APPLICATION OF PASSIVE SONAR TECHNOLOGY TO MINERALS PROCESSING AND OIL SANDS APPLICATIONS

"If you can measure it, you can manage it."

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ABSTRACT

In this presentation, the *SONARtrac*™ technology platform will be described. CiDRA's proprietary clamp-on, passive sonar array-based flow meter technology performs two independent measurements – flow rate and fluid characterization. Firstly, the meter provides the volumetric flow rate of the mixture by measuring the speed at which naturally occurring turbulent structures convect with the flow past an axial array of sensors. Secondly, the meter uses similar sonar-based processing techniques and naturally occurring sound in the process fluid to measure entrained air levels. The result is a unique ability to measure the flow rate and entrained air level of most fluids – clean liquids, high solids content slurries, and liquids and slurries with entrained air.

Also to be presented is the application of the sonar-based technology platform in a variety of oil sands processes, hydrotransport, and minerals beneficiation applications. In particular, difficult slurry flow measurement and control in the areas of comminution and flotation such as mill discharge, hydrocyclone feed/overflow, final concentrate, thickener discharge, and tailings will be discussed. In addition new real time maintenance free process measurement capability will be presented in the areas of entrained air in slurry, collection zone gas holdup (εg), and slurry velocity profiling. The operational advantages and value of these measurements, even in the presence of scale buildup, will be discussed.

INTRODUCTION

Flow measurements in the mineral processing and oil sands industry suffer from the limitations placed by previously available flowmeters including the commonly used instruments such as ultrasonic meters, magmeters, turbine meters, orifice plate meters, vortex flow meters, Coriolis flow meters, and venturi meters. The desire or requirement to make a non-contact measurement that is accurate and robust, and can be performed on practically any type of fluid within practically any type of pipe has driven the creation of a new class of flowmeters. This new class of flowmeter technology utilizes sonar-based processing algorithms and an array of passive sensors to measure not only flow, but also fluid composition.

The sonar-based flowmeter technology is truly unique. "To the best of my knowledge, there has not been a completely new industrial flowmetering principle produced since the invention of the Coriolis mass flowmeter....Finally, I've seen a new one.....Enter the CiDRA Corporation (www.CiDRA.com). They've produced just such an instrument," (Boyes 2003)

PRINCIPLE OF OPERATION

Sonar-based flowmeters are ideal for tracking and measuring the mean velocities of disturbances traveling in the axial direction of a pipe. These disturbances generally will convect with the flow, propagate in the pipe walls, or propagate in the fluid or slurry. First let us focus on the disturbances that convect with the flow. The disturbances that convect with the flow can be density variations, temperature variations or turbulent eddies. The overwhelming majority of

industrial flows will have turbulent eddies convecting with the flow, thus providing an excellent means of measuring the flow rate as described below.

Turbulence

In most mineral processing and oil sands processes, the flow in a pipe is turbulent. This turbulence occurs naturally when inertial forces overcome viscous forces. This can be expressed as the condition when the dimensionless Reynolds number, which is basically the ratio of the inertial forces over the viscous forces, exceeds approximately 4,000. Below a Reynolds number of 2,300, the flow is laminar, leaving the middle ground of 2,300 to 4,000 as a transitional flow regime containing elements of laminar and turbulent flow. The Reynolds number is given by:

$$\mathrm{Re} = \frac{Ud}{\nu}$$

where U is the mean velocity of the fluid in ft/sec or m/s
d is the diameter of the pipe in ft or m
ν is the kinematic viscosity of the fluid in ft^2/sec or m^2/s

As an example, an 8 inch pipe with water (at 20C) or slurry with similar kinematic viscosity flowing at 0.9 m/s (3 ft/sec or 468 GPM or 38.1 m^3/h) has a Reynolds number of over 200,000; clearly well above the criterion for turbulent flow.

Turbulent Eddies and Flow Velocity

Turbulent flow is composed of eddies, also known as vortices or turbulent eddies, which meander and swirl in a random fashion within the pipe but with an overall mean velocity equal to the flow, that is they convect with the flow. An illustration of these turbulent eddies is shown in Figure 1. These eddies are being continuously created, and then breaking down into smaller and smaller vortices, until they become small enough that through viscous effects they dissipate as heat. For several pipe diameters downstream, these vortices remain coherent retaining their structure and size before breaking down into smaller vortices. The vortices in a pipe have a broad range of sizes, whose sizes are bracketed by the diameter of the pipe on the largest vortices and by viscous forces on the smallest vortices. On the average, these vortices are distributed throughout the cross section of the pipe and therefore across the flow profile. The flow profile itself is a time-averaged axial velocity of the flow that is a function of the radial position in the pipe with zero flow at the pipe wall and the maximum flow at the center as seen in Figure 1. In turbulent flow, the axial velocity increases rapidly when moving in the radial direction away from the wall, and quickly enters a region with a slowly varying time-averaged axial velocity profile. Thus if one tracks the average axial velocities of the entire collection of vortices, one can obtain a measurement that is close to the average velocity of the fluid flow.

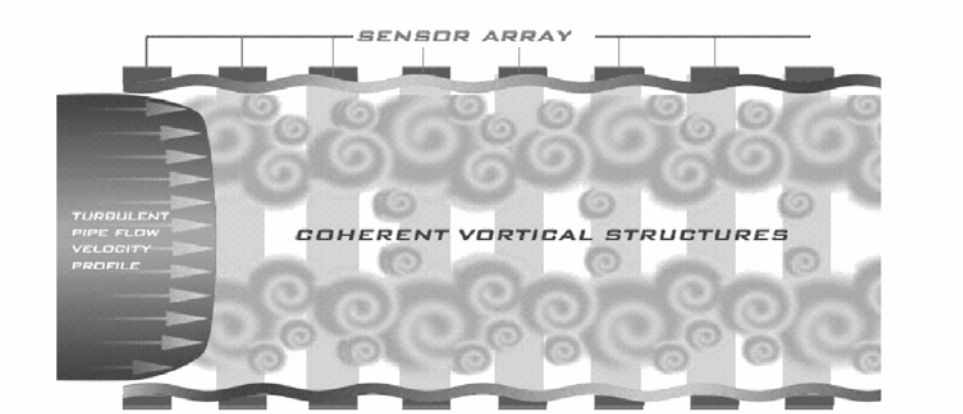

Figure 1 Diagram of Pipe with Turbulent Flow Showing Fully Developed Flow Profile and Turbulent Eddies

Array Measurement of Flow Velocity

Through the combination of an array of passive sensors and the sonar array processing algorithms, the average axial velocities of a collection of vortices is obtained. The sequence of events to perform this measurement is as follows:

- The movement of the turbulent eddies creates a small pressure change on the inside of the pipe wall
- This small pressure changes results in a dynamic strain of the pipe wall itself (Figure 1 exaggerates)
- The mechanical dynamic strain signal is converted to an electrical signal through a passive sensor wrapped partially or fully around the pipe – no couplant gels or liquids are required
- This electrical signal is interpreted as a characteristic signature of the frequency and phase components of the turbulent eddies under the sensor.
- This characteristic signature is detected by each element of the array of sensors. These sensors are spaced a precisely set distance from each other along the axial direction of the pipe.
- An array processing algorithm combines the phase and frequency information of the sensor array elements to calculate the velocity of the characteristic signature as it convects under the array of sensors.

The challenges of performing this measurement in a practical manner are many. These include the challenges of operating in an environment with large pumps, flow generated acoustics, and vibrations all of which can cause large dynamic straining of the pipe. The impact of these effects is that the dynamic strain due to the passive turbulent eddies is usually much smaller than the dynamic strain arising from pipe vibrations and acoustic waves propagating in the fluid. The strength in the array processing algorithm is its ability to isolate and measure the velocities of these different components, including the weak signal from the convecting turbulent eddies, and the strong signals from the acoustic waves and vibrations.

The algorithm processes the signals from the sensor array elements to deconvolve the frequency and length scale components. Each wavenumber, which is the inverse of the corresponding length scale component, is analyzed to determine the energy contained in its frequency spectrum. The peak energy in this frequency spectrum occurs at a frequency point given by:

$$f = \frac{U}{\lambda}$$

where f is the frequency of the signal
U is the velocity of the disturbance passing through the array
λ is the length scale of the disturbance

When performed over the entire range of desired wavenumbers, a plot of this energy distribution called a k-ω plot ($k=2\pi/\lambda$ and $\omega=2\pi f$) is generated with the x-axis defined by the wavenumber ($1/\lambda$) and the y-axis defined by the frequency (f). By rearranging the previous equation we obtain:

$$U = \frac{f}{(1/\lambda)}$$ which is basically the slope of the energy distribution

where U is the velocity of the fluid

An example is shown here:

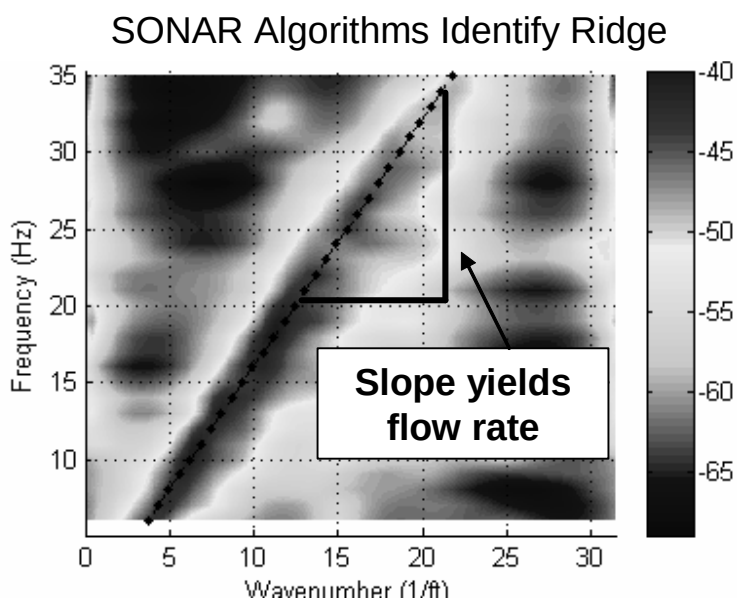

Figure 2 Representative k-ω Plot Showing Convective Ridge

This allows us to readily see how every point on the peak energy ridge contributes to the velocity measurement. In this example, the amplitude shown in the graph is on a log scale, so the peak energy is about 15 dB higher than the energy next to the ridge and about 25 dB higher than the other energy regions seen in the graph. The resulting slope of the ridge formed by these peak energy points is equal to the average velocity of the passing disturbance, which in this case is the

passing turbulent eddies or vortices. The technology lends itself to the generation of an indication of the robustness of the measurement otherwise known as a quality factor. Typically flowmeters do not provide an indication of the quality of the measurement. Conversely, in the sonar processing algorithm such a quality factor can be generated by comparing the strength of the ridge against background energy levels. A quality factor ranging from 0 to 1.0 is generated, with any flow measurement providing a quality factor above 0.1 to 0.2 (depending on the application) having the confidence as being a good measurement.

Currently this technology can report the volume flow rate on liquids and slurries with flow velocities extending from 3 to several hundred ft/sec. The technology lends itself to measurement on practically any pipe size, as long as the flow is turbulent, and for some non-Newtonian fluids, even without turbulence. The pipe must be full but it can have entrained air in the form of well mixed bubbles.

Calibration and its Maintenance

The volume flow measurement provided by tracking the turbulent eddies does require some adjustment or calibration. In practice the calibration adjusts the reported output by only a few percent, depending on the Reynolds number. The correction is implemented using the following equations:

$$U_{\mathrm{Re}\,ported} = \frac{U_{Measured}}{1 + CorrectionFactor}$$

$$\text{where} \quad CorrectionFactor = C_0 + \frac{C_1}{\mathrm{Re}\,ynolds^{C_2}}$$

As an example of the correction factor that is applied -seen in Figure 3 the degree of correction that is required for a 10-inch Schedule 10 pipe with water.

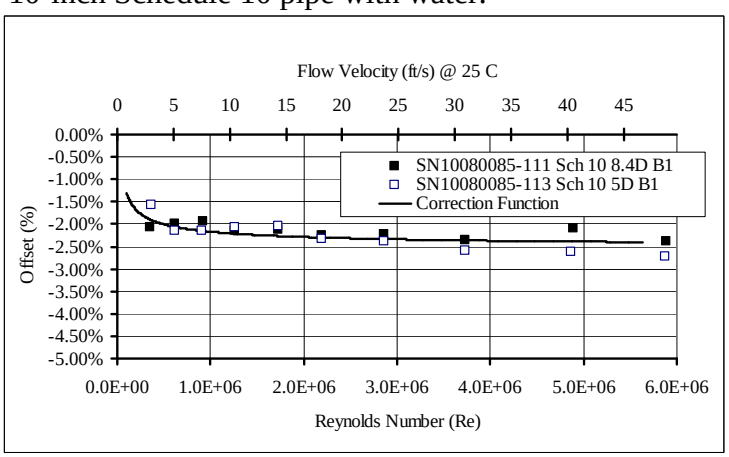

Figure 3 Correction Required for a 10inch Schedule 40 Pipe

In this example, after applying the correction factor, the offset is brought to within +/- 0.4% as seen in Figure 4.

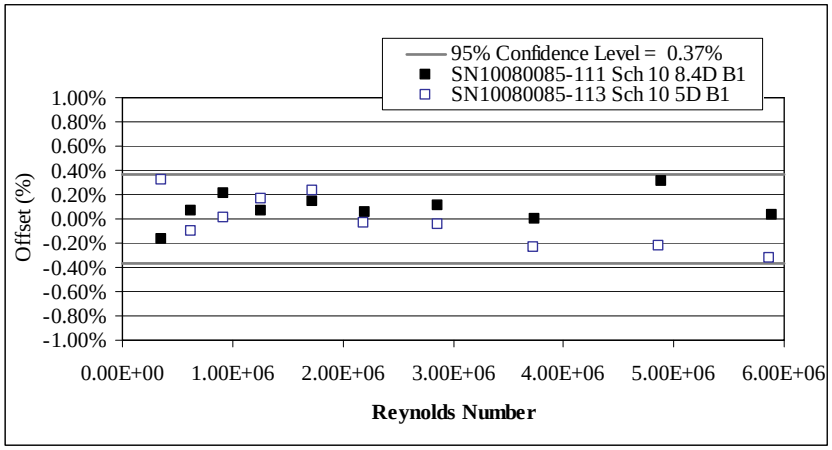

Figure 4 After Application of Correction Factor

Since the flow measurement and hence calibration is not dependent on the absolute values of any analog signals, it will not drift with time or temperature. Maintenance of the calibration from meter to meter and from temperature effects and aging is dependent on maintaining the spacing between the sensor elements and maintaining the stability of the clock used in the digitizer. The spacing between the sensors is set in the factory where they are bonded to a stainless steel sheet and cannot be adjusted by the customer. The clock stability is better than 0.01% and thus is 50 times better than the technology's typical accuracy of +/- 1% in the field; and +/- 0.5% under reference conditions or after in-field supplemental calibration. As a result the impact of clock stability can be neglected. In Figure 5 one can see the results from applying the same calibration coefficients to six flowmeters, all of the 8-inch variety and all tested on the same pipe. As can be seen, the meter to meter variation is quite low and will not change with time.

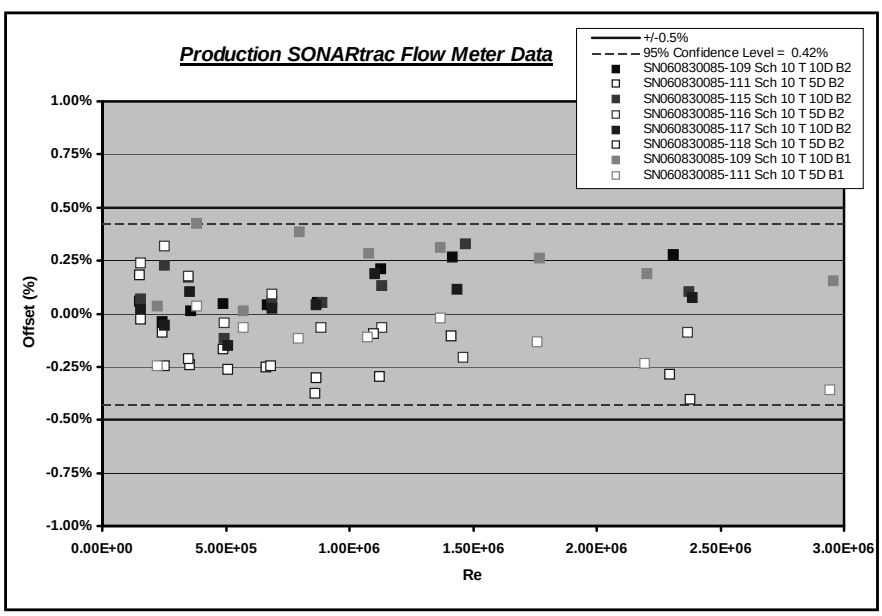

Figure 5 Illustration of Calibration Consistency from Meter to Meter. All Meters Have Same Calibration Coefficients.

Array Measurement of Acoustic Waves

As mentioned earlier, the same sensors and algorithm can be used to measure the velocity of naturally occurring acoustic waves that are traveling in the fluid. This fluid can be multiphase, or multicomponent single phase. In a single phase fluid, the acoustic velocity is a function of the ratio and acoustic properties of the two fluids, thus this measurement can be used to determine mixture ratios through application of the simple mixing rule (volume average of velocity). The resulting acoustic velocity c_M can be given by:

$$c_M = \phi_1 c_1 + \phi_2 c_2 \qquad \text{(Wang and Nur 1991)}$$

where $\phi_{1,2}$ are the phase volume fractions

$c_{1,2}$ are the acoustic velocities of the phases

Using $\phi_2=1-\phi_1$ this can be rearranged to give:

$$\phi_1 = \frac{c_M - c_2}{c_1 - c_2}$$

In multiphase fluids that consist of a gas mixed with a liquid or slurry, the acoustic velocity can be used to determine the amount of entrained gas (gas void fraction) when the gas is in the form of bubbles that are well mixed within the liquid or slurry.

These acoustic waves are generated naturally from a variety of sources, including pumps, flow-through devices, and flow-through pipe geometry changes. These acoustic waves are low frequency (in the audible range), and travel in the pipe's axial direction, and have wavelengths much longer than the entrained gas bubbles. An illustration of these acoustic waves in a pipe is shown in Figure 6 and as can been seen in the figure they can propagate in either direction down the pipe or in both directions. Since acoustic waves are pressure waves, they will dynamically strain the pipe during the cycling from compression and to rarefaction and back. This dynamic strain is then captured by the sensors, and converted to an acoustic velocity measurement.

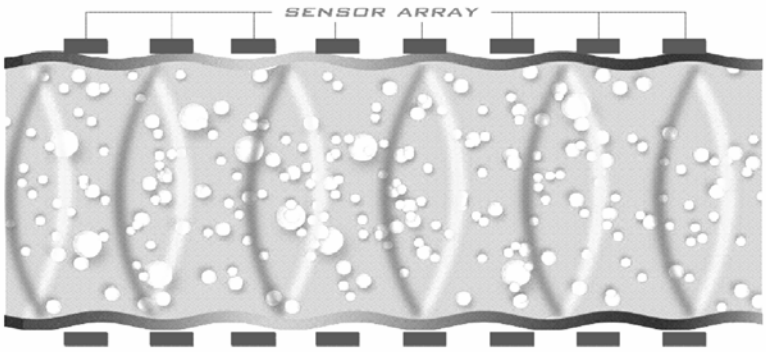

Figure 6 Illustration of Naturally Occurring Acoustic Waves Propagating in Pipe under the Sonar Array Sensors

A representative k-ω plot of a hydrocyclone feed line with entrained air is shown in Figure 7. Here one can see the vortical ridge and the acoustic wave ridges on the left graph. By rescaling the graph and looking at higher frequencies, a better view of the acoustic ridges is obtained.

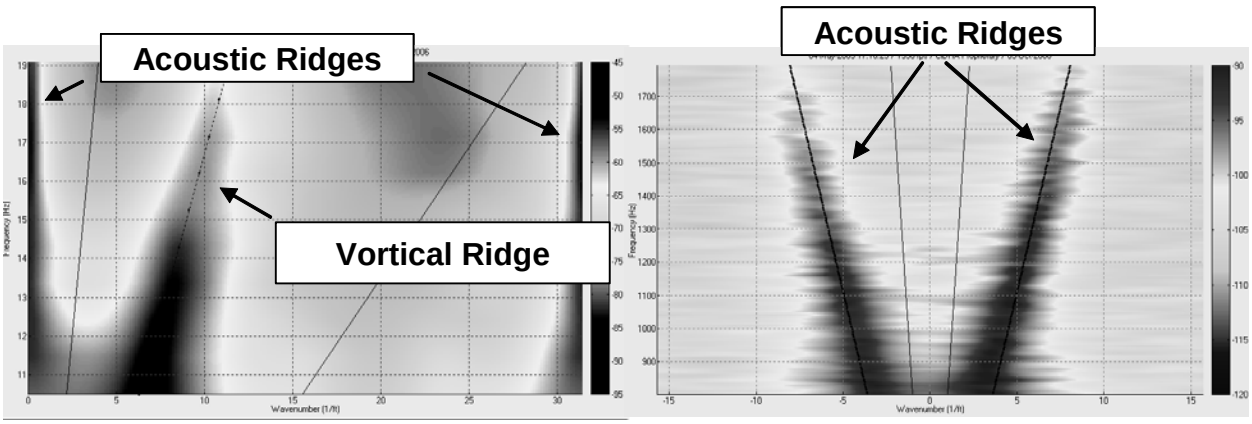

Figure 7 (Left) K-ω Plot Showing Both Acoustic Ridges and Vortical Ridge (Right) Rescaling of Graph and Change in Frequency Range Enhances View of Acoustic Ridges

Since the wavelengths of the acoustic waves are much larger than the bubble size, a complex interaction takes place that sets the acoustic velocity to be a strong function of the gas void fraction. In this case, the relationship is expressed with Wood's equation (Wood 1930). The speed of sound is proportional to the square root of the ratio of the compressibility and the density. The mixture compressibility equals the volumetrically averaged compressibility of the two separate components. The mixture density follows a similar relationship in which it equals the volumetrically averaged density of the two separate components. The resulting equation is given by:

$$\frac{1}{\rho c} = \frac{\phi}{\rho_g c_g^2} + \frac{1-\phi}{\rho_l c_l^2} \quad \text{(Wood 1930)}$$

where ϕ is the void fraction of the gas or air
ρ_g is the density of the gas
c_g is the speed of sound in the gas
ρ_l is the density of the liquid or slurry
c_l is the speed of sound in the liquid or slurry

and $\rho = \phi\rho_g + (1-\phi)\rho_l$

By solving for ϕ, and taking into account the compliance of the pipe, the acoustic velocity or speed of sound can be converted to a phase fraction of gas (gas void fraction). An example of the resulting relationship is shown in Figure 8.

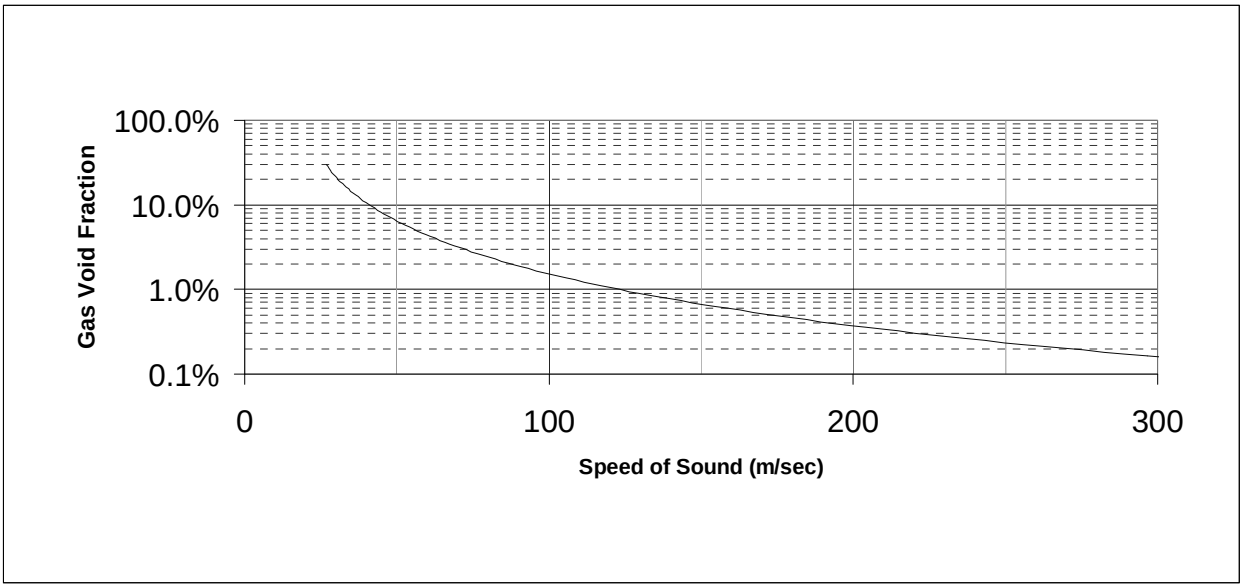

Figure 8 Example of Relationship between Gas Void Fraction and Speed of Sound

The gas void fraction measurement is used in a variety of different fields and applications. Within mineral and oil sands processing, it is used for nuclear density gauge correction, flowmeter correction to provide true volume flow, and air injection applications. It has been successfully used for entrained air applications ranging from 0.01% to 20% gas void fractions with an accuracy of 5% of the reading.

VOLUMETRIC FLOW APPLICATIONS

Sonar-based flow instruments have been installed in over eleven countries and have proven themselves in grinding/classification, refining, leaching and smelting operations. These include hydrocyclone feed lines, hydrocyclone overflow lines, hydrocyclone underflow lines, water feed and recovery lines, SAG mill discharge lines, ball mill discharge lines, thickener underflow lines, tailings lines, final concentrate lines, red mud and green liquor bauxite lines, pregnant leach solution lines, raffinate lines, organic lines, acid lines, and scrubber water lines. A few examples of these applications are outlined in this section.

Hydrocyclone Monitoring and Control

It is quite common to measure the flow of a hydrocyclone battery feed line. The combination of flow rate, pressure and specific gravity is used in many operations to control the number of hydrocyclones that are activated in a hydrocyclone battery. This control is essential for the optimization of the separation process in to obtain the correct particle sizes needed in the flotation, leaching or magnetic separation steps, while maximizing throughput in the mills by minimizing overgrinding. "Poor cyclone operation is the commonest cause of grinding inefficiencies." (Napier-Munn, Morrell, Morrison, and Kojovic, 2005)

The sonar flow monitoring technology was tested by a major copper producer who installed it in series with and next to a new magmeter. Both flowmeter outputs were compared to the pump power. Pump power has a non-linear relationship to the actual flow rate and is influenced by several factors, including the pump curve and the system curve in which the latter is in turn influenced by the flow rate itself, the viscosity of the fluid and by the specific gravity of the slurry. Nonetheless, one can expect that changes in the pump power would be reflected in changes in the flow rate, and an overall increase or decrease in the pump power would be mimicked by a first order proportional response in the flow rate. By comparing the magmeter and sonar array flowmeter outputs in Figure 9, we can see that the flow rate reported by the new magmeter has a low correlation with the pump power whereas the sonar technology flowmeter exhibits an excellent relationship with the pump power, reflecting changes and magnitudes in the flow rate that line up with the corresponding state in the pump power. The difference between the actual flow rate and the magmeter flow reading would result in an overload of the hydrocylones in the battery.

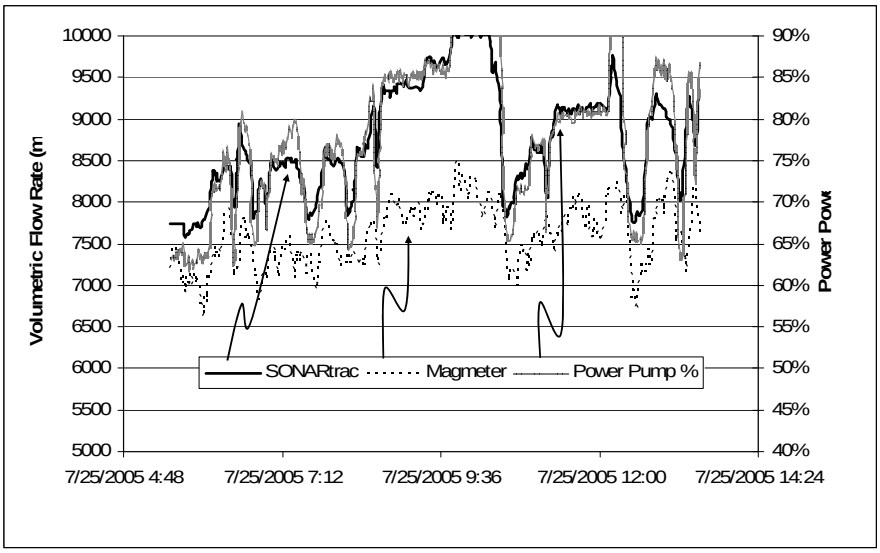

Figure 9 Comparison of Sonar- Based Flowmeter with Magmeter and Pump Power Showing Excellent Correlation between Sonar- Based Flowmeter and Pump Power

Another hydrocyclone measurement which is desirable to have in order to fully monitor and control the separation process and the circulating load is the hydrocyclone overflow or underflow. This can be used to ensure that a circuit is not overloaded and is operating with the correct separation ratios. Due to the presence of air captured in the slurry as it passes through the hydrocyclone, it can be rather difficult to perform this measurement using any of the traditional flowmeter technologies, in particular for the overflow discharge. The unique measurement principle of the sonar array technology allows one to measure the volumetric flow rate even in the presence of entrained air. The gas void fraction measurement aspect of the platform can be used to measure the amount of entrained air and be used to correct the flow rate measurement to provide a true volume flow rate.

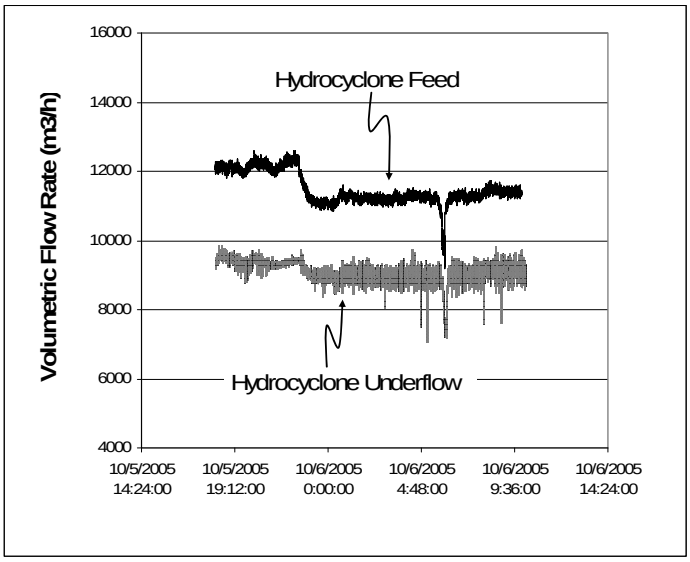

Figure 10 Measurement of Flow in Hydrocyclone Feed and Overflow.

Scale Build up on Interior Pipe Walls

A common situation in hard water lines, scrubber lines, bauxite lines, and lines carrying lime, is the buildup of scale on the interior of the pipe walls. This scale buildup can vary from a thin layer to several inches thick, depending on the pipe material and lining, the fluid composition, the flow rate and the time intervals between maintenance actions performed to remove the scale. The impact of this scale build up on most flowmeters varies from small such as an increase in noise, to large such as a drift in the reported flow measurement, or a complete failure of the flowmeter to report any flow. No flowmeter is truly immune to the effects of scale buildup but flowmeters commonly used in mineral processing such as magmeters and ultrasonic flowmeters are particularly sensitive to scale.

Impact of Scale Buildup on Ultrasonic and Electromagnetic Flowmeters

In transit time ultrasonic flowmeters, an ultrasonic wave injected into the fluid has to travel between two transducers using known bending or refraction of the ultrasonic wave at the pipe to fluid interface. The impact of scale on such a meter involves three effects: 1) attenuation of the ultrasonic signal in the scale, 2) scattering of the ultrasonic signal at the scale to fluid interface, and 3) change in the refraction angle at the scale to fluid interface.

Ultrasonic Doppler Flowmeters operate on a different principle than transit time flowmeters and their transducer arrangement differs as well, but they do suffer from similar problems induced by scale. Whereas the change in refraction angle may not necessarily cause the ultrasonic signal from one transducer to miss the second transducer, it certainly will change the reported flow. The conversion of the Doppler frequency shift to a flow reading requires that the instrument know the angle between the ultrasonic wave propagation direction and the axial direction of the pipe. Scale will change this angle thus producing an erroneous flow reading.

Magmeters operate by using the interaction of a magnetic field with a flowing conductive fluid to create an electric field within the fluid. The electric field is in turn detected and measured by a pair of electrodes placed on opposite sides of the interior of the pipe. Scale buildup on the electrodes serves to electrically isolate the electrodes preventing the flowmeter from measuring the flow induced voltage. The only recourse is to stop the process or divert the flow, remove the magmeter and remove the scale.

Impact of Scale Buildup on Sonar Array Flowmeter

The passive sonar array technology does not rely on the contact of any electrodes with the fluid, nor does it rely on the injection and retrieval of a signal into the fluid. The turbulent eddy induced pressure signals simply strain the scale which in turn strains the pipe wall and then the sensors. The impact of scale buildup is that the effective stiffness of the pipe may increase which will reduce the magnitude of the strain. Since the absolute magnitude is not used in the flow calculation, there is no change in the measurement of the flow velocity.

This technology has been proved on a variety of pipes with scale buildup from scrubber water, bauxite green liquor, and lime. An example of the ability to operate in the presence of scale is shown in Figure 11. Here a sonar based flowmeter is operating on an 18-inch pipe which is feeding water to a ball mill. In this case, based on previous magmeter cleanings, the pipe is estimated to have about two inches (5cm) of lime scale. Downstream of the meter is a magmeter that is cleaned out every few months to remove the scale from the electrodes and allow the magmeter to function again. This operation is labor intensive, it results in the loss of flow measurements and it relies on a bypass system to prevent a process shut down. Unfortunately, the valve used to divert the flow is developing problems from the same scale build up and the bypass system has a limited life. As can be seen in the figure, both flowmeters have similar noise levels, flow rate changes responses, and outputs. The difference is in the maintenance requirements, and the flow measurement downtime.

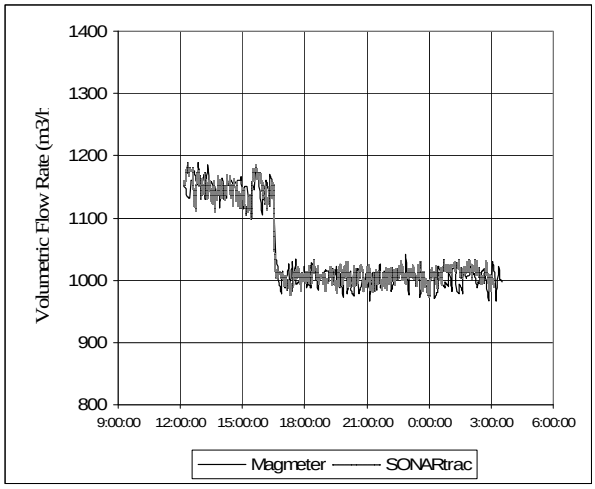

Figure 11 Sonar- Based Flowmeter Operation in Water Pipe with Two Inches of Scale Buildup. Comparison to Recently Cleaned Magmeter is Shown.

Lined Pipes

The sonar based flow monitoring system operates in the presence of practically any type of pipe lining for the same reason as it operates in the presence of scale. As long as the lining provides good mechanical contact with the pipe wall in order to transfer the strain from the lining into the pipe, the passive sonar array system will work. *SONARtrac* technology has been used successfully on rubber lined, teflon lined, cement lined, and urethane lined pipes. As an example, in teflon lined pipes carrying acid used in a leaching operation, the sonar based flowmeter was used to replace frequently leaking magmeters. The teflon lining is not attached to the interior of the pipe, but when filled with the acid under temperature and pressure, it makes intimate mechanical contact with the pipe wall. The mechanical contact transfers the strain from the passing vorticals or turbulent eddies to the pipe wall, leading to a solid measurement of the flow, as illustrated in Figure 12. On the left is seen a representative k-ω plot which shows a good, robust convective ridge. On the right is seen a plot of the volumetric flow rate and quality factor, showing a quiet signal that clearly shows flow changes with a quality factor of about 0.9, in which 1.0 is the maximum possible and 0.1 to 0.2 is the minimum for a robust measurement.

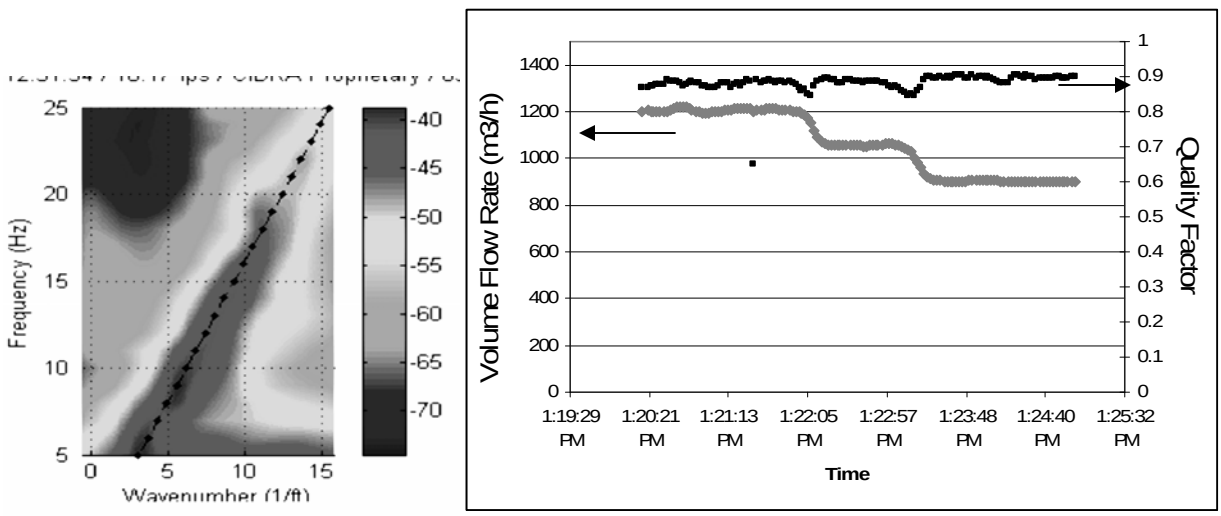

Figure 12 (Left) Convective Ridge in K-ω Plot Showing Robust Measurement and (right) Flow Measurements Results with Good Volumetric Flow Measurement and Quality Factor

High Density Polyethylene Pipe (HDPE)

High density polyethylene pipe (HDPE pipe) is a thick-walled, low modulus, inexpensive pipe that is well suited for carrying pregnant leach solutions and raffinate. A picture of a cross section is shown in Figure 13. HDPE is a semicrystalline material, which is it has both crystalline and amorphous structure; it exhibits both elastic and ductile properties. Coupled with its low coefficient of thermal expansion (CTE), which is about 20 parts per million per deg C or 10 times more than steel, it presents challenges in mating to and maintaining leak free seals at metallic structures such as magmeters. The thick wall and ultrasonic attenuation in the wall

make it difficult to obtain reliable ultrasonic flowmeter measurements. In contrast, the strain signals pass readily through the low modulus material, resulting in a superb signal for the sonar array measurement method.

Figure 13 Picture of HDPE Pipe Cross Section Showing a Typical Thick Wall

Figure 14 provides an example of the results of a sonar based flowmeter installed on a 30-inch HDPE pipe with 2.25 inch thick walls. In this case the pipe is carrying a raffinate solution in an environment that exhibits large temperature variations. The volumetric flow measurement was verified through a tank draw down test and found to be very accurate, and as can be seen in the figure, the quality factor is very close to the theoretical maximum of 1.0, indicating a robust measurement.

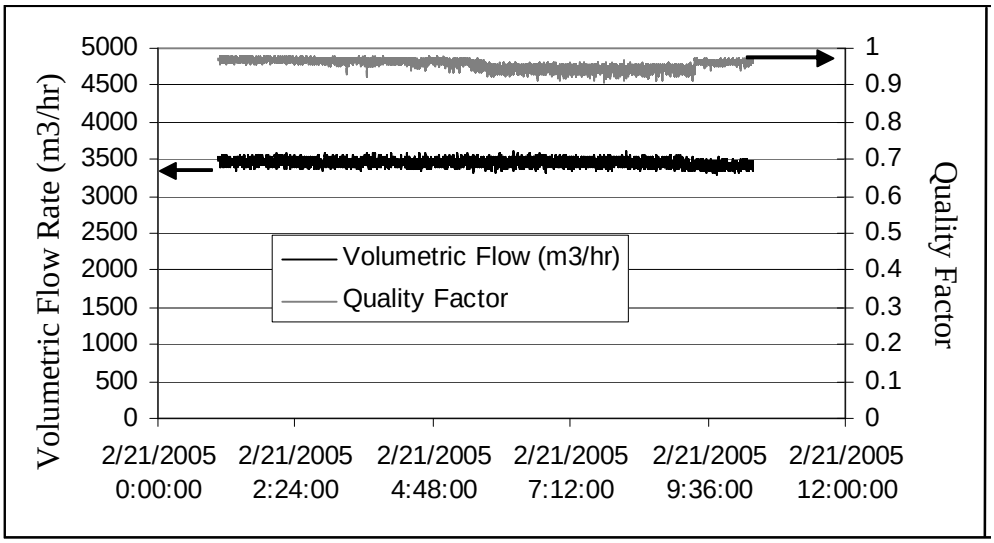

Figure 14 Flow Measurements of Raffinate in a 30 inch High Density Polyethylene Pipe

Magnetite

Magnetite in a slurry line, whether intentional in an iron ore mill or whether unintentional in mills concentrating other metals, poses a potential problem for magmeter flow measurements. Quite a few locations mining copper, gold or other non-ferrous metals have magnetite in or near their ore body. The magnetite, even in small quantities, changes the magnetic field within the magmeter and can cause the magmeter to register a higher flow rate than the actual flow rate, or introduce a high quantity of noise in the flow rate output. Magmeter manufacturers have attempted to circumvent the impact of magnetite with a third coil, with magnetic field measurements, and with manual offset adjustments based on laboratory samples of the typical slurry. These methods have resulted in mixed results in which many times, the calibration or offset changes depending on the quantity of magnetite present.

A better solution is to use a flowmeter technology that is not impacted by the presence of magnetite. Since the passive array technology used in the sonar based flow monitoring system does not rely on the use of any magnetic fields, it is totally impervious to the effects of magnetite. An example of this is illustrated in Figure 15 in which a sonar-based flowmeter was placed on a line in which ultrasonic doppler flowmeters and several magnetite compensated magmeters had failed. In the figure, one can see the readings provided by the sonar based flowmeter and whose accuracy was verified with tank fill tests.

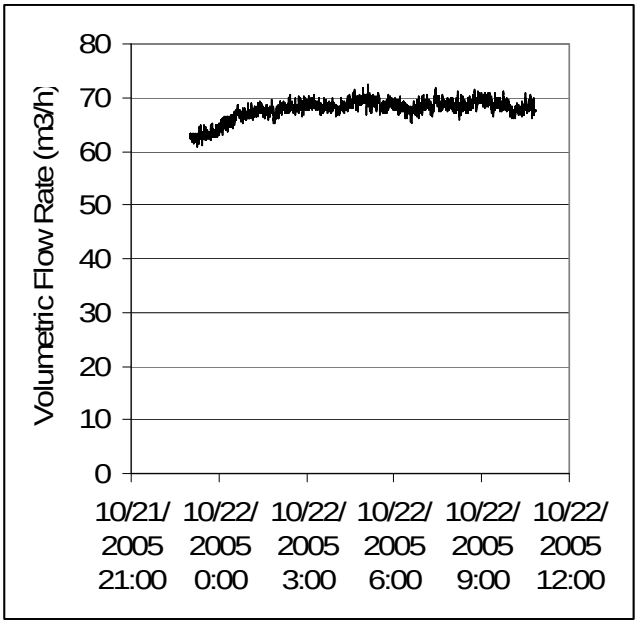

Figure 15 Flow Reading in Magnetite Slurry

Table 1 Flow Measurement Reproducibility Results

Pump Speed	Test 1 – Flow Rate	Test 2 – Flow Rate	Difference
100%	313.72	313.93	0.07%
88%	263.16	262.84	0.12%

Reproducibility and flow reading noise tests on both a 4-inch final concentrate line and a 24-inch tailings line were performed to ascertain the performance of the sonar based flowmeter. A snapshot of data from these series of tests is shown in Figure 16.

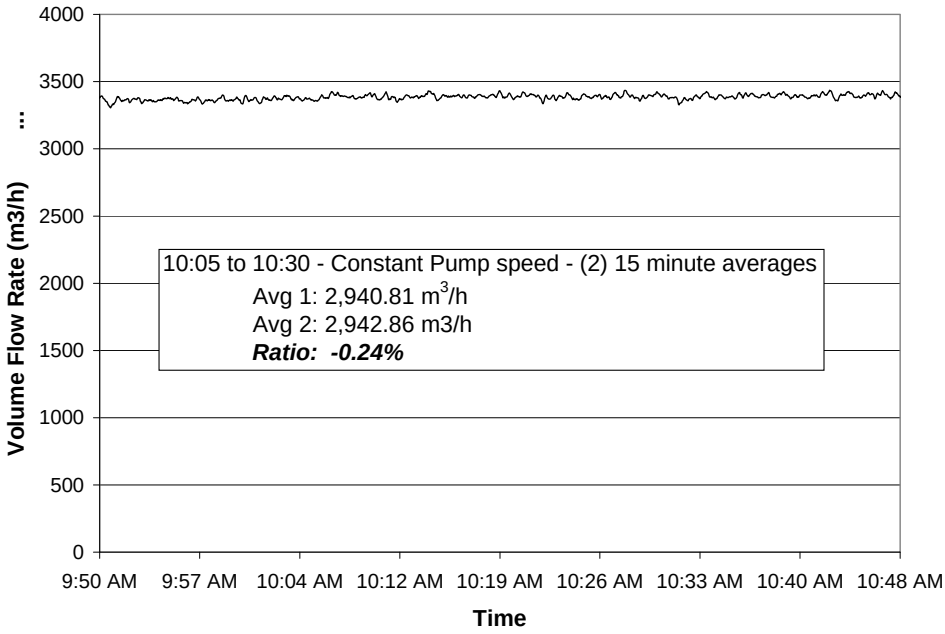

Figure 16 Magnetite Tailings Line Noise Tests (At Least 20x Quieter than Magmeter)

Tank fill tests on a 4-inch magnetite final concentrate line were performed to determine the accuracy of the sonar array based flowmeter. With the correct pipe inner diameter entered into the instrument, the results indicate a good agreement with the tank fill tests as can be seen in Table 2.

Table 2 Flow Measurement Accuracy Tests in Magnetite Slurry

Tank Fill Test	Pump Speed	Tank Fill (m3/h)	Sonar Based Flowmeter (m3/h)	Difference
1	100%	73.39	73.5	0.15%
2	100%	73.62	73.55	-0.09%
3	88%	61.48	61.65	0.28%
4	88%	62.03	61.58	-0.73%

GAS VOID FRACTION MEASUREMENT

The same sensor head and transmitter used to measure the volumetric flow rate is used to measure the fluid composition. In the mineral processing application area, this typically entails using the sonar based flowmeter to determine the amount of air entrained within the slurry. In most cases, plant engineers are unaware of the amount of air entrained within their slurry. Despite the best care in plant design, air can enter the slurry through a variety of sources including leaks on the suction side of pumps, low sump levels, discharge into a sump hydrocyclones, and mills.

Entrained air can impact a process by causing errors in the nuclear density gauges and flowmeters. In some cases, air is intentionally injected into a process to assist in the separation of materials such as bitumen from the sand in the oil sands industry, or in an external sparging system for a flotation column. In these cases, it is desirable to measure the entrained air or gas void fraction in order to compensate the outputs of the nuclear density gauges and flowmeters, or to ensure that the correct amount of air is being injected into a process. In other processes, defoamers are used to reduce the amount of entrained air and their dosing should be controlled by a gas void fraction meter.

In Figure 17, an example is given for the gas void content in a 24-inch hydrocyclone feed line. In this case the customer was unaware of the presence of the air and the resulting nuclear density gauge and flowmeter errors.

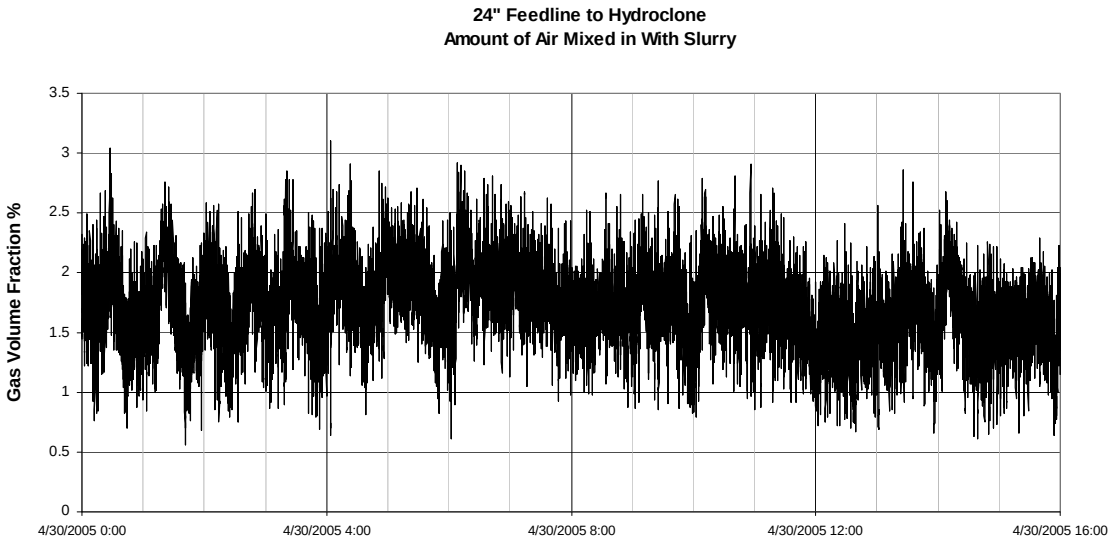

Figure 17 Gas Void Fraction in a Hydrocylone Feed Line

Oil Sands

OIL SANDS SLURRIES

Background

The Athabasca oil sands located in Alberta, Canada employs two methods for extracting oil from the sand. Oil sands between 70 and 75 meters of the surface are mined. Beyond that depth, the method used to access the resource too deep to mine is Steam Assisted Gravity Drainage (SAGD). Water makes up about 4% of the oil sand by weight and surrounds each grain of sand, keeping it separate from the oil. Without this water envelope, the oil and the sand could not be separated by the water-based extraction methods now in use in surface mining applications.

The mining approach exposes the oil sands by stripping the overburden and then removes the oil sands using truck and shovel mining methods. Currently approximately 600,000 barrels of bitumen per day are produced from the deposits at three major operations. By 2010, that amount is estimated to climb to an estimated 1.2 million barrels per day as new technology and projects come on stream. By 2015, the number is expected to rise to 1.8 million barrels daily.

Oil sands slurries consist of a thick, highly viscous mixture of hydrocarbons called bitumen, combined with sand, clay and hot water. Crushers and sizers prepare the ore which is mixed with hot water and delivered to primary separation vessels via large diameter conditioning slurry or hydrotransport lines that are kilometers in length. The primary separation vessel separates the raw bitumen from sand. Secondary operations clean the bitumen slurry by removing clay

particles from the bitumen and water mixture. The bitumen then goes on to upgrading facilities where it is further processed and refined. The water, sand and clays that are extracted from the oil sands and bitumen from primary and secondary extraction are called tailings and are pumped, typically, several kilometers to tailings ponds.

Flow Measurement Technologies and Challenges

Oil sands, tailings and bitumen slurries present numerous measurement challenges for in-line flow measurement devices in terms of measurement accuracy, reliability and maintenance. Oil sands and tailings slurries, in particular, act as "liquid sandpaper" to both process pipe and in-line flow measurement devices. Slurries containing coarse sand, gravel, and rocks travel through pipes that are typically 24-inch to 30-inch in diameter at flow velocities of up to approximately seven meters per second. Bitumen froth flows are highly viscous and its fluid properties are non-conductive.

The choice of flow instrumentation for oil sands operators, as one can imagine, is limited by the fluid and slurry properties described above. Some key, critical process points go unmeasured as a result. One particular flow technology that has been used for years in the oil sands is based on differential pressure, specifically, venturi and wedge meters. While having broad applicability to oil sands process flows, these flow devices are limited in terms of providing measurement accuracy, certainty and reliability since once they are installed in highly abrasive slurries they tend to wear rapidly. In the more aggressive hydrotransport and tailings slurries, venturi and wedge meters are highly maintenance intensive due to their intrusive nature to the flow. In addition, because both the wedge and venturi meters rely on other instrumentation to make a flow measurement, they tend to be weak links in the reliability chain, both from a measurement and asset uptime perspective.

To some extent, electromagnetic meters based on Faraday's Law, are used in the oil sands and offer an improvement over wedge and venturi meters as they don't "pinch" the flow. However, since they are in-line meters, the lining and electrodes come in contact with the flow and are subjected to the same wear considerations and degradation of signal as the wedge and venturi meters after installation in aggressive slurries. Electromagnetic meters, unlike the DP-based meters, provide a direct measurement of velocity; however their use in oil sands is limited due to the non-conductive nature of the bitumen content of hydrotransport, and of coarse, bitumen froth flows. Typically, electromagnetic meters are seen in some coarse tailings slurries, but the aggressive nature of the slurries create high wear on both liners and electrodes and regular maintenance and process down time to change out the meters are incurred by the operators.

In some cases, particularly in process water applications, clamp-on ultrasonic flow meters are utilized, however the dirty nature of the process water, pipe wall interface, alignment and scattering issues do not make for measurement reliability or certainty in these types of applications.

Another measurement challenge for any velocity based flow measurement device or nuclear densitometer used widely in the oil sands industry is the presence of entrained air in slurries or

bubbly fluids. Some instruments will have difficulty in making a reliable measurement in the presence of entrained air and in all cases a velocity-based flow meter, using the cross sectional area of a pipe to calculate the volumetric flow, will measure and report the volume of the total mixture, including the air, thus misstating the true liquid flow. Likewise, the nuclear densitometer would provide a density measurement based on the total mixture of air, solids and liquids, thus misstating the density of the slurry.

The implication and challenges then for process, reliability, instrumentation and maintenance engineers given the use of traditional, older technologies in oil sands are as follows:

1. Existing flow measurement devices are weak links in the reliability chain, both from a measurement and asset uptime reliability perspective.
2. The presence of entrained air in some slurries and froth flows misstate flow and density measurements thereby affecting volumetric and mass flow measurements which in turn causes inaccuracies in mass balance results and limits process optimization opportunities.

Given these conditions, the challenge for oil sands operators then is how to get a reliable flow measurement that would allow accurate and repeatable mass balance results which, as a result, would enable the oil sands operators to make the necessary process improvements and adjustments to optimize their processes. When the actual volumetric flow as reported by these existing flow meter devices do not support the process engineers' mass balance calculations there are many variables to look at and question. Is the flow meter worn and out of calibration? Are the ports to the DP meters of the venturi or wedge plugged or worn? Are the electrodes of the electromagnetic meter worn and coated with bitumen? Is entrained air present in the fluid? Is the measurement device working properly or are the valves worn or possibly stuck? From an asset uptime perspective, in some applications particularly hydrotransport, separation cell underflow and coarse tailings applications, depending on the amount of wear, existing flow meters can be changed out up to four times a year depending on the application. Downtime associated with scheduled (or even worse, unscheduled) change-outs can cost millions of dollars per year in terms of lost production and the labor and materials necessary for such change outs.

In an industry where billion dollar assets run on flow, the ideal flow measurement device would maintain its accuracy and reliability over time and have the following characteristics: (a) clamp-on to existing process piping - lined or unlined – (b) would be indifferent to the density or composition of the fluid or slurry, (c) be utilized in virtually any process flow application, (d) would be able to measure and report the entrained air in the mixture as a percent to total volume and (e) would not require on-going maintenance once installed.

Clamp-on sonar-based flow and entrained air measurement systems as described previously in this paper provide the above attributes and benefits to oil sands operators.

Feature	Venturi/Wedge	Electromagnetic Meter	*SONARtrac* Flow Technology
Measurement Principle	Differential Pressure	Faraday's Law	Passive SONAR-Array Processing
Installation	In-line	In-line	Clamp-on
Broad Applicability to Oil Sands Processes	Yes	No	Yes
Direct Measurement of Velocity	No	Yes	Yes
Subject to Wear and Signal Degradation	Yes	Yes	No
Maintenance Intensive	Yes	Yes	No
Measurement of Entrained Air in Slurry or Fluid	No	No	Yes

Table 3: Flow Technologies for Oil Sands Applications

Application of *SONARtrac* Flow and Entrained Air Measurement Technology to Oil Sands Processes

Clamp-on, passive sonar-based flow and entrained air systems were first introduced to the oil sands industry by CiDRA Corporation in 2003 to help fulfill the industry's need for new, innovative technology that would help enable increased asset uptime, measurement reliability, process and operating efficiencies and help lower costs.

Sonar-based flow and entrained air measurements systems are commercially installed on a wide variety of oil sands applications such as hydrotransport slurries, primary and secondary underflow, coarse and fine tailings slurries, middlings, primary and secondary bitumen froth flows, diluted bitumen, fine tailings, and process water applications. Both the volumetric flow and entrained air measurements are being utilized in a number of applications.

As with any new technology, sonar-based flow technology has been thoroughly tested and compared with the performance of existing flowmeter technologies in a variety of commercial applications as well as in independent laboratory tests to near natural conditions as seen in the field. One such test, sponsored by Syncrude Canada, Ltd. tested the *SONARtrac* flow technology in a wide variety of slurries, flow rates and conditions against venture and magmeters at Saskatchewan Research Council. A limited sample of test conditions and results are illustrated in Table 4 and Figure 18 respectively. These tests demonstrated that in controlled testing with actual oil sands and tailings slurries of different densities and conditions, the *SONARtrac* flow meters were in good agreement with the venturi and electromagnetic meters.

Density	*d_{50}*	*Rocks*	*Entrained Air*
1000	–	–	–
1080, 1300 1580, 1600	169 um	–	–
1300, 1580	169 um	–	5%
1600	169 um	2%, 5%, 10%	–
1080, 1300 1580, 1600	324 um	–	–
1300, 1580	324 um	–	5%
1600	324 um	2%, 5%, 10%	–
1500	Oil Sands	–	–
1500	Oil Sands + additional Bitumen	–	–

Table 4: Test Matrix

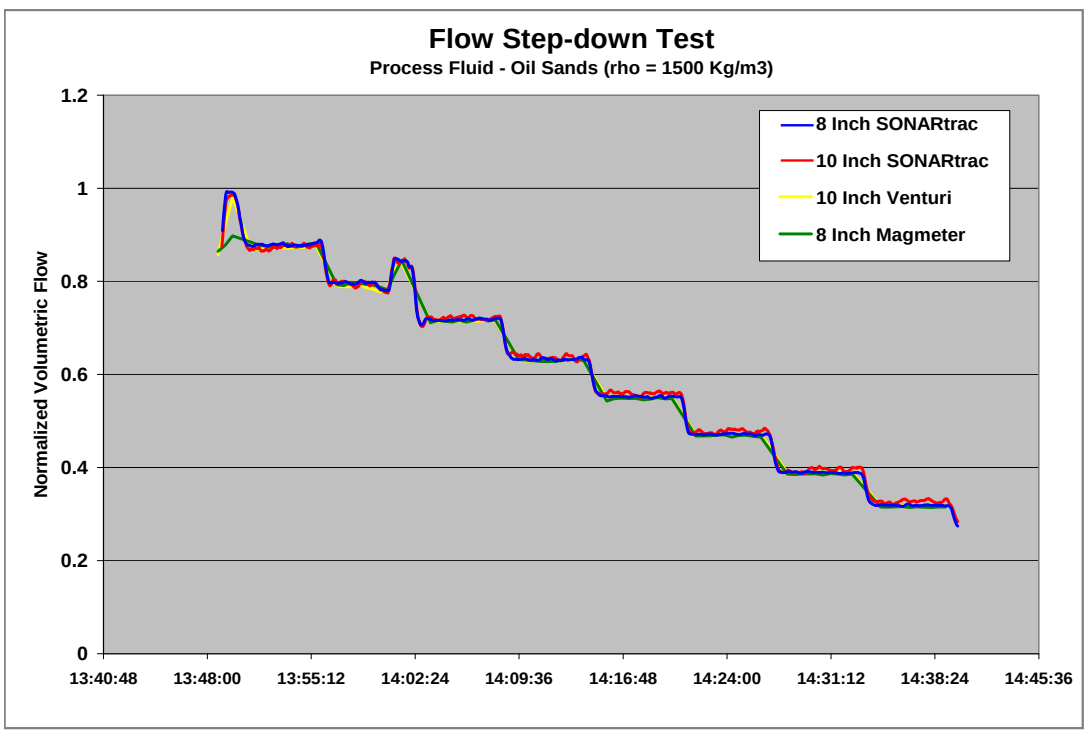

Figure 18 Flow Step-Down Tests

In addition to independent testing and comparative tests with existing flow technologies, the *SONARtrac* flow and entrained air technology has been involved in mass balance tests and tank draw down tests and provided excellent results over existing technologies in place.

During the three years of use in oil sands applications, sonar-based flow and entrained air instruments have been proving their value in terms of measurement accuracy, reliability and asset uptime reliability. When entrained air is present, the *SONARtrac* technology's ability to provide an accurate, real time measurement of entrained air has allowed oil sands operators to adjust their volumetric flow or nuclear densitometer measurement as reported to the DCS in order to get a "true liquid" and more accurate mass flow. Additionally because the sonar-based clamp-on technology does not come into contact with the slurry, there is no wear or signal degradation which enables certainty and accuracy of the measurement. This, in turn, leads to better control and optimization of the process. In more abrasive slurries, where the inner wall of the pipe is worn, a simple and easy adjustment can be made through the user interface provided in the *SONARtrac* transmitter. Using the inner wall dimensions typically measured by reliability engineers on a regular basis with a wall thickness indicator to measure pipe wear, the new inner diameter can be easily input into the front panel of the transmitter thereby reflecting the change in wall dimensions and adjusting the volumetric flow to actual pipe wall conditions.

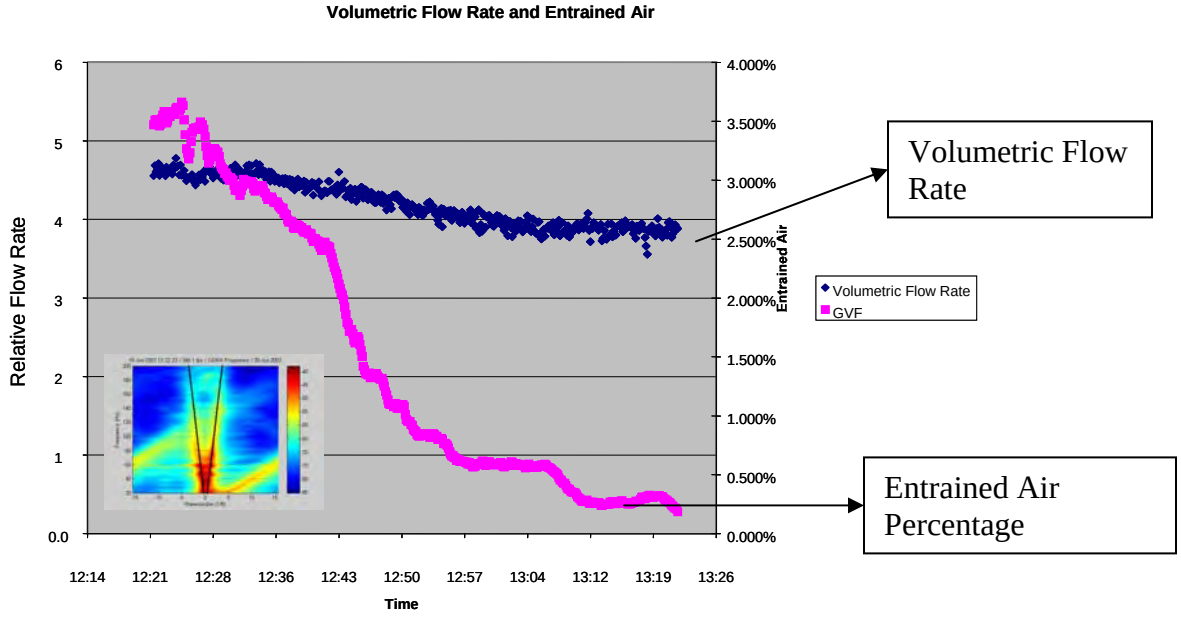

Figure 19 SONARtrac Technology: Dual Measurements of Flow and Entrained Air Percentage (Gas Volume Fraction or GVF)

SONARtrac flow and entrained air meters clamp onto existing process pipe so there is no need to shutdown the process to install. The sensor head can be installed by one or two people usually under two hours and requires no alignment or special tools to install. Once installed, the flow instrument does not wear or suffer from signal drift or degradation so ongoing maintenance is not required. Typically in aggressive applications the system's payback is measured in months and even weeks.

In summary, sonar-based flow and entrained air measurement systems are meeting the most challenging flow measurements issues that have been experienced by oil sands operators over the years: (a) clamps-on to existing process piping - lined or unlined, (b) is indifferent to the density or composition of the fluid or slurry, (c) is utilized in virtually all process flow application, (d) is able to measure and report the entrained air in the mixture as a percent to total volume and (e) does not require on-going maintenance once installed (f) maintains its accuracy and reliability over time.

GAS HOLDUP MEASUREMENT

Gas holdup in a flotation process is one of the key gas dispersion parameters used to define the efficiency of a flotation process. Measurement of this parameter, combined with some readily measured parameters provides the information need to fully control a flotation process. The need has been for an accurate, low maintenance, robust instrument that can provide a continuous reading of the gas holdup without recalibration or cleaning.

By creating a submersible version of the sonar based gas void fraction meter mounted to a four inch PVC pipe, it is possible to measure the gas holdup in a flotation cell or tank. By aligning this gas holdup meter in a vertical orientation, and placing it in the collection zone of the cell, rising bubbles can freely enter into the bottom of the PVC pipe, rise through the pipe and interact with the ground ore that is entering the top of the pipe. Thus it will provide a good continuous measurement of the gas holdup in the cell and its interaction with the ground ore. It can also be moved around within the cell to look for malfunctioning spargers, an application already in use by a mineral processor. A picture of the completed gas holdup meter is shown in Figure 20 along with a typical location for its use in a column cell.

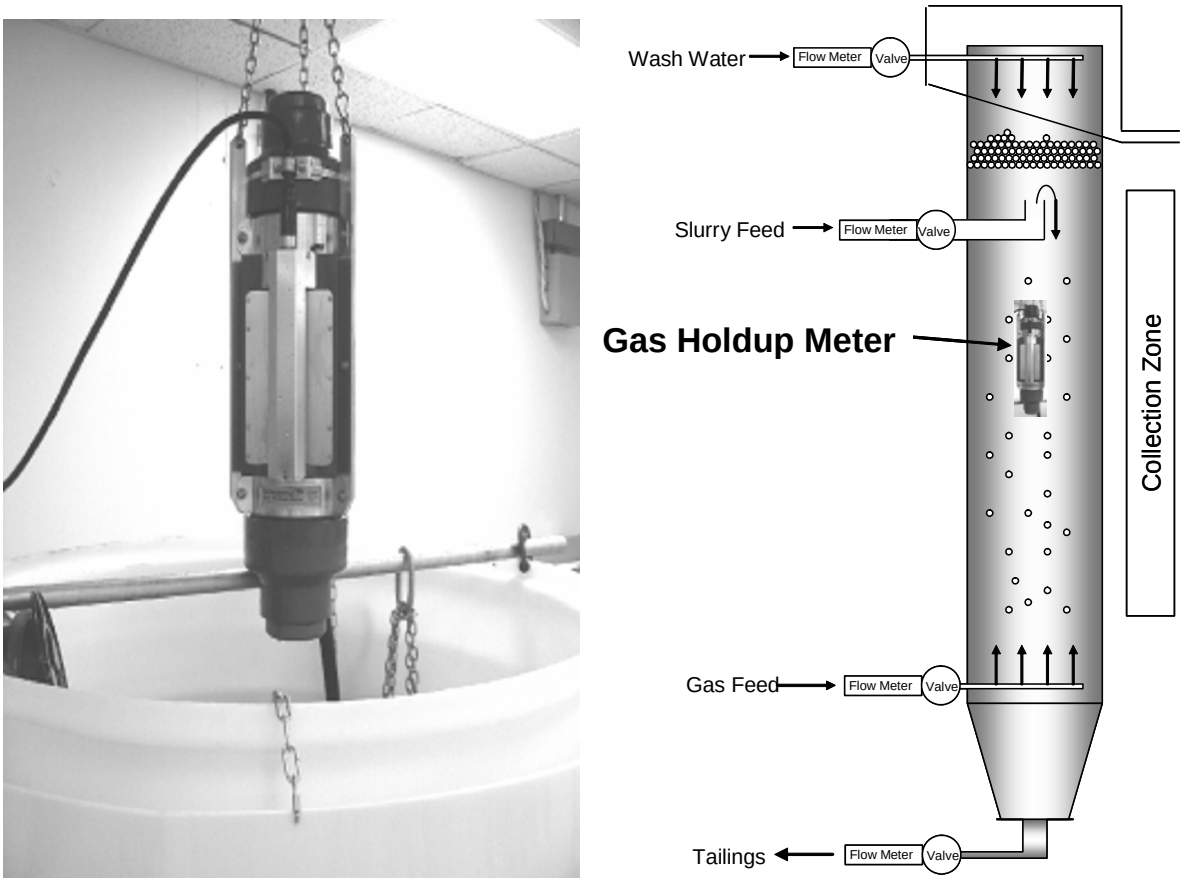

Figure 20 (Left) Picture of Gas Holdup Meter and (Right) Diagram of Column Cell with Typical Location for Gas Holdup Meter

The gas holdup meter technology has been tested in a variety of mineral processing facilities, including our own test tank. In Figure 21 one can see the impact of a "bump" test in which the concentrator plant personnel changed the superficial gas velocity to determine the response of the meter. Since scale buildup does not affect the sonar array measurement technique, the gas holdup meter has demonstrated to be a robust measurement instrument. Its calibration does not change with time, temperature, or scale buildup.

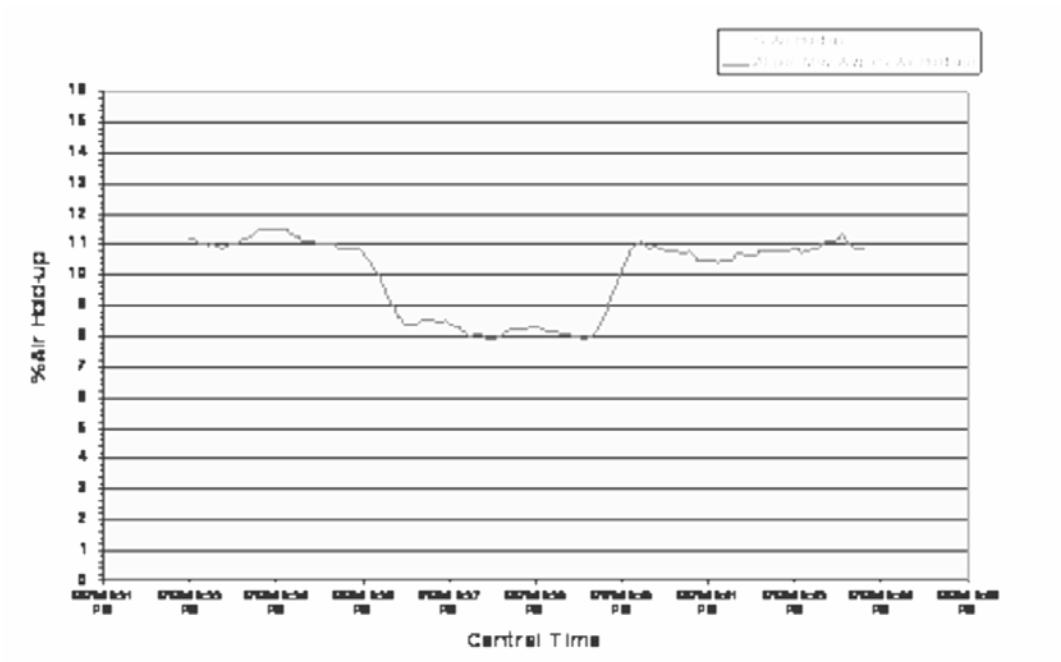

Figure 21 Gas Holdup "Bump" Test in Copper Flotation Column (Y-Axis Range is 0% to 18% Gas Holdup)

SONARtrac™ Scalable Architecture and Platform

SONARtrac™ technology is based on a scalable architecture, and its functions and performance can be expanded and enhanced through algorithm development and hardware configuration. This scalability enables the addition of new and innovative measurement features that can enhance current measurements, enable new functionality and insight into the dynamics of process flows. One example of these innovative measurements have been tested in the field and/or in independent test laboratories and are presented below.

Clamp-on Velocity Profiling Using Sonar-Based Technology

In oil sands, the length of the hydrotransport line and other key process parameters in a conditioning slurry line is critical to the ablation and liberation of bitumen from the sand prior to the arrival into the primary separation cell or vessel.

Having on-line, real-time insight into the distribution of water, clays, fines and coarse sand in a conditioning slurry line is seen as one of the keys that will enable increased yields and efficiencies. A real time velocity profile measurement can also be used to prevent sand-outs from occurring within the process pipe which can cost millions of dollars due to downtime.

As it is well documented, the degree of stratification within a process pipe is a function of density, particle size, velocity and pipe size. *SONARtrac* velocity profile technology can measure the local velocity at different heights of the pipe as shown in Figure 22. Having this type of real time insight into the flow dynamics within a process pipe can help the process engineer or operator optimize flow parameters to improve flow efficiency, yield and prevent sand-outs which are caused by the settling of solid particles into a stationary sand bed that could eventually "plug" a process pipe.

Sand-outs are typically are avoided through the control of the specify gravity and flow rate of the slurry. However, these conditions are determined through experience, possibly through monitoring line pressures, densities and flows, and sometimes through calculations. Unfortunately, all of these methods can leave the operator with a great deal of uncertainty in the minimum flow rate needed to prevent settling of the particles. This is particularly true when there are changes in the slurry conditions such as the specific gravity of the particles themselves, their specific gravity distribution, the particle sizes and their distribution, including the quantity of fines as determined by the quality of the ore being processed. The impact of small changes can be quite large and sometimes counter intuitive. As an example, a reduction of fines can increase the minimum flow rate needed to prevent settling, since the fines can increase the effective viscosity of the water. (Shook, Gillies, and Sanders, 2002) The most direct method of preventing or detecting sanding out conditions is through a monitoring of the flow profile or the detection of a moving or stationary sand bed or both.

A viable method for detecting sand-outs is to measure the velocity profile of the various layers of liquids and solids within a process pipe. As can be seen in Figure 22, a passive array of sensors configured in a certain manner and using sonar-based processing is able to measure the faster moving water at the top of the pipe, the slower moving fines and clays suspended in the middle of the pipe and the even slower coarse particles of sand and rock tumbling along the bottom of the pipe at even slower velocities.

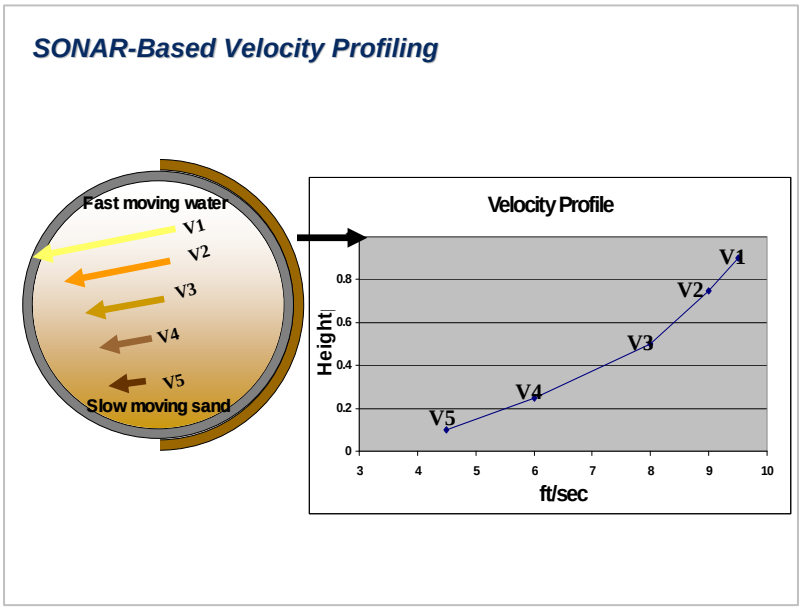

Figure 22 SONAR-Based Velocity Profile

A graph of an oil sands slurry velocity profile is illustrated in Figure 23. If the fluid being measured was completely homogeneous with a symmetrical flow profile, the line shown in the graph would be vertical. However, because of the settling of the various solids, the flow profile is skewed hence the curvature of the profile.

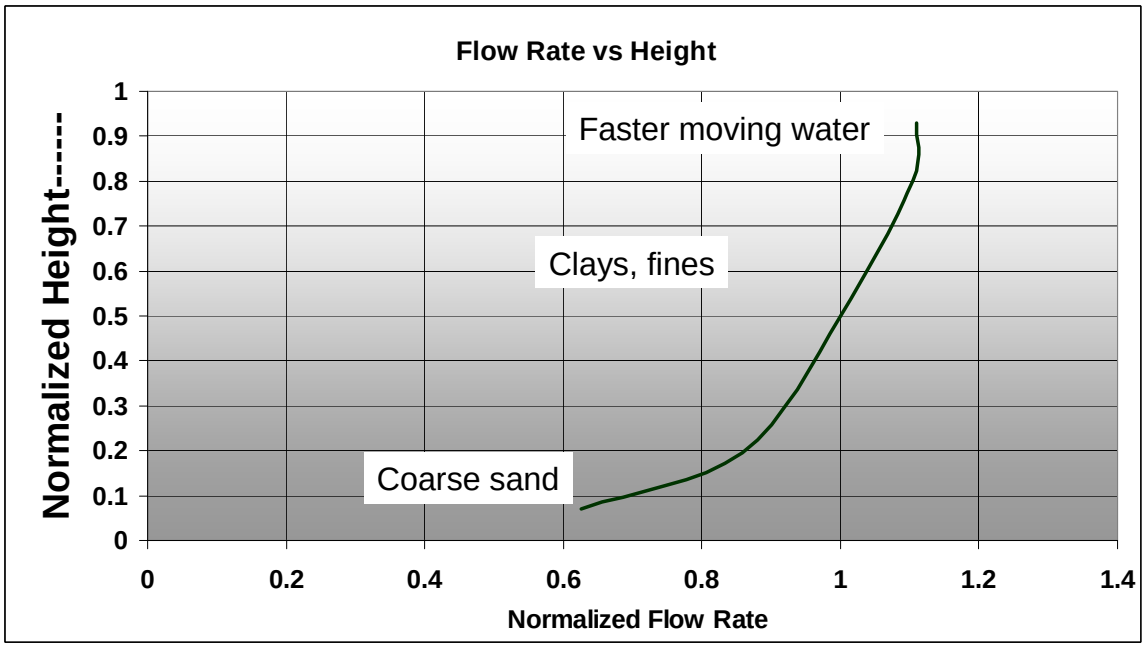

Figure 23 Oil Sands Slurry Velocity Profile

The shape and slope of the velocity profile curve is capable of providing information as to the distribution and quality of the ore being processed in the conditioning (hydrotransport) slurry line. Also, in both hydrotransport and tailings lines the same information, delivered in real time, can help the operator monitor sand bed development and take necessary action to prevent a stationary sand bed to occur which can cause sand-outs and millions of dollars in expense and lost production.

In a hydrotransport or conditioning slurry line, the benefits of utilizing a real-time velocity profile meter can be just as compelling. Most processes are typically run at higher velocities and with more water to prevent a stationary bed from forming. If the degree of stratification can be controlled and density can be increased while reducing the velocity, the benefits that can accrue are as follows: (1) decreased pipe wear, (2) longer “scrubbing” time, and (3) better conditioning and lower water usage.

SUMMARY

SONAR-based flow and entrained air measurement instruments are a new class of industrial flow and compositional analyzers leveraging over 60 years of SONAR development and utilization. SONAR-based flow meters are installed worldwide in many industrial applications and are ideally suited for a wide range of minerals processing applications and provide new measurement insight and quantifiable value to operators.

SONAR-based, clamp-on *SONARtrac* technology is a scalable platform that is more than just a flow technology. It has the ability and capability to provide several other value added measurements and information such as speed of sound, entrained air/gas, gas hold-up, and velocity profile.

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