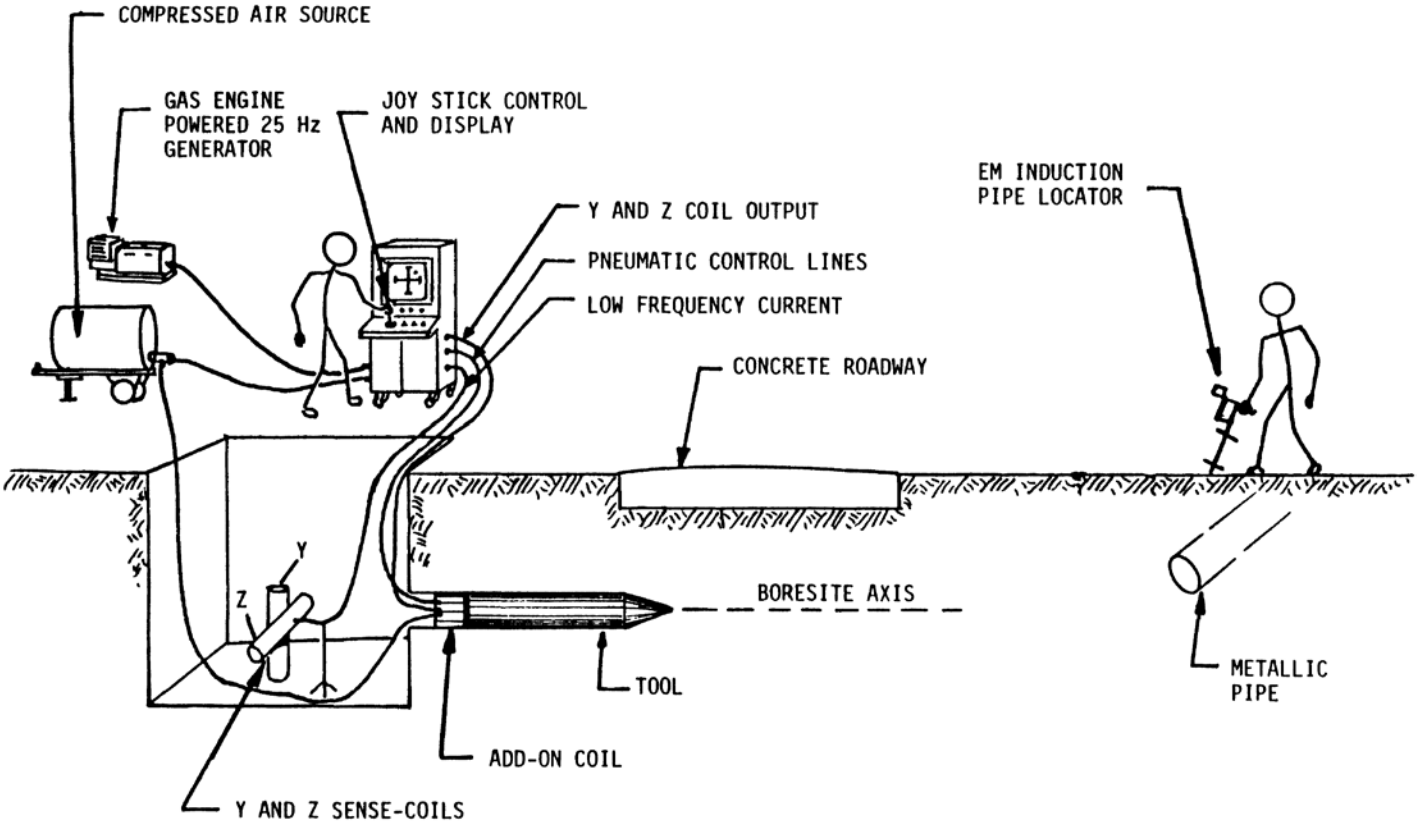

Figure 5. Conceptual Design of the Magnetic Field Attitude Sensing System.

CONCLUSIONS

There are several areas of gas distribution operations were novel sensors and automated systems can be used. During the next few years, several types of sensors described in this paper will be adapted or added to existing and new equipment in use by gas utilities. These advancements in sensor technology will provide greater safety and improved productivity in a cost-effective manner. The technologies will assist gas operators in pipe inspection and location, pipe installation and repair, and non-destructive evaluation.

The future will bring forward many more sensors for use by the gas industry. Most activities or operations in some way can use a device that will measure critical features and supply knowledge to allow operators to function more effectively. Mechanical or electronic sensors can be developed for volumetric flow rate, energy content, mass flow and pressure of natural gas. Fiber optic sensors could be used to detect physical damage, leaks or temperature extremes in pipe. Chemical and biological sensors will be used to identify contaminated environments. Expert or knowledge-based systems will assist in the operation of compressor stations and in the location of pipes or leaks. These are just a sampling of the types of operations were sensors can be applied.

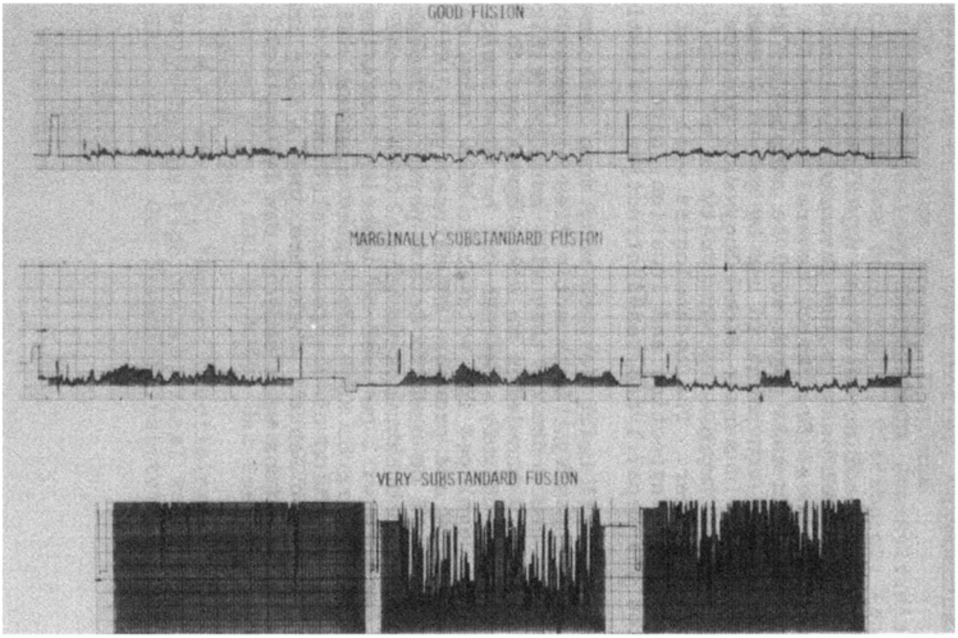

Figure 6. Ultrasonic Test Results for: 1) Good, 2) Marginally Substandard, and 3) Very Substandard Butt-Fusion Joints.

ACKNOWLEDGEMENTS

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CENTRALIZED METER READING: PAST, PRESENT, AND FUTURE

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ABSTRACT

One of my competitors mentioned to me that a predecessor of mine used the same title I am using today for a speech he gave several years ago. Well, not wanting to be embarrassed, I decided to change my title. But after reading what I had written, it was obvious that the title "Past, Present, and Future" accurately described what I am about to talk about.

The concept of reading meters centrally has been around for many years. All of us present have looked at one or more new technologies for reading meters. But what usually came from those investigations were two prohibiting factors. One, cost and two, product realibility. The economics of utility cost justification required a product at a cost that could compete with traditional forms of meter reading including augmentation by hand-held computers.

Why were early generations of central meter reading systems so expensive? First, component cost. The electronics comprising CMR systems are complex and before the advent of integrated circuits were extremely expensive. Today, we can buy a single integrated circuit chip for under $3.00 that five years ago would have cost $200 for a chip or $75 for discreet components. Second, component reliability. Realibility impacts cost and most of the early systsms were built with discreet components which are rather susceptable to failure. Third, lack of telephone company cooperation. Predivesture AT&T had ultimate control over the deployment of telephone network based CMR systems. AT&T determined that at the then product cost, there was little to no market for CMR. Therefore, AT&T never really actively cooperated with the development of CMR.

On the other side of the cost justification equation, traditional forms of meter reading were still cost-effective when compared to available CMR systems. Meter read to bill cycle float had not been recognized as a significant cost component of meter reading. Access to homes was just beginning to be a problem. Wages, transportation, and fringes were not unrealistic. And, state regulatory bodies were somewhat docile about customer complaints of erroneous or estimated bills. Thus, the bottom line was the economics of system cost compared with business as usual would not justify the implementation of CMR.

CENTRALIZED METER READING: PAST, PRESENT, AND FUTURE

However, both sides of the cost justification equation have changed radically during the past few years. CMR costs have dropped substantially due to a dramatic drop in the cost of electronic components. As mentioned earlier, fully integrated chips used in CMR systems can now be purchased for under $5.00. With the advent of cheap integrated chips has come increased reliability; there are simply fewer parts to fail and no mechanical parts that wear or break.

Another major impact on the deployment of CMR was the breakup of AT&T on 1/1/84. The resultant telephone companies are now functioning in a semi-competitive environment with a need to optimize underutilized capital capacity as well as enter new lines of business. Tariffs filed for CMR by the telephone companies are generally now at rates that will support the overall economics of CMR for utilities.

On the other side of the equation, the cost of meter reading has risen dramatically. First, lock-outs are probably the biggest headaches meter reading departments now have and have a direct impact on the overall cost of meter reading. The demographic trends that have led to the problem of lock-outs continue to move against utilities. Over 55% of all U.S. women now work. By 1990, the labor department estimates that this number could reach 75%. Even if someone is home, the probability that access will be gained by the utility is diminishing, largely due to the fear of crime by the residents. Second, labor rates and attendant indirects have risen faster than the Consumer Price Index over the past ten years, thus utilities are now looking for means to automate what have been labor intensive functions. Third, the cost of capital has also played a significant role in the increasing cost of meter reading. Almost all utilities are seeking ways to reduce meter read to bill cycle in order to reduce float on their revenue streams. Fourth, the cost of liability insurance is reaching extreme proportions for the amount of coverage carried. Although this generally is an overhead item, the cost will eventually reach meter reading departments and impact read costs. Fifth, state regulators have become extremely active in monitoring estimated bills and responding to consumer complaints, And, finally, in some areas, meter reading has become a hazardous occupation. For instance, some utilities in New York are required by union contract to send out meter readers in pairs for safety reasons.

The economics of CMR have now reached a point where almost all gas, electric, and water utilities can justify remote meter reading on their hard to read and limited access meters. And in addition, CMR can now economically compete with the cost of moving meters outdoors. Therefore, we at NIS are very optimistic about the future of CMR.

NIS and our parent, Allied-Signal Corporation, are dedicated to providing low cost, highly reliable CMR systems and components to the gas, water, and electric industries. NIS has been involved in CMR for over five years, during most of that time as part of Neptune Water Meter Company. Last year we were physically separated from Neptune Water Meter and our staff enlarged to almost fifty people. Neptune Informations System's singular objective is to develop reliable, cost-effective products for gas, electric, and water utilities,

Neptune Information Systems has two CMR systems; one which works over telephone lines and one which works over cable television lines. The telephone system has four major components:

- Meter Interface Unit (MIU)—customer's residence
- Communications Controller Unit—telephone company's office
- Data Translation Module (DTM)—utility office
- CMR Link on an IBM XT—utility office

Using CMR Link the utility directs the communications controller to dial up a customer's residence and ask the MIU for meter usage data. Once the MIU "wakes up" it interrogates the meter encoder and sends the information back through the communications controller to the utility. The DTM reformats the data so that it can be read by CMR Link software.

The cable CMR system works in a similar manner to the telephone system except a Cable Data Interface Unit (CDI) located at the cable head end is used instead of a communications controller to access the MIU. The cable MIU is "smart" and wakes up once every nine hours, reads the meters, and sends the data to the cable head-end. The utility accesses the data via telephone modem.

During this first year as an independent company, NIS has had several major successes. We installed a full CMR system in York, Pennyslvania for The York Water Company. Over 6,000 homes have been equipped with our cable CMR product and by year-end over 12,000 homes and small businesses will be equipped. NIS has also been able to cost reduce our meter interface unit while meeting the stringent quality and technical requirements of the telephone companies. NIS is now actively pursuing applications in the gas industry. Corporate engineering and marketing resources will be focused on cost reducing our current gas encoder technology and to providing a costeffective and efficient alternative to the gas utility industry.

DATA ACCUMULATION AND COMMUNICATION

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ABSTRACT

Microelectronics, microprocessors, state-of-the-art, high-tech, are some of the new “buzz” words reaching into gas distribution. The introduction of intelligent flow computers, electronic volume, temperature and pressure correctors along with fully automatic communication and alarm systems, at an affordable price, automates distribution. This holds true also in production and transmission.

A gas utility having the ability to remotely calculate consumption and with accurate communications, transmit the data, opens up new avenues for creative rates. This is becoming more visible in the interruptible, transportation or carriage, and peak demand billing accounts. Cash flows are enhanced by the ability to read and bill the same day with total accuracy.

Alarm capabilities which will notify the gas company immediately for such non-standard conditions as: energy diversion, intrusion, tampering, regulator failure, compressor failure, leak detection, and low pressure, to name a few, also help justify this new technology.

The following paper introduces a system which allows a utility to incorporate the above benefits and maintain control of its destiny. The system is solely owned and controlled by the distribution company without third party interface.

DATA ACCUMULATION AND COMMUNICATION

Introduction

In today’s changing world, it is necessary to have more and more information available to adequately manage any business. Certainly, this is no less true for a gas utility than it is for any other commercial business. Until recently, however, it has been uneconomical for the utility to obtain all of the information it needs for efficient system operation because of the diversity of its customers. Now, because of recent advances in technology, it is becoming more and more feasible to collect the information needed. Several different communication technologies are currently maturing into economically justifiable systems. Today, I will concentrate on a means of communication that has been in existence for quite awhile, but has only recently become viable for widespread application. I will be talking about using existing telephone lines for automatically reporting information about the gas consumption back to the utility from the customers meter site.

The recent deregualtion of telephone service has made such use of customers phones possible. Essentially, deregulation means that the customers now own the wiring within their structures and therefore can attach any approved device to these lines that they wish. Later, I will duscuss the economic impact of this change and what it can mean to you—the utility. I will also explain the process used for communicating between the customer site and the utility's central location. Obviously, sharing the customer's phone requires special equipment so that the customer will not be inconvenienced or have his normal use of the telephone curtailed.

First, I will briefly describe some potential applications for this data collection technology. Included will be meter reading, load management, and alarm reporting.

Applications

Everyone would like the ability to remotely gather consumption data, rather than having to send someone to each site to collect it manually. Although this is a desirable goal, the reality of the situation is that electronic meter reading alone is just not cost effective at this time. The decrease in price of electronic component parts and the increase in cost of the Amercian labor force are bringing this reality closer each month.

However, in any service area, pipeline or distribution, a certain percentage of meters are significantly more expensive to read than those in the average residential sub-division. Remote data collection systems can read such hard-to-access accounts effectively. Automating the meter reading process for the ten to fifteen percent of your accounts that are hard-to-read is normally very easy to cost justify. In addition, using such a process significantly lowers your average meter reading cost throughout the system.

Lets look at what types of meters or accounts we would want to read and why:

A. Large Industrial or Commercial
B. Transportation or Carriage Accounts
C. Interruptible Accounts
D. Purchasing Points or Town Border Stations
E. Firm Accounts
F. Multi Rate Accounts
G. Remote Accounts
H. Residential Accounts

1. Hard-to-read
2. High Crime Areas
3. Inaccessible
4. Transient
5. Bi-monthly Average Billing
6. Rate Studies, Load Profiles

Justifying the Application

Industria1 and Commercial Accounts. A significant amount of revenue is generated from these accounts. Many types of instruments and chart recorders are placed at these sites. An automatic metering system with full programmable communication placed at these sites will allow you to monitor uncorrected and corrected gas consumption on an hourly basis. The central computer will provide you with gas consumption profiles and monitor, from the uncorrected and corrected reads, the pressure factor. This will enable you to ascertain the accuracy of your mechanical instrument and the pressure regulators. Many gas utilities are also researching a potential “peak demand rate structure”.

Transportation or Carriage Accounts. Some large industrial accounts purchase gas direct from the producer and only pay the gas company a transportation fee. Since gas, a commodity, is purchased on a twenty-four hour period, profiling these accounts and their demands offer the utility the opportunity for creative and competitive rates and possibly win back the account as a full customer.

Interrugtible Accounts. An automated monitoring system is almost a must for utilities who not only have interruptible customers, but actually interrupt them. If timing and penalty billing is important, a system that will monitor time, meter reading, and consumption during the curtailment period is a must. Purchasing Points and Town Border Stations. This is an important point in gas transmission and distribution where monitoring is necessary. Monitoring the flow and pressure is important for the gas control function in a distribution company.

Firm Accounts. Where a customer agrees to purchase a certain quantity of gas for a specified period, the quantity very often dictates the rates. Did that account meet his contract requirements? After the contract amount is he on interruptible rate or another metered rate? Remote metering of these accounts enables the utility to answer these questions and address control.

Multi Rate Accounts. Much like the above scenario, many accounts are or could be utilizing multi rates. This allows the utility, in many cases, to be more competitive against other fuels. The problem is monitoring with accuracy the various rates and the consumption in each rate. Obviously, the problem compounds when there are multi meter runs and the total consumption versus time must be measured.

Remote Accounts. The expense of reading a meter or changing out a chart compounds with the remoteness of the accounts. These remote accounts are a primary target for the new automated meter reading and alarm systems.

Residential Accounts. Automating meter reading for residential accounts, in general is NOT justifiable yet. The row houses in a community, if the meters are accessible, are not too costly to read. The hard-to-read meters stated previously are of first concern. Call backs, for instance, in order to obtain a meter reading are very expensive to handle.

Manual meter reading costs, as you know, are highly labor intensive, and this is one of the considerations which make an automated system highly desirable. On the other hand, electronic cost trends are downward and substantially less labor intensive. If we could accurately define these two costs and plot them on a graph, we would find the cross-over point closer than most people would predict.

There are many cost considerations for automatic meter reading and many variables. Some of these considerations and variables are as follows:

The cost of:

- Meter Reading Operations
- Customer Accounting Operations
- Customer Relations Operations
- Credit and Collection Operations

- Data Processing Operations
- Meter Department Operations
- Service Operations
- Mail-room Operations

Communication Process

Now that we have discussed the necessity and applications for the first part of this paper, lets proceed with the actual process of communication with the central computer.

I mentioned in the introduction that I will concentrate on using the existing telephone network as the means of communication.

How would you actually use these telephone lines to communicate information to a central computer? Probably the best mode of operation for this type of data collection is to allow the remote unit to dial the central computer—as opposed to having the central computer dial out (that is, poll) the remote sites. The typical process that would be used is as follows:

1. The remote data-collection device would decide for some reason, whether at a pre-scheduled time or because of some alarm condition, that it is time to call the central computer.
2. The device first looks at the phone line to determine whether or not the customer is currently using it. If the customer is using the phone line, the device must recognize this and not attempt to use the phone at the same time. Typically, the device would then go into a retry mode so that it will check periodically (for example, every five minutes) until the phone line becomes available.
3. If the line is available, the device will pick up the line and dial the number of the central location.
4. The central location will detect that its incoming line is ringing and pick up the phone. When this happens, an identifying signal is sent down the line to the remote site that a communications link has been established.

   If, for some reason, the central site does not pick up the line (for example, the line is busy) the remote site would have to be smart enough to recognize that it did not get an answer, then hang up the line and try again later.
5. Once the communications link has been established, the data is transferred as appropriate to that particular data collection device and the call is terminated by each end hanging up the line. At that point, the unit at the central end is available to receive another call from a different device and the customer line is once again available. Also, the central end can be equipped so that it can process calls from more than one data-collection device at a time.
6. A key ability, which is provided only when the remote site can initiate calls to the central computer, is reporting alarm conditions. Via alarms, company personnel can be notified immediately whenever the remote device detects that someone is tampering with the meter. A wide variety of tamper-detecting sensors can trigger alarm calls based on almost any conceivable type of tampering that is attempted. In addition, this same alarm reporting capability allows the utility to offer additional services to its customer base—such as fire, burglar, or health emergency alarms.

   An interesting extension of this alarm reporting ability is that it provides a fairly low-cost automatic fault-isolation system, where the computer system could simply detect where the fault in the network exists. This is an example where using the telephone lines, which operate completely independently, is a great advantage.

It is important to note that, throughout this data-transmission process, the customer might pick up the phone line to use it. If this occurs, the device at the remote site must recognize that the line has been picked up and immediately abort its call. In this way, customer inconvenience due to the data-collection device is minimized. Just as important to the utility, of course, is to prevent information to creep into the data base at the central computer if the customer does interrupt a call.

Conclusion

Using state-of-the-art technology to remotely collect data for many various reasons is becoming very cost justifiable because of immediate fault condition alarms, and also an increase of cash flow.

Using dial-up telephone lines is not necessarily the answer to all data-communications requirements a utility will have, but it does provide a solution that is currently feasible in many cases. In addition, since it requires additional equipment beyond the data collection device and the central computer, it is frequently the least expensive and cost effective system available.

ELECTRONIC VOLUME CORRECTION AND DATA COLLECTION

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ABSTRACT

With the "Coming of Age" of micropower electronics and the concentrated effort to acquire accurate measurement instruments, a comprehensive evaluation of electronic correction devices and data acquisition units is underway. An economical approach to this end is looked at using the Dresser ROOTS® Electronic Volume Correctors and Data Collection Systems. Since the instruments are battery powered, extensive use of micropower electronics is utilized throughout the design.

ELECTRONIC VOLUME CORRECTION AND DATA COLLECTION

GENERAL

The ROOTS® Electronic Volume Correctors totalize gas volume to standard conditions. Designed for accuracy, reliability, and ease of maintenance, the ROOTS® Correctors fit all ROOTS® instrument drive meters and instrument drive meters from other manufacturers. Requiring very low drive torque makes these Electronic Volume Correctors ideal devices for meters requiring low torque instruments. These electronic correctors will also accept volumetric pulse inputs from any meter capable of providing pulses.

The enclosures are rugged aluminum housings with provisions for sealing against the harshest environments. The front panels are constructed of an aluminum polycarbonate composite with pocket inserts for labeling different parameters and scaling factors. Seperate compartments are provided for the electronics, battery, transducer, and input/output termination strip.

Power for the Electronic Volume Correctors is provided by a 9-volt, 8-ampere hour lithium sulfer dioxide battery pack providing in excess of five years operating life for the micropower CMOS electronic circuitry. Lithium batteries provide excellent cold weather operation in the northern environments by retaining 60%

of their capacity (ability to deliver current) at −40°. Since the lithium batteries are hermetically sealed rather than crimp sealed, they do not exhibit a tendency to leak in the warmer environments of the Southwest.

A low battery warning indicator shows on the volume displays whenever battery replacement becomes necessary. This low battery warning flag gives in excess of three months warning notice. The battery compartment is located external of the electronics so that battery replacement does not require access to calibration controls. A battery backup system is supplied to prevent losing count while replacing the battery.

Shorting plugs are provided in order to set base pressure and corrected volume scaling factors in the field. This permits the instruments being set up from shelf stock for any application. Provision for setting totalized volume with an external handheld device is also provided for ease of installation and maintenance.

The Electronic Volume Correctors use a unique optical pick-up circuit for recording pulse inputs. This feature eliminates the need of relying on mechanical switches which are prone to failure or magnetic switches which are subject to outside magnetic interference.

All of the Electronic Volume Correctors are designed to be intrinsically safe which means they are incapable of producing enough electrical or thermal energy to cause an ignition of an explosive atmosphere during normal or abnormal usage. Some of the volume corrector models have received Factory Mutual approval for Division I, Class I, Group D operation. The other models have been submitted for Factory Mutual approval.

The Electronic Volume Correctors have been tested and are in compliance with the requirements in Part 15 of the FCC Rules for a Class A Computing Device.

Liquid crystal displays with a special cold weather fluid are used on all the Electronic Volume Correctors to provide reliable readouts under all environmental conditions. An uncorrected counter is also provided in the base of each instrument and can be either mechanical or electronic.

Additionally, ROOTS® Electronic Volume Correctors have the benefit of built-in test equipment, or BITE. BITE removes the necessity of pu rchasing and transporting manufacturer-peculiar test boxes. It provides a level of convenience to the field that is impossible to provide in mechanical correctors. BITE is a full-time operating system that continuously monitors the pressure and/or temperature correction. Either the correction factor or equivalent pressure and/or temperature value can be displayed for quick on-line verification of correct calibration. Because the indicated values are derived from the factors that are being applied by the correction circuits, verification of correct calibration may be accomplished by simply viewing the pressure and/or temperature displays through the front panel.

Other standard features include corrected and uncorrected pulse outputs for remote mounted electronic totalizers or data collection devices, that are optically isolated to provide maximum protection for the internal circuitry while providing remote signals capability.

ETD: Temperature Corrector

The ROOTS® Electronic Gas Volume Corrector, Model ETD, corrects actual gas volume to standard conditions of temperature. Eight digits of corrected volume are totalized on a large, easy-to-read, liquid crystal display that will operate even in extreme cold. The flowing gas temperature is also constantly displayed in degrees Kelvin or degrees Rankin on a special cold weather liquid crystal display.

A semiconductor device is used with the ETD as a temperature probe to provide good linearity while requiring only single point calibration to remain within tolerance over the entire operating range. The temperature operating range is from −40°F (−40°C) to +140°F (+60°C).

The standard temperature probe is provided with an armoured cable and has been designed to reduce common temperature measurement errors caused by differences in gas and pipe temperatures. The probe may be used without a thermowell to a maximum pressure of 200 PSI; for line pressures to 1440 PSI, an optional thermowell may be used. A user-adjustable factor multiplier for fixed factoring is also available.

EPD: Pressure Corrector

The ROOTS® Electronic Volume Corrector, Model EPD, corrects actual gas volume to standard conditions of pressure. Fixed factor supercompressibility can be provided for in the calibration. The ROOTS® EPD fits all ROOTS® meters having instrument drive (ID) outputs, plus those meters with instrument drives from many other manufacturers. Eight digits of corrected volume can be totalized on a large, easy-to-read, liquid crystal display that can be driven at increments equal to or greater than the meter drive rate.

Absolute pressure is measured using a Heise transducer which is well known for its accuracy and reliability. Several pressure ranges are available from 0 to 30 PSIA (0 to 200 kPa(abs)) through 0 to 1500 PSIA (0 to 10,000 kPa(abs)). The transducer can be mounted internally or externally, depending on the application.

The Heise pressure sensor incorporates an optical means of detecting the effective pressure on an elastic member, so there is no physical contact between the strained member, acted upon by pressure, and that portion which produces the electrical signal. This unique pressure sensor results in the extraordinarily accurate Heise precision transducer used with the ROOTS® electronic correctors.

The fundamental operation of the sensor is quite simple. The diaphragm, or small helical Bourdon tube element, moves only 0.020 inches during a full scale excursion, almost imperceptible to the eye. Fixed to the element is an opaque vane, a kind of miniature window shade, which blocks near infrared light impinging on one of two monolithic photodiodes. The other photodiode continuously measures the intensity of the light source, an LED, and serves as a reference against which the measured light is compared.

Ambient temperature can affect both light intensity and sensitivity. But since a single light source is used, and the sensitivity for each diode is the same due to the monolithic structure, the two voltage signals generated by the reference and the measuring photodiodes are affected by temperature in the same proportion eliminating errors.

By using dual voltage to frequency converters, one proportional to pressure and the other fixed as a reference, analog pressure is converted to a ratiometric digital signal for processing by the EPD. These techniques remove the need to calibrate the EPD for pressure at the instrument. All pressure calibration is done at the pressure transducer. This also allows true interchangeability of transducers and ranges, without having to also adjust or recalibrate the instrument.

The small motions of the pressure elements result in almost negligible hysteresis, generally on the order of 0.02 percent full scale or less, and repeatability is better than 0.02 percent full scale.

EPT: Pressure/Temperature

The ROOTS® Electronic Gas Volume Corrector, Model EPT, corrects actual gas volume to standard conditions of pressure and temperature. Fixed factor supercomressibility can also be provided for in the calibration. The ROOTS® EPT is provided with an eight digit corrected volume display, a continuous pressure display, and a temperature display that is also used with the built-in test equipment feature for indicating pressure factor, temperature factor, and other test parameters. The displays are filled with a special fluid that permits operation even in extreme cold weather.

The EPT uses the same standard semiconductor temperature probe with an armoured cable as the ETD. Absolute pressure is measured using the same Heise transducer as the EPD. Options include both corrected and uncorrected optically isolated pulse outputs for remote mounted electronic totalizers.

The ROOTS® Electronic Volume Correctors with temperature, pressure, or temperature and pressure compensation are designed for long term, highly reliable operation with minimal maintenance requirement. Detailed accuracy specifications allow the user to confidently project total performance of the instruments for any given operating environment. Accuracy, reliability, and ease of maintenance are provided at a reasonable cost making the ROOTS® Electronic Volume Correctors an economical approach for gas volume correction.

DATA COLLECTION

The Data Collection System consists of four parts: (1) the Data Collection: DCO; (2) the Hand Held Retrieval Unit: HHDRU; (3) a Modem Unit; and (4) PC Software. The Data Collection System centers around the DCU which is located in close proximity to the instrument and is used to collect data from it. Once the data is in the DCU, it can be retrieved either by an operator on site with a HHDRU or remotely from a personal computer via the modem.

Data Collection Unit (DCU)

The DCU will accept pulse inputs from any source and accumulate them for any time period from one minute to one day and store the information for future retrieval. The DCU will also accept pressure and temperature factors from the ROOTS® Electronic Correctors for any time period and store them. Two external alarm inputs are also available for monitoring battery status, tampering, or any type alarm that is an on/off condition. All the collected data is stored in internal memory and time/date stamped for retrieval. The microprocessor in the DCU is asleep most of the time and only wakes up to store data, acknowledge alarms, or transmit data if requested. The unit is powered by a lithium sulfer dioxide battery and uses micropower electronics for battery conservation.

Several internal user-programmable alarms are included and whenever an alarm is set or cleared, a time-stamped entry is made in an alarm list. Alarms include four high/low pressure alarms, four high/low temperature alarms, pressure and temperature update busy alarms, external input transition alarms, communication problem alarms, data overwrite alarms, high/low flow rate alarms, and DCU low battery alarm. The alarms can be individually enabled or disabled and set up to require acknowledging. An alarm status is maintained in the DCU database which contains the current state of the alarm, and the current state of the acknowledge alarm.

The time interval at which the DCU records volume and factor data is configurable. Associated with this interval is the interval at which the DCU wakes up to check alarm limits and acknowledge the watch dog timer. Although the hardware counters are large enough to maintain data for 24 hours, the wake-up timer is set to a maximum of one hour. This allows the watch dog timer circuit to rectify problems in a maximum of an hour’s time, and also forces alarm checking on rates and factors a minimum of once an hour.

Communications with the DCU can be done either with the hand-held data retrieval unit or with a personal computer. Communication between the DCU and the personal computer uses Xmodem protocol, originally developed by Ward Christensen. Basically, information is transferred by files in 128 BYTE blocks with CRC type error checking. Communications between the DCU and the HHDRU uses a special protocol which better handles the type and length of data packages and commands being sent between the units.

Three levels of security are included in the DCU configuration consisting of user assigned passwords which are required to access various command functions.

Hand Held Data Retrieval Unit

The Hand Held Data Retrieval Unit (HHDRU) is a small portable unit which is used to collect data from a number of DCU's. Once the data is in the HHDRU, it can be visually reviewed on the LCD display, sent to a printer, or sent to the personal computer. Additionally, the HHDRU can be used to set the configuration data in the DCU. The DCU is able to store data from approximately thirty "data sets". Memory partitioning is done so that more data sets can be accommodated if less than the maximum 840 samples are loaded from the DCU's.

An infrared link to communicate between the DRU and DCU is used while a standard RS232 port is used to connect to either a personal computer or to a printer. The DRU is powered by rechargeable batteries with a recharge period of four hours, and an operation period of thirty hours.

A thirty-two key, touch sensitive keypad and a two line by twenty-four line alphanumeric LCD display is used. The HHDRU has a small audible "beeper" which is used to provide the operator with feedback whenever he presses a key or makes an invalid entry. Operator prompts appear on the first line of the display and operator entries will appear on the second line with a cursor indicating the place where the entry will appear. An invalid operator entry will cause an error sign ('*E*') to appear at the far right of the second line.

Modem

Signal interfaces to multiple DCU's are available using a bell 212A type modem operating at 1200 BAUD. Multi-conductor cable is used from the DCU to the modem and the DCU interface is intrinsically safe. NICAD-powered batteries power the modem and can be recharged from an external AC-DC converter or DC supply.

Personal Computer Software

The personal computer software provided is intended to run on an IBM PC compatible type machine. As much as possible, commercially available software packages are used. The software package enables the personal computer to automatically answer a call from a DCU. The data sent by the DCU (alarm or sample data information) will then be converted to ASCII and stored in a standard format file.

SUMMARY

The ROOTS® Electronic Correctors and Data Collection Units offer an economical approach to accurately correct to standard conditions of pressure and temperature and record data for archival purposes and future references. Detailed accuracy specifications allow the user to confidently project total performance of the instruments for any given operating environment. Accuracy, reliability, and ease of maintenance and testing are provided at a reasonable cost.

SONIC INTEGRATED GAS MEASUREMENT ASSEMBLY: A REAL TIME MEASUREMENT AND CONTROL STATION

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ABSTRACT

The Sonic Integrated Gas Measurement Assembly (SIGMA), is a system developed to meet the need for a pipeline measurement device that can be precisely calibrated at the site under real installation and operating conditions. System accuracy is ±0.2 percent at operating conditions and is completely automatic and controllable remotely.

SONIC INTEGRATED GAS MEASUREMENT ASSEMBLY: A REAL TIME MEASUREMENT AND CONTROL STATION

Custody transfer meters, such as turbine or orifice meters, are affected by broader than desired tolerances and variations in installation and operating conditions that continuously affect the measurement. The turbine meter has a point accuracy band that is larger than desired and initial calibration (or recalibration) may introduce systematic measurement bias at operating conditions. The orifice meter is a full-scale instrument whose accuracy is dependent upon many assumptions of conditions and assembly at the site, but does not include a site calibration.

Even if these meters have perfect point accuracy after calibration, the effects of installation conditions (such as gas turbulence, swirl and jetting) systematically alter the measurement. Changing operating conditions affects the measurement. Besides the ideal effects of pressure and temperature of the flowing gas, there are significant non-ideal gas effects that introduce error into the calculation to arrive at base conditions (especially with orifice meters). Friction, wear and damage are other operating conditions that can increase error.

The SIGMA design concept provides a volumetric measurement device that is automatically recalibrated and adjusted continuously to detect initial and changing operating conditions of measurement.

SIGMA consists of a skid mounted Measurement Assembly and a Control Station. The Measurement Assembly is prepackaged and ready to attach to the pipeline. It contains two custody transfer meters, a

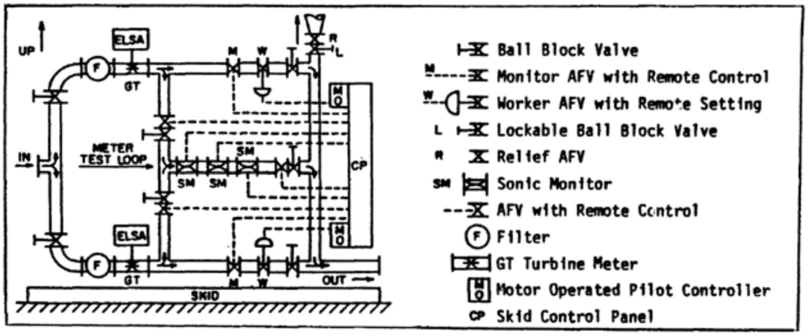

Fig. 1 — Measurement Assembly Layout

meter calibration loop, a unique experiment to continuously determine the compressibility factor Z, and all necessary sensors, controls, valves and piping. The operation of the station is fully automatic; measurement data collection, station outlet pressure, meter and transducer calibration and communicaiton to and from the station are controlled by a touch screen CRT master communications computer, two meter data terminals and a station controller.

The measurement assembly is a dual flow metering and pressure control station with an integral test loop for the American GT Turbine meters. Refer to Figure 1.

Each turbine meter is equipped with an ELSA flow computer and a high density pulser. The ELSA flow computers provide totalized base volume utilizing meter volume, pressure and temperature sensors and programmed constants for gas composition, i.e., specific gravity and N2/CO2 content. Both ELSA computers are battery powered (rechargeable) to provide local corrected measurement in the event of an electrical power interruption.

The meter test loop provides a number of meter calibration points, using Sonic Monitors. A Sonic Monitor is a unique mounting and valving arrangement for a Sonic Flow Nozzle where the nozzle is mounted coaxially within a special Axial Flow Valve. By using these and other Axial Flow Valves under computer control, these in-situ sonic flow standards can be placed in series with either custody transfer meter. The nozzles, based on a modified Smith-Matz geometry, are sized at about 10, 20, 40 and 80% of the maximum meter capacity and have a certified accuracy traceable to the United States Bureau of Standards of ±0.15%.

SIGMA also contains a unique gas composition effect sensor; a sensor that is able to measure the compressibility factor (Z) and a critical flow factor C* in real time. Refer to Figure 2.

The compressibility factor Z is determined by very accurately measuring the flow rates of a diaphragm meter (Ql) at station pressure (P1) and temperature (T1) and comparing these conditions to that of a Rotary Meter (Q2) at near atmospheric conditions (P2) and the resultant temperature (T2) after flowing through a Sonic Flow Nozzle (Q3). After correcting for the ideal gas laws, the calculated difference of flow rates is the compressibility Z. Since meter flow rates are used instead of volumes, the determination of the factor is continuous. The significance of employing a live Z factor in the base volume can be seen in Charts A and B which show how the compressibility factor varies as a function of Specific Gravity and CO2/N2 content versus line pressure.

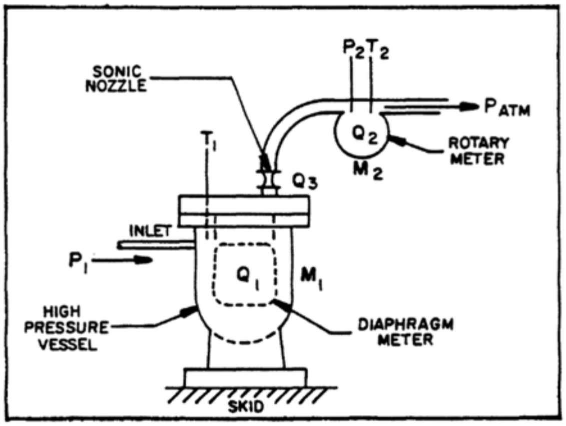

Fig. 2 — Unique Gas Composition Effect Sensor

Performing a sonic nozzle calibration of the station meters would normally require a knowledge of the gas composition. In SIGMA, the critical flow factor is determined by very accurately measuring the flow rate of the diaphragm meter (Q1) compared to the calibrated flow rate of the critical flow Sonic Nozzle (Q3). After determining the prevailing meter flow rate on the gas currently flowing through the station, it is possible to ratiometrically determine a critical flow factor and, thus, the precise flow rate of each sonic nozzle in the calibration loop. This experiment is also continuous. Since it measures the effect on sonic velocity caused by 100% of the gas, this method is more reliable than trying to compute the factor from gas analysis (not all gases are detectable in a gas chromatograph, for example).

These experiments, Z and C*, eliminate the need for auxilliary equipment such as gas chromatographs and eliminate the manpower needed in gas sampling methods. The results of the experiments are fed to the station's Meter Data Terminals for computation of standard volume and flow rate.

Normally, the equation for base volume is expressed as:

$$Vb = Vf \quad \frac{Pf}{Pb} \quad \frac{Tb}{Tf} \quad \frac{Zb}{Zf} \qquad \text{Equation \#1}$$

Where Vf is volume in actual cubic feet at flowing gas conditions. In practice, the Vf term is expanded to:

$$Vf = \text{pulses} \times \frac{1}{K} \qquad \text{Equation \#2}$$

where the number of pulses is related to whole or partial revolutions of the turbine meter rotor and the K factor is a <u>fixed</u> value in pulses per cubic foot determined during calibration at some point on the calibration curve.

The SIGMA station recognizes that the K factor for a turbine meter is <u>not</u> a constant, that it can vary as a function of:

1. Flow Rate — The calibration curve of a turbine meter is not a perfectly flat, horizontal line over the total flow range of the meter, as shown in Figure 3.
2. Density — The accuracy of a turbine meter can vary slightly between atmospheric and high pressure calibration tests.

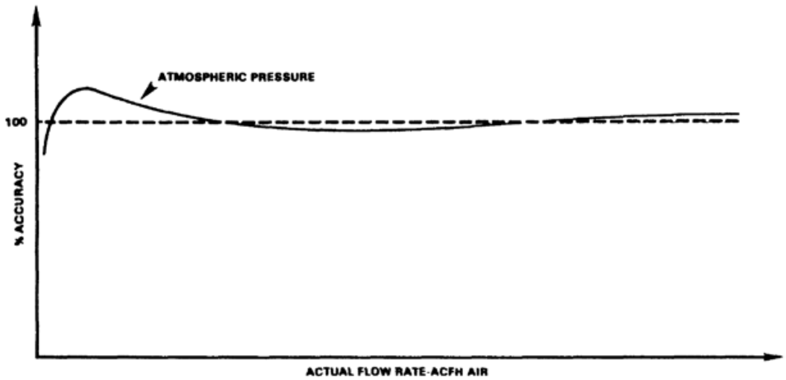

Fig. 3 — Accuracy Curve of a Gas Turbine Meter Plotted Against Actual Flow Rate in Atmospheric Pressure Air

3. Piping Effect — Pipe bends, pipe fittings and obstructions such as regulators, valves or even foreign matter ahead of a turbine meter can cause severe changes in the K factor due to gas jetting, swirl turbulance, or pulsing.
4. Service Condition — Friction, wear or rotor damage may affect turbine meter calibration, particularly at the lower end of the meter flow range.

To insure the accuracy of the uncorrected volume term (Vf) in the base volume equation, the SIGMA calibration loop tests the turbine meter at several flow rates while operating at line pressure, under actual inlet piping conditions and in its current service condition. This allows the station to compute base volume using a modified volume term:

$$Vb = \text{Pulses} \times \omega \times \frac{Pf}{Pb} \times \frac{Tb}{Tf} \times \frac{Zb}{Zf} \qquad \text{Equation \#3}$$

where the term replaces the fixed K factor and accounts accounts for the four operating variables listed above.

In effect, SIGMA extends the concept of real time measurement beyond the inclusion of a dynamic Z factor by automatically correcting for any possible errors in the meter factor, Vf. The result is base volume computation, in accordance with Equation #1, where all the factors in the equation are measured on a real time basis.

None of what has just been described would be possible without microelectronics. For instance, the SIGMA Station Controller (Figure 4) orchestrates the operation of the calibration loop and the Z and C* tests as well as controlling station pressures and flow rates. The Meter Data Terminals (microcomputers) accept data in digital form from several sources to compute and display base volume and flow rate in addition to other information. The station's Master Communications Computer facilitates local or remote control of station set pressure, flow rate, alarm values, and test cycles; it also displays, records and prints any history (for instance, P, t, flow rate, Z and C* history).

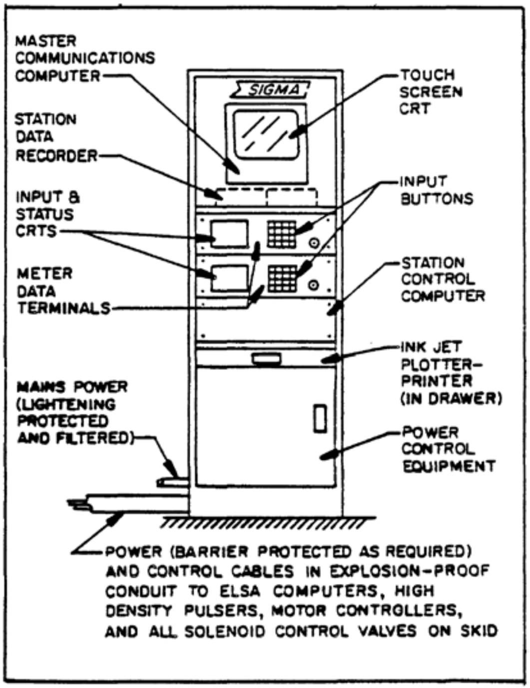

Fig. 4 — SIGMA Station Controller

JUSTIFYING AUTOMATED METER READING TECHNOLOGY IN THE GAS INDUSTRY

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ABSTRACT

Implementing new technologies into mature industries can take on fairly repeatable patterns. First, a market need must exist which is not now being met with conventional technologies. The need must be recognized by someone with sufficient resources and long-term commitment to make the opportunity a reality.

EnScan, Inc. the energy management subsidiary of Diversified Energies, Inc., recently introduced a new technology into the gas distribution industry. The EnScan AccuRead™ System is an automated method of utility meter reading based upon mobile radio technology. The system consists of a remote transceiver which can be field retrofitted on common gas meters and a mobile data acquisition unit. Through use of the system utilities can achieve virtual 100% accessability to meters— whether they are inside or out. Quality of service to the utility customer is enhanced as estimated billing can be substantially reduced. Meter reading productivity can be enhanced by 30 to 50 fold. Productivity of downstream operations are also improved. Unlike many other automated meter reading alternatives, the AccuRead system does not require a third party to operate the system. Finally, the EnScan approach offers numerous financial benefits to the utility including the ability to turn a portion of operating cost savings into allowable earnings without negative impact to the utility customer.

The EnScan™ AccuRead™ system is a revolutionary but practical approach to solving utility problems with the meter reading and customer billing process. The system delivers new standards of performance within the industry which were previously thought unachievable.

JUSTIFYING AUTOMATED METER READING TECHNOLOGY IN THE GAS INDUSTRY

IMPLEMENTING NEW TECHNOLOGY

Implementing new technologies into mature industries tends to take on a fairly predictable and repeatable pattern. Several mature industry segment examples can be sited such as in computer integrated manufacturing (CIM), direct digital control (DDC) of the process related industries or justifying automated meter reading (AMR) technology in the gas utility industry.

Typically a situation will develop within the industry where conventional cost saving and productivity improvement practices have all been exhausted. The existing suppliers to the industry facing maturing product life cycles focus on product cost saving programs and low risk product line extensions. A classic example comes to mind from the process control industry where Taylor, Honeywell and Foxboro owned the differential pressure flow transmitter market in the early 1970's and were content to continue investing in pneumatic technology. The industry asked for improved performance available from digital electronic technologies but the vendors would not move away from their mature product lines until a significantly improved new technology emerged. They were vulnerable. Rosemount, Inc., now a subsidiary of Emerson Electric, looking for a new market for it's aerospace differential pressure flow measurement technology, repackaged their electronic differential pressure transmitter as an industrial product and gained a 60% share in a completely new market to them, displacing the instrumentation giants.

This example points out a second factor in introducing new technologies into mature markets. A clearly defined need must exist which existing suppliers must be unable or unwilling to meet with conventional technologies.

Next, someone must be able to recognize this need and bring the resources to bear to make the market opportunity into a product line or business. Typically this happens as Hearne of A.D. Little points out by an internally funded program within the mature industry infrastructure or when someone applies existing technology developed in another industry segment to the mature industry need.

An inherent resistance to change within the mature industry will usually emerge as the new technology begins commercial application. The mature industry structure inherent resistance to change emerges. As Kaplan points out in Harvard Business Review, the capital costs of the new technology begin to be compared with direct operating cost savings. The conservative nature of the financial community within of the mature industry deems the technology too expensive. Even though the technology may make strategic sense to the industry, incremental and "soft cost" savings cannot be documented and justified. But as Kaplan points out, "although intangible benefits may be difficult to quantify, there is no reason to value them at zero in a capital expenditure analysis. Zero is after all no less arbitrary than any other number. Conservative accountants who assign zero values to many intangible benefits prefer being precisely wrong rather than being vaguely right."

In spite of the apparent marginal economics, commercialization of the new technology will slowly begin as the industry leaders will evaluate performance and study implementation issues.

Eventually, assuming the market need really existed and the product lives up to expectations, those leaders in the industry will recognize the strategic importance of the new technology and will begin implementation. The trick to the product developer is to keep this time as short as possible and to hang on through the red ink.

DEI New Technology Program

When Diversified Energies began looking at growth opportunities in 1982, we didn't have to look very far. As the owner of the 13th largest gas distribution utility and located in a northern climate, we recognized a market need. Find a solution to the gas industry's problems in meter reading and the customer billing process. In short provide a solution to utilities problem of customer billing satisfaction at an investment level that provided good value to the utility and it's customers.

Our first step was to define a set of functional and financial criteria which we felt would provide the optimal solution for the gas industry and it's customers. The next step was to find out if there was existing technology which met our criteria and if not, find out who we might be competing with, if we proceeded with the program. After almost a year of study and analysis of scores of proposed alternatives, we concluded that no existing technology in the gas industry met our criteria, and we were unable to motivate any of the existing suppliers in the gas industry to develop a product for us.

In 1983 we spent most of our time defining the architecture of our ideal system. We chose mobile radio technology because it provided the best balance between all of our functional criteria, did not require a third party, such as a telephone company, to be involved in the billing process and because we felt mobile radio could provide the lowest product life cycle cost of any automated reading technology.

As we defined product life cycle cost, we addressed: capital purchase cost, cost of implementation, annual operating costs, and maintenance costs.

The FCC had recently opened up a new 900 MHz band exclusively for utility communications, and, after careful analysis, we found that this part of the spectrum has excellent propogation characteristics. We could live with the power supply requirements, and recent advances in cellular radio telephone technologies had brought component costs down to an affordable level.

At this point we had identified a market opportunity and had a product concept that appeared to make sense, but we had a long way to go before we had a commercial system. We entered a critical phase in the program. It was time to develop a comprehensive business plan, assure the funding to develop the product and obtain the resources to create a new product and business.

After receiving the green light from DEI in 1984 we formed a separate company, which later became EnScan, to focus on product development and on alternative business entry strategies. Through focused market research within the gas industry the basic system architecture was defined as well as many of the key performance criteria. After completing our strategic business plan we were convinced that we had a significant growth opportunity for DEI in a market we understood. But we had a major obstacle, we had no experience in electronic manufacturing and the necessary technical expertise to support a major program of this type.

Working closely with DEI's business ventures group as well as several management consultant's specializing in new business ventures we concluded we must form some type of strategic alliance to obtain the critical resources we required. After evaluating the alternatives we found what we felt was the perfect fit, right in our back yard.

E.F.Johnson Company (EFJ) is the third largest land mobile radio company in the United States. Established in 1924, EFJ has become widely recognized as a industry leader in 800 MHz radio technology. After being acquired by Western Union in 1982, EFJ gained substantial experience in R.F. data transmission technology while developing cellular telephone systems.

When we first approached EFJ in late 1984 to perform some consulting engineering for us we were immediately impressed with their organization and technology, our product seemed to fit directly with their strategic direction and when Western Union put EFJ up for sale in early 1985, we knew we had a once in a lifetime opportunity. A few months later EFJ was part of the DEI family and we had a state of the art manufacturing facility and world class engineering capability in radio technology.

The EnScan™ Approach

The EnScan AccuRead™ system consists of three major components. A small radio transceiver (ERT™ index) mounted on the meter which encodes gas consumption data, receives radio activation signals and transmits data to a mobile transceiver (DataCommand™ unit) mounted in a medium duty utility vehicle. The DataCommand unit is linked to the utility mainframe computer via the DataCommand link. The ERT index can be retrofitted to most common gas meter sets in minutes and contains a long life lithium battery power supply and a meter tamper detection feature. The DataCommand unit contains all necessary radio equipment, power supplies, a data acquisition computer and an interactive touch sensitive operator display. With high meter density, the system is designed to read up to 15,000 meters per eight hour day.

The AccuRead™ System is authorized for use by the Federal Communications Commission (FCC). The DataCommand™ unit transmitter operates at 952 MHz under the utility power radio service. Each DataCommand Unit is licensed for use by a utility. The ERT™ index is a low power device which is "certified" by the manufacturer to comply with FCC requirements for low power communication devices. No license is required by the utility to operate the ERT index.

EnScan™ Advantages

The EnScan AccuRead system offers significant advantages to utilities and their customers.

Access. One of the most significant problems facing utilities today is access to inside meters. With the EnScan approach meters are virtually 100% accessible for reading inside or out and no matter what weather conditions are encountered. EnScan also offers you the flexibility to read at any time of day.

Quality of Service. There is significant interest within the utility community to improve customer satisfaction with the billing process. The EnScan approach significantly reduces estimated billing and the problems and risks associated with manual reading practices. This is accomplished without disrupting the customer or his lifestyle thereby enhancing the quality of service to the utility customer.

Productivity. The AccuRead system is designed to read up to 15,000 meters per eight hour day. This represents a 30 to 50 fold increase in direct labor productivity. EnScan also delivers significant productivity improvements on downstream operations such as customer service which will enjoy the benefits of improved reading performance.

No Third Party Requirement. Unlike many proposed automatic meter reading alternatives, EnScan does not require third party intervention in the customer billing process. This utility operates and controls its own data communication system. This adds to system flexibility as well as significant ongoing operating cost savings.

Financial Benefits. Utilities are now facing several financial issues which can affect allowable earnings and ultimate value to its shareholders. The timing is right for the utility industry to invest in prudent capital expenditure programs which can deliver better value to its customers. Investing in the AccuRead system can allow a utility, through savings of operating costs, to increase allowable earnings. Properly implemented this can be done without a negative economic impact to the utility customer. AccuRead can in effect turn operating cost savings into allowable earnings, thereby hedging the affect of decreased allowable rates or return.

Costs of Ownership. A critical factor in selecting a product or system is assuring that the product will not be obsoleted by a significantly new technology. The EnScan™ system provides revolutionary benefits through the use of state of the art communication and instrumentation technologies. The AccuRead system will be on the forefront of technology for decades to come. In fact, we believe that when product costs of ownership are compared, the EnScan will deliver the least cost of ownership of any automated reading technology.

Justifying Automated Reading Technology

A decision by a utility to implement automated reading technology will be one of the most important issues to be addressed in the next few years. The right system must make strategic and economic sense to the utility and provide good value to the utility and its customers. Utility regulators as well as the financial community must also see it in a positive light.

Automated meter reading will allow the utility industry to achieve levels of performance in billing effectiveness never before possible with conventional methods. Quality of service to the utility customer will be enhanced and customer satisfaction with the utility's service will be impacted very positively. Capital expenditures will certainly be increased, but properly managed, these expenditures can be offset with direct as well as indirect cost savings.

Automated meter reading technologies will have a significant impact on how utilities run their business. The Federal Energy Regulatory Commission (FERC) accounting process currently captures cost information on the utility billing process into five accounts. However, an individual utility may have a majority of its departments/cost centers which are impacted by meter reading and the billing process. The challenge for utility managers is to improve their operations by carefully analyzing each cost center for the benefits that will accrue under an automated meter reading technology. These benefits will be both direct and indirect cash flow savings and revenue enhancements.

One thing we have learned from experience is that innovation is a necessary but sometimes messy process. Much of the unpredictability of innovation can be mitigated through careful planning and proper implementation programs. We believe that automated reading is a necessary innovation for the utility industry whose time has come. Properly managed these new technologies hold much promise for the industry.

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VOLUME CORRECTORS AND FLOW COMPUTERS

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ABSTRACT

The conversion of measured volumes to base conditions at the meter site has long been the exclusive domain of the mechanical correcting instrument. Until recently, electronics have been slow to penetrate this area of gas measurement, and for good reason. Mechanical correcting instruments must operate in a wide variety of climates, under severe temperature conditions and without any external source of power. These are stringent conditions for any product, especially for a device whose primary characteristic is accuracy. While digital computers and advanced transducer technology have made base volume computation not only feasible but highly accurate, their use has generally been restricted to protected areas and where electrical power is readily available.

The American Meter Company now introduces ELSA, a digital electronic flow computer developed specifically to operate in gas transmission and distribution systems with turbine, rotary and diaphragm meters, Figure 1. Developments in semi-conductor and battery technology have now made it possible to offer digital computer accuracy and reliability in all gas measurement environments.

VOLUME CORRECTORS AND FLOW COMPUTERS

The gas industry is now seeing a new wave of electronic correctors and flow computers; devices that are designed to be totally interchangeable with the vast population of mechanical correctors that have been placed into service since the 1930s. These electronic instruments do the traditional Boyle's and Charles' Law corrections, but have the capability of computing base volumes with greater accuracy. And yet, improved accuracy is only part of the potential benefits offered by these instruments. ELSA has several advantages in addition to better accuracy, including faster calibration, major reductions in maintenance, real-time data communication, complete application flexibility and security or resistance to "Gas Diversion".

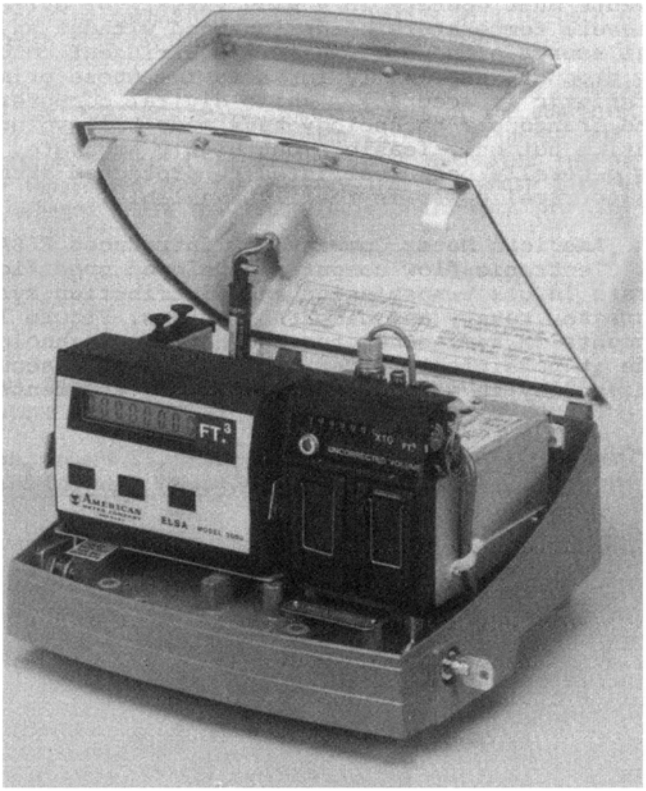

FIGURE 1

Accuracy

The accuracy capability of a mechanical volume corrector under normal ambient temperature conditions is ±1%. ELSA has a calibration accuracy of better than ±½%. Further, the electronic corrector has much better stability at temperature extremes, where mechanical correctors suffer from the effects of material expansion and contraction. While the exact performance of mechanical correctors under severe temperature conditions is difficult to predict, ELSA has a well-defined temperature coefficient; 0.007% per degree F over an ambient temperature range of −40°F to +140°F.

Another area where microprocessor-based correctors excel is in the supercompressibility computation. Mechanical correctors approximate the Z correction by assuming a fixed temperature and applying a Z correction strictly as a function of pressure. ELSA computes supercompressibility as a function of pressure and temperature and programmable values of specific gravity and carbon dioxide/nitrogen content. The difference can mean an improvement in accuracy of ±½% at 100 PSIG line pressure and ±3% at 500 psig.

Calibration

A full calibration of mechanical volume correctors normally takes from 2 to 3 hours in the hands of a skilled technician. The work is usually done in a meter or instrument shop since it involves lengthy calibration runs under stable pressure and temperature conditions.

A major advantage of electronic correctors, and especially a microprocessor based unit like ELSA, is the speed in which it can be calibrated without highly skilled servicemen. ELSA's program allows it to display diagnostic data such as pressure and temperature, making calibration a 10 to 15 minute exercise. This is possible because electronic correctors do not require time consuming calibration runs. And calibration can take place in the field, while the instrument is in service, on a meter that is fully operational. In fact, no corrected volume is lost while ELSA is being calibrated.

Maintenance

Maintenance is an inherent characteristic of any mechanical device with moving parts. Correcting devices are no exception. There are key points to lubricate to minimize wear and to maintain low torque levels.

ELSA's only moving parts are a mechanical counter assembly and the shafts necessary to drive it. No lubrication is ever required. And because there are so few moving parts, the torque level is about 1/4 oz-in, a value that has no measurable effect on (turbine) meter performance.

Data Communication

Correctors, like gas meters, have often been referred to as cash registers. Except that meter readers must travel periodically to collect the information required for billing. The data collected is usually limited to corrected volume unless the correcter is installed with a companion recorder.

Electronic correctors can make many types of measurement data available on a real time basis. ELSA, for example, will transmit all the items on its program menu including the maximum meter rate; maximum and minimum line pressure, flowing and ambient temperature, the current correction factor (PxTxl/Z), uncorrected volume, flow rate in standard units, and battery voltage. It will also transmit any of the seven possible alarm conditions such as low battery voltage or an overrange pressure condition. And the data is current; not more than 32 seconds old.

Application Flexibility

A typical mechanical correcting device is made in a wide variety of models and dedicated to a specific application:

- CW or CCW Rotation
- 5ft, 10ft, 100ft or 1000ft drive
- Specific pressure range
- Calibrated for specific base and atmospheric conditions and gas composition

ELSA was designed with standardization in mind. There is only one basic option; a 150 psi pressure range or a 1500 psi range. It is electronically and mechanically programmable for any set of meter site conditions. The computer can read in English or metric units, perform pressure correction only, temperature correction only or pressure and temperature correction, all with or without supercompressibility correction. It will do gauge or absolute pressure correction and is programmable for base and atmospheric pressures from 11.00 to 15.99 psia, specific gravities from 0.55 to 0.75 and CO2 and N2 contents up to 15%.

One model will handle CW or CCW meter rotation, 5ft drive meters or any multiple of 10ft drive. It can even be set up to read in metric units while operating on a meter with an English unit output.

The flexibility of ELSA means that one model in inventory can take the place of dozens of mechanical models, which not only reduces inventory costs, but also guarantees the right model is there for any application.

Security

Decades ago, when the original correcting devices were first developed, gas theft was not the problem it is today. Security features added later to these existing products consisted mainly of wire seals or tamper resistance screw covers.

ELSA's instrument case and mounting are based on the clam-shell principle. First, the screws that assemble the instrument to the meter are concealed within the mounting plate. The die cast aluminum cover is then held in place with concealed hinge pins anchored in the casting. Finally, the cover is locked with a pair of barrel-type locks. To penetrate the instrument requires that irreparable damage be done to the case. There is even a method of determining if the line pressure to the instrument is reduced to zero.

Summary

In addition to the primary advantages of improved measurement accuracy and reduced maintenance expense, the ELSA electronic flow computer has features and functions that go well beyond the capabilities of current mechanical correcting instruments.

- Complete application flexibility
- Ease of calibration with lower skill levels
- On-site programming of base measurement conditions
- On-site programming of gas composition
- Local display of corrected volume and flow rate
- Absolute pressure correction to 1500 psia
- Gage pressure correction to 1500 psia
- Diagnostic and measurement data display
- Automatic alarm indication
- Pulse output to remote counters
- Broad operating temperature range
- Designed-in system security
- Bi-directional volume counting
- Real time data communication
- Complete application flexibility

SELECTING A GAS SCADA SYSTEM

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ABSTRACT

This paper describes the process of selecting a SCADA (Supervisory Control and Data Acquisition) System for a Gas Distribution Company. Consolidated Edison Company of New York is presently in the process of acquiring such a system. The process of selection described here is based on Con Edison's experience.

Typically these SCADA Systems cost in the range of $400,000 to $5,000,000, take about two years to design and build and are expected to be in operation for about ten years.

Con Edison operates a large Gas Distribution System serving the New York City area. The SCADA System selected will be used to monitor and control this Distribution System. The selection process involved a seven step process with emphasis on technical considerations.

Some of the important technical and general considerations included were:

- System Availability
- System Expansion Capability
- Risk of Obsolescence
- Vendor's Past Experience

A SCADA System is selected to operate for an extended period of time therefore its design should be flexible and the vendor who provides it should be capable of supporting it over its operating life.

SELECTING A GAS SCADA SYSTEM

INTRODUCTION

Typical SCADA Systems for gas distribution companies cost anywhere between $400,000 to $5,000,000 and have a 10 year operating life span. They consist of a single or dual CPUs, a set of disk drives, long term tape storage for archiving information, communications hardware and CRT monitors to monitor and control the system. It takes about two years from the time the specification is written to the actual installation of the system. Therefore with these considerations it is important to design and select a system that will meet the requirements of the gas distribution system over this extended time period.

This paper describes the process that Con Edison employed in the selection of a first generation SCADA System. This System will be used to monitor and control the gas distribution facilities in the New York City area. However before we go on further it is important to describe the gas distribution system for which this system is being selected.

Con Edison’s Gas Distribution System has over a million residential and commercial customers in Manhattan, the Bronx, parts of Queens, and Westchester County. In addition Con Edison also burns natural gas in its electric and steam generating stations. Total annual gas usage by all classes of customers is about 14Ø Million MCP. This natural gas is supplied by four pipeline suppliers—Transcontinental Gas Pipeline Company, Tennessee Gas Pipeline Company, Algonquin Gas Transmission Company and Texas Eastern Transmission Company. Con Edison is also a part of the New York Facilities System, a system of mains installed for gas distribution among Con Edison, Brooklyn Union Gas Company and Long Island Lighting Company. The three companies of the New York Facilities System exchange gas with each other by displacement. Since the gas distribution system is so complex the SCADA System has been designed to initially just monitor and control the Con Edison system. Later as more experience is gained in operating this system, it will be linked to the SCADA Systems of the other two New York Facilities Companies.

PROCESS OF SELECTION

The selection process for the SCADA System involved the following steps:

(a) Preparation of a Functional Requirements Document.
(b) Solicitation of Budgetary Proposals from SCADA vendors.
(c) First round selection of vendors.
(d) Preparation of Detailed Specification.
(e) Solicitation of Final Bid Proposals
(f) Evaluation of Proposals for Technical Compliance
(g) Selection of Final Vendor on evaluated cost basis

The budgetary proposals received from the vendors in the initial phase served a two-fold purpose. First they provided ball park estimates of the cost of the system, and secondly they provided considerable understanding of the available SCADA Systems’ capabilities. This information was helpful in preparing the final specification document and also helped in allocating resources for budget purposes.

The evaluation of the budgetary proposals mainly involved checking vendor references. This involved telephone surveys and field visits to Gas Distribution companies. A few vendors were disqualified based on their past performance or their total non-conformance to the design requirements.

The detailed specification was then prepared by a consultant, Macro Corporation, Horsham, Pennsylvania, which specified CPU Loading, Availability of System, Alarm System Design, Communication Protocol Requirements, Response Rate of CRT Displays, MTBF (Mean Time Between Failures), Application Programs, Detailed Software Design, Testing, Training of Personnel, Maintenance of Equipment, Project Management and Cost Breakdown of each Component of Hardware and Software.

The final proposals from the vendors were received based on the detailed specification document. They were evaluated in two steps. First, on the basis of technical compliance. Where the vendor did not comply to the specification, and his suggested alternative was not acceptable he was asked to conform to the specification at an additional cost. If this was not done then a penalty amount was associated to the non-compliant feature. This penalty amount reflected Con Edison's cost of having that feature being not available or Con edison's cost of making it available from other sources. Next penalties and the cost of selected options were added to the base price of the proposal to come up with a total evaluated cost.

The second step involved selecting the proposal that had the least evaluated cost of the system. This determined the successful vendor of the SCADA System.

SELECTION CRITERIA

The following selection criteria were used in the evaluation of proposals:

I.
TECHNICAL CONSIDERATIONS

(a) System Availability

The SCADA System performs very vital data acquisition and control functions. The gas distribution system pressures have to be monitored for safety and the flow through the supply stations to avoid over running the contract limitations, on a real time basis. Therefore it is important that the system be available at all times. A 99.8 % availability was required . Also the system design should not allow a single failure to result in the loss of any critical function. The configuration should also not allow multiple device failures.

(b) Programming Languages

A requirement for the application programs was that the language used should be of higher level, like FORTRAN. This provides a greater flexibility in modifications later on. However where required to speed up resource allocation, assembly languages could be used.

(c) Graphics

A significant amount of information will be displayed to the Gas Dispatchers in the form of graphs and one line diagrams of regulator stations and gas supply stations. So the resolution of the CRTs and the ease of building graphics should be good.

(d) Forecasting Capability

The Gas Dispatcher's major task each day is to figure out exactly how much gas will be used for the contract day. Forecasting computer models using weather as a criteria are now available that utilize regression techniques and similar day searches. The vendor was required to provide these programs.

(e) Display Build Capability

Designing the display screens on the CRT can be a very tedious task depending on the process employed. A requirement for the vendor was that the system should be very easy to learn and use, since new displays will be built as requirements change.

(f) Spare Parts Availability

Design of hardware should be modular. This allows replacement of complete boards as opposed to individual components. Spare parts for board level trouble shooting should be provided. This allows minimum down time of the system.

(g) Training

Courses for software and hardware maintenance should be provided by the vendor in addition to courses pertaining to the operation of the system. Majority of the courses should be at the gas dispatch center to minimize travel by key operating personnel. Courses should be both class room and hands-on type.

(h) Risk of Obsolescence

With the fast pace of changing computer technology, one of the biggest concerns in the selection process was the risk of having the computer system get obsolete too soon. Often small computer manufacturers do not support products that have been phased out from their production lines. No software upgrades are provided and availability of spare parts becomes a problem. Therefore both the computer manufacturer's and the SCADA vendor's reputation were significant factors in the selection process to avoid obsolescence.

(i) System Expansion Capability

Since the SCADA System is expected to last for about ten years it is important that it should have enough capacity to expand with the changing needs. Some computer systems have limitations on number of additional memory boards that can be installed and the size and number of peripherals including CRTs, disk drives and Input/Output hardware for communicating with remote locations.

(j) Ability to Communicate with RTUs of Different Protocols

One of the critical issues was the SCADA System's ability to not only communicate with existing field RTUs (Remote Terminal Units) and other rather out-dated equipment but also the RTUs and data links that are planned for future installation.

(k) User Friendly Software

The software design should allow retrieval of information by cursor movement using a track ball or light pen, thus minimizing typing. Menus and sub-menus should be used to retrieve desired displays or functions.

II.
GENERAL CONSIDERATIONS

(a) Vendors Project Management

It is important to find out exactly how many people would be working on the project, and their background and qualifications. Knowledge of the organization and qualifications of the people is especially important these days because a lot of garage based software and hardware companies have sprung up making tall claims of their expertise.

(b) Documentation

A requirement for the vendor was to provide documentation of the system as built and not standard brochures that cover several classes of similar equipment. Smaller SCADA vendors tend to do the latter because they lack the manpower and expertise to produce custom designed documents, instruction manuals, maintenance procedures, operating guides etc.

(c) Past Experience

A vendor that has performed similar work on the other projects would be in a much better position to design the next one. The vendor would have already ironed out most of the problems based on his past experience and would have also incorporated some of the enhancements to his earlier versions of the system.

This feature was checked in great detail to avoid designing the system right from scratch and the possibility of having innumerable errors.

A telephone survey was also conducted to check the past experience of the vendors.

(d) Delivery Schedules

Unusually short or unusually long delivery schedules are signs of potential problems. A short schedule could mean that the vendor may not have done his homework and does not fully understand the scope of the project or is merely trying to get selected for the project and then worry about the consequences later. On the other hand a long schedule may indicate that the vendor lacks the expertise in the area and may spend time to learn and train his people during the course of the project. It could also mean inefficient project management.

CONCLUSION

Selection of a SCADA System for a Gas Distribution Company is an involved process that requires a lot of careful planning and foresight. Most important of them all the SCADA System selected should be flexible enough to meet the needs over a period of ten years.

ACKNOWLEDGEMENT

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SCADA SYSTEMS IN GAS DISTRIBUTION FROM THEN, 'TIL NOW, 'TIL TOMORROW: AN EVOLUTION OF METERING

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ABSTRACT

The Brooklyn Union Gas Company, as the name implies was begot out of a union of smaller gas companies. Incorporated in 1895, Brooklyn Union serves the energy needs of 4 million persons who live and work in the Boroughs of Brooklyn, Staten Island and Queens in New York City; a total of 187 square miles. There are currently 1,084,100 active meters and 3,761 miles of mains. Its peak day sendout was 941,773 DTH and has a 0 degree day Design Peak of 997,000 DTH. Additionally, Brooklyn Union maintains facilities for the storage and processing of Liquified Natural Gas (LNG) & the production of Substitute Natural Gas (SNG).

In 1951 Natural Gas delivered by pipeline was introduced to Brooklyn Union's territory. In 1956 Brooklyn Union commissioned its 1st Remote Controlled City Gate Station and since that time Brooklyn Union has built 14 such stations. In 1974 equipment went underground with Mini Gate Stations. Mini-Gates are capable of delivering 2 million standard cubic feet per hour into the distribution network. Brooklyn Union currently maintains 25 gate stations, with one additional station in the planning stage. Additionally, Brooklyn Union maintains metering and telemetry equipment at four non BUG Custody Transfer Stations as well as LNG & SNG Plants.

In the beginning man created the valve & the gauge and when he looked at it he saw that it was good and all the creatures involved with gas dispatching were pleased.

SCADA SYSTEMS IN GAS DISTRIBUTION FROM THEN, 'TIL NOW, 'TIL TOMORROW: AN EVOLUTION OF METERING

From the beginning, Brooklyn Union recognized the need for effective metering & control. Utilizing of the technology available at the time, BUG outfitted its gate stations with a variety of devices. Metering consisted of mercury body differential pressure recorders, circular chart recorders with slidewire transmitters, vacuum tube instrument amplifiers, electromechanical totalizers and correctors. All devices had electromechanical linkage and were cam driven. Communications schemes utilized DC grade lines split to ground, one leg for motor power the other leg for signal data. Diode steering logic allowing 2 control functions out and 2 data signals back using bipolar power supplies. Audio tone telemetry was used for stations with larger amounts of data.

The System Control Center is the nerve center of B.U.G.'s gas distribution network. Control Center Gas Dispatchers monitor and control pressures and flows to ensure that adequate gas supply to meet customer demand is available at all times. Gas Dispatchers also schedule delivery of purchase gas and monitor the usage by gas customers. They can revise the initial delivery schedule as gas use deviates from forecasted values, and prepare logs of hourly and daily operations.

The Gas Dispatchers rely on a variety of devices to assist them in performing their duties. The principal devices are mounted on the System Control Center panelboard: they indicate and record system variables, execute control actions, and display and enunciate alarm conditions. Through necessary but piecemeal expansion over the years, the panelboard has been enlarged as much as possible within the existing System Control Center, leaving no room for future expansion.

The needs of the Control Center have undergone several changes throughout the years. Brooklyn Union found itself with the need to revise its control center operation. Originally installed in 1975 Brooklyn Union's computer driven Data Acquisition & Control System (DACS) was literally being held together with masking tape. Our DACS System was limited in function. The on-line computer system gathered data from Brooklyn Union territory and assisted the Gas Dispatcher in planning the gas day, monitoring supplier deliveries. It prepared logs and reports, performed calculations, recorded alarm conditions, and stored historical data. Although originally proposed, control functions were never installed. Confidence in the system was low.

At numerous locations throughout the Brooklyn Union system, process and status information is measured, locally indicated and recorded, and/or telemetered to the Systems Control Center. As with the Systems Control Center panelboard, there was an extensive variety of types, models, and ages of field instrumentation from several manufacturers. The age of many of these instruments had caused maintenance problems due to the cost and availability of spare parts. Much of the existing instrumentation represented old technology, not directly compatible with currently available equipment.

Control functions had to be performed via discrete push buttons. Additionally the paperwork, reports, sendout forecasting, valve records data, gas setups & contract monitoring were becoming the primary task for the operator. Gate station equipment had not been updated since they were built. Some equipment was obsolete and unrepairable due to lack of replacement parts. Our maintenance group did an admirable job of replacing some transducers and using the removed older equipment to keep other stations on line. We were running a cut & paste system.

In 1981 Brooklyn Union began planning its SCADA System, utilizing the technology available at the time, to build a system which would not only meet current needs but would serve well into the future as a viable gas dispatch tool. Locations where telemetry modernization was proposed included gate stations, interface regulators, district regulators, lowpoints in the high pressure system, and locations relating to LNG, SNG, as well as interruptible customers metering information.

The importance of the Gas Dispatching function along with the current state of the equipment used for measuring, telemetering, displaying, and processing gas distribution data demanded a coordinated approach to the modernization of the System Control Center and its associated equipment. Our objective was to explore all available possibilities and investigate <u>any</u> and <u>all</u> approaches. In many ways imagination and creativity was the guide to the best solution for B.U.G. Many SCADA system houses were heavily involved in electric transmission & distribution systems. Manufacturers who were building gas systems were generally selling unmodified systems with a minimal custom application layer. We looked for a vendor who had experience in both electric & gas distribution networks. Their experience with detailed applications & customization in electric distribution systems along with the ability to speak some “gas” would have to be an acceptable marriage. Although Brooklyn Union’s needs were by no means unique in the industry, we realized that special circuit cards for the Remote Terminal Units (RTU’s) would have to be designed and built. Gas applications such as contract monitoring would have to be written. Firmware would have to be coded and special interfaces needed to be designed.

Parallel & separate to this SCADA effort were internal engineering efforts in communications networks, mapboards, ergonomic console designs, computer room layouts, gate station control piping modernization and facilities planning for control center & emergency evacuation sites.

The Brooklyn Union system will consist of:

23 RTU’s which are slated to grow to 29 by next year of which 13 are major stations & 10 are minors.
12 Tone based minors.
30 Low point PDM transmitter and
30 Industrial telecounters.

As in all centralized communication systems a vulnability exists. For this reason BUG will utilize a sub star communications network. Effectively each major RTU becomes a data collection hub for minors, descrete points (those being generated at the major’s own site) and single remote data points such as low point PDM transmitters and industrial telecounters. Minor RTU’s may also support tone based sub minors as well as low pressure points & counter points. Each RTU depending upon the station configuration is capable of supporting 3 communication links to the Systems Control Center. The first two are dedicated lines with distinct and alternate routing through the territory and the third a dialup link. Each RTU is capable if supporting up to two minor Rtu’s as well as any number of tone based minors. Minors presently do not have dialup capability. By removing most telephone lines from the Control Center we hope to reduce the vulnability to communications failure by distributing risk.

Brooklyn Union designed two Emergency Backup Systems (EBS). They are PDP 11/23C micro computers and contain subsets of the SCADA software. The backup systems provide data acquisition and control only, are portable and operate on dialup lines. One unit will remain in the Control Center and the other offsite at an emergency evacuation center. It is possible to use this system in any location where there is AC power and a phone. In order to keep the EBS current and not have to update 2 independent data bases, a data link is installed between SCADA & Control Center EBS. Periodically the EBS is updated with the latest changes to the data base. A copy is made for the second EBS and kept at the alternate site. The only difference between each EBS is that the unit located in the Control Center can handle dedicated lines as well as dialup and can drive the mapboard in the event of both main computers going down.

All this redundancy has not eased our anxiety about phone line reliability & availability. To further secure the integrity of critical data, stations responsible for custody transfer, therm zone information and other propriatory data, have been equipped with circular buffers which store volume and therm data on a per hour/per run basis. This requires each RTU to perform Flow & Energy calculations. The calculations are done on a co-processor board freeing up the RTU’s CPU for other tasks. This may be in the form of AGA-3 or turbine meter calculations. Depending on location, the AGA-3 calculation will have live inputs for differential & static pressures, temperature, Btu valve and specific gravity. Constants can either be loaded via a terminal in the field or downloaded from the SCADA System. To further secure this data, an emergency power generator will automatically start if there is a commercial power loss. In the event of generator failure, batteries keep the RTU crunching its flow data and billing data buffers secure. At last effort a technician is dispatched to the station to extract the buffer data with his hand held terminal.

The results of the flow calculations will be used for chartless electronic custody transfer billing & customer related therm billing. Additionally the RTU routes the flow result to an analog output card for local station display via a loop powered LCD readout or for odorant pump pacing. All RTU internal clocks are re-synchronized from the SCADA computer every 20 minutes to minimize possible drift which would affect the hourly volume accumulations.

RTUs are modular in the sense that cards plug in to a card cage. The point seems trivial, but several manufacturers have offered stacked boards on stand offs making accessability and maintenance an annoying and time consuming task. We felt that this was a major shortcoming.

All RTUs contain debug firmware which aid the technician in trouble-shooting, calibration, data collection & control testing. The routines are accessed via any standard dumb terminal.

The vendor has provided a custom test frame, enabling the technician to do further on or off line testing of RTU cards in a shop environment.

Certain special RTU cards were custom designed. They are PDM input cards and controlled contact output cards. The PDM card actually converts PDM signals into a digital representation of analog. Special care was taken to normalize a fast or slow chart motors so that washing does not occur. A form of the algorithum is as follows:

$$\text{Value in\%} = \frac{(4P-N)}{3(P+N)} \times 100\% \qquad \text{Where P is on time and N is off time}$$

Other criteria are also checked such as total cycle time (P+N) and Pmin and Pmax. Should predefined limits be violated the result is set to zero.

Each analog & PDM point in the RTU is converted to digital format in a 12 bit A & D converter. Front ending this converter is a solid state flying capacitor multiplexer circuit. This type of circuit is ideal for instrument ground isolation and increased common mode noise rejection. An important factor when considering accuracies. The 12 bit converter can accurately can resolve 4095 bits, better than .025% accuracy. With accuracy in mind BUG selected a smart transmitter which has an accuracy rating of .1% of calibrated span. In order to maintain accuracy of the transmitter the RTU must be at least twice as accurate as the devices connected to it.

At Brooklyn Union, low point PDM transmitters have traditionally been powered via the same dedicated telephone line used for the pressure signal. Using one wire and earth ground for the PDM pressure signal and the other wire and earth ground for power. Control signals are, in several instances, included through the use of diode steering logic. We were using flea power motors with internal oscillators for speed stability in those transmitters. These motors frequently tended to stall in cold winter temperatures or stop completely. The original manufacturer was reluctant to retool to manufacture several pieces. Brooklyn Union decided to contract to an independent electronics firm to build a solid state PDM transmitter that could be powered from the phone line. What resulted was a unit that operated as low as 8 volts at 8 milliamps accurately (12 bit resolution). 50% of our system has already been converted with failures in the past 3 years limited to one.

The Controlled Contact Output (CCO) card replaces the vendors standard control card which was an RTU card based on variable resistors to set relay operate times. The new card allow the gas dispatcher to enter a time value via keyboard and operate the associated point accordingly (software timers). Additionally, software is capable of outputting control action times for automatic operation. At Brooklyn Union we will be using 2 custom algorithms for meter run control. The first being a meter run inlet valve operating sequence. In manual operation an operator would jog open an inlet valve and wait to see if a safe minimum differential pressure is established before fully opening the valve. The algorithum does this sequence automatically. Failure to meet defined criteria or complete the command is signaled to the operator and the algorithum reverses the sequence in an attempt to bring things back to normal. The second algorithum is a pressure control sequence. Flow controlled stations may be converted into pressure control via this routine. Several meter runs are base loaded with one run selected as dominant. Periodically outlet pressure is monitored via software. If the selected outlet setpoint is not satisfied within dead band, the flow controller on the dominant run is jogged a fixed amount of time in order to reach setpoint within dead band. This jogging will occur a software settable number a times. If the setpoint is met within a specified deadband or the jog limit is exceeded, jogging will stop. After a defined interval the process of looking at outlet and jogging will repeat. If after several attempts to satisfy setpoint fail, the operator is notified to bring one of the base loaded runs on or off. Although not presently planned, the algorithms can be linked together and run without manual intervention.

This brings us back to the heart of the SCADA System, the System Control Center. The new SCADA System consists of Dual/DEC Vax computers with automatic failover controlled via a watchdog timer. Included are computer controlled peripheral switches, display generators, 8 color CRTs with trackball cursor positioning, line multiplexer and modems, dual 451 megabyte hard disk drives, two tapedrives and a host of printers & programming terminals. Any device may be configured to the A or B machine manually or via the man machine interface operator's CRT. Should failover occur all devices are switched to the surviving machine automatically. The Control Center will have 2 dual CRT consoles for the gas dispatchers. Two single CRT consoles for the shutdown coordinators and 1 CRT each for the fuel dispatchers and visitors area. The operators will have a variety of devices to prepare reports. Color printer for copies off the CRT's, X−Y plotter for historical and live trending, and line printers for reports and logs. In addition, a dynamic mapboard driven as a peripheral. The mapboard will have an overlay of the major gas delivery lines and gate stations with LED readouts for pressures and flows. A static mapboard showing all high pressure mains and services for use by the shutdown coordinator in plotting the current situation completes the configuration.

All functions will be available on all CRT's and are subsetted and restricted by password level. One application includes gas day setup. Criteria such as temperature, day of week, etc. are entered and the computer will search thru 2 years of historical data and return the most similar day's sendout data. This setup can be segmented and revised mid-day if required. Economic dispatching will be enhanced via computer suggested order priority. Information about 2,500 valves and regulators such as make, model, # of turns, landmark references, visit and maintenance history etc. are included in applications. This data base is linked to graphic displays of pressure areas. By cursor selecting these points, valve information, # of services involved, etc. as well as written shutdown plan scenerios will be available. Hourly and daily logs, fuel dispatchers reports etc. are automatically scheduled to be printed. Load data is prepared for Engineering, Rate and Marketing Department studies. Gas contract monitoring and storage balances will also be aided by the SCADA applications.

We have created an open ended system which will allow for changes & growth as the situation demands. A study has just been completed on the use of radio data transmission, in lieu of dedicated phone lines. Survey results from a path test indicate that strong signals can be acquired at all major gate stations. It is these stations, where radios would be located. Installation and maintenance costs as well as path availability and reliability seem to dramatically outweigh the costs and problems associated with dedicated lines. Each radio link to the gate station would eliminate the dual dedicated lines. The dialup path would remain. Minor gate stations, low points, tone supported stations, etc. would remain on dedicated lines in the Sub-Star. This is due to a lack of property facilities required to have a secure installation (eg. curb side boxes). Two base stations would be built, each with hot standby transmitters/receivers. The communications load is to be split equally between each base station. Additionally each base will be equipped with dialup capability should the radio tie line fail. This feature will allow the system to place 2 calls to receive all stations rather than 13 individual calls. The radio system will operate on the 928–952Mhz channels.

Brooklyn Union, Consolidated Edison & Long Island Lighting form what is called the New York Facilities System. As individuals we buy gas from several suppliers and have it delivered into common main. Gas is metered between territories to determine the percentage taken and bill of each company. Each hour telephone conversations take place in order to confirm changes in gas order and verbally exchange data such as large load swings (gas powered electric generation) and pressure settings. A Sub Committee of the facilities group is currently studying the feasibility of linking the 3 companies SCADA systems together in a shared data network. Our pipeline suppliers would be invited to join in such a data sharing network with the three SCADA systems. It is the desire of each company involved to create a sub network of PC's in a hostless environment in which each SCADA computer uses the PC as a data buffer. The PC's in turn handles the communications and form the actual network. Several vendors are now currently investigating solutions to this proposal.

Brooklyn Union has created a system which will be a viable tool for the foreseeable future. By utilizing the most effective techniques from the past and melding them into an open ended system we feel that our options are left open for new developments in technology.

The key to all successful systems are:

1. Understanding the current needs.
2. Raising the level of understanding through education.
3. Designing the system for the future.
4. Providing the necessary tools to do the job.
5. Dedicating qualified manpower support.

New technology and equipment demands a fresh outlook at past metering, calibration, and training, and hiring practices. Todays test equipment must exceed metering equipment specs and be ruggidized for the field. It must be properly handled and periodically recalibrated. Today's gas costs force us to "split hairs" in measurement accuracy. The technician can no longer just be a screwdriver squeeker. He must now not only have a full knowledge of the system but be capable of understanding fairly sophisticated electronics. It will be your people who are responsible for keeping the system up & running who will make it successful. Nothing else is more important!

Brooklyn Union anticipates moving its corporate headquarters as well as Control Center in the early 1990's. One full floor has been planned for the creation of a massive War Room. The Gas Operations, Distribution, Customer Service and Customer Inquiry Departments will occupy this floor. When a situation arises, movable walls will be retracted to form a huge command center with shared facilities. Some SCADA equipment will be replaced with improved versions. Some old tchnology will be retained. We look at our current SCADA system as being flexible enough to be as if it were designed for the Future Control Center. We've come a long way from the valve and the gauge. So let it be written, so let it be done!

RADIO-TRANSMITTED, MICROCOMPUTER-BASED TELEMETER SYSTEM

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ABSTRACT

In 1983, a project was initiated to replace the 25-year-old SCADA system at Northern Illinois Gas Company. The selection of new telemetering equipment was based on three objectives. It had to be reliable, readily expandable and reduce operating costs.

A microprocessor-based system which uses solid state modules for various control operations was chosen. With this equipment, data is transmitted by radio rather than by the conventional method over telephone lines.

Each of the system's 13 cells has a central microcomputer which monitors the stations within that cell. Sequentially, a master CPU records and relays data from the cell microcomputer to NI-Gas' Gas Control computer.

The system monitors nearly 500 separate data items at 70 stations. In addition, it provides flow control capability at 14 stations and on/off control for two line valves and five odorizers. Ultimate plans include closed loop flow and odorant control.

Future expansion will occur by adding stations to existing cells and creating new cells. Satellite transmission is also a viable option.

RADIO-TRANSMITTED, MICROCOMPUTER-BASED TELEMETER SYSTEM

HISTORY

Northern Illinois Gas (NI-Gas) installed its first SCADA system during the early 1960s. This system, which has always been known as "the telemeter system," utilized remote transmitting units built by Gulton Industries. The units monitored system pressures, flows and temperatures, and relayed information to Gas Control through telegraph-grade telephone lines. Raw data was transmitted by a pulse-duration technique.

In the Gas Control Department information was received by an Elliott computer, which used the raw data to compute pressures, flows and temperatures. The computer would then maintain file records, issue hourly logs and daily summary reports.

NI-Gas also had the ability to use the computer to control flow at certain key stations. A coded signal was entered by the operator. This signal was transmitted through the phone lines to the station, where it was converted to a 3–15 psig signal pressure to activate a positioner. The operator would maintain flow levels by observing the telemetered flow data and activating the positioner to make any desired changes. This was an "open-loop" flow control system because it required external input to change the positioner setting.

The system has worked well for over 25 years. The only significant changes made since its inception were installation of a Hewlett Packard 2100 MX computer system to replace the Elliott unit and inclusion of approximately 15 additional stations during the early 1970s. These stations utilized Teledyne TC-10 units as RTUs because the Gulton unit was no longer available and the TC-10 used a protocol compatible with that of the Gulton unit. This raised the total number of stations being monitored to 70. Flow could be controlled from Gas Control at 14 of these stations.

Planning and Development of the New System

During 1982 NI-Gas completed a study indicating that continued maintenance of the Gulton units would become increasingly more difficult. The units had been obsolete for more than ten years and certain parts were no longer available. Replacement would soon be necessary.

At the same time company officials began to take a greater interest in problems relevant to telephone line data transmission. Line charges were a significant budget item each year and costs were increasing. Division of maintenance responsibility complicated and delayed repairs. Additionally, realignment of responsibilities within the telephone industry further aggravated the situation. System reliability, which had always been excellent, was beginning to deteriorate. These facts prompted an evaluation of systems using alternative transmission methods as well as traditional telephone transmission of data. Following the study, replacement of the telemeter system was proposed.

The concept chosen for design of the new system incorporated a series of "cells," each linked by VHF frequency radio to the Hewlett-Packard computer in the Gas Control office. Each cell contains from two to thirteen stations. A remote transmitting unit at each station is polled by a microcomputer located at a tower near the center of the cell. These are shown in Figure 1. Data is transmitted by the RTU and stored in a data file in the microcomputer. A master microcomputer, located in Gas Control polls the cell towers sequentially. When polled, the microcomputers located at the towers transmit their data files to the master microcomputer, which feeds the data to the Hewlett-Packard.

The cell concept was developed by Amocams, Inc., and NI-Gas engineers and technicians, using Amocams basic systems and hardware. Programming for the system's external operations (the operations of the master and slave micros) was developed by Amocams personnel, with considerable input from NI-Gas programmers and technicians. NI-Gas also adapted programs running on the Hewlett-Packard to accept data from the master microcomputer.

The new system has a number of advantages over the old. Some of these are:

1. Single responsibility—all aspects of the system are under NI-Gas control
2. Faster data transmission—600 bits/second, compared with 12 bits/second for the old system.
3. Fewer weather-related interruptions.

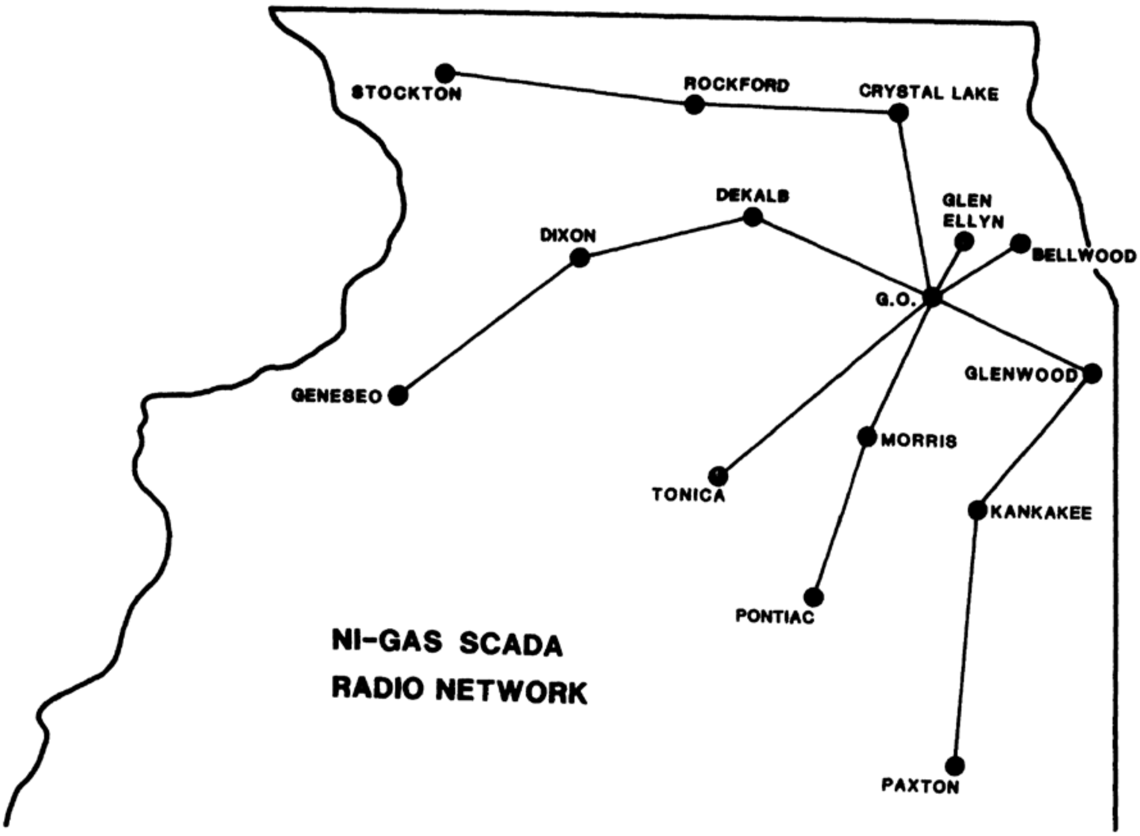

Figure 1

4. Modular equipment—only those functions required at a particular location need be included in that RTU. Additional capabilities can easily be added later if required.
5. System expansion is facilitated by the cell concept. Additional RTUs can be easily added within a cell.

The project received corporate approval in March 1983. Installation would take place over three-years with completion by spring of 1986. Because many of the design concepts were untried, a schedule was developed to prove each one as the project progressed. The following paragraphs highlight the more significant these concepts.

INSTALLATION

Figure 2 shows the geographical location of each of the cell towers and the stations within the cell. Each tower must poll the RTUs within its cell every twenty seconds. The master microcomputer in the Gas Control office polls all 13 cell towers every 60 seconds. The first tests were made to prove communications between Gas Control and certain of the cell tower sites. NI-Gas needed to determine minimum power requirements for radios to be used in the system. Four watts was ultimately chosen as an appropriate power level for almost all RTU-to-tower communications, although two-watt radios are used in some locations. Tower-to-tower communication is done using power levels from four watts at the closer cell towers, to as high as 20 watts at the central Gas Control tower.

After proving the initial communications links, the basic Amocams program was tested. This is the coding which causes each of the cell microcomputers to poll the RTUs, storing the RTU-transmitted data. The coding also causes the master microcomputer to poll each cell tower, to receive data from them, storing it until requested by the Hewlett-Packard.

At this stage, it was necessary to start field installations. Microcomputers were installed at Glen Ellyn and Bellwood towers, along with the necessary radios and antennas. Two or three stations in each cell received the new RTUs, and antennas were mounted on newly-erected towers. These towers are all 30 or 40 feet high, similar to a residential TV tower.

When the field equipment was installed, personnel were able to test and debug the scanning program. NI-Gas was able to continually monitor conditions at a remote station, transmit raw data to another site on request, and hold it there until needed.

Program Testing and Operation

Completing some field installations also enabled personnel to test program modifications to the Hewlett-Packard programming. The original telemeter system consisted of 13 telephone circuits, each with from two to six stations. The Hewlett-Packard computer polled each circuit sequentially, over 90-second intervals. The program modification directed the Hewlett-Packard to treat the Amocams system as a 14th circuit. The program then overlaid telephone-transmitted data for a station with data received by radio for that same station. Once it was determined data received from a station via the new system was accurate, the Hewlett-Packard was programmed to use the data. Both systems were considered operational, with the phone system functioning as a backup. Our first operational use of the system began with data from three stations in September 1984.

The next concept proved the ability to “forward scan,” or communicate with an outlying tower by relaying a message through one or more intermediate towers. Tests transmitted data from Gas Control through Bellwood to Glen Ellyn, and also in reverse. These towers are close enough to Gas Control that a radio in the Gas Control office tuned to the same frequency picked up transmissions from either tower. It was a tremendous aid in debugging this portion of the program because personnel could determine exactly which stage a transmission message was failing.

While debugging the forward scan program and elimination of other smaller bugs was taking place installation of the field units was continuing. By the time the forward scan programming was perfected most of the RTUs in the first tier of cells had been installed and were operational. Installation of the second and third-tier RTUs and tower equipment progressed as rapidly as the hardware was obtained.

Separation From Telephone Lines

By February 1986 all RTUs were installed and transmitting data to Gas Control. Starting in May, NI-Gas began disconnecting from the telephone lines. By July 1 only 26 stations were still connected. As each phone circuit was disconnected, the Hewlett Packard was instructed to disregard that circuit. When all phone lines are disconnected, it will poll only the Amocams microcomputer. All phone lines will be cut by September, when the system will rely totally on radio transmission of data.

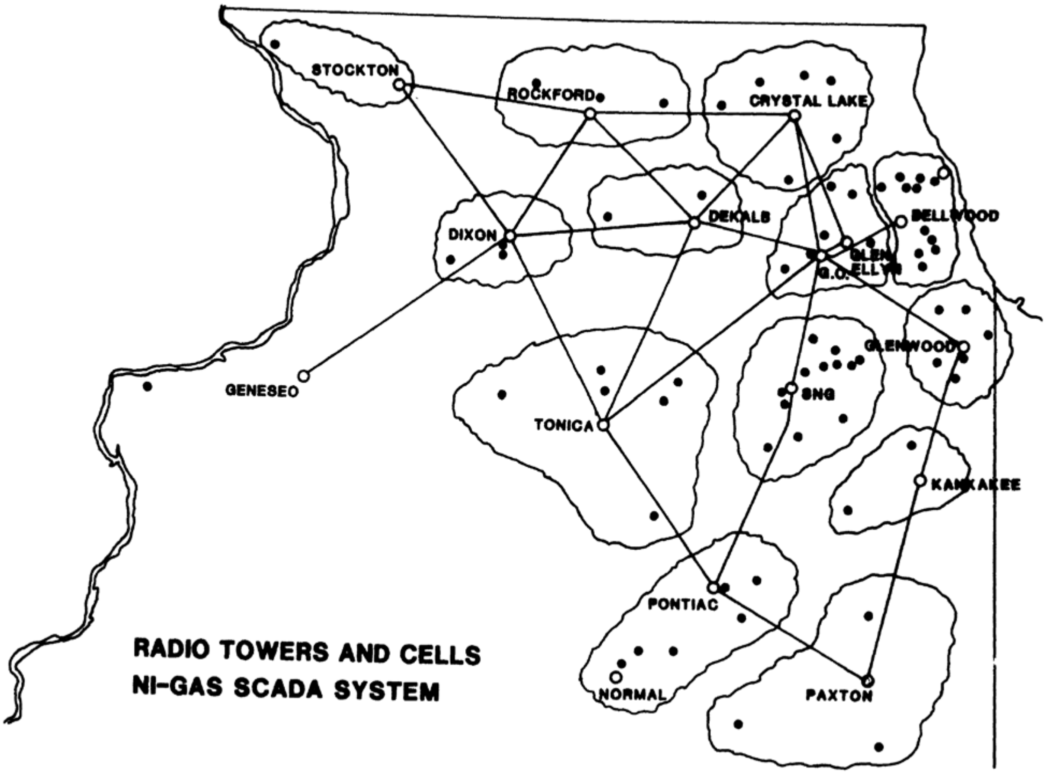

Figure 2

System reliability has always been a prime consideration to NI-Gas. Maintaining a high level of reliability was a major objective in designing the new system. Radio communication faced difficulty both from other operators on the same frequency, and from atmospheric conditions. The new scanning routine was developed to increase the probability that current data would be transmitted to the Hewlett-Packard every time it was requested.

In each cell, the tower microcomputer polls each station approximately every 20 seconds. If an individual station does not answer, the tower will retry once, then go on to the next station. The master microcomputer polls each cell tower every 60 seconds. If an individual tower doesn't respond, the master microcomputer will retry once, then go to the next tower.

With this scheduling, every station has at least two or three opportunities to provide updated information to the tower before the master microcomputer asks for it. Because the Hewlett Packard computer scans approximately every 90 seconds, many towers get two opportunities to provide updated information between scans. This increases the average number of possible data transmissions to four or five from each station between Hewlett-Packard updates.

As added insurance against data loss, the system also provides alternate routing of data transmissions. If the Gas Control microcomputer receives no reply from one of the remote towers, it will retry once, then go on. The next scan it will try to reach the tower through its alternate transmission path. If successful, it will continue to use that path until it misses. It then goes to the next alternate, which may be the original path. This method provides a measure of insurance against data loss should one tower be disabled for a period of time.

FUTURE IMPROVEMENTS AND EXPANSION

At the present time the system is almost 100 percent operational. There are a few bugs requiring additional effort. NI-Gas has experienced intermittent failures when control set points are sent to specific stations. Occasionally, the signal gets lost. When this happens, the computer will try again. Usually one or two retries are all that are necessary. We are currently working to solve this problem.

Frequency drift with some radios in the system has also been a problem. The company is searching for a more reliable radio, perhaps one designed specifically for data transmission.

No significant changes in type or volume of data transmitted was undertaken in the changeover to the new system. The information has not changed. Several enhancements are in the planning stage, some which could not have been done with the old equipment.

For example, NI-Gas is planning to install odorant control capability at several stations, beginning later this year. It will be a “closed loop” system, in which the gas controller can enter a specific odorant rate through the computer and equipment in the field will monitor the rate and continually adjust to keep it constant.

In the future, “closed loop” flow control is also planned. It would be a significant improvement for the gas controller, who now must make frequent set point adjustments to keep the flow constant. In such a system, the controller could assign the system to maintain either constant flow or constant pressure. He or she could even choose a combination of the two, such as a flow program to maintain system pressure within a specified range.

Future system expansion has also been considered. NI-Gas is using the system to transmit data from points as far as 150 miles. Expansion beyond that distance, however, may. cause undesireable delays. Satellite transmission could prevent the problem. Use of satellite transmission would make forward scan through intermediate towers obsolete, because all cells would be equally positioned when measured from the satellite.

NI-Gas decided three years ago to go with this system because we believed it to be most adaptable to our present and future needs. Now, with the installation virtually completed, knowledge and experience has grown significantly The company is confident the best choice was made. The advantages hoped for are already becoming a reality: dependable, accurate hardware, a readily expandable system, and freedom from telephone lines.

FIELD IMPLEMENTATION OF A REMOTE METER READING SYSTEM

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ABSTRACT

Equitable Gas Company has installed, tested and recently completed an extensive evaluation of the remote meter reading system developed and marketed by Metscan, Inc. The improvement in minicomputer technology and related software along with the recent deregulation on the telephone industry enable the remote reading system to become a reality.

As a result of this extensive pilot program, several factors have been identified which should have been considered in the selection of a remote meter reading system. These factors include a cost benefit analysis, system advantages to the customer and the utility, pilot site selection, network overview, and evaluation criteria. All of these factors are discussed in detail within the text of this paper. Equitable Gas Company is presently installing additional devices with full implementation to begin in 1987.

FIELD IMPLEMENTATION OF A REMOTE METER READING SYSTEM

I. COMPANY OVERVIEWS

Equitable Gas Company is a division of Equitable Resources, Inc. with its corporate headquarters located in Pittsburgh, Pa. Equitable provides natural gas service to approximately 258,000 retail customers in the Southwestern Pennsylvania, Northern West Virginia and Eastern Kentucky Areas. The majority of these customers are located in the Pittsburgh Area. Equitable's industrial load for 1985 consisted of 10.0 billion cubic feet of natural gas while commercial sales load represented 15.7 billion cubic feet and residential sales 30.5 billion cubic feet.

The concept of remote meter reading (RMR) has generated a great deal of interest—and enthusiasm among utility companies during the past few years. The reason, simply stated, is that remote metering promises improved efficiency and long-term cost savings for the company while providing better service for its customers. The deregulation of the telephone industry now makes it possible for Federal Communication Commission approved devices, developed and manufactured by non-telephone companies, to be connected to the local telephone network facilities. Moreover, falling prices of minicomputer and networking software make it feasible to establish an economical data collection network. We, as gas utility management, see the need for a firm commitment to reduce costs while providing better service as a cornerstone in the competition for a significant share of the energy market place.

Equitable Gas Company's decision in selecting a remote, meter reading system for a pilot program was based on the following objectives:

II.
REMOTE METER READING SYSTEM EVALUATION OBJECTIVES

1. Improved Meter Reading Efficiency & Effectiveness
   Meter reading effectiveness can be accomplished by the elimination of estimated readings, reading errors, missed readings and by increasing the number of actual meters read. Improved meter reading efficiency results from reading a meter for less cost. Lower cost can be further achieved through the elimination of meter reading cards and key inventories, as well as reducing the number of customer complaints resulting from the meter reading process.
2. IMPROVED BILL PROCESSING EFFICIENCY
   The automation of the meter reading process will greatly reduce the costs associated with a manual, meter reading system. These cost savings can be realized from the field reading to the processing of the actual bill.
3. IMPROVED COLLECTION RATE
   An improved collection rate is perceptibly achievable with the implementation of a personalized billing schedule designed to meet the financial needs of the customer (this is achieved through the tendering of a bill on a selected day).
4. IMMEDIATE REPORTING OF THEFT
   In order to help curb the problem of residential and commercial gas theft, it would be advantageous for the RMR system to be capable of providing immediate notification of meter tampering.
5. PROVIDE OPERATIONAL DATA
   For a RMR system to be truly cost effective, it should provide additional data which can be utilized to enhance monitoring of the gas distribution system while providing more accurate design data to insure more efficient use of available capital dollars.
6. COST EFFECTIVE INSTALLATION & OPERATION
   The installation and operation of the RMR system must be inexpensive to install and operate relative to the information it provides. It should require little manual involvement while handling a data stream in the order of 100,000 discrete pieces of information on a daily basis.
7. RATE STRUCTURE DESIGN
   The RMR system should have the potential to provide information which will enable the utility to design its rate structure relative to peak-system loads.

III. EVALUATION OF AUTOMATED, METER READING SYSTEM

Prior to the establishment of a pilot program at Equitable Gas, various systems were evaluated. These systems included:

A. Hand Held
B. Radio Frequency
C. Telephony Base

IV. METSCAN INC.

The system chosen by Equitable Gas Company for its pilot program is the Metscan system. This system utilizes a computerized network which retrieves meter readings via standard telephone lines. The advantage of the Metscan-System architecture is that the RMR device contains a significant level of on-site intelligence which permits the initiation of the call to the Company's IBM mainframe computer via the local telephone network.

The Metscan system consists of the following architecture:

THE PROBE: A sending device which registers the change in position of the test hand on the index of the meter.

REMOTE METER READING DEVICE (RMD): Part of the system that has built-in intelligence to register the consumption of gas via the cable attached to the probe and also has the capability of storing data into a table which can be accessed at the time the RMD initiates the call to the data-collection computer.

This information is transmitted via standard telephone line at a 300 baud rate to the data collection computer (DCC). The DCC collects data from a multitude of RMD'S in the local calling area network and then transmits this data via standard telephone lines (at 1200 baud rate) to a master data collection center (MDCC) which is linked directly to the mainframe billing computer. The RMD on the customers meter normally would be programmed to call in the data monthly during off-peak phone hours (a five-second call between midnight and 6 a.m.) and capable of accepting a new set of instructions regarding the next reading period if so desired.

V. CUSTOMER ADVANTAGES

The evaluation of the RMR system included an assessment of the advantages to the custmer as well as the utility. The perceived advantages to the customer are as follows:

1. **Elimination of on-site meter reading**
   The fact that the Metscan system is a telephony-based system eliminates the need for the customer to be inconvenienced by the monthly visits of the meter reader, make arrangements for special readings, or provide the utility with a key for access.
2. **Elimination of estimated billing**
   The device is designed to provide an actual monthly reading and thereby eliminates the need for estimated bills.
3. **Customized billing schedule**

This system has the flexibility to schedule the billing date to meet the financial needs of the customer.

4. **Monthly consumption history**
   The RMD device has the capability of providing the customer with their daily consumption via use of the data table for each day of the billing period.
5. **Potential to monitor daily consumption**
   The RMD has the intelligence to provide real time consumption to the customer by utilization of a display device.
6. **Potential off-peak billing rates**
   By utilization of the data table and an appropriately designed rate structure, the customer could realize a cost savings for off-peak gas usage.
7. **Potential for leak detection**
   With the development of a gas detection probe and the technology of utility directional calling by the RMD, the automatic reporting of detected leaks could provide a greater degree of safety for the customer.

VI.
AREAS OF POTENTIAL ADVANTAGES TO UTILITIES ARE AS FOLLOWS:

1. **Reduction in meter reading costs**
   Reductions can be realized by decreased operating costs in customer meter reading, customer accounting, and data processing. Further cost reduction can be achieved through the elimination of these major problems:

   A. Post Card Readings
   B. Key Inventories
   C. Access Problems
   D. Adjusted Bills
   E. Skipped Reads
   F. Lost Reads
   G. Altered or Lost Records

2. **Improve accuracy in meter reading**
   This is achieved by the elimination of human error due to the automation of the system.
3. **Immediate tamper notification**
   The system has the ability to detect tampering and immediately triggers an electronic message to a central monitoring point.
4. **Immediate usage variance detection**
   Through the use of appropriate usage level checks the system can detect non-registering meters as a result of equipment failure or customer tampering.
5. **Improve monitoring of the distribution system**
   By utilizing the information contained in the data table, accurate load analyses can be performed as well as improved meter sizing. With the development of a pressure-sensitive probe and the utility directional calling ability of the RMD, critical pressure points can be inexpensively monitored.
6. **Reading for account shutoffs**

The data table capability of the system will enable a final bill to be rendered without a visit to the site in transient areas.

7. **Potential combination gas, electric and water readings**
   With further development of sensing probes the RMD has the capability of reading multiple metering devices.
8. **Potential increase of cash flow**
   Since the system is a RMR system and does not rely on a scheduled reading route, the utility company can coordinate its billing with customers financial profile in order to optimize its collection rate.
9. **Potential for pressure/temperature compensated billing**
   With further development, the system can provide a means to compensate for pressure/temperature billing of residential meters.
10. **Potential gas leak detection**
   With the development of a gas detection probe, the utility can monitor for gas leakage.

VII.
COST BENEFIT ANALYSIS

A. **Costs**

1. **Cost of Remote Meter Reading Device** $ 65.00 **(RMD)**
   (This cost will decrease with increased production and advanced technology)
2. **Cost of Installation** $ 30.00
   (This cost will also decrease with advanced technology)
3. **Telephone Expenses** $ .05
   (This cost is based on a per-call rate)
4. **Computer Network and Associated** $ 1.00 **Software and Support**
   (These costs will average out to approximately $1.00 per remote meter reading installation. Example: If devices were installed on 100,000 meters, the associated cost would be $100,000)
5. **Computer Operation/Analysis** $ 32,000.00
   (Upon complete installation, one computer operation/analysis would be necessary for a yearly salary of $32,000. This cost may be substantially reduced with the utilization of existing personnel)

B. **Benefits—This section indicates a percent of saving of current costs in each of the areas listed.**

1. **Meter Reading**—A fully-implemented 90.0% system would realize a saving of 90%. This would include trainers, meter readers, clerks and supervisors.
2. **Collection and Meter Investigation—** 30.0% An accurate meter reading system will reduce manpower requirements by 30.0%. The reading of all accounts monthly would eliminate estimated billing.
3. **Customer Accounting**—Reduction in man- 18.0% power due to the elimination of incorrectly processed meter reading.
4. **Customer Relations—**This percentage is 6.5% based on the reduction of the number of calls and pieces of correspondence processed.
5. **Customer Service**—This system would reduce 90.0% the soft shut-offs handled by customer service men.

6. **Theft**—The ability of immediate tamper 50.0% notification supported by the data table consumption history will enable the utility to identify gas theft and self turn-on in a timely fashion.

The aforementioned savings items would further result in a chain-reaction reduction in the following expense items:

1. Transportation
2. Postage
3. Shut-Off Hardware
4. Telephone Changes and Equipment
5. Uniforms
6. Tools

There are many additional intangible advantages associated with a remote meter reading system: reduced insurance costs resulting from the manpower reduction; the availability of an information system for printing scanning and merging meter reads and documents; and a resultant increase in cash flow generated by a one-day decrease in processing meter readings are just a few examples.

In addition there are unique revenue-generating possibilities associated with the areas identified in the section “Advantages To The Utility.”

The cost saving associated with the areas mentioned in this paper represent a 3- to 4-year payback for most utilities. These numbers were derived from statistics compiled by, not only Equitable, but also National Fuel and Philadelphia Gas Works.

VIII.
EQUITABLE’S PILOT PROGRAM

The pilot program began in July of 1985 and originally consisted of approximately 140 installations on both residential and commercial Class A meters in the metropolitan Pittsburgh Area. Equitable targeted a cross section of social and economic groups, as well as the various types of meter manufactures and meter installations commonly found in the field. Test sites included inside and outside meters meters set remotely from the structure (100 feet or more), and multi-meter installations.

Prior to installation of the program, Equitable contacted approximately 140 consumers; 97 percent of them were in favor of the concept, and asked to be included in the pilot program.

Two experimental installation teams, consisting of one Equitable and one Metscan employee each, were assigned to complete the installation.

The networking equipment installed by Equitable for the pilot program consists of a digital equipment corporation PDP-11/23 (DCC) which calls a DEC PDP-11/73 (MDCC) utilizing a RSX 11+ operating system which accumulates and transmits the data on a daily basis to Equitable IBM 4381 mainframe running a DOS/VSE operating system. The data is transferred between the DEC and IBM computers as a remote, job entry (RJE) workstation.

Presently the program is being expanded to an additional 1,750 sites. This phase of the program is being installed by outside contractors and will be completed by late August.

IX.
EVALUATION OF PILOT PROGRAM

A rigorous evaluation of the program results has been conducted throughout all phases of the pilot program. The criteria analyzed in this evaluation are:

A. Accurate and Timely Readings
B. Accurate Data Transfer
C. Tamper Detection
D. Detection of Missed Readings
E. Installation Time of RMD
F. Operation Under Inclement Weather
G. Ability to Install on Telephone Network
H. Ability to Handle Large Volumes of Data
I. Ability to Coordinate Meter Readings to Billing Record

X.
SUMMARY

Equitable Gas has concluded that the implementation of a remote meter reading system is economically and operationally desirable. Experience gained through the additional installation of 1,750 units should further enhance the evolution of a full-implementation program beginning in 1987. Equitable currently perceives this to be a 10-year effort designed to mesh with existing maintenance programs and coordinated with manpower reductions through appropriate attritional reviews.

SYSTEM EVOLUTION IN THE MATURE SCADA ENVIRONMENT

Donald K.Diel

Gas Management Systems, Director

Niagara Mohawk Power Corporation

ABSTRACT

This paper addresses Niagara Mohawk's progress in replacing its-original SCADA system with a second generation system, Although the original system met expectations, demands for more complete information, combined with the need to do "what if" models, led to the decision to replace the system.

SYSTEM EVOLUTION IN THE MATURE SCADA ENVIRONMENT

INTRODUCTION

Niagara Mohawk is a combination gas and electric utility ranked as one of the most prominent investor-owned utilities in the United States. Our electric system extends from Lake Erie to New England's borders, to Canada and Pennsylvania, and meets the diversified needs of nearly 1.4 million customers. Our natural gas system serves 433,000 customers in Central, Eastern, and Northern New York, nearly all within our electric territory. The gas franchise area covers 4,500 square miles with approximately 6,100 miles of pipeline and 402 regulating stations. Exhibit 1 represents the mix of residential, commercial, and industrial customers serviced by the system, including sales in thousands of dekatherms.

Along with many other natural gas utilities, Niagara Mohawk recognized in the late 1970's and early 1980 that accurate, predictive techniques for forecasting natural gas load growth may not, in themselves, be sufficient to ensure optimum in-service dates for new and revised supply and distribution facilities, due to the many uncertainties in external pressures coupled with long lead times for new gas energy facilities. In the pre-oil-embargo era, utility forecasting dealt primarily with peak gas consumption projections, which were based on relatively simple trending techniques. The post-embargo era has significantly increased the complexity of planning techniques and variables including: fuel supply uncertainties complicated by uncertain national policy; new pipeline system profiles due to shifts in energy demand and conservation; new end-use technologies or mandatory rate structure changes; and delays in construction due to external constraints. In order to supplement forecasting techniques, a gas load management program was initiated during 1981 to develop energy technologies that would provide Niagara Mohawk with the flexibility to respond to unforeseen changes.

The system was developed for three purposes: (1) to control peak day demand costs, (2) maintain system integrity, (3) and to minimize the embedded cost of capital expenditures for the expansion of Niagara Mohawk's pipeline system. Additionally, Exhibit 2 identifies other areas of consideration that must be included in the premises of any gas energy management system. Until February, 1986, the Company was a full-requirements customer of the Consolidated Gas Transmission Corporation and was billed on a three-part rate structure: peak daily demand, winter requirements, and commodity. For demand billing, Consolidated would bill for 95 percent of the maximum daily demand that occurred in the last twelve months ending with its current bill or on a contract minimum demand. Daily quantities taken in excess of the maximum daily demand created a new billing demand for our Corporation. At the current rate, each dekatherm taken above this value would cost the Company approximately $50 annually.

Niagara Mohawk's present gas load management system utilizes large dual-fuel customers to minimize its peak day purchases from its supplier. Daily purchases are

EXHIBIT 1

1985

GAS SALES

(THOUSANDS OF DEKATHERMS)

RESIDENTIAL	55,180	
COMMERCIAL	27,590	
INDUSTRIAL	27,600	
OTHER GAS SYSTEMS	3,448	
	113,818	TOTAL

EXHIBIT 2

PREMISES
GAS ENERGY MANAGEMENT SYSTEM

* ACCURATE, PREDICTIVE TECHNIQUES WILL NOT, IN THEMSELVES, BE SUFFICIENT TO OPTIMIZE EXPANSION OF OPERATIONS AND DISTRIBUTION FACILITIES TO MEET ADDITIONAL LOAD GROWTH,
* THERE WILL BE A CONTINUED AND IMPORTANT NEED TO REDUCE DEPENDENCE ON CRITICAL PETROLEUM FUELS,
* THE PUBLIC CONSUMER AND INDUSTRY WILL BECOME MORE RELIANT ON NATURAL GAS,

* THERE WILL BE INCREASED REQUIREMENTS TO MINIMIZE THE PEAK DAY DEMAND,

monitored during potential peak periods; and at the same time, weather forecast data is used to predict the Company's daily purchases. When it appears as if the maximum peak day demand may be exceeded, customers with dual-fuel capabilities of 100,000 Dt or more annually may be temporarily interrupted to reduce the Company's daily purchase.

Niagara Mohawk's present Gas Load Management system actually is a combination of two systems which were developed as monitoring and control needs became apparent. Our computer data acquisition system is designed to collect gas flow data through various intelligent remote terminal units (RTU). All RTU's are intended for unattended operation in indoor or limited outdoor environments. The basic function is to acquire and store profile data related to gas consumption. The units require a source of 60 Hz, AC power, and the memories are battery supported such that power failures do not affect data retention. The computer-driven central station is able to gain access to the data over the switched telephone network. Commands and data transfers are checked for accuracy on both ends of the communications link. Errors are eliminated through retransmission. Data transmission rate is 300 baud asynchronous, full duplex.

The first system installed was provided by Automatic Terminal Information Systems (ATIS), allowing continuous and automatic scan of RTU's at 17 delivery points throughout Niagara Mohawk's natural gas pipeline system.

The second system, which monitors customer activity, was developed and provided by Process Systems Incorporated and will be described in a later segment of this document. Exhibits 3 and 4 describe the configuration of these two systems as used at Niagara Mohawk.

The central terminal unit (CTU) gathers data from each of the RTU's which is stored and updated in the memory of the CTU. This system handles several operations. The CTU is constantly providing feedback to the operator, concerning the operating status of the RTU's, the printers, the disk drives, communicating as to specific software situations, and displaying the time and date. With the gas flow data gathered, several time-initiated reports (hourly, daily, and monthly) are automatically generated on the report printer. System alarms are automatically generated on the alarm printer. There are also numerous reports and other important information which are operator initiated.

Exhibit 5 is an example of the monthly gas sendout report generated upon operator request, listing each gate station RTU and its associated sendout in MCF and DTK (dekatherms) for each meter run. On the lower portion of this report are the total sendouts by geographic divisions and System total. Our pipeline system is physically separated into two separate geographic systems referred to as the Eastern Division and Central Division. An hourly sendout report is also generated upon operator request and

EXHIBIT 3

EXHIBIT 4

EXHIBIT 5

DAILY GAS SENDOUT REPORT FOR CUSTOMER ACCOUNTING

84/142 05/21/84 08.00

Gate Station Name	Gate No.	MCF Sendout	Dekatherm Sendout	Therm Factor
Skaneateles	01	664	681	1.026
Therm City	02	56,927	58,347	1.025
Tully	03	106	108	1.025
Cazenovia	04	2,089	2,142	1.025
Scribners Cor. —Oneida	05	27,211	28,038	1.030
Higby Road —Utica	06	10,696	11,043	1.032
Herkimer	07	3,861	3,976	1.030
Marshville—Canajoharile	08	1,736	1,785	1.028
Shellstone—Amsterdam	09	7,710	7,939	1,030
Putanam Rd. —W. Sch	10	13,829	14,222	1.028
Burdeck St. —Sch	11	18,386	18,930	1.030
Wolf Rd. —Alb.	12	6,231	6,392	1.026
Normanskill—S. Alb.	13	58,960	60,640	1.028
Troy	14	7,409	7,614	1.028
E.Greenbush	15	7,329	7,571	1.033
Brookview	16	1,079	1,109	1.028
Total		224,223	230,537	

GAS SUPPLY DEPT:

Checked By____________ Approved By ____________

CONTROLS & REPORTS DEPT:

Checked By____________ Approved By ____________

is referenced later in the document when load forecasting is discussed.

The second system developed at Niagara Mohawk as a result of rate filings by our Corporation specifying a totally interruptible rate for dual-fuel customers. Customers with dual-fuel capability and an annual consumption of 250,000 dekatherms or more are required to participate. Curtailments, when necessary, are made by customer category beginning with totally interruptible customers, proceeding to those industrial and commercial customers with dual-fuel capability to the extent of that capability, and so on as necessary. This system monitors sixty-seven remote metering sites including three sites where Niagara Mohawk uses natural gas to fuel boilers and jet turbines to generate electricity. It was necessary for our Corporation to know how much gas load could be shed at a particular time as well as the quantity of natural gas being used for electric generation.

As a result of these needs, Process Systems, Inc., was selected as a vendor to provide us with their Sentry 7000 remote metering system.

The central station is a micro-computer-based system for acquiring, storing, viewing, reporting, and translating pulse data.

The system consists of a central processing unit (CPU), a CRT terminal, two-way auto dial modem, line printer, and table console. The CPU has a 5 Mbyte Winchester drive disk, 800 Kbyte floppy disk, along with multitasking operation. The CPU (Sentry 7000) is designed to serve as the central station for the Sentry 100 solid-state recorder which is located at the customer metering site. Functionally the system provides the following:

1) customer masterfile maintenance and display
2) autodial file maintenance and viewing
3) data capture, viewing, and translation
4) demand and statistical reporting
5) spooling of translated data, and
6) central system tailoring

Exhibit 6 is an example of a printed report which can be generated by the PSI system summarizing the hourly consumption for a given day, and providing the daily total for each customer. This information can also be provided for fifteen-minute intervals if requested by the operator.

Forecasting obviously is an important function to any energy management system. In addition to the ATIS system, which monitors our delivery points of gas into the system,

EXHIBIT 6

MONTHLY REPORT

05/01/84 08:00

		TUBE 1		TUBE 2		TUBE 3	
	RTU	MCF	DTH	MCF	DTH	MCF	DTH
1A	Therm C35	938,788	965,317	382,047	392,178	1	2
1B	Therm C21	741,280	761,411	27,389	28,077	0	0
1C	Therm C31	356,589	365,998	180,494	185,582	2,998	3,075
2	Tully	3,161	3,223	3,145	3,206		
3	Cazenovia	71,022	72,903	6,484	6,642		
4	Skaneateles	35,425	36,408	13	14		
5	Scribners	699,217	719,961	746,076	767,670	10,002	10,297
6	Highby Rd.	408,093	419,906	213,890	219,881	1,947	2,002
7	Herkimer	168,134	173,090	14,177	14,582		
8	Marshville	47,914	49,245	33,820	34,750		

MONTHLY REPORT

05/01/84 08:00

		TUBE 1		TUBE 2		TUBE 3	
	RTU	MCF	DTH	MCF	DTH	MCF	DTH
9	Shellstone	149,366	153,796	235,174	241,785	2,544	2,599
10	Putnam Rd.	205,989	211,950	201,147	206,893	150,674	154,306
11	Burdeck St.	302,789	311,910	430,789	443,841	290,063	298,702
12	Wolf Road	213,658	220,075	205,665	211,679	12,719	13,146
13	Normanskill	808,028	828,777	1,614,398			
14	Hudson	46,435	47,824	12,140	12,492		
15	E. Greenbush	0	0	0	0	0	0
16	Troy	114,606	117,992	165,182	169,960	242,808	249,787
				MCF		DTH	
CENTRAL DIVISION TOTAL				5,010,372		5,151,425	
EASTERN DIVISION TOTAL				5,525,009		5,667,076	
SYSTEM TOTAL				10,535,381		10,828,501	

and the PSI system, which monitors gas used for electric generation and gas consumption of our large customers, Niagara Mohawk maintains a forecasting system written in APL. This program runs on an in-house IBM 3088. As a backup, the same APL programs are installed on IP Sharpe APL Service in Toronto. The APL forecasting system is stand alone and does not interfere with either the ATIS or PSI systems.

Less than five years after implementing these two systems, Niagara Mohawk was faced with a dilemma. The Corporation had placed two microprocessor-based systems into operation as reactionary moves to counter the effects of peak day demand charges, threats to system integrity, high cost of capital expenditures, and rate considerations. Both systems were limited as to capacity, flexibility of software, and the hardware was becoming expensive to maintain. In fact, due to the limited availability of replacement parts, the hardware was subject to failures for which there was no solution.

Given that a need or potential need for a replacement control system had been established, Niagara Mohawk had to proceed to justify, define, specify, and implement the required system in a cost-effective manner. Through this process our Corporation had to also determine whether its system would include data acquisition only, supervisory control with data acquisition (SCADA), or advanced application systems. These systems are listed in Exhibit 7. Independent of which system was selected, the steps shown in Exhibit 8 must be followed in one form or another.

Internal project approval was, of course, the first step in acquiring a replacement system, and the items shown in Exhibit 9 had to be accomplished. The most important item of this group is development of the study team, The composition of a typical study team is shown by Exhibit 10. At least one person associated with the maintenance and programming of the existing (if any) control system should be included in order to utilize their direct experience. Commitments should be obtained from the source departments of the study team personnel for the time required for study team meetings and other support activities. This commitment during the internal project approval stage is generally 10 percent on the average for the study team members, with the exception of the study team manager who will be required at least 50 percent.

In order to meet its needs, a key goal was established by Niagara Mohawk during internal project approval:

> Cost reduction through improved gas management, improved utilization of existing distribution systems, and theft detection.

The following objectives were developed for the Niagara Mohawk Gas Energy System:

EXHIBIT 7

CONTROL SYSTEMS

* DATA ACQUISITION

  – DATA ACQUISITION FROM MULTIPLE LOCATIONS
  – CRT-ORIENTED MAN-MACHINE INTERFACE
  – LIMITED LOGGING

* SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA)

  – ALL DATA ACQUISITION FUNCTIONS
  – SUPERVISORY CONTROL TO MULTIPLE LOCATIONS
  – COLOR GRAPHIC MAN-MACHINE INTERFACE

* ADVANCED APPLICATIONS

  – GAS SYSTEM MEASUREMENTS (ORIFICE FLOW, TURBINE METER FLOW, FLOW COMPUTERS, THERM CONVERSION)
  – LINE PACK, PACK OR DRAFT
  – PEAK DETERMINATION
  – GAS PLANT MONITORING
  – UNDERGROUND STORAGE FIELD MONITORING
  – GAS ACCOUNTING/CONTRACT MONITORING
  – WEATHER DATA ACCOUNTING
  – GAS DEMAND FORECASTING
  – HISTORY DATA PROCESSING
  – FLOW/PRESSURE SETPOINT CONTROL
  – CUSTOMER METERING
  – PIPELINE SIMULATION (REALTIME AND PREDICTIVE MODELING)
  – CONTINGENCY ANALYSIS
  – COMPRESSOR AUTOMATION
  – LEAK DETECTION

EXHIBIT 8

REQUIRED STEPS FOR
CONTROL SYSTEM PROJECTS

1. INTERNAL PROJECT APPROVAL
2. FEASIBILITY STUDY
3. SPECIFICATION PREPARATION
4. BIDDER'S LIST SELECTION
5. BID EVALUATION
6. WORK STATEMENT PREPARATION/CONTRACT NEGOTIATION
7. SYSTEM INTEGRATION, TEST, AND INSTALLATION

EXHIBIT 9

INTERNAL PROJECT APPROVAL

1. FORM A PROJECT STUDY TEAM
2. DEFINE GOALS AND CONSTRAINTS
3. DEVELOP PLAN FOR PERFORMING FEASIBILITY STUDY
4. OBTAIN INTERNAL STAFF AND/OR CONSULTANT
5. OBTAIN MANAGEMENT APPROVAL TO PROCEED

EXHIBIT 10

TYPICAL STUDY TEAM (DEPARTMENTS/UNITS REPRESENTED)
GAS OPERATIONS

– DISPATCHING
– STORAGE OPERATIONS
– GAS PLANTS

ENGINEERING

– TECHNICAL SUPPORT/GAS SYSTEM ANALYSTS
– PLANNING/DESIGN/R & D
– CONTRACTS ADMINISTRATION
– GENERAL FACILITIES MANAGEMENT
– COMMUNICATION ENGINEERING
– PIPELINE ENGINEERING
– COMPRESSOR ENGINEERING

ENERGY CONSERVATION AND UTILIZATION DEPARTMENT
CUSTOMER SERVICES DEPARTMENT

– CUSTOMER ORDER DIVISION
– BILLING DIVISION

DATA PROCESSING DEPARTMENT

– COMPUTER UTILIZATION
– PROGRAMMING RESOURCES

Develop load shedding technology to reduce demand.

Reduce gas delivery system capacity requirements by coordinated monitoring and control of system configuration, load occurrences, and alternative supply.

Control delivery and manage demand in a manner to defer capital and operating costs.

Respond rapidly to emergencies and supply scenarios.

Reduce theft of service to a minimum.

The key research subprograms selected to meet these objectives are:

Pipeline System Monitoring and Control

Customer Supply Management

Theft detection

Following management approval to proceed, the feasibility study can immediately begin. The principal objective of the feasibility study is to develop a control system concept, with budgetory costs and schedule, to obtain management approval to proceed with the overall project. It is during this study that the recommended system functions implemented in modern computer-based gas control systems can be grouped into four categories:

Basic SCADA system functions

SCADA system enhancement functions

SCADA/GAS system functions

Gas Energy Management system functions

In determining the recommended system functions, Niagara Mohawk considered these categories because the categories generally correspond to levels of system size, complexity, and cost. The basic SCADA system functions can be implemented using relatively small computers and a minimum of effort and cost. In contrast, the Gas Energy Management system functions require multiple and large-scale computers, demand substantial efforts by both the vendor and the purchaser, and can result in multimilliondollar costs. As a general rule, the choice of one or more of the higher level functions establishes the system at that function's level.

The system level defined by Niagara Mohawk's recommended functions is that of a SCADA/GAS system. This does not imply, however, that all of the functions comprising that and less complex levels were recommended. Those functions which provided clear and immediate benefits to Niagara Mohawk were recommended. Several functions were recommended because of tangible future benefits or the realization that the function may be required in the future by Niagara Mohawk regional gas operations or the regulatory agencies. Numerous candidate functions were considered and rejected. All of the Gas Energy Management system functions were rejected.

The basic SCADA system functions are those which all vendors can furnish and which most vendors have productized to the extent that a minimum of effort is needed to produce and document a system. The basic functions can typically be implemented on microprocessor or small-scale, 16-bit computers and a minimum amount of mass memory. The recommended basic SCADA system functions are as follows:

Supervisory Control of Gas System Devices

Acquisition of Instantaneous Gas System Data

Acquisition of Integrated Gas System Data

Local Alarm and Data Monitoring

Non-Telemetered Points

Gas System Monitoring and Alarming

Alarm and Event Logging

Periodic Data Logging

Communication Channel Integrity Monitoring

System Internal Integrity Monitoring and Support

Color CRT Console Support

The SCADA system enhancement functions are those which most vendors can implement with moderate hardware and software impact at a moderate increase in cost. Most vendors will use small-scale, 16-bit computers. Additional computer memory and mass storage will be required. Many of the vendors have implemented many of these functions on a system-by-system basis, but only the major vendors will have any of the functions productized, and no vendor will have all of the functions productized. The recommended SCADA system enhancement functions are as follows:

Rate-of-Change Processing

Analog Value Averaging

Generalized Data Calculator

Flow Totals

Historical Data Processing and Storage

Communication Channel Quality Accounting

Trend Display Processing

Dispatcher and Technician Training Support

Mapboard Support

The SCADA/GAS System functions are those which would be added to a basic or enhanced SCADA system to adapt it to gas system operation. Vendors will typically implement these systems using more powerful 16-bit computers or smallscale 32-bit computers. The engineering effort involved in configuring and programming these systems to match a utility's unique operating and record-keeping requirements is significant. The increase in cost over a basic or enhanced SCADA system can be significant as the number of gas functions increases. The recommended gas system functions are as follows:

Weather Data Input

Sendout Forecasting

Peak Determination

Pressure/Flow Closed Loop Setpoint Control

Flow Calculations from Pulse Data

Odorization Monitoring

Corporate Computer Data Link

Contract Purchase Monitoring

Gas Load Management/Curtailment

Therm Conversion

Gas Energy Management system functions primarily differ from SCADA and SCADA/GAS systems in their computational and memory requirements. Whereas a SCADA/GAS system might have dual 16 or 32-bit computers with dual 50-megabyte disk memories, a Gas Energy Management system might have multiple 32-bit computers and several 300-megabyte disk memories.

A total of five distinct Gas Energy Management system functions were considered by Niagara Mohawk and were judged as not offering sufficient benefits to justify their costs.

The rejected functions are categorized by system level as follows:

Basic SCADA system functions

- No basic SCADA function was rejected

SCADA system enhancement functions

- Sequence of Events Monitoring
- Combinatorial Sensing
- Dynamic mapboard support

SCADA/GAS system functions

- Weather Service Computer Data Link
- Line Pack, Pack or Draft
- Orifice Flow Calculations

Gas Energy Management system functions

- Leak Detection
- Transient Modeling
- Computerized Mapping/Property Records
- Emergency Zone Accounting
- Economic Optimization

After functions are selected, the various system configuration alternatives may be defined; e.g., centralized vs. distributed control centers. It is also necessary to analyze whether existing remote terminal units (if any) can be retained, where new remotes are required, and the desired level of "intelligence" of the remotes must be determined.

If management approves the recommendations and allocates the associated budget, the project can proceed to the next phases which are described briefly below.

SPECIFICATION PREPARATION

The objective of this phase is to thoroughly specify the control system requirements in a procurement document which will allow several qualified bidders to respond with acceptable bids. Several important goals for specification preparation are shown in Exhibit 11.

BIDDERS' LIST SELECTION

Prior to release of the request for proposal (RFP), it is desirable to have selected the most qualified subset of bidders from all available vendors. If bidders can be pre-qualified, the steps shown in Exhibit 12 can be utilized,

BID EVALUATION

The objective of this phase is to select the most costeffective bid for subsequent award of contract. Typical

EXHIBIT 11

GOALS FOR
SPECIFICATION PREPARATION

1. WRITE SPECIFICATION TO FORM BASIS FOR CONTRACT WITH MINIMAL CHANGE,
2. EXPLICITLY STATE ALL REQUIREMENTS TO AVOID LATER MISUNDERSTANDINGS AND CONFLICTS,
3. DO NOT FAVOR ANY PARTICULAR BIDDER'S SYSTEM DESIGN,
4. WRITE A REALISTIC SPECIFICATION WHICH PROVIDES FOR THE FUTURE, YET CAN BE IMPLEMENTED WITHOUT MAJOR NEW HARDWARE OR SOFTWARE DESIGN,
5. STATE REQUIREMENTS FUNCTIONALLY TO ALLOW STANDARD SOFTWARE WHEREVER POSSIBLE; MINIMIZE REQUIRED NEW DEVELOPMENT.

EXHIBIT 12

BIDDERS' LIST SELECTION

1. REVIEW PROCUREMENT REGULATIONS
2. COMPILE LIST OF CANDIDATE VENDORS
3. DEVELOP AND TRANSMIT QUESTIONNAIRE TO VENDORS
4. INTERVIEW AND EVALUATE VENDORS
5. SELECT QUALIFIED VENDORS

steps for this phase are shown by Exhibit 13 and are generally self explanatory.

WORK STATEMENT PREPARATION/CONTRACT NEGOTIATION

The objective of this phase is to develop a single contractual document to replace all prior documents in order to expedite the project implementation and minimize future conflict with the vendor. The steps involved in development of the work statement are depicted in Exhibit 14.

EXHIBIT 13

BID EVALUATION

1. REVIEW PROCUREMENT REGULATIONS.
2. DEVELOP BID EVALUATION CRITERIA AND PROCEDURES.
3 PROVIDE INDIVIDUAL PRE-BID MEETING WITH EACH BIDDER TO CLARIFY SPECIFICATION, ISSUE ADDENDUM IF NECESSARY.
4. EVALUATE EACH BID FOR TECHNICAL AND COMMERCIAL COMPLIANCE AND COMPARE WITH PRICE RANKING TO REDUCE THE NUMBER OF BIDDERS TO TWO OR THREE,
5. SUBMIT QUESTIONNAIRE TO FINALISTS TO CLARIFY THEIR PROPOSALS/QUOTES.
6. PROVIDE INDIVIDUAL MEETING WITH EACH FINALIST.
7. PERFORM FINAL EVALUATION AND RANKING OF BIDS AND WRITE A SUMMARY REPORT WHICH RECOMMENDS THE WINNING BIDDER.

EXHIBIT 14

WORK STATEMENT PREPARATION

1. REVISE SPECIFICATIONS TO INCLUDE ADDENDA, BIDDER EXCEPTIONS, LIST OF DELIVERABLES, PROJECT SCHEDULE, AND VENDOR OFFERINGS IN EXCESS OF SPECIFICATIONS,
2. MEET WITH VENDOR TO AGREE ON TEXT.
3. MAKE FINAL TEXT REVISIONS AND REVIEW FINAL DRAFT.
4. PUBLISH THE WORK STATEMENT FOR INCLUSION IN THE CONTRACT.

SYSTEM INTEGRATION, TEST, AND INSTALLATION

The purpose of this phase is to assure that the vendor delivers the system as defined in the contract per the schedule. Typical items performed by the purchaser in this project phase are listed in Exhibit 15. The magnitude of effort for these items depends upon:

Number and complexity of applications

Quality of contractor documentation

Number of changes requested by purchaser

Level of detail required for testing

It is generally recognized today that the current energy situation is more specifically a problem associated with particular fuels having major availability uncertainties, due to either regulatory limitations, international economic policy constraints, or possible international politics. Although it will be necessary to continue partial reliance on petroleum, Niagara Mohawk expects that there will be increasing pressure to minimize the use of these critical fuels. To maintain current pipeline system reliability levels, reserve requirements may need to be increased, due to interstate supplier constraints and environmental requirements and economic constraints. Additional pipeline and customer components will require greater flexibility to allow cost-effective reserve capacity for the same reliability levels. The reliability problem is compounded by the fact that increased competition for the use of available land resources will require maximum utilization of existing pipeline facilities. Maintaining current reliability levels, reducing the cost per Dt delivered, providing the customer with specific BTU's, and assuring the customer that natural gas will be available regardless of the demand, are expected to be major concerns for technological development of existing natural gas operations, distribution, and load management.

EXHIBIT 15

SYSTEM INTEGRATION, TEST, AND INSTALLATION

* REVIEW OF HARDNESS APPROVAL DRAWING
* REVIEW OF SOFTWARE DESIGN DOCUMENTS
* REVIEW OF CONTRACT CHANGES
* UPDATE WORK STATEMENT AS CONTROLLING TECHNICAL DOCUMENT
* PARTICIPATION IN PROJECT REVIEW MEETINGS
* REVIEW OF FACTORY ACCEPTANCE TEST PROCEDURES AND ATTENDANCE AT TEST
* REVIEW OF FINAL DOCUMENTATION

INTEGRATION OF CORPORATE DATA SYSTEMS

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ABSTRACT

Historically, data bases have been established in a variety of locations within the typical gas distribution utility. Data bases would exist for:

- Corporate administration/reporting
- Metering
- Billing
- System operations and dispatching
- Engineering and Planning

In normal operations of a publicly franchised gas distribution company, there are numerous requirements for transferring information between data bases in order to formulate reports, monitor contracts and, in general, provide information necessary for the day-to-day control of the organization's activities. These transfers of data involve the manual collection and insertion of data from one system to another—this activity requires manpower and is prone to errors.

The application of modern electronic information technology to the workplace has led to the introduction of a variety of product developments and innovations which lead towards the networking of data resources. Although there is a considerable amount of effort towards standardization of message protocols and hardware interface capabilities, it is unrealistic to expect that the integration of real-time and record-keeping data bases can be established without application of engineering expertise to the specific requirements of each organization.

A major step in the integration of corporate data systems will be the automatic flow of information from the real-time monitoring systems which an organization employs, such as computer based SCADA systems and meter reading systems into data bases resident in the corporate mainframes which provide updated administration and control information.

This paper will discuss some of the techniques and possibilities currently available and look into the near-term future for other possibilities.

INTEGRATION OF CORPORATE DATA SYSTEMS

INTRODUCTION

For more than 30 years the information oriented technologies have brought radical changes in the business place. The gas distribution industry is no exception to this trend. These changes have been accelerated by the advances in microelectronics which have greatly reduced the real costs of computer technology. These orders of magnitude cost reductions have accelerated the rate at which computer systems have entered our workplace.

Initially, these systems were limited to the billing, payroll and financial activities resident in the "Corporate Mainframe." Lagging only slightly behind these "batch processing" activities, real-time systems were developed for monitoring, controlling and alarming gas network activities. These systems also performed extensive logging activities by keeping track of operational data. Still, computer systems have not fully made their imprint on the daily operations of the organization because these systems were resident either within the financial/administrative or system operations groups of the organization.

With the development of microprocessors, we saw the introduction of the micro or desktop computer and the adoption of word processing systems which have greatly reduced manhour requirements for day-to-day office and engineering chores.

At this phase of development the companies have made extremely meaningful improvements in their operations involving significant capital costs without any regard for system compatibility and ultimate system integration. At the current stage of development, this type of system compatibility does not exist and delaying these improvements could not be justified until product enhancements were made. As a result, individual systems—corporate mainframes, system dispatch computers or office automation systems—have been acquired which run independently and rely on human interface in order to complete their contribution to the overall organizational objectives.

While the concept of local area networks (LANs) has received much attention and certainly a lot of developmental effort, this concept could be far in the future for many organizations because of the need to replace still valuable and useful hardware and software systems. Furthermore, there are a variety of specialty systems which are used for logging, metering, and control in unique elements of the organization. These systems will continue to be bought as independent packages, rather than part of a totally integrated automation system.

Previously, these functioning systems have been bridged by the manual transfer of information. This involved gathering, physically transferring and manually entering this information into another computer system or database. This procedure involves delays and errors, and frequently distracts system operations personnel from the more important elements of their jobs. In the following, we will discuss some of the systems currently in use by gas distribution utilities or available to them and consider the means currently available to automate communications between these systems using microprocessors and inexpensive software packages.

CURRENT TECHNOLOGY

Currently, there are a variety of systems being employed by gas distribution utilities which have been acquired over time in response to specific administrative or operating problems. These systems were acquired either through major computer manufacturers or through hardware manufacturers or OEMs, i.e. companies selling complete packages including hardware from computer manufacturers and proprietary software.

One thing these systems have in common is that they were conceived and developed without any regard for compatibility between major corporate information sources. Major among these systems are:

The Corporate Mainframe

This system (or systems) was developed to handle the financial and administrative procedures of the organization including such activities as customer database, metering and billing information, payroll information, and other financial operating data. The system, among other things, may be used for the development of regular reports involving corporate performance in relation to its gas distribution business. Initially, it started out in the "batch process" mode where all inputs were made manually through keypunch operators. In recent years, it has matured to the point where user terminals are available throughout the administrative and financial sections for entering or gathering information, and developing new software systems. Frequenty, the corporate mainframe was used for running engineering and project management programs. These were more frequently used as terminals and were distributed throughout the organization; however, there has always been concern about turn-around time and responsiveness to the engineering/ project environment. These problems have typically been alleviated by the acquisition of dedicated minicomputers used for engineering functions.

Network Telemetry Systems

Historically, gas distribution utilities have used some form of telemetry in order to monitor and possibly control gate stations, regulators and key valve locations. These systems have involved transducers at the monitored location, communication lines, either dedicated or dial-up phone lines (in some cases microwave or radio) and centralized stations which have readout devices for each individual telemetered point.

The telemetered points were then recorded and necessary calculations were made manually for such items as flow and contract conditions. Many companies have, however, adopted computer-based supervisory control and data acquisition (SCADA) systems which automatically scan the remote locations, compute flows and other system variables, and update a real-time data base with all the telemetered information. Using this information, extensive logs are developed based on the operational requirements of the organization, system alarms are received and logged based on time of alarm.

These systems can be comprehensive depending on the size of the utility and specific operational requirements. Generally, redundancy is added in order to give the necessary degree of reliability and extensive provisions are made for the man-machine interface, i.e. the mechanism whereby the system dispatchers communicate with the machine. These systems represent a vast improvement over the manual procedures previously employed and the system dispatchers can make more meaningful contributions to the overall operation of the system.

Having access to a realtime data base, which is updated as frequently as every fifteen seconds, the system dispatchers can use other software routines within the SCADA system to perform such daily functions as weather profile and sendout forecasting, dispatcher guidelines, contract monitoring, pressure flow relationships, inventory controls, linepack calculations, and storage and deliverability determinations. All of these functions are resident within the software structure of the SCADA system, and are updated to reflect system changes through dispatcher or telemetry interface. They do not require computer programmer capabilities. This information is valuable in effectively managing gas contracts and economically dispatching the gas system.

Remote Meter Reading Systems

Companies which provide special rates to interruptible or two fuel industrial customers have adopted or have available through system suppliers microprocesor based metering systems which scan each remote meter through the use of dial-up phone lines. Metering information is then transmitted back to the host microprocessor and stored in this system for printout. These systems are generally used only with major industrial/commercial customers. The gas made available by a planned interruption is considerable. It can be important to the utility in meeting its overall residential sendout requirements, therefore, this information is also necessary to the system dispatchers. These metering systems provide a means to verify concurrence with contractually allowed curtailments when requested. Typically, they would function on an independent basis dialing as many as 300 customers automatically and taking in the meter data and developing a print-out of the information. This information would be manually transmitted to the other corporate entities as required.

Weather Data

As a primary driver of the system sendout requirements, accurate weather data including temperature, wind velocity and cloud cover is provided to system dispatchers from the various operating districts through a number of weather sources. Most recently, this weather data is made available in digital format so that it can be printed out in hardcopy format for manually calculating sendout forecasts or sent directly to the system dispatch computers. The availability of this data in digital format for inclusion in a variety of forecasting programs, including regression analysis, makes it possible to provide updated sendout forecasts and foresee the need to invoke curtailment agreements and/or utilize LNG or other forms of peak-shaving.

Engineering Analysis Systems

Companies have developed independent microcomputer/minicomputer based systems for performing of various engineering analyses which might include such activities as computer simulation for steady state or transient pressure/flow relationships in gas transmission systems. In order to relate these studies to the real world, actual system data is required for the engineering programs used to predict pressure relationships on the actual network. By using this approach, potential problems under unique flow conditions can be anticipated and mitigating measures taken in a timely fashion. This data should come directly from the network telemetry system.

Project Management Systems

The engineering computer can also be the host for a variety of project management and scheduling programs which are used to track progress on various construction efforts. Unlike many of the systems above, this activity is almost totally reliant on manually reported and entered data. Output from these programs can be used to support corporate cash requirement projections on a periodic basis; however, there is no need for interfacing with real-time monitoring systems.

NETWORKING

The most commonly used method of communication between several computers is networking. There are a number of networking schemes being employed. Among these are “star” networks and “ring” networks. With a “star” network, there are usually terminals, personal computers or subordinate computers clustered around a central main computer which is usually larger and faster than the machines on the extremities. Within the “star” network, communications are done by passing everything to the central computer which then distributes the data to the needy extremities. The “ring” network is a collection of computers and workstations. Although they may have different priorities for use of the resources of the network, they are more or less peers with each being only one node on a ring of many. Data is sent down a data highway by any of the peers, and can be collected by any or all of the peers. There is no main computer although there is usually a highway supervisor to control the traffic. The “ring” network would represent the ultimate in interconnection with commonality of protocols and hardware among all the components.

There is a similarity between all commonly used networks even between “star” networks and “ring” networks—they are expensive. To create a network out of diverse computers consumes many manhours and usually high capital expense. To create a network out of expensive and dissimilar computers can be prohibitive technically and financially. IBM never intended to have their machines fraternize with DEC machines, and even the IBM-PC is nearly an orphan in the family of IBM mainframes. While XEROX has tried desperately to get all machines talking to each other by providing their ETHERNET as a standard, the cost has still kept the standard from being the commonly used standard.

Of immediate interest are cost effective solutions for some specific situations which will perform effectively and use systems currently in place. The solutions may not be of a general nature, and don’t have to be if they represent use of existing systems with minimal additional expense. Let’s take a specific example and show an effective solution.

EXAMPLE

Gas Company A has a Gas SCADA System with automatic backup (redundancy) for their Gas Distribution system. The computers are real-time Data General computers.

Gas Company A has an IBM 3083 mainframe at the corporate headquarters and an automatic metering system based upon an IBM-PC. The company also gets weather data automatically from a weather service computer which is a VAX 11–740. The weather report must be sent to three offices within the company, but not within the same facility.

Gas Company A wants to get data from the weather service and the metering system into the real-time Gas Control System. Gas Company A wants to automatically control the IBM-PC based metering system from their real-time Gas Control System. Gas Company A wants to send pages of data on demand from the real-time Gas Control System to the IBM corporate mainframe which is located in a different city. Gas Company A wants to distribute the weather service information to all locations within the company that need it. Let’s say that would be three locations. The management of the Gas Distribution Department has also discovered a need for using data from the real-time Gas Control System on a personal computer in a form acceptable to LOTUS-123(R) or Dbase III(R) two very common spreadsheet and data base programs.

Gas Company A doesn’t want to spend a lot of money to get all of these machines equipped to talk to each other.

As a solution, we propose a modification of the “star” network. A “star” can be created without any network equipment or software. In this case, we must let all of the machines in the network think that they are the boss. This makes all of the computers in the network appear as peers such as in a “ring” network, but

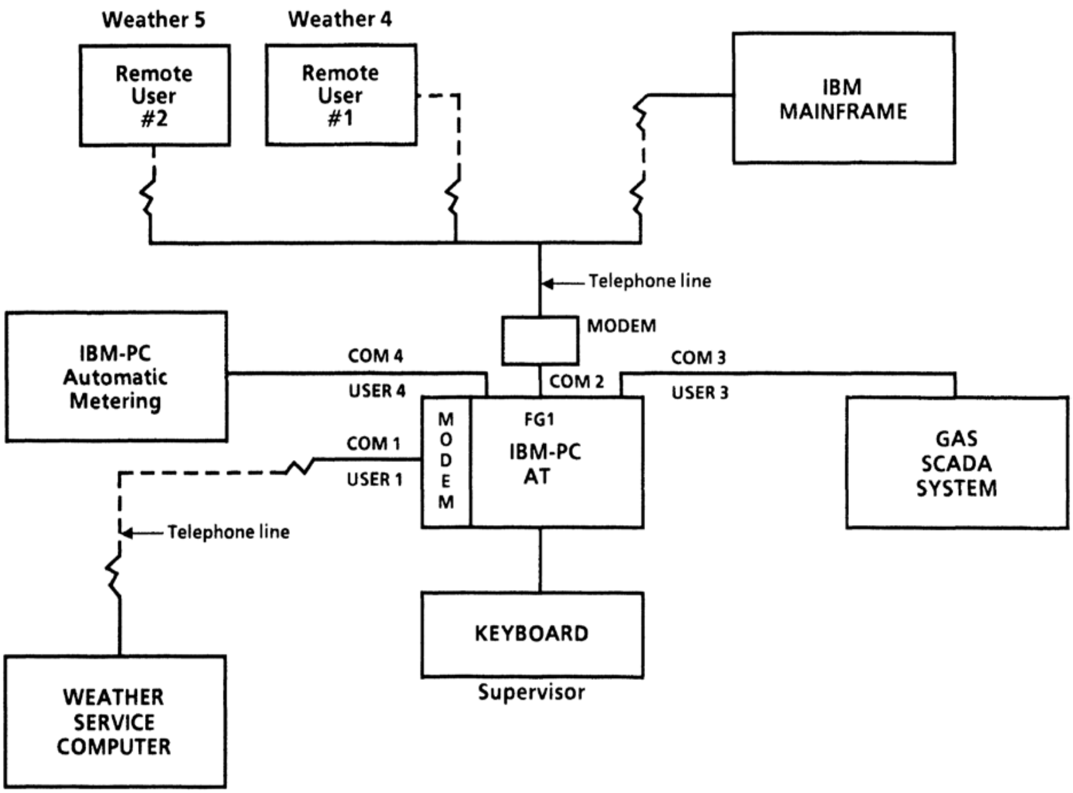

FIGURE 1. EXAMPLE A

they are also the center of the "star." To create this computer illusion, we will add to the menagerie of machines an IBM-PC AT(R). This IBM-PC AT will be the central player in this "star" network although none of the other computers know that it is the logical center of the "star." Refer to Figure 1.

Let's describe this IBM-PC AT. We will start with a regular extended AT. This means that the AT has at least 512K of memory and 20 megabyte hard disk. We will get the AT with a color adaptor and a color monitor although it isn't necessary to have color although it enhances the use of many software packages. To this AT we will add an internal smart modem and instead of the usual 2 RS232 serial parts we will add a multi-I/0 card with 4 RS232 serial parts. Since several of the members of this network are distant, we will add another external smart modem and plug it into an RS232 serial part. Let's get this port configuration straight:

COM1	Port 1	internal 1200 baud modem
COM2	Port 2	1st RS232 Port of 4 multi-I/0 card.
COM3	Port 3	2nd RS232 Port of 4 multi-I/0 card.
COM4	Port 4	3rd RS232 Port of 4 multi-I/0 card.
COM5	Port 5	4th RS232 Port of 4 multi-I/0 card.

Two different ports cannot be at the same address. The internal modem could be configured for COM1 or COM2. The multi-I/0 card could be configured for any 4 consecutive port numbers. It is more convenient then to make the modem COM1 and start the multi-I/0 card with COM2. This gives us the most flexibility and eliminates conflicting addresses.

Since we are using 5 ports and PC-DOS (R) only accepts 2 ports, we will not be able to use PC-DOS as the main operating system. The operating system is the software system which controls the operation of the machine. There are a number of operating systems which will use additional ports and still allow PC-DOS programs to run. These operating systems are generally termed multi-user systems, and they allow additional terminals to be attached to the RS232 ports to share the use of the AT. We also want to be able to work within the familiar framework of PC-DOS and be able to run packaged programs written for the IBM-PC. While it is not the purpose of this paper to extol the virtues of IBM hardware, it is readily acknowledged that IBM has the greatest amount of third party software written for use on its machines.

There is not extensive information comparing different operating systems for use in this environment so there is no good reason to pick one multi-user operating system over another. For this example, we will pick a product called MULTILINK by the Software Link, Inc., Atlanta, Georgia. MULTILINK will allow one foreground user and as many as 9 background users if enough memory is available. This is not a product endorsement of MULTILINK; it just has a generic sounding name for linking multiple computers together. MULTILINK has problems and drawbacks, but it can be made to provide a reliable interface media. In this case, one of the problems was that MULTILINK's port addresses did not coincide with the hardware addresses, so the MULTILINK utility program was used to modify the address to suit the hardware.

We will install MULTILINK as our operating system and for each computer in the network we will generate a user space and assign a port. We assign COM1-port 1 with the internal 1200 baud modem to the weather service computer and generate MULTILINK background user 1 (USER1) to communicate with the weather service. See Figure 1. We plug the external modem into the RS232 COM2-port 2 and attach this modem to a separate telephone line from the modem on COM1 port 1. COM2-port 2 will be used by the foreground user (FG1). This user FG1 is assigned to communicate with the far flung reaches of the Gas Company A empire.

For this example, it will be calling the corporate IBM mainframe with real-time data as well as two other remote locations requiring weather data. COM3-port 3 will be attached to an RS232 port on the Gas SCADA System and will be under the control of background user number 3 (USER3). Background user number 4 (USER4) will use COM4-port 4 which will be connected to an RS232 port on the IBM-PC of the automatic metering system. We will generate a background user number 5 (USERS) to help us by automatically sorting out the weather data so that the appropriate data can be sent to the different locations requiring parts of that data. We still have COM5-port 5 available, but to add another user we would have to add more memory. We have now satisfied the requirements for our EXAMPLE A.

Here is the illusion. All of the other computers think that the AT is a very dumb terminal attached to one of their inconsequential ports. The AT thinks that all of the other computers and remote terminals are dumb terminals being operated by amateurs who have limited knowledge of what the AT can do and limited need for information from the AT. The hardest thing that the AT has to do is keep track of what data is available for each user. This means that within the AT the different users processes must communicate with each other at least in a limited way.

Under MULTILINK, each user thinks that it is running a standalone version of PC-DOS. There is nothing such as electronic mail, mailboxes, interuser communications or messages. We are, however, able to have all users access any data files while other users are also accessing the same data files. So we will create our own mailboxes in the form of records within a data file or specific data files for certain users. The interuser communications are essential, but luckily under a multi-user operating system such as the one we are using and several other known systems, this communications capability is included in the system although it can be complicated to describe.

SCADA SYSTEM

Let's first describe the communications between the user processes necessary to complete the function of sending several pages of data from the real-time Gas SCADA System to the IBM corporate mainframe. This is the simplest of the functions to describe. A user on the IBM mainframe starts a program which calls the AT. The AT FG1 process answers and receives the message. The FG1 process stores the message in a disk file called MESSAGES. The process USER3, which always communicates with the Gas SCADA System, reads the MESSAGE file about every 5 seconds. USER3 process sees the message for logging data to be sent to the IBM mainframe and USER3 sends the message to the Gas SCADA System. The Gas SCADA System receives the message and prepares the pages of the logging data.

When the logging data is complete, the Gas SCADA System sends the logging message to the AT and includes in the message the number of pages that are ready. The USERS process receives the message and prepares a disk file we will call LOGS3. The Gas SCADA system then transmits the prepared pages, the AT receives the pages and the pages are stored in the file LOGS3. When all pages have been received, the USERS process renames the file LOGS30.

While all that has been going on, the FG1 process has been searching the disk for the file LOGS30. FG1 does not search for LOGS3 file. This is to prevent the FG1 process from sending out the logging data before the USERS process could completely receive and store all of the data. When the LOGS30 file appears, the FG1 process then calls the IBM mainframe and automatically enters the appropriate passwords and opens a data set on the mainframe. The data from the file LOGS30 is sent to the IBM data set. When all of LOGS30 has been sent, the FG1 process closes the data set on the IBM mainframe and logs off. The FG1 process then continues checking the phone for incoming calls and checking the disk for files that it is supposed to send. Other files FG1 might send are WEATHER4 and WEATHER5.

Weather Data

The function of getting the weather data from the weather service and sending it to the different parts of the network is considerably more complicated than the logging data. The weather service computer could call at almost any time with weather updates, and it always calls at least once each day in the morning. We have created the USER1 process which utilizes the internal 1200 baud smart modem to constantly wait for the call from the weather service. The USER1 process only handles incoming weather data.

When the weather service computer calls the User 1, process creates a disk file called WEATHER. All data transmitted by the weather service computer is stored in the WEATHER file. When the weather service has logged off the USER1, process closes the WEATHER file and renames it WEATHER1.

The background process USERS has been waiting for the file WEATHER1 to appear on the disk or for a message in the MESSAGES file to create the files WEATHER4 and WEATHERS. When that file appears, the USERS process begins to work. The data file is searched for the relevant weather text and the good material is stored in a file called WEATHER3. The weather text is scanned for specific weather data pertaining to temperature, wind speed and humidity forecast for the next 24 hours. This data is strictly numbers needed by the Gas Control System for sendout forecasting. The numeric data is stored in a disk file called

WEATHER2. When all of the weather data has been evaluated and properly sorted and stored, the USERS process puts a message in the file MESSAGES for the USERS process.

The USER3 process will read the message that the weather data has been prepared. The message is sent to the Gas SCADA System that the weather data is ready. The Gas SCADA System then checks for the appropriate action and sends a message to the USER3 process on the AT to tell the AT of its decision. These are the messages it might send:

WEATHER 1	just create file WEATHER4.
WEATHER 2	just create file WEATHERS.
WEATHER 3	create files WEATHER4 and WEATHERS
WEATHER 4	send all weather files to Gas SCADA system and create files WEATHER4 and WEATHERS.

In this case, the Gas SCADA System will send the message 4 to tell the USER3 process to do everything.

The USER3 process receives the message WEATHER4 from the Gas SCADA system. This means that the Gas SCADA System is ready for the data. The USER3 then reads the files WEATHER2 and WEATHER3 and sends them to the Gas SCADA System. When the transmissions are complete, the USER3 puts a message in the file MESSAGES that the files WEATHER4 and WEATHERS should be created.

The USER5 process periodically checks the file MESSAGES between logging for the WEATHER file to appear. When the message is found to create weather files, the message is read and interpreted. Just the file WEATHER4 or just the file WEATHERS can be created or both. One of the remote users gets WEATHER4 and the other remote user gets WEATHERS. This time the message is to do both. USERS reads in the file WEATHER3 and makes from that the files WEATHER6 and WEATHER7. When both files are done, they are renamed WEATHER4 and WEATHERS.

The FG1 process has been looking for the files WEATHER4 and WEATHERS to appear on the disk. Of course, the FG1 process is still checking the phone and looking for other files and messages. But now both the WEATHER4 and the WEATHERS files have appeared. FG1 process then calls the remote user #1 and sends the file WEATHER4. When the transmission is complete, the file WEATHER4 is deleted from the disk. FG1 then calls remote user #2 and sends the file WEATHERS. When the transmission is completed, the file WEATHERS is deleted from the disk. FG1 then puts the message in the file MESSAGES that all was completed.

USER3 process checking the file MESSAGES sees the message from FG1 that the transmissions were complete and sends the message on to the Gas SCADA System.

Now suppose that FG1 was unable to get the transmission of the file WEATHER4 through to the remote user #1. The message FG1 puts into the file MESSAGES will indicate this failed attempt. USER3 transmits the message to the Gas SCADA System. The Gas SCADA System receives the message about the weather data and notifies the gas dispatching operator. The Gas SCADA System then sends another command to the AT. This time the command is WEATHER 1, which means just create the file WEATHER4.

The USER3 process receives the command WEATHER 1 and puts a message in the file MESSAGES. The USERS process sees the message to create the file WEATHER4. The User5 process reads the data file WEATHERS and from that creates the file WEATHER6 and upon completion, the file is renamed WEATHER4. The FG1 process recognizes that the file WEATHER4 has appeared on the disk and starts the appropriate action. The remote user #1 is called, the file WEATHER4 is sent, the file WEATHER4 is deleted and the completion message is put into MESSAGES. The USER3 process sees the completion message and sends the message to the Gas SCADA System which then informs the gas dispatching operator that all is well again. The SCADA System monitors communications to the remote users.

Automatic Metering

We could describe in detail the functions involving the automatic metering system, but they are more complicated than the weather function because individual accounts are involved. For simplicity we will just show the possible commands:

METER 1	XXXX	put account number XXXX into control mode
METER 2	XXXX	take account number XXX out of control mode
METER 3	XXXX	send the data for account number XXXX
METER 4	XXXX	send the data for all accounts
METER 5	XXXX	retry the last command sent
METER 6	XXXX	resend the last transmitted data

The Gas SCADA System sends the command to the USER3 on the AT. The USER3 process puts messages in MESSAGES for USER4 process. USER4 process sends commands to the metering system and gets any data back. USER4 then puts in messages for USER3 to send to GAS SCADA. Gas SCADA tells USER3 when to send the data.

Expansion

This EXAMPLE A system still has room for expansion. There is still a USERS process and COM5-prot 5 available for another set of functions. With an 8-port multi-I/0 card and a lot more memory, additional user processes could be added. All of the data files could be copied to a floppy disk while the system is in full operation and the disk can be used on another PC. It is also possible for the USERS process to be a manual process involving perhaps the use of LOTUS 123 or Dbase III working with the system data files or other files. All of the systems data files can easily be converted to LOTUS 123 files.

For this example, an IBM-PC AT was chosen for more speed. If the speed is of no concern or if fewer functions are required, then a standard IBM-PC or IBM-PC XT would be sufficient. There are many IBM compatible machines available that will run just as well and perhaps faster than the equivalent IBM-PC. We have done several systems using IBM compatibles and have no more problems with them than with the IBMPC’s. If the machine can run PC-DOS and LOTUS 123, then it is compatible enough for this application. I prefer IBM compatibles because if you only have enough money for one IBM-PC, then you can buy two compatibles and will have one for a backup. Based on using IBM hardware total equipment costs should not exceed $8000.

This example can utilize PC-DOS batch files, one commonly used communications program and MULTILINK as the only software necessary. The program running in USER3 which communicates with the Gas SCADA System is complicated enough that it could be written as a special program instead of a PC-DOS batch file. We have tried both approaches and both seem to work. The main difference seems to be that the batch file has a lot more disk access and runs slower than a dedicated program, thus slowing all other processes. We used an inexpensive C language compiler and wrote a program in the C language that doubled the speed of the USERS process.

Here are some thoughts for future consideration. If the corporation already has a network, such as ETHERNET, but the Gas SCADA system is left out, it will probably be a lot less expensive to put a PC into the network and connect the PC to the Gas SCADA system as we did in the EXAMPLE than it would cost to connect the Gas SCADA System to the network. Almost every corporate mainframe has at least one modem for calling in to the corporate computer. The example could have called in data to any mainframe computer with a modem port. This can be a very cost effective way of transferring data from a real-time Gas SCADA System to a batch processing mainframe.

Remember the important point to this networking scheme. All of the other computers think the AT is a very dumb terminal and the AT thinks that all of the other computers are very dumb terminals. This way all of the software in the AT that talks to the other computers thinks it is talking to terminals and all of the software in the other computers think they are talking to a terminal. This way all of the machines are talking the same language and remain compatible.

PERSPECTIVES ON STANDARDIZATION

In the initial development of information/computer systems, the marketplace was technology driven. Products were differentiated based on improvements in capability and capacity, and manufacturers capitalized on this uniqueness by having specialized communication protocols which made it impossible for other equipment to communicate with theirs and, therefore, enhanced sales of their equipment. As this process continues, the stronger players become stronger, and the weaker players fall by the wayside until, eventually, there is dominance by a number of major systems suppliers.

These system suppliers then have the capability to ensure their continued market domination by capitalizing on the unique communication protocols in their product line. In this vein, we have seen IBM's System Network Architecture protocol (SNA) become the defacto industry standard in many organizations because of the market dominance of IBM. Consider that IBM does $55 billion in volume a year and number DEC does $7 billion.

When this situation occurs, it is competitively to the advantage of the other players to formulate standardization in the industry so that they may compete with the giant in a more unified stance. A possible alternative is to have major consumers establish standards under which it will buy its equipment. This type of standardization is being forced by General Motors Corporation's Manufacturers Automation Protocol (MAP). In order to maintain control, a number of manufacturer supported standardization efforts are underway both domestically and internationally.

In order to open up competition internationally, the international standards organization has developed an open systems interconnection (OSI) model and the Integrated Services Digital Network (ISD), so that different brands of computers can talk to one another and establisa single consistent set of tests and certification methods to insure that they do. In the U.S., an organization called the Corporation for Open Systems (COS), funded by Computer Systems manufacturers has been formed to promote U.S. support of proposed international standards.

If COS can eventually ensure that different vendors' machines will communicate with one another without the various and often convoluted gateways and interfaces, that are necessary today, there will be a significant change in the methods used to integrate various systems. This, however, looks at the market very idealistically because even the companies who support communications standards will be tempted to differentiate products where they have unique advantage and technology so as to bring along other more mundane product lines on the coattails of its innovation.

And the other factor under consideration is the time it takes to implement standardization. Under normal circumstances, a strong marketplace will develop systems which will permit their hardware to talk to the other manufacturers' products, especially the stronger manufacturers. However, they can be very hesitant to provide information or encouragement for helping other manufacturers talk to their hardware. The authors conclude that ultimately integration and standardization of communication protocols will occur, there is work already underway. However, the actual implementation of standardized products will take longer than expected because it is not in the best interests of the stronger companies.

For this reason, it is beneficial for progressive gas distribution utilities to develop customized methods and procedures for integrating computer systems using third party software packages and communications processors.

IMPLEMENTATION OF AUTOMATIC METER READING

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ABSTRACT

The Hackensack Water Company has decided to implement automatic meter reading for all of its approximately 220,000 customers in New Jersey and New York. A brief outline of the history of that decision is presented. The key elements upon which the decision is based are highlighted. Some critical success factors, and the problems created by the management of change among the parties involved are identified, and some approaches to handling them outlined.

IMPLEMENTATION OF AUTOMATIC METER READING

INTRODUCTION

The implementation of automatic meter reading (AMR) at Hackensack Water Company, the subject of this paper, is a case study in the management of change. The principals of the management of change are applicable to the implementation of any new technology, organizational structure, discipline, etc. This paper briefly reviews the evolution of the design philosophy of the automatic meter reading system we have selected, the driving forces behind the decision to go to automatic meter reading, and the major issues that have come into play, to provide some perspective on the process rather than just on the technology itself, which is the subject of other papers in these proceedings. At the time of the writing of this paper, the executive staff of Hackensack Water Company had decided to recommend adoption of AMR to the Board of Directors, and quotes on alternative systems were being analyzed.

No reader of this paper should suppose that because he is not an executive or a member of senior management within his or her organization that the management of change should be irrelevant or of no interest, for such a position condemns its holder to repeat the past and eschew progress.

HISTORY OF AMR AT HACKENSACK WATER COMPANY

The Hackensack Water Company, the nation's oldest investor owned water utility in continuous operation, serves about 1 million people in northern New Jersey and part of New York State.

Primarily due to economic forces, the Hackensack Water Company watched its meter reading productivity decline dramatically through the 1970's. In 1978 the Company investigated electronic alternatives to the analog, mechanical recording meters used for production monitoring and special studies. These alternative devices could count pulses from commonly available generator remote meters. However, counting pulses seemed to have inherent reliability shortcomings in the context of the domestic meter. In 1979, the Company learned of the Cain encoder, which used field effects to monitor the positions of the dials of a common electric meter. Cain's device was not readily adaptable to water meters nor did he have a data transmission device. He referred us to Metretek Inc., of Melbourne, Florida. The Metretek unit, a dial-inbound AMR device, was more readily adaptable to counting pulses, and showed promise of being relatively cheaper and more reliable than the data recorders we had been experimenting with. In 1980 and 1981, the Hackensack Water Company and its subsidiary, the Spring Valley Water Company in New York, conducted trials with 20 Metretek units reading water and electric meters. Eventually, the Metretek system was judged too expensive and insufficiently reliable for the domestic meter environment. The Metretek system, as is the case with all dial-inbound systems, places most of the intelligence at the customers' premises. However, the trial demonstrated that the deployment of AMR equipment was feasible.

The Hackensack Water Company searched for an alternative design philosophy that would require less intelligence and therefore less per customer cost. While testing the Metretek system, it discovered a telephone-based scanning system developed by International Teldata Corporation. The scanning system placed a very simple modem/meter interrogator in each customer's premises. The system was controlled by a central computer and a multiplexer installed in the telephone central office. Cross connections were made between each customer's loop and the multiplexer, thereby bypassing the telephone switch. This approach allowed meter reading rates as high as two reads per second. Hackensack Water Company's first trial of this technology in 1982 involved 105 volunteer customers.

Encouraged by the scanning system's reliability and cost projections, Hackensack undertook a larger trial of the system in 1984 on 950 water customers. This trial, conducted this time in conjunction with New Jersey Bell, was designed to simulate fullscale implementation. For example, instead of soliciting volunteers, the utility selected the customers who would participate. Installations were conducted door-to-door without skips, and done by outside contractors, so that installations could take place evenings and on weekends. All installation problems were dealt with as they were encountered. While it was recognized at the outset that the scanning technology would not be economically feasible in most situations for domestic meter reading, this trial used the same technology as before so the research could focus on the institutional aspects of automatic meter reading. This trial provided the following results:

1. While the overall system reliability, defined in terms of the number of times a meter reading was obtained compared to the number of attempts, was only 96.6%, most of the performance degradation was due to a four day malfunction of the central control computer. The average reliability of the meter interface units was 99.67%, the water meters 99.7%, and telephone lines 99.8%.
2. In surveys of the trial participants, 96% said they were satisfied with AMR and indicated a willingness to pay some nominal amount of money for the convenience of not having to be at home during the day or having to be bothered or inconvenienced by estimated bills.
3. From detailed economic and financial analyses based on the trial results, an analysis of installation times and costs, and manufacturers' estimates of system and components costs, it was projected that an

AMR system could be economical. However, by December 1984, after discussions with the manufacturers and New Jersey Bell, Hackensack Water Company determined that the scanning system would not be economically viable and that the system should be converted to dialoutbound. In the dial-outbound system, a meter reading access circuit seizes the customer's telephone line (provided it is not in use) without ringing the phones, by using the telephone company test trunk. It then sends a special tone to the meter interface unit, which responds with the meter readings. It had already been demonstrated that the scannable MIUs could also be dialed.

In April 1985, a full evaluation of automatic meter reading was presented to the Board of Directors of Hackensack Water Company. The Board endorsed a proposal to implement AMR provided the projected costs and benefits were confirmed. Letters announcing Hackensack Water Company's commitment to implement AMR were sent to New Jersey Bell Telephone and the manufacturers as well as the New Jersey Board of Public Utilities. New Jersey Bell responded with a similar commitment to implement an automatic meter reading service. A new test of the dial-outbound equipment under New Jersey Bell's auspices was proposed so that they could evaluate the technical requirements for the system. Two competing manufacturers delivered prototypes of new dial-outbound equipment to New Jersey Bell's central office in Westwood in June 1985. In addition to converting the existing 950 customers from scanning to dial-outbound, 100 new MIUs with improved specifications and reliability were installed in place of old ones. Only one of these new units has failed as of the date of this writing.

DEVELOPMENTS LEADING TO AMR IMPLEMENTATION

In September 1985, New Jersey Bell solicited proposals for central office equipment and asked Bell Atlantic Management Services to undertake the product selection process. After field tests in February and March, 1986 of equipment proposed by vendors in response to its Request for Proposal, Bell Atlantic negotiated the specifications and design of the central office equipment with the winner of that process, Base 10 Telecom, Inc., of Trenton, New Jersey. After review by Bell Communications Research, Bell Atlantic released a technical reference encompassing the specifications for the central office equipment and the interfaces between that equipment and the utility's computer system and the MIU.

Meanwhile, AMR implementation developments for Hackensack Water Company continued on other fronts. In January 1986, Hackensack Water Company signed a contract with Public Service Electric and Gas Company for the inclusion of about 100 gas meters in the trial. Recently, some electric meter encoders have also been inducted.

In New York, the New York Telephone Company filed a tariff for automatic meter reading service. Their intent was that further experimentation with automatic meter reading should take place under a tariffed service. Before the New York State Public Service Commission, New York Telephone argued that the tariff should be based on value of service pricing. Spring Valley Water Company, the subsidiary of Hackensack Water Company that serves Rockland County, New York, intervened, arguing that AMR service is universal, that its relative contribution to local exchange service is small, and that the water utility and telephone customer are virtually the same person. In May 1986, the New York State Public Service Commission ruled that automatic meter reading service should be provided under a cost of service basis. Although the revised tariffs have not been released as of this date, the cost of a nighttime message unit is about 2 cents; that will be the basis for the unit cost for the service.

All through the course of the development of AMR at Hackensack, a number of issues have been raised, each one of which might represent a critical hurdle to the continuing progress of AMR development. These include technical reliability, economic and financial feasibility, impact on rates, customer acceptance, and the ability to avoid sole source or monopolistic supply situations. A paradox of the management of change is that as one approaches implementation of a new solution to an existing problem, the solution itself becomes the problem. As pieces of the AMR puzzle started to fall into place there developed within the Company a growing concern about dealing with what may represent dramatic changes in many fundamental areas of the Company's operations, and about using a technology which had never before been widely applied. To deal both with the range of critical issues and the concerns of company personnel, a full day session was held off-site in early June, including some thirty of the Company's top executives and managers. This session was designed to apply the best thinking of all of the people, who would be involved in the automatic meter reading conversion process or who would have to live with the system. Based on the discussions, four critical issues emerged as highest priority: (1) customer acceptance, (2) regulatory approval and support, (3) optimal and non-disruptive installation and conversion, and (4) the development of normal operation and maintenance procedures.

On June 13, 1986 requests for quotes on automatic meter reading systems were mailed to all major manufacturers. Responses were received on July 3, and as of the time of this writing are under analysis.

OVERCOMING IMPEDIMENTS TO AMR IMPLEMENTATION

Throughout the development of automatic meter reading, we have learned a great deal about the implementation of a new technology in a conservative organization. While every utility's situation is different, there are some basic principles that apply across the board.

The decision to adopt automatic meter reading hinged on the following key elements: (1) economics, including the price of the equipment, (2) operating costs and maintenance (such as the telephone tariffs), (3) the cost savings over existing procedures, (4) the noneconomic benefits such as improved customer service or better information for management and system design, and (5) the administrative feasibility of maintaining an automatic meter reading system, e.g., keeping track of customer's telephone numbers. Economics must be approached from three perspectives: (1) simple benefit-cost analysis, to see if the project makes sense; (2) financial impact on the utility, including what it will have to borrow, what the cost of borrowing will be, how the project will impact the debt-equity ratio, how the equipment will be booked and depreciated, and the after-tax impact on cashflow over the life of the system; and (3) the impact on customers' rates. Quantifying noneconcmic benefits is important, but not easy. In lieu of that, all noneconcmic benefits (e.g., improved customer service) must be explicitly described. A decision often hinges on the tradeoffs between the dollar costs and these benefits. Any system must be evaluated with respect to its alternatives, the principal one of which is doing nothing, and others of which include partial deployment or a mix of different system types.

A set of critical hurdles, representing the different key players involved in the AMR conversion, must be overcome. Some of these, and approaches to them, are described below. A major hurdle involves the carriers and manufacturers. Most telephone companies have a "Ma Bell" mentality, which they recognize and are attempting to change. There are multiple layers of bureaucratic decision-making, which slows movement. Telephone companies typically have had a product orientation rather than a customer orientation. They do not yet have a clear idea of what it takes to bring about automatic meter reading and the changes it implies for their utility customers. They may have little overall understanding of the utilities' economics despite the fact that their Bell operating companies are similarly regulated utilities. Their tariff proposals have been very high. The phone companies are not always clear why they are involved in automatic meter reading. In some cases it is to avoid bypass, in others it is to generate a major source of new revenues, which is unlikely to materialize at high prices. Perhaps AMR will pave the way for additional similar services and perhaps phone companies can eventually become the integrated service providers they hope to be as soon as the FCC and the Department of Justice allow.

At this point in time, automatic meter reading system manufacturers are in risky positions--they cannot commit to making the wrong product. They can afford to establish but one or two initial products, not a whole product line at the start. Those companies that have existing products may make the mistake of attempting to market the automatic meter reading system the same ways their existing products are sold. Established products usually get priority and organizational protection, and since they are usually mature, require different marketing approaches. Engineers designing automatic meter reading systems tend to make them complex and wondrous, and thereby uneconomical or unreliable. Utilities, often used to the noncompetitive luxury of doing things their own way, typically define requirements instead of desires, consisting of the moon and nearby stars. Little attention is given to the cost versus reliability tradeoff.

From the carriers the utility must exact a commitment by offering a commitment. This is a win-win game: the phone company would like to avoid bypass; the utility would like to get guaranteed price stability. Perhaps the price can be tied to some existing telephone tariff or the consumer price index. Manufacturers need information from the utility about what the product should be as well as a commitment that the product will be purchased. This requires a close working relationship with manufacturers.

An AMR system will probably succeed or fail based upon its customer acceptance. Clearly an AMR system provides convenience and billing accuracy. Most customers are interested in technological advances and are concerned about personal security. However, customers worry that an AMR system will have an impact on rates and the displacement of utility employees. They are concerned about the invasion of their privacy, since an AMR system provides certain monitoring capabilities. If approached wrong, the customer will see AMR in terms of an ugly little black box intruding in his household. Typically, the utility's customers are not favorably impressed by the utility and may be unwilling to cooperate, yet the utility will need to maintain their phone numbers.

The proper approach to public and customer relations is to identify one's constituents—the employees, customers, regulators, and investors—and to take a proactive approach. This means starting public relations well ahead of time, and carefully managing publicity. The utility should not wait to be asked, but offer honest information, having as many answers as it can ahead of time without appearing know-it-all. It is useful to tell everyone exactly what one is attempting to do, so that there are no surprises and there is time to generate the necessary support. Above all, one must be internally consistent.

Within the utility there will be plenty of problems implementing an automatic meter reading system. Utilities are typically resistant to change. Most utility managers would rather "wait until the technology is perfected." This sort of argument would preclude anyone from ever buying a personal computer, or even an automobile. Utility managers are also driven by a need to control. When utilities do innovate, it is usually in a slow and methodical way. An AMR system will involve a great deal of corporate politics because the centers of control will shift. Some employees may loose jobs and others will be subject to new procedures, more technical requirements or job displacement. Unions will typically object to all of these aspects.

Automatic meter reading wpill require a champion in the utility, and he or she should touch as many bases as possible. Implementing an automatic meter reading system ought to require as prerequisite the adoption of an employee displacement plan. All objectives raised by utility managers are real, simply because the managers feel them. Not everybody can be a winner, but automatic meter reading implementation should make sure the most critical players provide support and cooperation. One cannot proceed to make an across-the-board change unilaterally. People need time to develop comfort levels and to get used to the idea of new technology.

The champion of an automatic meter reading system must take a careful look at the regulatory environment. Most regulatory commissions are interested in automatic meter reading principally to solve customer service problems. They evaluate utilities in terms of their customer service performance more often than not and they are concerned about the impact on rates and on employees. They are sometimes disproportionately concerned with issues of equity and need to protect disadvantaged groups. For example, they may be interested in those people that don't want to participate or those people that don't have telephones. Regulatory agencies are also usually interested in innovation. The problem is that with all of these concerns, the utility could be forced into a nonviable position. There are many issues regarding procedures that will need to be changed, e.g., frequency of visit to the meter. The electronics should perhaps not be regulated like the meter.

The Regulatory Commission may be expected to help in dealing with the carrier. The utility's regulatory agency will have primacy over decisions on who can install customer premises wiring.

The proper approach to a Regulatory Commission is to keep the commissioners and their staff informed, to try to obtain the endorsement and support of staff, and to deal with as many objections as one can. All of this will take a great deal of time.

A FINAL WORD

This paper has attempted to provide a brief perspective on implementing an automatic meter reading system, which embodies the management of change. These approaches to dealing with the the different parties involved invoke lots of common sense, sensitivity and a great deal of planning. Their application is not an ironclad guarantee of success in innovation, but their absence means almost certain sabotage. Years from now, automatic meter reading will be part of mainstream utility operations and not considered innovative, but something else will be. The same principles apply.

ELECTRONIC SOLUTIONS TO METER READING

Vel S.Casler, President

Porta-Printer Systems, Inc. (PPS)

ABSTRACT

The utility industry today is expected to reduce costs; increase productivity; offer top quality, efficient service; build and maintain good public relations; and still show profitability. Attaining these goals is quite an achievement, but many gas, electric, and water utility companies are succeeding. One area wherein they are meeting success is meter reading. They are discovering that electronic data collection offers solutions to many of the costly, time-consuming problems of reading meters, managing the information and issuing regular statements to the consumers.

ELECTRONIC SOLUTIONS TO METER READING

METER READING BEFORE ELECTRONIC METHODS

A little over 100 years ago, meter reading was practically nonexistent in the utility industry. Then, technology advanced to the "pay-as-you-use" meters, especially with the gas companies that measured gas consumption with "shilling meters," wherein, consumers deposited shillings into a coin collector on the meter as they used gas.

For many years, water was unmetered or practically free with only a flat rate service charge, even for consumers who allowed faucets to drip and garden hoses to run.

Eventually, as engineering technology offered improved meters, electric companies measured kilowatt usage, and water and gas companies began measuring consumption, too, usually in cubic feet. As these utilities measured usage, they had to send someone out to each meter location on a regular basis to read the meter and record the data. This process was costly and too often resulted in erroneous information.

Until the introduction of electronic meter reading, the utility industry used three paper-based techniques for collecting meter-reading information. At first, meter readers carried clipboard meter books on their routes. These books contained specific information for each consumer. Meter readers wrote down figures for the current reading and subtracted the previous reading to arrive at the actual consumption for the current billing period.

By 1960, meter reading had improved to a computer-generated, mark sense, punched card for each consumer. With a stack of these cards for a particular route, a meter reader marked the current reading on each individual consumer's card. These cards were then processed by machine.

From these punched cards, some utilities advanced to a somewhat better method—the Optical Character Recognition (OCR) cards. Again, meter readers had to carry stacks of these cards for each route.

These three meter reading techniques—books, punched cards, and OCR cards—all had similar problems:

- They were all subject to human error in mismarked or illegible information;
- They all required the creation of a new page or a new card if customer information changed;
- They resulted in slow turnaround time for monthly statements which often were erroneous, sometimes outrageously high with five and six figures for residential consumers;
- Cards were often damaged or misread by optical scanning machines;
- All three were affected by inclement weather; and
- They were all inaccurate, time-consuming, and costly.
- They certainly did nothing to promote consumer relations.

As increased fuel prices resulted in higher operating costs in the late 60's and early 70's, the utility industry began to concentrate heavily on accuracy, efficiency, and economy. Utility companies sought ways to provide better, more efficient service while increasing productivity and reducing costs.

They allocated research funds to improve meter reading activities. They experimented with radio meters read by radio trucks which collected data as their drivers drove up and down the streets. Some companies even resorted to helicopters flying over houses to "read" these radio meters. Though these meters considerably reduced meter reading paperwork, they were not feasible because of time and costs involved.

CURRENT METHODS

Even though the outdated paper-based data collection methods are still used, most utility companies are currently evaluating or have already installed an electronic meter reading system. These systems improve data accuracy, increase productivity, save time, boost employee ego, enhance public relations with the consumers, and improve cash flow while reducing costs.

PPS BACKGROUND

In 1976, Porta-Printer Systems, Inc. (PPS) began as the pioneer developer of these electronic meter reading systems and placed the first product in the field in 1980.

Since those pioneer days, PPS continues to grow and remains a leader in electronic data collection. Today, the company's corporate headquarters occupy 19,000 square feet in a modern office complex in Largo, Florida, with regional offices in Pittsburgh and Los Angeles. PPS has built a network of dealers throughout the United States and has added several distributors for the international market.

Over 90 dedicated professionals plan, design, implement, install, and service PPS electronic data collection systems. These employees have many years of experience in various aspects of computers with expertise in Series/1 minicomputers, personal computers, hand-held microcomputers, telecommunications,

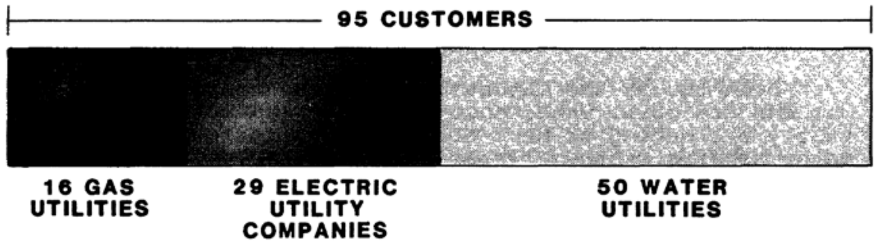

Figure 1. PPS Customers

software and hardware engineering, as well as data processing. They are the innovative force behind the PPS data collection systems.

PPS Customers

To date, PPS has 95 customers for its electronic meter reading systems, including 25 IBM Series/1 systems and 70 PC-based systems. Of the 95 total systems, 16 are in gas utility companies, 29 in electric utility companies, and 50 in water utilities. Some of these systems have been in operation for over six years, while others are currently in the installation stage. These users of the PPS systems report the ongoing benefits of electronic meter reading, such as reduced operational costs, faster read-to-bill cycles, and increased productivity. In fact, Otter Tail Power Company, recently recognized by the National Association of Regulatory Utility Commissioners (NARUC) as number 1 in productivity for the last 10 years out of 125 major utility companies, installed a PPS electronic meter reading system early in 1985. This company expected a 10% increase in productivity, but realized an 18% increase with as high as 35% in some service areas. Electronic meter reading is helping Otter Tail Power Company maintain its "number 1 in productivity" position as well as the "dead last" position in rate increases to its consumers.

PPS PRODUCTS

Meter Reading Management Systems

PPS designs and produces both standard "off-the-shelf" and customized meter reading management systems, including the Series/1 systems and the Enterprise systems.

Series/1 Systems

Currently, the company has 25 IBM Series/1 systems in operation, 22 throughout this country and 3 in Canada. The design of these Series/1 systems is completely customized to meet the specific meter reading requirements of each individual utility company; thus, there are 25 variations of this Series/1 system.

Furthermore, utility companies, from Clearwater, Florida to San Diego, California and Ontario, Canada, have systems which use one of the three generations of the hand-held microcomputer, called the Porta-Processor, from the first generation 787 Porta-Processor with 1-line, 16-character display; to the 790 Porta-Processor with 2-line, 32-character display; to the state-of-the-art, fully environmentalized 701E Porta-Processor with 4-line, 64-character display.

The nucleus of the Series/1 system is one or more of the IBM Series/1 minicomputers, complete with hard disk storage, diskette drive or drives, and a tape backup system. These Series/1 systems interface to the host computer through a direct channel attached on the mainframe or through a data communication link.

Meter readers use the Porta-Processor to collect meter readings and other information on their routes. They begin their meter reading day with a Porta-Processor already loaded with their route assignments. These hand-held microcomputers weigh approximately two pounds and can store up to 2400 customer accounts in up to 512KB of memory, certainly more than a meter reader can read in one day. Meter readers average 350 meters per day, but one PPS customer, San Diego Gas and Electric, has meter readers averaging 713 meters per day.

The 701E Porta-Processor is environmentally sealed so that it operates in heat, rain, or snow in temperatures of −22°F to +140°F and is shock resistant so that it does not stop working if it is banged or dropped.

These Porta-Processors prompt the meter readers to enter information, such as beginning and ending vehicle odometer readings; to re-read a meter if the current reading is outside a preset high or low range; and to enter special codes for meter conditions, such as broken glass, dirty dial, or broken meter box. The Porta-Processors also inform the meter readers of unusual, special, or hazardous conditions, such as the location of a meter or an access key, or of a bad dog on the premises.

The Porta-Processor issues audible signals for error messages, special information, or unusual conditions. It also records the time of each meter reading, a useful feature if a consumer should question the date and time a meter was read or if a supervisor wants to check on a meter reader's progress on a particular route.

Further time-saving features include the search function with which the meter reader can look for a specific meter number, specific address, or first account in the route, and can move both forward and backward within the route. When meter readers have read the route assignments loaded into their Porta-Processors, they return to the central location where they place their Porta-Processors into a Communications Interface Device (CID). These CID's are linked to the Series/1 for unloading and loading of route information into the Porta-Processors.

Once the meter reading information is unloaded from the Porta-Processors, it is automatically transferred by the CID's to the Series/1 minicomputer for processing and eventual printing of various management reports which are automatically available in these PPS Meter Reading Management Systems.

For example, the Route Detail Time Study Report gives a detailed report of the meter reader's route, sorted in time order. With this information, utility companies can re-allocate routes where necessary without expending extra manpower.

The Change Data Report contains valuable information which the meter reader captured in the field and recorded on the Porta-Processor, such as a replaced meter not reflected on the host database. When this information appears on the Change Data Report, the report is routed to the appropriate departments for database updating.

The New Account/New Meter Report reflects any new accounts the meter reader "picked up" while reading the route.

The Meter Condition Report lists such data as suspected diversions and damaged or broken or missing meters. This information is valuable to other departments, such as Turn On/Turn Off or Credit and Collections.

Utility companies using the Series/1 systems range from a system of one Series/1 with CID's attached in the same location, to a system of six Series/1's in one room at Columbia Gas in Columbus, Ohio with the CID's located in five different states, to a system at Public Service Gas and Electric in Newark, New Jersey which has fifteen Series/1's, all running separate systems in separate locations, but all tied together for communications. In fact, Otter Tail Power has meter readers, called "Service Representatives," located in three

Figure 2. 701E Porta-Processor

states. These employees have modems in their homes so that the 701E Porta-Processors can dial the phone to communicate with the Series/1 to load and unload route information.

Enterprise 2000 Systems

As PPS realized there was a need of the smaller utility company for a simple system offering some of the same capabilities as the Series/1 system, the company created the Enterprise 2000, consisting of an IBM PC XT or AT (or compatible), 790 Porta-Processors, 790 Communications Rack, a communications package to link the mainframe and the PC, and a printer for reports.

This PC-based system employs the 2-line, 32-character display 790 Porta-Processor with one line local communication to the Porta-Processors. The data is cycled through this system as in the custom Series/1 systems. The utility company selects a communication package to the mainframe. Data is sent to the PC, and the Meter Reading Department assigns the routes to the Porta-Processors.

The Enterprise 2000 is a standard, “off-the-shelf,” packaged system, parameter driven, and designed to meet the meter reading requirements of a wide variety of small utilities whether gas, electric, or water.

Enterprise 4000 Systems

The Enterprise 4000 system evolved from the concept of the Enterprise 2000 in that it is a standard, “off-the-shelf,” turnkey system designed to meet the meter reading management system requirements of either

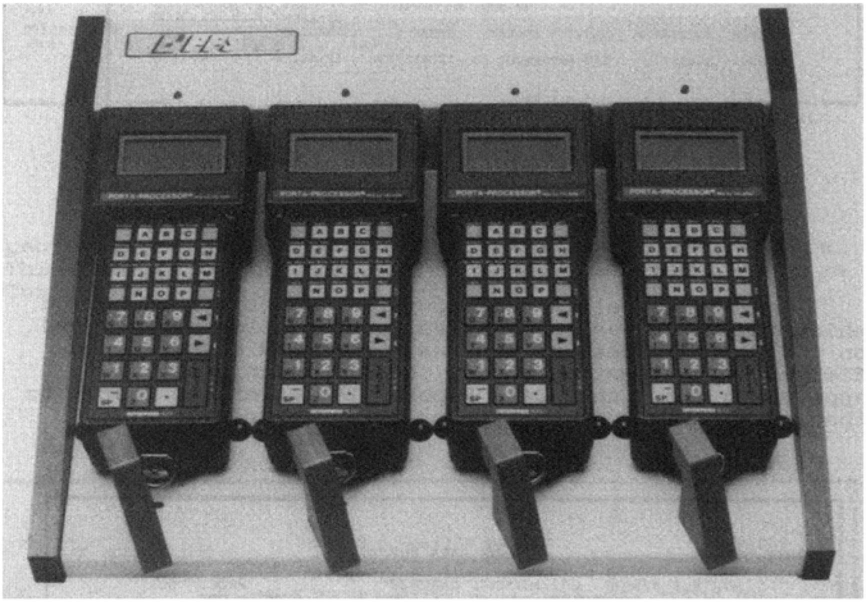

Figure 3. Communications Interface Device (CID)

```
MM DD YY              ROUTE DETAIL TIME STUDY REPORT              PAGE: XXX

     MTR RDR #/NAME: 0001/MICHAEL GARTNER                   PROC:  001
                           MR HDQ: 01 OFFICE: 01  CYCLE: 02  ROUTE: 012
                                                 TIME OF     TIME SINCE
SEQ#  ACCOUNT #   SERVICE ADDRESS   METER #      READING     LAST READ

0001 1234567      123 AMBERWOOD LA  123456789    12:24:33    12:30:15

*** E N D  O F  R O U T E ***
TOTAL METERS REPORTED    0001
*** E N D  O F  R E P O R T ***
```

Figure 4. Route Detail Time Study Report

small or large utility companies. This system, however, can be expanded and customized to meet the specific meter reading needs of large utilities.

This product features the 701E Porta-Processor, the IBM PC XT or AT (or compatible), up to four simultaneous communications lines, an optional tape drive, and a communications package that interfaces the mainframe to the PC.

The Enterprise 4000 has many added features above those of the Enterprise 2000. With the Enterprise 4000, the customer can resequence accounts on the PC, adjust the high and low parameters set by the host, and key readings into routes from the PC after the route has been read, a feature especially useful for the large volume accounts. The Enterprise 4000 also features a report generator for creating custom reports. Further, the Enterprise 4000 is menu-driven and requires little operator intervention.

In the Enterprise 4000 system, the 701E Porta-Processor also has additional features, such as block resequencing, backwards processing, seal condition reporting, and general use record processing for displaying a custom record.

```
MM/DD/YY                    CHANGE DATA REPORT                    PAGE: XXX

       MTR RDR #/NAME: 001/MICHAEL GARTNER              PROC:   001
                 MR HDQ: 01 OFFICE: 01  CYCLE: 02  ROUTE: 002

SEQ# ACCT#    SERVICE ADDRESS    METER NBR    ITEM    CHANGE TO

0001 1234567  123 AMBERWOOD LA   123456789    LOCAT      BR
                                              NBR DLS    04
                                              INSTRUC    RW
                                                         BRIDGETOWN

**** E N D  O F  R O U T E ****
TOTAL REPORTED METERS CHANGED 001
*** E N D  O F  R E P O R T ***
```

Figure 5. Change Data Report

```
MM/DD/YY                     NEW ACCOUNT/METER REPORT              PAGE: XXX

     MTR RDR #/NAME: 000/MICHAEL GARTNER                  PROC: 001
                             MR HDQ: 01  OFFICE: 01  CYCLE: 02   ROUTE:  012
                                         MTR   METER  # OF              PRESENT  DMD
SEQ#  SERVICE ADDRESS    METER#    TYPE  LOCAT  DIALS CONST     READING  TYPE
133B  123 AMBERWOOD LA   123456789 XXXX   02       Y  1234.56   12345     1

***  E N D  O F  R O U T E  ***
TOTAL NEW ACCOUNTS/METERS  0001
***  E N D  O F  R E P O R T  ***
```

Figure 6. New Account/New Meter Report

```
MM/DD/YY                     METER CONDITION REPORT                 PAGE: XXX

          MTR RDR #/NAME: 001/MICHAEL GARTNER                 PROC: 001
                      MR HDQ: 01  OFFICE: 01   CYCLE: 02   ROUTE: 002
   SEQ# ACCOUNT #    SERVICE ADDRESS   METER #      READ      CODE DESCRIPTION

   0001 1234567      123 AMBERWOOD LA  123456789    12345     MM   MTR MISSING
                                                              BD   BAD DOG
                                                              WB   WASP/BEES
                                                              SC   SEAL CUT
                                                              99   12345

*****  E N D  O F  R O U T E  ****
TOTAL REPORTED METERS         0001
***  E N D  O F  R E P O R T   ***
```

Figure 7. Meter Condition Report

A larger utility company can now select the Enterprise 4000 instead of a Series/1 and make the Meter Reading Management System a “distributed system,” operating several Enterprise 4000 systems, each one being an entity of the entire meter reading system.

In the 1986 Governor’s New Products Award Competition conducted by the Florida Professional Engineers in Industry, the Enterprise 4000 system was “commended on the quality and innovation displayed in its design, as well as its economic contribution to Florida and its citizens.”

Figure 8. Enterprise 2000 System

Host-Based Software

PPS host-based software serves as an interface between the mainframe computer and distributed personal computers, and provides an efficient method of high volume data transfer. The host-based software, designed to operate on IBM mainframe computers utilizing CICS, includes several primary functions:

- System Configuration Control—online and user accessible definitions of the PC and meter reading environment.
- Data Distribution—Segmenting route data based upon user parameters before transmission to the PC's.
- Data Consolidation—Grouping of meter reading data received from the PC's for user access and billing.
- Management Reporting—Provides both an on-line and hard-copy audit trail of system status and performance.

Benefits

All the PPS electronic Meter Reading Management Systems—the Series/1, Enterprise 2000, and the Enterprise 4000—give the utility companies numerous advantages over the old book and card meter reading systems and result in a chain reaction of numerous time-saving, cost-reducing benefits.

For example, productivity increases as meter readers use Porta-Processors to read more meters each day and the data they collect is transferred automatically for processing. This automatic processing leads to

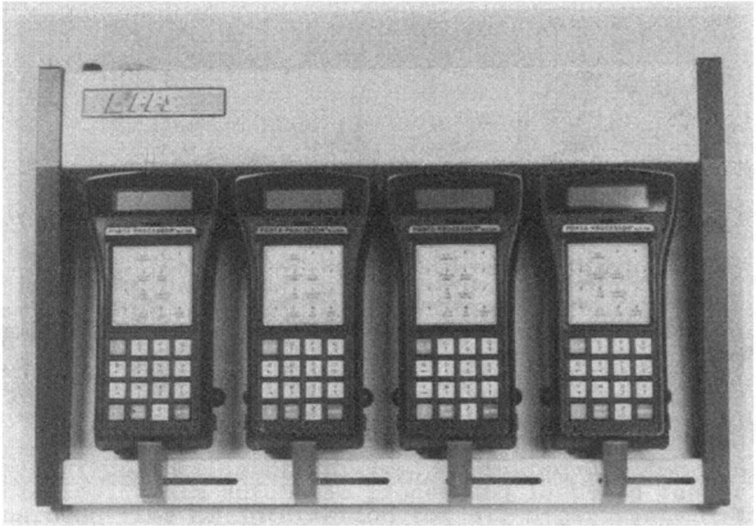

Figure 9. 790 Porta-Processors in 790R Communications Racks

Figure 10. Enterprise 4000 System

faster turnaround time of information for all departments. In most companies, the read-to-bill cycle is only one day. This feature results in immediate cash flow.

Furthermore, the chain reaction continues as accuracy greatly improves with the electronic recording and automatic transferral of data without the numerous chances for human error or misinterpretation evidenced with the old meter book and computer cards methods.

The improved accuracy and faster turnaround of data enhance customer relations. Timely statements reflect the accuracy of readings, and information is more readily available for customer inquiries. These inquiries are reduced considerably as re-reads are minimized and the more accurate statements result in fewer billing adjustments.

Then, too, supervisors have better control and more insight into the meter reading function as the various reports inform them of route activities or problem areas.

All these benefits result in a reduction of personnel requirements and overall operating costs so that an electronic Meter Reading Management System pays for itself within two to three years or less, depending on system size.

OTHER PPS PRODUCTS

In almost 10 years of operation, PPS not only designs and produces Meter Reading Management Systems, but the company has now diversified to offer other data collection products to the utility industry, such as the Field Data Entry System (FDES).

FDES

The FDES system is an applications generator. It allows multiple applications to co-exist in the hand-held microcomputer. The system is built on a virtual form concept rather than on a collection of prompt windows. This feature allows the user to access any information at any time. Because it is a form-based system, the FDES allows for easy and quick changes to the form, allowing the user to change data displayed, the types of verification, and the form processing. The package also uses a database manager which allows for data modification and reporting. PPS has designed several FDES applications for the utility industry.

Pole Inspection

One of the FDES applications designed for the utility industry is the Pole Inspection system with which the utility can collect assorted information on individual utility poles. The operator is prompted for information, such as pole number and circuit number, construction of the pole, equipment hung on the pole, foreign companies using the pole, and meters that are attached to it. Redundant information is carried over for each pole to reduce key entry. The information is then processed by a database manager to produce a variety of reports, such as a time-study report, hazardous conditions encountered in the field, and data entry errors.

Pipeline Inspection

A Pipeline Inspection system enables gas companies to collect various readings at tank and pipeline locations. Daily inspection data is down-loaded to individual handheld microcomputers. This information prompts the user to collect gravity, temperature, and other various gauge readings. The information is then processed by a database manager to produce various reports.

Substation Inspection

A Substation Inspection system enables the utility company to collect and verify substation equipment. Daily substation inspection information is loaded into the handheld microcomputers. The inspectors are prompted to collect oil temperatures, tap changes, and gauge readings. They are also prompted for an assortment of verification checks, such as bushing conditions, oil leaks, and switch settings. This information, in turn, is processed by a database manager to produce a variety of reports on the condition of the substation and the results of the collector.

Credit Collections

The Credit Collection system displays various types of account information to the credit collector. Some of this information consists of the past 12-month billing history, past 6 payments collected, miscellaneous comments, and meter location information. The system prompts the operator for the type and amount collected, or the shut-off method used. The assignment program optimizes all data assigned into geographical collection routes. Once the information is collected, it is processed by a database manager to produce various reports.

Field Service

The Field Service system collects information on the type of service rendered in the field. The account information can be preloaded into the hand-held microcomputers which, in turn, lead the serviceperson through the route, or the account information can be entered when emergency situations arise. The serviceperson is also prompted to enter the service data, such as the type of service rendered, parts used in the repair, and miscellaneous comments. The time and date of the service rendered is automatically recorded. Once the information is collected, it is processed by a database manager that can produce a variety or reports, such as a time-study report, daily parts consumption, and miscellaneous comment reports.

FUTURE TRENDS IN ELECTRONIC METER READING

Ongoing research and vendor competition ensure that the future of meter reading systems will hold even greater technological advances and user benefits.

For example, one idea is the portable on-site reading and billing system wherein meter readers use a portable microcomputer to enter the data and print out a bill which they leave with the customer. Postage savings alone with this system are phenomenal. PPS has such a system now in operation in Canada.

Another method of meter reading is based on the probe meter wherein the portable microcomputers are plugged into these meters and the data is automatically entered into the hand-held unit from the meter. Another version of this technology wherein the probe meter and portable microcomputer communicate through a fiber optic link is under development.

Other research is underway wherein meters transmit data directly to the central site by telephone, radio, or video cable, thus eliminating the necessity for anyone to visit the premises to collect meter reading data.

Today, many gas, electric, and water utility companies that already have the most sophisticated electronic meter reading systems available are ready and waiting for even more advanced technology. They realize that these systems increase their productivity, ensure greater accuracy, save them money, and build customer good will, all excellent reasons for continuing to improve their meter reading function.

For those utility companies planning to move away from the outdated meter books or computer card systems but still hesitant about an electronic meter reading system, the words of Will Rogers are appropriate: “Even if you’re on the right track, you’ll get run over if you just sit there.”

ADVANCED GAS DISTRIBUTION RESEARCH AT IGT

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ABSTRACT

IGT is developing an "advanced distribution system" that addresses the automation of distribution from a total system perspective. Program objectives are to demonstrate the technical feasibility of this concept and to assist the gas industry by identifying the final state toward which automated distribution technology is evolving.

Automated distribution systems have five key requirements: a sensor or encoder, a communication link, a data decoder or display unit, a power supply, and an installation technique. The total system approach facilitates exploitation of the intrinsic efficiencies and synergies among these five key features.

The IGT approach to automated system design includes: 1) a total integrated system design, 2) compatibility among components, 3) modular design that accommodates the diversity of individual utility requirements, 4) distributed intelligence, and 5) provision for future technological expansion.

IGT began developing a prototype of this system with a five task program. First, 14 components were defined in order to automate 28 utility operations. These definitions included component function, communication requirements, interface and operating requirements, and failure mode. Second, system issues arising from the interaction of individual components were resolved. Third, a laboratory version of the integrated system was designed to test the thoroughness of the definitions. Fourth, construction of the laboratory system was initiated to test the designs, demonstrate the technical feasibility of the system, and identify and resolve a variety of practical problems. Finally, well-developed technologies are being investigated to determine the extent to which they can be integrated into the system.

ADVANCED GAS DISTRIBUTION RESEARCH AT IGT

INTRODUCTION

IGT has begun a multi-year project to support the development of automated gas distribution systems. The primary objective is to lay the foundation for future systems that will be designed in accordance with what we call a "total system approach." The novelty of this approach is that it addresses automation of distribution as a total system, rather than addressing the automation of individual features such as meter reading or city gate stations.

The underlying premise of this program is that most distribution systems ultimately will be automated. In defense of this premise, we have found that nearly all the utilities we visited have at least one automation project in progress. Many utilities have several independent automation activities under way with additional projects in the planning stages. These automation projects range from custody transfer operations to residential meter reading. If the premise of ultimate automation is correct, we should consider ourselves to be in the initial period of transition from primarily manual operation to automated operation.

PROGRAM OBJECTIVES

The IGT program has two major objectives. One key objective is to demonstrate the technical feasibility of total automated systems by constructing and operating those components that form the system core. The program also addresses the issues of retrofitting advanced distribution systems to existing equipment. A second major objective is to assist utilities and manufacturers in making better decisions during the transition period by identifying the final state toward which automated system technology is evolving.

AUTOMATION TRENDS

Two significant trends have been observed during visits with a variety of utilities and manufacturers. The first trend is to increase the demands on an individual automated system after it is installed. For example, a company will initially automate some phase of its operation with the intent of solving a single problem. Often the equipment is intentionally designed with limited capability to minimize the first cost. After a shakedown period of a few months, management will be so pleased with system performance that new demands will be placed on the system, such as providing data to other departments, more rapid flow of information to operating people, or more detailed data than had been made available previously.

The second trend suggested by our investigations is that "islands of automation" frequently arise as designers address individual automation tasks. Later, designers are asked to build "bridges" between the islands as the utility seeks a more complete understanding of its operation. Trying to combine systems that were originally designed to function separately into a single integrated system produces incompatibility problems and results in an inefficient final design. It is probably not necessary for us to belabor this point, because most companies have already had several encounters with compatibility problems. This is particularly serious in companies that are moving toward total integration of their corporate data bases. Costs and inefficiencies arise because of the incompatibility of components and systems that were never intended to operate together. This can lead to a more expensive final design than would have been realized if the total system had been designed from the start.

"Evolution" is one possible approach to the transition to automation. However, we believe that utilities will make more cost-effective and efficient automation decisions it they have a better idea of the final state toward which the technology is moving. If present trends continue, the “islands of automation” will be joined by “bridges”, or interfaces, until they finally become a total system. One of our goals, therefore, is to anticipate what these “total” or “advanced” systems will look like when the automation transition period has ended. This project aims to assist utilities in making better decisions during the transition period by delineating the probable final states of technological development.

The development of advanced distribution systems is likely to be influenced by three factors. First, the cost of microelectronic components will continue to decline, even as capabilities increase. Second, utilities' demand tor timely information and tighter system control will increase as the industry encounters increased competition. Third, utilities will begin to identify and exploit efficiencies and synergies inherent in automated systems; these efficiencies and synergies are discussed in more detail in the next section.

EFFICIENCIES AND SYNERGIES

Our analysis of advanced distribution systems reveals that they contain several intrinsic efficiencies and synergies that can be readily exploited with appropriate design choices. Efficiencies here refers to the possibility of using system hardware to perform multiple functions by making small differential investments. Synergies refers to the fact that the existence of two independent automated capabilities frequently confers a third capability that was never anticipated in the design of either.

The potential benefits of efficiencies and synergies can be more readily appreciated within a conceptual framework in which we view automated systems as composed of five key, generic parts:

1. a sensor (or encoder)
2. a communication link
3. a data decoder/display unit
4. a power supply
5. an installation technique.

The efficiencies inherent in an advanced system can be illustrated with a simple example. Consider an automated gas meter with two independent capabilities: the ability to read itself and the ability to detect meter tampering. It is possible to build each capability to be totally independent of the other. However, it is clearly more efficient to use the same communication link (1) and power source (2) for both the tamper detection device and the meter reading circuit. It is also possible to design the electronic hardware (3) for a combined meter reader-tamper detector at a lower cost than for the cost of hardware for the two independent systems. Similarly, whatever receiving, recording, or display hardware (4) required for the combined system can be designed for substantially less than the cost of two separate units.

While this example is simple, it illustrates the key point of the system efficiencies: with proper design, small differential costs can provide substantial increases in system capability. When these additional capabilities reduce operating costs — for example, by reducing theft — substantial additional savings can be made for minimal differential investment.

The existence of potential system synergies can also be illustrated by a single change in the previous example. Assume that the meter is modified to permit automatic termination of gas flow. The combination of the capability to compute flow with the capability to shut off gas service gives an example of a synergy because the combination provides for a sophisticated excess flow protection. If the computed flow exceeds a predetermined level, either flow can be terminated or an alarm can be sent to the utility and/or customer.

Although this is also a simple example, it illustrates that the total system capabilities (three, in this example) can be greater than the sum of the individual capabilities.

A more meaningful example of a synergy arises from introduction of some of the communications technologies now being considered for retrofitting advanced distribution hardware to existing gas systems. Several of these technologies would use the gas mains themselves as conduits for information as well as gas. In many cases, it may be possible to detect and identify the communications taking place within the main from above the ground. If these expectations are borne out, the communications within mains would not only provide utilities with their own communication link, but would greatly simplify the location of buried mains and protection of mains from third-party damage.

KEY CONCEPTS OF THE TOTAL APPROACH

The existence of intrinsic hardware efficiencies and synergies suggests that the designers of advanced systems will ultimately exploit these opportunities. The five key concepts we anticipate will be involved in the design of advanced systems are:

1. A Total Approach to the System

   The potential to exploit efficiencies and synergies suggests that advanced systems should incorporate a total, integrated design. Combining several capabilities can make the combination more cost effective than automating individual capabilities. The total approach is to solve many problems together rather than one at a time.
2. Component Compatibility

   All system components must be designed to be mutually compatible and independent of the specific technology by which they interface to the rest of the system. This will assure a utility of choices in selection of automated features, the method of implementing those features, and compatible equipment from several manufacturers. While compatibility must be assured, the system must be sufficiently flexible to permit incorporating future technical developments.
3. Modularity

   Components should be developed in modular form so that a utility can select one or more alternatives to solve its problems. Modularity permits both a choice of technologies to solve a particular problem and permits tailoring a system to address utility-specific problems. For example a modular communication link lets a utility select any method, such as telephone, and later replace it with radio, wires, and fiber optics depending on its needs, economics, or technical advances. Alternatively, the utility should be able to use one mode of communication in part of its system and another mode in the rest without making any other changes in equipment.
4. Distributed Intelligence

   The use of many microprocessors located throughout the system (distributed intelligence) both avoids communications bottlenecks and permits a variety of tasks to be performed without requiring a single, large, expensive computer capable of handling all the details at every meter. Many tasks can be performed automatically or upon system wide command without constant supervision. Other tasks require communication with a “centralized authority”, a computer(s) monitored by a person(s) at one (or more) main control point(s).
5. Preservation of Future Options

   Recognizing that technology is likely to advance during the 50+ year lifetime expected of systems installed today, options should be kept open for future advances. This includes incorporating additional bits into microprocessors, providing access ports at selected points in the system, and using microprocessors that can be reprogrammmed remotely.

IGT'S ADVANCED DISTRIBUTION RESEARCH PROGRAM

In order to develop a prototype of an integrated, automated distribution system, IGT initiated a five task program in October 1985. These tasks are listed below:

1. define automated components
2. define the automated system
3. design laboratory system
4. construct laboratory system
5. investigate well developed technologies.

Each task is summarized below.

Definition of Automated Components

The generalized definitions of the automated components were formulated in two steps. First, 28 utility operations with the potential for automation were identified. Second, the 14 components required to automate these operations were defined without regard to the technology needed to implement the component.

The results of this work included the definition of the 14 automated components listed in Table 1. In addition, provisional definitions were developed for several robotic units and required support systems. Each definition included the component's required physical function, data communication requirements, interface requirements,

Automated Meter

Tracer Wire-Meter Interface

Telephone-Meter Interface

Radio Frequency Transmitter-Meter Interface

Automatic Curb valve

Automatic External Meter Valve

Automatic Internal Meter Valve

Customer Provided Power Supply

Utility Provided Power Supply

Back-up Power Supply

Distributed Intelligence Sub-Center

Communication Control Center

Advanced Thermostat

Generic Sensor/Actuator Interface

operating requirements, failure mode, and special design considerations. Components were defined to insure that they were mutually compatible and modular.

Definition of Automated System

In addition to defining the individual components, it was necessary to define and resolve the system issues that arise from the interactions among components. It was also necessary to optimize the interactions among components. For example, the factors that delimit the "span of control" of a distributed intelligence sub-center had to be identified. These factors include signal and power attenuation, multiplexing limits, and address length. In some cases the resolution is technology dependent.

The result of this work was the identification of 13 system issues. Where possible, technologically independent solutions were developed. Where technologically independent resolutions were not possible, the issues were resolved for one specific technology — the tracer wire system.

This latter system, which uses tracer wires for communication and power supply, was selected for several reasons. First, commercial telephone and radio frequency systems already exist; manufacturers of these systems have already resolved many of the issues. Second, this system offers a number of substantial advantages that suggested a need for development.

Design of Laboratory System

There were three goals in designing and constructing a laboratory model of the integrated, automated distribution system. First, the design of the laboratory system forced a careful and detailed evaluation of the component definitions. Second, this exercise led to the identification and resolution of a variety of detailed practical problems. Finally, the design of an actual system served to verify the thoroughness of the conceptual system.

Although a detailed discussion of the design of the laboratory system is beyond the scope of this paper, some of the highlights can be mentioned. The capabilities of the first generation laboratory system are listed in Table 2.

Table 2. Laboratory System Capabilities

Automated Meter Reading	Backup Power
Automatic Valve Closure	Access Port
Variable Rate Billing	"WHAT-IF" Analysis
District Meter Reading	Automatic Billing
Cathodic Protection Potential	Tracer Wire Interface
Tamper Protection	Main Pressure Control
Remote Reconfigurability	

Although it is important that these components are technically feasible, their greater significance is that they are part of a total integrated system. They are designed so that the tracer wire interface is a module that can be replaced at will with a telephone or a radio frequency transmitter interface. The automatic meter can operate on its own or in conjunction with an automated curb valve, an automated meter valve, an absolute or pulse counting encoder, a cathodic protection potential measurement device, or any of the other units defined as part of the system. We will return to the theme of what is necessary to interface to these modules later in this discussion.

The physical construction of the laboratory is as representative as possible of industry practice. The mains are 50% 2-inch plastic, 25% 2-inch steel, and 25% 6-inch cast iron. Pressures range from 40 to 60 psi in the plastic and steel sections to 6 to 10 inches water column in the cast iron. The supply system consists of a simulated city gate station and peak shaving plant. The 23 meters in the system are made by American Meter (10) and Rockwell (10), with 3 of the Japanese “smart meters.”

Construction of the Laboratory System

The primary purpose in constructing the laboratory system is to demonstrate the technical feasibility of selected components of the totally integrated automated system. This is particularly important because modularity and compatibility impose stringent requirements on equipment designs. The construction task further verified the completeness of the system definitions and forced the resolution of a variety of practical problems. These included a method of passing a set of wires through a regulator without hindering its function and passing insulated wires through pipe walls. When complete, this unit will be used to determine whether the power and data signals carried on the tracer wire can be detected above ground, thus providing a convenient pipe locating technique and assistance in preventing outside force damage.

Two electronic circuits were developed during this work —the Individual Service Unit (ISU) and the tracer wire interface. The ISU is a key component of the system because it contains the microprocessor and the input and output circuitry required for many functions. This unit is made possible by the recent development of low-power CMOS single chip microcomputers that include serial and parallel communication interfaces, multichannel analog to digital encoders, pulse counters, and three types of memory — all on a single chip the size of a quarter. The specific chip selected for the laboratory unit sells for $11 in quantities today, but its cost is anticipated to decrease in the future.

The second circuit that was developed is the tracer wire-meter interface. This circuit draws power from a two wire tracer system and also communicates over the same two wires. This allows the utility to communicate bidirectionally and to initiate the call from either the central office or the customer premises. This eliminates the need for battery power and allows the utility to have complete control of the communication system.

The laboratory system is expected to become operational in November 1986.

Investigate Well Developed Technologies

The fifth task of this program is to determine the extent to which well-developed technologies and existing equipment can be integrated into the total system approach. It is anticipated that this will lead to work with various manufacturers to integrate their equipment with the equipment of other manufacturers, either directly or through the medium of modifications made for the laboratory system.

We have found that while most commercial equipment cannot be directly connected to the totally integrated system, partial integrations appear possible. This results from two important phenomena. First, several manufacturers have recognized the potential benefits from developing equipment that is compatible with other, non-competing, units. For example, some meter reading systems produced by one manufacturer can read a variety of meter encoders and tamper detectors made by other manufacturers. The second phenomenon that helps in integrating equipment into a total system is the use of interfacing standards. For example, some meter reading systems can read, store, and transmit data from any sensor that can output its measurement in the corresponding standard.

FUTURE WORK

During the next two years, work will focus on several new areas. First, efforts to integrate both foreign and domestic commercial equipment into the total system approach will be emphasized. Second, additional capabilities will be added to the existing laboratory system to explore the synergies that arise from total integration. Finally, we will explore the potential benefits of integrating some new and emerging technologies into the total approach. The technologies to be explored include robotics and artificial intelligence.

SUMMARY

To develop a prototype of the total integrated system, IGR initiated a five task program in October 1985. Progress to date includes definitions of the individual components, identification and resolution of a variety of system issues arising from component interaction, and the design of a laboratory version of and integrated system. The lab system is now under construction and is expected to be operational within a few months. Well-developed technologies are now being investigated to determine the extent to which they can be integrated into a total system approach to distribution automation.

A LOW POWER MICRO DATA PROCESSING AND CONTROL SYSTEM PROGRAMMABLE ON SITE IN BASIC

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ABSTRACT

When trying to define the specifications of a micro dataprocessing system, the designer is always confronted by two incompatible requirements: relative specificity of the problem and lowest possible cost for the system.

Up to now, for applications resulting in production in large numbers, the only solution was to construct each unit according to individual requirements. This carried several major disadvantages : design costs were high, and it was impossible to modify the specifications or to adapt the product to a new, but similar application.

A survey of the gas industry requirements for small data acquisition units enabled the Process Control and Electronics Section to define and develop equipment well adapted to the majority of situations.

ALPAGA (small scale data acquisition for gas applications) is a low cost unit which nevertheless provides the functions normally required in industrial micro-computing (various forms of date acquisition, control possibilities, clock, display, transmission, considerable operating autonomy with battery). In addition, it may be programmed on site in BASIC by a non-specialist, to solve a multitude of problems.

Examples of utilization in fluid metering, flow rate correction, data acquisition, on site recording and processing of measurements, remote operation etc,…are described in the paper.

The programs are represented by a few lines of instructions and may be adapted to all specific needs by the operator himself.

A LOW POWER MICRO DATA PROCESSING AND CONTROL SYSTEM PROGRAMMABLE ON SITE IN BASIC

INTRODUCTION

Industrial data processing is a generic term which covers all the resources used to process information produced in industry. It has expanded spectacularly over the last few years, in particular in the gas industry, and constitutes a growing proportion of computer applications, alongside more traditional uses in scientific research and business.

Whith the appearance of the microprocessor in the 1980's, it became possible to create intelligent, and hence more independent peripherals; able, for example, to take certain immediate control decisions without reference to the central system.

This movement towards decentralization accelerated over time with the increasing integration of "silicon chips", producing two apparently paradoxal consequences: the production of more and more powerful circuits at ever lower prices.

The organization of computing was thus modified: the information processing sequence was broken down into different levels. The lowest level is in direct contact with the industrial process. It receives information from sensors and operates switches. It must deal with all the requirements of the industrial world. The highest level handles only information that has been previously analysed, sorted, pre-processed. In a pure industrial architecture, its role is to centralize and store data. It is in charge of the synchronization of subordinate systems and the supervision of the whole, it presents the overall results to the operator.

Within a structure of this kind, the flow of information between the levels, and the frequency and urgency of exchanges is reduced. While reducing telecommunication costs (it is possible, for example, to use the public switched network instead of a specialized line) the overall speed of response of the system is increased and a total breakdow of the structure is avoided. Moreover, as the processing carried out at each level is relatively simple, it is possible to use fairly low performance computers or even very small devices.

However, an obstacle to the generalized used of these local systems exists: though it is possible to use high cost equipment for the central computer, it is difficult to implant a large number of intellegent local systems which are relatively more expensive than the systems of the previous generation.

GAZ DE FRANCE therefore set out to find a solution to bring down the cost.

1—
ECONOMIC ALTERNATIVES

Several approaches could be considered:

– the first involved the construction of specific equipment, corresponding exactly to specifications, in the hope of obtaining in this way the lowest possible unit price. This would oblige the user to bear the full costs of development, which is feasible for units produced in large numbers and indispensable for units sold on the commercial market, but incompatible with the small numbers in question.

– the second involved reducing as far as possible the fixed development costs. To do this, a modular unit could be made available on the market in the form of boards which can be assembled in a rack. In order to meet the needs of a very wide market, the manufacturers of this equipment must provide several functions per board. In a given configuration, there may thus be unused functions which push up the final cost. Though a solution of this kind is acceptable for the most powerful microcomputers, it is totally unfeasible for small scale systems.

The third solution is, in our opinion, the best for systems to be produced in fairly large numbers. The basic idea exploits the possibility of constructing a system capable of satisfying several different specifications. After drawing up the list of utilizations of small microprocessor systems in the gas industry, we analysed the functions required and it was noted that a large number of them were shared. For these functions it is therefore feasible to develop specific, relatively low cost equipment. However, it must be possible to extend the basic system by adding modules for the additional functions required in each particular application.

On the other hand, it has been found difficult to delimit a common information processing core, and this leads to the creation of specific programs.

To sum up, we have adopted the following principles for our ALPAGA system (small scale data acquisition for gas applications).

– development of expandable basic equipment,

– specific programming of this equipment for each application, if possible in a high level language in order to reduce the development costs of the program,

– possibility of on site programming by the user to solve specific problems.

2— SPECIFICATIONS OF ALPAGA

2.1— PROCESS INTERFACE

Microelectronic systems differ from other fields of data processing in that the exclusively numeric world of the microprocessor must be connected to the process to be controlled (signals from sensors, remote control, regulation instructions, alarms, remote transmission…).

Similarly, it must adapt to the very diverse forms of information to be handled (voltages, currents, impulses, temperature,…) in order to be applied to the widest possible range of technical configurations.

The number of physical quantities acquired or generated by the computer is very variable, as is the accuracy of measurement required.

To obtain a compromise between all possible applications, the following configuration was chosen:

– acquisition of three to four analog entries for temperature probes or 4 – 20 mA transmitters with an accuracy greater than 99,9

– generation of one to two analogic quantities for voltage (0–5 V) or current (4–20 mA) with the same accuracy,

– availability of several on/off input/outputs and one or two impulse metering inputs.

2.2— REAL TIME

The process is an entity which acts upon certain events (switching of a relay, flow rate pulse, alarm detection…) which cannot be postponed or brought forward in time. The industrial microcomputer must therefore be able to perceive these events continuously and simultaneously. In addition, certain processes or actions must be triggered at very precise moments in the day or at regular intervals (daily reading, integration of a flow rate to obtain volume). The system must therefore include a clock which remains highly accurate under all operating conditions (even after numerous cuts in electricity supply).

2.3— ENVIRONMENT

The third major requirement for microprocessors is related to the operating environment. These systems are often installed on isolated sites which may or may not be linked by remote transmission to manned monotoring stations. Apart from periods of installation, calibration and inspection, they are left to themselves over several weeks.

Moreover, as it is not rare for stations to be subject to electricity cut-offs, systems must be highly independent, able to run on batteries. They must have a powerful memory for storage of results and data with a possible connection to a remote monitoring or remote operation system.

However, local display is highly recommented during the installation phase, but also for all subsequent consultations, particularly if the unit is installed in customers, metering stations.

2.4— OPERATING SAFETY

These systems are regularly installed in a disturbed industrial environment. They must be designed to operate in often wide temperature ranges, to be insensitive to variations in mains voltage and to electromagnetic interference. The adverse effects of lightning, shock and bad weather must be accounted for. Systems must be isolated in order to avoid disturbing the cathodic protection systems which may be installed.

Each system must be checked individually, in burn-in cycles, carried out in weathering chambers, before being used in operation.

They should be as compact as possible so that they can be used at all gas stations and even in metering boxes.

In order to deal with the largest possible number of operating problems, the functioning of the system must be adaptible to all operating practices.

The system is programmed using a widely used language well known to the general public: BASIC. In order to meet each specific requirement of each site, the program can be modified on site; ALPAGA is a product that can be installed anywhere.

The final requirement is of a financial nature. In operation, budgets are tight and investments are limited even for equipment which simplifies problems of organization, such as fixed date readings, which reduces the number of interventions and uneccessary movements of personnel. The economic advantages of such a choice are only noticeable after a certain period of adaptation.

3— PRESENTATION OF THE ALPAGA SYSTEM

3.1— DESIGN PRINCIPLES

Bearing in mind the requirements discussed above, the microelectronics engineers opted for two basic principles.

In order to guarantee both the independence of the system and excellent immunity to different forms of interference, CMOS (Complementary Metal Oxide Semiconductor) technology was chosen for all ALPAGA circuits. This technology uses almost perfect condensers which maintain the electric charges representing the items of information at their terminals. Only during modification of these states is there any notable electricity consumption.

It should be noted that consumption is higher when the speed of the system increases. The quartz for the synchronization of the logical circuits should therefore be chosen with care in order to obtain a compromise between response time and consumption.

The second principle chosen is that of using highly integrated, multifunction and “intelligent” components in order to reduce bulk and consumption. However, we took care to use only well tried components available on the market from numerous manufacturers at a reasonable price.

The models produced according to these two principles resulted in consumptions incompatible with an autonomous battery electricity supply of several mouths.

It was therefore necessary to pay particular attention to the problem of supply by designing a device to deactivate the system automatically, maintaining supply to a few circuits only. A low consumption logic reactivates the system automatically when necessary (external event, flow rate pulse, start of processing time, period of time elapsed…).

3.2— TECHNICAL DESCRIPTION

The ALPAGA microprocessor is an INTEL 8031 microcontroller. This device has a built in arithmetic and logical unit (ALU) and also offers many integrated functions such as a one hundred byte RAM, an 8 bit input/output parallel port, two 16 bit event counter/timer registers, a programmable serial input/output channel for telecommunications, two interrupt lines for different uses (activation, counting) and a low power idle mode which maintains data storage.

Sockets have been installed so that memory circuits of differing technologies can be used indifferently (RAM for measurement results and data, ROM, EPROM and EEPROM for the program), up to a total of almost 64 kilobytes.

A calendar clock is built-in for various different uses: dating of events, triggering of certain actions or computing cycles, time integration.

A 16 character alphanumerical liquid crystal display (LCD) displays messages in uncoded form and presents the different parameters, including the computer time.

A 12 bit, 4 channel analog-numeric converter, a high stability reference voltage and an electronic conditioning unit are used to connect 4 type 4–20 mA transducers and a type PT 100 platinum probe.

A two channel, 12 bit numeric-analog converter generates two 0–5 volt or 4–20 mA electric signals which can be used both for the remote transmission of an internal variable or to control a regulation unit.

The BASIC interpreter implanted in the system gives access to different functions performed by the circuits:

– loading and storage of variables or measurements,

– carrying out of complex and accurate calculations, thanks to the presence of mathematical operators and transcendant mathematical functions, on floating point reals,

– handling of the clock and time intervals,

– communication by means of the display or the serial channel,

– acquisition of measurements or output signals.

Using the very complete yet very simple instruction set, programming can be done from a terminal connected onto the serial channel without any knowledge of the internal architecture, of the operation of the circuits used or the machine language of the microprocessor.

The list of instructions constituting the program is locked in the EEPROM memory by a simple command. However, it is possible to unlock it at any moment to make required modifications.

All components are mounted on two “EUROPE” format (100×160 mm) boards placed in a rack with a set of three long life alkaline batteries. Rechargeable batteries with a mains charger can also be used.

The display is visible through a window on the front panel. On the back panel, a certain number of terminals and connectors are available for connection of the process input/outputs and peripherals (terminal, printer, remote transmission).

The system can be extended by adding optional boards in order to obtain larger numbers of inputs/outputs and a greater storage capacity.

4— PRACTICAL USES

A system of this kind has a very wide range of uses.

The user who does not wish to develop his program, establishes a description, and the programming in BASIC is performed by the manufacturer, if it does not correspond to an existing application. However, more and more users wish to modify the original program or even write it entirely thamselves.

4.1— INSTRUMENTATION

The instrumentation is the hingepin linking the industrial world and data processing: it is the interface between the sensors and the computer. Data acquisition systems are costly as their performance and their capabilities are remarkable, and often much greater than the real needs of the operation. In addition, as they are built for laboratory use, they are unable to withstand the outside environment or frequent transport.

A microsystem can carry out effectively some of their functions. Moreover, it can preprocess and record the measurements collected.

Here are some examples of the possibilities offered:

1) Instrumentation

For practical reasons it is useful to have transducers which generate an electric signal proportional to the physical quantity to be measured. However, the sensitive element is very rarely linear, and it is necessary to use “black boxes” which know the law of variation and can perform the linearization.

ALPAGA can perform this function and also take into account the ambient quantities (eg. temperature, pressure), correcting their undesired influence on the measurement.

2) Satellite stations

ALPAGA can either be installed permanently or during measurement sessions in gas stations in order to acquire and store diverse measurements. A member of the operating staff can empty the memory at any moment, but this may also be done automatically from the central system via the telephone network.

An ALPAGA system receiving measurements at the limit of validity is capable of calling the central system to transmit the alarm.

As it is possible to take account of on or off states, ALPAGA also monitors the triggering of elements of operating equipment (bypass valves, safety valves,…).

With on site programming, it is possible to adapt to each station and to perform additional tests, time-filling between different event or actions…

3) Billing and special prices

In billing applications, the systems on site accumulate the meter pulses. They make continuous corrections to take account of the pressure and temperature of the fluid. The corrected volumes are classified per period and are regularly transmitted to the central station which, after multiplication by a factor representative of the average calorific value over the period, determines the energy consumed. A bill can then be drawn up taking account of the gas rates charged at different periods.

In a closely related domain, ALPAGA can be used as a unit for checking special industrial contracts, for which it gives all the information, over several consecutive months, concerning the dates, hours and quantities of the largest hourly and daily consumptions, peak flow rates etc…

4) Data acquisition

In problems of modelization, it is useful to check the influence of certain parameters on the subject of the model (eg: influence of the ambient temperature on gas consumption). In order to do this, it is necessary to take measurements on the premises of different types of customer using a device which records the meter registrations and the outside temperature.

By using ALPAGA, the mass of information to be stored is limited as a certain amount of statistic processing can be carried out in situ. Autonomy is thus further increased.

5) Tracing and chromatography

The computing possibilities of ALPAGA associated with the timing function make it possible to use ALPAGA for flow rate measurement by tracing.

The system controls the injection of a regular series of pulses of tracer gas into a pipeline and analyses the signal emitted by the sensitive cell placed several kilometers downstream. After detecting the tracer gas, it calculates the average time taken by the gas to travel the distance and gives the gas flow rate. This is all entirely automatic.

Similarly, the ALPAGA system, associated with a chromatographic sensor, can detect, characterize and determine the content of one or several predefined compounds in a mixture.

Applications are numerous, in the field of odorization control, for example.

4.2—
REGULATION

The simultaneous presence of analog inputs, of control outputs and a processing unit mean that ALPAGA can be used for the regulation of several simple processes. The algorithms can of course be standard, such as proportional, integral or differential, but also much less simple and familiar. In the latter case, conventional regulators cannot be used.

Instructions are transmitted either analogically or by the serial channel.

The system is used independently, but may be linked to a monitoring computer.

CONCLUSION

ALPAGA is the fruit of the technological development of microelectronic components combined with the study of the needs of potential users.

It may be used in production, transmission and distribution as well as in the laboratory.

This system is attractive not only due to it low price, but also due to its many qualities (user friendliness, capacity for adaptation and modification on site).

Moreover, as it is accessible to the operator, he is more likely to accept its introduction.

The continuous development of more and more highly integrated components will result in further improvements in the man-machine interface.

HOW MICROELECTRONICS SAVES MONEY ON GAS SYSTEMS

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ABSTRACT

Many devices and systems based on microelectronics are available for economic and operational control of gas systems. They include software that gives each device its distinct capability. Effective use of these capabilities requires the user to examine the sources of system operating expenses on a company-wide basis. This paper is an introduction to such an analysis. The emphasis is on using the same equipment as a basis for economic and operational optimization of gas systems.

HOW MICROELECTRONICS SAVES MONEY ON GAS SYSTEMS

Introduction

Any gas system is a collection of processes for the production, transportation, and distribution of gas to the users thereof. Measurement and Regulator Stations measure the gas at wells, processing plants, compressor stations, and at sales and purchase points. Since gas systems have a finite capacity, and must operate continuously, care must be exercised to insure that each user gets his contracted share of gas and that no interruptions in service occur. By definition these two criteria override all others. Meeting them can be costly. Small compensations for operator uncertainty lead to persisting inefficiencies whose costs continuously accumulate. Microelectronic devices reduce these inefficiencies by providing accurate decision level information, precise controls, and manageable data base. Most important they provide operators with realtime response to system needs, and immediate feedback of the results.

Microelectronic compressor control systems give the operator a realtime output of specific fuel consumption (BTU Burned/BTU Pumped). He knows immediately the effect of control strategy on fuel consumption.

Microelectronic systems do a lot of analysis of system problems. This analysis includes their own reliability. Operator confidence in the system is the prime ingredient need to achieve the savings proposed. The operator must compensate for uncertainties usually to the economic disadvantage of the company.

The combination of reliable information and analysis allows the user to cut down significantly on scheduled inspection, labor, and travel. Maintenance persons are dispatched to various sites for a distinct requirement and can be equipped with the tools and parts for the task at hand.

Identificaion of Lost Gas

Lost gas is a major factor in operation of gas systems. Historically many accounting and regulatory techniques have evolved to reduce its economic effect. With the present trend toward deregulation, many of these techniques will cease to exist. Cost for losses will be directly on the gas company. We can address the causes and cures directly rather than examine the history.

Loss of gas occurs in four major ways. Mitigation, or elimination, of these losses requires the interaction of various systems of accounting and telecontrol. The four areas of interest are:

1. Metering errors.
2. Seepage to atmosphere.
3. Thefts.
4. Unmetered company use.

Metering errors occur in several ways, all susceptible to significant improvement by use of microelectronic techniques.

1. Basic metering accuracy is the sum of the accuracies of the primary element, and of the various auxiliary measurement and computing devices. Mother nature has presented us with a complex set of choices in the flow meter technique. The resulting choices are less than ideal. Let us examine some facets of this problem and how microelectronics help.

1.1 Accuracy is stated as ±N% of full scale. This means that if the meter is flowing its maximum capacity ±N% of the gas may be or may not be in the system. When it is flowing at 50% of full scale, ±2N% of the gas is an uncertain quantity.

Microelectronic devices improve the accuracy of auxiliary measurements to better than ±0.2% of full scale. They can correct for non-linear performance of the primary devices and other measurements. Special calibration techniques are available for this.

Repeatability of measurements is generally an order of magnitude better than the accuracy. Microprocessors can operate on this repeatability rather than the full scale accuracy. The end result is that uncertainty is reduced by a half-order-of-magnitude.

The computational accuracy of modern micro-processors is better than ±0.1% of reading. Reading is emphasized to remind the reader that no degradation of accuracy occurs as the flow rate decreases. All meters have a turndown ratio over which their accuracy is acceptable. Microelectronic devices allow the user to operate each meter in its most accurate and repeatable region, then switch other meters on or off to control the measurement range. Conventional practice has fixed points very close to the maximum useful range of the meter. Microelectronic devices allow other switch points; allow switching of combinations and types of meters to achieve the best results.

Common applications will exist for a combination of a positive displacement meter and one or more Vortex shedding meters and/or one or more orifice meters.

A little arithmetic problem will show the amount of money involved in the above concepts.

Table 1

Daily				
Daily Flow MSCF	Cost per MSCF $	Amount $	Uncert. Conven.	Uncert. Micro-Elect.
500	$3.50	$1,750	$45.00	$4.20
1,000	3.50	3,500	105.00	10.50
1,500	3.50	5,250	157.50	15.75
500,000	3.50	1,750,000	525,500.00	5255.00

These uncertainties can lead the operator to buy added supplies, to curtail industrial interruptables, or to activate high priced peak shaving plants when it is not necessary.

2. Seeps from the system occur at many locations. Individually seepage from a connection, a corrosion pit, or valve packing is insignificant. Collectively they are significant. On some systems this can be 4–5% of total thruput. The seepage rate is directly proportional to the absolute pressure in the line. With a system having a loss rate as shown:

Table 2

Daily Flow MSCF	Cost per MSCF	% Loss	Daily Amount $	Annual Amount $
11,000	3.50	5	175.00	2, 100
	3.50	4	140.00	1,680
		3	105.00	1,260
		2	70.00	840
500,000	3.50	5	87,500.00	1,050,000
		4	70,000.00	840,000
		3	52,500.00	630,000
		2	35,000.00	420,000

It is obvious that fairly small systems and subsystems would profit from grid pressure control. Figure 1 shows a dispatch system which automatically controls pressure. Figure 2 shows a CRT display of pressures.

Microelectronic devices allow us to control the grid pressure of a system to meet the expected load. Figure 3 shows the regulator discharge pressure profile for a system in the City of Birmingham, Alabama. The dispatch computer automatically sets the discharge pressure setpoint during the day. The system operator selects one of a number of profiles stored in the central computer. Previously the regulator was set seasonally to the high pressure indicated on the charts. (30.73 psia). Now the average pressure is about 27.63 psia or an average 10.08% reduction. The user reports a saving over $1,000,000 for one heating season. He is expanding the system to include outlying areas of his system.

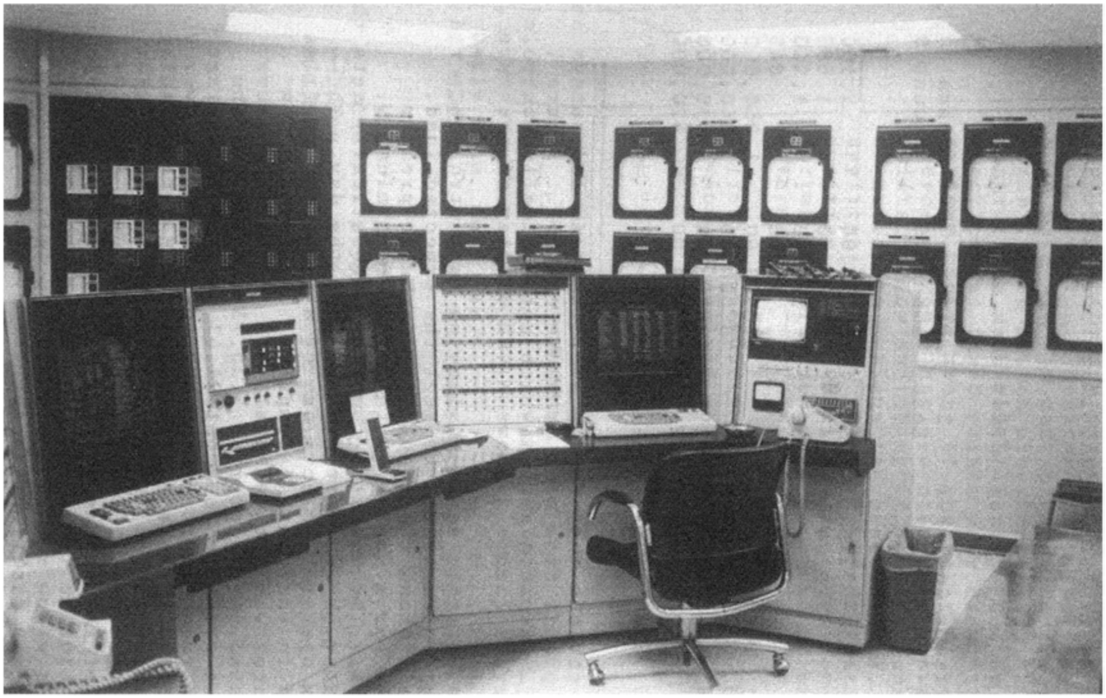

Figure 1. A computer based gas dispatch system which automatically controls sixty (60) district regulators for Alagasco, Birmingham, Alabama. Metameters give the operator a quick view of grid pressures.

Theft of gas became popular during the dramatic price escalation in the 1970s. Modern microelectronic systems allow remote monitoring of fairly minor loads. In distributed computer systems a subcentral can monitor an area and determine over a period of time which load is pressure sensitive (seeps), which is temperature sensitive, which is time sensitive, and load which is none of the above. Areas with a high base load would be candidates for more detailed theft surveys.

Elimination of uncertainty by microelectronic techniques has had some rather dramatic effects. These effects involve not only direct operational activities, but economic activities, and even use of management resources. This involves the concept of system modeling to determine:

- System line pack with trends and time to maximum pack, and time to minimum pack. This one capability saved a lot of management time supervising system line pack.
- System contracts supervision records the performance of each system supply or sales contract every five minutes during the gas day. It keeps totals for each contract grade of gas by order of take and/or by percent of station flow. This capability saves money by assuring contract performance in connection with the load forecasting. Peak shaving gas and company use are treated as psuedo-contracts in the problem.

These methods require continued updating as commercial practices are always changing. Again, the state-of-the-art allows this to be accomplished more economically than was possible in the past. User friendly software and self organizing data bases simplify the job. Industrials can contract for supply from third parties who may be:

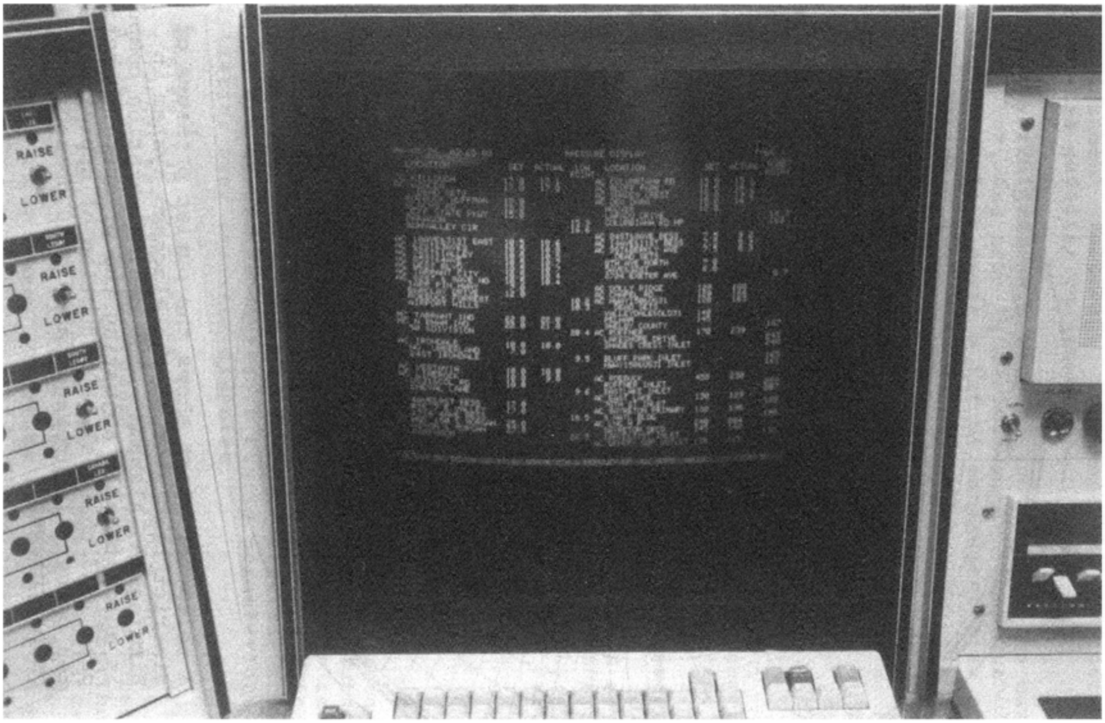

Figure 2. A CRT display of grid pressure setpoints and grid pressures in the Birmingham area.

- Producers
- Brokers
- Others

Unless this gas is accounted for in realtime custody transfer, the buyer will be at risk of losing substantial quantities if his ability to accept delivery is impaired. Microprocessor-based Metering and Regulator Station controllers allow secure accounting. Realtime audit trails are generated to reduce costly negotiations and litigation over transfer disputes.

- System load forecasting and negotiations achieving one forecast per day was a great effort in the past. With a distributed microprocessor system, a new forecast is generated every fifteen minutes so that opportunities to make money from system operational changes can be seized while they exist. Give-ups can be sold, or diverted to storage. Overruns can be detected before the system is in any danger. The microprocessor system creates a large historical data base. This provides the possibility of "Like Day" forecasting as well as statistical (Box-Jenkins) forecasting based on regression analysis.
- System gas balance, and subsystem gas balance insure that purchases, sales, and storage all balance within acceptable limits. This aids in fracture detection, in detection of major meter errors, and large thefts.

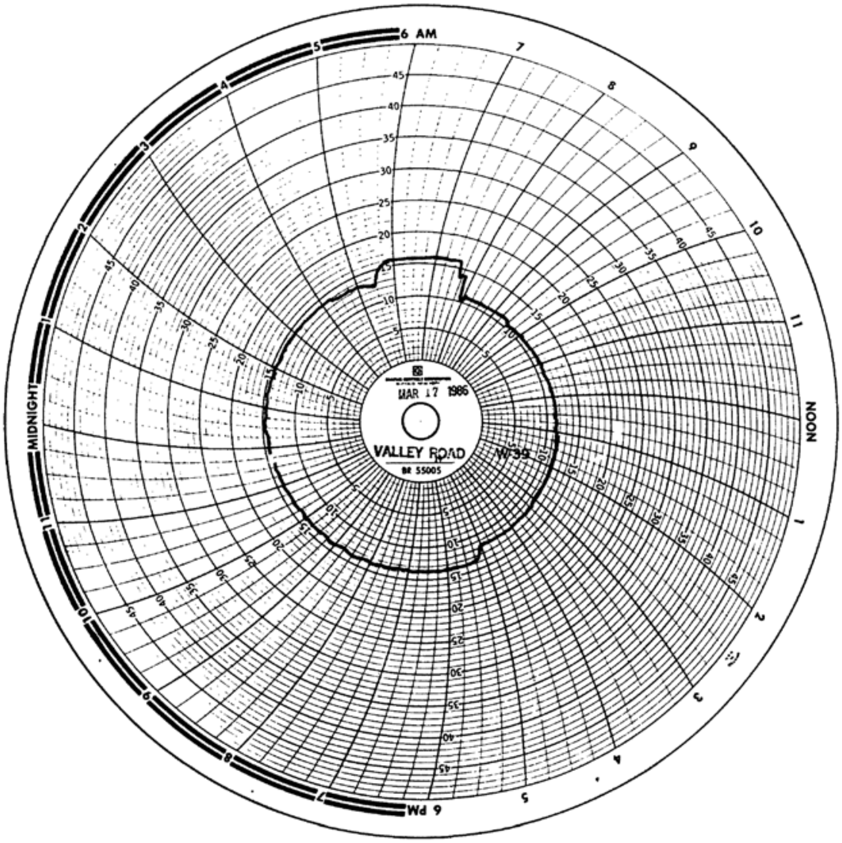

Figure 3. A telemeter chart shows the outlet pressure of a district regulator on the Alagasco system in Birmingham, Alabama. The central station computer is automatically adjusting the pressure to anticipate load changes. A reduction of approximately ten percent in average daily grid pressure has been achieved.

- Realtime calculations of system state and capacity are generated by the distributed microprocessor system. Since each microprocessor in the system has a limited, usually site specific task, constructing systems of highly divergent size is possible.

  Judgments based on realtime data concerning the system ability to handle more load can postpone construction projects and prevent loss of sales.

A lot has been said about the functions microelectronics can perform. Some examples of microelectronic elements and assemblies are appropriate. It is impossible to discuss all configurations and techniques available. Anyhow the discussion will be out of date before it can be run thru a copying machine. Some classes of components are:

- Analog Integrated Circuits that are used to amplify signals, convert them from analog to digital and digital to analog, and to generate analog frequencies for communications carriers. Comparators compare one analog voltage to another.

- Medium Scale Integrated circuits that perform a few digital logic functions. These are used when it is not appropriate to use a microprocessor for the task.
- Large Scale Integrated circuits are usually microprocessors with various capabilities. These chips contain hundreds of thousands of circuit elements. Some contain memory circuits as well as the processor. Other chips are devoted exclusively to memory functions.
- Very Large Scale Integrated circuits contain processors, memory, and various peripheral drivers on one chip. Their advantage is increased speed of operation from the very short conductors and small circuit elements. Electron transit times thru these elements become a problem if the elements are more than a few thousandths of an inch in length.
- Gate Array Circuits allow custom circuits to be packaged in LSI configurations. These are used as specialized drives on the input/output circuits of equipment such as the remote digital controller shown in Figure 4.

These circuits are assembled onto circuit cards and soldered into place. From these circuit cards we make measuring devices, computational and control devices, communication devices, video terminals, and computers.

Summary

Microelectronics have added capability to provide economic and operational control in one package for many gas system control requirements. It would take many hours to describe these in detail, and many more hours to digest the effect these can have on gas system profit and safety. The hope is that you will be willing to study and try these units, and that you will follow the lead of the several progressive companies who already have impressive installations.

Figure 4. A modem microprocessor based Remote Digital Control Unit. The 16 bit microprocessor and user friendly software allow construction of very powerful expert systems in the field.

Figure 5. A microprocessor based personal computer configured as a central for the remote shown (and in Figure 4). It may also be the Man Machine Interface for a Local Area Network in a larger hierarchy.

ECONOMICS OF ELECTRONIC MEASUREMENT

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ABSTRACT

During the past years the management of the measurement departments in many of the gas transmission companies across the United States and Canada, have been in a quandary about what to do with electronic metering systems vs. the use of charts in gas metering. Abundant questions have been asked about electronic measurement such as:

Is it time to change?
Which method of measurement really is more accurate?
Our pipeline and stock balances are OK? Aren't they?
How will electronic measurement be different from the old method?
Will electronic measurement ever become universally accepted like the paper chart?
Don't we need electronic measurement standards in this industry?
When is the pay off.
With the new FERC 436 ruling how can electronic measurement help me.
How do I establish an audit trail.

It is the intent of this paper to seek an understanding of the standard method vs . electronic measurement systems and their respective costs. The electronic systems referred to in this paper are mainly the type that stand alone and have inputs of differential pressure, static pressure, temperature, and can retain an audit trail similar to the chart recorder except in a digital form . These systems operate on a battery which is recharged via solar or thermoelectric or other conventional means . Most of the cost analysis shown later refer to gas transmission companies. Many producer companies require additional data gathering and control systems such as tank gauging, well head pressure readings, well control, and surveillance, which may require a higher intelligent type of device located at the well site.

WHO IS AFFECTED BY MEASUREMENT IN A GAS TRANSMISSION COMPANY?

Today the measurement communities have built a entire world around the processing of paper charts. The following is a list of the different areas the paper chart or its output is employed in a major gas transmission company:

1. Measurement Department
2. Auditing Department
3. Operation Department (Dispatching)
4. Contract Department
5. Accounting Department
6. Management

These departments have essential needs, all of which must be satisfied by the paper charts used today. Some of the departments are interested in the accuracy of the device, while others will be interested with the installation and maintenance, and still others require an audit trail of any changes at the metering site . It's obvious that a change in the measurement device (actually the orifice plate or positive displacement are the primary measurement device and the chart recorder or flow computer is the secondary measurement device) can drastically effect many functions in a large organization.

PRIMARY ELEMENTS

The orifice and the positive displacement meters have become the two primary methods of gas measurement in the United States and Canada. During the early 1900's, the bomb-type recorder provided a daily record of differential pressure. With the development of diaphragm and mercury manometer differential pressure recorders with pressuretight chambers separate from the chart chambers advanced the state-of-the-art for orifice measurement. This paper will concern it self with orifice plate measurement and chart recorders primarily.

METERING UNCERTAINTY: ORIFICE AND CHART RECORDER ACCURACIES

It has been said that the majority of gas measurement for custody transfer is handled by orifice plates with a bellows chart recorder. Some estimates put the number of orifice measurement and chart recording devices in the United States near the half million mark. Over 40 to 50 years, with the existence of charts, the standardization of an orifice plate and a chart recorder and their procedures, has become so strong that no new method of measurement has occurred appreciably.

The following excerpt from "Pipeline System Measurement Accuracy" written by Don Bell with Nova will define clarify metering uncertainty as used in orifice flow measurement:

"Accuracy can be defined as how closely a measure conforms to the true value. In gas flow measurement, as is true in other forms of measure, the true value is unknown. The flow rate is generally inferred within limits and the degree of inaccuracy is based upon statistical probability. Therefore, when speaking of metering accuracy we are generally referring to measurement uncertainty. This is a calculated value based on experimental or test data which provides an estimate of the possible error. As the absolute maximum error is seldom known, the metering uncertainty is expressed in terms of a range within which the true value of the observed or reported flow rate is expected to fall. The number of times the true value will lie within these limits, is stated in terms of probability, which is normally set at the 95 percent confidence interval. This means that 95 percent of the time the true value of the measured quantity would fall within the estimated uncertainty limits."

As stated above the true value in flow measurement is unknown, but the probability of being within 95% of the true value is very high with standard measurement practices. In this paper we will be trying to understand the uncertainties associated with chart, flow computer and orifice measurement.

Before any true appreciation can be made of the comparison of electronic measurement to chart recorders, an explanation of orifice plate measurement accuracy is in order. According to AGA-3 report September 1985 edition (the green book) page 46 section 7.4 Uncertainty Estimation affirms the Root Sum Square (RSS) method for calculating uncertainty in an orifice plate as follows in Table 1:

TABLE 1
EXAMPLE OF THE EFFECT OF UNCERTAINTIES USING EQUATION 75 (From AGA-3, 1985)

Exponent	**Variable** **Square**	**Percent Uncertainty of Variable** (+ –)	**Effect Factor**	
Fb	Basic orifice factor	0.5	1	0.25
Fr	Reynolds number factor	0.1	1	0.01
Y	Expansion factor	0.25	1	0.0625
Ftf	Temperature factor	–	–	–
Fgr	Relative density	0.6	1/2	0.09
Fpv	Super compressibility	0.25	1/2	0.0156
hw	Differential pressure	–	–	–
Pf	Absolute static pressure	–	–	–
	Sum of squares			0.4281
	Square root of sum			**+– 0.648%**

Notice the flowing temperature (Ft), the differential pressure (hw), and the absolute static pressure (Pf) percent of uncertainties have been left out. The reason for this is to establish the uncertainty of only the calculated (F) values. The remaining uncertainty variables are the calculated parameters in the AGA –3 equations.

By using the same technique as illustrated in Table 1, a determination of the stated full scale accuracies from a popular manufacturer of a chart recorder is shown in Table 2:

TABLE 2
MANUFACTURE STATED ACCURACY FOR STANDARD 3 PEN CHART RECORDER

Variable **Exponent**	**Percent Uncertainty of Variable (+–)** **Square**	**Effect Factor**	
Differential Pressure Eleement	0.5 FS	1/2	0.062500
Temperature Element	0.25 FS	1/2	0.015625
Pressure Element	0.5 FS	1/2	0.062500

Variable	Percent Uncertainty of Variable (+−)	Effect Factor
Exponent	**Square**	
Sum of Squares		0.140625
Square Root of Sum		**0.375000**

Table 2 demonstrates the RSS method of calculating full scale accuracies of a 3 pen chart recorder. From this Table one can derive the accuracy of a chart recorder to be +– 0.375% of F. S. This accuracy statement above does not include any temperature coefficient which ultimately effects the total accuracy of the chart recorder. This issue will be addressed later.

By adding the result from the Table 1 and Table 2 one can derive the result obtained from the AGA −3 manual of + − .7541 uncertainty in an orifice metering device and a standard chart recorder.

Although chart recorders have an uncertainty of + − 0.375% of full scale they have other areas of concern such as: improper inking, chart shrinkage or expanding, motor drive speed control, mechanical linkages sticking, etc . Additional areas to be discussed later are the uncertainties of integrating charts that are painted.

DIFFERENTIAL HEAD DEVICES — INFERRED MEASUREMENT

An important truth to realize when dealing with differential head devices such as an orifice plate, is the fact that orifice measurement is an inferred type of measurement. That is, the measured differential and static pressure along with temperature are measures of volume and are subject to interpretation (usually by human means via integration procedures). The point is to understand that an audit trail is necessary for orifice measurement systems. Over the 50 years of reading charts, the industry has become dependent on an audit trail, and for any new method of metering to be acceptable this audit trail requirement must be satisfied.

A device that is not inferred measurement is the positive displacement meter. A P. D. meter has a known displaced volume, under known flowing conditions, and can determine an accurate measurement of a fluid.

Its interesting to note that P. D. meters with mechanical totalizers do not have an audit trail requirement. Liquid P. D. meters for measuring crude oil (used in LACT units) often have correction for temperature and or pressure, but are not required to have an audit trail as does orifice measurement, at least no more detailed than 24 hour averages and totals. Whereas in gas measurement a continuous audit trail of data is demanded.

CHART INTEGRATION

In understanding chart measurement as done today, it is important to grasp how the gas industry processes charts, and how the operator accomplishes this task. As will be illustrated later the integrator has a major part to play in determining the final volume from a chart.

There are two major manufactures of chart integrators recognized in the gas industry: (1) U.G.C Industries Inc. in Shreveport La. and (2) Flow Measurement Co. in Tulsa Okla. Both companies offer manual integrators and optical scanners.

UGC MANUAL INTEGRATOR

The manual integrator is an instrument that allows the operator to locate pens on the differential line and the pressure line on a paper chart. With the pens located properly, the operator can use a foot switch to control the rotation speed of the chart. Using the manual controls the operator follows the static pressure and differential pressure lines. The integrator in turn extracts an extension calculation, and an average pressure over the full rotation of the chart, along with a scan count. Charts have a time period based on the field recorder clock. These time periods range from 24 Hr. to 31 day rotations.

The extension is integrated with the time period of the chart and the square root of the product of differential in inches of water column times the static pressure measured in PSIA.

After a chart has been integrated the operator can determine an average temperature (with a 3 line chart or a separate recording) based on an average of a full rotation from the chart being calculated. Today some of manual integrators have the capability to down load the extension factor along with the scan count to a host mainframe computer for final calculation of volumes.

Manual integrators are stated to have an accuracy of 0.2% F. S., but it is important to understand that the operator may have some effect in determining this +−0.2% calibration. The two manufactures of integrators believe that the more extensions or readings over a given time period of *a* chart an integrator can perform, the closer to the true accuracy the readings will be. Most industry leaders are in agreement with this statement.

The manual integrator is in widespread use across the country simply because of its simplicity and reliability. This technology has been used for nearly 50 years along with the paper chart.

UGC OPTICAL SCANNER

All of the major gas transmission companies across the U.S. use this type of integrator for their chart processing. The advantage is it's speed to integrate a chart and less reliance on an operators skills. Under normal conditions the manual integrator will take any where from 10 seconds to 2 minutes depending upon the variation in the differential line and pressure lines. With the optical scanners approximately 10 seconds is required for full Most all the experts in flow measurement agree that if the differential swings are considerable then the induced error due to the amount of extensions calculated becomes significant.

WIDE BAND CHART

Fluctuating of flow has always been the major complaint for circular paper charts. The differential pen and sometimes the static pressure pens, can move dramatically over the chart (see Figure C). The manual integrator is the only method of determining the flow from this type of measurement. Most optical integrators can not be used if the static pressure line crosses the differential pen line, and therefore can not distinguish between the two.

In researching this paper many different gas transmission companies were asked how they handle painted band charts. The response was surprising since no two gas transmission companies handled it exactly the same way. A common denominator displayed among the gas transmission companies was the use of high speed test charts to spread out the painted band, to determine where the operators should integrate the charts. The clock speed of the chart drive on the test chart would be increased to 1 hour, or 30 integration. With todays technology these new optical scanners can be incorporated to communicate with host main frame computers, and in this way expedite the final calculation with minimal handling by operators.

The accuracy stated by the manufactures are the same as the manual integrators that is 0.2% of full scale. Again the operator controls the calibration procedure, but in this case very little human error can be induced to the final calibration.

Both systems serve a purpose and allow the gas industry to process just about any type of chart. Although painted charts can be integrated, it is universally accepted that error's can and do occur. Since painted charts are processed with a manual integrator, the operator could pick the wrong average differential, or pressure, and therefore calculate an erroneous volume. A better illustration of this error is shown later under perceived integration.

COMPARING "EXTENSIONS AND TIME" WITH FLOW COMPUTERS AND CHART RECORDERS

To better comprehend how a flow computer compares to chart recorders, the realm of time has to be considered. Realize that the modern flow computers of today, calculate not only the extension but the full AGA-3 calculations on a one second or faster basis. To illustrate the effect on the extension alone the following table shows how many extensions are performed in one day, seven days, eight days, and thirty days increments. On the other side of the table are the two manufacturers of integrators with their stated scan counts.

TABLE 3
TABLE OF COMPARISON

Chart Period	Computer Extension/Period	UGC	Flow Measurement
		_800–	–3072–
1 Day	86,400 sec.	.925%	3.555%
7 Day	604,800 sec.	.133%	.508%
8 Day	691,200 sec.	.115%	.444%
30 Day	2,592,000 sec.	.031%	.118%

As illustrated on Table 3 — only one time period with the flow measurement integrator, revealed more than 1% of all the necessary extensions being taken. Obviously the older method of calculating the extension vs. the real time calculation of a flow computer is drastically different.

To determine the amount of error induced by not calculating all the necessary extensions is very difficult. minutes, and even sometimes to 15 minutes (Figure D). This method of determining the correct location of the average differential and static pressure has become somewhat of a standard in determining the true volume of painted charts. An assumption is made that once a test of this type is run, the pattern will remain the same until another test is run.

It's quite obvious that this method does have its limitations. The gas company has to assume that if the fast clock chart displays more flow near the lower portion of the paper chart, then the chart in question will be integrated on this lower portion, and the flow is expected to stay the same over the whole (24Hr. or greater) chart period. Understand with todays technology of charts, and chart recorders, there is no better way to estimate the final volume from this type of recording.

Graph #1 illustrates a 108 second period of time. The 108 seconds comes from taking 24 hours converted to seconds and divided by 800, the number of extensions from an optical integrator. Notice the span of the chart is from 7.5" to 24.5" or a 17" band width. A chart with this size of band width compressed over 24 hours would be seen as a solid painted band chart running from 7.5 to 24.5 inches. Obviously an optical integrator would not be able to determine the proper flow.

With the use of a manual integrator the average mean differential of this graph is 15.87. This is the most likely center the integrator would chose because of the symmetrical balance around the 15" mark. On the other hand a flow computer would be taking the square root (extension) every second and coming up with 108 extensions displayed by the squares on the graph. The average as determined by the manual integrator is 15.87 and its square root is 3.98 and the average of the 108 square roots as determined by the flow computer is 3.95. The difference is –0.77 percent. In other words the chart recorder being an analog device is averaging higher by +0.77 percent as compared (in this example) to the flow computer.

One fact that is interesting to note, as shown on Graph #2, is if the flow is centered around the 100" mark, and with the same pattern, the percent difference between the integrator vs. flow computer calculations is less. This occurs because one inch error at the 10 inch level has a much greater effect then one inch error at the 100 inch level, (i.e. square root of 11=3.31, the square root of 10=3.16 or a difference of 5%, where as the square root of 100=10 and the square root of 101=10.05 or .5%)

Graph #3 shows a pattern of flow where the differential stays relatively steady except for spikes that travel from 30 inches to 5 inches of differential seen quite often on separator dump or gas lift type wells. The time duration of these spikes is only 8.3 percent of the total time. Notice in Graph #4, which is based on one hour of time, the same pattern was compressed and appears almost like a solid band. How would a manual integrator operator handle this graph? The study shows that the majority of operators would pick a line right down the center of the band (17.5), provided a fast chart was not run. Some gas transmission companies require the operator to run their pens just under the mean point to take into account the square root effect error as shown earlier in this paper. The result would be an average of 17.5 inches or about 15 inches. The outcome from a flow computer calculating extensions on a one second basis is +19.3 percent higher than the 17.5" average as determined by the manual integrator.

To further analyze the problems with painted charts, could take the remainder of this paper, so a simple graph has been developed to illustrate what is called the Perceived Differential vs. the True Differential. Graph #5 details this phenomenon.

An explanation of graph #5 is in order. The X axis is the percent of spikes as shown on Graph #3. The Y axis is the differential inches along with the percent of error, as discussed later.

Notice the true differential starting with 1 percent spikes and 30 inch differential. Follow this true differential across the graph to the 11 percent spikes vertical line. At that point the true differential is over the 27 inch differential mark on the Y axis. Next, notice the perceived guess which means the differential of inches guessed from an operator of a manual integrator. On the far left at the 1 percent spike the operator's perceived guess was right on with the true differential. On the 2 percent spike the operator perceived the differential to be about 27 inches of differential. Now, notice the final column labeled % error. On the 2 percent spike the operator perceived a 27 inch differential, so the % error indicates a better than 4 percent error. From about 5 percent spikes along to the 11 percent spikes the operator continues to perceive the differential to be about 17.5 inches (as stated earlier) with an error of about 18 to 21 percent.

The point here is to understand that the job of integrating the paper chart can be a very difficult procedure. Add to the job, being rushed to meet close out deadlines, and other outside distractions and the operator can easily add or subtract to the final result.

ELECTRONIC MEASUREMENT SYSTEMS

Earlier in this report the orifice plate and the chart recorder were investigated for their contribution of error to the final volume. The electronic flow computer systems will be analyzed for their manufacturer full scale inaccuracies. Below on Table 4 the stated manufacturer Full Scale accuracies are listed along with the effect of exponents and summarized as they were in the previous Tables in this report.

TABLE 4
Manufacture Stated Accuracy For Standard Flow Computer (Including Differential Pressure, Static Pressure, and Temperature Transducers)

Variable	**Percent Uncertainty of Variable (+−)**	**Effect Factor**	
Exponent	**Square**		
Differential Pressure Trans.	0.25 FS	1/2	0.015625
Temperature Transducer	0.10 FS	1/2	0.002500
Pressure Transducer	0.25 FS	1/2	0.015625
Flow Computer	0.10 FS	1	0.010000
Sum of Squares			0.043750
Square Root of Sum			**0.209165**

The effect the standard Flow Computer system has on error for the complete system as shown is + −0.209 percent of full scale. Flow computer systems do have other disadvantages. First of all, new equipment such as the low powered systems of today are susceptible to static discharge from environmental conditions such as storms or simple body contact. Other areas of concern should be in the temperature, moisture, and physical areas where these systems are installed. Some computers do not meet hazardous locations or handle sour gas environments well. All computers become old (usually old would be within 10 to 15 years) and the plastic I.C's (Integrated Circuits) could breakdown and become inoperative, although some computers are operating, in a SCADA capacity, that are 20 years old with only minor problems. Flow computers can not be expected to last 30 to 40 years as have some old mercury meters. So continuous updating and repairing of these electronic systems has to be considered as a long term cost.

The maintenance and repair aspect of a flow computer has not be addressed in this paper. To account for maintenance and repair it is necessary to add these costs of 5−8 % to the final project cost.

ACCURACY COMPARISON TABLE: FLOW COMPUTER VS. CHART RECORDER

The following Table 5 will help detail the true difference of the accuracy between the two types of metering. One area that should be discussed is the temperature coefficient. This occurs because the metal chamber that makes up the recorder is expanding and constricting due to the temperature changes. The same effect occurs with flow computer but to a much lesser extent. This effect occurs when the environment around the instrument changes temperature. It can be easiest seen in a chart recorder that has been zeroed on a dark cold day. If the next day is hot and sunny and the chart recorder is exposed to the sun, then often a 24 hour chart will (assuming there is no flow) show a small amount of movement of the differential pen off the zero line. Please understand all modern chart recorders do attempt to compensate for this effect, but can not eliminate it.

Some of today's flow computers can compensate for the temperature drift experienced with transducers. Table 5 includes the Temperature Coefficient calculated in the same manner as were the chart recorder and flow computer uncertainties per a RSS method.

TABLE 5
ACCURACY COMPARISON TABLE FLOW COMPUTER VS. CHART RECORDER

PARAMETER	CHART	FLOW COMPUTER
Accuracy (RSS)	+ − 0.375 %FS	+ −0.209160 %FS
Temperature Coef: (RSS)	+ −0.012/Deg. F.	+ −0.009/Deg. F.
RSS % INACCURACIES:	**+−0.37519FS/D.F.**	**+−0.209330 %FS/D.F.**

Comparing the chart recorder and the flow computer, one would determine the flow computer has a +−44. 26 percent less uncertainties (again calculated with the RSS method) when reading the conditions from the orifice meter. But this is not the final result.

In Table 6 a summary of full scale uncertainties from the chart recorder and the flow computer are combined with the AGA-3 and integrator uncertainties established earlier:

TABLE 6
COMBINED UNCERTAINTIES OF ORIFICE MEASUREMENT AND SECONDARY DEVICES

PARAMETER	CHART	FLOW COMPUTER
AGA-3 Uncertainty	+ −0.648	+ −0.648
INTEGRATOR:	+ −0.200	N/A
INACCURACIES:	+ −0.37519	+ −0.20933
RSS TOTALS:----	**+ −0.775 %**	**+ −0.649 %**

With the stated AGA - 3 uncertainty of the orifice meter tube included into Table 6, along with the uncertainty of a integrator device than a real difference can be shown to be **+−19.41** percent involving the two types of secondary devices. With any appreciable volumes of gas being metered this **+−19.41** percent uncertainty between a chart recorder and a flow computer can become significant. Actually the overall difference in measurement can only be realized to be the difference between the two devices as **+−0.126%.**

For example, if a production site produces IMMCF/day under steady state conditions, then according to the last statement above the uncertainty in the measurement improves by 1.26 MSCF/D. With today's price of gas at about $2.00/MCF a dollar value of $2.52/Day can be realized by the buyer or seller. The pay off for the computer (assuming the uncertainty is consistent in one direction and the price of the computer system is under $3,000.00) could be within 3.27 Years.

OPERATIONAL COSTS OF THE CHART INTEGRATION AND RETRIEVAL PROCESS (24 Hour Charts)

In this section, an analysis of the incurred cost of handling charts will be detailed, and summarized in a tabular manner. To establish a low, medium, and high cost, three hypothetical gas companies need to be detailed.

Gas company A: is a low operational cost stripper company that simply strips the liquids from gas it receives from producers and sells this gas to a transmission company. There usually is a processing plant between the field wells and the transmission company meter, this is where the field measurement man is housed. Two employees staff the chart integration department while 15 employees handle the field needs. These needs in the field consist of not only chart recorder maintenance, but include looking for problems in leaking pipes and other visual inspections. A total of 700 meters are handled by this company and 6,000 8 day charts are integrated each month. A routine of 10 visits/month/site for retrieval of the charts and inspection of the pipeline is required. Each chart changer can change out 23 meters per day. All metering sites are onshore.

Gas company B: is a medium cost transmission company that purchases gas from producers and moves this gas to market. The integration department staff consists of 2 supervisors and 3 chart handlers and 3 operators of the scanner and manual integrator, along with one secretary. The field areas are made up of 4 supervisors and 12 field measurement technicians. A total of 500 meters are handled by this company and 15,000 charts are integrated each month. A routine of 5 visits per month and 24 hour charts are used. Each chart changer can change out 10 meters per day. All metering sites are onshore.

Gas company C: consists of the higher cost transmission company that purchase gas from producers. The integration department staff consists of 3 supervisors, 5 chart handlers, and 5 operators of the scanner and manual integrator, along with 3 secretaries. A total of 300 amount of meters are handled by this company and 9,000 charts are integrated each month. A routine of 5 visits per month and 24 hour charts are used. All of the metering sites are offshore. Each chart changer can change out 5 amount of charts per day.

Through the remainder of this paper these three gas companies will be referenced for their respective costs.

COMMON COSTS OF CHART RECORDERS AND FLOW COMPUTERS

Certain cost areas of both the chart recorder and the flow computer balance out. Table 7 lists these common areas. The first item listed is in regard to the field calibration. Both chart recorders and flow computers require the same equipment to calibrate and approximately the same amount of time to complete the procedure. The second item deals with personnel training. Flow computers are said to be easier then the chart recorder for a young trainee simply because he is more familiar with digital devices today. But the old hand who has been around operating the mechanical devices for the past 20 to 30 years may have some difficulty understanding how these new computer charts operate. The as found and as left reports may be easier to complete with the flow computer, as long as it has the ability to store the required information. Plate changes and any other changes will be logged on the field flow computer as are done with the charts, so no time differences can be determined.

TABLE 7

COMMON COSTS TO BOTH DEVICES

Item	Task	Chart Recorder	Flow Computer
1.	Field Calibration	Same	Same
2.	Train New Personnel	Same	Same
3.	Train Old Personal	None	Retraining Required
4.	As Found and As Left Reports	Manual	Digital
5.	Recording of Plate changes	Manual	Digital
6.	Installation Time	Same	Same

INTEGRATION DEPARTMENT COSTS

First lets look at the cost of the office integration department based on 24 Hour Charts. In Table 8 a break down of all the overhead costs occurred in the integration department can be seen. Notice there are three costs listed: low, mid., and high as described earlier. The first item is simply the cost of each chart, which is ten cents when bought in quantity. The second item pertains to the cost of the operator and personnel staff (labor) for integrating the chart. This cost was reached by determining the amount of time the office personnel handled the charts. The third item lists the depreciation costs for the office equipment and space to house the personnel and equipment. The fourth item concerns itself with the management and corporation overhead costs. The subtotal determines a per chart cpst for each of the different scenarios. The final total is a summary of the monthly cost when 30 charts, or 5 charts are integrated.

TABLE 8
CHART INTEGRATION COSTS: THE OFFICE INTEGRATION DEPARTMENT

Based on 24 Hour Charts

Item	Task	Low	Mid.	High
1.	Chart cost	$0.10	$0.10	$0.10
2.	Office, employee Labor.	$0.90	$1.50	$2.00
3.	Office space and Equipment	$0.15	$0.75	$1.00
4.	Manager and Corporate	$0.05	$0.25	$0.35
	Subtotal -----	**$1.20**	**$2.60**	**$3.45**
	Number of charts/Month/Site	5	30	30
OFFICE INTEGRATION COSTS/SITE/MONTH:		**$6.00**	**$78.00**	**$103.50**

FIELD COSTS FOR CHART RECORDERS

Table 9 details the cost incurred from the field end of the charts system. Again three different costs are listed to demonstrate the different scenarios suitable for the gas industry. The high as listed in Table 9 is to illustrate the cost incurred for offshore chart retrieval.

The first item determines the number of trips the field chart changer performs on a monthly basis to a single site. Notice the low or gas company A requires 10 visits per site per month. This is necessary because of their requirement to inspect for line loss. (A site consists of only one meter if more than one meter is present then an adjustment needs to be considered.)

Each scenario has established the amount of sites a field man can visit per day. Usually the first chart of the month is pulled and four weeks of charts pulled on a routine basis. This accounts for the five visits to the same measurement site for the medium and high. The second item is based on the hourly pay with benefits for this chart changer divided by the amount of meters the man has as a responsibility for (item 5.). The third item accounts for the auto, auto again, or helicopter expenses incurred for each trip. Item number four is an estimate for the number of sites a man visits in a day. The fifth item is the cost is the total number of sites one man has under his jurisdiction. The time to retrieve the charts are shown on item 6. Any outside service or materials to maintain or rentals are shown on item 7. Transportation of charts are calculated and shown for each of the scenarios on item 8.

The total for the field retrieval is shown at the bottom of table 9. the low or gas company A has the lowest cost because of the amount of meters one man can get to, along with low overhead costs. The gas company B show a significantly higher cost due to the field offices maintained along with fewer sites visited. The last gas company C, incurs the highest costs simply for the reason of the offshore helicopter costs.

OPERATIONAL COSTS OF THE FLOW COMPUTER AND RETRIEVAL PROCESS

In this section we will determine the costs to operate and retrieve the data from the meter locations with the use of a flow computer. Accessories such as radio retrieval and phone transmission have not be included in this section. The use of a hand held terminal to retrieve the data from the sites will be the only method discussed in this paper.

Table 11 illustrates the estimated costs incurred after 1 year into the retrofit process. Notice the costs are about 40 percent of what they were before the automation process started. The integration office costs stay high because other producers or transmission companies will still

TABLE 9
CHART INTEGRATION COSTS: THE FIELD RETRIEVAL FOR ONE MAN

Based on 24 Hour Charts

Item	Task	Low (Onshore)	Mid. (Offshore)	High
1.	Chart Retrieval/Site/Visits/Month	10	5	5
2.	Labor Costs $/Site/Visit/Month Includes: Vacation, Non productive time, Overheads, and Payroll tax.	$3.04	$15.41	$39.50
3.	Auto/Auto/Helicopter/Visit/Month SUB TOTAL (Sites/Month) ---	$1.20	$25.00	$133.00
4.	Numbers of Sites Visited/Month	23	10	5
5.	Numbers of Sites Visited/Month Under one man’s jurisdiction	46	40	20
6.	Time to retrieve charts per site/visit	18min.	45min.	1 1/3Hr.

Based on 24 Hour Charts

Item	Task	Low (Onshore)	Mid. (Offshore)	High
7.	Outside Services, Rents, Material and Equipment, Utilities and Employee, Expense/site/month .	$15.00	$30.00	$108.00
8.	Transportation of charts total / 4 times a month	$0.75	$2.50	$4.00
TOTAL OF FIELD COSTS/SITE/MONTH:		**$58.15**	**$234.55**	**$974.50**
	Sub Total +(7.)+(8.)=			
ADD OFFICE COSTS (From Previous Table 8)				
OFFICE INTEGRATION COSTS/SITE/MONTH:		**$6.00**	**$78.00**	**$103.50**
GRAND TOTAL FOR THE THREE SCENARIOS FROM THE TEXT FOR A CHART RECORDER:				

want to audit the converting companies charts. Possibly one day the majority of the gas industry will accept electronic measurement devices.

TABLE 11
FLOW COMPUTER COSTS: THE OFFICE INTEGRATION DEPARTMENT

Item	Task	Low	Mid.	High
1.	Chart cost	$0.10	$0.10	$0.10
2.	Office, employee Labor.	$0.90	$1.50	$2.00
3.	Office space and Equipment	$0.15	$0.75	$1.00
4.	Manager and Corporate	$0.05	$0.25	$0.35
Subtotal -----		**$1.20**	**$2.60**	**$3.45**
Less Discount 60% --		$0.72	$1.56	$2.07
OFFICE COSTS/SITE/MONTH:		**$0.48**	**$1.04**	**$1.38**

FIELD COSTS FOR FLOW COMPUTERS

The modern field flow computer of today will incur about the same amount of costs as does a 30 day chart. Table 12 breaks down these costs again on a Low, Mid., and High basis. Notice the differences with a chart and a flow computer are in the number of chart retrievals (1.) and the number of visits to the sites (5.). Just about all other cost factors stay the same.

Table 13 summarizes the differences in operational savings when converting from the chart recorder method to the flow computer. Not only is their a substantial savings on the/month basis, but an increase in the amount of sites an operator could visit/month. For the low scenario, only 46 sites could be handled by a single operator with the use of charts, since he had to visit the site 10 times a month. With the use of flow computer that same operator reduces his visits/site to 3. This in turn increases the amount of sites he could visit by three times. Another way to look at this savings is illustrated in Graph #6. Each of the three gas companies illustrated show a reasonable rate of savings.

TABLE 12
FLOW COMPUTER COSTS: THE FIELD RETRIEVAL

Item	Task	Low (Onshore)	Mid. (Offshore)	High
1.	Chart Retrieval/Site/Visits/Month	3	3	3
2.	Labor Costs $/Site/Visit/Month Includes: Vacation, Non productive time, Overheads, and Payroll tax.	$3.04	$15.41	$39.50
3.	Auto/Auto/Helicopter/Visit/Month	$1.20	$25.00	$133.00
	SUB TOTAL (Site/Month) ---	$12.72	$121.23	$517.50
4.	Number of Sites/Visited/Day	23	10	5
5.	Number of Sites visited/Month Under one man's jurisdiction	153*	66*	33*
	(Number of Sites from Table 9)	(46)	(40)	(20)
6.	Time to retrieve charts per site/visit	18min.	45min.	1 1/3Hr.
7.	Outside Services, Rents, Material and Equipment, Utilities and Employee, Expense/site/month.	$15.00	$30.00	$108.00
8.	Transportation of charts	$0.75	$2.50	$4.00
total/4 times a month				
TOTAL OF FIELD COSTS/SITE/MONTH:		**$28.47**	**$153.73**	**$629.50**
	Sub Total +(7.)+(8.) =			
ADD OFFICE COSTS (From Previous Table 11)				
OFFICE COSTS/SITE/MONTH:		**$0.48**	**$1.04**	**$1.38**
GRAND TOTAL FOR THE THREE SCENARIOS FROM THE TEXT FOR A FLOW COMPUTER:				

TABLE 13
OPERATIONAL SAVINGS/SITE/MONTH

	LOW	MEDIUM	HIGH
Chart Recorder Operational Cost	$54.15	$312.55	$1,078.00
Sites Visited/Month	(46)	(40)	(20)
Flow Computer Operational Cost	$28.95	$154.77	$630.88
Sites Visited/Month	153*	66*	33*
Savings/Site/Month:	**$25.20**	**$157.78**	**$447.12**
Number of additional Sites that can be visited:	107	23	13

THE PAYOFF OF RETROFITING CHART RECORDERS WITH FLOW COMPUTERS

Once the monthly operational savings has been established than a summary table can show the savings on a yearly basis. Table 14 has been designed to show the savings realized when retrofiting a chart recorder system with a flow computer.

One area not discussed is the actual cost to retrofit this chart recorder with a flow computer. It is usually assumed that the same amount of time and equipment required to install a standard chart recorder will be required for the flow computer. With this in mind just determine amount of money required to install a standard chart recorder and subtract that cost from the savings shown in Table 14.

TABLE 14

RETROFITING CHART RECORDERS WITH FLOW COMPUTERS SAVINGS/ SITE/MONTH

	LOW	MEDIUM	HIGH
Savings/Site/Month**:**	**$25.20**	**$157.78**	**$447.12**
OPERATIONAL SAVINGS/SITE/YEAR			
	LOW	MEDIUM	HIGH
Savings/Site/Year**:**	**$302.40**	**$1,893.36**	**$5,365.44**

Obviously a reasonable rate of return can be profited by automating an existing chart metering system.

AVERAGE 10 YR. RETURN ON INVESTMENT

The final Graph 7 shows the 10 year operational saving for the three scenarios illustrated in this paper. To use this graph simply pick one of the Low, Mid., or High scenarios, and settle on a price for the flow computer product. For example, if we use chose a flow computer price of $7,000.00 and a high amount of savings, than we show an internal rate of invested dollar of about 100% over 10 years. This graph does account for 5% maintenance, and an installation program over 5 to 7 years with hand held terminals to operate the flow computer.

Obviously, a reasonable rate of return can be demonstrated with the use of a flow computer from the operational cost savings alone.

ELECTRONIC METERING STANDARDS

Will electronic data gathering and storage ever evolve into a standard like the paper charts? Committees within the American Gas Association are being formed to address this problem today. With the help of manufacturers and industry personal, hopefully, a standard as far as the format, protocol, and storage method will be resolved in the near future.

One possible solution is if the manufactures pick a medium such as an IBM-PC for all their data collection and storage, then a common data transfer mechanism could become feasible. Time will only tell.

ORDER FERC 436

Many gas companies around the country have signed up on the order of FERC 436. This requires the gas companies to act as a transportation company and in this way they do not have to commit to purchased gas contracts from the producer or for sales gas contracts. This creates a spot market environment where the gas companies involved maybe dealing with the purchase and sale of large and small amounts of gas contracts. By using the standard method of measurement (chart recorders) these new gas contracts will become a major burden on the chart processing and field retrieval departments. In some cases where spot sales are only on hourly contracts, 24 hour charts would have to be broken down into hourly flows, which will force the integration department to changes which will only slow them down.

Electronic measurement systems with complete communication capability will allow the gas companies to real time bill and or control these new spot sales or purchase contracts. Not only do the new flow computers of today demonstrate a reasonable rate of return on invested dollar on retrofiting measurement systems, but adding in the spot market capability for billing and SCADA requirements for dispatch control, one would have to come to the conclusion, “why haven’t we changed?”.

SUMMARY

Over the next decade, electronic measurement will eventually capture the existing conventional gas measurement sites along with any new applications. Once the acceptance and reliability is achieved, which is considered to be within the next 5 years, exciting new developments will likely occur. Already some manufacturers of these type of low powered flow computers offer means of data transfer. Either through radio, phone modem, or possibly satellite transmission will allow this data to be sent from the metering site to the headquarters office for dispatch control and billing. The final result will be the ability for the gas transmission companies to compete in a competitive market with real time figures of volumes of gas.

“The future belongs to the Efficient” and the efficient gas companies will be the winners in the long run.

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REAL TIME MEASUREMENT: A CANADIAN GAS TRANSMISSION COMPANY APPROACH

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ABSTRACT

Real Time Measurement (RTM), or more specifically, the use of micro-processors for the purpose of performing on-site volume and energy calculations, is gaining popularity in Canada and the United States. The incorporation of computer based, on-site metering for purposes of natural gas custody transfer measurement has been a relatively slow process in North America due to the established chart based systems and the age and size of the gas transmission and utility systems. Acceptance of this technology has been further hampered by the broad familiarity and acceptability of conventional chart metering and the lack of trend and audit data available from standard flow computer systems. In confronting this situation and over-coming these apparent obstacles, NOVA, AN ALBERTA CORPORATION developed a real time measurement system which provides significant benefits over chart recorder devices and "off-the-shelf" flow computers.

REAL TIME MEASUREMENT: A CANADIAN GAS TRANSMISSION COMPANY APPROACH

INTRODUCTION

Natural gas has been used in Canada for 100 years for a wide variety of residential, commercial and industrial applications including chemical feedstock and power generation. Today, natural gas supplies about 25 percent of all the Canadian energy needs and represents a major source of export revenue with earnings of approximately $4 billion in 1985.

NOVA owns and operates a gas transmission system in the Province of Alberta and handles more than 75 percent of the Canadian gas sold in North America. In 1985, NOVA's Alberta Gas Transmission Division recorded receipts of 63.4 10^9 m^3 (2.25 TCP) with an average of 173.6 $10^6 m^3$ (6.16 BCF) being moved per day and a peak day volume of 240.8 10^6 m^3 (8.55 BCF). The system consists of 756 receipt and major delivery metering points, 38 compressor stations, all connected through 13 500 km (8 415 miles) of pipeline. With a system of this size and the general gas industry acceptance of chart recorder measurement, implementation of RTM at 4 major delivery points provided several challenges. These were resolved through innovative engineering and current technology.

CHARTS AND FLOW COMPUTERS

Historically, natural gas measurement using orifice metering has been based upon static and differential pen tracing on a circular paper chart representing flow over a time interval, typically 24 hours. In order to convert chart data to an equivalent volume, the chart must undergo processing. This involves either optically measuring the placement of the tracings using an electronic scanning device or manually integrating the lines using a chart processor. In both cases the daily volume is based upon one flow calculation in which the average 24-hour product of differential and static pressure values are utilized. These averages are calculated from 800 individual differential and static pressure samples equivalent to a calculation every 108 seconds. Average temperature, specific gravity, and heating values are also utilized in the volume and total energy calculations.

Under fluctuating flow conditions the technique incorporated by chart processing systems of applying 800 values over a 24-hour period, represents a low sample frequency.

Consequently, during the scanning or integrating process, the change in flow rate cannot be followed. This can result in a given flow condition being applied to a longer or shorter time frame than actually experienced, thus introducing a source of measurement error.

Conventional flow computers report 24-hour volumes based on a series of instantaneous flow calculations usually performed at a rate of one calculation every two to three seconds. This sampling frequency is a significant increase over chart processing allowing the system to more readily follow fluctuating flow conditions, thus reducing processing errors associated with over or underweighting of sample data. The increase in sample size also statistically improves the confidence level associated with the reported volumes. With the utilization of on-site energy and gravity measurement, it is also possible to apply instantaneous, (real time), specific gravity and heating values to volume and energy calculations. At facilities with changing flow rates and fluctuating gas quality, this technique significantly improves measurement accuracy.

NOVA, like all other North American transmission companies, is a chart based company. Sixty thousand charts are processed monthly using 3 electro-scanners, 1 micro- scanner, 3 chart processors and a staff of fifty.

Approximately six years ago NOVA in its ongoing commitment to measurement accuracy, began a program to evaluate the feasibility of using RTM for custody transfer measurement. The objectives of the program were to:

- select the most appropriate method and equipment
- determine the effect on measurement accuracy
- determine the equipment maintenance and calibration requirements
- determine the ultimate function
- provide the cost justification
- develop design specifications

A standard flow computer and transducers suited for orifice measurement installations were purchased and placed on test in parallel with existing orifice charts. Flow computers configured for orifice measurement provided improved accuracy under fluctuating flow conditions.

Although electronics are more accurate than the mechanical chart, the standard flow computer did not provide adequate accuracy verification, audit procedures or report generation capabilities to meet our requirements. These shortcomings prompted NOVA to develop a functional specification for a custom built flow computer.

FUNCTIONAL SPECIFICATIONS

The measurement accuracy and audit techniques used in chart processing formed the basis for the functional design of the RTM system. This, coupled with refinement of 'standard flow computer' and instrument principles, led to the development of a system that improved on electronic flow measurement accuracy and effectiveness. These improvements have been taken a step further by combining measurement, telemetry and flow control requirements, resulting in a cost effective electronic system which provides significant improvements in measurement accuracy and immediate availability of custody transfer billing data.

- Volume Calculation

  Each flow computer performs a complete AGA calculation including supercompressibility on up to six meter runs every second and is equipped with a differential pressure root mean squared (RMS) averaging capability. With this option, although a calculation is performed once per second, the calculation is based on up to 60 discrete differential pressure readings. In addition to the sample frequency, the square root values of each of the 60 differential pressures are calculated and the average of these values is utilized in the flow calculation. As differential pressure falls under the square root sign in the ANSI/API 2530 flow equation, this method of square root averaging is analogous to performing a flow calculation at a rate of 60 times per second. This system can therefore follow varying flow conditions, ensuring correct processing of sample data and improved measurement accuracy.
- On-site Verification of Measurement Accuracy Capabilities

  In addition to standard input device failure, electronic malfunction, and internal data checking alarms, the system is equipped with several measurement related diagnostic capabilities. These detect and, through alarms, identify potential measurement inaccuracies.

  Measurement diagnostics are achieved through the incorporation of two essentially identical but independent flow computers. These devices are commonly referred to as Remote Terminal Units (RTU's). It is upon these building blocks that the overall system concept was developed.

  Although these units are basically "stand alone" devices, under normal operation they are linked together and are continually conducting 'real time' comparisons of several measurement parameters. One of the flow computers is designated the primary RTU and the other, the secondary (see Figure 1). Standard operation has the primary device volumes being used for custody transfer billing with the secondary unit supplying comparison data. In the event of a primary system failure or scheduled maintenance, the secondary device provides the billing volumes.

  The measurement diagnostics offered by this system can be separated into two categories; those which identify potential transmitter errors, and those which suggest errors associated with the meter run.

  i) Transmitter Verification Diagnostics

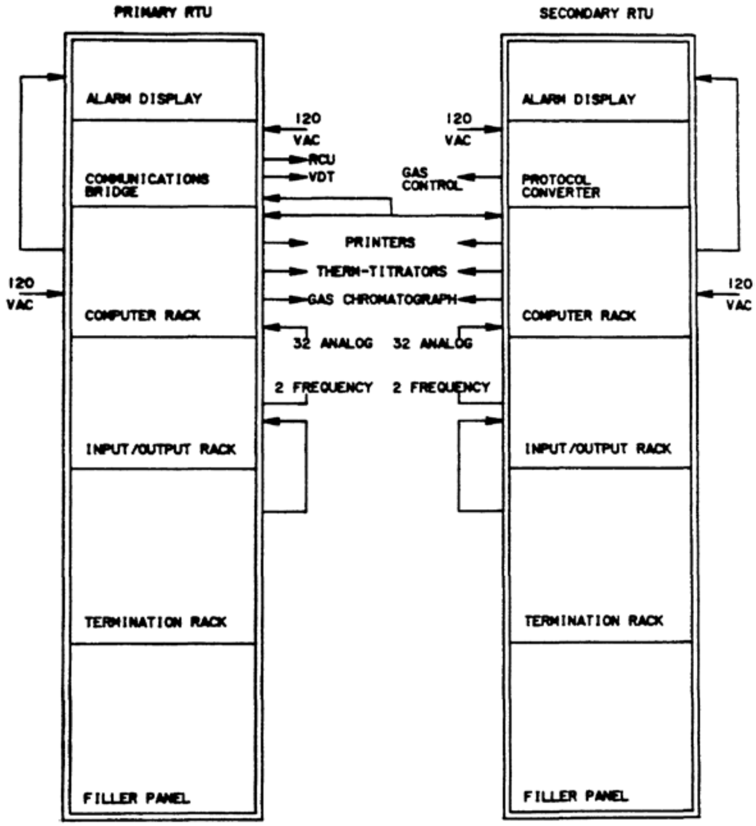

Figure 1. DATEK RTM SYSTEM REMOTE TERMINAL UNITS

Comparisons between redundant transmitters are utilized to detect calibration drift and instrument malfunction. Two differential and static pressure transmitters are installed on each meter run (see Figure 2). One supplies input values to the primary RTU and the other to the secondary (see Figure 3). The system is also equipped with two temperature transmitters, each situated on a different meter run. Similarly, these devices feed either the primary or secondary flow computer, however, when a meter run, housing one of the transmitters, is temporarily removed from service, the flexibility to supply input from the active transmitter is available. Through the evaluation of historical trends between the primary and secondary trans- mitters, acceptable comparison limits are identified. These values are used to establish alarm limits and are entered into the flow computer during start up. If, during operation, comparisons between primary and secondary transmitter readings deviate from the pre-determined acceptable values, an alarm will be generated. Immediate corrective action by field personnel is taken to ensure measurement integrity.

Specific gravity comparisons are also conducted. Up to three gravity measuring device inputs can be received by both flow computers at one time. They include a conventional chart gravity measuring device, a specific gravity transmitter, and a gas chromatograph. These instruments are common to both flow computers (see Figure 3). Although each RTU receives inputs from all three devices, the volume calculations are based on the specific gravity measurement of one device with the other two instruments providing comparison data only. Under typical operation, the device used

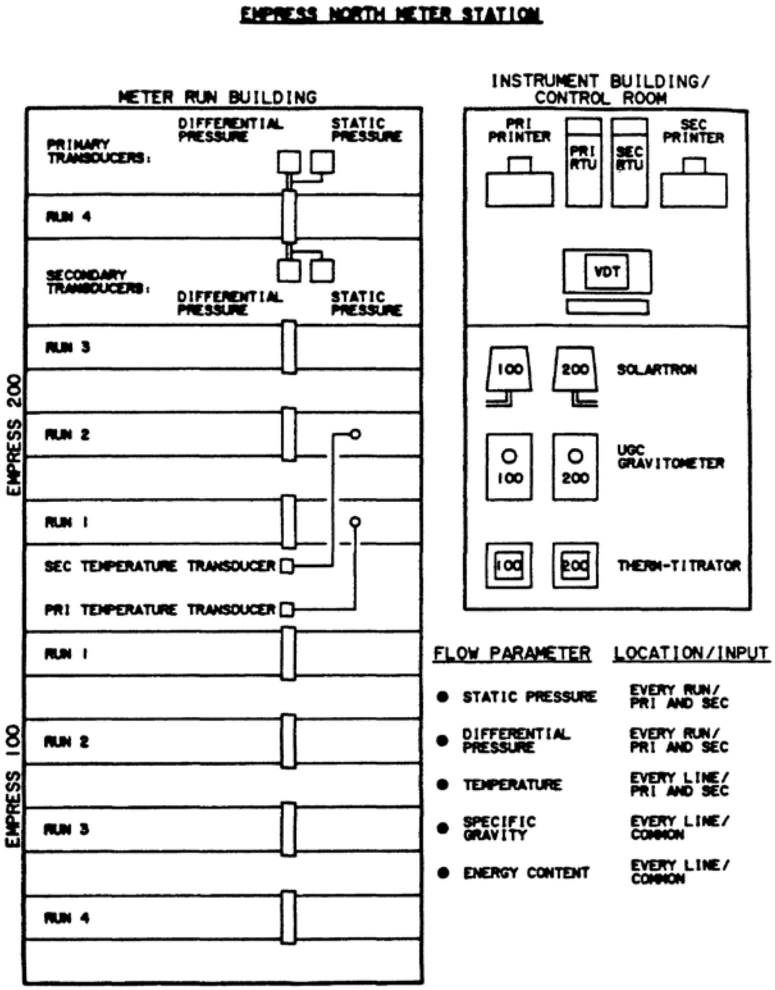

Figure 2. METER RUN TRANSMITTER CONFIGURATION

in the volume calculation is different for the primary and secondary flow computers. In this way, an error associated with the device utilized to supply gravity for the volume calculations conducted by the primary RTU will not affect the secondary flow computer integrity.

Specific gravity alarm limits are also established through the collection and evaluation of historical station data.

This custom-built system is also capable of receiving inputs from and conducting comparisons on two energy measuring systems. The devices used are Therm-Titrators and gas chromatographs. The inputs from these instruments are common to both flow computers. In lieu of a Therm-Titrator or gas chromatograph, a calorimeter can be utilized to supply an input energy signal to each of the flow computers.

ii) Meter Run Verification

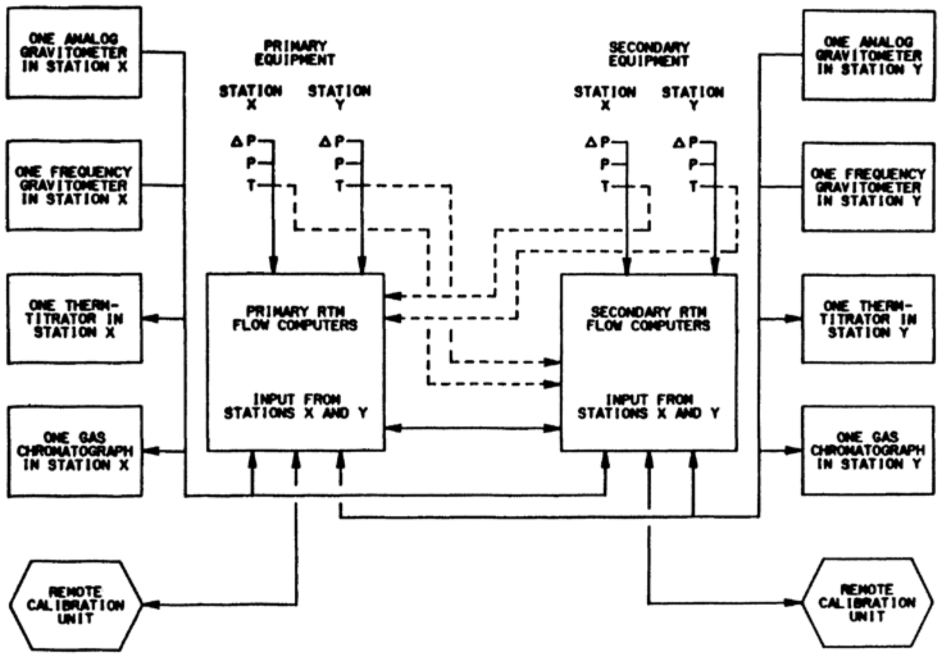

Figure 3. BASIC CONFIGURATION DUAL REDUNDANT FLOW COMPUTER SYSTEM

This system incorporates a tool commonly used in audit and processing procedures known as run ratio comparisons. Utilization of the run ratio coupled with the transmitter verification comparisons, makes it possible to determine whether a measurement related error is associated with the meter run assembly or one of the input devices.

All stations have a slightly different hydraulic profile resulting in a flow split which is characteristic of each facility. By calculating the percent difference in volume for each individual run compared to that of a common run (i.e. Run 1), run ratios are developed.

i.e. Run 1 — Run 2/Run 1×100

These ratios are like fingerprints and can be effectively used to detect measurement related problems.

Each flow computer calculates run ratios on up to 6 meter runs on a “real time” basis. If the run ratio changes by a value greater than that determined acceptable, an alarm will be generated.

A run ratio alarm can be caused by a transmitter related error or a meter run problem associated with a secondary input device accuracy problem. A transmitter comparison alarm would also result. If the run ratio alarm is not followed by a transmitter alarm, the measurement related problem can be attributed to the meter run itself. Liquid contamination, incorrect orifice plate size, meter tube obstruction, and meter tube damage are some of the conditions which will result in run ratio alarms and potential measurement errors.

Although these verification techniques are performed during chart processing, substantial delay in problem detection is usually experienced. Often the problem may correct itself before it is detected. This makes it impossible to ascertain the cause of the change in run ratio and difficult to apply estimations.

On site verification of primary device accuracy ensures timely detection and resolution of meter tube related errors.

iii) Comparison Alarms

The set-up configuration and alarm limits for all comparison tasks are based on the collection and evaluation of historical station data.

The system is capable of generating two levels of alarms. This option can be used to identify the seriousness of the problem, priority to be given, and the type of personnel to be notified. In addition to the alarms being indicated on an LED display, information pertaining to the specific alarm which assists in pinpointing the source of the problem is routed to a printer. This also provides a permanent document which can be utilized when reporting custody transfer volumes.

- Report Generating Capabilities

NOVA CORPORATION'S custom designed RTM system is equipped with improved report generating capabilities providing a number of benefits not supplied by "off-the-shelf" devices. These reports can be broken into two categories; those which provide the technical data necessary to establish and monitor historical trends, and those used for audit purposes.

Eight reports are generated by both the primary and secondary RTU on a daily basis. If required, any or all of these reports can be generated on demand. All report data is retained in memory for an additional 24 hours and can be printed upon request.

i) Technical Summaries

Technical Summary reports include statistical information on all variable inputs. Twenty-four hour minimum, maximum and average static pressure, temperature, relative density and heating values provide the data necessary to establish alarm bandwidths. Transducer comparison reports are also generated, and identify the minimum, maximum, mean difference and standard deviation of the primary versus secondary on all input transmitters.

Run ratio and primary versus secondary RTU daily volume comparison data is also reported every 24 hours. This information is utilized in establishing alarm limits and is beneficial in the analysis of potential measurement errors.

The final technical data report contains alarm limit bandwidths and is utilized to tighten operating parameters. This report is also useful in ensuring acceptable alarm limits are being incorporated during routine operation and have not been changed.

ii) Audit Reports

The audit series of printouts supplies the data necessary to verify all reported volumes and total energy values. Historically, verification of measurement accuracy has been based upon re-processing of chart tracings. With incorporation of Real Time Measurement, this is no longer possible. With processing being conducted on site and calculations no longer based on average samples, it becomes difficult to verify the accumulated daily volumes. This led to the development of an ANSI/API 2530 factor report. This document contains all the factors necessary to verify the volume calculation. When printed, this report identifies a 24 hour volume and energy value based on the instantaneous conditions being experienced just prior to printing. All the corresponding instantaneous ANSI/API 2530 factors are also reported on this printout. By manually applying these factors to the ANSI/API 2530 calculation it is possible to verify the flow calculation by reproducing the reported 24 hour volume and energy values appearing on the printout.

A second audit report which lists all of the fixed parameters associated with the calculation can be utilized to further verify the validity of the ANSI/API 2530 individual factors. Information contained on this report includes meter tube diameters, orifice bore diameters, base temperature, base pressure, atmospheric pressure, and transmitter ranges.

A daily summary of system alarms and a log of any changes made over the course of the day (i.e. orifice plate change) are other audit printouts which can be utilized to monitor the overall system performance and verify measurement accuracy.

The actual accumulated 24-hour individual run volumes, total station volume, individual run energy and total station energy values are printed daily.

It is on this information that custody transfer billing is based.

- Remote Calibration Device

Another feature which improves measurement accuracy and has been incorporated into this specially designed system is a “Remote Calibration Device”. Although the Remote Terminal Units (RTU’s) were designed around quality hardware components, like all flow computer systems they experience calibration related inaccuracies. When an analog signal is converted to a digital value, calibration errors may result.

The remote calibration device supplies a digital display of all transmitter input values as converted by the computer. It is a portable hand-held device which the technical staff take to all instruments being calibrated.

The calibration method normally utilized by conventional RTM systems involves calibrating the various transmitters to a digital volt meter (DVM). This minimizes transmitter calibration error, but results in analog to digital measurement related uncertainties.

Utilization of the remote calibration unit allows the transmitters to be calibrated to what the computer is interpreting the output value to be and improves measurement accuracy by eliminating analog to digital error.

System Security

This custom-built system offers improved security over other systems in two ways. Overall measurement security is maintained by incorporating two totally independent systems. If measurement at one of the RTU’s is momentarily interrupted, backup measurement is available.

The second form of security is associated with access to the system. Change of parameters is achieved through a video display terminal (VDT). In order to obtain access to the system, a three-step security sequence must be followed. Any changes made to the system, such as an orifice plate change, are logged on the printer.

Only station set-up and operational parameters such as meter run sizes, orifice plate bores, transmitter ranges, etc. can be changed. Volume data and information contained on any printed reports cannot be altered through the Database access.

The logged information includes the time and date the change was made, specifics pertaining to the changed parameter, and the name of the individual making the change. In the event an error in parameter change inadvertently occurs, all the information required to accurately correct the affected volumes is available.

The database also requires locking after any changes are made. If it is not returned to the locked position, the terminal will remain idle for approximately five minutes, then independently lock the database. This further protects against tampering of parameters by disallowing access to an unattended computer by unauthorized personnel.

SYSTEM JUSTIFICATION

In order to be feasible, the RTM project must demonstrate sufficient cost reduction to guarantee a recovery of expenditures in a reasonable time.

- Measurement Accuracy

  As the price of natural gas increases, the emphasis on accuracy increases. The trend in the industry is toward tighter tolerances, more stringent procedures and higher calibration accuracies to ensure the highest possible degree of accuracy. The principle of operation of the transducers and flow computers, supports a higher degree of reliable, accurate measurement compared to the mechanical chart recorder and chart processing equipment.

  If a company is objective about the increased accuracy attainable with RTM the cost of installation is easily recovered. From a practical view, this means RTM will measure a different, but more accurate value than the chart recorder system. The values may be either higher or lower depending upon the unique conditions at the station. If the company's interest is measurement accuracy, the decision for installation is straight forward. It is when improved accuracy creates a change in revenue that the decision can become clouded.

  NOVA CORPORATION is in the business of transporting natural gas for others and does not own the product. Therefore, the question of 'higher or lower' than the chart system is not a compromising problem and does not enter into our economic evaluation.

  Theoretical accuracy of the orifice meter calculation using chart recorders is ±.75% and ±.50% for an electronic system. This net increase of .25% is a conservative figure based upon stable flow conditions. It can be expected that the difference can be greater as the flow conditions fluctuate.

  Applying the net accuracy factor results in a substantial dollar difference for a given volume.
- Operating Costs

  Costs associated with operating a measurement system from field to office, can be reduced with the utilization of RTM. Emergency or critical measurement situations will be known in advance with the improved on-site operational analysis, alarm and status capabilities. This results in early warning of calibration shifts and equipment failures. These features reduce the manpower required for station visits and at the same time increase overall measurement integrity.

  The reliability and calibration stability of transmitters will permit the elapsed time between calibrations to be increased over the chart recorder. This again will decrease manpower requirements.

  Chart processing is a manpower intensive portion of any measurement system. With the appropriate planning and subsequent integration of on-site custody transfer information with existing head office measurement data, manpower reductions can be realized. Taking the station information, through a communication medium, directly to the mainframe database eliminates a variety of chart processing functions.
- Custody Transfer Availability

  Natural gas marketing is changing from the historic long term and firm contract base to a situation of spot markets, short term and best effort contracts. These changes are creating a greater demand for quicker turnaround time of custody transfer information. Many companies today are forced to make critical business decisions based on gas flow and therefore must have the appropriate information in a timely fashion.

  The information from a chart system, which is one month behind, may not be sufficient in the future to maintain the appropriate balance of each company's account or provide the required data to make an informed decision regarding market fluctuations affecting purchases or sales. A RTM system provides a significant enhancement in time limits of information over the chart based system.

SYSTEM OPERATION

The true test of any new device or system is its performance under field conditions over a reasonable time interval. NOVA CORPORATION has had the custom built RTM system in service, in a custody transfer application, since July 1984. During this period a variety of evaluations has been conducted on the operation, reliability, and accuracy of each component and of the complete system.

- Operator Acceptance

  A key ingredient to the success of a system is the ability to gain the confidence and acceptance of the users. Each meter station on the NOVA system is operated and maintained by a number of field personnel including Station Operators, Measurement, and Automation Technicians. Each has a different level of interaction with the RTM system. The system software was written in such a manner that all man-machine interactions are “user friendly”. Instructions and prompts were added to the displays to guide the user through the correct sequence of actions and to avoid incorrect entries. Automatic self-checking routines and alarms are used to ensure correct data entries.
- System Reliability

  The redundant design of the NOVA RTM system provides a unique degree of reliability unsurpassed when compared with standard flow computers or chart recorders. Careful selection of hardware, quality engineering specifications, and appropriate software architecture has produced a system which has maintained a high standard of performance over the past eighteen months. During this period, there has been only four hours of unscheduled downtime for eight units, on either of the primary and secondary flow computers. At no time did coincident outages occur, thereby continuous station measurement was attained.

  Our statistical analysis of a chart based system compared with the redundant computer concept has shown an improvement in reliability of 125% with RTM.
- System Accuracy

  With the redundant flow computer’s report generating capabilities, dual transducers on each orifice fitting, separate static and differential pressure readings on each set of orifice taps, a variety of analytical comparisons can be collected which support the system’s accuracy.

  As each flow computer calculates and reports a volume using separate transducers on different sides of each orifice fitting, it is easy to quantify the relative accuracy of the calculation. The expected accuracy, according to ANSI/API 2530 of the and the F_b, basic orifice factor, is ±0.74% and ±0.5% respectively. Our experience has demonstrated that the flow calculations of the primary and secondary systems compare to within ±0.2% over the eighteen month time frame. This consistent, narrow bandwidth provides the confidence that the system accuracy is not only within but surpasses acceptable industry standards.

  In addition to system accuracy, individual input device accuracy and stability can be monitored with the diagnostic and report capabilities of the flow computers. From the perspective of input parameters, the differential has the greatest effect on the calculation outcome and typically has created the most concern in our system. The diagnostics of the RTM system coupled with high accuracy transducers and precision calibration devices have enabled the technical staff to maintain the differential transducers within ±0.10% of the full scale reading.

Similar accuracy tolerances are attained with the other input devices (i.e. temperature, static pressure, and specific gravity).

- System Calibration

  The majority of our chart recorders are calibrated on a monthly basis either as a result of a contract requirement or because of acceptable industry practice and therefore it seemed reasonable to follow the frequency with the RTM system. An analysis of monthly calibrations of 96 transducers over eighteen months has demonstrated that the transducer calibration is extremely stable, maintaining a ±0.10% accuracy. A secondary outcome is that the greatest instability is seen immediately following the calibration which leads to the conclusion that extending the period between transducer calibrations will not degrade the system accuracy. With the diagnostic and comparative capabilities of the RTM system, it is reasonable to predict that in the near future scheduled calibrations may no longer be required and the technician would calibrate only when an alarm indicated a transducer calibration problem.

FUTURE DEVELOPMENTS

The earliest reference to the occurrence of natural gas in North America is in connection with the visit of George Washington to Kanawha Valley, now in West Virginia, where he found a “burning spring”. The natural gas industry has progressed through significant technological and economic eras since the 1775 Kanawha experience and is presently in the midst of another. The era of electronics has played an integral role in many industries including important functional applications such as telemetry and station control in the natural gas industry. The implementation of electronic devices for on-site custody transfer measurement is only in its infancy in comparison, and the industry will see a strong movement in this direction over the next few years. The momentum for electronic measurement will be fueled by the need for more timely and accurate information to meet the challenges of the present economic and gas market situations.

THE CAIN ENCODER™—AUTOMATIC METER READING FOR THE REAL WORLD

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ABSTRACT

Developed under the philosophy that a new technology or product must fit the prospective user's needs, the Cain Encoder™ has been designed from the beginning to meet the utility companies' expressed needs, to mesh with existing operating practices, and to tolerate the range of environmental conditions to which meters are exposed.

The Cain Encoder™ retrofits existing meters, and advanced prototypes have been field-tested through many millions of readings, withstanding New England summers and winters with no reported errors. There are no moving parts, optics or light sources; nothing touches the meter hands, shafts or register gears; it does not require constant monitoring nor a power supply; and it obtains direct dial readings (not pulses) in standard ASCII code, regardless of communications system—telephone, powerline carrier, TV cable, radio or hand-held readers. The Cain Encoder™ offers these and other benefits with its high accuracy and reliability, yet production models will sell for about $20.

By bringing to the field of metering a new approach, Cain Encoder Company can offer the utilities a piece of utility equipment which fits their needs for low cost, for ease of use, and for simple integration into the real world of automatic meter reading.

THE CAIN ENCODER™—AUTOMATIC METER READING FOR THE REAL WORLD

Cain Encoder Company is a small R&D firm which has developed and field-demonstrated a new type of encoder for the direct reading of gas, electric, and water meters. Advanced prototypes of the Cain Encoder™ have been in actual utility service through two New England winters and summers, and have produced several million dial readings with not one error reported. We believe we've solved the problem of getting direct dial readings from existing utility meters reliably.

But, you say, lots of things can be made to work, and some of them reliably. The larger question is "how well does this device fit our needs, including our need for low cost, ease of use, and compatibility with our present meters and operating practices?" Let me begin with a personal observation.

During twelve years as a physicist for E.I.duPont, developing new products and processes, I learned that the only good way to ensure the success of a new process was to make it easier to use, and to use correctly, than to use it incorrectly or not at all. For only if the process was easy to use would the plant personnel adopt it with a willing spirit, become involved in its application, and get the most profitable use out of it. Processes which were hard to use, or which somehow didn't fit into the plant routine, almost inevitably produced low yields, high cost, and poor quality. I later saw the larger truth in this: a new technology or a new product must fit the needs of the prospective user AS HE UNDERSTANDS THEM, or it cannot succeed.

The ancient Greeks must have foreseen much of today's electronics industry, for they described it well in the myth of the giant Procrustes. You may recall this cheery bedtime story from your youth: Procrustes stood beside a road, with his bed nearby, ostensibly offering hospitality but in fact imposing on passersby the somewhat arbitrary requirement that they could not pass unless they fit his bed snugly. Most were too short or too long: Procrustes stretched or trimmed their legs as necessary until they fit the bed, whereupon if they survived they were free to pass. Just so, much new technology being developed today has a strong Procrustean flavor: the supplier has learned to do something, and the user's needs and practices must be distorted as necessary to fit the supplier's capabi1ity.

At Cain Encoder Company, our early development work included studying gas, electric and water meters to learn how they are made, how they are used, and what their typical tolerances are. We visited meter shops throughout the industry to learn how meters are tested, calibrated, and maintained. We watched and talked with meter installers and meter readers to learn their problems, practices and suggestions. Although there are several ways in which the Cain Encoder™ differs from any other sensor, probably the most important is that, because we did our homework, our encoder has been carefully developed to meet the actual daily needs and practices of operating utility companies. Unlike any other encoding device, our encoder is not simply a piece of electronic gear that has been made to fit inside a meter—it is a piece of utility equipment which happens to contain electronic components. It fits not only inside the meter, but fits as well the real-life tolerances of the meters which inhabit this imperfect world, and the difficult environment in which meters actually toil. It fits, too, your need for a reliable, yet simple, low-cost encoder which can be quickly and easily installed in your existing meters, and it does its job with the accuracy you should expect from something that will be used to monitor your cash registers.

The field-proven Cain Encoder™ offers these principal benefits:

- it has no moving parts
- it uses no light sources, no brushes, no cams, no magnetic fields
- it does not require constant monitoring
- it does not interfere with visual reading of the meter
- it produces direct dial readings in standard ASCII code
- it requires no power other than a brief interrogation signal
- it quickly clips onto the existing meter
- it reports suspected tampering

and

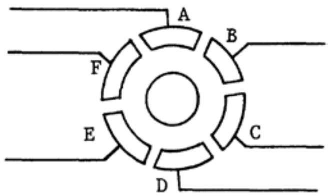

FIGURE 1

– it can be used with telephone, TV cable systems, powerline carriers, radio, or portable hand-held readers.

Broadly speaking, the Cain Encoder™ obtains a reading, when interrogated by a brief DC signal, by scanning the dials of the meter with an electric field. The meter pointers cause disturbances in the field, and these disturbances are analyzed by the encoder to determine the precise positions of the meter pointers. The encoder can read to the nearest tenth of the meter's least significant digit, and produces in ANSI-standard code (ASCII) its own identification number, readings of up to five dials, and a tamper-reporting code in slightly less than one-third of a second. Readings may be repeated as often as desired. The encoder monitors its own operation during the brief reading process, and if it suspects its operation may be faulty it sends question marks rather than risk producing an incorrect reading. All interdial comparisons are automatically performed internally by the encoder. The sensing element is completely transparent and the meter can be read visually without obstruction. The encoder connects to the interrogating system by three wires: these are, respectively, interrogation signal input, data output, and ground.

For those interested in slightly more detail:

The sensing element of the encoder consists of a glass plate resembling a microscope slide. In one surface of the glass is a series of transparent conductive patterns, one pattern confronting each meter pointer. A schematic representation of one such pattern is shown in Figure 1. When interrogated, the encoder's electronic circuit controls the glass plate, interprets the signals coming back from it, and produces the proper output code.

A reading is obtained by applying a DC signal of +9 to +15V to the interrogation lead. Using only this interrogation signal for its operating power, the encoder internally produces a set of three-phase signals at about 4 kHz, and distributes these among the transparent conductive patterns (electrodes A–F in Figure 1), producing an electric field which rotates in space 4,000 revolutions per second. At the geometric center of the array (electrode R of Figure 1) the vector sum of this rotating field is ordinarily zero, so there is no signal induced on the center electrode. But the meter pointer disturbs the symmetry of the field, causing a signal to appear on the center electrode. The important feature of this signal is that its PHASE exactly corresponds to the angle of the meter pointer. The encoder performs several tests to ensure that the desired signal is within specifications, then measures its phase, converts this to a numerical code, performs all necessary interdial comparisons, then sends the reading of this dial while reading the next dial to the left. No moving parts are required, nothing contacts the meter hands, shafts or register gears, and no power supply is needed—only the interrogation signal supplied by the communications system. At each interrogation the encoder automatically checks the status of a pin to which simple tamper-detectors (a breakwire, for example) may be attached: if the status is abnormal, a special code is sent as part of the encoder's identification number.

But can such a capable instrument be economical? Indeed it can, for production models of the Cain Encoder™ will consist simply of the glass sensor plate with two custom integrated circuits mounted directly on the glass. In volume production the encoder will sell for about $20 ready to mount in your meter. With our patented mounting technique, by the way, installing the encoder in your meter is very quick and simple.

With its unequalled accuracy, reliability, ease of use and economy, the Cain Encoder™ will contribute heavily to making automatic meter reading genuinely useful and economically attractive. We at Cain Encoder Company have tried to avoid the pitfalls of the past by taking a fresh approach, and as a result we are now in a position to make a very significant contribution to your industry. What we have done is to remove one of the two traditional obstacles to automatic meter reading: the high cost of the equipment—pulse accumulators, optical encoding devices, special meters—heretofore required at the meter. And Cain Encoder Company stands ready to help remove the other obstacle: the lack of a truly complete system for cost-effective automatic meter reading. You will be best served if the manufacturer of your preferred telecommunications equipment integrates our advanced encoder into his offering, and we are prepared to make it available to him. If you share our belief that the Cain Encoder™ meets your needs, please let him know—and tell us too.

One final word: the patented technology embodied in the Cain Encoder™ shows promise for robotics as well, and we welcome opportunities to explore this and other new applications.

DISTRIBUTION ROBOTICS IN THE GAS INDUSTRY: ISSUES AND APPLICATIONS

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ABSTRACT

The new engineering field of "Distribution Robotics" is emerging in the gas industry. The purpose of this paper is to encourage the gas utility managers and engineers to take notice of this new technology and start factoring it into their planning strategies.

The defined goal of distribution robotics is to improve the quality of service, lower operating costs, reduce work hazards, and perform in situ tasks. Applications of the distribution robotic system range from internal leak detection and repair to pipe condition assessment and cleaning; as stated, these applications are performed in a live system.

To achieve the desired application missions, the robotic system requires robots of different designs along with appropriate tools, peripherals, and external support systems. The robot consists of several subsystems that allow motion, sensory perception, action and reaction, communication, and entering or exiting the system. Each subsystem has several choices for robot configurations with advantages and trade-offs for the purpose, mode, range, and speed required by each mission.

External support systems are required for a complete distribution robotic system. An external computer and human operator are needed as well as the physical hardware necessary to support a robot operation.

Finally, issues raised by a distribution robotic system need consideration for proper planning. The major issues raised are robot miniaturization, obstacles, safety, coverage, and control.

DISTRIBUTION ROBOTICS IN THE GAS INDUSTRY: ISSUES AND APPLICATIONS

INTRODUCTION

In 1982, the Institute of Gas Technology (IGT) described an advanced gas distribution system that included robotics.[1] The Gas Research Institute (GRI) also noted the potential of robotics in 1983 when it stated: "Other R&D needs:

- Improvements of efficiency and service through automation. Robotics, computer control, and automation may be increasingly applied to providing gas to the meter and assisting the utility in reducing the cost of operations.
- Computer-aided manufacture of piping; new joining or welding techniques applied to pipe to reduce the cost of construction.
- Automated, in situ determination of pipe condition and in situ pipe conditioning and repair."[2]

Robotics in the gas industry is not a new idea; and it is now developing for applications in the distribution system. Recent research and development successes in robotic pipe and vessel inspection by the transmission and nuclear industries have provided the gas distribution industry with a transferable technology that can be adapted to suit the gas industry's needs. The transmission industry has already taken advantage of this technology and is developing robotic systems for the inspection and repairing of their pipe lines which in the U.S. is a $90 billion investment.[3] British Gas has also been quite active in pipeline robotic development and application, and has developed a commercial service which inspects their approximately 9, 000 miles of pipeline. The On-Line Inspection (OLD service uses a fluid driven, "torpedo-like train packed with electronics" for the inspection of pipes.[4]

The nuclear power industry has taken hold of this technology and has funded a large portion of the research relevant to pipeline robotics. They have developed robotic systems that not only inspect pipes and joints, but also perform remote in-pipe welds.[5] Such R&D successes suggest that advanced robotics is emerging from the laboratories into the commercial market.

It is a major premise of this paper that substantial advances in robotics will be made in the next several years and that the transfer of this technology to the gas industry will create a new field of "distribution robotics". The purpose of this paper is to encourage the gas utility managers and engineers to take notice of this technology and start factoring it into their planning strategies. This will ensure that the utilities will have a clear understanding of the technical and economic factors. A thorough discussion of distribution robotics must begin with a clear definition of what it is, what applications are possible, and what issues it will raise.

DEFINITION OF DISTRIBUTION ROBOTICS

We define distribution robotics as the design, use, and operation of multifunctional, perceptual, and reprogrammable machines which are computer controlled to perform human desired tasks that improve quality of service, lower operating costs, reduce work hazards, and optimally perform humanly impossible tasks. The robotic system should be able to explore, document, act or react to commands and its environment. Through the use of artificial senses and computer programs, the robot can assess its surroundings and report back to the operator while carrying out its specified functions.

APPLICATIONS OF DISTRIBUTION ROBOTICS

Given the assumption that advances in robot technology will occur, it is appropriate to consider the variety of tasks and applications that can be serviced by the distribution robotic system. These applications will require different designs of robots, sensors, and manipulators. Some of the suggested present and future applications are listed below:

- Internal leak detection
- Internal leak repair
- Automatic Mapping
- Pipe condition assessment (buried)
- Gas data condition recording
- Emergency flow shutdown
- Obstacle removal
- Pipe cleaning and general maintenance
- Meter Calibration

Internal leak detection can be achieved by the acoustic sensing of leaking gas or by the phase disturbances caused by cracks or interruptions in the pipe wall to induced magnetic fields or broad-band acoustic frequencies.

New robotic sensors, manipulators, and special purpose tools can be used to improve a variety of chemical and/or mechanical internal leak sealing technologies.

The robot can be programmed to traverse the system in an orderly fashion and record the distances and directions. As each section is completed, the electronic "map" of the system can be merged with a street map referenced to several points. The joint map can then be printed out, and stored in a computer memory. In this way, the robot can complete an automated mapping of the entire system.

Pipe condition assessment or inspection is accomplished through the making of a "fingerprint" of the pipe. There are many methods to do this in practice today. Cracks, dents, deformations, and corrosion areas in the pipe can be detected within buried pipe. In addition, a camera can be mounted on the robot to allow a human operator to view the interior of the pipe.

The condition of the gas in the system can be ascertained by recording the pressures, temperatures, water content, odorant levels, and methane concentrations. The effectiveness of load shedding techniques could be analyzed from inside the system. An accurate history of the system or a portion of the system could be maintained for comparisons of specified time periods.

Emergencies in the distribution system could be detected by a robot, which could then move to the affected area. In the case of a broken or collapsed line, the robot could shut off gas flow. The safety benefits in this maneuver could be quite high and prevent further damage to surrounding areas of the system.

When a robot detects an obstruction in the pipe such as water, a failed robot, or some foreign matter, the robot can be equipped to transport the obstacle back to a location for removal.

General maintenance and thorough cleaning of the pipe could be accomplished on a regular basis with a robotic system. Using stiff and polishing brushes, the robot could clean the interior of the pipe. This would allow a more accurate view and picture of the pipe's condition. Also, this process could serve to clean the pipe for good adherence of a sealant for a leaking section.

Finally, a future capability could be remote and <u>in situ</u> meter calibration. In an advanced automated gas distribution system, the robot could compare what it detects by passing through the service tap with what the meter measures passing through it. Meters in error could be flagged for service.

ROBOTIC SYSTEM COMPONENTS

Because it is unlikely that a single robot design will be able to provide all of the service required by a distribution system, a robotic system requires robots of different designs along with appropriate tools, peripherals and external support systems.

Robot Subsystems

A robot that can accomplish a desired task is composed of several subsystems enabling it to move, sense, act and/or react, communicate, and enter or exit the system. A single robot incorporates several of the subsystems into one unit depending on the mission and purpose of the robot. Because it is crucial that the robot's capabilities match its mission, the designer must select the combination of subsystems that provide for maximum efficiency.

Motion

The mode, range, and speed of the robot depend on the following "parameters:

- Body design
- Drive system
- Energy system
- Navigational system
- Positioning systems

Body Design. The design of the robot's body is of utmost importance to its end purpose. As not all missions are alike, neither are all robots alike. The size and nature of the distribution system are critical considerations. For a large diameter, long main with few turns, a rigid robot is in order; for the smaller mains, a smaller, more flexible robot is needed. A combination can be reached in an articulated robot. These examples illustrate the three general body designs:

- Rigid
- Flexible
- Articulated

Rigid robots such as the "bullet" or "pig" are usable in a variety of pipe sizes. The bullet is a thin body that houses the robot drive system and tools. The drive system and tools can "expand" out of the robot when it is activated inside the pipe. This is ideal for installing the robot through temporary, narrow openings. The pig is generally a large robot that can only be inserted into large, high pressure pipes. The rigid robot has the advantage of applying tools or manipulators to a work surface with a high degree of accuracy.

Designs such as the "worm" or "snake" are considered flexible. This permits insertion through small openings. It also permits the body of the robot to contract and expand against the side walls, then compress or expand its body lengthwise for movements. The body may be hollow so the flow of gas is not blocked. The flexible robot may also be able to bend its body around 90° bends. This type of body lends itself to the smaller mains which have many bends. High speed is difficult with flexible robots using their own power for locomotion, such as the worm. The snake has the option of being self-powered or being pulled through the system by a cord for short hauls.

Another design option is a combination of a flexible and a rigid robot. The articulated design consists of short, rigid modules that are joined to form one flexible robot. The robot could maneuver in a complex pipe system and accurately position and apply tools to work surfaces. A train of function modules with drive units at both ends is a prime example of an articulated robot. This allows the robot to be reconfigured by changing the function modules for different missions.

Drive System. The drive systems vary according to mission requirements such as accurate positioning, high or low speed, high torque, and low energy demand. Drive systems include the following:

- Line Pressure
- Wheels
- Treads
- Rails or Cogs
- Shuttle

Line pressure can be used to push the robot through the line. The speed is set by the gas flow rate and the range is limited to the entry and exit points only. This is not a desirable method for drive in a distribution system as this would not allow the robot to travel to an arbitrary location or back to its starting point.

A wheel driven module consists of wheels, which could be direct gear or extended belt driven. The direct gear drive is acceptable for a fixed-position wheel and has the advantage of higher torque for steep or vertical inclines. The driven wheels can be placed at the end of a self-positioning arm. This allows the robot to be used in various sizes of pipe, easier traversing of obstacles, and easier turns. Neither drive option has a particular advantage over the other in speed or positioning accuracy. Both drive options are capable of high or low speed, and with low speed and accurate positioning.

Using tank-like treads as a drive system could give less slippage and, therefore, more accuracy in travel and positioning. The treads can use a gear and suspension system for attachment to the robot; this is more complex and bulky than other drive systems. The larger size of the tread system might present design complications in the smaller 2" diameter pipes, but could be ideal for 6" cast iron pipes.

A drive system such as a dual rail, monorail or notched rail for cog travel has some unique advantages. The friction involved in rail travel is far less than the conventional drive system; power and communications can be transmitted through the rail; and accurate positioning, high or low speeds, as well as moderate energy demands are all possible with a rail drive system. Turns are also accomplished with greater ease. A drawback of this system is the initial installation of the rail. The retrofit installation of rail systems, however, may require the development of a new robotic technique.

Energy System. Robot drive, sensor, navigation, manipulation, and communication subsystems all require energy in the fulfilling of its missions. The range, speed, and mission actions can vary from mission to mission and, therefore, have different energy demands. To meet the mission requirements, the energy supply could be from one of the following categories:

- Constant
- Rechargeable
- One Shot

A constant energy source would allow the robot to work continuously, if desired. A possible energy source would be electrically provided in an umbilical cord, reeled cord, or rail. The umbilical and reeled cords are attached cables with a line for power and a metallic or fibre optic line for communications. Compressed gas such as methane or nitrogen can also be provided through the umbilical and reeled cords. The line pressure is also a constant energy source that pushes the robot through the pipe. In any system that uses something other than line electricity for drive power, the robot electronics would require a battery for operation.

The battery, incapsulated compressed gas, or liquefied propane can be used as a rechargeable energy sources for the drive systems. Once again, a battery would be needed for the electronics. The length of the mission would be limited by the life of the rechargeable energy source; this would only be a minor limitation.

Energy sources that are needed for short intervals or one job applications are often termed “one shot”. An example could be when an undesired open line was detected, an emergency robot could be sent to the specified location and shut off the gas flow, when determined safe, the robot would be manually removed from the line.

Navigational Systems. Guidance and location determination methods are essential to distribution robotic systems. To know where the robot is in the distribution system, an accurate method of measuring the distance from a referenced point and the checking or recalibration of that measurement is necessary, some systems that combine distance measurement and recalibration are listed below:

- Inertial and checkpoints
- Acoustic and landmarks
- Dead reckoning and vision

Each system can be reconfigured for different combinations.

Inertial navigation uses an odometer to measure movement of a non-drive wheel. Recalibration is needed it the odometer loses accuracy when the wheel slips or encounters many reverses. Checkpoints throughout the system can be provided to supply recalibration points. Checkpoints could be optical beams in the pipe, magnetic markers, or signal transmitters inside or outside the pipe. The transmitters could send a constant frequency or, if desired, send an address corresponding to its place in the distribution system.

Acoustic navigational techniques could use a mounted transmitter to generate traveling waves and a mounted receiver to detect reflected waves from obstacles such as turns and bends. The transmitter/receiver combination can also be pointed at the wall and look for a lack of reflected waves to detect an intersection. The phase measurements in the waves can produce accurate distance measurements. The robot could recalibrate its measurements whenever a known intersection or bend is reached. Another combination for recalibration could be the checkpoints previously discussed.

Dead reckoning would include the need of an electronic “map” of the distribution system and a camera for visual distance measurement and recognition of turns, intersections, or obstacles. The camera could also be used by an operator for controlled guidance.

Positioning Systems. Positioning of a manipulator,arm, or tool usually requires a separate drive system, gear system for proper minute movements, and sensor systems for touch and positioning. The drive system can be chosen from those previously discussed. The gear system would be individually designed for each tool or type of manipulator and arm. A full discussion of the sensor systems follows.

Sensory Perception

A robot must have senses to perform its tasks; this is achieved through four basic groups of electronic and mechanical sensors:

- Proximity
- Tactile
- Visual
- Environment

These sensors are alike in that the sensor is simply a feedback device that allows the robot to make adjustments or additions in its motions, actions, and information based on its external environment.

Proximity. The proximity sensor senses when one object is close to another object; "close" can be anywhere from several inches to hundredths of an inch. Most proximity sensors only indicate the presence or absence of an object within their region. Proximity sensors are ideal for navigation and for positioning a tool to a work surface. Rapid movement is possible until close to the surface when a slower movement is necessary to prevent damage to the robot or the tool. The different types of proximity sensors are based on —

- Optical or infrared light
- Ultrasound or acoustics
- Magnetic fields

An optic ram or light sensor would detect a reflected light from a light emitting diode (LED). As the robot approaches an obstacle, bend, or side of the pipe in positioning a tool, light is reflected and triggers the light sensor. Likewise, an optical sensor looking for an intersection or branch off might look for a lack of reflected light.

Acoustic waves work in much the same manner in that reflections or lack of acoustic reflections indicate the presence or absence of an object. An acoustic sensor can also be used in the location of leaks as the gas emits a specific range of sounds as it escapes through a crack. The sensor also has the ability to measure distance as mentioned in navigation systems.

A disturbance caused by an obstacle in a generated magnetic field can be detected. This field can also be used to obtain a "fingerprint" of the pipewall. This will give the robot and the utility a picture of the pipe's condition and if any cracks, dents, or other deformations exist.

Tactile. Tactile sensors respond to contact forces between the sensor and solid objects. This is unlike the proximity sensors because the tactile sensor does not tell of the object's presence until touched. The two types of tactile sensors are based on touch and/or stress. Touch sensors can be as simple as a switch or more complex such as specially doped rubber sheets or tips that conduct electricity when compressed by touching an object. Stress can be measured through the use of strain gages to make force sensors and torque sensors. These sensors are useful in slow positioning a robot or tool to a work surface.

Visual. Visual sensors provide the operator with visual feedback from a camera or optic ram, but automatic computer vision for the robot has not yet been perfected. At the moment, robot vision is too slow for real time operation, various types of information can be provided by visual feedback such as object recognition, depth measurement, surface orientation measurement, and position measurement. An operator can use this type of sensors in the navigation and control of a simple remote robot.

Environmental. Environmental sensors include the familiar pressure and temperature sensors. Others might be oxygen, methane, and propane detectors, humidity sensors, water level sensors, etc.

Action/Reaction Subsystems

An ideal distribution robotic system should be able to do more than just collect data from pipe inspections; special tools and manipulators can be added to allow the robot to act in the pipe via operator command or programmed algorithm. The operator or human authored program can use the manipulator to perform some task such as inspection or maintenance, movement of an obstacle, or placement of a tool or sensor at a specified location. Thus using the operator, the robotic system can act on or react to any command or situation by using the following tools:

- Computer program
- Manipulators
- Special tools

Computer Program and Human Operator. The robot cannot function without a computer program.This is really the operator's tool to control and communicate with the robot. For every mission, there has to be a program consisting of all the commands for movements, processes, calculations, information to store, and/or any action taken by the robot. These programs are stored in the robot's memory for access by the operator through the robot's brain: the microprocessor.

Manipulators. If the operator wanted to position a tool or sensor in any particular direction or location, a manipulator is needed. A manipulator can be a gear or beltdriven arm with an optional "hand" or clamper on its end. The clamper can grab objects as manufacturing robots do in grabbing parts and tools. The manipulator can also be an arm with a permanently attached device. This is a more simplified approach, easier to implement, but is not as flexible in future applications.

Special Tools. Special tools are needed to perform the various tasks in each mission. These tools could be brushes, drills, blowers, cameras, sensors, sealers, heaters, welders, flow restricting devices, transmitters, or almost any other modified tool now used in the gas industry.

Communication

An essential part of any system is communication between parts involved so that the proper action is taken. Communication with the external computer is needed for reception of commands and the transmission of data collected and operating conditions. Quick notification to the operator and utility is necessary when an emergency or a problem in completing a task arises. To accomplish this, the robot needs to have the capability and hardware to communicate; the requirements are listed below:

- Microprocessor
- Memory
- Communication Hardware and Link

Microprocessor. Since the robot needs a microprocessor for all of its functions, close attention to the size, speed, and capabilities are important. The capabilities should be matched to the missions proposed. There are many inexpensive and yet powerful microprocessors on the market today.

Memory. The memory holds all the programs that the robot carries with it. These programs are generally sequences of commands and actions for the robot to complete a task. The memory also holds all incoming data. Memory size has several determining factors: level of intelligence, size of programs, and amount of data to be sorted. It is always better to have extra memory because memory is inexpensive and adding memory later is very difficult and costly.

Communication Hardware and Link. The robot designer can choose from various communication electronics depending on the method chosen for transmission and reception with the external computer. A link such as a hard wire or fibre optic cord can be attached in an umbilical cord. Acoustic and RF transmissions are possible for short ranges to a receiver in the pipe; a possible location for the transceivers would be in the robot ports. If a tracer wire is used in an advanced gas distribution system, the communication signal could be transmitted inductively onto and through the tracer wire. A signal can also be inductively coupled to the rail provided in a rail drive system.

Peripherals and External Support Systems

Distribution robotics includes more than just the robot; it requires outside intelligence and peripherals for system support. A complete system would include the following:

- Computer and human operator
- Multifunctional ports
- Navigational

Computer. The size of the electronics and computer system in the robot is constrained because of its size; an external computer is needed for the large amounts of data collection, programming, and control. The computer also serves as a human interface. The computer itself is dumb and requires a programmer to author programs and controls from which the operator can control the robot. The computer could then take over and run the control programs. This is an important step and where most systems will vary greatly. The program determines how much self reliance and self control the computer/robot combination have. In future systems, artificial intelligence techniques will allow greater freedom for the operator as the system runs itself and reports to the operator.

Multifunctional Ports. Ports are generally considered to be entry and exit points. The distribution robotic system can use this port for more than just entry and exit; it can be used as a recharging or power generating station, communication terminal, and/or storage location for the robot and its tools and function modules. The port does not always have to be a stationary fixture. If work is being done on a section not serviced by the robotic system, a robot can be put into a live or dead system via a “hottap” port. This special port could be clamped onto the pipe, and then an opening tapped into the line. A part of the distribution system could be serviced by mobile ports.

Navigational Aids. In the discussion of navigation, several external components were required for operation and completion of the systems. These aids to navigation were as follows:

- Acoustic remote receivers
- RF receivers
- Checkpoint transmitters
- Magnetic markers
- Address or signal transducers

DISTRIBUTION ROBOTICS ISSUES

It is appropriate to address several issues that must be resolved before the potential benefits of distribution robotics can be realized. These include the following:

- Robotics Miniaturization
- Physical Obstacles
- Safety
- Coverage
- Control, Levels of Intelligence, Self-Reliance, and Supervision

Robot Miniaturization

An obstacle in the path of applying distribution robotics to smaller diameter pipes is the mechanical miniaturization of the robot. Electronic components are at a stage that miniaturization has already been accomplished. Further difficulties lie in the development of an arm and manipulator that can function with enough torque to perform the necessary functions. It is likely that the application of distribution robotics to 2" diameter mains will require the development of sensors and manipulators that depart significantly from the more traditional units used by other industries. The gas industries as well as others have brought a new focus on the miniaturization of robotics and their uses in pipes. It is only a matter of time before a line of useful robot designs emerge. It would be to the utilities' advantage to voice their needs and concerns during the design stage.

Physical Obstacles

There are various obstacles in the distribution system. Some of these obstacles are insurmountable such as regulators and closed valves. Obstacles of this nature only limit the range of the robot and create operational borders. Another robot can be placed on the other side of the obstacle and another operational area is created. There are other obstacles that can affect the robot. The siphon taps in cast iron systems are obstacles that might be by-passed with a properly designed robot. Other conditions can include water, sharp bends, and non-circular openings. The internal pipe environment is not ideal for electronics and this can prove to be an obstacle to the robot's continued operation. Special design consideration are necessary to protect the robot body and electronics.

Safety Considerations

Safety of the distribution system must be the major concern. At no time should the distribution robotic system endanger any portion of the system. Intrinsic safety of the robots and peripherals should be part of the designing stage. Depending on the configuration chosen for drive, navigation, and communication, the designer must make sure that no one subsystem or combination poses a safety hazard during operation or upon failure. The designer and programmer have the task of ensuring that the robot is failsafe. It cannot block or endanger the lines.

Coverage

Robot coverage refers to the number of robots needed to service an entire system. The range, speed, and application of each mission needs to be matched with the appropriately designed robot. Even the most ideal robot would not be able to fulfill every type of mission; so, a number of robots are needed in each area. The area is defined by the range of the robot. The range can mean how long the energy supply will last and how far the robot can go before an insurmountable obstacle is reached.

Control, Levels of Intelligence, Self-Reliance, and Supervision

The level of control for the robot cannot be divorced from the level of intelligence, self-reliance, and supervision included in the robotic system. Control of the distribution robot comes in the following three modes:

- Remote
- Automatic
- Autonomous

Remote Control

Remote control is the direct human control of the robot; only a low level of intelligence and self reliance is needed. The great limitation to remote control is the constant necessity of a human operator or a high level of supervision. This is a past and present method of controlling robots or, more aptly termed, manipulators as the definition of a robot specifies a higher level intelligence and self-reliance with a lower level of supervision in the robot. A higher level of remote control could be the human guidance of the robot through the system using a camera for operator navigation. Once the location has been reached, the robot can be commanded to perform a programmed sequence of actions to perform a task. Then only the navigation of the robot is limited by the operators' time.

Automatic Control

One step further would be automatic control. The level of intelligence or complexity of programs is raised so that a task can be performed on command of the operator. The operator might still be asked to supervise the actions or movements of the robot; this is tied to the level of self reliance that the robot has. In automatic operation, the robot continues with the repeated task until some problem arises or the task is ended. No deviation is allowed unless the robot is interrupted or turned off. If a problem arises, the robot stops and asks the operator for assistance. When the robot is finished, it will remain stopped until the operator sends the next command. The robot does not have the ability to make changes in its programmed movements or actions because of changes in its external environment.

Autonomous Control

The highest level of computer control for a robotic system is termed autonomous. This operation is basically self control through the sensory feedback of conditions from its surroundings. The robot still needs human authored programs and commands for its intelligence. The difference in autonomous operation and lower levels is that most of the programs and commands are internal to the robot and limited changes can be made in its movements and actions according to what it senses. Commands from the operator through the external computer are still allowed, but more complex operations can be accomplished without intervention or supervision. The robot would be able to solve problems in its navigations without interrupting its assigned tasks. If desired, tasks can be performed on *a* priority basis without the prior command of the operator. Examples might be the cleaning and sealing of a pipe section when the robot senses a leak in that section or a system emergency such as a burst or blocked pipe. The robot could be able to detect an abnormal amount of gas flow and drop in pressure. The robot could then travel to the location involved and restrict the flow (flow shutoff) or remove the obstacle, whichever the case may be. In either case, the robot would immediately notify the utility that such an emergency exists. If the operator wishes no action to be taken, this can be sent to the robot. All of this would take place much faster than is humanly possible.

A cautious approach and testing period is likely in the development of robot control. Eventually, control will become autonomous with artificial intelligence techniques allowing the robot system to learn as it goes.

SUMMARY

Distribution robotics is emerging as a new engineering force. Serious planning strategies are needed to prepare for its arrival. Each utility needs to define its applications; match these applications with variations of robotic system designs; and deal with the issues of control, supervision, intelligence and self reliance before distribution robotics emerges from its infancy.