Sampling: What the standards don't tell you

NSFMW 2013

Introduction

International standards are developed to form a basis for trust in the uncertainty of measurement, they can be normative and informative, and they demand conformance to performance criteria.

Unfortunately there remain areas of design easy to misinterpret that can significantly influence the overall uncertainty of the measurement. This has gained the attention of measurement engineers, the standards committees and some research investment to further improve knowledge.

The commercial value of the uncertainties caused by poor sampling has never been more evident; originally developed in the 1980's the API, IP/EI and ISO standards are under review. The philosophy and techniques for sampling hydrocarbons needs to change to correlate poorly understood "best practices" developed between users and vendors with practical reality.

With over 35 years field experience in designing and proving sampling systems and with developing the standards used to define them both then and now, we are uniquely placed to share.

This paper will summarise some of the main issues that repeatedly arise and provide suggestions as to their relevance, effect on system uncertainty and how best to address them.

Newsflash - The Standards are changing!

The original need for better sampling standards in the early 1980's was driven by the oil shocks of the 1970's and specifically for the receipt and pumping of crude oils (API Chapter 8.2). It comprised essentially the experience of "pipeliners" and the then relatively new role of "loss controllers" with not much recognition of the needs of offshore production or product quality sampling.

The API standard based much of its "Table 11" on a series of tests based at the old Mobil Paulsboro' facility and some other testing performed in a meter calibration loop of the, then, Smith Meter in Eyre, Pennsylvania.

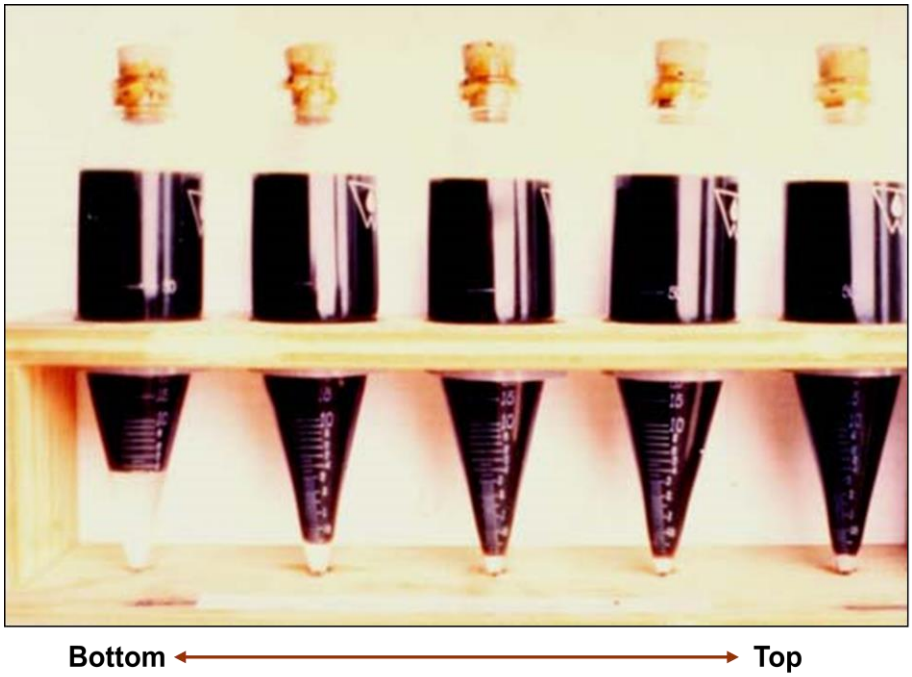


Table 11 — Suggested minimum flow rates versus mixing elements

Mixing element	Piping	Minimum pipeline flow rate, m/s								
		0	0,3	0,6	0,9	1,2	1,5	1,8	2,1	2,4
Power mixing	Horizontal or vertical	Adequate at any flow rate								
Static mixing	Vertical	Stratified	Not predictable	Adequately dispersed						
Static mixing	Horizontal	Stratified		Not predictable		Adequately dispersed				
Piping elements	Vertical	Stratified		Not predictable			Adequately dispersed			
Piping elements	Horizontal	Stratified				Not predictable			Adequately dispersed	
Line	Horizontal or vertical	Stratified or not predictable								See C.2 e)

This table was based upon the testing of a single oil viscosity/density in a limited range of pipelines – it is therefore really only applicable as a very rough guide.

As this was gestated under API, the then IP 6.2 (now EI) and the ISO 3171 were concurrently developing their own standards taking a slightly more guidance based approach and seeking to insert more practical examples of designs (either in use or on the drawing board at the time) and science by way of calculation associated with pipeline mixture quality and recognising ongoing testing then being performed. Real data was used to correlate the calculations based upon profile measurements in a large pipeline.

Most of the committee work concluded in about 1984 and the ISO standard was published in 1988. The design of the optimal sampling systems used today for crude oils appear in the IP document

which in contrast to the ISO and API document also considered to some degree the sampling of higher RVP products, but not "clean" products.

The API was revised in 1995 (and re-confirmed since); key changes included adding the statistical approach of the ISO/IP documents, but also significantly to allow for the use of manifold sampling, component testing and the requirement for two sequential tests to prevent the "ethically challenged" from repeating the overall testing until they got the result they wanted. It also broke out the question of sample handling and mixing (including the containers used for retention into API 8.3 and API 8.4). The largest change of all was the abandonment of a grading system based upon the proving tests in a favour of a single (but still perhaps flawed) pass/fail criteria. (below)

Calculate the ratio

$$\frac{W_{dev}}{W_{inj} + W_{base}}$$

and obtain the rating of the sampling system under the test condition from table 4.

This was the original "graded" acceptance criteria used by the API 1983 version and STILL current for ISO 3171, IP 6.2

Table 4 — Sampling test ratings for injected water concentrations of 1 % and above

Rating	$\frac{W_{dev}}{W_{inj} + W_{base}}$
A	not greater than ± 0,05
B	greater than ± 0,05 but not greater than ± 0,10
C	greater than ± 0,10 but not greater than ± 0,15
D	greater than ± 0,15

Total Water ($W_{bl} + W_{inj}$)	Allowable Deviations	
	Using Tank Gages	Using Metres
0.5	0.13	0.09
1.0	0.15	0.11
1.5	0.16	0.12
2.0	0.17	0.13
2.5	0.18	0.14
3.0	0.19	0.15
3.5	0.20	0.16
4.0	0.21	0.17
4.5	0.22	0.18
5.0	0.23	0.19

This is the current API Pass/fail criteria

The focus of the standard remained stabilised crude oils.

Also in 1995 the Norsok I-SR-100 "Automatic Oil Sampler" was published; essentially a reference to the API and ISO standards.

The API, IP, ISO standards were never designed to address the needs for multi-product pipeline sampling or recognise the many special demands of offshore measurement which included convoluted piping configurations, smaller diameter pipes, high RVP products etc. and indeed the requirements for the measurement of density and on-line water determination (OWD).

This has perplexed those seeking to use the standards, specifically in the area of pipeline mixing when they think they have faithfully applied them only to discover their results do not make sense.

Over the same timescales, many of the onshore and pipeline systems designed under these standards have been tested by water injection with the significant majority passing, but some that failed have done so without explanation. Unfortunately people are reluctant to admit failure and much of that data is immediately lost.

Work continues to revise the API document to recognise the wider application of sampling technology in both process i.e. extending them from stabilized crude oils to un-stabilised and to recognise the sampling of products including those with higher RVP's.

An early objective was that the standards generated may be balloted for adoption by ISO, unfortunately this now looks unlikely.

In the meanwhile the offshore North Sea has long been seeking guidance to improve measurement of un-stabilised oils and to deploy on-Line water determination (OWD) systems.

Sampling Technology

Comprised typically in-line sample probes and low pressure receivers (often stationary), pipeline mixing was often overlooked because Table 11 was the datum and people did not read the small print:

> Table 11 is a useful guide for initial screening of potential sampling locations. It should be noted that this table is based on flow rate and does not take into account such parameters as viscosity, pipe size, density and water concentration any of which may affect the predictions of the table. Therefore, when a potential sampling location has been selected it is recommended that the calculation procedures in annex A should then be used to estimate the adequacy of the water dispersion, and thus confirm or disprove the choice of location.

High RVP was a nuisance that typically resulted in flaring until late in the 1970's when legislation in the North Sea meant it had to be piped ashore so technology was developed to try to properly sample it.

Most systems so designed catered for stabilised crude oils of middle range viscosity and density, not to the extremes now seen in the form of condensates at one end and heavy oils (or even tar sands) at the other.

Density compensation for metering was generally made by using the analysis of the sample so taken and much debate arose about the meaning of "Wet" or Dry" density. Later slipstream loops were created to pass a stream of oil through a duty standby (parallel) arrangement of density meters and this grandfathered practice often continues.

The holy grail of quality measurement, WaterCut meters (or as some still continue to erroneously title them – " B S & W probes") certainly existed as simple capacitance meters and were used as go/no go measurements.

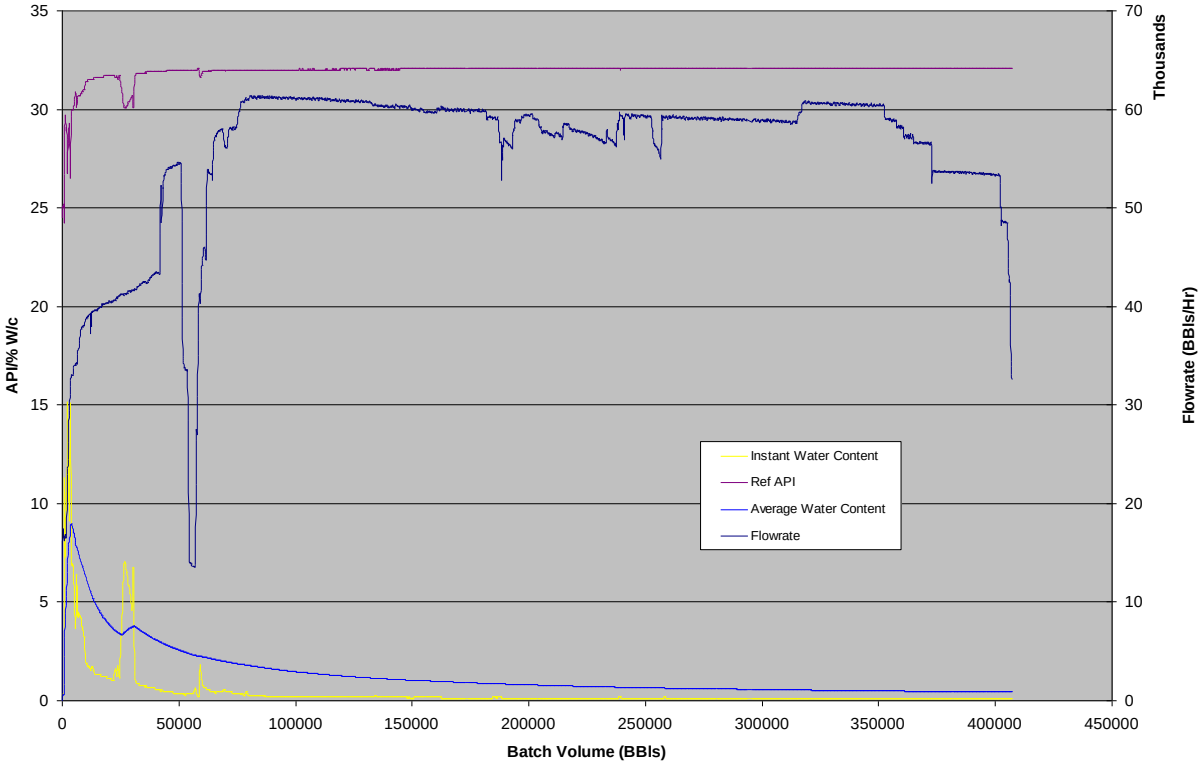
Some local standards also required the sampling system to be upstream of the metering system because the metered volume should NOT include the sample volume removed! (as a result the benefit of mixing induced by strainers, meters, and control valves was lost).

The standards paid little attention to the issues of sample handling and mixing until the release of API 8.3, indeed some specifications still mistakenly call out IP 386 as a reference for sample mixing. This is in fact a Karl Fischer Titration standard!.

Pipelines

Designers must treat sampling systems installed offshore or at the end of a long pipe run that may include elevation changes differently to the sampling of stabilised crude offloaded from a ship (and sampled close to the tanks in which oil has been resident for days).

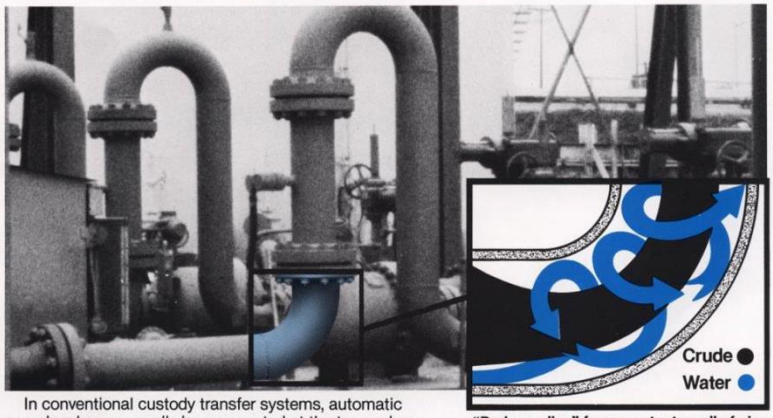
In the best (ship) case the process comprises oil with a small concentration of water that must be adequately mixed into the stream at the point the sample is taken, but in itself this provides challenges. We like to consider that the concentration does not change markedly in the short term and indeed unloading profiles would suggest this. However, this stability will not arise in piping configurations as typically found in a production environment (platform etc.) which are subject to a large number of orientation and elevation changes which are actually "slug" generators!



However we all accept that crude and water do not mix well; separation is inevitable at low velocities in a pipeline and this gets worse with higher difference in density and viscosity (for examples condensates) and higher water concentration.

What we often fail to consider is that a steady input of water concentration even in a horizontal environment creates the potential for significant fluctuation over a length because the water under certain flows will collect into "rolling" slugs. Placing a steady input to a horizontal line followed by an elbow to a riser makes the situation worse, many of you will be aware of the annular, churn or barber polling that render sampling in vertical flow an optimistic proposition unless the flow entering the riser is already well dispersed. The poor droplet sizing and distribution can also be seen in the photograph of a vertical riser on page 10.

Conventional mixing methods are not adequate.



"Barber poling" forces water to wall of pipe

In conventional custody transfer systems, automatic samplers have normally been mounted at the top or down side stream of the mixing loop as shown above. This sampler placement attempts to assure that a homogenous sample of crude and water will be taken approximately every 5 seconds for later analysis and *price adjustments.*

Since the automatic sampling probe projects about four to six inches into the crude oil stream with a small side opening of under one inch to receive the periodic sample of crude and water, it is extremely important that the sample is a truly homogenous blend of uniform droplets of water in the crude at all operating flows.

Right angle or 90° pipe elbows are not good mixers. Laboratory tests with oil and water have proven that at varying velocities the hydrostatic forces created by a right angle (90°) elbow at the bottom of the conventional mixing loop centrifuges a percentage of the heavier water to the wall of the pipe. This internal wall-streaming or barber-poling, illustrated above, allows a percentage of the water to pass the automatic sampler without being detected. The result can be *costly.*

[1]American Petroleum Institute, Manual of Petroleum Measurement Standards; Chapter B Section 2; 1980.

Technology Development

Much of the technology that has been developed has been initiated by industry requirements and best endeavours and the investment in time and effort in testing by individual oil companies in conjunction with their preferred suppliers a process that continues to this day.

JIP's

JIP's in the UK sector (for example NEL), in Norway and elsewhere have run a number of excellent projects to validate the best available technologies. Examples of this would be the NEL "Hi-water" projects dealing with the ability of samplers to meet representivity, the need for "Isokinetic" (actually not – this is more related to droplet size vs. opening) and the current crop of activity focussed to validation of the Annex A.

Mixing

Pierre Hayward and Ari Segev did much theoretical work on pipeline mixing that drove the standards development focussed largely to steady state pipelines.

Vendors proposed a number of static mixer designs, including the use of variable static mixers, turbine mixers and variety of valve types (Swing Checks and the Neles "Q-Ball")

A number of profile tests have been executed to seek to validate steady state flow regimes (….and some accidental tests on unsteady states)

Testing of profiles for low-spot corrosion hotspots in pipelines (Yuri Fairzurov)

What is clear is that the calculations within the current standard are limited in application and because this is not clearly understood they are easily misused.

High RVP

When high RVP crude was first piped ashore from the North Sea two alternate approaches were taken:

- High pressure collection receivers (requiring a constant pressure receiver to be handled offshore, transported mixed and analysed onshore)
- "Split-Phase" Samplers (requiring the sample pressure to be reduced offshore to collect a stabilised oil sample and a low pressure gas sample)

The procedures for mixing high pressure sample collection receivers are *not* defined in any standard.

The migration to sampling at close to vapour breakout renders its own challenges to the sampling beyond the sample collection. Mixing such a stream is a challenge as mixing implies the dissipation of energy either from the process in the form of pressure loss or by external addition. High RVP oil/water mixtures simply cannot afford the creation of pressure loss and the resultant vapour breakout in the form of gas as this will significantly affect the metering system.

It is postulated by some, I believe erroneously, that placing the quality system off-take in a vertical line provides a suitable location for mixing. Certainly in some aspects it is an improvement but such an approach completely forgets the transient nature of the process!

Proving

API 8.2, 1983 proposed a methodology for water injection proving a sampling system using a single test and assigning a grading to the outcome based upon the deviation from the expected result. (the testing method expected the use of Centrifuge or Dean and Stark distillation as Karl Fisher was not widely available.)

The first tests of installations under this draft were made on systems installed at BORCO in the Bahamas and over time more and more systems have been tested with mixed success. Unfortunately it is easier to access successful results than those that failed!

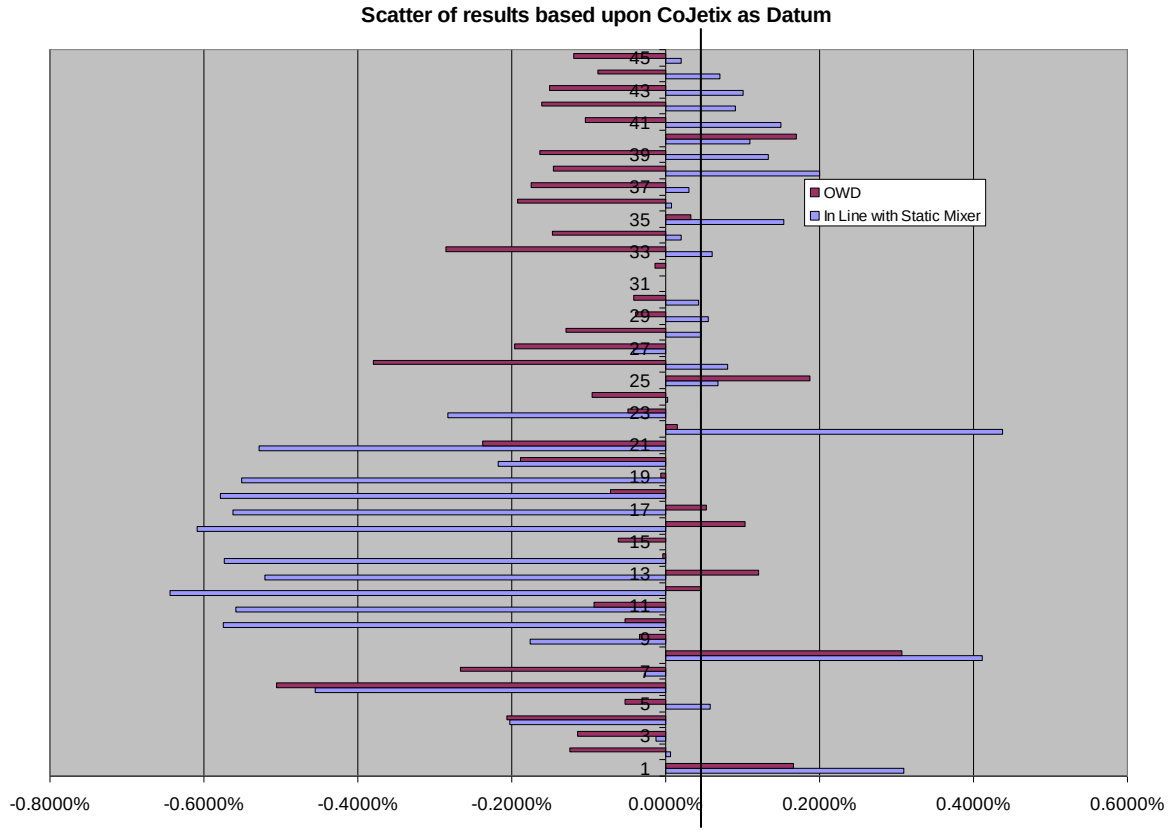
When the API standard was revisited in 1995, the committee concluded that it was statistically impossible to render a meaningful grading system (where "A" – suitable for custody transfer (+/- 0.05% /%) and despite EI provision of a number of tests indicative that it was attainable and desirable, the input was rendered as technically non-persuasive and the standard was changed to a simple pass/fail criteria based upon a negotiated set of wider tolerances based upon whether the oil measurement was by tank gauging or metering. This test had one key highlight of great significance in that it required two sequential tests to be within the acceptable boundaries which precluded those that would test repeatedly until the combination of errors worked in their favour to pass a system! The EI and the ISO standard however retained the tighter tolerances and the graded criteria.

Water injection proving has been carried out now thousands of times, mainly on loading, unloading, pipeline and allocation based samplers and generally on stabilised oils. This is because it is significantly easier to control the stability of the baselines and to perform sample handling and analysis. These results can be used to validate that the mixing, handling and analysis meet the acceptance criteria for the COMPLETE system. It does not seek to differentiate error sources as the result is a cumulative one.

One other issue the API did seek to address was the idea of "component testing". Both the API and the ISO/EI standard always allowed for the testing of pipeline profile using a profile probe and this remains a useful tool with some limitations to use. The API also allows for the design of a system to be ported without further testing between applications, provided that the installation and process is identical (a rare idea!).

OWD

Simple capacitance probes have been used for years to control whether "oil" quality was adequately processed to be used, but they have at best been a trending device. Several attempts to improve the technology were made by use of additional calibration inputs (typically density, temperature) and the current generation of these devices have more sophisticated electronics but suffer many of the same problems. The design of sensors using microwave frequencies provide an overall improvement to the result but there remain unknowns in the process that continue to preclude them being accepted for fiscal use. The API spent considerable time and effort in the collection of field data and then in drafting a standard which ultimately failed to gain acceptance because there was insufficient validating information; it was ultimately published as a technical report. The scatter below of a calibrated system shows the OWD results are well outside the expected +/- 0.05%



Density

On-line Density meters were initially installed in bypass loops either pumped or driven by differential pressure from an orifice plate or sometimes a simple forward facing takeoff probe. Often no recognition was made that the standard requires that the off-take be "representative". A good designer now recognises that the density metering off-take MUST match that used for sampling and it makes logical sense to integrate the density, sampling and OWD in a single system subject to the same design constraints.

Although the current density standard proposes that the two density meters be mounted in parallel, there is limited logic to this approach. Suppliers typically recommend that the density meter be mounted vertically; with the flow upwards and in excess of 3 m3/hr (to mitigate effects of entrained gas/bubbles). Mounting them in parallel requires that the overall loop flow rate be higher and that provision is made to ensure that the flow stream is fully homogenous before division.

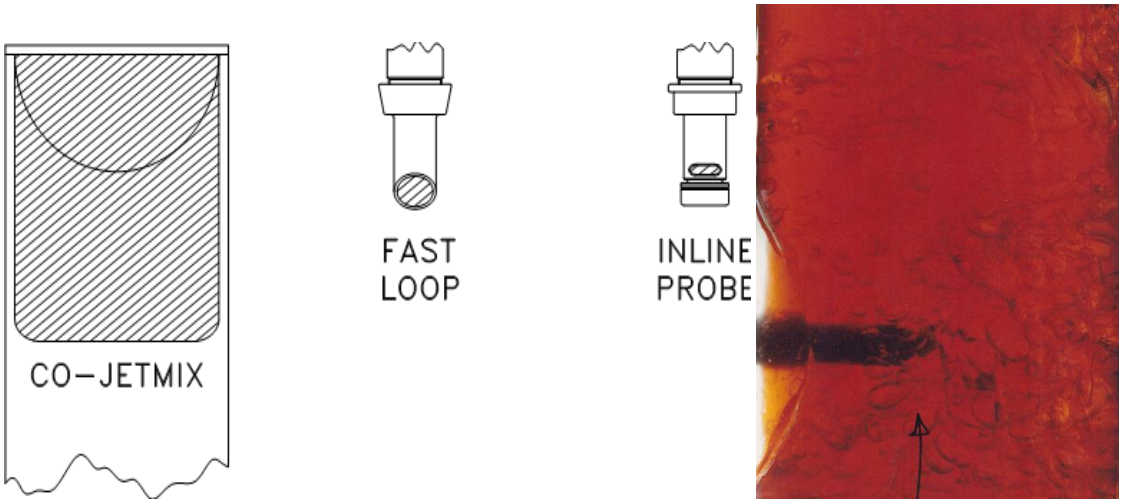
Ideally if two density meters are to be used for "run and check" they should best be mounted in series.

Parallel run density meters are typical, but they should not be.

Isokinetic

The API has little guidance on the design and implementation of loops in which the sample extractor is mounted externally to the pipeline, it currently defines "Isokinetic" as of "matching velocity between the pipeline and the inlet to the sampler", this was relaxed to suggest that provided that velocities match between 50-200%. Neither of these statements was based on testing. The IP did some field testing and in that standard suggested that as the opening of the sampler gets larger in comparison to the droplet size, 10-300% velocity matching appeared to be of little influence.

In practice we have found that the larger the entry the better, though certainly any opening over 11/4" (33mm) does not seem to be influenced from a variance between the process pipeline velocity and the sample inlet velocity in a properly mixed pipeline.



There is a relationship between droplet size and the capability of a sample off-take to handle it. The photo to the right shows a vertical riser oil/water mix and clearly the droplet sizes are large and poorly distributed – the probe seen is unable to sample representatively.

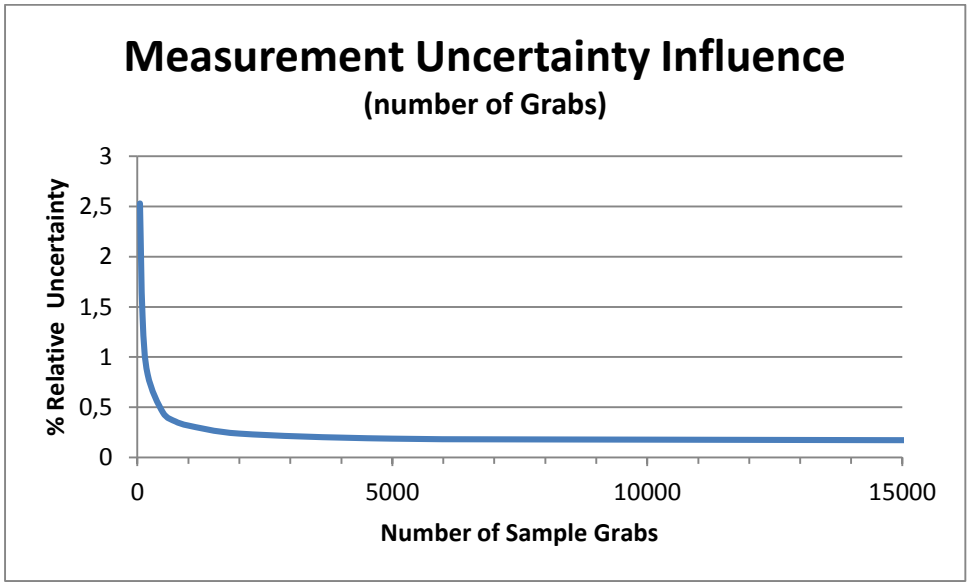
From our direct experience we would contend that "Isokinetic" sampling is undesirable in properly designed sampling loops for a number of reasons,

1. Proven accuracy of well designed sampling systems using fixed velocity "loop" technology at larger inlet sizes.
2. Water can fall out within the sampling loop if a true Isokinetic flow regime is created at the inlet as the flow range changes perhaps by factors of up to 30:1. This will certainly make the imbalance between parallel mounted density meters or samplers more extreme that is found even today.
3. Low flow velocities create water fallout and where there are directional and orientation changes, will create a more "sluggy" flow regime, hence potentially reducing sample representativity.

Uncertainty

The ISO provides a statistical method to calculate uncertainty based upon a number of influential parameters, frequently misunderstood.

It is evident that dispersion/distribution quality is the single largest influence on the result but grab size repeatability, the number of samples taken per batch, the number of repeat analyses are also important. In getting to an overall result (on paper) the issue of mixing and subdivision of the sample and indeed the number of analysis results and how they should be handled is more often than not ignored.



We have seen companies taking a sample and repeatedly analysing it until they got the "best" number they could! The uncertainty calculation shows that averaging two lab analyses will improve uncertainty by 0.01% (20% of the allowable error under ISO at a nominal 1% water.)

The standards propose that the number of grabs should relate to the batch volume, it is clear that if the process is subject to transient flow, then a higher grab count should improve representivity. However it is also clear that the graph above would suggest that over a certain number of samples, there is not a significant improvement in uncertainty with grab count. In this example the threshold appears to be about 2,000 and even when a large sample is easy to collect (i.e. low RVP samples) anything over a maximum of 10,000 samples unlikely to yield a significant improvement. The practice in small leases of collecting and processing 30 gallons (over 100,000 ml) would seem counter-intuitive because the mixing, handling and sub-sampling (not to mention disposal, cross contamination, cleaning etc.) would surely increase uncertainty.

One interesting observation and one that causes some debate is the use of the phrase "Systematic uncertainty" or bias. In the process of proving many sampling systems, which requires two sequential tests under API (and which we also do even when proving under ISO) it has become evident that for some system designs both of the results will be within the negative tolerance bands and therefore the averaged result is almost always negative.

A study of this has led us to conclude that many sampling systems exhibit a negative bias, which if compared to a metering system it could be 'tuned out', unfortunately with a sampling system this is a physical manifestation that we cannot simply magic away with a "K-factor". It is also clear that some sampling system designs show no such bias.

Pipeline Mixing

The standard includes a calculation methodology for mixing which has significant provisos on its range of application. It requires the assumption that the water concentration is at all times below 5%, that the flow is steady state, that the pipeline is essentially a long horizontal pipe with no transients and that viscosity and density are within a tight range.

Since these calculations were based upon large pipelines, there is some debate as to how they work on smaller pipelines. It is unsurprising then that many people are looking to CFD for answers.

Our company has been seeking to use CFD for assessing pipeline mixing for many years and certainly with the improvement in computing power and the sophistication of cell based meshing it has progressed significantly. Since we joined Cameron we have been lucky to have access to these tools and qualified scientists to run them. We have spent considerable efforts in comparison of CFD models to the calculations within the standards and we have discovered that it is all too easy to convince yourself that the answers you see are right, simply because they look convincing - a minor change to an input parameter can make a significant change to a result that perhaps only yesterday you believed to be true! We like to think that CFD can account accurately for the complete process but decisions not only on the configuration, mesh sizes, time cycles, inlet properties, length, droplet size and distributions, coalescence etc. etc. etc all add complexity to the model and time. A simple 10 seconds of flow simulation (which is rarely enough to create stability) for can take many hours of processing time!

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As an example of the challenge we are sharing three practical comparisons:

- The profile data within the API standard,
- A system where the JetMix in a conventional installation was upgraded after many years' service.
- A JetMix installed in large pipeline around elbows and vertical risers.

Case Study 1

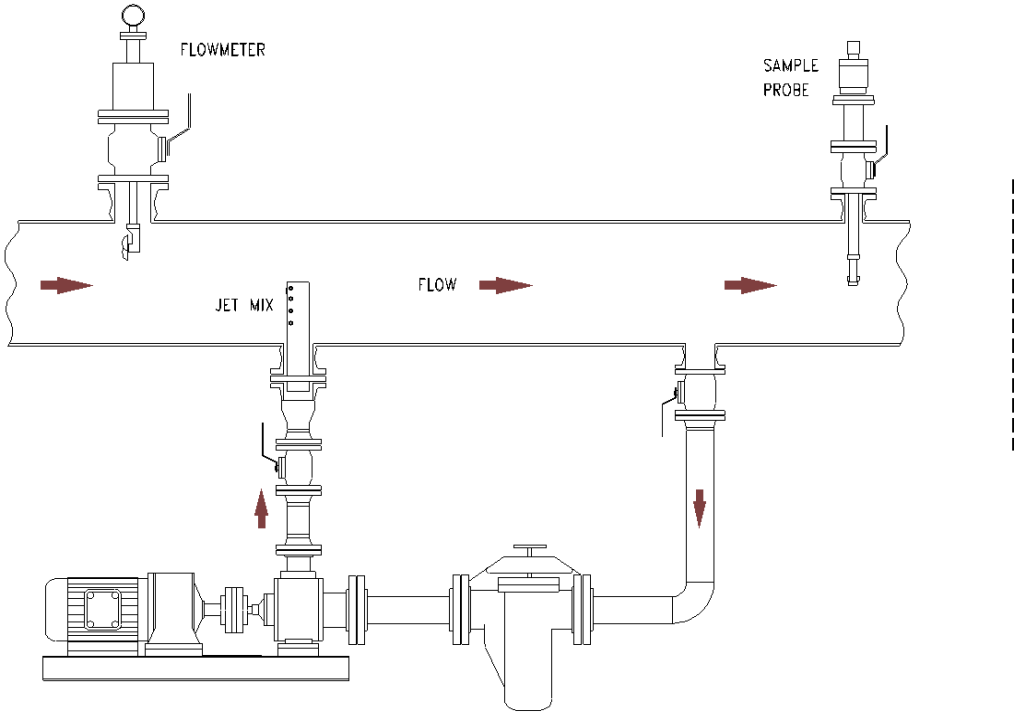
API made a number of profile tests with a multipoint probe. We would define these profiles as "REAL" and they are repeated within the ISO 3171. A CFD estimates "local" values in the profile free of the influence of the offtake profile probe, sample collection errors and analysis errors, that said the trend should be easily comparable.

	ISO 3171 - Page 52	CFD Simulation-1	ISO 3171 - Page 52	CFD Simulation-2	ISO 3171 - Page 52	CFD Simulation-3	ISO 3171 - Page 53	CFD Simulation-4	ISO 3171 - Page 53	CFD Simulation-5
Velocity (m/s)	1.84		1.84		1.84		2.38		2.38	
Water Injection %	3.1		5.17		7.24		3.2		5.11	
Point A	3.6	2.9	4.6	4.654	5.3	6.2	3.4	3	5	4.73
Point-B	3.4	3.09	5	5.166	5.7	7.22	2.9	3.19	5.3	5.107
Point-C	3.8	3.1	5.4	5.17	6.1	7.24	3.4	3.2	5.4	5.11
Point-D	3.2	3.1	5.3	5.17	6.6	7.24	3	3.2	5.4	5.11
Point-E	3.8	3.09	5.9	5.169	6.7	7.24	3.4	3.19	5.5	5.109
Point-F	3.4	3.09	5.7	5.169	7	7.23	3.2	3.19	5.8	5.109
Point-G	3.8	3.09	5.9	5.169	6.8	7.23	3.6	3.19	5.6	5.109
Point-H	4.4	3.37	6.4	6.275	7.2	7.9	3.6	3.48	6.2	5.8

But looking at the results, the CFD data does not match within the expected tolerance to the field data! This could be influenced by a multitude of choices made by the modeller – what it is imperative to understand is that it is therefore critical that methods are established to calibrate CFD method with other data sets to enable us to better understand how we can use CCFD^{tm} (Calibrated CFD) with confidence.

Case Study 2 (Jet Update1)

A major crude oil Terminal that imports 1.7 MBPD (300,000 m3/day) had a Mk1 JetMix system with and in-line probe installed in the late 80's in the main incoming offshore feed pipeline.



This sampling system was successfully (meeting the acceptance criteria) and repeatedly certified to the API 8.2 standard yielding an average uncertainty of -0.13% (note the negative systematic bias)

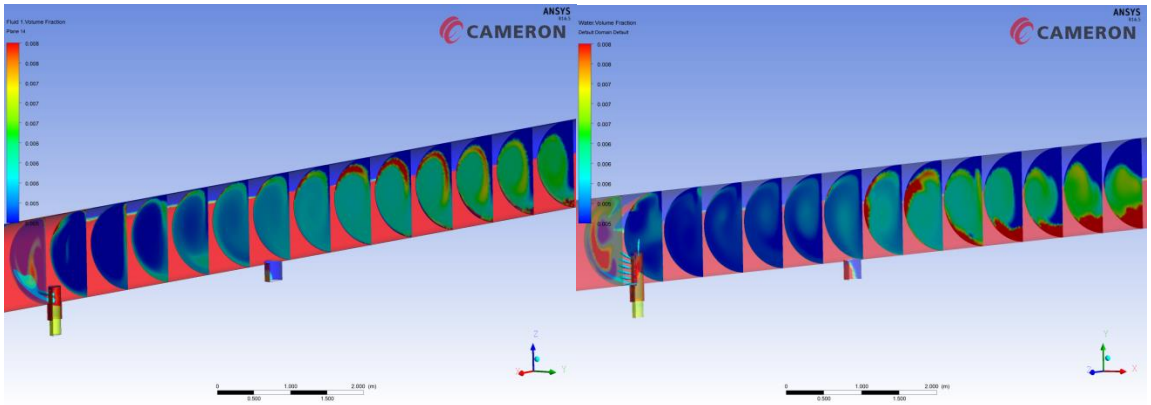
The customer wished to see if the uncertainty could be improved. The original JetMix system had 4 large perpendicular jets; it was redesigned with a new Jet head design similar to the photo using our latest calculations and design methodology. Because no changes were made to either the pump used for the mixer or to the rest of the sample collection, handling or analysis equipment (or methods) this enabled us to understand the influence of the design changes to the Jet Head. It also allowed us to witness any erosive or scaling effects on the Jet Head.

Original Jet as removed and new Jet type.

The system was retested using the new Jet head but under the same, worst case, operating conditions. The results were impressive; following the exact prediction of the CCFD, the API

certification test came in at -0.03% uncertainty. This resulted in improvement to the customer's bottom line measurement uncertainty of $136,000 per day. As an aside after over 25 years of daily service there was no evidence of significant scaling or erosion to the original part.

CFD Modelling shows the difference between the two designs



Case Study 3 (Static Mixer update)

Another site had an installed 48" static mixer which due to the rangeability was generating good mixing at high flowrates but damaging equipment due to high vibration. At low flowrates it was clear that the mixing was inadequate. They pondered if a JetMix design could be used, but consideration was compounded by the installation configuration which was in a short length of pipe around a number of "out of plane" elbows – a situation frequently seen in North Sea applications (but of course significantly smaller pipes than 48"!). A conventional jet had been installed in a vertical rising section but after initial testing it was felt the results, though better than the Static Mixer, could be improved. Observations from a sidewall mounted density offtake loop led us to conclude that the water was "poling" around the elbows and missing the highest turbulence zone of the Jet head. As a result we redesigned the head to change the energy intense zone and successfully proved the system.

Many of you will have heard us speak of other similar experiences where the physical performance did not match either a conventional model or one generated using un-calibrated CFD technologies, indeed at a transient complex flow consortia meeting a delegate complained as to when the "C" in CFD would mean CREDIBLE.

CFD can provide useful insights into the potential "influencers" to the result, but they cannot provide an absolute estimate of the result unless they are calibrated. Some proponents with no supporting field data confidently state they can halve the amount of energy required to mix a pipeline! Again we suggest that inexplicable failures are more expensive than conservative and field proven success.

The capability to calibrate or normalise CFD can only be attained with the collection and comparison of significant volumes of practical field data across a wide range of pipeline sizes, oil types and flow ranges . We call this CCFD^{tm} or Calibrated CFD. We are blessed to own such a data set, admittedly largely forged in success, but tempered by the occasional failure.

Proving

The water injection proving of a sampling system is the catchall method, similar to the ongoing proving of a metering system, except a sampling system *cannot* currently be proven during each batch process whereas a metering system can.

Proving a sampling system should exercise ***all*** the contributors to the uncertainty of the measurement system, unfortunately some testers use the overall tolerance allowance in comparison to a limited testing of the system, not recognising that one or more sources of uncertainty have been eliminated with no recognition of their influence to the result. A sampling system is intended to render a result on a piece of paper and therefore all the steps to the written results can be influential to the error.

- Pipeline mixing dispersion/distribution.
- Sample extractor.
- Sample collection receiver.
- Sample receiver mixing and sub-sample withdrawal.
- Number of sample results used, sample analysis method.

Two questions are debated with regard to proving, the first being the process conditions under which a proving takes place. Received wisdom suggests that we should select what we believe to be the minimum flow rate, minimum viscosity and minimum density but in truth the worst conditions for one design of sampling system may not be the worst for another!

The second is proving frequency and this must clearly be a function of risk and opportunity. Proving a sampling system is expensive; it requires a stable baseline and this may simply be impractical in the transient regimes often typically found in a production environment. Even when the system is capable of being subject to a stable regime to allow proving, how frequently should it be performed? Some have suggested every 5 years is mandated, my view would be when the process has changed significantly (for the worse) or the mechanical performance of the system is known to have changed.

While certainly in the past the highest risk and hardest application for a sampling system was unloading ships through large diameter pipelines, other processes are in their own way equally demanding.

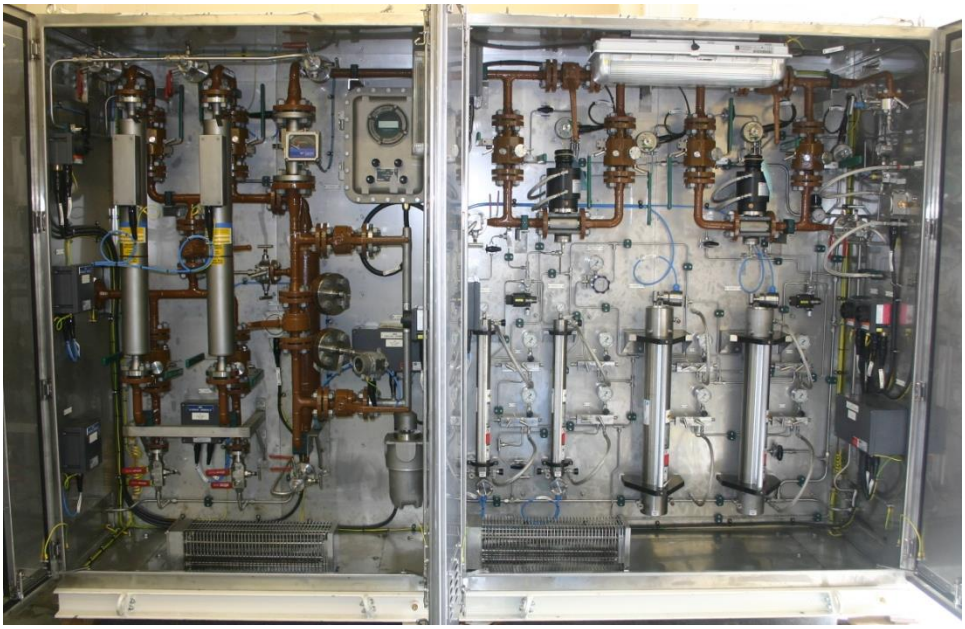
Sampling at the outlet of a separator provides a flow stream potentially rich in free water where any change in pressure used to promote mixing will cause gas breakout.

Many production sources now have higher water concentrations, higher sand and even more corrosive properties. In light service a sampler can easily surpass a million grabs, but the bituminous crude oils derived from tar sands have caused the creation of expensive severe duty samplers using enhanced metallurgy, coatings and seals which can multiply the expected life by several orders of magnitude.

The first universally used sampler was made by Clif Mock, ironically when Jiskoot was acquired by Cameron in 2008 this sampler was returned to our portfolio and still sells well, but meanwhile

Jiskoot has progressed from the loop samplers we manufactured in the 1970's through in-line samplers and Jet Mixers in the 1980's to the sophistication of the CoJetix designs that we now use.

There is a place for all of these technologies including CFD, but it takes considerable skill and field experience to apply them correctly.



A typical quality system for use on high RVP oils including cell samplers, CPC receivers, density meters, OWD. (Part of a CoJetix system)