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Uncertainties in Pipeline Water Percentage Measurement

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Abstract

Measurement of the quantity, density, average temperature and water percentage in petroleum pipelines has been an issue of prime importance. The methods of measurement have been investigated and have seen continued improvement over the years. Questions are being asked as to the reliability of the measurement of water in the oil through sampling systems originally designed and tested for a narrow range of densities. Today most facilities sampling systems handle vastly increased ranges of density and types of crude oils. Issues of pipeline integrity, product loss and production balances are placing further demands on the issues of accurate measurement. Water percentage is one area that has not received the attention necessary to understand the many factors involved in making a reliable measurement.

A previous paper[1] discussed the issues of uncertainty of the measurement from a statistical perspective. This paper will outline many of the issues of where the errors lie in the manual and automatic methods in use today. A routine to use the data collected by the analyzers in the on line system for validation of the measurements will be described.

Introduction

Composite samplers have been used as the standard by which water content is determined in pipelines. Losses and gains between tankage and pipeline, marine unloading and shore may reflect an acceptable mean value but is the system within acceptable control limits? Results for composite samplers are only available at the end of a batch and there is no recourse if something goes wrong with the sampling system during the batch. At the end of the batch only a single number is available to argue about the water delivered. The exposure of personnel to hazardous liquids and the errors associated with processing the samples are additional issues. On line real time analysis of the water content can be obtained with analyzers on the market today. Real time data makes it possible to know when the water arrived providing several beneficial operational advantages. Knowledge of when the water arrives and the magnitude provides an opportunity to do something with the water before it hits the pipeline or tankage. The real time data can show if the water was several short periods of time or if it was across the entire load. In addition, real time analyzers can be used as a comparison of the validity of the composite samplers, something not done until recently.

Originally pipelines only shipped products with a narrow range of densities and due to this fact composite samplers only required testing against one density of oil. Today pipelines ship products with extremely large variation in density and molecular chemistry but the older methods of validation are still in place using one or two densities. Samplers are typically proved on one type of product with the assumption that it is valid for all densities and types. Original API methods suggested testing on the lightest density oil. If the oil becomes heavy, cold and very viscous does the sampler provide the same acceptable deviation from acceptance tests? There are many more issues and questions which must be asked to determine the overall system performance.

The better a process can be understood and the errors controlled the easier it is to assure a good measurement. Each process will be analyzed for the potential errors and their sources. Finally, a new analysis routine will be investigated to compare the on line measurements.

1 – Uncertainty

The petroleum industry generates and uses volumes of data used to buy, sell and balance production. Unfortunately, the documentation with this data typically does not contain statements of uncertainty. Decisions about expectations and corrective actions cannot be made without a statement of uncertainty typically expressed as a standard deviation from a mean value. The standard deviation can only be obtained through taking enough data that can then be used to generate the statistical comparisons against some other method. If there is no other standard to compare against then the uncertainty cannot be obtained. There have been statements about loading losses by crude types and losses for load and receipt terminals but are these statements qualified for all of the contributing factors?

If one composite sample is obtained and laboratory methods performed with two different analysis techniques, what does the uncertainty analysis represent? The composite sample container, Sample 1, is mixed then a sample pulled that is Sample 2. Now the laboratory takes this Sample 2 and pulls two more samples one for titration, Sample 3, and another for distillation Sample 4. This results in a statistical analysis determining the uncertainty between the two laboratory methods and the ability to pull the Samples 3 & 4 from Sample 2. Therefore, if the sample itself is processed using two independent laboratory methods this routine will only check the uncertainties of the two laboratory methods and the operator’s ability to pull a sample from the larger composite sample. Nothing can be said about the uncertainty of the actual in line measurement because the sample into the composite sampler has nothing for comparison.

If API Chapter 8.2 is followed to prove the composite system, the allowable deviation for 1% level of water in a batch is 0.11% and for under 0.5% water the allowable is 0.09%. These numbers are relational to the testing of the composite system by water injection. If the system has been tested on several crude types it is likely that they do not represent the entire spectrum of crude types being shipped through the system after the testing was completed. Therefore, the results may or may not fall in the allowable deviation seen during the injection water testing. Therefore the remaining question is how can the measurement be validated not only across crude types but also for every batch shipped?

Can anything be said about accuracy of the measurement? Accuracy must be compared against a known standard. There does not exist a standard by which to measure the water in the crude oil that is flowing with a specific chemical structure, density, temperature, pressure, viscosity and water content equal to what is in the line. The best that can be done is to qualify a system against an independent measurement for the validity of measurement uncertainty, not accuracy. Independent means that it is not dependent upon the same sample or method of measurement.

If an on line analyzer is installed in a separate fast loop or in line then this is independent of the sampling mechanics of the composite system. This analyzer can be used to aid in arriving at the uncertainty of the measurement when using the composite system. The analyzer should be located in a position that is viewing the main liquid stream in the same homogeneous state as the mechanical sampler. If both methods are reproducible then the resulting uncertainty analysis will be meaningful and one can be used to aid in validation of the other.

2 – Discussion of Data for a Pipeline

The following data in Table 1 was collected by the operators and entered manually into a worksheet and is representative of many types of data collection in the field. The unusual aspect of this table was that it contains several laboratory methods (Karl Fisher and centrifuge) instead of the usual one lab method and the density was quite consistent through the entire month of data.

The data is from a composite sampler on a pipeline across a month where all of the data was obtained with one operator using a laboratory that followed API standards closely. The real time water analyzer was installed after the static mixer and sampling system. The results are shown in Figure 1. The dotted lines represent the best-fit line through the data. In this case the on line analyzer compared favorably with the composite by titration but composite by centrifuge shows the water much lower. More data may change the analyzer trend line to fall more correctly without a skewed slope against the titration. Another question this trend may ask is if the titration is biased at higher water percentages. One centrifuge point (batch 66) which appeared to be a bad data point was correct with respect to titration. Possibly this was an error in the entry of the centrifuge result or some operator influence, as it would be expected to follow

Table 1. Hand Entered Batch Data

Date	Batch #	Analyzer %Water	KF %Water	Grind Out %Water	Avg.Batch Density	API at 60	Obs.Grav.	Obs.Temp	(BBLs)
4/1/2003	52	0.17	0.40	0.20	0.8575	32.2	33.3	75	197931
4/4/2003	55	1.27	1.14	0.60	0.8567	32.1	32.0	58	115454
4/6/2003	56	0.45	0.39	0.15	0.8559	32.2	32.1	58	78690
4/9/2003	57	0.17	0.37	0.10	0.8548	32.4	33.3	72	196547
4/10/2003	58	0.10	0.24	0.10	0.8571	32.1	33.0	72	78624
4/12/2003	59	0.12	0.23	0.10	0.8564	32.1	33.1	74	182087
4/14/2003	60	0.24	0.22	0.10	0.8552	32.0	33.0	74	78626
4/16/2003	61	0.23	0.21	0.10	0.8538	32.2	33.2	73	197371
4/17/2003	62	0.26	0.30	0.10	0.8565	31.7	33.0	78	78733
4/20/2003	63	0.40	0.40	0.10	0.8500	33.0	33.2	63	183877
4/23/2003	65	1.03	0.85	0.50	0.8507	32.8	32.9	62	78546
4/25/2003	66	0.67	0.67	0.70	0.8548	31.7	33.4	83	65583
4/27/2003	67	0.69	0.60	0.30	0.8541	32.1	33.6	80	130832
4/29/2003	68	0.40	0.50	0.25	0.8548	31.9	33.4	80	120000
									1782901

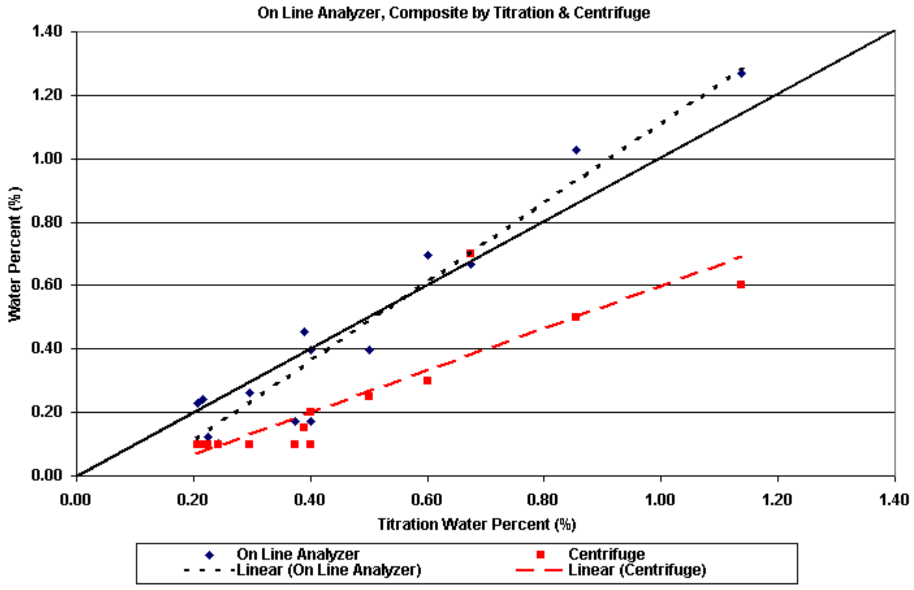


Figure 1. Water Percentage Analyzer & Centrifuge vs Titration

the same trend as the other centrifuge points.

Another aspect of this data is seen when the trend lines are compared with the least error line that is a 45 degree line between the two graph end points. The centrifuge versus the titration is showing the centrifuge consistently low while the comparison with the on line analyzer shows titration slightly less in water than expected. Normally centrifuge is expected to produce a lower water percentage than titration. Since all of the data consisted of moderate crude density and viscosity the centrifuge results would have been expected to be closer to the same water result as the titration.

3 – Ship Unloading Data

The following examples were from an on line analyzer and a composite sampler using titration as the laboratory method. All of the data collection was by computer with checks for the composite sampler built into the data collection.

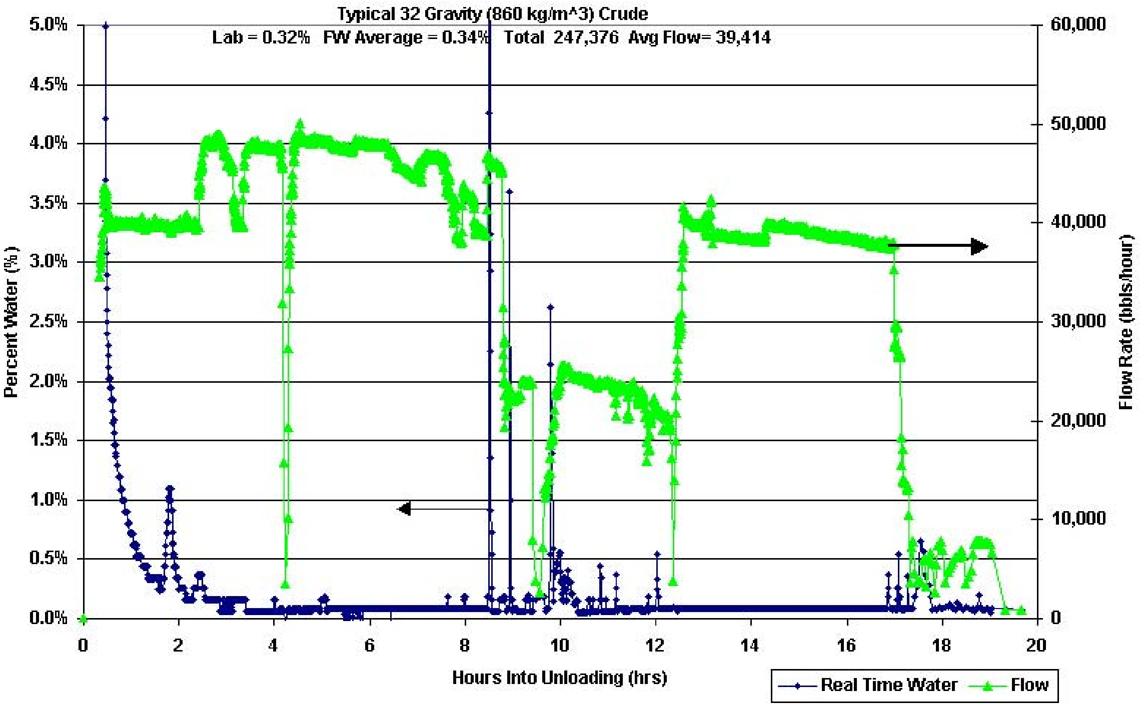


Figure 2. Medium Crude Density Ship Unloading Profile

In the ship unloading profile of Figure 2 the flow started and stopped, ran at one half the rate for several hours and had some very large water spikes. The results from the composite sampler were 0.32% water using titration and the flow weighted average from the on line water analyzer gave 0.34%. Very good results with the lab compared to the on line analyzer with the standard density crude oil. What happens when the same facility receives a higher density and viscous oil?

Figure 3 is a graph for a ship unloading profile for a 21 degree API density crude oil. Now the laboratory results from the composite sampler are much higher than the on line analyzer. Which one is correct? This question would not be asked without the on line analyzer for comparison. The composite sampler was not tested against this heavy crude.

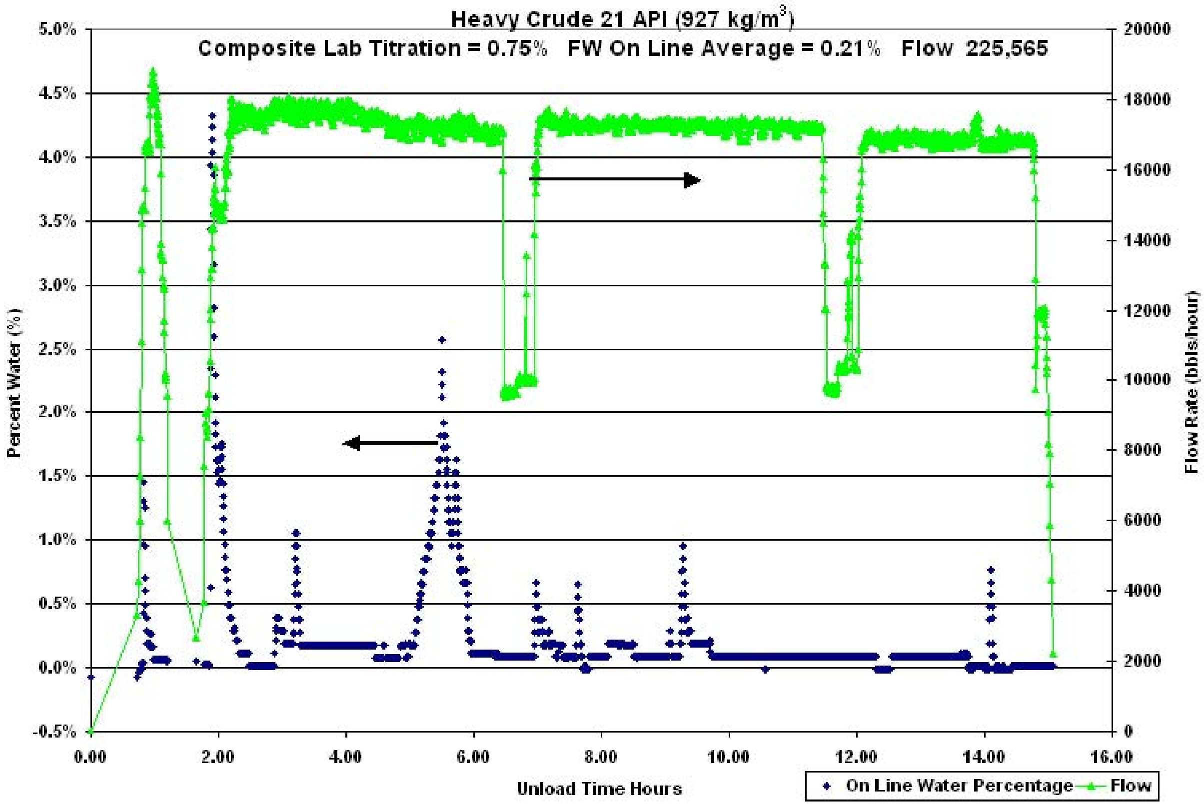


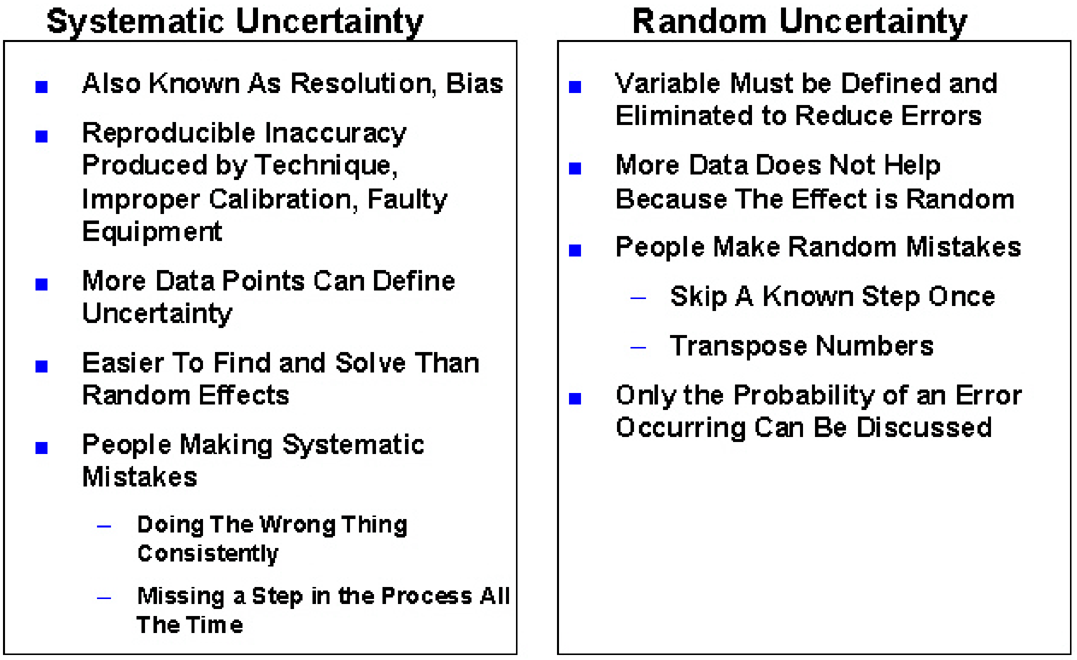
Figure 3. Heavy Crude Oil Ship Unloading Profile

The measurement of density affects the offset calculated for the on line water analyzer baseline and defines where zero water percentage is with respect to density. Was it simply an offset calculation problem or a density measurement issue? Did the sampler have trouble with the higher viscosity of this crude oil? Was there bias in handling the heavy, cold crude oil in the laboratory? Was there a chemical interference with the titration from some component in the crude oil? Although the chemical interference was suspected and partially proven, no answers to these questions were acceptable with enough certainty to be accepted as true. The composite sampler was correct because it was the standard.

4 – Uncertainty Components

In the petroleum industry the measurement of water cut using centrifuge could have the following uncertainty components (not all inclusive): sample probe location in the main pipeline (center 1/3, wall, top, bottom), sample probe size, valve type and size, upstream conditioning (mixer, elbow, two elbows), flow rate in main line, flow rate in sample probe, difference in pressure between line and atmosphere, temperature differences between ambient and liquid, sample container material, size and type of seal for lid, volume of sample, time before processing sample, mixing of sample before extraction to centrifuge tube, solvent type used, de-emulsifier type, temperature of centrifuge, oil type and viscosity, type of centrifuge tube, operator reading the meniscus, solids content, and clarity of the water.

Table 2 is a partial description of what may define systematic and random uncertainties. These components of the total uncertainty need to be separated and discussed as to the contributions in each portion of the measurement. The British Standard Methods for Sampling Petroleum Products, Part 2 (BS3195: Part 2:1989, IS)3171:1988) defines the formula for uncertainty calculations where the Relative Systematic Uncertainties are additive while the Relative Random Uncertainties are relational to one fourth of the sum of the squares of the relative random uncertainties. Relative uncertainty is the uncertainty of a factor divided by the value of the factor.



Systematic Uncertainty

- Also Known As Resolution, Bias
- Reproducible Inaccuracy Produced by Technique, Improper Calibration, Faulty Equipment
- More Data Points Can Define Uncertainty
- Easier To Find and Solve Than Random Effects
- People Making Systematic Mistakes
  - Doing The Wrong Thing Consistently
  - Missing a Step in the Process All The Time

Random Uncertainty

- Variable Must be Defined and Eliminated to Reduce Errors
- More Data Does Not Help Because The Effect is Random
- People Make Random Mistakes
  - Skip A Known Step Once
  - Transpose Numbers
- Only the Probability of an Error Occurring Can Be Discussed

Table 2. How to Recognize Systematic and Random Uncertainty

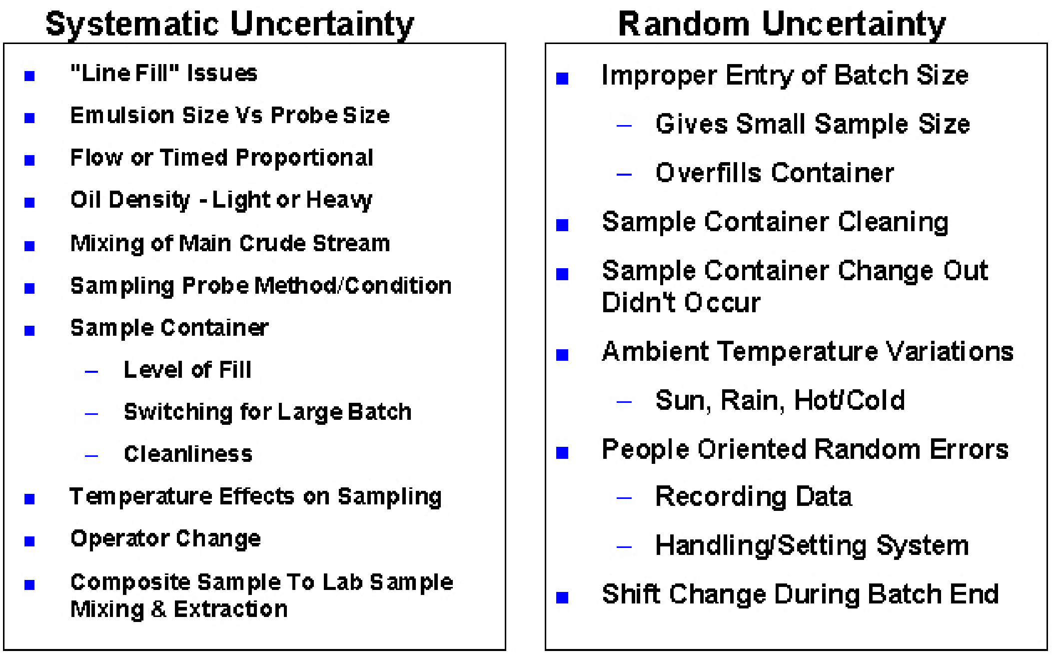
As defined by the British Standard, there are two numbers for each line below, one for the systematic and one for the random uncertainty:

1. non-homogeneity of the water content
2. changes in the water content caused by sampling
3. uncertainty of the grab volume
4. uncertainty in the flow rate causing non-proportionality of sampling
5. changes in the water content during sampling
6. changes in the water content caused by sample handling and mixing
7. changes in the water content caused by transfer to laboratory apparatus

The systematic uncertainties add therefore, they are the most important source of errors.

5 – Sources of Uncertainty for a Composite Sampler

Table 3 suggests some of the uncertainty components for the composite sampler. Notice that many of these are related to people handling and inspecting the process. Although many can be automated for verification that the process is progressing during a batch sample, all cannot be controlled simply by monitoring. In the British Standard, description of the variables number one through four describe the expected issues with the sampler.



Systematic Uncertainty

- "Line Fill" Issues
- Emulsion Size Vs Probe Size
- Flow or Timed Proportional
- Oil Density - Light or Heavy
- Mixing of Main Crude Stream
- Sampling Probe Method/Condition
- Sample Container
  - Level of Fill
  - Switching for Large Batch
  - Cleanliness
- Temperature Effects on Sampling
- Operator Change
- Composite Sample To Lab Sample Mixing & Extraction

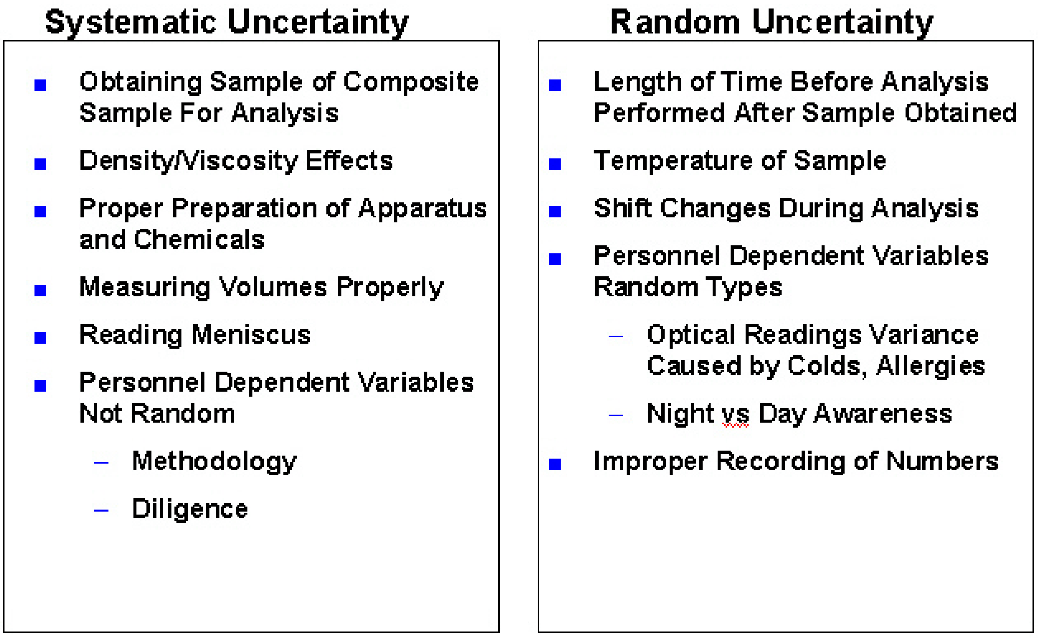
Random Uncertainty

- Improper Entry of Batch Size
  - Gives Small Sample Size
  - Overfills Container
- Sample Container Cleaning
- Sample Container Change Out Didn't Occur
- Ambient Temperature Variations
  - Sun, Rain, Hot/Cold
- People Oriented Random Errors
  - Recording Data
  - Handling/Setting System
- Shift Change During Batch End

Table 3. Systematic and Random Components for Sampler System

6 – Sources of Uncertainty for a Laboratory Analysis

Table 4 suggests some of the uncertainties that may be found in the laboratory. In these steps the personnel become one of the most important influences to uncertainty. In the British Standard, description of the variables number five through seven describe the expected issues with the laboratory.



Systematic Uncertainty

- Obtaining Sample of Composite Sample For Analysis
- Density/Viscosity Effects
- Proper Preparation of Apparatus and Chemicals
- Measuring Volumes Properly
- Reading Meniscus
- Personnel Dependent Variables Not Random
  - Methodology
  - Diligence

Random Uncertainty

- Length of Time Before Analysis Performed After Sample Obtained
- Temperature of Sample
- Shift Changes During Analysis
- Personnel Dependent Variables Random Types
  - Optical Readings Variance Caused by Colds, Allergies
  - Night vs Day Awareness
- Improper Recording of Numbers

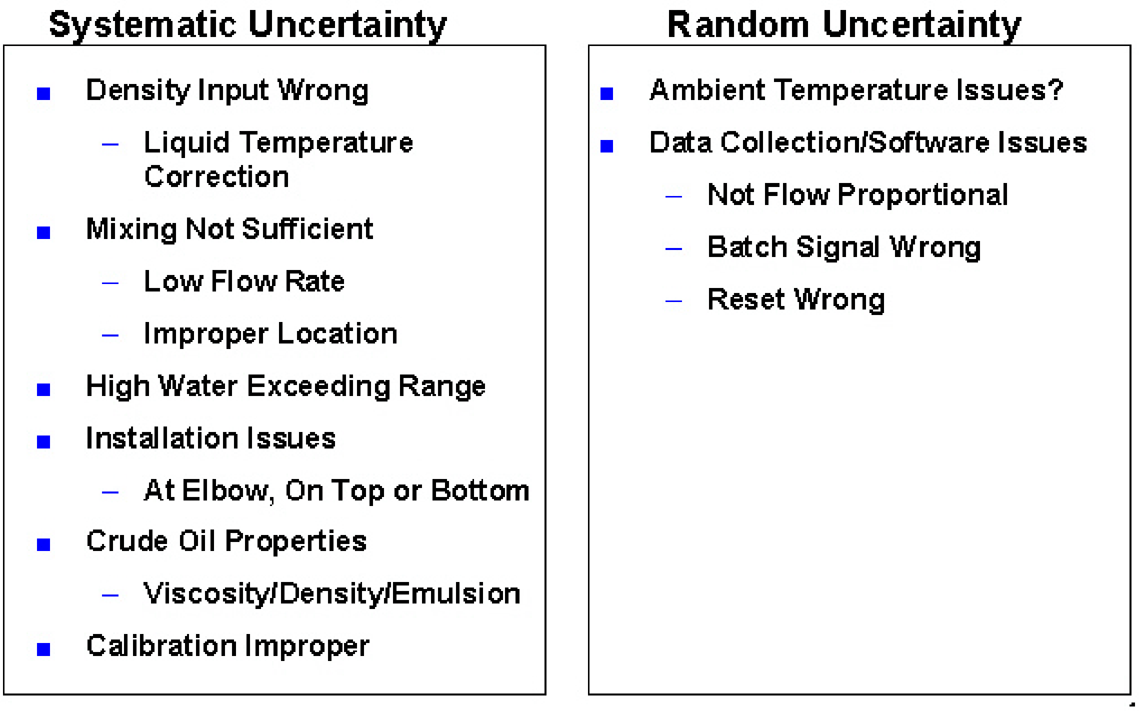
Table 4. Table for Laboratory Uncertainty

7 – Density Measurement Uncertainties

The typical online measurement of density has the potential for being affected by many influences. One of these is the ambient temperature variation in addition to liquid temperatures that are typically compensated. If the sun shines on the analyzer during the day and then turns cold and rains, it is possible that the density measurement is affected. Some vendors recommend insulation to prevent this and possibly a sun shield. The accuracy of the density measurement is stated by one vendor not to be "accurate" unless it is calibrated on that specific crude type. This is due to viscosity and other physical liquid variables. Temperature compensation using the actual liquid temperature measurement instead of making the measurement on the outside surface of the pipe can also affect the answer.

8 – On Line Water Analyzer Measurement Uncertainties

On line water analyzers must see a representative sample of the actual flowing stream just like the composite sampler probe. This has always been a requirement for any analysis for water content, density or sampling system. The analyzer will be only as good as the representative sample that is presented to the measurement section.



Systematic Uncertainty

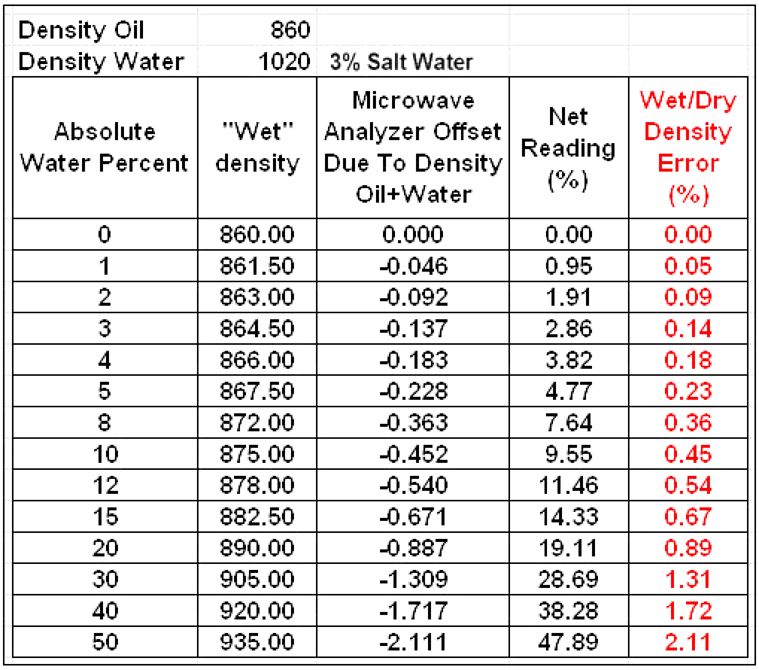
- Density Input Wrong
  - Liquid Temperature Correction
- Mixing Not Sufficient
  - Low Flow Rate
  - Improper Location
- High Water Exceeding Range
- Installation Issues
  - At Elbow, On Top or Bottom
- Crude Oil Properties
  - Viscosity/Density/Emulsion
- Calibration Improper

Random Uncertainty

- Ambient Temperature Issues?
- Data Collection/Software Issues
  - Not Flow Proportional
  - Batch Signal Wrong
  - Reset Wrong

Table 5. On line Water Analyzer Uncertainty Table

There has been a lot of information improperly presented in the past as to how "wet oil density" versus "dry oil density" affects analyzers. As the water increases so does the density. The density correction for the baseline zero water content for typical permittivity based analyzers is approximately 0.03% change in water for a 1 kg/m^3 change in density. Therefore, for a 10 kg/m^3 change in density the change is 0.3% water. A summary of the impact is shown in Table 6. These results are with the oil density set at 860 kg/m^3 (approximately 32 API degree) and the water is a 3% salt content which give a water density of 1020 kg/m^3.

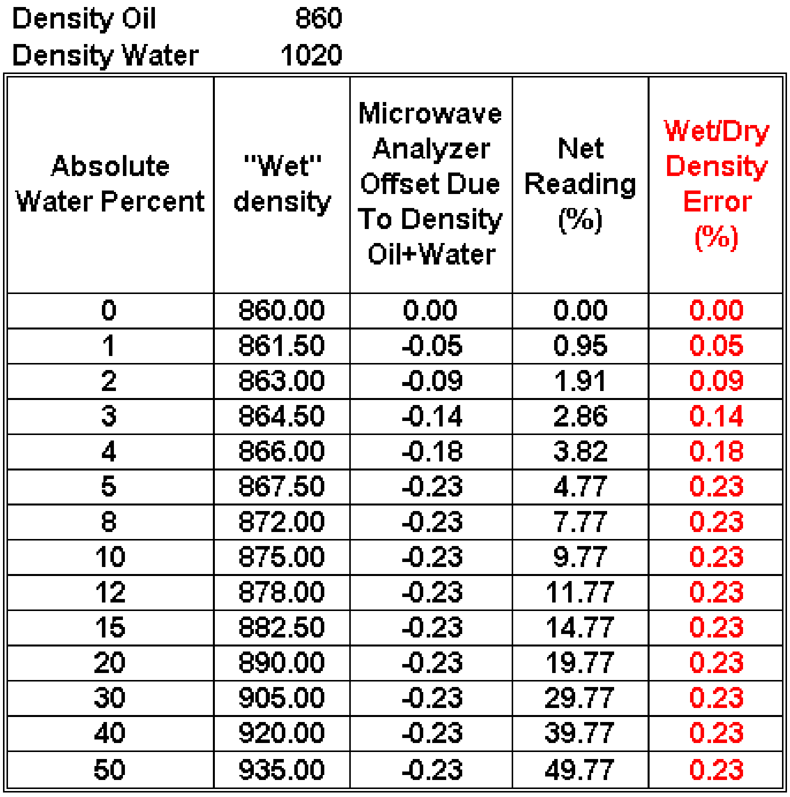


Density Oil 860
Density Water 1020 3% Salt Water

Absolute Water Percent	"Wet" density	Microwave Analyzer Offset Due To Density Oil+Water	Net Reading (%)	Wet/Dry Density Error (%)
0	860.00	0.000	0.00	0.00
1	861.50	-0.046	0.95	0.05
2	863.00	-0.092	1.91	0.09
3	864.50	-0.137	2.86	0.14
4	866.00	-0.183	3.82	0.18
5	867.50	-0.228	4.77	0.23
8	872.00	-0.363	7.64	0.36
10	875.00	-0.452	9.55	0.45
12	878.00	-0.540	11.46	0.54
15	882.50	-0.671	14.33	0.67
20	890.00	-0.887	19.11	0.89
30	905.00	-1.309	28.69	1.31
40	920.00	-1.717	38.28	1.72
50	935.00	-2.111	47.89	2.11

Table 6. Wet Density Effect on Water Analyzer

The solution is to hold the earlier density within the analyzer memory for excursions above say 5% water. Then the impact of the density is limited to a very small number as shown in Table 7.



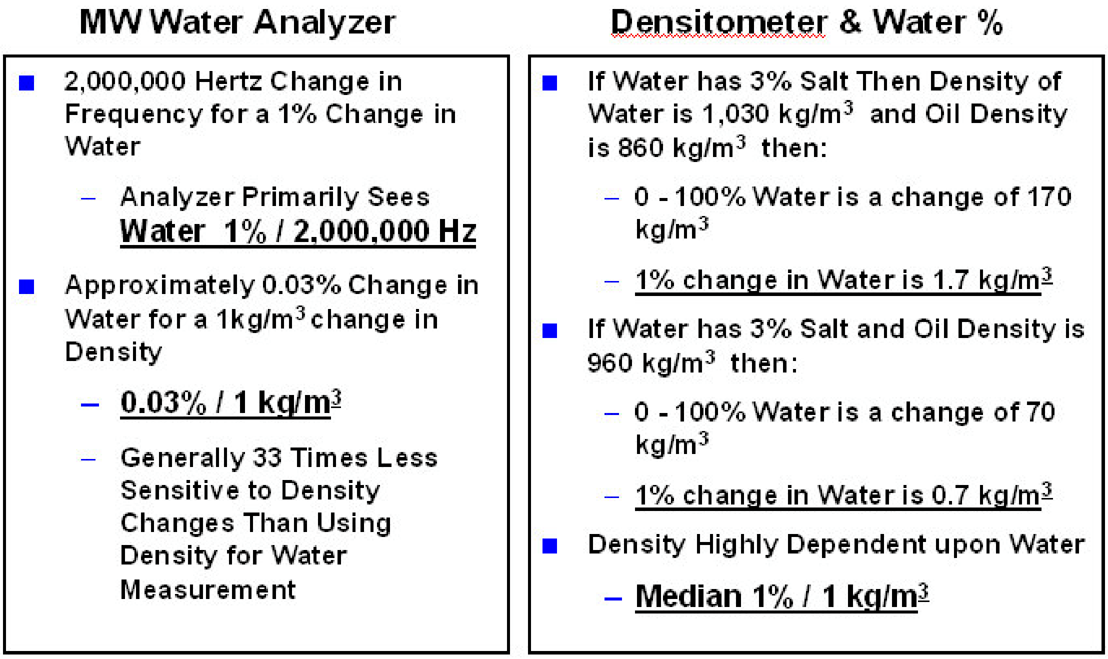
Density Oil 860
Density Water 1020

Absolute Water Percent	"Wet" density	Microwave Analyzer Offset Due To Density Oil+Water	Net Reading (%)	Wet/Dry Density Error (%)
0	860.00	0.00	0.00	0.00
1	861.50	-0.05	0.95	0.05
2	863.00	-0.09	1.91	0.09
3	864.50	-0.14	2.86	0.14
4	866.00	-0.18	3.82	0.18
5	867.50	-0.23	4.77	0.23
8	872.00	-0.23	7.77	0.23
10	875.00	-0.23	9.77	0.23
12	878.00	-0.23	11.77	0.23
15	882.50	-0.23	14.77	0.23
20	890.00	-0.23	19.77	0.23
30	905.00	-0.23	29.77	0.23
40	920.00	-0.23	39.77	0.23
50	935.00	-0.23	49.77	0.23

Table 7. Hold Density Constant Over 5% Water Measured

9 – Method Comparison for Water Measurement

If no adjustment is made for the "dry oil density" then the data in Table 6 is close to being the error in water percentage for the on line analyzer for those given densities. Now a comparison between the sensitivities using a microwave water measurement which is based on the polar moment of the molecule (the permittivity or at lower frequencies and water percentages, the dielectric constant) and the calculation of water percent using density is made in Table 8. The microwave method is more sensitive to the water molecule because the parameter of measurement is the large difference between the small polar moment of crude oils (2.5) and the high polar moment of water (80). With this additional sensitivity the microwave method's ability to resolve water is approximately 33 times greater than that when density is used for measurement.



MW Water Analyzer

- 2,000,000 Hertz Change in Frequency for a 1% Change in Water
  - Analyzer Primarily Sees **Water 1% / 2,000,000 Hz**
- Approximately 0.03% Change in Water for a 1kg/m^3 change in Density
  - **0.03% / 1 kg/m^3**
  - Generally 33 Times Less Sensitive to Density Changes Than Using Density for Water Measurement

Densitometer & Water %

- If Water has 3% Salt Then Density of Water is 1,030 kg/m^3 and Oil Density is 860 kg/m^3 then:
  - 0 - 100% Water is a change of 170 kg/m^3
  - 1% change in Water is 1.7 kg/m^3
- If Water has 3% Salt and Oil Density is 960 kg/m^3 then:
  - 0 - 100% Water is a change of 70 kg/m^3
  - 1% change in Water is 0.7 kg/m^3
- Density Highly Dependent upon Water
  - **Median 1% / 1 kg/m^3**

Table 8. Water Percentage Measurement by MW Analyzer & Density

10 – The Opportunity to Improve Oversight

The opportunity to use more than one independent measurement provides the ability to make a more educated choice as to what method may be less uncertain. Such an opportunity exists using a composite sampler and an on line water analyzer although the sampler results will be considered the correct answer by default. If an additional method was available then there exists an opportunity to better decide which may be the correct answer. The differences between the microwave and density determination of water were given in the previous section. Although these are not totally independent measurements they are sufficient to study as a course of action to better a measurement.

The first issue when using density for water percentage measurement is to determine the dry oil and the produced water density at flowing conditions. If this information can be determined, then the densitometer used for pipeline measurements becomes another check on the final answer to the question "what was the water in the pipeline." The answer lies in the fact that the water analyzer is capable of accuracy at higher water percentages with reduced sensitivity to density. The higher the water percentage the smaller a change in density from the on line density when the low water density is used as in Table 7. The key to this method is to store all of the data for a batch process such as that for ship unloading, well testing or the like and then process the data at the end of the unloading or testing period. In addition, the ability to store the data and then sort it versus some variable such as density, water percentage or flow rate is of interest in the ease of processing the data.

11 – Sorting and Analyzing the Data

Figure 4 is the data from the first tanker shown in Figure 2 with the no flow rate cases removed and then the remaining data sorted by density.

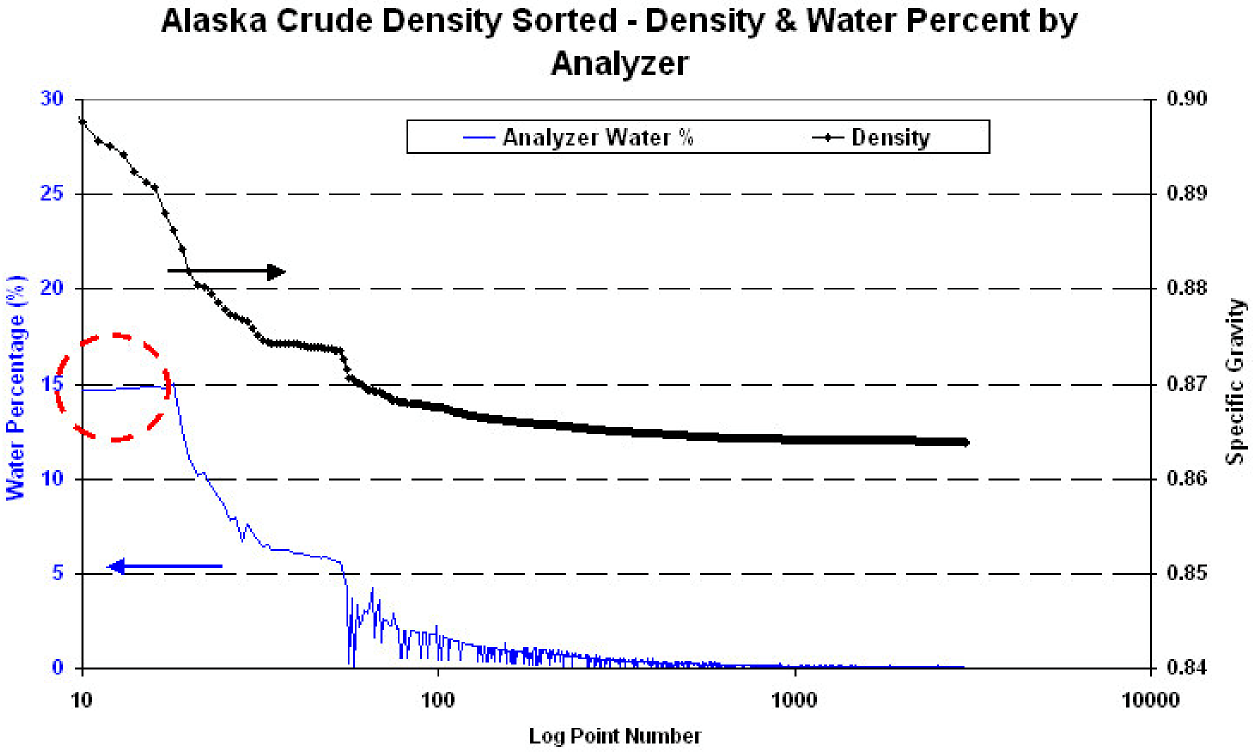


Figure 4. Data Sorted by Density From Figure 2

The circled region is where the water percentage exceeded the range of the analyzer and therefore it demonstrates how high the water can be at times. The region starting at 15% water cut and declining is selected to begin the analysis and the minimum specific gravity is used which corresponds to the minimum water percentage. In a simple iterative process a water percentage by density can be calculated to match with to the microwave analyzer's initial high water data points. The result of this analysis provides the following graph of Figure 5.The resulting density of the oil was 0.864 versus the laboratory of 0.867 and the water density was 1.025. There was no lab density of the water available but, this is close to the expected density from that region. The resulting conclusion is the three methods gave similar results.

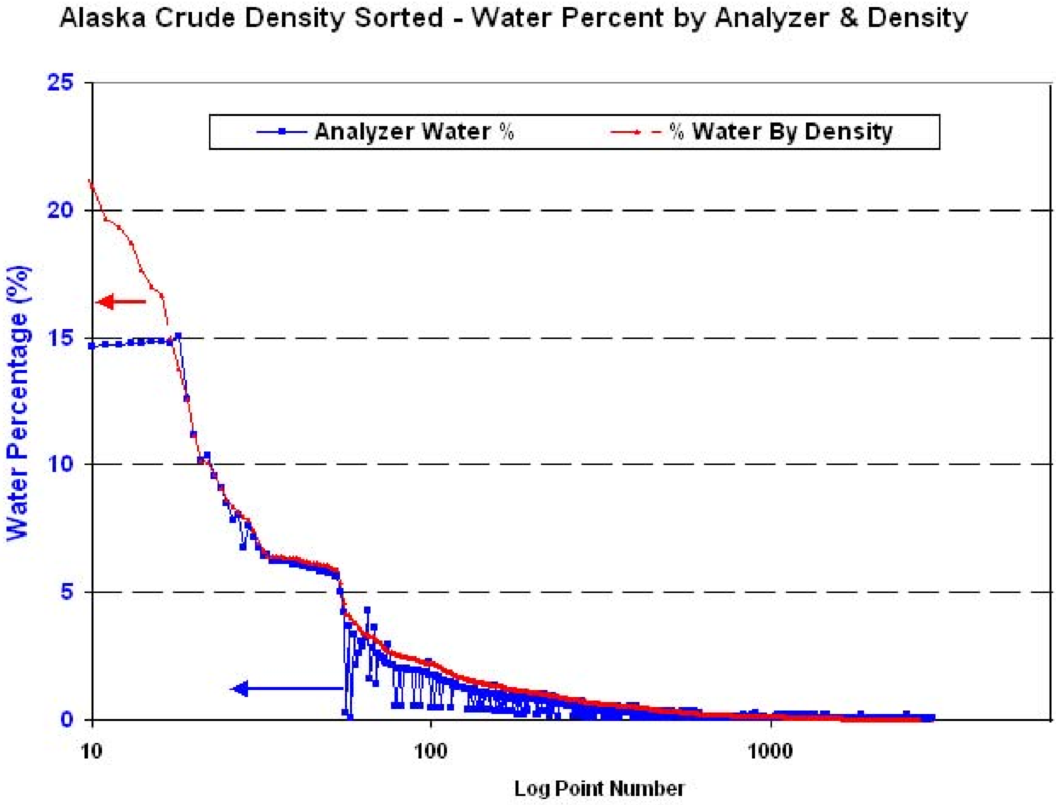


Figure 5. Alaska Water by Analyzer & Density

12 – Another Example

An example with a heavy crude taken from Figure 3 and sorted for density is shown in Figure 6. In this example the laboratory was at 0.75% water while the online analyzer average was 0.21%. Notice that the data is based on the log of the data point number so that the beginning fit to the water calculated by density is obvious. It appears visually that the analyzer would have a resulting average well below the laboratory.

This figure appears to demonstrate data for the density that contains much more noise than the data from the Alaskan crude oil data above. A look at the temperature during the discharge was a next step of analysis since the density is temperature corrected.

Figure 7 shows the temperature and water percentage with time on unsorted data. At several major points where the water was higher the temperature is lower which suggests that the water did not come along with the crude. Theoretically the temperature should be the same or a higher temperature due to the thermal capacity of water being so much higher than the crude oil.

From the observation with temperature the water analyzer was reset to use the line density without any temperature correction. This was not suggesting this is the right answer but instead to compare the results and curve shapes. Figure 8 shows the resulting water by analyzer that levels off to a reasonably consistent number. A question as to the validity of the temperature correction for density at the densitometer would be of interest at this point.

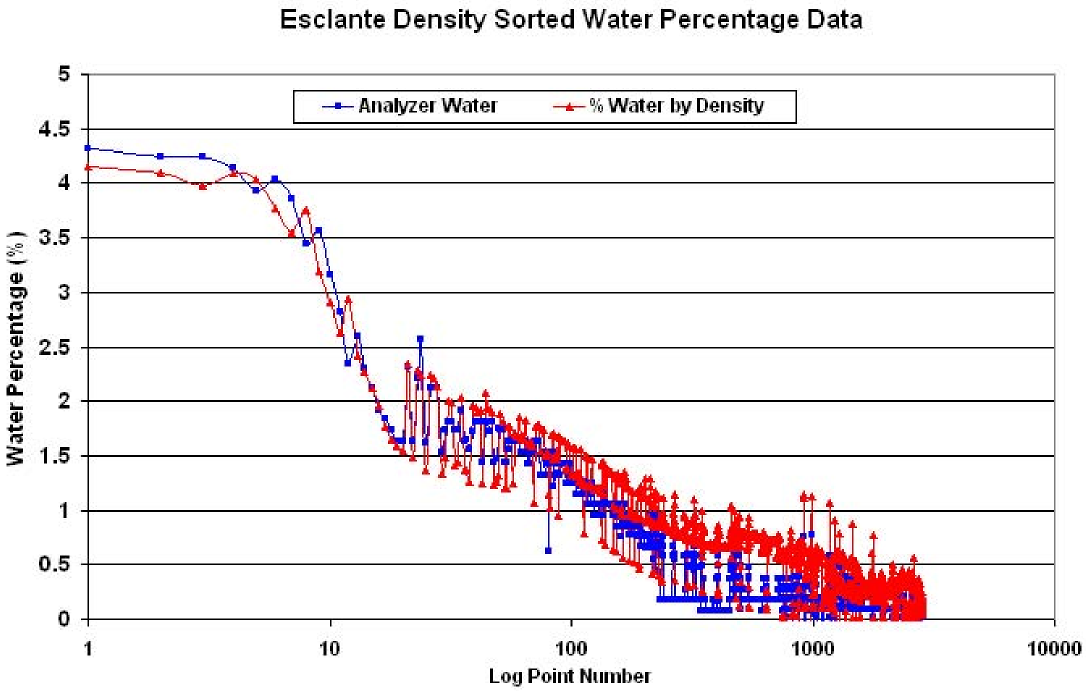


Figure 6. Figure 3 Sorted by Density Heavy Crude

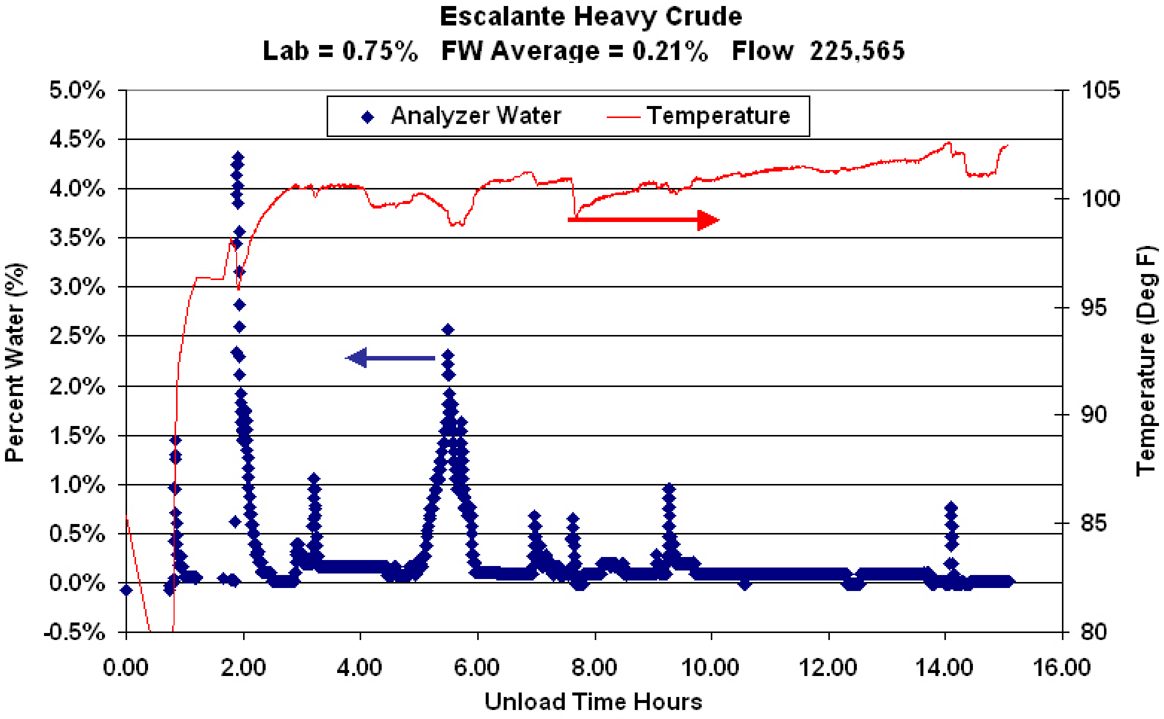


Figure 7. Unsorted Temperature & Water With Time

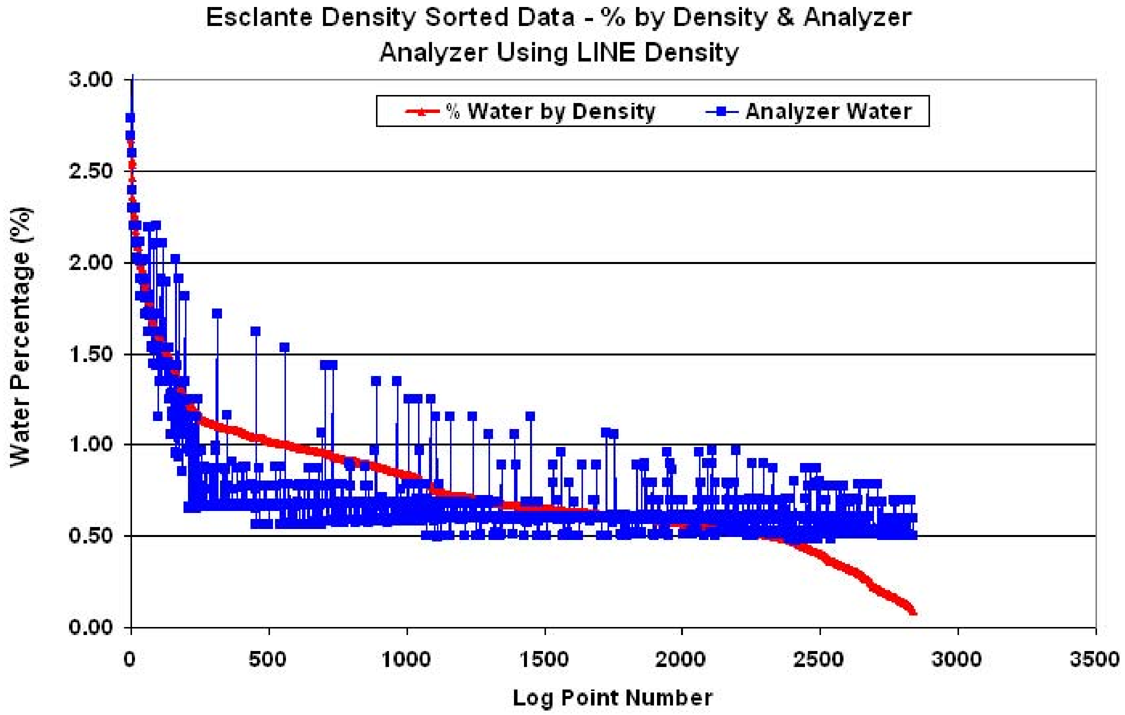


Figure 8. Water Analyzer Using LINE Density

13 – Conclusion

Although the composite sampler will be around for many more years, the on line real time companion may aid in improving the measurement. In addition, data techniques may allow an independent set of measurements by which validation of the results can be compared. When differences occur, they can be identified and resolved if the data obtained during routine operation can determine that a question should be asked. The data obtained from composite samplers is not real time and can only provide answers that are obtained by human involvement after the batch has left the station. Analytical measurement coupled with the computing power that is now available will change the way pipeline data on water cut is collected and analyzed. Methods to prove the viability of this approach are just now being tested. Among the remaining things to be understood and defined are how to automatically process the data and alert an operator that some further inspection of the data or comparisons are required.

With the current price of petroleum products exceeding US$50 per barrel, methods to measure and validate the transfer of crude oil must be improved. Real time on line analyzers should become a valuable tool in this pursuit of a better measurement. If the real example in Figure 3 was used where the difference of 0.54% in water delivered between the composite sampler (0.75% water) and the on line analyzer (0.21%) across 225,565 barrels would be a difference of US$60,903.

The greatest difficulty in moving the technology ahead is the lack of top level management stating that these issues need to be investigated and resolved. Taking data and looking for answers to questions that have not been asked before is time consuming and costly. Independent vendors will require additional help in the future to truly solve the issues for fiscal measurement and to bring these into this century.

14 – Acknowledgements

This paper would not have been possible without many diligent companies looking for answers to problems in their operations. The time to collect and properly analyze samples is time consuming and requires dedicated personnel. The data shown in this paper represents many man years of work. Many thanks are given to each and every person that have assisted in the collection, processing and transfer of the information which led to this paper. The companies who have allowed data to be collected and questions to be asked include but are not limited to the following: Shell Pipeline, Marathon, BP, ARCO Pipeline, Husky Oil, EXXON, Phillips Petroleum.

15 – References

1. Scott, Bentley N., Uncertainties in Pipeline Measurement. *Proceedings of IPC 2004 International Pipeline Conference*, Calgary, Alberta, Canada. IPC04-0046, October 4 - 8, 2004.