APPLICATION OF FLOW COMPUTERS FOR MEASUREMENT AND CONTROL

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INTRODUCTION

The measurement of oil & gas production has progressed considerably since the days of paper charts and manual integration. While still in use today, the technology has moved increasingly to microprocessor based flow computers. Such devices allow for greater measurement accuracy, increased control functionality, and are readily integrated into a company's enterprise computer networks.

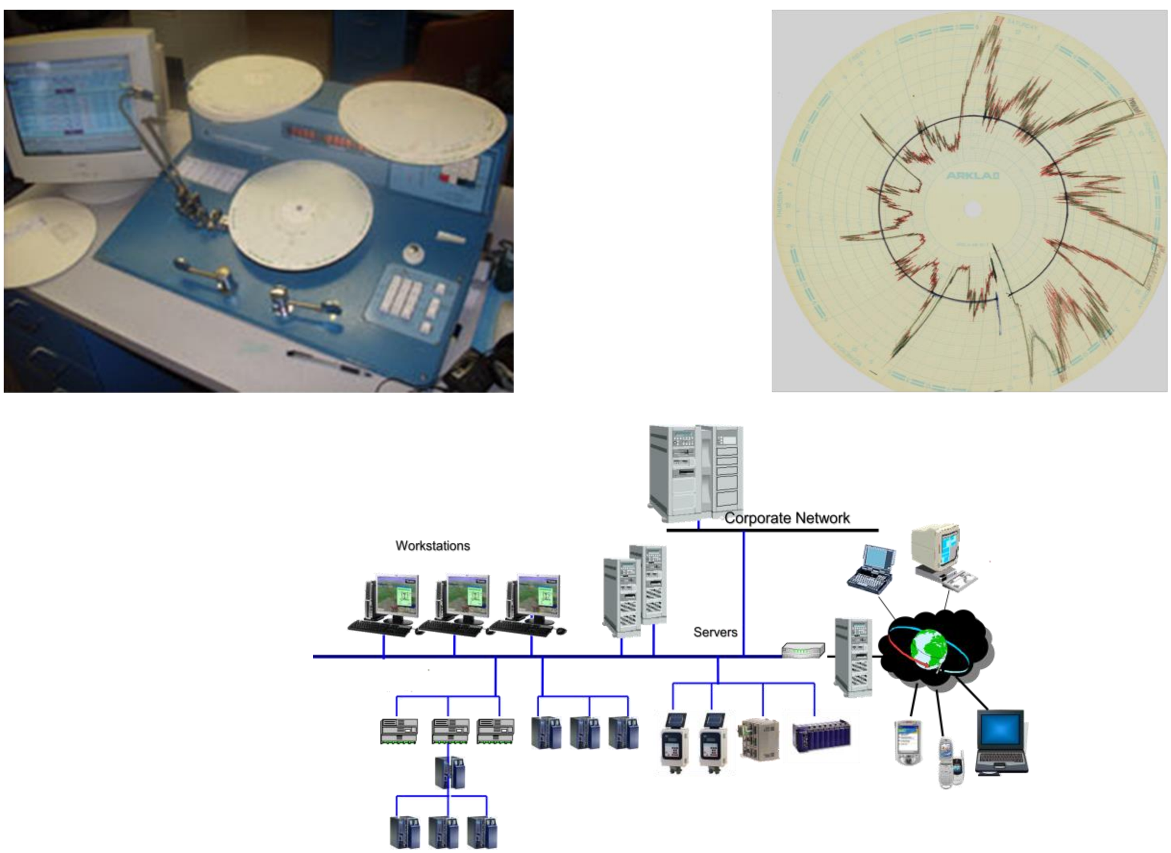


FIGURE 1: CHARTS AND INTEGRATION

Components of an Electronic Flow Meter

Primary, Secondary, Tertiary Devices

API Chapter 21.1, a document published by the American Petroleum Institute (API), describes fundamental elements in natural gas measurement:

- ***Primary device*:** Orifice, turbine, rotary, or diaphragm measurement devices that are mounted directly on the pipe and have direct contact with the fluids being measured.



Orifice Meter ***Vortex Meter*** ***Ultrasonic Meter***

- ***Secondary device***: provides data such as flowing static pressure, temperature flowing, differential pressure, relative density, and other variables that are appropriate for inputs into the tertiary device.


Delta Pressure Transmitters

- ***Tertiary device:*** is an electronic computer, programmed to correctly calculate flow within specific limits that receives information from the primary and/or secondary devices.

Our interest lies with the electronic computer, or flow computer.

Industry Sectors

There are three sectors of the measurement industry generally referred to as Upstream, Midstream, and Downstream metering. It is worth noting that the Downstream sector is viewed somewhat differently between the gas and liquid sides of the Oil and Gas industry as depicted below.

Upstream: This term is used commonly for the searching for and subsequent recovery of crude oil and natural gas - oftentimes referred to as the Exploration and Production sector.

Midstream**:** After producing the fluid, the product must be moved to market. Pipelines are typically used to transport products; this sector is referred to as the Midstream portion of the industry.

Downstream- Gas: After the gas is produced (Upstream) and transported (Midstream) it is then delivered to the gas distributors (Downstream), the natural gas may have been measured at least four times prior to arrival at your home. Downstream refers to the final delivery of the gas to homes, businesses, and industries.

Downstream- Liquids: In the case of liquids, the downstream segment begins with a crude oil refinery or Natural Gas Liquid fractionation facility.

Applications

Measurement Application - Custody Transfer

The most driving factor behind Electronic Flow Measurement from the inception of the technology has been applications involving Custody Transfer. Custody Transfer locations are the cash registers of the industry. A measurement station may include metering runs for multiple streams such as a "city gate" station where natural gas is transferred from a transmission pipeline. 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, requiring extensive reporting and data acquisition capabilities. Table 1 indicates the financial impact that can be attributed to accuracy in these measurements. Applications of this nature may be found in all three segments of the aforementioned sectors.

	Yearly Financial Uncertainty		
BPH	Price of Oil per Barrel		$65.00
1000	$569,778	$1,424,444	$2,848,888
2000 (6" Line)	$1,139,555	$2,848,888	$5,697,775
4000 (8" line)	$2,279,110	$5,697,775	$11,395,550
8000 (10" Line)	$4,558,220	$11,395,550	$22,791,101
16000 (16" Line)	$9,116,440	$22,791,101 Typical	$45,582,202
32000 (24" Line)	$18,232,881	$45,582,202	$91,164,403
64000 (36" Line)	$36,465,761	$91,164,403	$182,328,806
Uncertainty	0.10%	0.25%	0.50%

TABLE 1: FINANCIAL UNCERTAINTY IN OIL TRANSFER AT $65.00/BBL

In the gas industry virtually all calculations meet standards set by the American Gas Association (AGA) and the American Petroleum Institute. 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

Interestingly, there is not a certification agency for adherence to these standards. Most manufacturers will submit their designs to independent groups for testing. The result is a report indicating that the design is compliant to the particular standards involved. Groups such the Southwest Research Institute (SWRI) and the Colorado Engineering Experiment Station, Inc (CEESI) are commonly used by the industry.

Most all electronic gas measurement systems have a way to collect data remotely from metering sites. There is still the practice of manually driving to the sites and collecting the measurement data via a PC or some type of hand held device. Generally, though, there is a Host Supervisory Control and Data Acquisition (SCADA) computer system in place that resides in the corporate office or in the field office.

This system contains a polling software package that is designed to communicate via radio, satellite, or hard wire to the remote location. Usually these systems communicate once an hour, or on a more frequent basis to the well sites to both assure the processes are running properly and to retrieve timely information.

Most polling/Host systems have features to allow retrieval of data along with editing of historical data.

Midstream Application – Wireless Instrumentation

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

Wireless Transmitter

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

Device: Pressure Transmitter, Sample Rate 16 seconds

AMBIENT TEMP.	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. The common midstream application, however, is custody transfer, which by API 21.1 standards 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
1 second	0.8 (*less than 1 year*)
16 seconds	7 years

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. Power packs with greater battery capacity are available but shift the estimated life to only slightly more than one year.

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

Upstream Application – Closed Loop Control of a Free-Flowing Gas Well

Sizable drilling programs in the shale plays of North America bought about a massive 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 (reference Figure 1). 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.

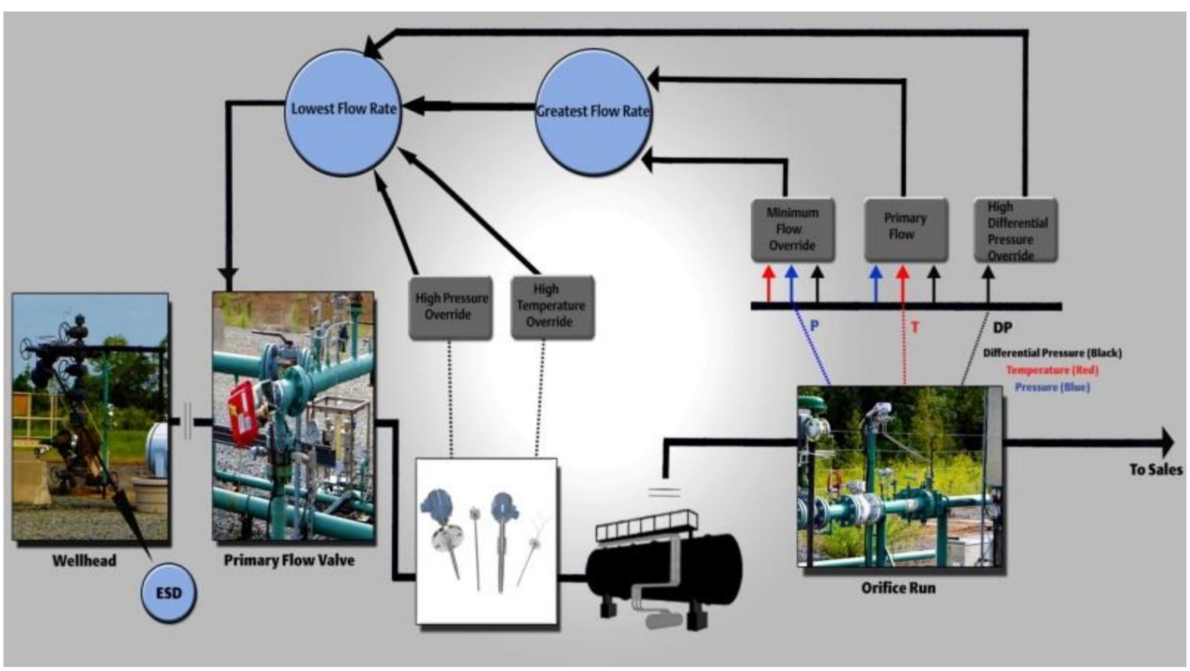


FIGURE 2: CONTROL SCHEME FOR SHALE GAS WELL PAD

The electronic platform requirements include the ability to execute AGA style flow computations, customized PID (proportional–integral–derivative) control loops, and coded algorithms in addition to communicating with an existing SCADA system. From a hardware perspective, units need to be rugged enough for demanding outdoor environments. Also, lack of electrical power in the area forces reliance upon a solar powered system.

Issues tackled via a Flow Computer

Start-Up Sequencing: Automation can perform an operator determined sequence allowing a consistent, quick, and easy method to achieve minimum flow. Once on-line, an operator has the ability to ramp the flow up over time for a soft landing at the desired flow rate.

Liquid Loading: Whenever slug flow 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.

Maintenance of Critical Velocity: Logic within the 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 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.

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.

Upstream Application – Distributed Automation manages Multi-Well Pads

Horizontal drilling practices have permitted more than access to long dormant Shale opportunities. The approach also is very conducive for multiple wells to be placed on a single pad. Reduced drilling costs and significantly smaller environmental footprints have resulted. Automation techniques commonly used in the past often become unmanageable when attempting to handle the quantities and densities involved.

Classical automation schemes (Reference Figure 3) suffer many drawbacks in this type of scenario including:

1) Lengthy cable runs
2) Inconsistent data update times
3) Extensive MODBUS register mapping
4) Advance notice of additional drilling

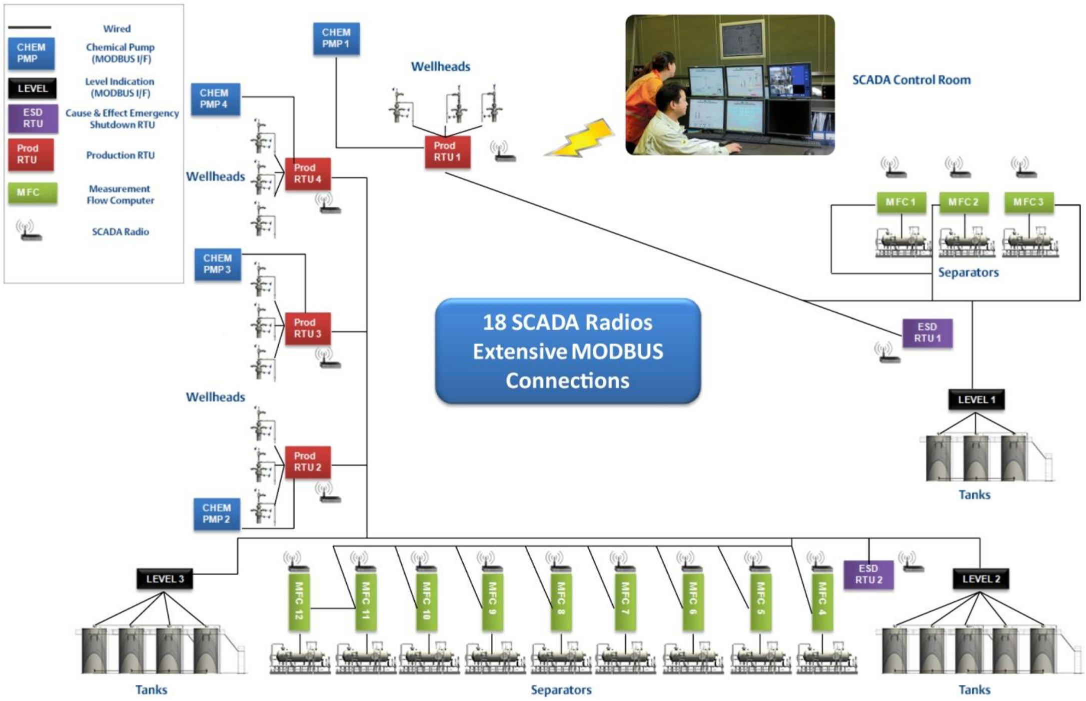


FIGURE 3: CLASSICAL APPROACH

As shown in Figure 4, wireless Remote Terminal Units (RTUs) acting as nodes on a network can distribute the logic and control functions on a well pad resolving these issues.

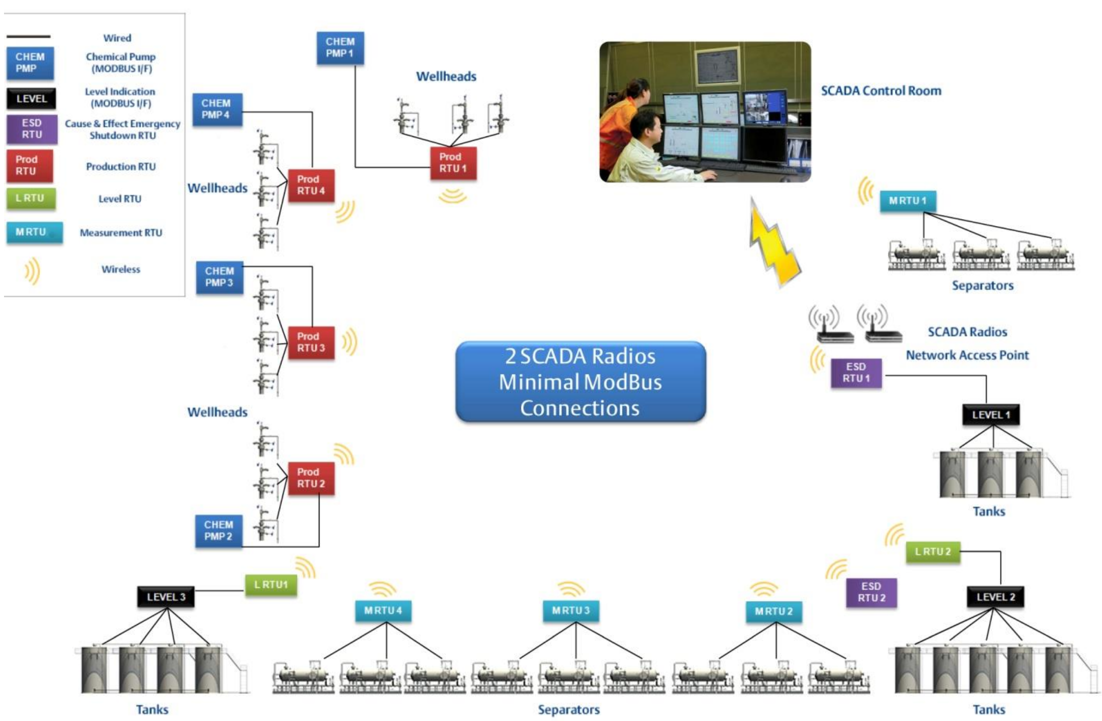


FIGURE 4: DISTRIBUTED APPROACH

Benefits include:

- **Elimination of Cabling and Heavy Equipment Trenching**

  Wireless technology eliminates the need to trench and bury conduit between the well head equipment.

- **Minimal MODBUS communications**

  Instead of using hardwired multi-dropped MODBUS communication protocol interfaces and associated registers to map data between RTUs, a distributed system makes use of a Drag-and-Drop technique in its design mode. This means an RTU's database is "browsable" by other RTUs in the network.

- **Scalability**

  A distributed system consists of intelligent nodes each with a capacity to serve their respective purposes, therefore, the system capability automatically grows in proportion to need. In short, once determined to fit a particular use, computing and memory issues are no longer worries.

  From an installation standpoint, the ability to quickly add RTUs to an existing wireless network is a distinct advantage. This ability extends to multiple pad sites within range of the pad, providing the ability to automate production between multiple pad sites.

- **Reduced Deferred Production**

  Usually, automation is one of the last functions placed in service before commencing production. With the distributed system, time to reach first production on a greenfield installation can be reduced by a nominal three days.

- **Lower Total Installed Cost**

  From an equipment perspective, the ability to use a node as an access point to pass through data for other units on the wireless network eliminates additional radios. When combined with diminished cabling and trenching work savings in the millions of dollars can be recognized for large drilling programs.

Upstream Application – LACT for liquid measurement

Until pipelines can be constructed, trucking can be the only means available to transport liquids from field locations. The large number of trips necessary dictates that operators seek out the safest, most efficient means of handling truck load-outs.

A field that has consolidated tank facilities can readily support a loading facility intended to handle multiple trucks at a time for crude oil transfer. Central to the concept is a Lease Automatic Custody Transfer (LACT) unit implemented with an automation package. LACT units are used in the industry to transfer the ownership of liquid hydrocarbons between a buyer and a seller.

FIGURE 6: CORIOLIS METERS ARE COMMONLY USED

Upon arrival, a driver parks in one of several loading areas and connects a vehicle grounding cable. This is a safety practice to prevent sparks from occurring while loading the truck. Lack of a grounding connection will be detected by the controller, and no loading will be permitted to occur. The driver then proceeds to the controller panel. Using the touch screen, passwords such as company identifier and driver ID's are entered to grant loading access. Finally, the driver enters an amount of gross barrels to load – a preset value – and the loading sequence is initiated.

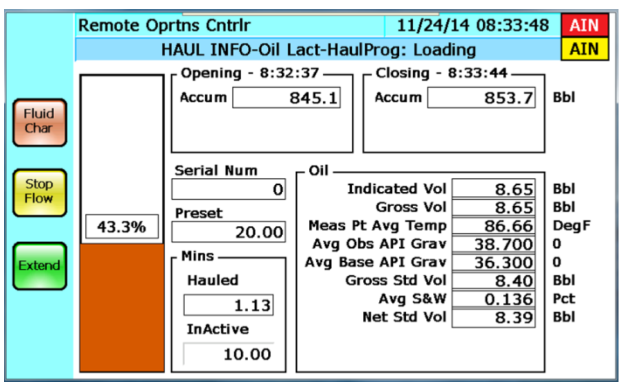


FIGURE 7: DRIVER LOCAL HMI

When the sequence begins, product is initially routed to a Diverter Tank by means of an automated three-way valve. The flow computer monitors the output of a Basic Sediment & Water (BS&W) meter placed on the incoming flow line. Once the reading is within contractual limits, the controller will automatically adjust the valve to route the liquid away from the Diverter Tank, and move it through a Coriolis Meter to the truck.

When the volume preset value is met, the valve is automatically closed and the pump shut off thereby completing the load. A ticket can be locally printed for the operator and truck hauling company records. Or, the driver may input the data from the HMI screen into a trucking company computer and print a copy to be left for the operator records. In either case, an electronic version can sent via the Operator's SCADA communications network to an enterprise accounting system.

Benefits from this application over manual approaches include:

HSE

Elimination of routine trips to the tops of tanks by personnel is of great importance. Concerns over exposure to hazardous gases and inclement weather conditions are significantly reduced.

Shorter Loading Times

In non-consolidated tank design, drivers can spend close to two hours at locations widely spread over the field. Loading operations have to be carried out during all hours of the day in order to keep pace with production. There is constant fear that wells will be shut-in should trucks not appear in a timely fashion. In the automated consolidated case, this time drops to an average of twenty minutes.

Accuracy Increases Revenues

Consistency of liquid measurement greatly improves as the effects of different people with different levels of training and capability are no longer an issue. Overall, the accumulative error of manual gauging operations is generally accepted by the industry as 1% or greater. The potential gross revenue savings at various crude prices using a LACT configuration is demonstrated by Table 2.

Daily Lease Production Bbl/day	Crude $/Bbl	1% Manual Gauging Loss/ Year	0.25% Coriolis Based LACT Alternative	*Annual Revenue Savings*
2500	$40.00	$365,250	$91,315	*$273,935*
2500	$50.00	$456,560	$114,140	*$342,420*
2500	$60.00	$547,875	$136,970	*$410,905*
2500	$70.00	$639,190	$159,780	*$479,410*

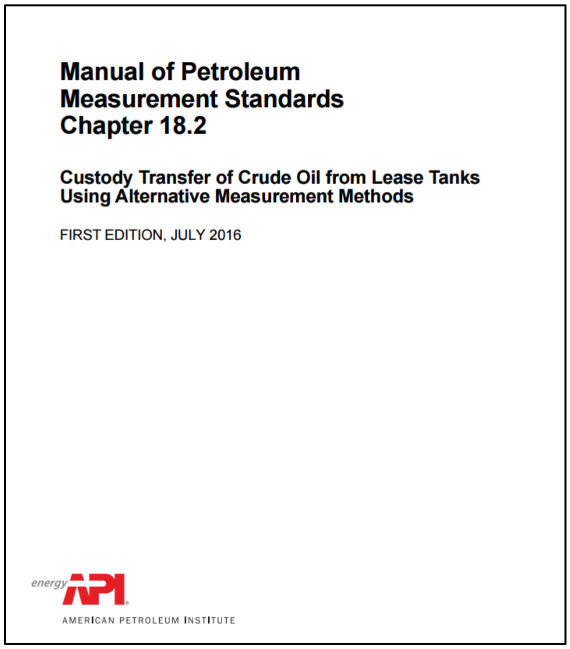
TABLE 2: POTENTIAL GROSS REVENUE SAVINGS

Quick Accounting Reconciliation

Manually generated tickets are left on-site for later pickup by company personnel. Depending upon timing and weather conditions, such pickups occur within a forty-eight hour span. Tickets would then be manually entered into the company enterprise system, adding perhaps another day. Since an average day supports many load-outs, challenging the result from any particular load is a difficult task. Using a flow computer system, haul logs are retrieved in electronic form via the company's SCADA system. The ticket information is available literally before the truck has left the site. The elimination of the time spent on manual entry is a clear savings. But, from an accounting standpoint, another plus to the electronic system is the disappearance of transcription errors and lost or damaged tickets that are inherit in any manual technique.

Upstream Application: API Standard 18.2

While a LACT unit is a very effective measurement solution, it can be uneconomical on sites with low production volumes. For this reason, manual tank gauging based upon the API 18.1 Standard has been in common use for many years. This approach requires personnel to climb to the top of storage tanks, open a hatch, and drop a tape for level measurement. However, between 2010 and 2014 at least nine deaths related to tank measurement occurred. This trend led to the publication in July 2016 of the API 18.2 Standard "Custody Transfer of Crude Oil from Lease Tanks Using Alternative Measurement methods" (reference Figure 8). The standard leverages existing technology and standards for custody transfer from lease tanks without opening the hatch.


Manual of Petroleum Measurement Standards Chapter 18.2

Custody Transfer of Crude Oil from Lease Tanks Using Alternative Measurement Methods

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energy API
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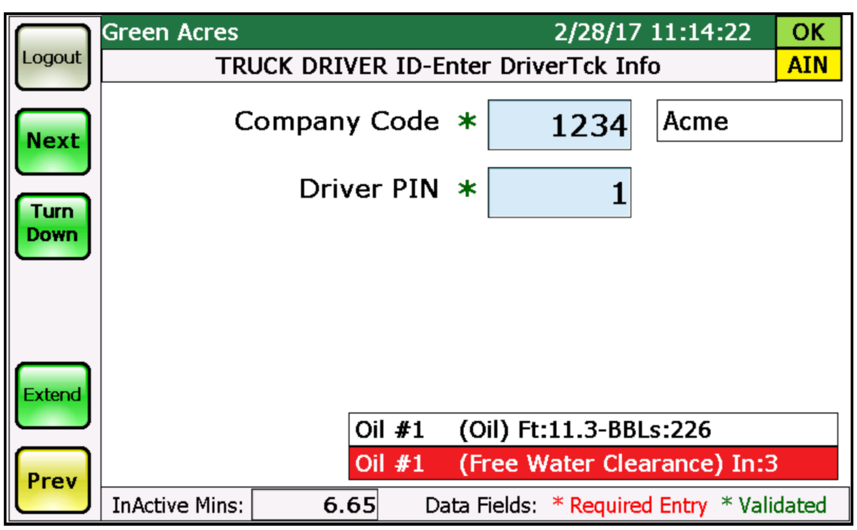
FIGURE 8: API 18.2 STANDARD

Software applications on a flow computer can pull together the automation used for tank measurement and assist drivers with compliance to the standard by guiding them through the hauling procedure.

Figure 9 depicts HMI screens for handling such issues as free water clearance calculation, and the timing of events in the hauling process requiring action to be taken.



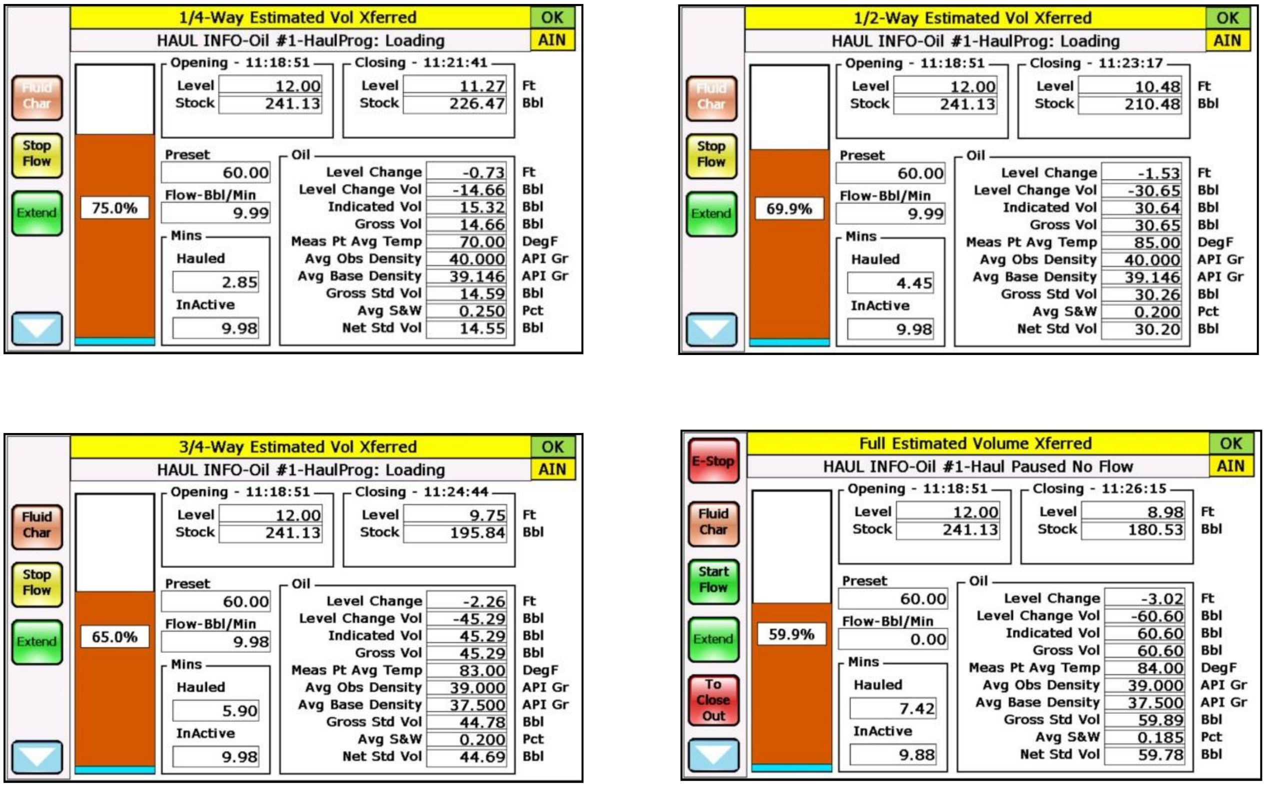


FIGURE 9: HMI SCREENS ASSIST IN COMPLIANCE TO THE STANDARD

Take Away

A flow computer is much more than simply a device to calculate flow. Certainly, it can serve as a method for remote retrieval of highly accurate data for Custody Transfer needs. But, units can make use of gathered information to perform sophisticated calculations in order to undertake control activities. Optimization and measurement of wellhead production in any stage of well's lifecycle exemplifies this capability. The ability to tie together the truck driver input and onsite automation for implementation of the 18.2 standard is another example.