Recognition & Resolution of Problems with Gas Ultrasonic Flow Meters

ASGMT Advanced Gas Ultrasonic Meters

Jim Bowen, SICK, Inc.

1. Introduction

Pipeline Operators have used Ultrasonic meters commercially for gas custody transfer applications since the late '90's. These meters' combination of operating features, including superior rangeability and on-board diagnostics have made this the technology of choice for most high volume gas metering applications. As user comfort with, and capabilities of, the technology has increased and the size and cost of ultrasonic meters has decreased, Operators and Manufacturers continue to stretch the envelope of application possibilities. This includes use in upstream, corrosive and high CO_2 applications, where the technology previously couldn't work or didn't make economic sense.

With these meters' proliferation both in numbers and use-cases, the need to apply "smart meter" diagnostics is of increased importance to identify and address operating issues early that may affect measurement accuracy. Near real-time data requirements are demanded by wide-spread business restructuring of gas transportation Pipelines into MLP's (Master Limited Partnerships) in the wake of de-regulation. These new business structures require daily cash-out and balancing in many cases, and monthly accounting settlement of transportation accounts in all cases, so the facility to recognize and fix measurement problems within an accounting period (i.e., prior to month-end business close) is imperative to avoid what have become in the MLP era, painful PPA's (prior period adjustments).

Meter manufacturers have long touted the diagnostic aspect of USM technology and over the intervening years since first publication of AGA TMC Report No. 9 in 1998, the companion software used for diagnostic analysis of meter performance has greatly improved through continuing development of the root meter technology and through field operating experience. Smart and consistent analysis of USM diagnostics can flag operating problems early, permit users to determine if measurement integrity/accuracy are in doubt and allows operators to take proactive steps to resolve issues on a close to real-time basis to avoid the business pain caused by the need for out-of-period gas accounting adjustments.

Improved software function however does not cover all bases so it is incumbent on operators to develop an understanding of both basic and extended USM diagnostics to recognize when problems may be occurring so remedial action can be taken before significant impact on fiscal measurement occurs. Manufacturers also have a responsibility to deploy diagnostic software with clear guidance for application with ease-of-use as a priority, and many have responded with automated diagnostic evaluation of USM's via these software tools.

Unfortunately, given the variety of operating environments and the way USM's work, there is usually no "silver bullet" diagnostic that can 1) definitively flag problems and 2) provide insight on the degree to which such problems affect measurement accuracy. Some operating problems, such as failed hardware or noise, are easy to spot and rectify, but in most cases a holistic approach to collecting and interpreting diagnostic information is needed to relate meter behavior to causes that may affect measurement accuracy.

General explanation of how USM diagnostics work in common with most manufacturers leads to deeper discussion and exposition how they relate to specific metering problems follows. Using diagnostic profiles for the USM helps provide a roadmap for recognizing abnormal meter response and relating that response to pipeline operating conditions that may skew gas measurement. Actual operating examples of field measurement problems identified through use of these diagnostics are presented herein along with remedies. Discussion of automating diagnostics, data reduction and piping facilities design, is included with a view toward providing operating personnel information regarding best practice deployment of USM's and subsequent application of diagnostic evaluation.

2 Basic Diagnostics & Operating Environment

It is important to take an eyes open approach to facilities design and operation starting with recognition of the challenges that may be imposed by local operating conditions. Many problems can be avoided during the design phase by taking prudent steps to address the better known issues that typically cause measurement error with USM's; for e.g.:

- **noise concerns** (for e.g. as caused by pinched valves generating interfering ultrasonic noise),
- **meter fouling** (for e.g., collection of liquids in a meter run) and
- **profile disturbance generators** (for e.g., bends and blind tees that may generate swirl and/or asymmetry in the flow profile.

It must be emphasized that diagnostics can identify but not fix these problems! Any steps taken at the design phase to minimize the occurrence and subsequent impact of these issues is highly desirable, and a guiding design principle might be: "Don't design problems into a meter stations". Additionally, any meter station design features that can ease routine and "special", or remedial, maintenance should also be considered and deployed when feasible. (for e.g., access to the meter runs and electronics; potential need to remove and replace a meter run; access to, and facility for, cleaning meter runs and meter… These factors should be considered during station design.)

Diagnostics common to all USM's are:

- Average Speed of Sound ("SoS"); ft/sec (m/sec)
- Per path Speed of Sound; ft/sec (m/sec)
- Per path gas velocity (sometimes referred to as "raw gas velocity");
- Transducer gain level; usually expressed in db
- Signal to Noise Ratio ("SNR"); dimensionless
- Accepted Pulses (sometimes referred to as "performance"); %

Brief explanations of the nature and relevance of these basic diagnostics follow, but these diagnostics need to be related to the context of the meter's operating principal and environment so users can make the connection between what the ***diagnostics reflect in an operating meter's response and what those outputs suggest is happening with the gas inside the pipe***… What happens with gas flow in the pipeline, and its effects on meter performance, are what drive accuracy problems that need to be recognized and fixed.

More often than not, if there is a problem inside the pipe that the meter's diagnostics are responding to, more than one diagnostic will show anamolous output. It is the combination of these diagnostic responses and evaluation of them that guides users toward the specific cause of degraded and/or changed meter performance that may affect measurement accuracy. A holistic approach in evaluating these diagnostics is needed to paint the full picture of meter response and in deducing whether meter accuracy is impaired. Possible remedial actions include:

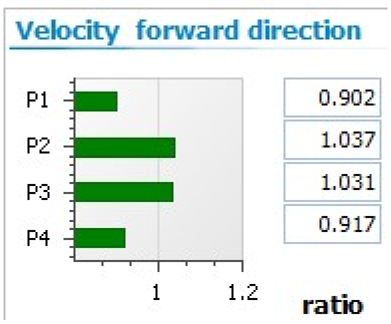
- Repair and/or replacement of components
- Removal, cleaning and replacement of individual transducers
- Cleaning of meter, meter run and/or FC, either in-situ or by removal
- Repair and/or replacement of secondary components (transmitters, etc.)

2.1 Average & Per Path SoS

Speed of Sound (SoS) is a critical and powerful diagnostic tool available in ultrasonic meters from which users can determine if a meter's ***functional*** performance has shifted. Two tests can be made using meter "measured" values for SoS: 1) an absolute comparison of meter corrected SoS versus that calculated from the gas' thermodynamic properties and 2) a per path comparison to determine if an outlier on a particular path suggests it's path length has changed, or more commonly, if pulse misdetection is occurring (path length changes are due either to meter configuration input errors, physical installation errors or debris build-up on transducer faces).

USM's depend on time and distance (clock and path length) to make accurate pulse transit time measurements and the absolute SoS comparison discussed below validates both. But this diagnostic does not by itself assure that meter accuracy isn't impacted by other factors such as fouling that result in bad flow profiles or diametric reduction.

2.2 Per Path Gas Velocity

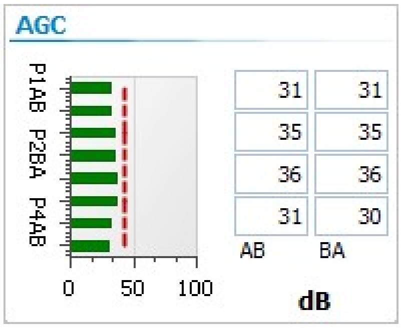


Maps of the per path gas velocities should be made from meter logfiles at each flow rate during meter flow calibration and during meter commissioning, or default values for relative velocity patterns need to be established. Profile and symmetry factors are often used to set default values, which technique is used in evaluating whether the relative path velocities have shifted, leading users to understand if disturbed flow profiles are present. These defaults can then be used to determine if flow profile has shifted.

USM's are flow profile dependent as regards maintaining meter accuracy, and as explained in the operating principals below, if a flow profile at a given flow rate differs significantly from that experienced by the meter at flow calibration, there is a shift in meter factor, or to put it more bluntly, a bias error is introduced because the bulk velocity calculation in the field has s different result than in the calibration lab.

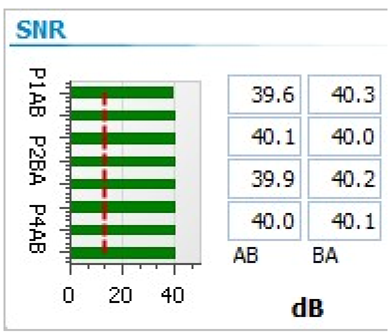
Disturbing elements such as blind tees, out of- and in-plane bends, headers and meter run blockage with debris, can cause flow disturbances that the flow conditioner might not remove. Additionally, fouling of the meter run with liquids, black powder, asphaltines, paraffin, etc., can cause the flow pattern to change with resulting flow measurement inaccuracies. Profile analysis indicates a possible shift in meter output and depending on the severity of profile discrepancy might suggest the nature of the problem, but most times a visual inspection of the meter run is needed.

2.3 Transducer Gain Level



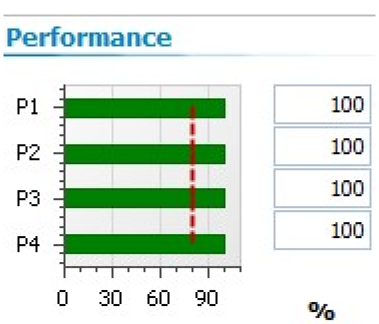
Pulse signals received by transducers from their path companions are amplified with automatic gain controls to improve pulse detection. Gains typically increase when signal recognition becomes more difficult such as in noisy environments, (for e.g. when gas rates are higher), or if debris is collecting on the transducer. Gains can also go high if a transducer is damaged or failing. It is often useful to compare gain levels as pairs by using the ratio of their levels to determine if one or the other of the transducers is struggling to detect signals. A high gain level on one side of a path might occur if the transducer concerned faces a noise source or if selective deposition occurs fouling the transducer face.

2.4 SNR



Signal to Noise Ratio, or SNR, indicates when the background noise approaches the limits of automatic gain adjustments. SNR values approaching a 1:1 level usually signify that ambient noise has made pulse detection impossible. “Ambient noise” refers to the ultrasonic noise present in the gas flow stream and is most often generated by throttled control valves. If there is too much noise, pulse signal detection becomes impossible and measurement stops.

2.5 Accepted Pulses



All USM’s employ detection criteria to validate transducer pulses that are used for transit time measurements. When these criteria are not met, the pulse is rejected. Rejection rates are noted in diagnostics by logging the number of accepted pulses. Noise, damaged transducers or fouling, among other mechanisms, might cause pulses to be rejected and high rejection rates should be evaluated for cause in tandem with other diagnostics. This might include visual inspection of the meter run or transducers and a review of detection criteria to insure they are relevant to the operating environment.

3 USM Operating Principal & Meter Error Propositions

3.1 Calculating Flow from Velocity Samples

Multipath gas ultrasonic meters all utilize digital electronics mated to multiple transducer pairs arrayed in paths; Figure 1 shows a representation of a chordal style meter with integral check (SICK 4+1).

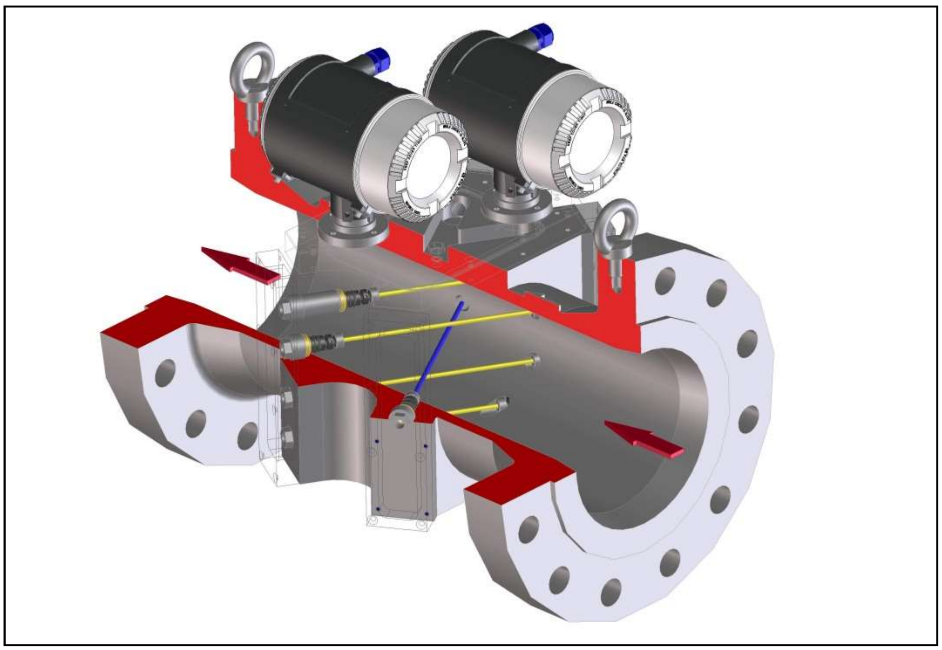


Figure 1, Chordal Meter with 4 Path Westinghouse Design and Integral Single Path Check Meter (courtesy SICK)

Gas flow in a pipe, when viewed in cross-section (Figure 2) is non-uniform, meaning that the velocity of gas particles over the pipe's cross-section varies.

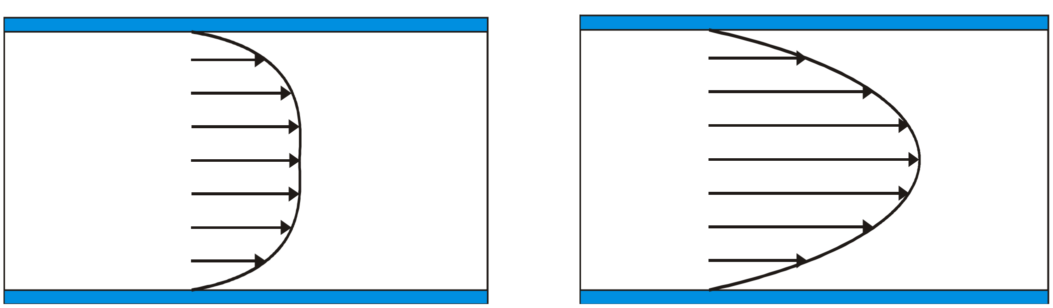


Figure 2, Vector Representation of Constant Velocity Streamlines in Cross-Section; Turbulent & Laminar

The variance in velocity across the measuring section is caused by frictional interaction of the moving gas molecules as they come into contact with one another and the pipe wall when gas flows. These frictional effects develop into a consistent flow pattern or flow profile as represented by the shapes shown in Figure 2: the blunter shape characterizes flow at higher velocities and is described as turbulent flow, while the smoother nose cone on the right depicts "smooth" or laminar flow. These flow regimes are demarcated by a dimensionless Fluid Mechanical parameter called Reynolds number. There is a 3rd flow regime, partially turbulent, between turbulent and laminar, but the key feature to note of ALL these flow types is that the can be represented by symmetrical, repeatable flow patterns.

Multipath USM's sample the flow profile at various cross sections f other flow area with individual paths and apply weighting factors to each path velocity (often based on a Gaussian distribution) and then the average or bulk velocity is calculated by the local meter firmware. Uncorrected flow rate is calculated as the product of bulk velocity and meter cross sectional area (equation 2).

(1) $Q = A \bullet V$

These per path samples, and respective weighting factors based on flow calibration lead to Error Proposition No. 1:

EP1: If the velocity profile sampled by the meter is different than the velocity profile the meter was flow calibrated with, application of the meter factor from flow calibration will generate a different result for the bulk velocity calculation. Such "Profile Shifts" can be caused by installation effects, debris, etc.

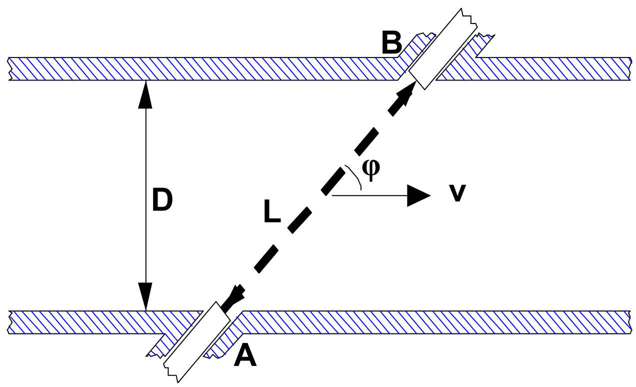
EP1 is best understood as stating that if the meter saw a "perfect flow profile" (Figure 2) during flow calibration with its attendant path weighting factors and a a meter factor derived from these calibration as applied, that it's valid so long as the flow profile is the same n the field operation environment. However, if swirl, asymmetry or combinations of these disturbances appears in the field, aberrant velocity profiles can skew meter factor and produce measurement error.

EP2: If the meter and meter tube become fouled with debris that adheres to the pipe wall, or liquids, sludge, etc. collect in the meter tube, the cross sectional area of the meter will change and error will be caused in flow measurement due to this change (Equation 1 relies on a fixed area; a % area blockage changes output by a like %).

EP3: If fouling occurs, and debris adheres to the pipe walls, the frictional characteristics of the dirty versus clean pipe differ and so the velocity profile will shift. Taking a cue from EP1, a change in velocity profile from that occurring when the meter was flow calibrated suggests the likelihood of a shift in meter factor.

3.2 Transit Time Measurement Principal

It was noted that multiple pulse paths, with transducer pairs assigned to each, are used to measure chordal velocities that are then weighted and summed to calculate bulk velocity of the gas flow through the meter's measuring section. Getting this part of the measurement correct requires that each chordal gas velocity is correctly calculated from pulse transit times. Review equations 3 and 4 below from AGA TMC Report No. 9 as, respectively, the upstream and downstream transit time equations.



Where:

L = Path length (ft or m)
t_u = Transit time upstream (sec)
t_d = Transit time downstream (sec)
c = Speed of Sound (fps or m/s)
φ = Path angle (degrees)
ν = Path velocity (fps or m/s)
Q = Uncorrected Flow (acfs or m^3/s)
V = Bulk Velocity (fps or m/s)
A = Pipe cross sectional area (ft^2 or m^2)

(2) $$t_U = \frac{L}{c - v \bullet \cos\varphi}$$

(3) $$t_D = \frac{L}{c + v \bullet \cos\varphi}$$

USM transducers both fire and receive pulses (i.e., act as both speaker and microphone), fire and receive pulses asynchronously, but with rapid enough repetition rates such that an assumption is made that instant gas conditions affect both forward and reverse pulse transmission rates equally (that is, there is no rapid change in gas density that requires application of a different speed of sound to the forward and reverse pulses).

At Q = 0, the transit time of the forward pulse (A-B) equals the transit time of the reverse pulse (B-A); Δt = 0. As gas begins to flow, the forward pulse, A-B is accelerated and the reverse pulse (B-A) is decelerated by the gas velocity: Δt ≠ 0. This pulse transit time difference is directly proportional to the velocity of the gas flow rate. Combining the transit time equations and solving for velocity, V, we have Equ'n 3.

(4) $$v = \frac{L}{2 \bullet \cos\varphi}\left(\frac{1}{t_D} - \frac{1}{t_U}\right)$$

(5) $$c = \frac{L}{2} \bullet \frac{(t_u + t_d)}{t_u \bullet t_d}$$

Rather than solving for velocity, V in equation 3, we could solve for speed of sound, C and Equation 4 results.

Simple inspection of these equations reveals that the fluid velocity, ***v***, and speed of sound, ***c***, are both directly dependent on the meter's path length and transit time measurements. Repeating in alternate language, meter pulse transit time measurements, and path length data permit calculation of ***both*** ***v*** and ***c*** from the same transit time measurements.

SoS in natural gas can also be calculated from its fluid properties of composition, pressure and temperature, with calculation Standards adopted by the AGA or GERG as applicable. Therefore it is possible to compare the "meter measured" value of SoS to that calculated with the AGA/GERG equations. The ***measured*** versus ***calculated*** values should agree closely (a limit of +/- 0.25% is typically used, but may need relaxing depending on the quality of compositional data).

Should a significant offset between the measured and calculated values be found, it indicates one or more of the following:

- The meter's path length(s) are in error
- The meter's clock has shifted causing transit time errors (or there is pulse mis-detection which is also an SPU programming problem).

- The data used to make the SoS calculation per AGA/GERG is incorrect (i.e., compositional data is in error suggesting a GC issue, or one or both of the pressure and temperature transducers is incorrect).

These conclusions can be made because meter clock/pulse detection (or SPU function), path length and fluid data are ***the only variables*** that can cause disagreement between measured and calculated value of SoS. Further, it can be stated that good correlation of measured and calculated SoS “prove” that clock/SPU function and path length are valid and it can be concluded, therefore, that the meter factor has not changed! (Caution: recall that other factors such as fouling can shift meter output!).

Be reminded that the SoS diagnostic is “meter only” verification of function, but accuracy may still be at issue if profile changes have occurred. See above discussion in re flow profiles.

All USM’s apply the pulse transit time principal to make chordal velocity measurements, and success or error in doing so drives the next set of error propositions:

EP4: The meter does not function correctly, I.e., the meter has the correct set-up, its path lengths have changed or its clock doesn’t keep time. These phenomena all relate to errors in obtaining accurate per path velocities because when the path length has changed or pulse transit time measurements are incorrect.

EP5: The meter has a signal detection issue and misdetects pulse signals resulting in a transit time measurement error and hence velocity/volume error or in the possibility that a pulse can’t be detected at all.

EP6: The meter measured average speed of sound and the AGA TMC Report No. 10 calculated value do not match: something may be wrong with the clock or path length and in these cases there is meter error OR, one of more of the inputs to the AGA 10 calculation (P, T, composition) is wrong and if this is not a fat finger (data entry) error, then measurement is not accurate due to improper application of pressure, temperature and supercompressibility factors.

4.0 Error Propositions, Operating Environment and USM Diagnostic Responses

A number of error propositions or possible modes of error were postulated above on the basis of the meter's operating principal with emphasis on 2 main areas:

1. Accurate, predictable bulk velocity calculation based on a stable and well characterized flow profile and,
2. Accurate pulse transit time measurement based on stable pulse detection with known path lengths.

In validating bulk velocity calculations, evaluation of "no-changes" in flow profile is required. Additionally, stable pulse detection and transit time measurements are needed, and are validated using SoS analysis.

4.1 Environmental Factors

A number of factors relating to potential profile distortion mechanisms were suggested above and recommendations made regarding flow profile review, as-installed versus as-calibrated. Additional external factors that should be considered for general effects are:

Factor	Influence on Flow	Diagnostic Response	Error
Flow Range; too low, too high	@ v < 2 fps, can cause gas stratification; @ v > 130 fps (line size dependent)	Per path SoS doesn't agree on low end; signal loss at high velocities (>130 fps)	Profile and temperature issues skew both corrected and uncorrected output; transit time errors on missed pulses
Temperature	@ v < 2 fps, can cause gas stratification	Per path SoS doesn't agree	Profile and temperature issues skew both corrected and uncorrected output
Pressure	High dp's can cause liquid drop out, pulsation causes time varying velocities	May see liquids: • w/high turbulence • velocity profile shift Pulsation w/unsteady profile and varying velocity outputs	Area blockage causes error in uncorrected volume calculation Liquids cause change in velocity profile. Pulsation skews average velocity value and meter doesn't track
Weather	At low velocities can contribute to stratification, liquid drop out.	Free liquids or freeze offs occur • High turbulence • Increased gains • Skewed velocity profile Signal rejection	Bad velocity measurements, area reduction.
Gas composition	Rich compositions subject to retrograde condensation; CO2 may attenuate signals	Free liquids or freeze offs occur • High turbulence • Increased gains • Skewed velocity profile Signal rejection	Bad velocity measurements, area reduction.
Contaminants Fouling potential (liquids, etc.)	Adheres to pipe wall; skews flow profile. Liquids block part of meter run, foul sensors.	Free liquids or freeze offs occur • High turbulence • Increased gains • Skewed velocity profile • Signal rejection	Bad velocity measurements, area reduction.
Fluid dynamic disturbances	Tees, protrusions, etc. cause disturbed velocity profiles	• High turbulence • Skewed velocity profile	Unstable velocity measurements, non-matching profiles might indicated bias error from installation effect.
Electrical interface (EMI, RFI)	Pulse accum. Errors, Timing errors	SoS	Missed or added pulses can affect measurement totals
Electronics drift	Timing errors, scaling errors	SoS	Rare
Thermal expansion, pipe work, etc.	Path length errors	Per path SoS	Effect generally negligible
Ultrasonic noise	May cause no measurement	SNR < 1	Measurement outage
Foreign object	Skew flow profile	Per path velocity pattern, or Profile and Symmetry factors out of limits.	Unstable velocity measurements, non-matching profiles might indicated bias error from installation effect.

These environmental factors need be considered during the design, commissioning and operational phases of placing the USM station in-service and in maintaining a performance log over its installed life.

4.2 Design Factors

1. Meter sizing: check operating range, Q_{max} at P_{min}, Q_{min} at P_{max}.
2. Meter run design & construction: honed?, spool lengths, flow conditioner
3. Entry and exit piping: possible flow disturbance generators, noise attenuators
4. Installation: siphon drains, inspection ports, clean out tees, maintenance access and removal route
5. Throttled valves: Pressure or Flow control valves installed near a meter, location proximate to the meter, valve type, Qmax/min; ΔP.
6. Gas Composition: liquids, high CO2, corrosive elements
7. Ancillary facilities: RTU, meter building, on-line GC, sample probe location, Data transfer
8. Calibration requirements: flow range, operating requirements.
9. Documentation: from Mfg. (material cert's), Flow Lab (cal cert), et al.

4.3 Commissioning Factors

1. Inspect meter run assembly: insure it is field installed identically as to that tested at the flow lab (labs commonly mark spools and provide an accompanying sketch)
2. Inspect Meter calibration certificate: insure the meter factor determined at the calibration lab is input to the meter's SPU; insure the appropriate linearization factors have been applied.
3. Log Files: insure that the diagnostic log files extracted during the flow calibration are accessible
4. Firmware & Software: Insure the correct version of firmware is installed in the meter, insure the appropriate version of software is installed on technician laptops.
5. Check Input/Output connections
6. Check Pulse scaling; insure it correlates with meter factor and calibration certificate; check pulse wave-form; check error frequency.
7. Copy, Save and date-stamp a meter config file.
8. Characterize As-Installed Diagnostics: Flow the meter at a variety of rates if possible: capture logfile data at each rate.
9. Inspection: Make a full routine inspection per company procedure; complete documentation and note commissioning date.
10. Records: Follow Company policy regarding retention of records as pertains to commissioning logs and Inspection Report.
11. Review diagnostic responses from calibration and commissioning logfile data for velocity profile, and other diagnostics comparison.
12. Make a flowing SoS check if not done as part of 9 above.

4.4 Factors in Routine Maintenance

1. Calibration Routine: Start by calibrating secondary devices, P, T and GC. Next, collect recent gas analysis and make meter inspection. By calibrating secondary devices first, one minimizes the possibility of an SoS error during meter inspection.
2. Collect diagnostic logfile and run against Manufacturer's maintenance/inspection tool.
3. Check for problems with:
    a. Meter vs. AGA 10 SoS: possible data input issue; otherwise, check gas stream unnormalized totals and if +/-2% of 100%, consider GC error (integration, calibration, unknown specie).
    b. Per Path SoS Spread: if wide vis-à-vis baseline, check for pulse detection issues.
    c. Velocity Profile
    d. Turbulence

e. SNR
f. Transducer Gains

4. Save Logfiles, Session files, etc.

4.5 Special Maintenance

Components Replacement: From time to time, it may be necessary to replace components on a USM: the main parts of the meter are the signal processing electronics and the transducers. Neither of these has a significant failure history, however manufacturers do have specific procedures and Approval Data to support their use as regards electronics or transducer replacement.

Electronics: An SPU may require replacement if subject to a power transient like a lightning strike. If this is the case,

1. Secure copies of meter configuration file, calibration files including log files and certificates.
2. Follow Manufacturer instructions on how to transfer meter set-up from configuration file to program SPU.
3. Review implementation of meter and linearization factors; insure they match calibration values
4. Review output of meter, Diagnostic outputs as compared to those from calibration.
5. Sanity check on volume output(s): pulse scaling, accumulation, etc.

Transducers:

1. Secure copies of meter configuration files
2. Follow Manufacturer instructions on transducer change out:
   a. Mechanical
   b. Electrical
   c. Programming of SPU w/new delay times, transducer characteristics.
3. Follow Manufacturer procedure to check indicated path SoS versus expected base-line.
4. Update soft copy and hard copy records with new transducer information and log files.

6 Operational Problem Examples

6.1 Fouled Meter

Background; new 6” meter set showed profile alarms (Figure 1) on start-up after installation of this flow calibrated metering system consisting of standard AGA 9 Meter run and CPA 50e Flow conditioner 10D upstream of the meter.

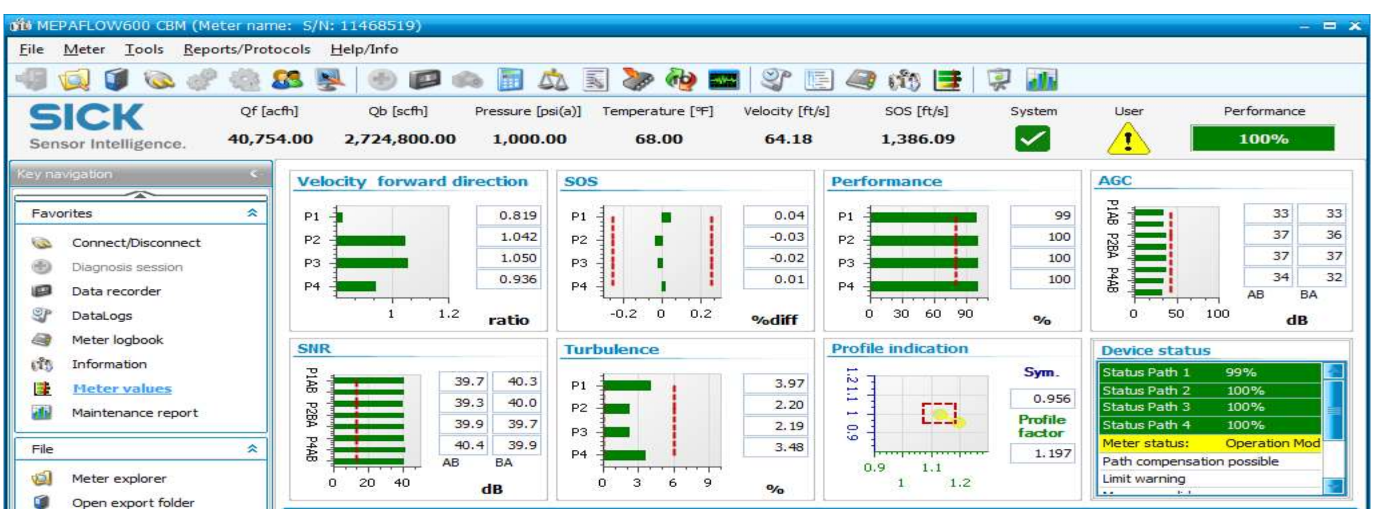


Figure 1. 6” Meter, as-found at field start up. Note alarms in yellow.

Drilling down on the alarm panes, Figures 2-5 shows the meter condition in both the “As-Found” and “As-Left” states. Note resolution of the alarms (Figure 2), the change in profile pattern (Figure 3) and the return to nominal status for the Profile Indication (Figure 4). More subtle, but worth showing is the decrease in Turbulence (Figure 5).

As- Found **As-Left**

Figures 1a and 1b: Device Status before and after cleaning.

Figures 2a and 2b: Velocity Profile ratios. Note skewing of P1 in the “As-Found” vs. “As-Left”

Figures 3a and 3b: Profile indication graphic. Note that the Profile Factor failed limits.

Figures 4a and 4b: note the relative reduction in P1, P4 Turbulence in clean meter of 4b

Data from the clean meter showed CBM dashboard in the state of Figure 5 below; note that the alarms are resolved.

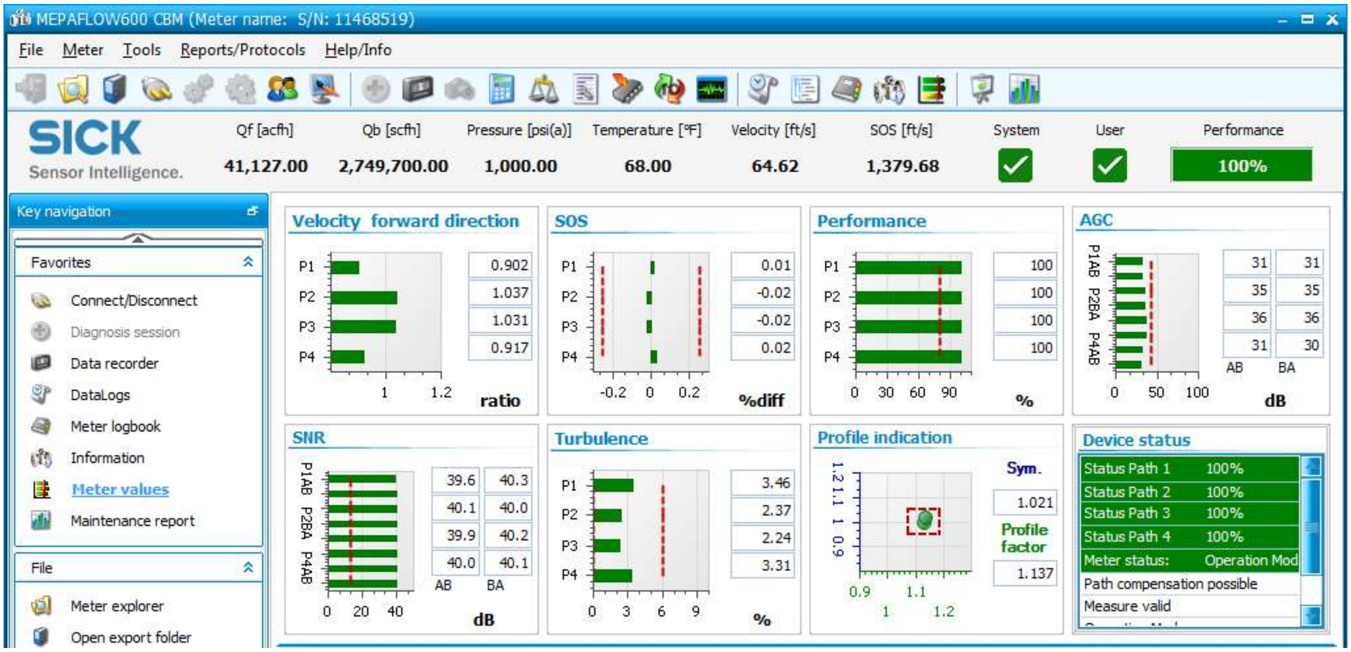


Figure 5: Clean meter & meter run CBM responses

Since this particular meter was new, the profile results were surprising and all parties thought something was wrong with the meter response, however upon inspection severe contamination from mill scale, etc. was noted.

Given the newness of the meter and interconnection, the degree of fouling and meter response was remarkable. Figures 6 and 7 below show a transducer and a view of meter run internals looking toward the flow conditioner…

Figure 6: Fouled transducer

Figure 7: Fouled Meter run

6.2 Blocked Flow Conditioner: Profile Factor and Symmetry

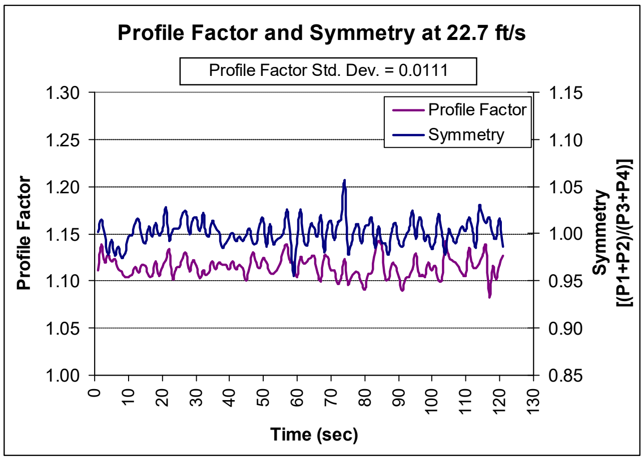
(Excerpted and abridged entirely from work by Lansing, et al)

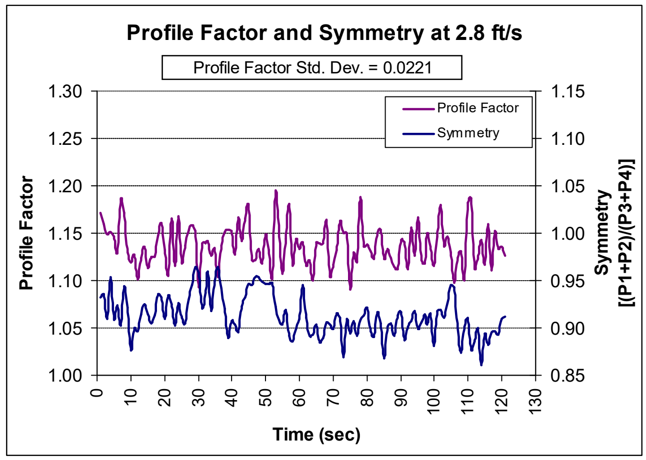
Looking at four path ratios takes understanding why the velocities are different. Since these can change by small amounts, a simpler method of identifying changes in profile is desired. A single value would be much easier to understand, and also easier to quickly analyze. One of these methods is called **Profile Factor**.

The Profile Factor is computed by adding the velocity ratios of paths 2 and 3 together and dividing by the sum of the ratio of paths 1 and 4. The equation looks like this: Profile Factor = (2 + 3)/(1 + 4). Assuming that paths 1 and 4 are 0.91, and the path 2 & 3 values are 1.02, the Profile Factor is about 1.12. This value does vary a little from meter to meter due to piping installation effects, and to some degree, the type of flow conditioner and its distance from the meter.

Another method used to analyze path velocities is to compare the sum of paths 1 & 2 to the sum of paths 3 & 4. This provides a look at the symmetry of the profile from top to bottom, and is called **Symmetry**. Normally the meter's path velocities will be very symmetrical resulting in a value close to 1.000. Figures 13 and 14 show both the Profile and the Symmetry in a single graph.

In Figure 22, when the meter was flowing at 23 fps, the Profile Factor was 1.115 (average of the magenta colored line). As the velocity dropped to 2.8 fps (Figure 23) the Profile Factor increased to 1.137. This is about a 2% change in profile when compared to the Profile Factor at 23 fps.



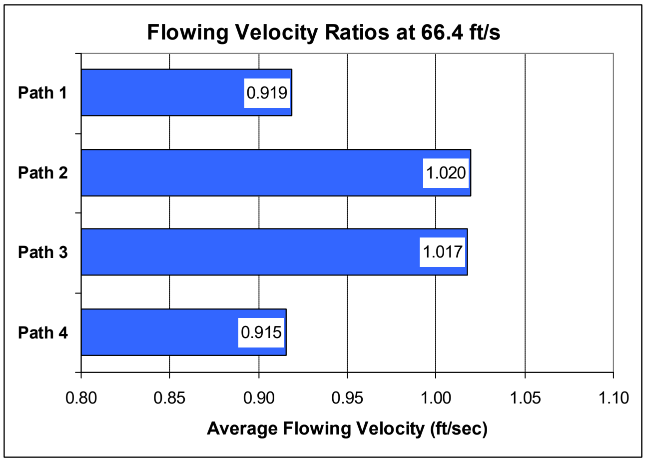


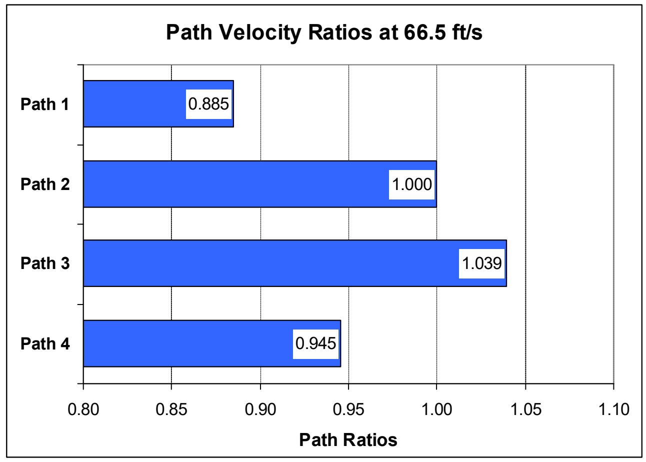
Figures 8 & 9: Profile Factor and Symmetry at 22 and 3 fps

The other diagnostic worth reviewing is the Symmetry value. Figure 9 shows a significant change (on the order of 10%) in the Symmetry at the lower velocities. This can be seen by comparing the blue line if Figure 8 to the blue line in Figure 9. These graphs indicate there was a change in the meter's profile and this is to be expected at lower gas velocities. So it is important to note when making velocity profile comparisons that these be done at similar velocities.

The Profile Factor can be a valuable indicator of abnormal flow conditions. The previous discussion showed what happens to the Profile Factor and Symmetry due to low velocity operation. This profile change is typical when the meter is operated at lower velocities.

Figure 10 shows an ideal profile from a 12-inch meter. This was based on the log file collected at the time of calibration. Users have often asked what impact partial blockage of a flow conditioner has on the meter's accuracy. This meter was used to show what happens not only to the profile, but to quantify the change in accuracy.





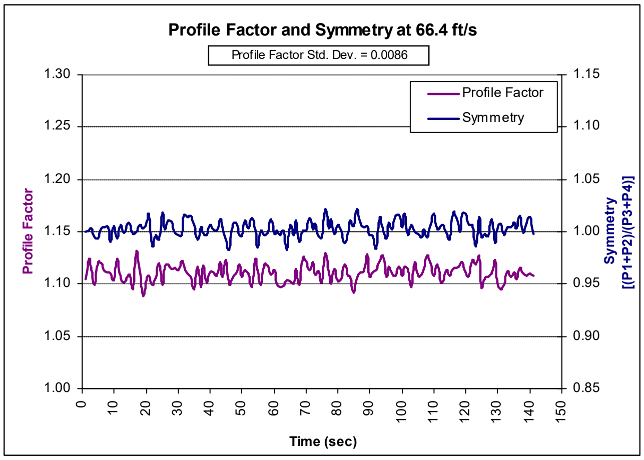
Figures 10 & 11: 12-Inch Meter Profile – Normal and With 40% Blocked

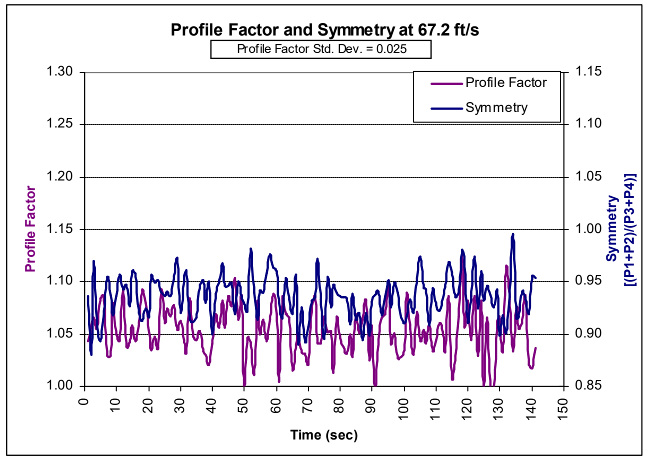
The Profile Factor for the unblocked meter is 1.118. For the flow conditioner blockage test, the flow conditioner was modified to have about 40% of the holes blocked with duct tape (Figure 12). Figure 11 shows the velocity ratios during the time the flow conditioner was blocked. This was taken at a velocity of 66 fps. The profile at two other velocities, 22 and 45 fps, looked the same.

Figure 12: 40% Blocked Flow Conditioner

The Profile is obviously distorted with higher-than-normal readings on path 3 and 4, and lower than normal on paths 1 and 2. The flow conditioner was installed with the blockage at the bottom of the pipe. As the gas flowed through the open holes, there was a low-pressure created just downstream of the blocked area causing the gas to then accelerate downward, thus causing the higher velocity at the bottom of the meter than at the top.

Figures 13 and 14 shows the graphical results of the Profile Factor and Symmetry with no blockage, and blocked.





Figures 13 and 14: Profile Factor and Symmetry at 66 fps respectively for unblocked and blocked states

From Figure 13 the average Profile Factor is 1.111 and the average Symmetry is 1.003. These are just about the ideal values for both. Figure 14 shows the Profile Factor and Symmetry graph with 40% blockage of the flow conditioner. The average of the Profile Factor is 1.053 and the Symmetry is 0.936. This is about a -6% change in Profile Factor and about a -7% change in Symmetry. Both of these would be considered significant and should be treated a cause for investigation.

After installation in the field a meter typically will generate a Profile Factor that is repeatable to ±0.02 (or about 2%). However, this does depend upon the piping, and makes the assumption that there are no other changes like flow conditioner blockage.

The next question is what was the impact on accuracy with this distorted velocity profile? Figure 15 shows the result of the three test velocities and the impact on metering accuracy.

Figure 15: Blocked CPA Results

Baseline vs. 40% Blocked CPA	
Velocity (fps)	% Diff. with Blocked CPA
68.4	-0.02
45.3	-0.12
22.9	-0.10

As can be seen the meter was affected by an average of about 0.15% for all flow rates. In this case the meter slightly under-registered with this distorted profile. Later in this paper a more advanced diagnostic feature will also show the meter has blockage, but for now one can see the Profile Factor has indicated a significant change.

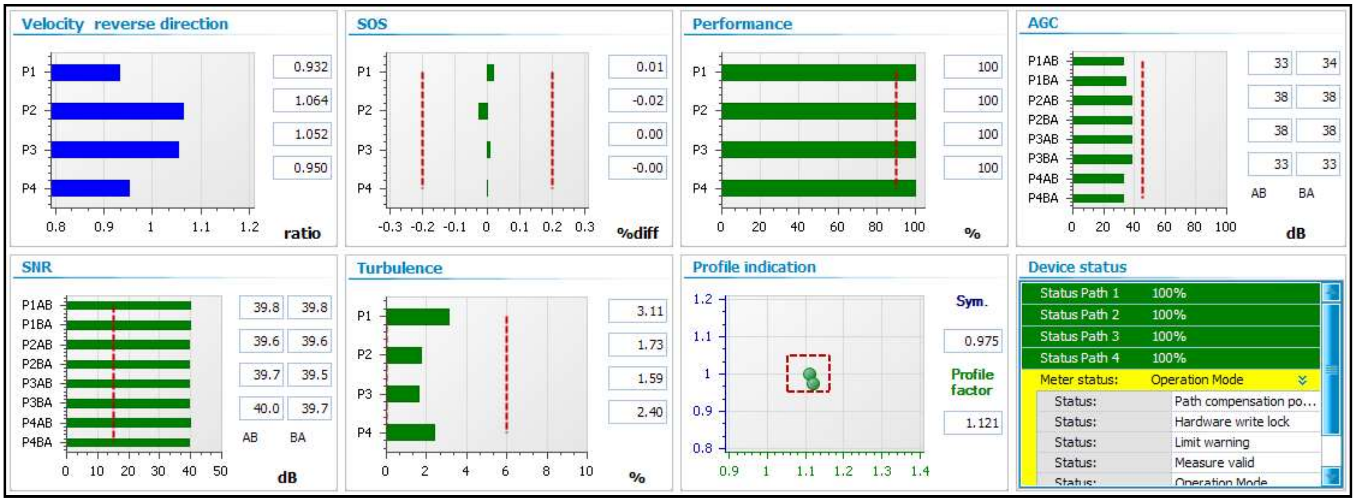


Figure 15 – Summary of All Diagnostics – Normal Velocity Profile

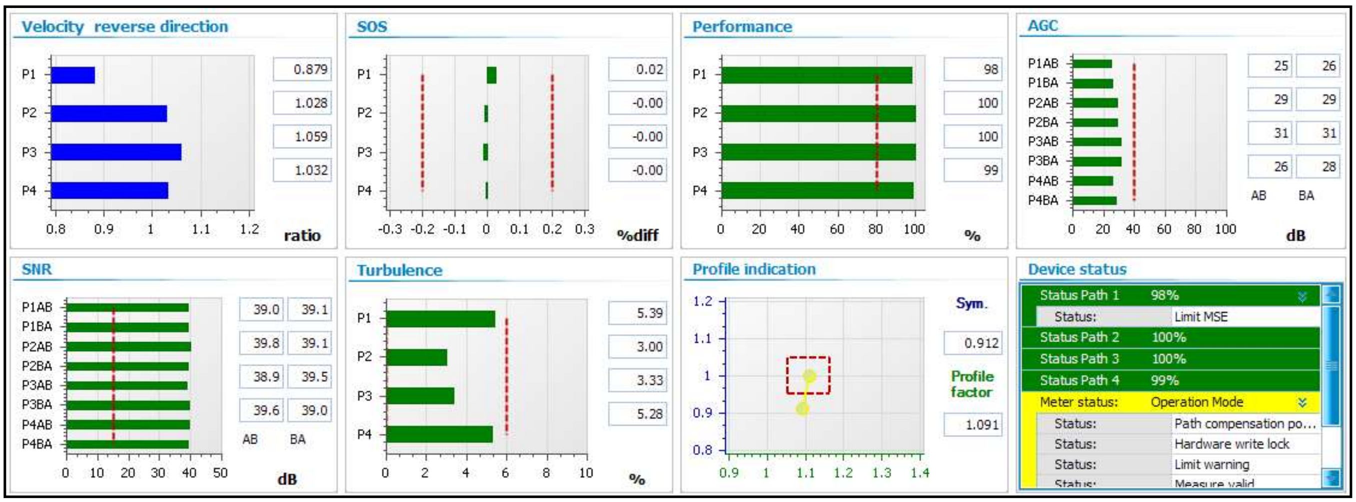


Figure 16 – Summary of All Diagnostics – Abnormal Velocity Profile

7 Extended Diagnostics: Turbulence

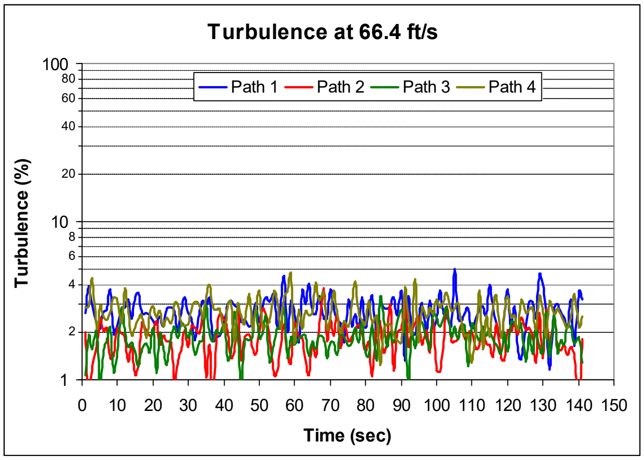
During the past several years an additional diagnostic feature has been studied by Engineering. This feature, called "Turbulence," is discussed thoroughly in a previous paper [Ref 6]. Essentially Turbulence is a measure of the variability of each path's velocity readings during the time the meter was sampling, and is provided each time it updates the velocity information[1]. This gives the technician an idea of the steadiness of the flow as seen by the meter.

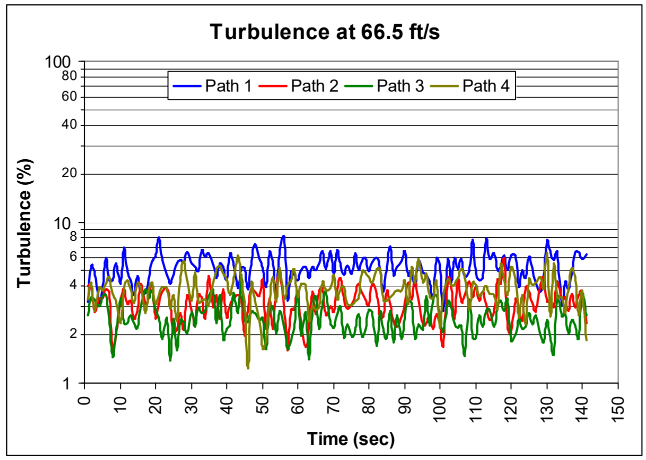
Typically the level of turbulence on a Westinghouse design shows paths 1 and 4 to have around 4% turbulence, and paths 2 and 3 around 2%. This is based upon the history of many meters. The outer paths 1 and 4, being closer to the pipe wall, always exhibit higher turbulence because they are more affected by the surface friction of the upstream piping.

[1] Turbulence is the standard deviation of transit time measurements about their mean; increased SD = Increased turbulence.

The Turbulence diagnostic has been used to identify and solve several metering problems. Distorted velocity profiles often cause concern about metering accuracy. If the velocity profile, as shown in Figure 10, now appears like that in Figure 11, the cause needs to be determined.

The 12-inch meter in Figure 40 shows a very consistent level of Turbulence during the period of the test. It was collected at the time of calibration and the velocity was about 66 fps. The average for these is 2.44% and this is considered normal.





Figures 17 and 18: Normal 12-inch Meter Turbulence, and with a 40% blocked flow conditioner as shown in Figure 12.

It is clear that the turbulence in Figure 18 is about 3 times higher, or an average of 7.03%. Certainly the velocity profiles for this meter, shown in Figures 19 and 20, look different. Anyone looking at the blocked profile would immediately recognize there is a problem.

It is possible, however, to have a partial blockage of a flow conditioner with something like a porous bag, or piece of carpet, and have a relatively symmetrical profile. In this situation the turbulence would be excessive, indicating there is a problem. This has been observed in the field and without Turbulence it would have gone un-detected.

The following figures show the Turbulence with the 3 holes blocked. The first is with the holes located at the bottom of the piping, and the second with the blocked holes rotated 90 degrees.

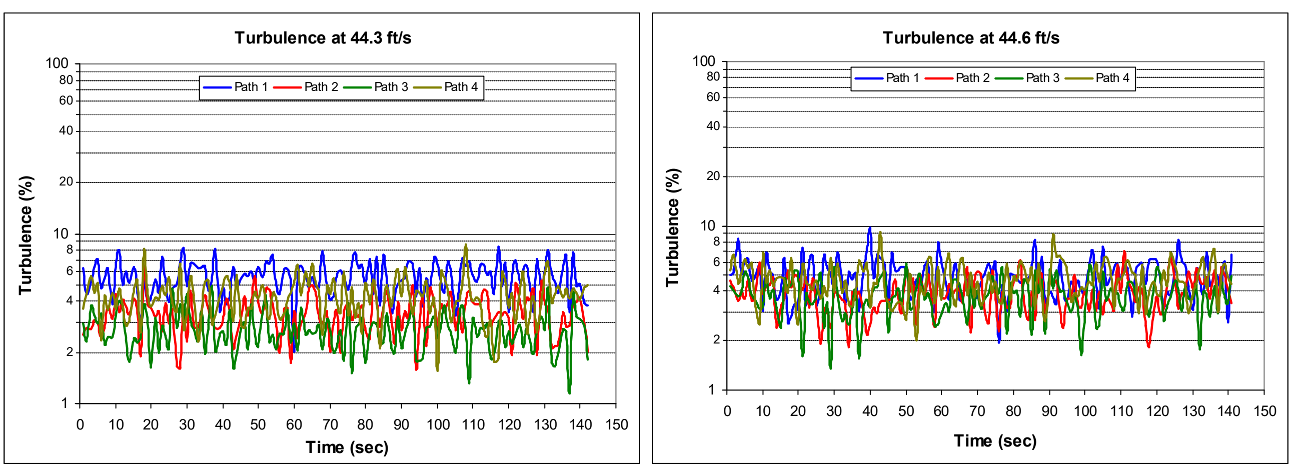


Figure 19: Turbulence Flow Conditioner w/3 Holes Blocked – Bottom and rotated to Side, respectively

Figure 42 shows the average Turbulence is higher than normal (the average is 4.02%). This isn't as high as the 40% blocked, but it is significant. Figure 41 shows the Turbulence when the blocked holes were rotated 90 degrees.

Figure 19 shows the average Turbulence is 4.33% and also higher than the average with no blockage of 2.44%. Both tests with 3 holes blocked indicate about the same and approximately 60% higher than normal. **Thus Turbulence is generally the best method of identifying flow conditioner blockage.**

Conclusions

During the past several years the industry has learned a lot about USM operational issues. The traditional 5 diagnostic features, gain, signal-to-noise, performance, path velocities and SOS have helped the industry monitor the USM. These 5 features provide a lot of information about the meter's health. Getting an initial baseline on the meter at the time of installation, and monitoring these features on a routine basis can generally identify metering problems in advance of failure.

Most operational problems with gas USM's are either fluid dynamic (i.e., disturbed flow profile) or related to meter performance outright (for e.g., a failed electronics), but can be recognized by diagnostics.

More advanced diagnostic indicators, such as Turbulence, are showing promise as tools to better focus on meter performance and in the future it is possible that a meter will gain sufficient power and intelligence to quickly identify potential measurement problems on a real-time basis. That depends on how knowledge of diagnostics can be refined both in raw and interpreted form.

As the industry learns more about not only the USM, and the operation of their own measurement system, the value of gas ultrasonic meter technology will continue to be recognized through wide-spread use. The USM industry is still relatively young and continuously improving technology will provide more tools to help solve today's measurement problems tomorrow.

REFERENCES

1. AGA Report No. 9, *Measurement of Gas by Multipath Ultrasonic Meters*, June 1998, American Gas Association, 1515 Wilson Boulevard, Arlington, VA 22209
2. Lansing, John, *Basics of Ultrasonic Flow Meters*, American School of Gas Measurement Technology, 2000, Houston, Texas
3. AGA Report No 10, *Speed of Sound in Natural Gas and Other Related Hydrocarbon Gases*, July 2002, American Gas Association, 1515 Wilson Boulevard, Arlington, VA 22209
4. Lansing, John *How Today's USM diagnostics Solve Metering Problems*, North Sea Flow Measurement Workshop, 2005, Tonsberg, Norway