Introduction

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 developing the standards used to define them both then and now, we can discuss the foundations for current designs and point to the future.

The paper will discuss the standards and the designs used for sampling, density and water in-oil measurement for all applications including arduous and severe duty configurations both onshore and offshore. It will also cover the use of CFD and some of its current limitations.

Do the Standards need to be re-written?

The original need for better sampling standards in the early 1980's was driven by the oil shocks of the 1970's 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.

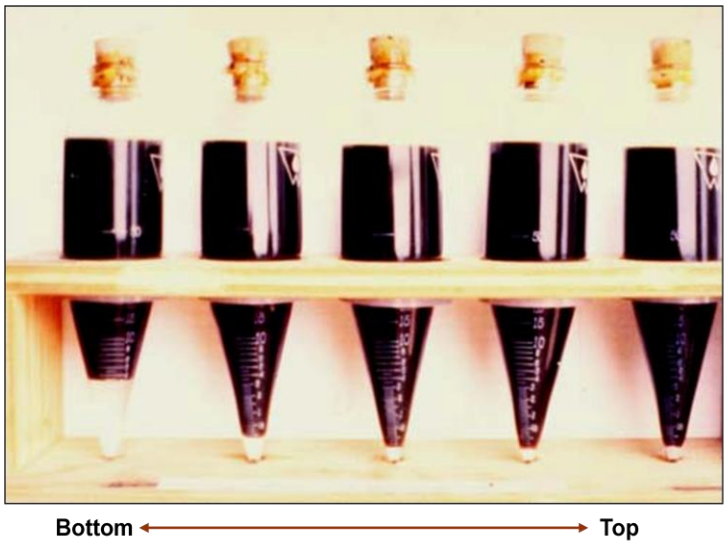


Table 11 — Suggested minimum flow rates versus mixing elements

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 in 2000) and key changes included the statistical approach of the ISO/IP documents , but also significant changes 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)) But 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 has been ongoing to revise the API/EI 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. There is a current draft in circulation to be discussed at the Fall API meeting this month.

The eventual objective is that the standard so generated may be balloted for adoption by ISO.

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 35 years ago…

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 and technology to try and sample it was developed.

Most systems 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.

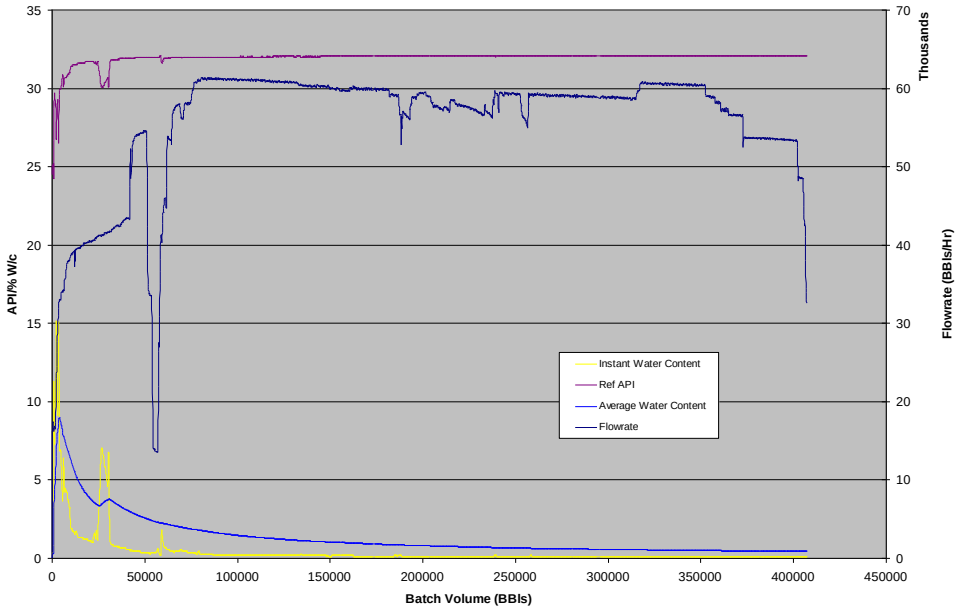
Some local standards also required the sampling system to be upstream of the metering system because the metered volume should NOT include the sample volume removed! (as a result the benefit of mixing induced by strainers, meters, and control valves was lost).

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

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

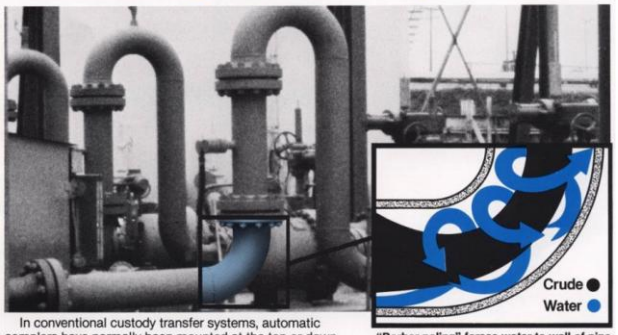
In the best case the process comprises oil with a small concentration of water that must be adequately mixed into the stream at the point the sample is taken, but in itself this provides challenges. We like to consider that the concentration does not change markedly in the short term and indeed unloading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



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.

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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 then 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!

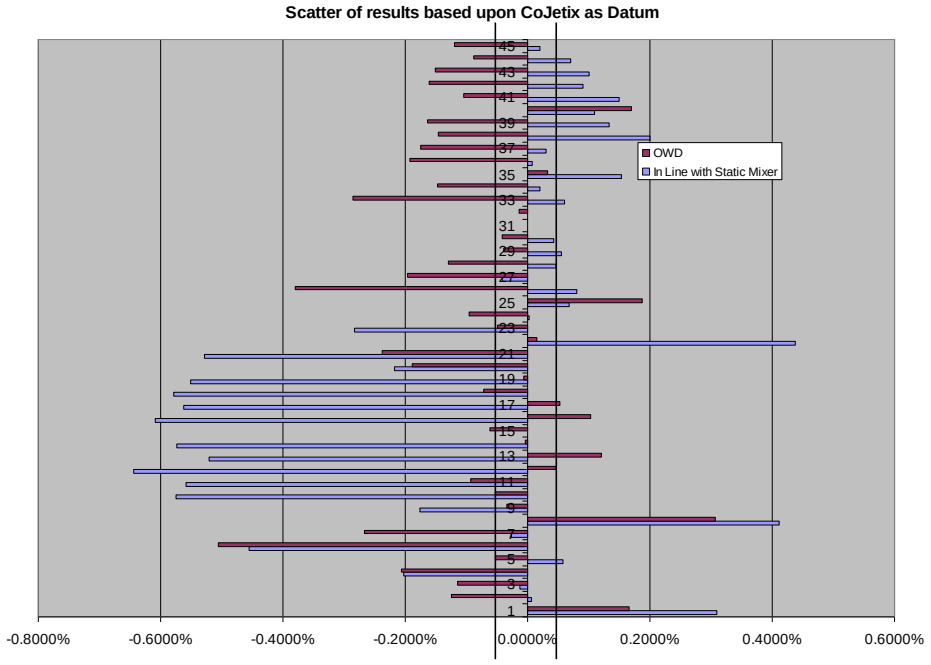
When the API standard was revisited in 1995, the committee concluded that it was statistically impossible to render a meaningful grading system (where "A" – suitable for custody transfer (+/- 0.05% /%) and despite EI provision of a number of tests indicative that it was attainable and desirable, the 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 could be pumped but they have at best been a trending device. Several attempts to improve the technology were made by use of calibration 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 despite the standard requiring that the off-take be “representative”, whereas 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 recommend that the density meter be mounted vertically with the flow upwards and in excess of 3 m3/hr. 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.

Gaps in the standards

Updates to the API/EI standard come under the following proposed headings:

A General Section that outlines the main requirements for sampling

A Crude Section (self evidently for Crude oil sampling both stabilised and un-stabilised)

A Products Section.

In the section on crude sampling the following challenges are to be adequately addressed:

- Sampling System Position
- Pipeline Mixing – specifically better modelling
- Sample Handling – the collection receivers and re-mixing for removal of an analysis sample
- Proving – acceptable methods and uncertainty for proving.

Within the Products Section

Pipeline Mixing is usually not relevant as these products should be cross-sectionally homogeneous (water free) although some debate remains about bio-fuels)

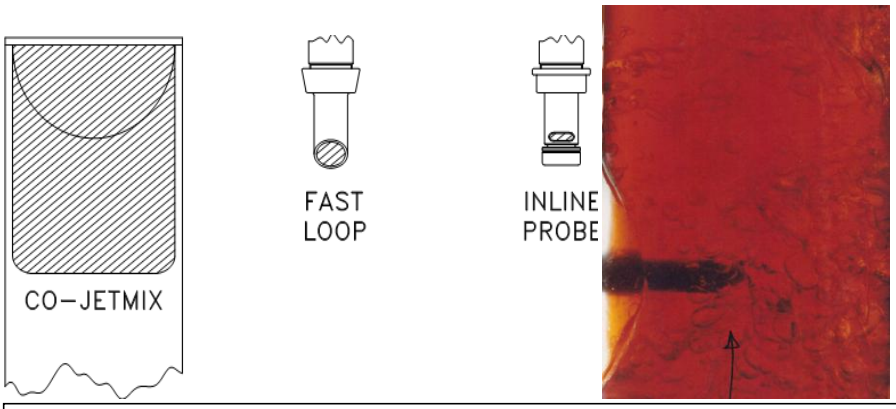
The primary issues to Product sampling are :

- Intra-batch contamination
- Maintaining the integrity of high RVP samples, and the ability to process samples quickly!

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 equal velocity between the pipeline velocity and the inlet to the sampler, this is relaxed to suggest that provided the velocities match between 50-200%, this should be suitable. Neither of these statements were based on testing. The IP standard suggests that as the opening of the sampler gets larger in comparison to the droplet size, 10-300% is acceptable based upon field trials.

In practice we have found that the larger the entry the better, though certainly any opening over 1 1/4" (33mm) does not seem to have 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.

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 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.

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 now 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 (this contradicts the steady state at low velocities!) with no transients and that viscosity and density are within reasonable ranges.

Being based upon large pipelines, there is some debate as to how this can work on smaller pipelines and there is little recognition allowed for the modelling of small pipelines with short sections with horizontal and vertical runs. It is unsurprising then that many people are looking to CFD and that there is an NEL JIP on this topic.

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 API/ISO/IP 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 for can take many hours of processing time!

The use of 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.

One study that we can share with you are initial studies of the REAL profile data calculations in the ISO 3171. Of course it is worth remembering that the CFD program estimates local values whereas the field data includes the influence of the offtake profile probe, sample collection errors and analysis errors.

	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

Clearly the CFD data does not match within the expected tolerance to the field data! It is therefore critical that methods are used to calibrate CFD method with other data sets to enable us to better understand how we can use CCFD^{tm} (Calibrated CFD) with confidence.

Sample Handling and Mixing

A further surprising oversight is in the need to provide guidance for the collection, handling, mixing and withdrawal for analysis of high RVP samples.

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)