APPLICATION OF PASSIVE SONAR TECHNOLOGY TO LONG STANDING MEASUREMENT CHALLENGES IN INDUSTRIAL PROCESSES

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ABSTRACT:

This paper will describe CiDRA's patented clamp-on, passive sonar array-based flow meter technology which performs two fundamental and independent measurements – flow rate and entrained air. 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 wrapped around existing process pipe. Secondly, the meter utilizes similar sonar-based processing techniques and the naturally occurring acoustical propagation in the process pipe to measure sound speed and hence the entrained air levels in slurries and fluids. This unique ability enables robust, reliable flow measurements in a wide variety of flows – high solids content slurries, heavy oils, bitumen flows and liquids/slurries with entrained air content.

Also to be presented in this paper is the adoption and application of CiDRA's *SONARtrac*™ product technology in a variety of oil sands, oil & gas, and minerals processing applications, helping to address the needs of measurement integrity, reliability and value delivery to the customer. In addition, case studies will be presented describing how the clamp-on sonar-based technology can be leveraged and applied to help characterize and deliver new insight into fluid mechanics of slurries and fluids in these industries, leveraging the two fundamental measurements of the clamp-on, passive sonar-based technology into new product extensions such as velocity profiling, gas hold-up for column flotation and secondary-phase measurement for density-based meters in the presence of air/gas.

Introduction: The Need for Accurate, Reliable Flow Measurement in Multiphase Fluids and Slurries

Flow measurements in the oil sands, oil and gas, and mineral processing industries are many times challenged by the limitations of existing, old and "new" flowmeter technologies including widely used instruments such as venturi flowmeters, orifice plates, turbine meters, vortex meters, electromagnetic meters, ultrasonic meters, and Coriolis flowmeters. Each one, based on its specific physical principles, serve various markets and applications extremely well from both a technical and economic perspective. That they are often placed in process applications or physical locations that are not well-suited to the particular physics of that specific flow technology reflects the need of process industries for accurate, reliable and economic flow measurement in challenging process fluids and environs. Trying to place a flowmeter in a fluid regime or location that the technology is not well-suited for is, similar to trying to fit a "square peg into a round hole". Nonetheless, because there has not been a flowmeter technology available to adequately address a wide range of multiphase process conditions, the best "tool" available is selected for these challenging applications. As a result, the process instrumentation, reliability, maintenance engineer – and the accountant – must often trade-off accuracy, reliability, efficiency and uptime in order to get a "measurement", many times relying on other instrumentation, data, operator experience, and other qualitative factors to try to "fine-tune" a measurement or mass balance.

While fundamental physics of the flow technology is a critical limiting factor in certain flow regimes, most of them share one key disadvantage - the flowmeter in some form or manner come in contact with the process fluid. The issues and disadvantages from a technical and economic perspective are painfully well understood and recognized by operating and engineering personnel in industries where processes do not operate under the ideal conditions of a calibration laboratory. Most fluid regimes in oil and gas, oil sands, and minerals processing are not clear, clean fluids that are single phase and completely homogeneous. Many critical, continuous processes in these industries are multiphase fluids and slurries that are highly abrasive, sometimes "bubbly" and many contain additives which may alter the physical properties of the fluid. These types of fluid regimes cause many sleepless nights for the plant manager, process and reliability engineers and accountants. At the end of the day the "square peg" selected to address these challenging applications, although acquired at a relatively attractive market price", inflicts high cost of ownership to the end user in terms of three key areas:

1. Measurement uncertainty: When a flowmeter contacts the process fluid and conditions drift out of tolerance, the question first asked by all engineers, "Is it my process, or my flow instrument?" Measurement anomalies or out of tolerance conditions are sometimes caused by the physical properties of fluids causing wear or plugging in some types of meters. In other cases, chemical injection will have an affect. Bubbly fluids, entrained air or gas will most often, affect the accuracy and reliability of both volumetric and mass flow meters.
2. Downtime: Shutting down the process to install or perform maintenance on a flowmeter in continuous process flows is extremely costly to any industrial process.

3. Maintenance and operating costs: Flow elements that come into contact with aggressive process fluids and slurries require ongoing costly preventative maintenance to maintain their measurement accuracy and reliability. These costs manifest themselves in the form of process downtime, loss of productive labor that can be used in value-added operations, high cost of repair, and the need to maintain a high level of spare parts inventory. In addition, certain flow technologies that "pinch" the flows, such as orifice plate, turbine and venture meters causing costly pressure drops, energy loss and wear points.

Non-Contact Flowmeters

To overcome these disadvantages, a new paradigm relating to flow measurement instrumentation is needed by the industry – non-contact flow measurement; that is, a flow meter that is able to easily clamp-on or wrap around the outside of existing process pipe and provide accurate, reliable flow measurements in multiphase and single phase fluids.

Ultrasonic flowmeters serve the need for an accurate and reliable, clamp-on flow measurement for certain fluid regimes, however the technology is limited by its fundamental physics to address the many challenges related to multiphase slurries and "bubbly" fluids. In spite of these limitations, the ultrasonic technology continues to experience good growth and widespread usage in many process industries, is in part due to the convenience that ultrasonic clamp-on technology provides the user and the ability to install the flowmeter without shutting the process down. On the other hand, because of it is convenient to install and move, ultrasonic clamp-on technology has unfairly suffered a bad reputation for being placed in fluid regimes where the physics of the technology is not well suited.

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, pipe material or lined pipe has driven the creation of a new class of flowmeter. 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.

Sonar-Based Flow Measurement Technology: 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 industrial 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.

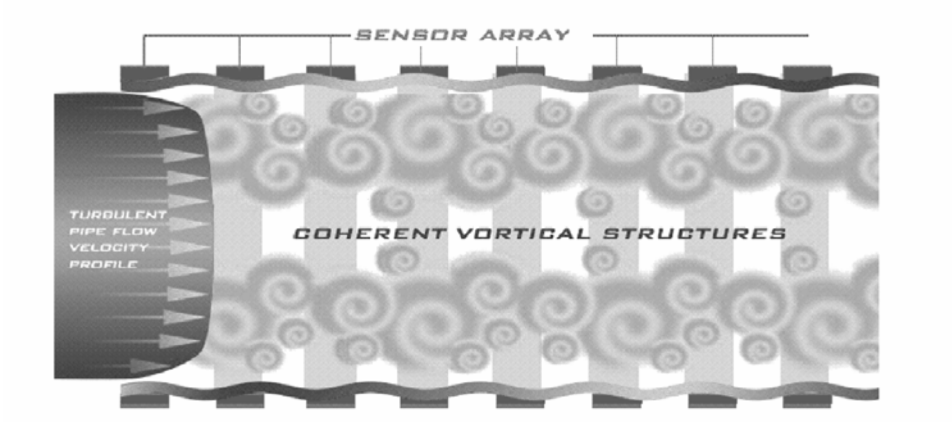

Figure 1: Diagram of Pipe with Turbulent Flow Showing Fully Developed Flow Profile and Turbulent Eddies

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 coupling 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 π / λ and ω=2 π f) is generated with the x-axis defined by the wavenumber (1/λ) 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:

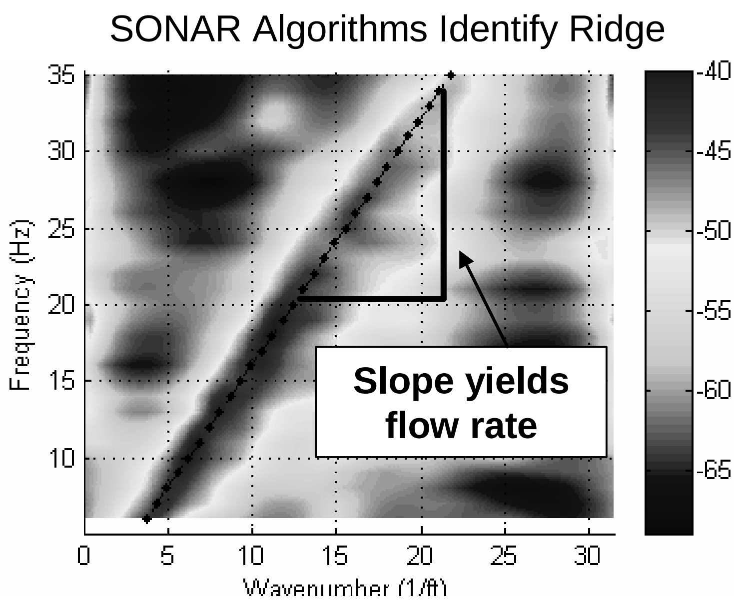

Figure 2: Representative k-ω Plot Showing Convective Ridge

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.

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 multi-component 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 ϕ_2=1-ϕ_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 3 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.

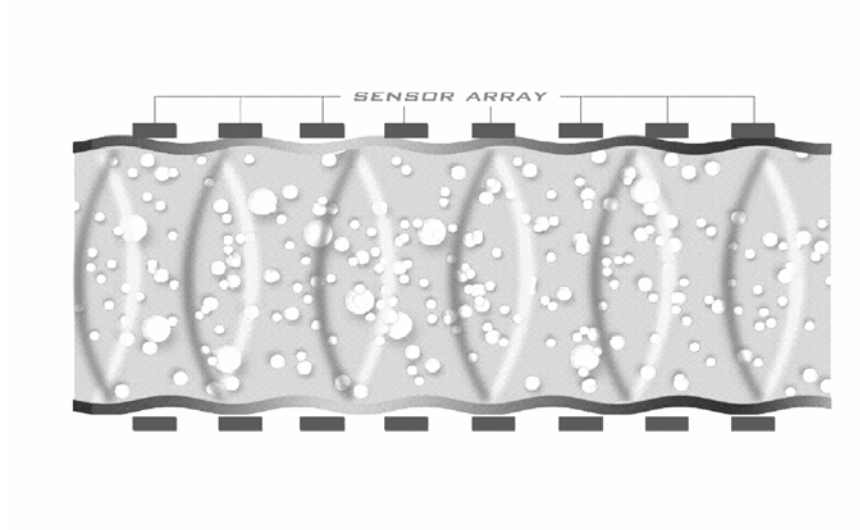

Figure 3: Illustration of Naturally Occurring Acoustic Waves Propagating in Pipe under the Sonar Array Sensors

A representative k-ω plot of a hydrocyclone feed line with entrained air is shown in Figure 4. 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.

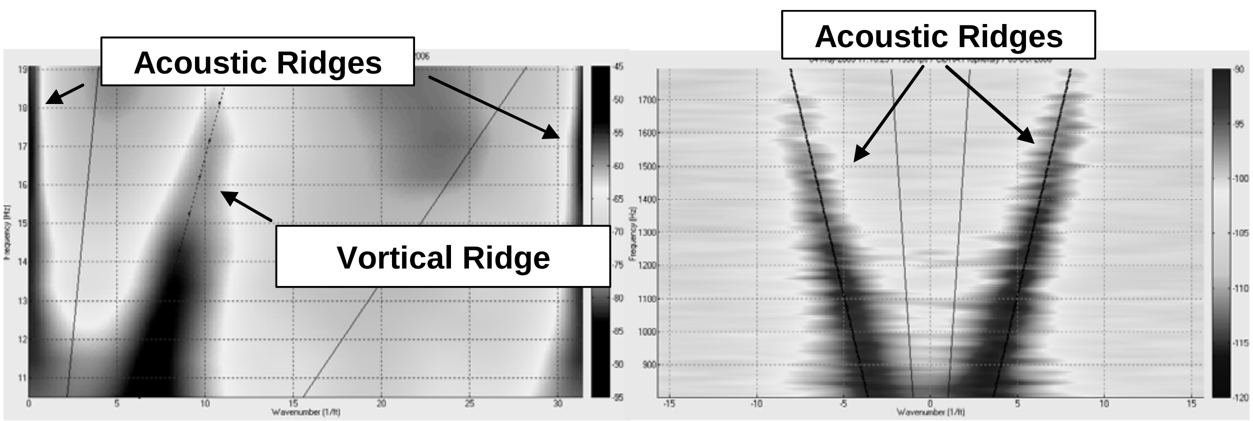

Figure 4: (Left) K-ω Plot Showing Both Acoustic Ridges and Vortical Ridge (Right) Rescaling of Graph and Change in Frequency Range Enhances View of Acoustic Ridges

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 5.

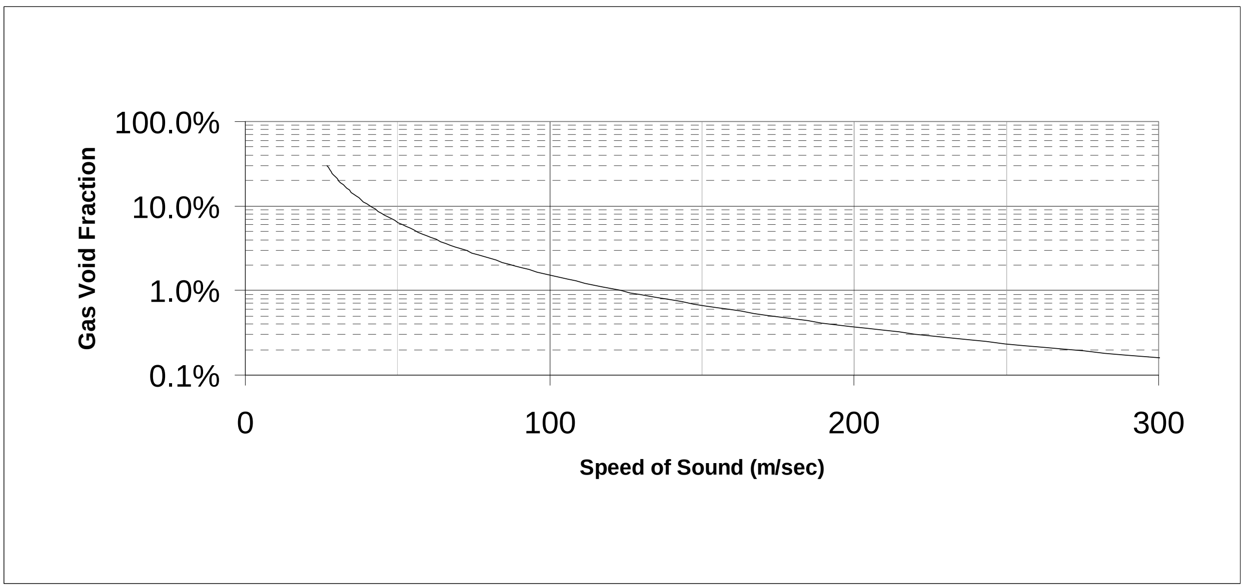

Figure 5: Example of Relationship between Gas Void Fraction and Speed of Sound

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 and Entrained Air/gas Applications utilizing passive SONAR-based flow instruments

Clamp-on Sonar-based flow instruments have been installed in over eleven countries in many process industry including oil and gas, oil sands, and mineral processing. They have proven themselves in many of the challenging multiphase slurries and fluids in harsh environments and in many process conditions. Outlined below are just a few examples of the versatility and application of sonar-based process flow and entrained air/gas measurement technology in these industries, with a focus on oil sands, probably the most challenging of all.

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 1: Flow Technologies for Oil Sands Applications

Application of Sonar-Based 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 passive, Sonar-based 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 2 and Figure 6 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 2: Test Matrix

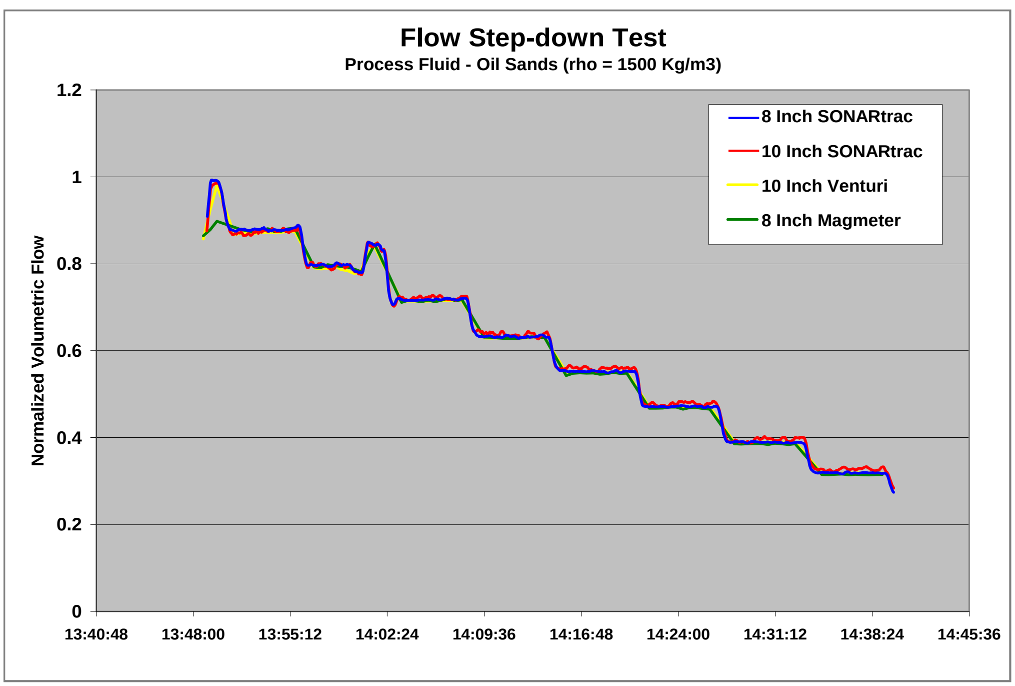

Figure 6: Flow Step-Down Tests

In addition to independent testing and comparative tests with existing flow technologies, the Sonar-based flow and entrained air technology has been utilized 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 Sonar-based 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 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.

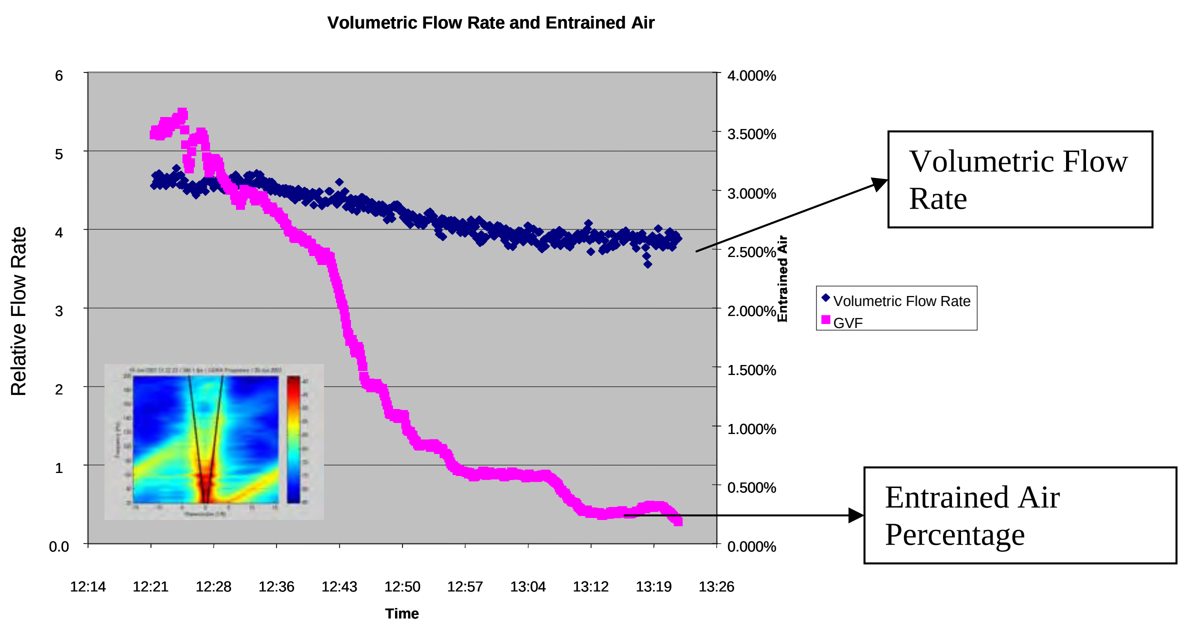

Figure 7: SONARtrac Technology: Dual Measurements of Flow and Entrained Air Percentage (Gas Volume Fraction or GVF)

Sonar-based 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.

Oil and Gas: The Utilization of Sonar-Based Gas Volume Fraction Meter for Improved Net Oil Rate Measurement

Introduction

Accurate measurement of net oil rate from individual wells is a critical component in effective oil field management, influencing production optimization strategies and financial allocations methods.
Driven by the goals of reducing the size and cost of three-phase separation approaches, many operators have adopted approaches utilizing smaller, two-phase, gas/liquid separation in conjunction with flow and water cut measurement to measure net oil. Many techniques are used for gas/liquid separation including level-controlled batch tank separators and continuous flow cyclonic separators (Kouba, 1995).

Although most gas/liquid separator-based net oil measurement approaches are designed to eliminate gases in the liquid leg of the separator, it has proven difficult to ensure complete gas/liquid separation. Furthermore, since the fluid exits the separator at near, vapor pressure additional out-gassing from the liquid can occur prior to measurement due to pressure losses in the flowing mixture. As a result, the errors in oil fraction measurement attributed to the entrained gasses can often be the single largest source of error in net oil measurement.

The first step in properly accounting for the presence of free gas on net oil measurement is to quantify the amount of free gas. An approach is presented which employs SONAR-based gas void fraction meter (Gysling and Loose, 2003) installed on the liquid leg of a gas/liquid separator to provide a real-time, entrained gas measurement. The real-time gas void fraction measurement is then used in conjunction with water cut devices to provide an accurate measurement of net oil. The ability to provide accurate net oil measurements in the liquids with entrained gases effectively eliminates the need for *complete* gas/liquid separation for accurate net oil measurement.

Oil Field Test Data

Oil Field Test Data
A SONAR-based gas volume fraction meter was installed on the outlet of a coriolis meter on the liquid leg of a continuous-flowing, gas/liquid cylindrical cyclone (GLCC) two-phase separator. Both meters were mounted in a vertical orientation with upward flowing liquid similar to the experimental test section as described above. The mass rate, density and drive gain from the coriolis meter and the gas volume fraction from the SONAR-based meter were output to a programmable logic controller (PLC) where the data could be stored and later retrieved. The pressure at the outlet of the coriolis meter was also output to the PLC. Figure 8 shows the gross flow rate and coriolis measured density during the 9 ½ hour well test. The gross rate was calculated by dividing the mass flow rate by the density, both directly measured by the coriolis meter.

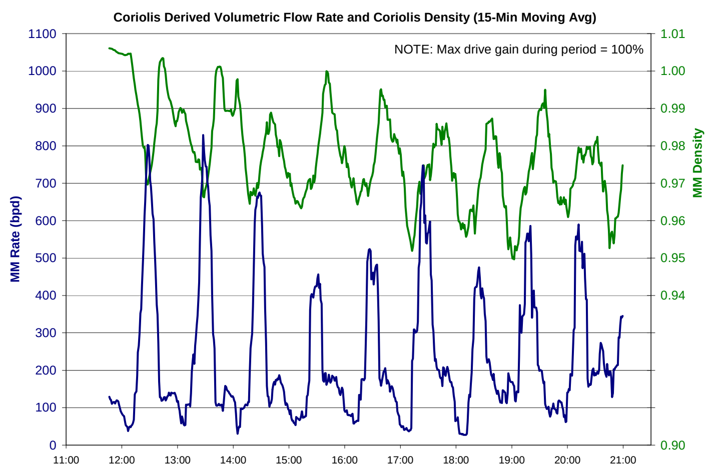

Figure 8: Coriolis Mass Flow and Density Reported During Well Test

Figure 9 shows the measured gas volume fraction and coriolis measured density. The gas volume fraction ranged from 0 to approximately 4%, varying significantly over the test period.

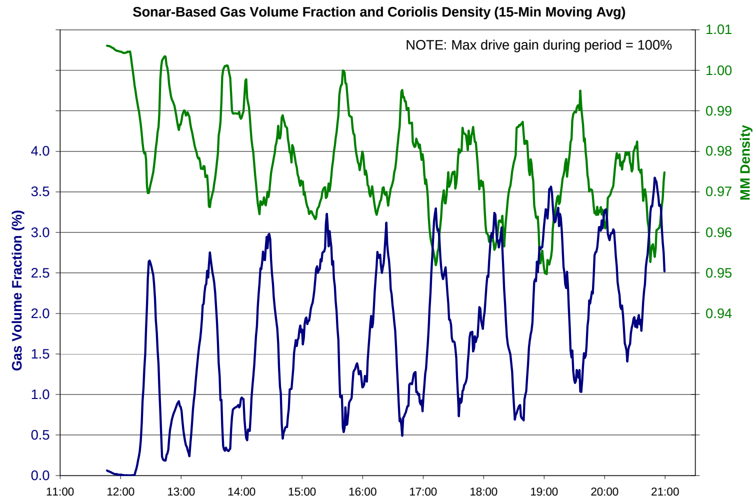

Figure 9: Coriolis Density and SONAR-based Gas Volume Fraction Reported During Well Test

Figure 10 shows 1) the measured density and 2) the coriolis drive gain plotted versus gas volume fraction. The measured density and the measured gas volume fraction show good correlation, with the decreases in measured density corresponding to increasing in gas volume fraction. However, unlike the laboratory experiment in which the liquid density was constant, the density of the liquid phase in the well test also varied due to changes watercut throughout the well test period. Time history data (Figure 9) shows that the gas volume fraction tends to increase with oil fraction. This effect would cause the density of the mixture to decrease more with gas volume fraction than it would if the liquid density were held constant. As shown, a best straight line fit through the data shows a mixture density decreasing at $(1.0\text{-}1.2{*}\phi_G)$, very close to theoretical $1\text{-}\phi_G$ for liquid / gas mixture with constant liquid properties.

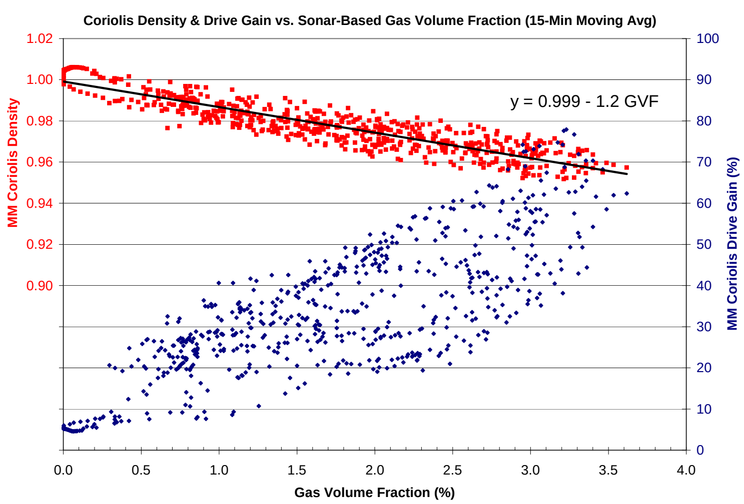

Figure 10: Coriolis Density and Drive Gain Plotted vs. SONAR-based Gas Volume Fraction During Well Test

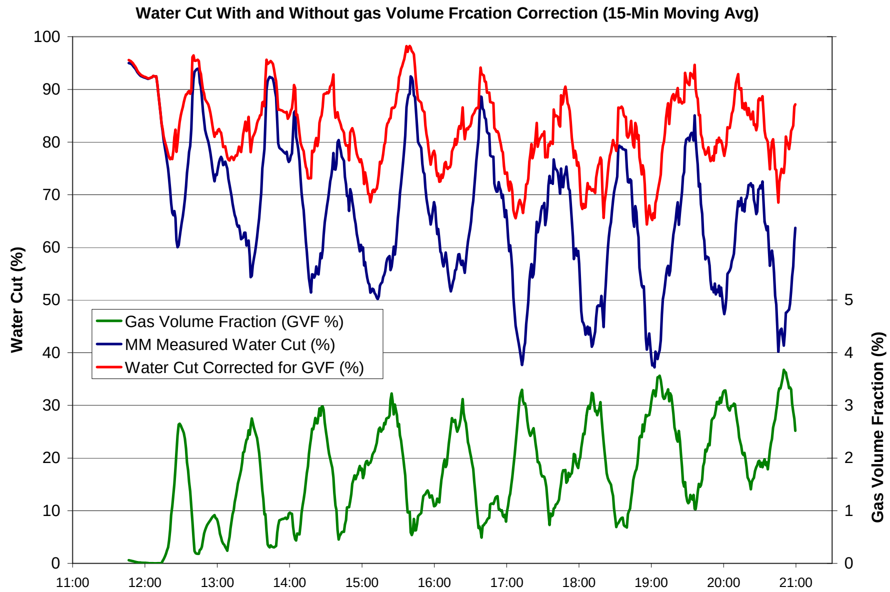

Figure 11: Reported and Corrected Coriolis Watercut and Gas Volume Fraction During Well Test

The cross-plot of the drive gain versus gas volume fraction is also shown. Although there appears to be a qualitative correlation, this data indicates that drive gain would not provide a quantitative measured of gas volume fraction. The water cut with, and without, the knowledge of the gas volume fraction is shown in Fig. 11.

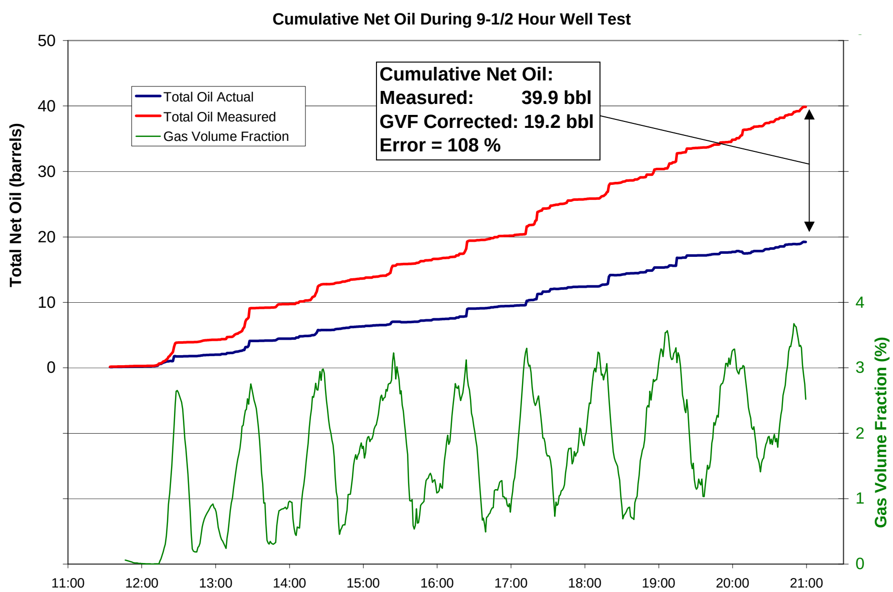

Figure 12: Cumulative Net Oil, Reported and Corrected, and Gas Volume Fraction During Well Test

Figure 12 shows the cumulative net oil over the well test period for the two cases. Using knowledge of the gas volume fraction when calculating the oil fraction yields a total oil of 19.2 barrels for this 9-1/2 hour well test. If the gas volume fraction were not known an assumed to be negligible, the total oil for this test would be reported as 39.9 barrels. This is an overstatement of the total oil by 20.7 barrels or 108%
(Fig. 12).

Application of Sonar-Based Flow and Entrained Air Measurement Technology in Minerals Processing

Introduction:

Sonar-based flow and entrained air measurement technology can be applied to a variety of minerals processing, 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.

Case Study: 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 –based 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 13, 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.

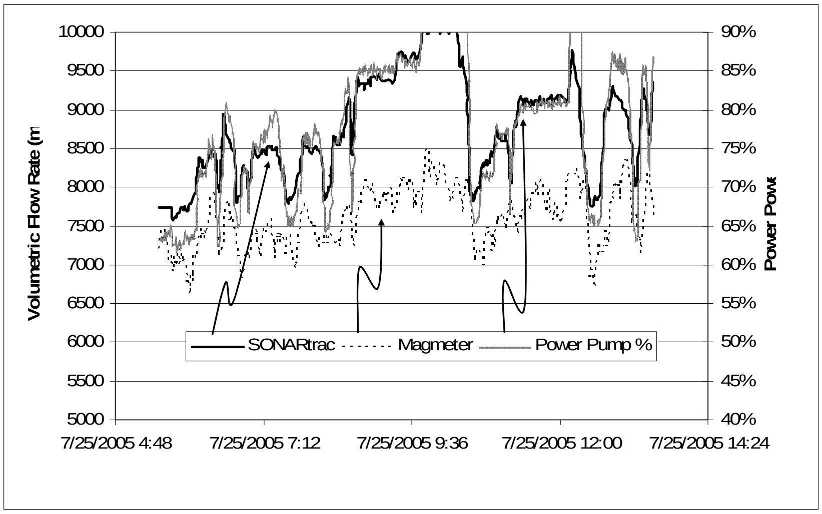

Figure 13: Comparison of Sonar- Based Flowmeter with Magmeter and Pump Power Showing Excellent Correlation between Sonar- Based Flowmeter and Pump Power

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.

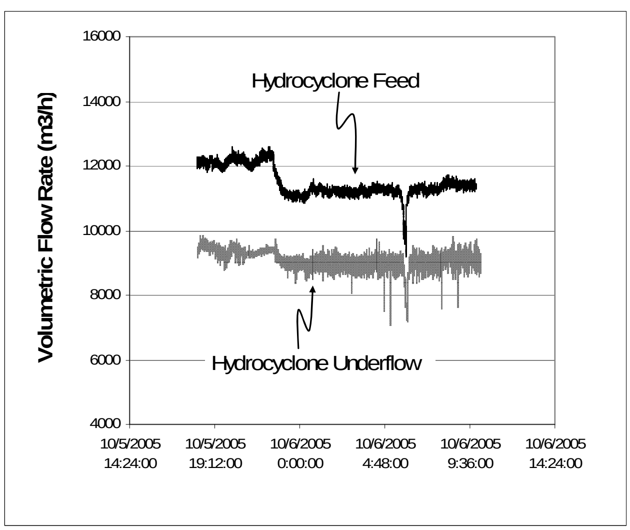

Figure 14: Measurement of Flow in Hydrocyclone Feed and Overflow.

Clamp-On, Passive SONAR-Based Technology - A Scalable Architecture and Platform

Sonar-based technology has 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 has been tested in the field and/or in independent test laboratories and are presented below.

Clamp-on Velocity Profiling Utilizing 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. Sonar-based 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 15, 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.

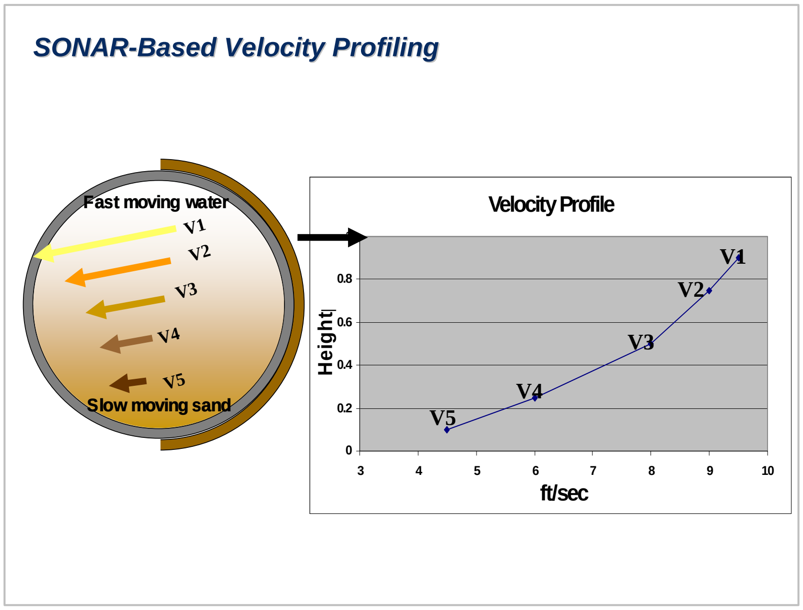

Figure 15 SONAR-Based Velocity Profile

A graph of an oil sands slurry velocity profile is illustrated in Figure 15. 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.

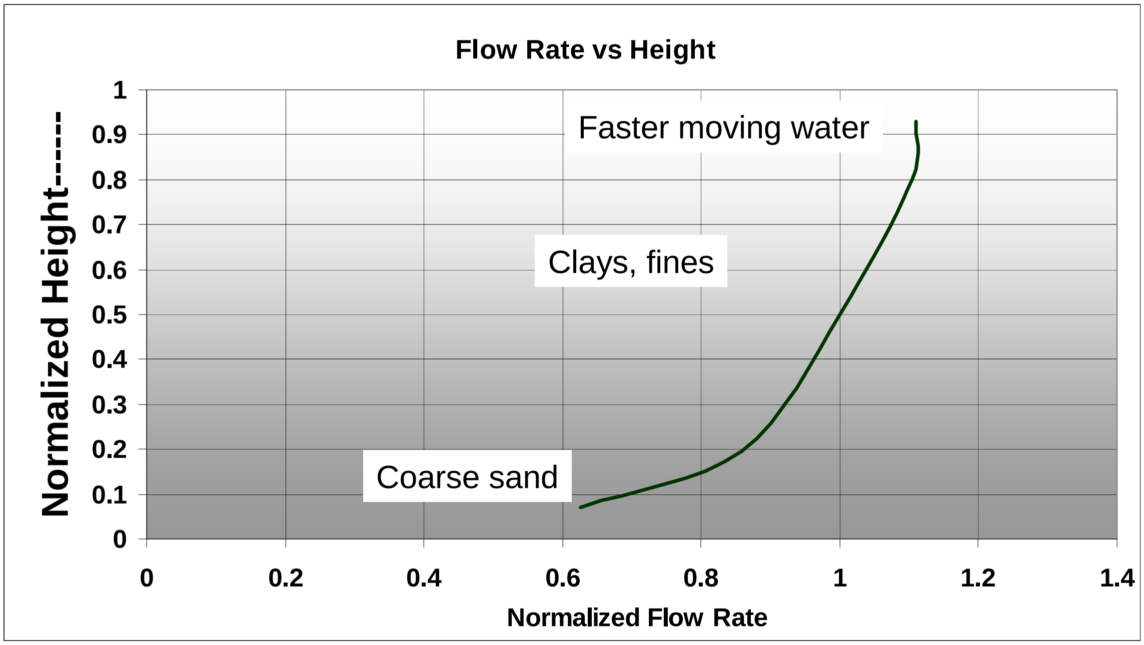

Figure 16 Oil Sands Slurry Velocity Profile

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.

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 17 along with a typical location for its use in a column cell.

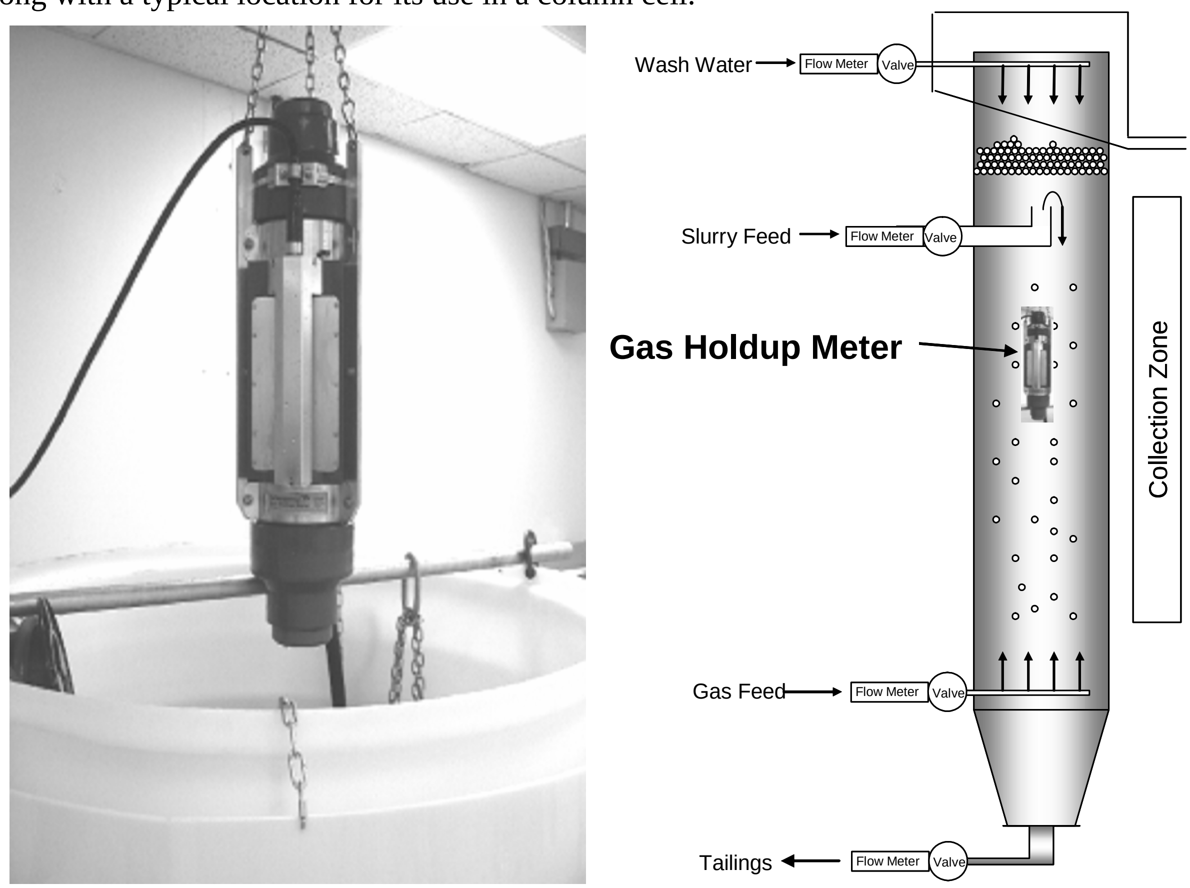

Figure 17 (Left) Picture of Gas Holdup Meter and (Right) Diagram of Column Cell with Typical Location for Gas Holdup Meter

The gas holdup meter technology has been tested in a variety of mineral processing facilities, including our own test tank. In Figure 18 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.

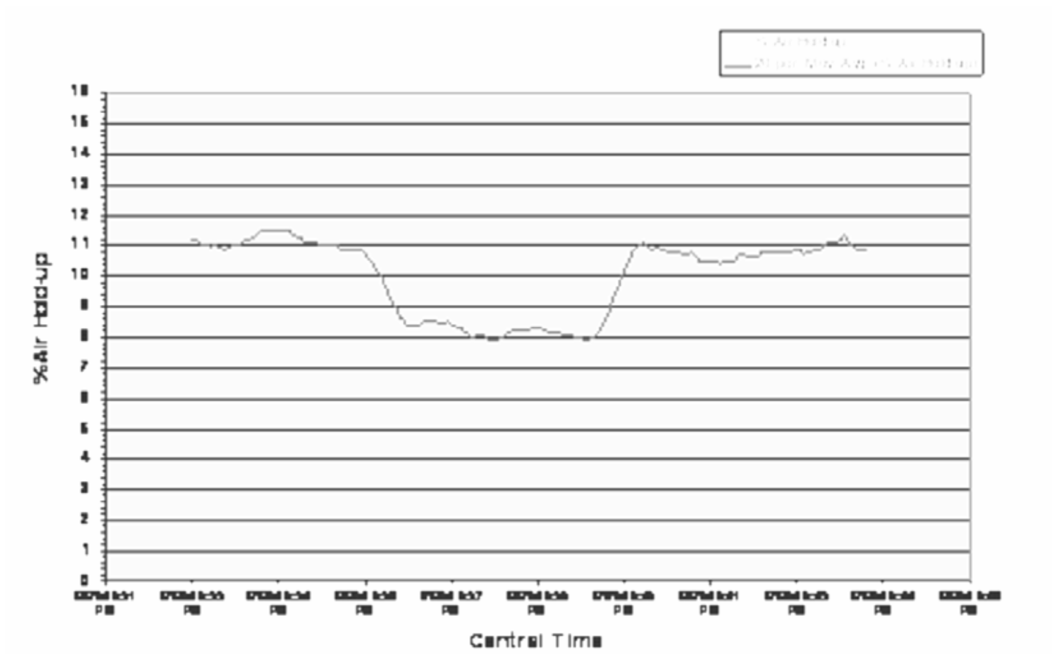

Figure 18 Gas Holdup "Bump" Test in Copper Flotation Column (Y-Axis Range is 0% to 18% Gas Holdup)

Summary

Sonar-based flow and entrained air/gas 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 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, having the capability to provide several other value added measurements and information such as speed of sound, entrained air/gas and velocity profile.

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