Real Time Electronic Gas Measurement

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Introduction

The measurement of oil & gas production has progressed considerably since the days of paper charts and manual integration. Technology has moved increasingly to microprocessor based flow computers allowing for greater measurement accuracy, increased control functionality, and ready integration into a company's enterprise computer networks.

Figure 1: Typical Flow Computer Configurations

Background

Prior to using computerized electronics, measurement was (and still in use today) based upon ink pen mechanical chart recorders. Unless in a plant, operators drove to facilities on a frequent basis to change charts and transport them to an office for integration.

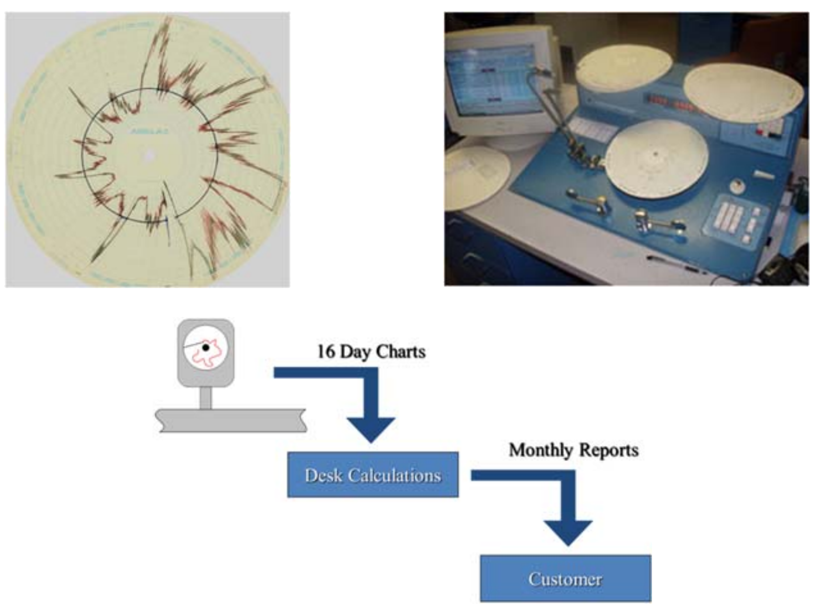

Figure 2: Charts and Integration

As shown in Figure 2, a common chart system would use a sixteen day chart, picked up on a regular basis, turned over to a person for integration, and ending with monthly reports issued to the customer.

In the early stages of Electronic Flow Measurement (EFM), a flow computer simply interfaced with the three primary inputs (Pressure, Delta Pressure, and Temperature) required for gas measurement and duplicated the chart recorder's measurements.

Figure 3: Orifice Primary Meter and P, DP, and T Transmitters

Differential pressure, static line pressure, and the meter temperature were typically acquired from an analog 4-20 ma or 1-5 volt transmitter, digitalized via an A/D convertor, and read into the flow equation. These transmitters had to typically be bench-calibrated and spanned using test equipment, electronic meters, and power supplies. The device was usually spanned to a range required for the particular application and matched to an appropriate electronic signal such as 4 ma for zero, and 20 ma for full span. Once the devices were bench-calibrated, they were taken to the field and installed on the meter. Calibration was then performed with the electronics of the meter so that 0 read 0 and full span read 100% in the meter. This calibration was recorded in the Meter History for archive purposes. As technology improved, the sensors advanced to converting the actual pressure or temperature measurements to a digital signal that could be read directly by a microprocessor-based flow computer.

Data was periodically stored in a database for retrieval and recalculation should the need arise; flow computers typically hold up to 35 days of data. Drive-by data acquisition (reference figure 4) was commonly done.

Figure 4: Collection of measurement data via a PC or hand held device

Accuracy

The most driving factor behind EFM from the inception of the technology has been applications involving Custody Transfer. Custody Transfer locations are the cash registers of the industry. Accurate measurements are required to meet contractual requirements between companies or common carriers such as pipelines. These measurements are often required to be implemented by local government entities for tax purposes. Therefore, for Custody Transfer it’s all about accuracy.

Charts at their best could achieve +/- 0.5% accuracy for measurement of the primary variables. Then chart integration accuracy would have to be factored in. Since this was usually a manual operation, results differed depending upon the person involved. By comparison, measurement of variables by a flow computer is typically +/- 0.1% and better. Once digitized, all calculations are performed based upon published industry standards resulting in highly accurate and repeatable results.

Standards

In the gas industry virtually all calculations meet standards set by the American Gas Association (AGA) and the American Petroleum Institute (API). For the US market, these standards include:

AGA Report No. 3, Orifice Metering of Natural Gas Part 3: Natural Gas Applications

AGA Report No. 7, Measurement of Natural Gas by Turbine Meter

AGA Report No. 8, Compressibility Factor of Natural Gas and Related Hydrocarbon Gases

AGA Report No. 9, Measurement of Gas by Multipath Ultrasonic Meters

AGA Report No. 10, Speed of Sound in Natural Gas and Other Related Hydrocarbon Gases

AGA Report No. 11, Measurement of Natural Gas by Coriolis Meter

API MPMS Chapter 21.1: Flow Measurement Using Electronic Metering Systems - Section 1: Electronic Gas Measurement

Standards serve three purposes:

- Define the best practices of industry.
- Allow buyers and sellers to refer to standards and not include all details in procurement documents.
- Enable two separate measurement equipment operating at separate locations and receiving the same inputs to yield virtually identical results.

Evolution

With increasing awareness of the additional horsepower of a flow computer and its ability to perform complex tasks, usefulness of these devices gained speed. Measurement inputs proved only the beginning of handling a vast array of input/output signals used at measurement locations.

The desire for more functionality quickly led to greater diversity in field I/O requirements. Metering moved from "simple to understand" analog inputs towards digital RS485 multi-drop communications with digital multivariable sensors. These are typical of most modern flow computers. Such communications involve the reading and writing of data to the transmitters. No longer would just measuring a voltage be enough. Digital communications require a bit more sophistication to diagnose and troubleshoot, therefore, new methods of verifying and troubleshooting had to be acquired. Computer software programs, for example, greatly aid in reading diagnostics of the device.

More devices such as turbine meters, ultrasonic meters, and coriolis meters came into play. These produced frequency pulses to pulse counters. The flow computer would perform the appropriate AGA7/AGA 9/AGA11 calculations and archival of the pulse input data along with the pressure and temperature readings.

Other advanced applications make use of discrete inputs for other device status inputs, analog outputs for remote set point signals, outputs proportional to flow signals for external devices, and specialized digital communications to many kinds of devices and locations. Systems are increasing showing up with Ethernet ports for local or wide area communications for purposes of local configuration, short haul local device communications, and SCADA (Supervisory Control and Data Acquisition) telemetry.

In short, the I/O has expanded to encompass discrete inputs, discrete outputs, analog inputs, analog outputs, pulse input counters, RTD inputs, thermocouple inputs, RS485/RS232 serial communications, HART protocols, and general purpose Ethernet ports.

Power Concerns

As these new features are added to the flow computer, one must consider the total power load in sizing the power system. Oftentimes, flow computers in a gas field will be solar powered making power consumption a critical issue.

Communications can be the single greatest power load on the system. The power draw from the communication device must be considered along with the polling load. Systems all too often have been initially designed underpowered because they were only planned to be polled once per day when in reality the intervals increased to hourly, and even further down to less than a minute. Other devices and their duty cycle loads on the system must also be taken into consideration when powering these advanced systems. One big culprit to pull down the power system is any type of solenoid or relay that has a coil to be energized.

Wireless Devices and Power Consumption

Beginning in early 2000, wireless instrumentation began to appear in industrial applications on an increasing scale. As the name implies, these transmitters eliminate the cost of wiring and the physical limitations associated with flow computer I/O. However, battery lifetimes of the devices can be a very critical consideration.

Figure 5: Wireless Transmitter

One consideration is ambient temperature. Using a pressure transmitter as an example, temperature effects are shown below:

Device: Pressure Transmitter, Sample Rate 16 seconds

AMBIENT TEMPERATURE	ESTIMATED BATTERY LIFE
86ºF	7.0 years
0ºF	6.3 years
-40ºF	5.6 years

Of much greater impact is the sampling frequency. In slow changing applications like tank level measurement, or non-critical applications such as temperature in non-custody transfer location, the requirement for data may be on a once every 16 second basis. However, for gas custody transfer the API 21.1 standard requires a sample *every second*. Battery lifetimes for these two sets of sample rates are exemplified below:

Device: Pressure Transmitter, Ambient Temperature 86ºF

SAMPLE RATE	ESTIMATED BATTERY LIFE
16 seconds	7.0 years
1 second	0.8 (*less than 1 year*)

To overcome such challenges a user may supply supplemental solar power. But, this usually requires cabling to an enclosure outside of Class 1 Division 1 areas. While there are energy harvesting techniques available to reduce the battery load, they entail adding cost and complexity.

For these reasons, current technology requires considerable deliberation be performed prior to the deployment of wireless transmitters in gas custody transfer applications.

Advanced Applications: PID Controller

The first functionality to consider beyond just measurement is control. This requires either a pre-designed control application such as Proportional Integral Derivative (PID) control or some sort of logic application. These applications should be readily accessible in a familiar format to allow for configuration, tuning, and input/output assignment. PID Control requires an input process variable, an output to some sort of control device, a means of entering a set point, and the ability to tune the application to maximize the ability to control without being unstable.

Upstream Example – Closed Loop Control of a Free Flowing Gas Well

Sizable drilling programs in the shale plays of North America have bought about a large number of free flowing wells. Maintaining optimal performance for so many sites can prove to be a formidable challenge.

To fulfill this need, producers have flow from each well manipulated via a single automated choke valve. The primary focus of the system is to maintain a steady flow from the well to the Sales Line based upon an operator entered set point. Multiple overrides come into play based upon operating conditions. Measurements include Delta Pressure and Flow Rate from an orifice run feeding a Sales pipeline, and Static Pressure and Temperature of the flow line feeding a separator.

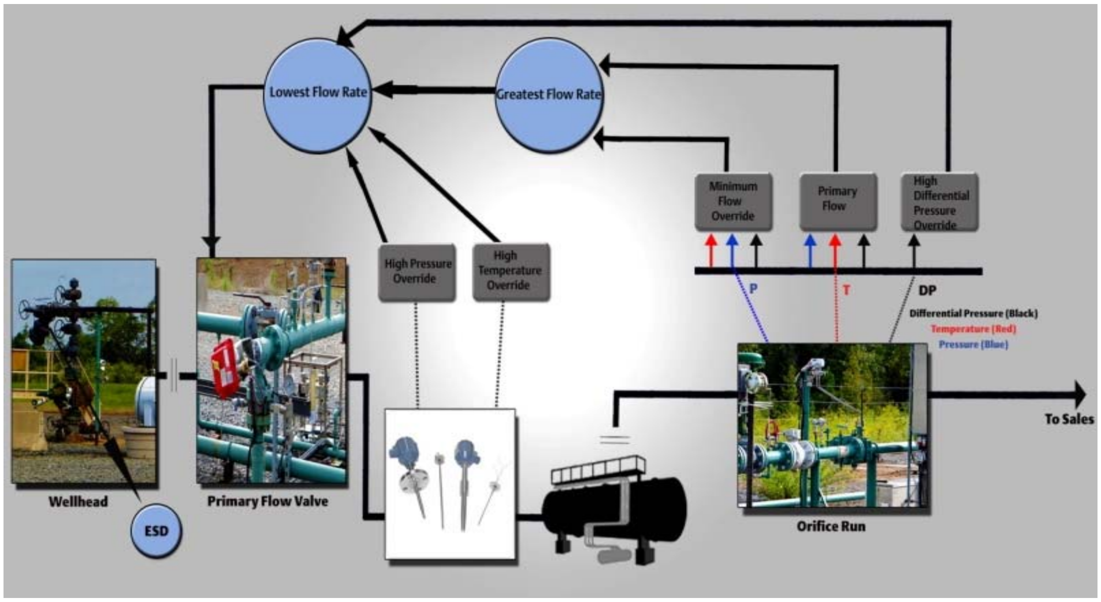

Figure 6: Control Scheme

Issues tackled via a Flow Computer include:

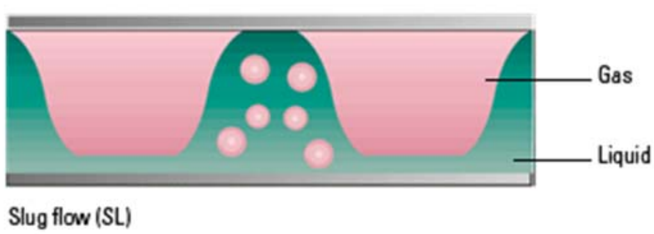

Figure 7: Slug Flow

Liquid Loading: Whenever slug flow (depicted by Figure 7) is present, gas flow through the Sales Line will drop as liquid is produced. The primary flow control logic reacts to this change and will open the choke to compensate. When the well unloads (water decreases) the gas flow increases quickly. Once again the primary flow control logic will compensate and commence to close the choke. Reaction time, though, may be too slow to avoid tripping the well off-line due to a high Sales Line pressure. To prevent this type of occurrence, the Delta Pressure (DP) of the orifice run is monitored. A DP override function in the flow computer logic is more aggressively tuned and therefore can bring the well back under normal flow control much sooner.

Maintaining Critical Velocity: Critical Velocity, determined by industry known Turner & Coleman equations, indicates the minimum rate of flow required from the well to lift liquids. Flow below this value will cause water to collect in the well eventually curtailing production. It is necessary to assure the well flow exceeds Critical Velocity. Logic within the flow computer will select between the greater of the primary flow control set point and the Critical Velocity set point. In this fashion, flow will be maintained at the operator set point so long as the Critical Velocity is reached. The control scheme then works to keep the flow rate sufficient to assure that liquids continue to be extracted.

Transient Flow Conditions: To avert the well from being tripped off-line due to a wave of high temperature production, a high temperature override PID loop responds rapidly to lower the flow set point. Reducing the flow through a heat exchanger (reference Figure 8) helps hold the average temperature to an acceptable level. Similarly, any upsets causing a spike in line pressure will trigger a high pressure override response and reduce flow.

Figure 8: Heat Exchanger Keeps Average Temperature Within Operational Limits

ESD: As is always the case for a safe operation, switches located on-site and a remote SCADA command can initiate an Emergency Shutdown (ESD) mode overriding all other logic and causing immediate closure of the choke.

<u>Host Applications, Acquisition Remote Data</u>

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Figure 9: Typical SCADA Host Systems

The ability to communicate remotely to the electronic flow computer is what really brings operations to the world of real-time measurement and control. It allows results to be seen and acted upon virtually instantaneously (reference Figure 10). Many possibilities beyond just data gathering can be considered. Depending upon the type of communications and frequency of polling the remote device, options for remote control can be implemented. From simple set point changes, to advance logic and emergency shutdown processes, the communication systems link the flow computer and controller to the measurement and gas control office.

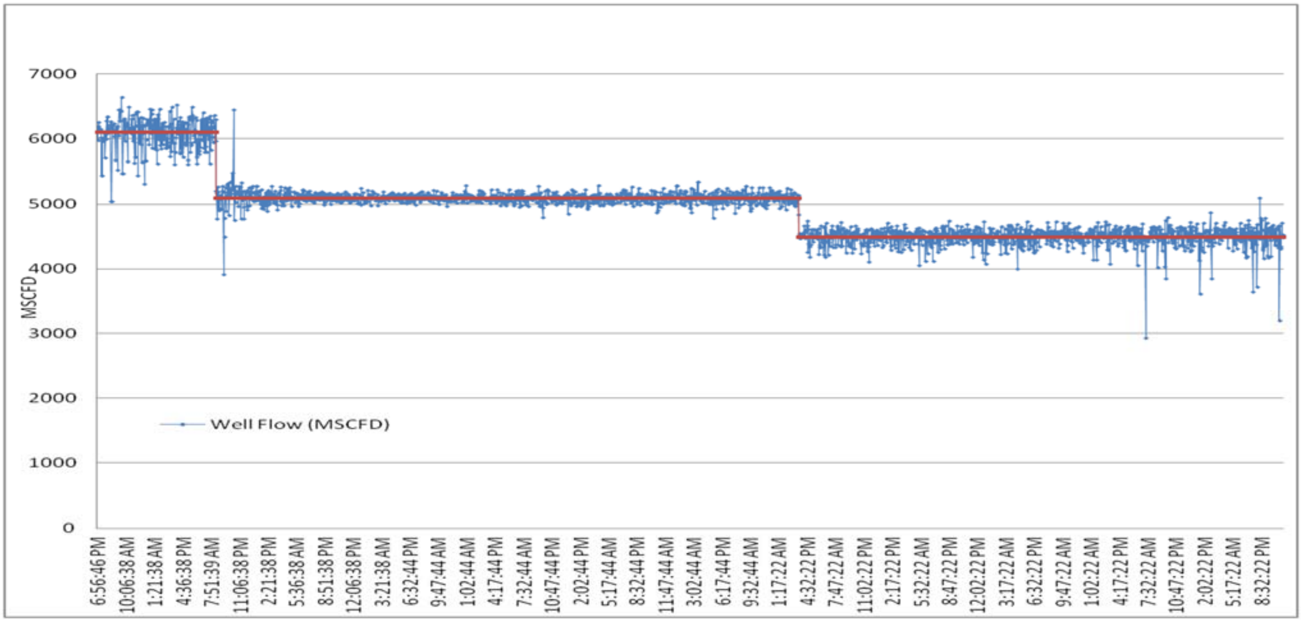

Figure 10: Remotely Controlled Flow Set Point

Data is viewed within seconds of acquisition → Real-Time

Summary

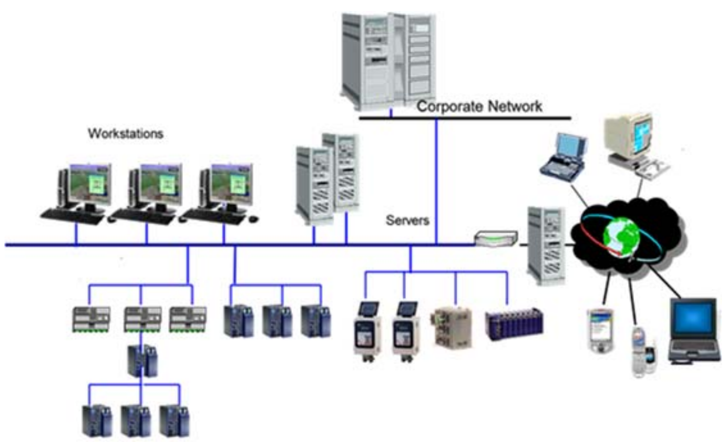

Figure 11: Fully Implemented System for Real-Time Measurement and Control

As one can come to understand, the widespread use of microprocessor based flow computers has expanded the field capabilities in the areas of data acquisition, remote interface, and control. The units found at today's measurement sites many times are underutilized as a complete solution to remote field measurement and control. By taking the time to understand the capabilities of various manufacturers' units, learning how to use these features, and implementing them in a planned way, the modern gas company can easily improve operations and ultimately their bottom line performance.