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Data Accuracy from Well Test Operations

By

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&

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Abstract

This master thesis presents a study on data accuracy from well test operations. All data measuring methods, except bottomhole and surface PVT sampling, is investigated for the accuracy related to procedure and equipment used. The objectives with this study is to highlight potential weaknesses in the procedures or equipment so that Expro can improve the quality of their data acquisition.

The main research area is the measurement methods, but also the impact of the type of fluids produced has been studied. Oil, gas or gas/condensate may have different inaccuracies for different methods.

Results from this study shows that some of the measurements should be improved. The most critical measurement is the oil flow rate, where no procedure for executing meter correction factor is given. Oil flow rate is one of the most important surface parameters the client want obtain with a well test and should therefor be as accurate as possible. Another weakness is an Excel spreadsheets that is used for various calculations for oil is not protected and formulas has been manipulated. This may again give wrong output values.

Another factor is the lack of knowledge among offshore personnell about phase changes due to changes in pressure and temperature. This may have impact on all the measurements that include gas and oil. Since this is something they can not expect offshore personnell to be experts on, should the procedures be updated to cover all scenarios for measurements of various phases.

The conclusion from this study is that measurements regarding oil and gas parameter are the most inaccurate and an update of procedures is necessary to improve the data accuracy. Most of the calculations today is done by computer softwares, but correct input values is necessary to get correct output values. Knowledge about what formulas the software contain is important to know to be able to make necessary measurement and data collection for input variables to the software. This should be taken into account if procedure is to updated.

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1. Introduction

1.1 Background and motivation

New exploration wells are drilled on a daily basis all around the world. As a part of the exploration process oil companies can decide to run well tests. The test objectives can range from simple identification of produced fluids and determination of reservoir deliverability to the characterisation of complex reservoir features. Determination of the well behaviour is completed by evaluating pressure data from downhole gauges. Surface pressure data can be used as an alternative to downhole data if required.

During a well test a number of surface measurements can be made of for instance sediments and water, hazardous gases, densities of oil and gas, flow rates, gas-oil-ratio, and others.

My motivation for this thesis is to look into the data collected and study the accuracy, based on the equipment used and how the measurements are taken.

1.2 Research objectives

Expro Group AS is an oil service company that executes Well Test operations and Production clean-ups. This thesis includes a study of the data accuracy of measurements taken during a selection of jobs executed by Expro. The required reports and procedures for execution of this thesis have been provided by Expro. The objectives of the research can be highlighted as follow:

- Study all the methods and equipment used for collecting data during a Well test and a Clean-up job
- Investigate inaccuracies due to mechanical factors
- Investigate inaccuracies due to human factors
- Identify if there are difference in accuracy for different types of reservoir fluids
- Study if there are possibility for improvement of the data accuracy

1.3 Study area

Three different wells which contains different fluids have been studied in this thesis:

1. **Case1** – Gas field, DST
2. **Case2** – Gas/condensate, Cleanup
3. **Case3** – Oil field, DST

Note: The three different wells will be referred to as Case 1, Case 2 and Case 3 due to confidentiality.

2. Summary

2.1 Database and methodology

In this study has procedures for collection of manual measurements, the equipment used and data collected from well tests been evaluated. Most of the data has been provided by Expro. The three reports that has been evaluated represents gas well, gas/condensate well and oil well.

Mathcad has been used for calculations comparing manual calculations and the software and Microsoft Excel for graphical presentation.

Expro is using a software called Report2 to plot graphs in conjunction with IDEA or EDGE-X software. The limited availability to the software listed above, was one of the limitations during execution of this thesis.

2.2 Chapter description

This thesis is divided into 7 chapters.

First chapter is a general introduction to the background and motivation for this thesis, including research objectives and study area.

Second chapter contains a brief summary about the database, methodology and limitations.

Chapter three contains assumptions and abbreviations.

Chapter 4 & 5 contain conclusion and recommendations.

Chapter 6 contains theory about well testing and equipment used in well testing.

Chapter 7 contains the discussion about the data accuracies.

Attachment I – Expro procedures

Attachment II – New procedure proposal

Attachment III – Tables used for calculations

Attachment IV – Technical specifications

Attachments V – Well Test job informations

Attachment VI – Mathcad calculations

2.3 Limitation

1. **Software** – one focus area was to be able to look into the equations used in the software to compare these with the equations given in Expro procedures and standards. Due to limited number of available licenses of the software at Expro and no available public program manual, I have not been able to research this. The comparison was then done of values given in well test reports instead.
In Expro, both IDEA and EDGE-X has been used to record and calculate well data such as pressures, temperatures, flow rates and others the last years, but EDGE-X is taking over more now.
2. **Well name** – data in this thesis have been taken from well test jobs performed by Expro. These reports have not been published by the Norwegian Petroleum Directorate, so they need to be treaded as confidential. The field and well number has therefore been replaced by case1, case2 and case3.

3. Assumptions and Abbreviation

3.1 Assumptions

1. If no reference is given the information has been taken from Expro internal documents[1].
2. All data used for evaluation in this thesis have been taken from post-completion tests.
3. A lot of data taken from a DST is also recorded during a Clean-up job.
4. Surface and bottomhole sampling are not discussed in this thesis.
5. Only equipment used within Expro is discussed. Other companies may use other equipment for the same measurements.
6. When oil is in the calibration tank, the temperature is assumed to be the same in center as in the edge.

3.2 Abbreviations

AGA – American Gas Association
AORV – Annulus Operated Reversing Valve
API – American Petroleum Institute
ARTS – Annulus Reference Trap System
ASTM – American Standard Test Methods
BHP – Bottom Hole Pressure
BHT – Bottom Hole Temperature
BOP – Blow Out Preventer
BPM – Barrel Per Minute
BS&W – Basic, Sediments & Water
CGR – Condensate Gas Ratio
CO₂ – Carbon Dioxide
CMSF – Combined Meter & Shrinkage Factor
CPU – Central Processing Unit
DAQ – Data Acquisition
DCP – Downstream Choke Pressure
DCT – Downstream Choke Temperature
DH – Down Hole
DHSV – Down hole Safety Valve
DHT – Down Hole Tools
DP – Differential Pressure
DST – Drill Stem Test
ESD – Emergency Shut Down
FS – Full Scale
GOR – Gas Oil Ratio
GPM – Gallon Per Minute
GPSA – Gas Processing Supplier Association

H₂S – Hydrogen Sulphide
ID – Inside Diameter
LRL – Lower Reading Limit
MF – Meter Factor
MRST – Multi Reverse Spot Tool
N₂ - Nitrogen
NCS – Norwegian Continental Shelf
OD – Outside Diameter
ODCT – Oil Density Cylinder Temperature
P&ID – Pipe & Instrumentation Diagram
POTV – Pressure Operated Tester Valve
ppm – parts per million
PVT – Pressure, Volume, Temperature
RA – Radio Active
RFT – Repeat formation test
RIH – Run In Hole
RTD – Resistive Temperature Detector
RV – Retainer Valve
SC – Standard Conditions
SF-TTV – Self Fill Tubing Tester Valve
SG – Specific Gravity
Shr - Shrinkage
SSTT – Subsea Test Tree
STT – Surface Test Tree
SSV – Surface Safety Valve
TCP – Tubing Conveyed Perforationg
TVCF – Total Volume Correction Factor
URL – Upper Reading Limit
VCF – Volume Correction Factor
WH – Well Head
WHP – Well Head Pressure
WHT – Well Head Temperature
WT – Well Test
X-mas – Christmas (tree)

Key phrases that are central in this thesis:

Upstream – the pipe that goes into an equipment

Downstream – the pipe that goes from the equipment

Upstream and downstream choke terms is used for determine the change in high pressure and low pressure

4. Conclusions

This thesis evaluated the data acquisition accuracies related to well test operations. The data measurements that was studied was:

1. Downhole pressure and temperature
2. Surface pressure
3. Surface temperature
4. BS&W
5. pH
6. Salinity
7. H₂S & CO₂
8. Oil gravity
9. Gas gravity
10. Oil flowrate
11. Gas flowrate
12. Coriolis meter

Some of the measurements mentioned above are more complex than others. Downhole memory gauges and surface pressure and temperature transmitters are equipment that are installed by qualified people before a job and flow starts and they are responsible for correct installation. The surface temperature transmitters come in full range, but the pressure transmitters come in various ranges. Special care must be taken concerning the choice of range in the surface system.

For the manual measurements the quality of procedures and equipment was varying. BS&W, pH, Salinity and H₂S and CO₂ is data measurements that are collected to ensure environmental safety and to identify properties in the mud produced in the clean-up phase. This is measurements that mainly is taken to prove that clean-up phase are completed and to determine the content of hazardous gases, but the accuracies of reading should be good. For the BS&W and H₂S/CO₂ was the procedures brief and did not include what to do in additional scenarios. If a measurement is affected by the type of fluids produced should special notes be included in the procedure on how to solve this challenge. In the H₂S/CO₂ procedure a wrong sampling compartment was also stated. A compartment with continuous flow should be used instead of gas bladders and stainless steel bottles.

The main surface data collected during a well test are oil and gas gravities and flow rates. This is the information the client is interested in to decide the quality of the reserves found. From this study can we see that these are also the parameters that have the highest inaccuracies. Phase changes due to reduction in pressure and temperature is the biggest challenge when it comes to these measurements. The gas gravity is measured at atmospheric pressure and temperature, but if the gas is a wet gas or gas/condensate, then liquids might affect the reading since the silica gel in the Ranarex gravitometer only can handle small amounts of moisture. For oil gravity the procedure is very poor. Unless you have a heavy oil the oil will most likely contain dissolved gas at sampling pressure and temperature. The reading

si taken at atmospheric pressure, but to make sure all the gas have evaporated from the solution, should the oil get some time to settle. Correction for temperature is also missing.

The gas flowrate is today calculated by software. The main input parameters are differential pressure across the orifice meter, static pressure, flowing temperature and specific gravity of the gas. From this study it is shown that several factors are included in the final flow equations. Most of the factors are included in all of the methods, but the orifice thermal expansion factor is only mentioned in GPSA handbook. If this factor is included in the software or not, is unknown. From subchapter 7.2 can we see that this is just a small factor, so it will not contribute to a much higher flowrate if it is included.

Oil flow rate had the most critical method on how to correct to standard conditions. There were no procedure given on how to execute a meter factor or combined meter and shrinkage factor. This is the factor that is multiplied with the turbine meter value to give flow rate and cumulative production in standard cubic meter or feet, and this should be very accurate. We saw that the Excel spreadsheet that was used for calculating this factor was not protected, and for Case 3 the formulas had been manipulated, thus giving a wrong CMSF.

We see that for coriolis meter both mass flow and volumetric flow be measured. Expro only uses mass flow so densities need not be included. Densities can be measured for liquids but is not recommended for gas by manufacturer. Coriolis meter is more and more taking over for orifice meter or a combination of both is used.

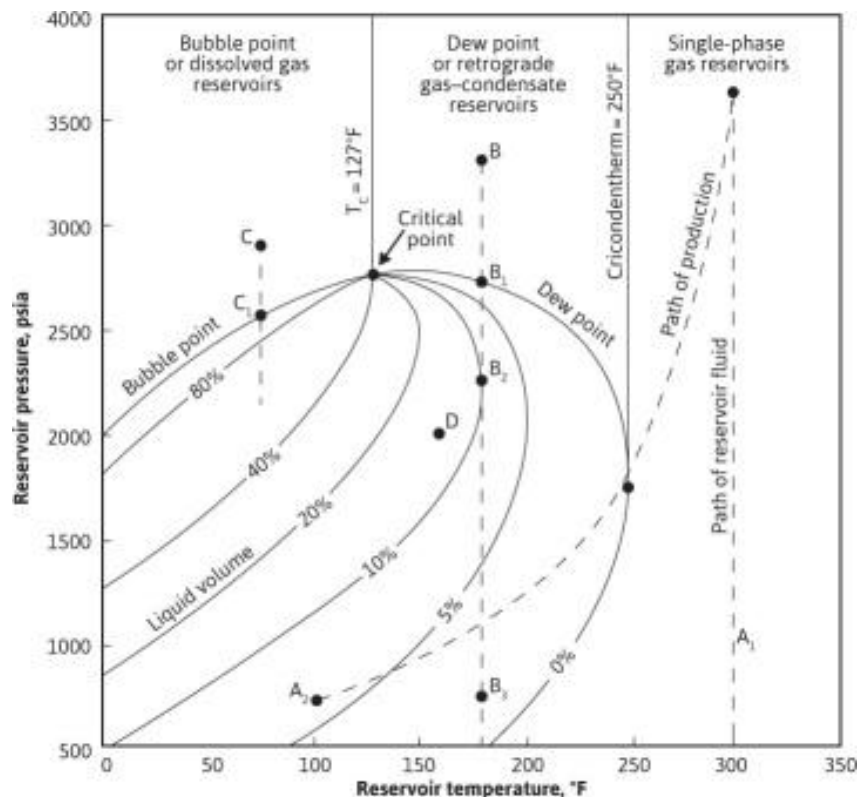


Figure 1 Fluid systems overview - phase envelope[30]

A lack of quality and updates of Expro procedures makes many of the measurements more inaccurate than necessary. Ignorance about what formulas the software uses and what inaccuracies that is related to this software is also something that lowers the quality of the data that are provided to the customer. Knowledge about fluids behaviour due to pressure and temperature is something there is lack of in learning courses and offshore personnel, and on many of the surface measurements this is something that can affect the reading.

An update of procedures is necessary to improve the quality of the data acquisition.

5. Recommendations

Below are some recommendations for Expro to improve the data acquisition:

- Get to know the background of the software used for data acquisition. Formulas, input parameter, unit of input parameters etc.
- **BS&W** – update procedure with how to take measurement with small liquid contents.
- **H₂S/CO₂** – update procedure with correct sampling compartment. Make sure all laboratory containers are equipped with this sampling compartment. Also include the importance of continuous and controlled flow to avoid splashing of liquid droplets.
- **Oil gravity** – let the oil get sufficient time to settle and gas to evaporate before oil gravity is measured. This should be done in the sampling cabinet in the laboratory container.
- **Gas gravity** – if a wet gas or gas/condensate is about to be measured, make sure to keep the inlet of the balloon upwards so no liquids will be collected at the inlet of the balloon. Only gas with a small amount of moisture will then enter the inlet of the Ranarex gravitometer. A test to confirm that the temperature in the balloon actually is the same as surroundings should also be performed.
- **Oil flow rate** – create a detailed procedure on how to execute and calculate a final meter correction factor.
- **CMSF Excel spreadsheet** – if an Excel spreadsheet shall be used to calculate the total volume correction factor for the meter, then all formulas should be documented and have a reference. The Excel spreadsheet should be protected with only input cells open for change.
- **Oil flow rate manual calculations** – update procedure with an approved standard.
- **Gas flow rate** – clearly state in the well test report or another public place if the static pressure is taken upstream or downstream of the orifice meter.
- **Gas flow rate manual calculation** – update procedure with an approved standard.
- **References** – all procedures and formulas should be based on an existing standard.
- **Phase behaviour** – personnel need to be trained in how oil and gas behave with pressure and temperature.

6. Theory

6.1 When to perform a Well Test

Once a well has been drilled the oil companies needs to decide whether or not to go ahead with a well test(WT). Some common situations when a well test is conducted is given below.

Prior to completion – WT can be run to assist with the choice of completion. Drill Stem Test (DST) or Repeat Formation Test (RFT), or both, is normally being carried out.

Post-completion – WT is done after the well is completed. A build-up, draw-down, or deliverability test can be run to quantify near-wellbore and reservoir conditions, and to determine inflow performance characteristics.

Pre-stimulation and Post-stimulation – stimulation is acidizing or fracturing of the formation to improve the well performance. This is usually done after a build-up test to evaluate the need for stimulation. After the treatment the productivity of the well should improve. Fracturing is also done to evaluate the strenght of the bearing rock.

Other scenarios:

Whenever change in operation – to evaluate any problems that may have developed

Periodic survey – to record the pressure build-up

Enhanced recovery – when fluid is being injected or if a well is converted from production to an injection well. Objective for the well test is to monitor fluid movement.

Most well tests can be group into productivity testing or descriptive/reservoir testing[29]:

- Productivity well tests
 - Identify produced fluids and determine their respective volume ratios
 - Measure reservoir pressure and temperature
 - Obtain samples suitable for PVT analysis
 - Determine well deliverability
 - Evaluate completion efficiency
 - Characterise well damage
 - Evaluate work-over or simulation treatment

- Descriptive tests
 - Evaluate reservoir parameters
 - Characterise reservoir heterogeneities
 - Assess reservoir extent and geometry
 - Determine hydraulic communication between wells

Whatever the objectives might be, well test data are essential for the analysis and improvement of reservoir performance and for reliable predictions.

6.2 Types of Well Tests

In Expro mostly two types of jobs are performed:

Clean-up flow - Bring mud filtrate, rock particles and extraneous fluids such as mud cake to surface, to allow the well to flow at its maximum allowable flow rate. This is done prior to a test on an exploration well or to clean up a well that is ready for production.

DST – Drill Stem Test - Focuses on obtaining near well bore information and PVT fluid samples from an exploration well.

A lot of the same data is gathered during a clean-up test where the main purpose is to remove mud filtrate prior to production and a full DST test. The main difference between the two: reservoir heterogeneity and geometry are additional parameters established during a DST.

There are several types of test that can be performed on a well. An important decision is the selection of the right test. This depends on

- Type of fluid expected
- Test objectives
- And more

Below the most common groups of test are listed. For more detailed description of each test see reference [2]

- PRESSURE DRAWDOWN TESTING
- PRESSURE BUILD-UP TESTING
- MULTIPLE-RATE TESTING
 - Two-rate flow test
 - N-rate flow test
- GASS WELL TESTING
 - Flow-after-flow test
 - Isochronal test
 - Modified isochronal test
- INJECTION WELL TESTING
 - Injection test
 - Fall-off test
- MULTIPLE WELL TESTING
 - Interference testing
 - Pulse testing
- CLOSED CHAMBER TESTING
 - Alexander Method
 - Surge testing
 - Slug testing

- FasTest Method
- SILD
- Wireline Formation Tests

Expro is often utilizing a N-rate flow test-program.

N-rate flow test

With a single pressure drawdown test it is often impossible to get a constant flow long enough to complete a drawdown test. Hence, a multiple-rate test is preferred. During a multiple-rate test a range from one flow with uncontrolled variable rate to a flow with a series of constant rates is available. Accurate flow rate and pressure measurements are essential since it is used in analysing transients of the well test. Without good flow rate data, good analysis of multiple-rate tests is impossible.

By utilizing a N-rate test additional data such as turbulent skin and max sand free rate can be determined.

Below is a schematic of a typical N-rate test

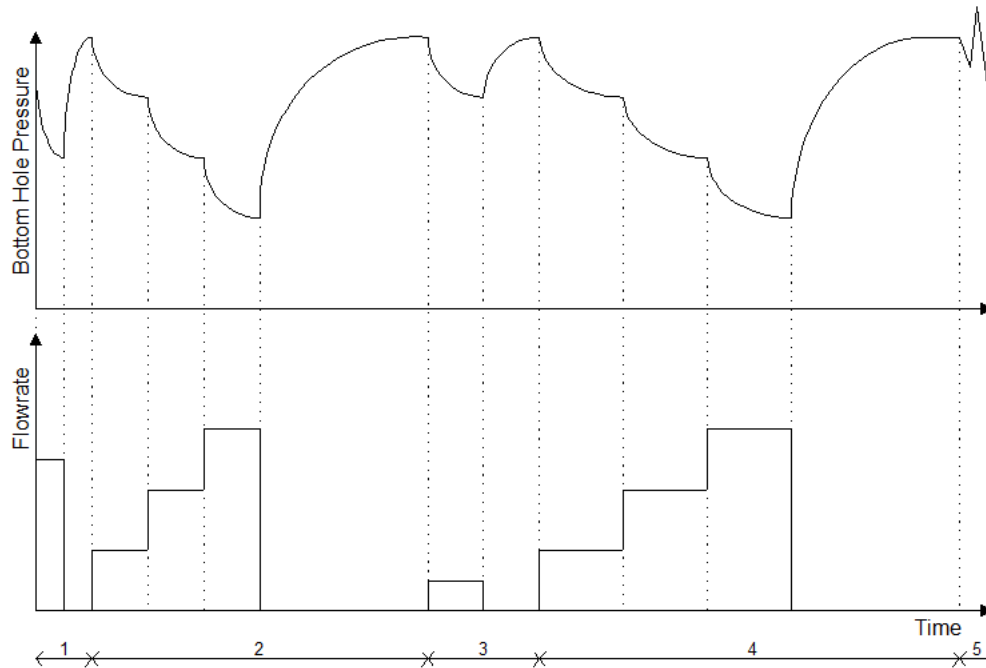


Figure 2 N-rate test [2]

Explanation of figure 1:

1. Initial flow with initial build-up
2. Clean-up flow with clean-up build-up
3. Sampling flow with build-up
4. Main flow with main build-up
5. Mini-frac test

6.3 Well Test Equipment

6.3.1 Downhole equipment

A set of Drill stem test tools is used for the temporary completion of a well. The tools are run as a means to provide a safe and efficient method of controlling a formation during a well test.

Many of the components are similar in function to those for permanent completions, but the temporary nature of the string requires some additional functionalities normally not associated with permanent completions. Temporary tools are designed for a wide range of operation environments and can be redressed between runs, while permanent completions are designed for specific installations and long life. The main components in a DST string are listed below[29].

1. TCP Guns, firing head & perforated tubing

Equipment used to perforate holes in the casing to allow communication with the reservoir.

2. Packer

A packer is a sealing and bearing device. Its purpose is to provide a seal and to isolate hydrostatic pressure in the well from formation pressure. It is very much the same as for a permanent completion packer[29].

3. Safety joint

A safety joint is operated only if the hydraulic jar cannot pull loose stuck tools. The safety joint is basically two housings connected by a coarse thread. Release is performed by a combination of reciprocation and rotation. 11 turns are required to release the test string from the packer[29].

4. Hydraulic jar

Provides the means of transmitting an upward shock to the tool string in case that the packer and lower assembly becomes stuck. An upward pull activates a regulated oil flow until the hammer section is released thus giving a rapid upward movement and generation the relevant shock[29].

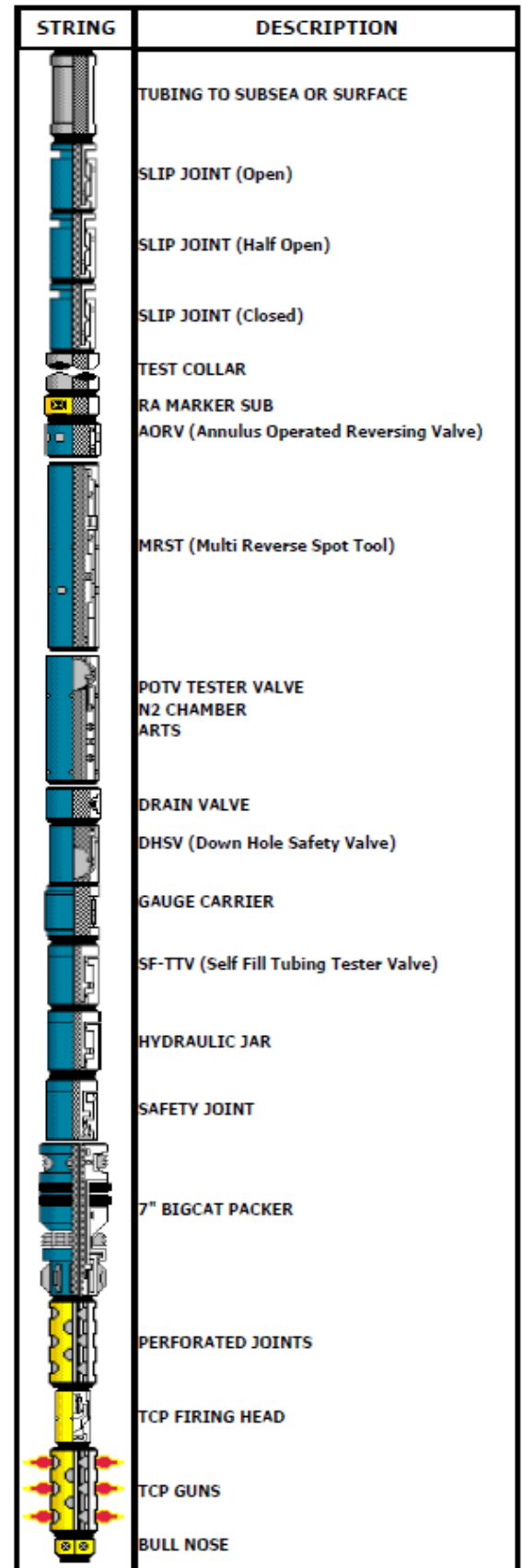


Figure 3 DHT String

5. SF-TTV

Used to pressure test the string when RIH. The SF-TTV is kept closed by rupture discs, and when the packer is set the annulus is pressurised to burst the rupture discs and the SF-TTV shifts to open position.

6. Gauge carrier

Gauge carrier for downhole memory gauges, to record DH pressure and temperature.

7. DHSV

A safety valve that is independent of the main tester valve is often required to provide an additional well control in case the main downhole valve fails. This is a single shot valve and is activated by bursting rupture discs and thus shifting the valve to a closed position. The DHSV has a pump through function allowing to kill the well[29].

8. Drain valve

Bleed-off point in case of trapped pressure between two closed valves, for example POTV and DHSV.

9. POTV, N2-chamber & ARTS

Downhole ball valve operated by annulus pressure with a nitrogen section below compensating for changes in annulus hydrostatic pressure. ARTS is used to trap the hydrostatic pressure inside the N2-chamber. This valve is opened and closed to allow for shut-in and flows per test procedures.

10. MRST

A circulation valve allowing communication between annulus and tubing. Used to spot cushion and acid treatments before testing and to remove produced fluids before POOH after a test[29].

11. AORV

A single shot circulation valve also called Annulus Operated Reversing Valve. Once rupture discs are burst, tool shift position and there is full communication between annulus and tubing. Closed position can not be obtained again, so the AORV is commonly used for killing the well.

12. RA Marker sub

Used to control the position and depth in the well against a RA marker in the casing.

13. Test collar

To provide the necessary weight required to set the packer. The weight can vary on what type of packer that is used.

14. Slip joint

A slip joint is an expansion/contraction compensation tool. It accommodates any changes in the string length due to temperature during a DST. The slip joint has a 5 foot stroke. The number of slip joints depends on the well conditions, but normally three or four slip joints are run, one closed , one half-open and one in open position, or two closed and two open.

15. Sampling chamber tool

A sampling chamber tool is used to trap downhole samples anytime during the test without shutting in the well. The sampling tool can be operated with rupture discs or accusticly.

If a production clean-up is performed, the string design has less components compared to a full well test string/DST string. A production clean-up test string comprises gun section, production packer, tubing to subsea and a subsea safety valve. Perforation can also be executed using Wireline .

6.3.2 Subsea equipment

When testing from a semi submersible or a floating vessel, a landing string is run and placed inside the blow out preventer. This is to allow the rig to shut-in the well, quickly disconnect from the main landing string and safely come off location in the event of unforeseen weather patterns causing excessive heave. The main components in the landing string are described below[29].

1. Adjuster sub and Fluted Hangar

The adjusted sub enables the adjustment of the fluted hangar to facilitate the correct depth of the primary safety barrier in the BOP.

2. Subsea Test Tree

It is the primary safety barrier and provides the possibility to disconnect the landing string from the well in case of emergency. It controls well flow and holds pressure from below in the event of an emergency disconnection of the rig from the well without requiring the BOP to shear the landing string. It has slick joints at the lower end and shear sub at the upper end, allowing it to be installed inside the BOP stack.

3. Retainer Valves

An environmental valve used to contain the riser content during a disconnection. It has a vent sleeve to vent off any trapped pressure between RV and SSTT, thus minimizing the time required to disconnect the rig from the well.

4. Subsea Lubricator & Cutting Lubricator Valve

Used for well isolation and is part of the landing string safety system. Used to establish an operable fail-as-is barrier in the landing string, capable to maintaining pressure control. The cutting lubricator is used when there is planned for coil tubing or wireline.

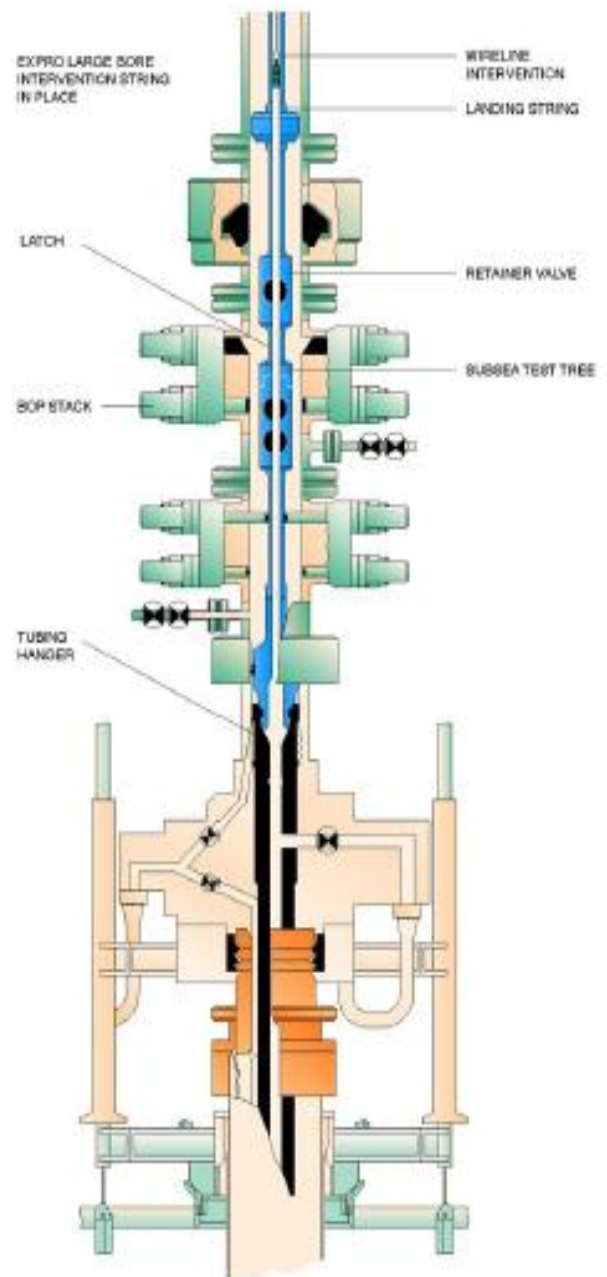


Figure 4 BOP

5. Hydraulic Control panel

To operate the subsea equipment from deck.

6. Other equipment

- Shear sub – positioned in the BOP allowing the shear rams to cut
- SSTT slick joint – enables closure of pipe rams
- Adjuster sub – Fluted hangar
- Umbilical Reeler Unit – connects the hydraulic control panel to the subsea equipment

The tools above are primary for semi-submersibles. For platforms, jack-ups or land rigs other safety system can be used.

7. SAFE Valve

A fail-closed valve that is held open during test operation due to applied hydraulic pressure. The SAFE valve is categorized as the primary safety barrier and is intended as the last line of defence and must only be operated in emergencies.

During an exploration test in the North Sea wireline operations are rare, but lubricator valves are included in the string design.

For clean-up tests subsea bigbore equipment is used. This is similar to subsea equipment, but with a larger diameter.

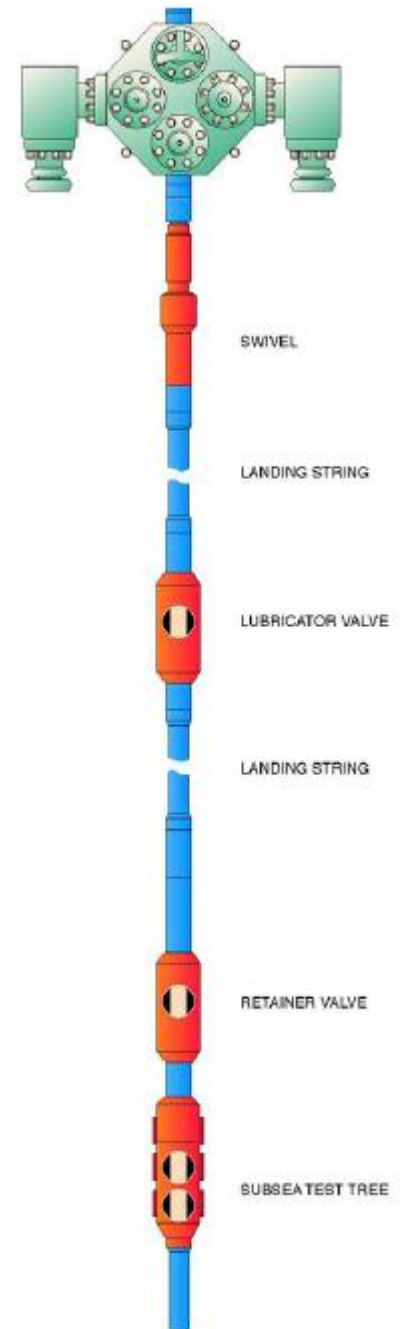


Figure 5 Subsea landing string

6.3.3 Surface equipment

At surface the produced fluid is handled by use of surface testing packages. This equipment needs to be designed and assembled to safely fulfill a wide range of operations[29]:

- Provide a means of quickly controlling the pressure and shutting in the well
- Separate produced fluids into oil, gas and water phases, allowing the constituents to be metered and record key parameters like temperature and pressure
- Allow representative samples of the produced fluids to be taken
- Dispose of fluids in an environmentally acceptable manner

A brief description of the main components in a surface testing package is given below. It must be emphasised that each well test job requires detailed planning and design related to expected operating conditions and customer objectives.

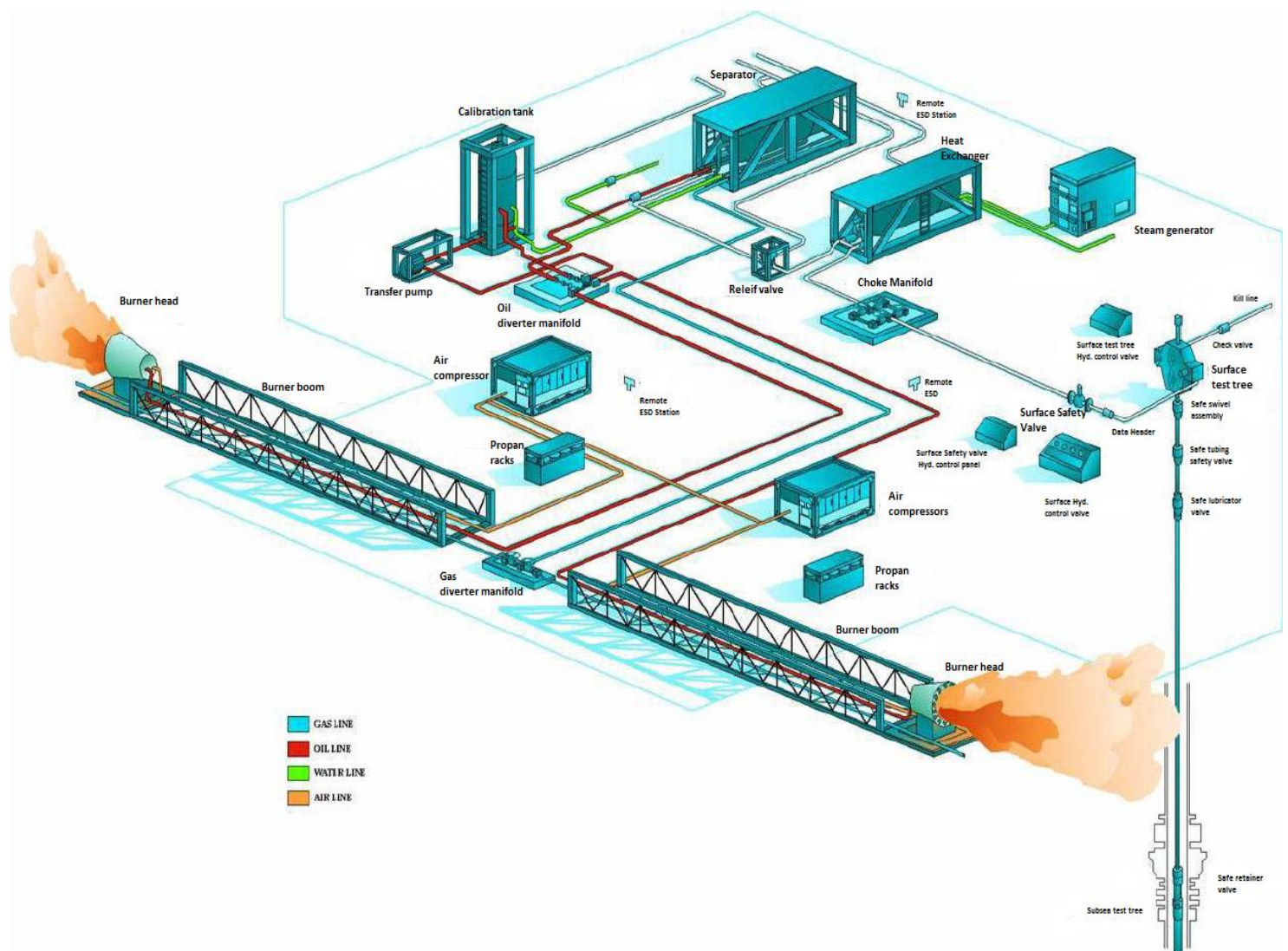


Figure 6 Surface well test system

1. Surface test tree(Flowhead)

A STT is installed directly onto a temporary completion string and creates a duplicate of a permanent X-mas tree. It contains four main valves[29]:

Master valve – allows isolation of the surface equipment from the downhole string.

Kill valve – allows to kill the well quickly

Swab valve – allows introduction and retrieval of slickline, wireline and coiled tubing.

Flow valve – equipped with an automatic hydraulic actuator which is linked into the ESD, thus automatically closing the valve in the event of a pre-programmed event (example too high presurre).

Lower master valve – An optional item which can be installed below the swivel. The lower master valve provide additional security in case of leakage in the swivel.

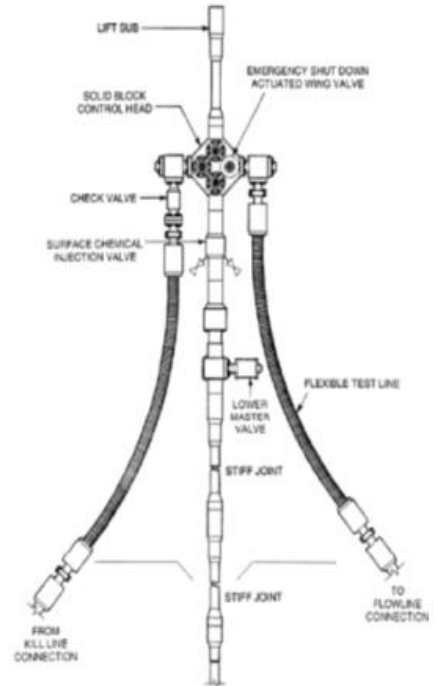


Figure 7 STT (Flowhead)

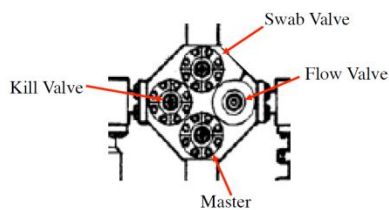


Figure 8 STT valves

2. Surface safety valve

SSV is a Fail-Closed valve that can be activated in case of an emergency. It is operated by air supply to be held open. It is connected to the ESD system and will close if Hi-Low Pressure pilots or Fluid level pilots are activated, or if any of the ESD buttons that are located around in the well test area are activated. If the ESD system is activated, air supply that is holding the valve open is cut, and the valves closes automatically.

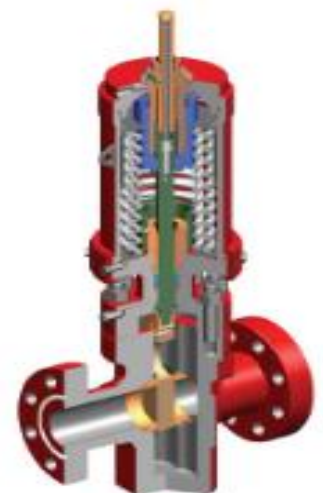


Figure 9 SSV

3. Sand filter

A filter installed upstream choke to remove drilling, completion and perforation debris during well tests and clean-ups. This is an additional equipment that is installed if high sand production is expected.

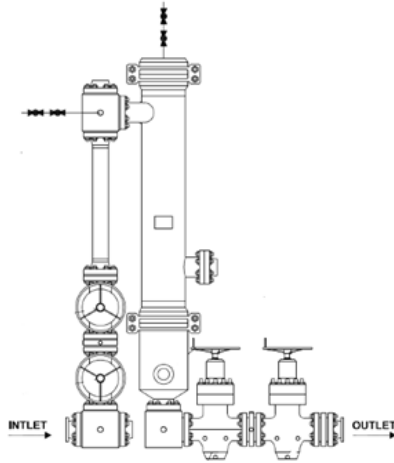


Figure 11 Sand filter

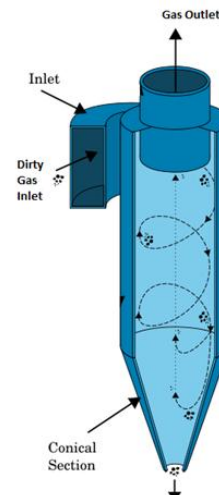


Figure 10 Desander

4. Choke Manifold

Primary means of controlling the flow from the well. Equipped with two types of chokes:

- Adjustable – used during clean-up period and allows for changing of fixed choke without closing in the well
- Fixed choke – a calibrated choke bean with an orifice that gives a more accurate flow

The flow can be controlled by changing size of choke bean or adjusting the adjustable choke. The fixed choke bean sizes are given in 64th. The aim is to get a critical flow across the choke. When this has been achieved, changes in pressure made downstream of the choke does not affect pressures and flow rates upstream of the choke.

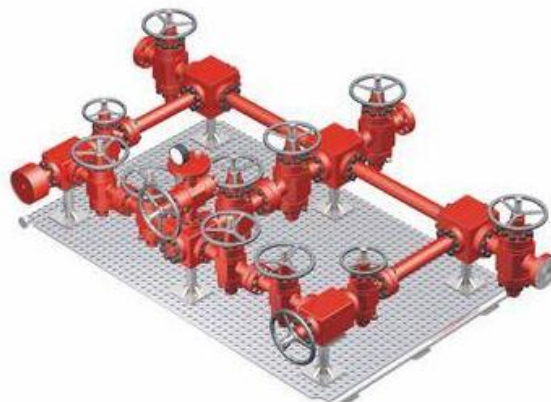


Figure 12 Choke manifold[3]

5. Heat Exchanger

Used if hydrating, emulsion, wax and foamy oil are expected due to heat loss through the choke. Heating of the fluids prevents the formation of emulsion, hydrates, wax and foamy oil and improves the separation of oil, water and gas in the separator. It also lowers the viscosity that promotes better flow to the burners.



Figure 13 Multitube Heat Exchanger

6. Separator

The fluids produced must be separated into oil, water and gas to be able to accurately measure flow rates and take samples. The separator is equipped with pneumatic controls which are needed for controlling the pressure and the fluid levels. Flow meters, either turbine meters or coriolis, are mounted on both the oil and water outlets and a daniel box or coriolis meter on the gas outlet. In the last years a new device called coriolis meter has been more and more used in well tests. Turbine, coriolis and orifice meters are described and discussed in chapter 7.

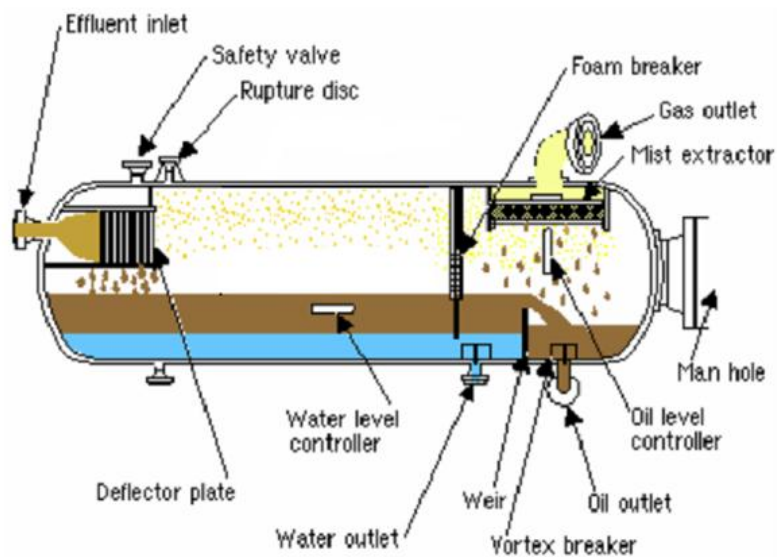


Figure 14 Separator

7. Calibration tank

The separated liquids can be diverted to a calibration tank which can vent to atmospheric pressure. The volume diverted to the tank is measured to help calibrate the flow meters. Because the pressure is reduced to atmospheric additional gas comes out of solution, causing shrinkage, which can also be measured[29]



Figure 15 Calibration tank[4]

8. Burner boom

To have a safe disposal of hydrocarbons on the offshore installation, it is important to position the gas/oil flare over the side of the installation. This requires that the burner heads are placed at the end of a boom.



Figure 16 Burner boom

9. Burner head

Used to provide clean and efficient disposal of produced oil during well test operations.

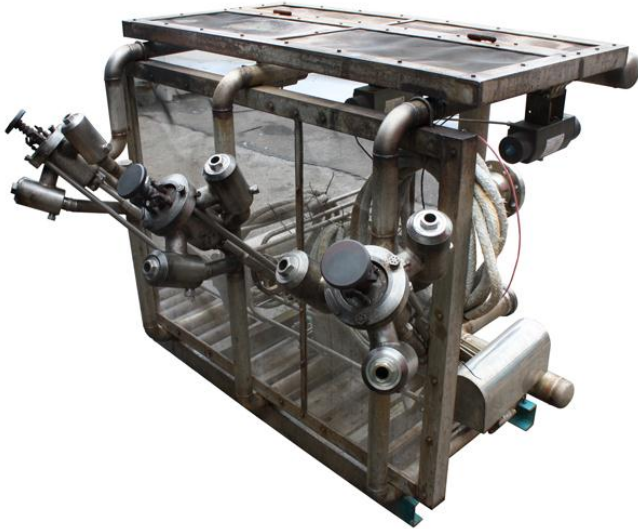


Figure 17 Burner head

10. Oil/Gas Diverter Manifold

A manifold with a number of valves (included number of gas/oil) used for diverting the oil and gas flow to the burners. Oil and gas manifolds are not commonly used on the Norwegian sector. Rig diverters are used to divert the oil or gas from the separator to burner booms.

6.4 Data Acquisition

Below is an overview of different data collected during a Well Test Operation and where in the system they are collected.

Table 1 Data Acquisition

Where data is taken	Description	Purpose
Bottom hole	Pressure	Find BHP and transient
	Temperature	Find BHT (and transient)
	Samples	Get samples as close to reservoir properties as possible
Well Head	Pressure	Find WHP and transient
	Temperature	Find WHT (and transient)
	WH fluid sampling	Get samples for PVT purpose and find CGR
Choke	Downstream pressure	Monitor pressure
	Downstream temperature	Monitor temperature
	BS&W	Monitor when clean-up phase is done
	Salinity	Monitor brine vs. formation water
	H ₂ S	Environmental and health risk
	CO ₂	Environmental and health risk
	pH	Monitor when clean-up phase is done
Separator – Gas line	Gas flow rate	Well productivity
	Specific gravity	Fluid parameter
	Gas samples	Recombination & GOR control
Separator – Oil line	Oil flow rate	Well productivity
	Temperature	Fluid properties for sampling at exact temp.
	Specific gravity	Fluid parameter
	Oil samples	Recombination, GOR control & wax/asphaltenes studies
Separator – Water line	Meter reading	Volumetric flow
	Water samples	Formation water analysis
Separator – shrinkage tester	Shrinkage factor	See shrinkage of oil from pressurised to atmospheric
Calibration tank	Correction factor	Correction of meter readings
	Bulk fluid samples	Separator experiment for field development

6.5 Calculations

A number of calculations lie behind the final parameters the client requires. Today softwares are available that do most of the calculations, but there are still some manual calculations needed to get the required input data for the software.

Two of the most important surface parameter the client is looking for, is the gas and oil rates. The gas and oil rate equations should form the basis for the calculations of rates in the software. Later in the thesis examples are given where equations are used to calculate the flow rates by hand and compared with rates calculated by the software to see the gap in the result.

6.5.1 Gas flow rate[5]

$$Q_{gas} \left(\frac{m^3}{h} \right) = \sqrt{h_w} * \sqrt{P_f} * F_b * F_{bp} * F_{tf} * F_{pv} * F_g * F_r * Y * F_{tb} * F_a$$

The gas flow rate is measured with an equipment called Daniel box or orifice meter. Alternative measurement is mass flow with a coriolis meter. We will describe this in more detail in chapter 7.

h_w – Differential pressure measured across orifice plate

P_f – Static pressure, upstream or downstream

F_b – Basic orifice factor

F_{bp} – Pressure base factor = $\frac{101.235}{P_b}$

F_{tf} – Flowing temperature factor = $\sqrt{\frac{288}{273+T_f}}$

F_{pv} – Supercompressibility factor, deviation from the ideal gas law

F_g – Relative density factor

F_r – Reynolds number factor

Y – Expansion factor (compensate for change in density through orifice)

F_{tb} – Temperature base factor = $\frac{273+T_b}{288}$

F_a – Orifice thermal expansion factor

6.5.2 Oil flow rate

$$Q_{oil} \left(\frac{Sm^3}{Day} \right) = V_s * MF * \left(1 - \frac{Shr}{100} \right) * \left(1 - \frac{BS\&W}{100} \right) * VCF$$

The oil flow rate is measured with a turbine meter installed on the oil line outlet from the separator. This is described in chapter 7.

V_s – uncorrected flow rate measured by turbine meter (M^3/day)

MF – meterfactor

Shr – shrinkage factor

$BS\&W$ – basic, sediment & water

VCF – volume correction factor.

6.6 Error and Accuracy[8]

Specifications of error and accuracy of a device can be written in different ways. In this sub chapter the different types of errors that might occur for instruments used for Well Testing are described.

In any measurements that is taken there will be some error. The lower the error, the higher the accuracy, and vice versa. It is important that the error and the accuracy are clearly specified.

Below is the most common types of errors that are considered in practice.

6.6.1 Absolute error

The absolute error is the difference between the real value and the meter reading.

Example: real value is 57 degrees and metered value is 55 degrees. Absolute error equals 2 degrees.

The absolute error itself does not give the full information and can be misleading. Two degrees error when we measure 200 gives 1%, while it is 10% if we measure 20 degrees.

6.6.2 Relative error (of rate error)

The relative error represents the relation between the absolute error and the real value .

Example: Real value is 300 bar and metered value is 295 bar. The absolute error is 5 bar. The relative error is 5 bar divided by 300 bar = 1.67%, and the accuracy equals 98.33 (of pressure)

The relative error does not take into account the range (the full scale) of the meter and where the real value is within the range, but we have clearly specified the error with this type.

6.6.3 Full scale error (FS)

Full scale error is the absolute error divided by the range(the full scale).

Example: A flow meter is specified to measure maximum 1000 GPM. We measure 50 GPM and the metered value is 45 GPM. The absolute error is 5 GPM and the full scale error is 5 divided by 1000 = 0.5% full scale. This means that no matter what the flow rate is the error will be 5 GPM.

On the next page are some illustrations of relative error and full scale error.

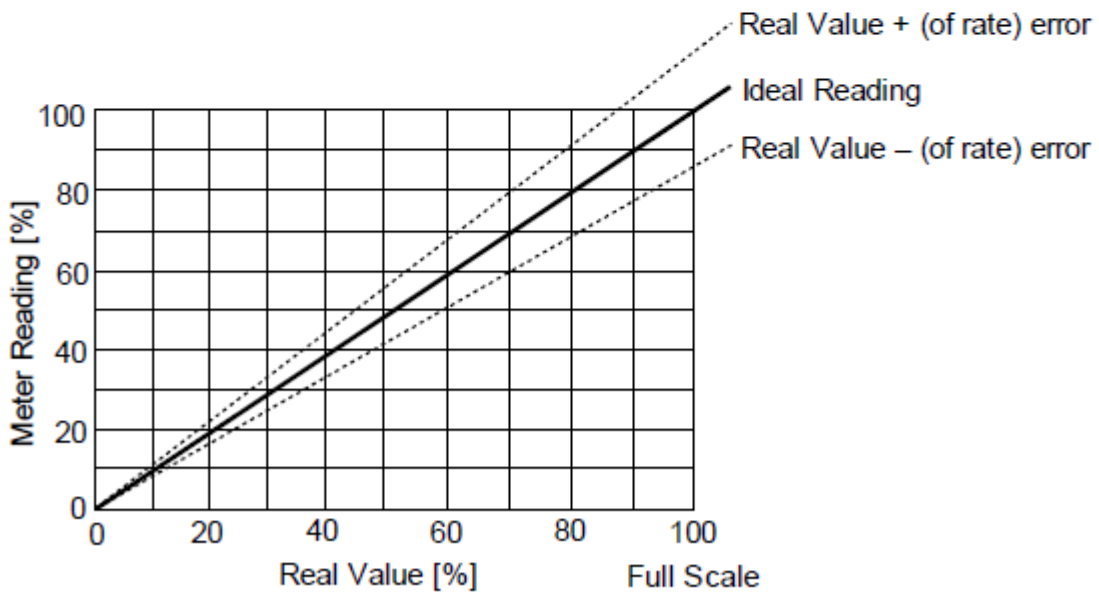
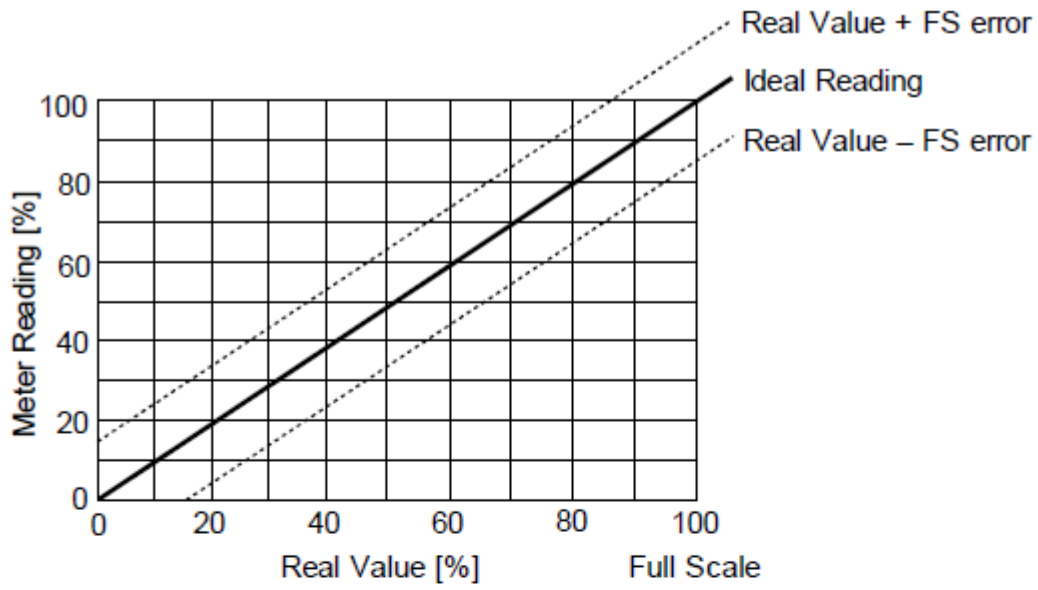


Figure 18 Full scale error & relative error[8]

6.7 Additional information

Below is an overview of different types of reservoir fluids and their characteristics. This categorizations comes from Petrowiki.com, and these values have been used to characterise fluids in this thesis. This is not a determined range, so companies and other organizations might have different ranges for the different fluids[7].

Table 2 Reservoir fluids characteristics

	Reservoir fluid characteristics					
	Gases			Oils		
	Dry gas	Wet gas	Gas Condensate	Volatile Oil	Black Oil	Heavy Oils and tars
Initial fluid mol. weight	<23		23 - 40	40 - 70	70 - 210	210+
Stock tank oil color	Clear		Orange to clear	Greenish to orange	Brown to light green	Black
API° gravity	45+		45 to 60	42 to 55	15 to 45	5 to 15
C7+ fraction mol%	0 to 1		1 to 6	10 to 30	35 to 50	>50
Initial FVF, B _o	20.0+		3.0 - 20.0	1.5 - 3.0	1.1 - 1.5	1.0 - 1.1
Typical res. temp, °F	150 - 300		150 - 300	150 - 300	100 - 200	90 - 200

6.8 Field information

Because field and well information need to be kept confidential, depths and critical information will not be mentioned, but a brief summary about what type of formation the discovery was found in will be given below. P&IDs and additional information for each well can be found in Attachment V.[6]

Case 1 – Gas field: this area is dominated by marine claystone.

Case 2 – Gas/consensate field: the area consists of sandstones, siltstones and shales with subordinate coal beds and conglomerates.

Case 3 – Oil field: this area consists mainly of fine-grained marine sediments with varying content of calcareous material. Calcareous clayston, slitstones and marstones is dominating, but subordinate layers of limestone and sandstone may occur.

7. Discussion

In this chapter I will describe each data gathering method and take a look at how the Expro procedures for performing the data gathering are. I will take a look to see if the procedures are in compliance with the standards that should be used and if there are some uncertainties related to the equipment that is used. I will also evaluate some data from three different jobs Expro has performed during the last 5 years and see if this has had some impact on data.

7.1 Data Gathering Methods

7.1.1 Downhole Pressure and Temperature

Downhole pressure and temperature gauges are used to get data as near reservoir conditions as possible. Today the technology has come so far that it is possible to get surface readout while a test is ongoing, but Expro is now using the old method with memory gauges. These are storing devices that take pressure and temperature readings during a test, but the gauges need to be retrieved to surface before the data can be read.

The most common used is a three-quartz crystal transducer. These work by vibration in the crystals that changes frequency in response to changes in pressure and temperature. The quartz crystal pressure transducer has an excellent gauge factor that gives an exceptional accuracy, resolution and long-term stability. The reference crystal is used to reduce the frequency signals from the pressure and temperature. This is to simplify the frequency counting requirements. The quartz resonators vibration can be driven with very little electrical power.[17,19]

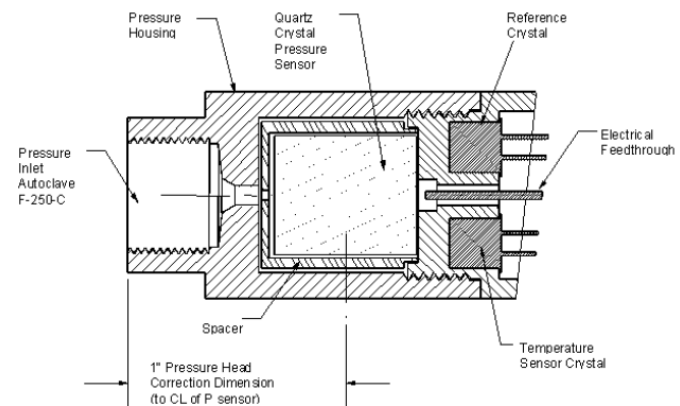


Figure 19 Three quartz crystal transducer[17]

A short summary of the accuracies related to the equipment used will be described in the next section. The full technical specification can be found in Attachment IV



Figure 20 Downhole memory gauge[18]

Memory gauges used by Expro:

1. Expro Memory Gauges

Table 3 Expro memory gauges specification

Technical specification			
	CT1000	MT1000	HT1000
Pressure range	0 – 16,000 psi	0 – 16,000 psi	0 – 20,000 psi
Accuracy	+/- 3.2 psi	+/- 3.2 psi	+/- 3.2 psi
Temperature range	32 - 350°F (0 - 177°C)	32 - 350°F (0 - 177°C)	32 - 392°F (0 - 200°C)
Accuracy	=/- 1.8°F	=/- 1.8°F	=/- 1.8°F

2. SPARTEK Memory Gauges

Table 4 SPARTEK memory gauges specification[34]

Technical specification			
	SS5063	SS5067	SS5200
Pressure range	0 – 16,000 psi	0 – 25,000 psi	0 – 25,000 psi
		0 – 35,000 psi	0 – 35,000 psi
Accuracy	0.020% Full-scale	0.020% Full-scale	0.020% Full-scale
		0.025% Full-scale	0.025% Full-scale
Temperature range	77-350°F (25 - 177°C)	77-350°F (25 - 177°C)	77-392°F (25 - 200°C)
Accuracy	0.9°F (0.5°C)	0.9°F (0.5°C)	0.9°F (0.5°C)

Inaccuracies related to this measurement:

Memory gauges – for the downhole memory gauge we will have the inaccuracies that are related to the gauge itself. One accuracy is related to the quartz pressure crystal and one to the quartz temperature crystal. For the SPARTEK Memory gauges the pressure might come in two different range. There will be different accuracy related to each range. The accuracies are shown in the table above.

For Expro memory gauges I assume that the accuracy is +/- 3.2 psi of reading, but it should have been written clearly in the specification what type of error it is.

Procedure – there is no procedure related to this measurement. Downhole memory gauges are run by personnel that are specialists in the field of gauges and data acquisition.

7.1.2 Surface Pressure

Surface pressure is measured by the use of a pressure transmitter. A pressure transmitter will produce an electrical output signal, current, when it is exposed to a pressure source and connected to an appropriate electrical source. Most of the pressure transmitters are designed to produce an output signal that is linear with respect to the applied pressure.

A transmitter works by having a sensing element of constant area and the responds to the force applied to this area by the fluid pressure. This force deflects a diaphragm and the deflections are converted to electrical outputs. The output will be a current between 4- and 20 mA.[14]

An illustration is shown below.

Another method for measuring pressure is a transmitter with Piezoelectric effect. This effect is the ability of a certain material to generate an electric charge due to applied mechanical stress. See picture below for illustration on how this effect works.[16]



Figure 21 Rosemount Pressure transmitter[28]

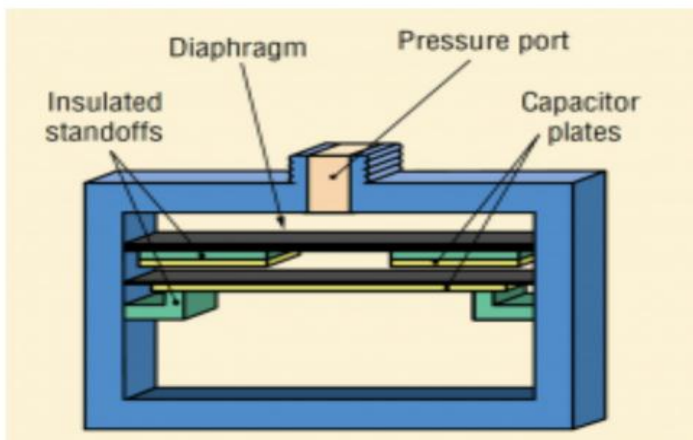


Figure 22 Mechanical displacement[14]

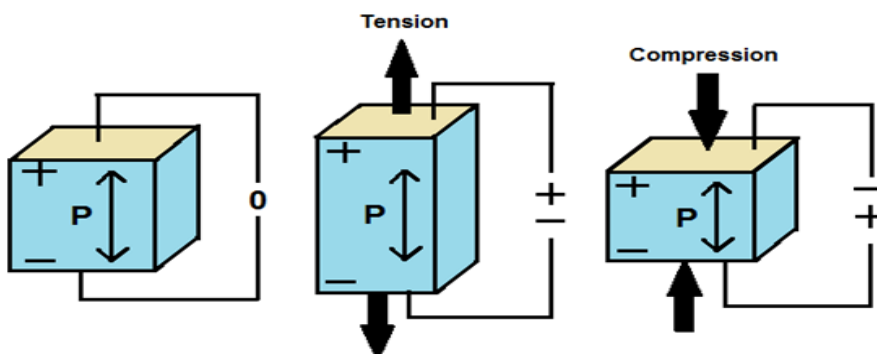
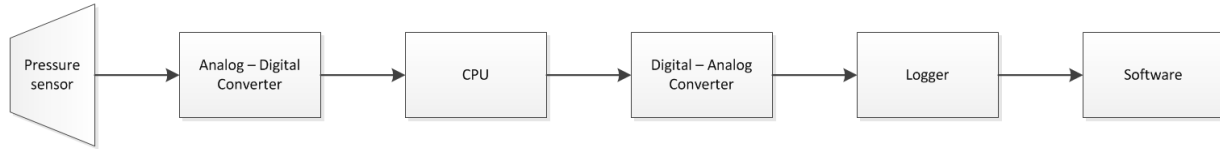


Figure 23 Piezoelectric effect - deformation[20]

The pressure unit itself is a very complex device with a lot of conversions to get the pressure value from the software. Below I have made a block diagram to show how the process works and to be able to evaluate the steps for error later in this chapter. I will describe each step to give the reader a better understanding how this system works.



In the first block a change in voltage due to mechanical displacement or deformation will be detected. This signal is sent to a analog/digital converter. The next step is the CPU that processes the digital value for temperature corrections and against the max and min range that is set, normally 4-20 mA. This digital value is sent to the digital/analog coverter and you will get a value that is between 4-20 mA. The logger is set up with a specific bit size and and the bit size gives some numbers that are used to calculate the output value in bar or psi. See a example below. The bit numbers are not correct, but used for illustration only. For this example a pressure transmitter with a range 0-750 bar is assumed.

$$13107 = 4mA = 0 \text{ bar}$$

$$65350 = 20mA = 750 \text{ bar}$$

A signal of 12 mA goes into the logger

$$12 \text{ mA} = 13107 + 8 * 3277 = 39323 = 350 \text{ bar}$$

A short summary of the accuracies related to the equipment used will be described in next section. The full technical spesification can be found in Attachment IV

Pressure transmitters used by Expro:

1. Rosemount 3051T

Table 5 Pressure transmitter specification[35]

Technical specification				
Range an sensor limits				
Range	Minimum span	Upper (URL)	Lower (LRL)	Lower gauge (LRL)
1	0.3 psi (20.6 mbar)	30 psi (2.07 bar)	0 psi (0 bar)	-14.7 psig (-1.01 barg)
2	1.5 psi (0.103 bar)	150 psi (10.3 bar)	0 psi (0 bar)	-14.7 psig (-1.01 barg)
3	8.0 psi (0.55 bar)	800 psi (55.2 bar)	0 psi (0 bar)	-14.7 psig (-1.01 barg)
4	40 psi (2.76 bar)	4000 psi (257.8 bar)	0 psi (0 bar)	-14.7 psig (-1.01 barg)
5	2000 psi (137.9 bar)	10,000 psi (689.4 bar)	0 psi (0 bar)	-14.7 psig (-1.01 barg)
Reference accuracy - standard				
Range 1 - 4		$\pm 0.065\%$ of span		
For spans less than 10:1		$\pm \left[0.0075 \left(\frac{URL}{Span} \right) \right] \% \text{ of span}$		
Range 5		$\pm 0.075\%$ of span		
Spans less than 10:1		$\pm \left[0.0075 \left(\frac{URL}{Span} \right) \right] \% \text{ of span}$		
Reference accuracy - high				
Range 2 - 4		$\pm 0.04\%$ of span		
For spans less that 5:1		$\pm \left[0.0075 \left(\frac{URL}{Span} \right) \right] \% \text{ of span}$		

Inaccuracies related to this measurement:

The pressure transmitter – as mentioned above there is a lot of conversion from detecting a change in voltage to get the output in bar or psi. There will be an uncertainty related to each conversion. The reference accuracy for the Rosemount 3051T takes into account all the blocks from the pressure sensor to the digital/analog converter.

Logger– the logger that is converting the analog reading to a pressure value will also have an uncertainty. The logger might be supplied by the vendor of the software used or Expro will buy components and build a logger. Since the logger is a part of the software package and this is one of my limitation in this thesis, I have not been able to find the accuracies related to this equipment. The loggers that were build by Expro were build in UK, and here as well did I not manage to find out who was delivering the components and what the accuracy related to each component was.

Location – the Rosemount 3051T comes in different range sizes. It is important to place a pressure transmitter with a correct range at the right place in the well test system. If a transmitter with lower range than necessary is placed in a particular place in the system you will not get the correct reading.

Procedure – there is no procedure related to this measurement. The installation of pressure transmitter is done by the data aquisition personnel.

7.1.3 Surface Temperature

The surface temperature is measured by the use of a temperature transmitter. A temperature transmitter has a sensor called a resistive temperature detector (RTD), and this will change the resistance as a function of temperature. The most common sensor is a Pt100 that measures 100 omhs at 0°C. A change in temperature on the Pt100 sensor will create a change in its resistance. The resistance can be measured and the temperature can be attained.[15]

A picture of a temperature transmitter from Rosemount is shown to the right.

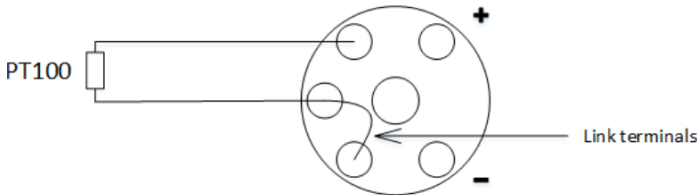
Inside the probe will there normally be a 3 wire circute system for a temperature transmitter. The wire will approximately be of the same length as the probe. Since we have some length on the probe to be able to measure temperature in the center of the pipe, there will be an additional resistance in the wire. To compensate for this resistance, an additional wire is used.

Illustrations of different wire setups and their function will be discussed briefly below.[15]



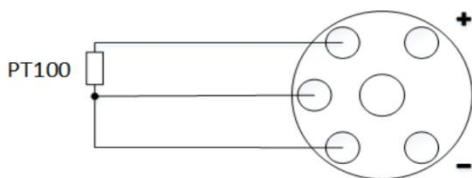
Figure 24 Temperature transducer[21]

2 wire connection[15]:

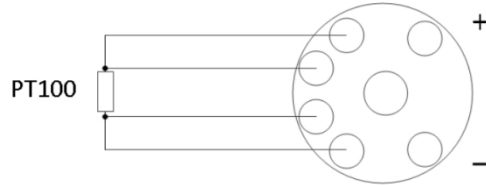


In a two wire probe you will have a lead resistance over the wire and no compensation for it. The lead resistance will be added to the sensor resistance.

3 wire connections[15]:

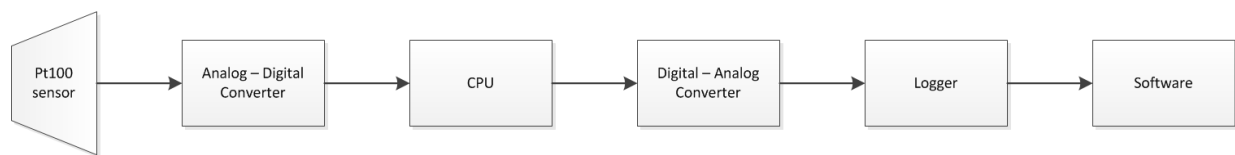


In a three wire probe you will have three wires connected to the temperature transmitter where the third is compensating for the resistance over the wire.

4 wire connections[15]:

A four wire probe is used when a higher accuracy is wanted. You will here have a lead resistance compensation on both sides of of the Pt100 sensor.

The temperature transmitter has a similar process as the one for pressure, see block diagram below.



The Pt100 element detect a change in resistance due to temperature change and sends it to the analog/digital converter. The CPU unit processes the resistance against the max and min range set for the transmitter and the process continues as for the pressure transmitter.

A short summary of the accuracies related to the equipment used will be described in the next section. The full technical specification can be found in Attachement IV.

Upstream choke where we have high pressure, clamp-on transmitters are used. This is a more secure way to measure temperature since no probe need to be inserted in a dataheader. As the name implies is this transmitter clamped around the pipe. The PT100 element is placed on the inside of the clamp, and changes in temperature of the fluid is transferred through the metal and gives a resistance change at the Pt100 element. It works exactly like the transmitter described above and has the same accuracies.

Temperature transmitters use by Expro:

1. Rosemount 644H

Table 6 Temp. transmitter specification 1[36]

Accuracy								
Sensor option	Sensor reference	Input range		Recommended min. span		Digital accuracy		D/A accuracy
2-,3-,4-wire RTDs		°C	°F	°C	°F	°C	°F	
Pt100	IEC 751, 1995($\alpha=0.00385$)	-200 to 850	-328 to 1562	10	18	± 0.15	± 0.27	$\pm 0.03\%$ of span
Pt100	JIS 1604, 1981 ($\alpha=0.003916$)	-200 to 645	-328 to 1193	10	18	± 0.15	± 0.27	$\pm 0.03\%$ of span
Ambient temperature effect								
Sensor option	Sensor reference	Temp. Effect per 1.0°C (1.8°F) change in ambient temperature			Range		D/A Effect	
2-,3-,4-wire RTDs								
Pt100	IEC 751, 1995($\alpha=0.00385$)	0.003°C (0.0054°F)			Entire Sensor input range		0.001% of span	
Pt100	JIS 1604, 1981 ($\alpha=0.003916$)	0.003°C (0.0054°F)			Entire Sensor input range		0.001% of span	

2. Rosemount 3144P

Table 7 Temp. transmitter specification 2[37]

Accuracy								
Sensor option	Sensor reference	Input range		Recommended min. span		Digital accuracy		D/A accuracy
2-,3-,4-wire RTDs		°C	°F	°C	°F	°C	°F	
Pt100	IEC 751, 1995($\alpha=0.00385$)	-200 to 850	-328 to 1562	10	18	± 0.10	± 0.18	$\pm 0.02\%$ of span
Pt100	JIS 1604, 1981 ($\alpha=0.003916$)	-200 to 645	-328 to 1193	10	18	± 0.10	± 0.18	$\pm 0.02\%$ of span
Ambient temperature effect								
Sensor option	Sensor reference	Temp. Effect per 1.0°C (1.8°F) change in ambient temperature			Range		D/A Effect	
2-,3-,4-wire RTDs								
Pt100	IEC 751, 1995($\alpha=0.00385$)	0.0015°C			Entire Sensor input range		0.001% of span	
Pt100	JIS 1604, 1981 ($\alpha=0.003916$)	0.0015°C			Entire Sensor input range		0.001% of span	

Inaccuracies related to this measurement:

The temperature transmitter – for the temperature transmitter a lot of conversion will also be done before the correct value can be read from the software. We have similar block diagram as for the pressure transmitter and the accuracy for each transmitter takes into account all uncertainties from the PT100 element to the digital/analog converter. This is connected to the same logger as for the pressure transmitter, so the accuracy for the logger will be the same here.

Procedure – there is no procedure related to this measurement. The installation of the temperature transmitter is done by the data acquisition personnel.

7.1.4 BS&W

BS&W stands for Base Sediment and Water. This is a measurement done to determine whether a clean-up is achieved or not. Equipment that is necessary is

- Sample bottle
- Centrifuge (mechanical- or hand-operated)

The sample should be taken downstream choke. At this location there will be turbulent flow and the fluids will be well mixed. A sample should never be transferred to another container because this will leave some content in the original container, making the sample unrepresentative. A sample should be taken directly into a centrifuge for separation. The BS&W is expressed and recorded as the water content and sediment/solid content.

Samples can also be taken from the oil line on the separator to indicate how much gas we have entrained in the oil.

BS&W equipment used by Expro:

1. Sampling cylinder
 - 100 ml
 - 250 ml
2. Centrifuge

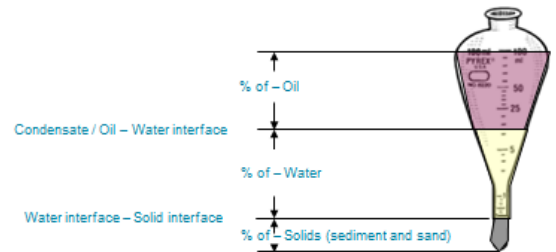


Figure 25 BS&W measurement

Inaccuracies related to this measurement:

Sampling cylinder – normally a 100 ml conical sampling cylinder will be used. If you have fluids with foaming problems, a 250 ml sampling is used to make sure you have enough space in the cylinder to get 100 ml representative sample. If the level is above or below when you take the reading, calculations need to be done to get exact percentage reading of BS&W.

Sampling point – the BS&W can be taken several places in the well test system. It is important to have correct sampling point to make sure you have a good mixing of the fluids and the best conditions will be when you have turbulent flow.

Condition of the fluids – the phase of the fluid will have an impact on this measurement. For crude oil you will have the possibility to take a sample of 100 ml, while for gas-condensate it might be more difficult. If you have a gas-condensate fluid, you would fill up the cylinder as best you can and take a reading from that. Since you do not have a full cylinder, calculations to find the right percentage have to be performed.

Procedure – the procedure that Expro has is similar to the one given by ASTM D4007-11e1. Both procedures state that toluene and demulsifier should be added to the sample to reduce interfacial tension between oil and water. A question was raised to offshore supervisors in Expro if this was something they actually add to the sample, and the answer was no. Normally special designed chemicals provided by customer are used if a field has fluids with separations problems.

7.1.5 Ph

The pH measurement is commonly done if an acid job is done prior to a test or a clean-up. To find out if the acid has been washed out during the clean-up, we will measure the pH of the produced water. It is not important in the field to know what the exact pH value is, just if it is acidic or not. pH paper, or litmus paper, is a colour reacting paper. A colour scale indicates whether the water produced is neutral, acidic or alkali.

- 7 on the pH scale is neutral
- Anything below 7 is acidic
- Anything above 7 is alkali



Figure 26 pH paper[11]

Inaccuracies related to this measurement:

No relevant unaccurasies – the pH is only a rough measurement. The objectives is to identify acidic content of the fluids produced if an acid job has been done prior the the well test. With the use of pH paper we get color indication of which pH the fluid contain and that is the only information we need.

7.1.6 Salinity

Salinity is a measurement taken of produced water. The purpose is to check if it is brine from drilling operations or formation water that is produced. In Expro a clean-up phase considered done when the BS&W is 0,1% or below. In some cases will this value not be reached, because formation water is produced. The salinity of the brine is known, so a refractometer is used to determine whether the produced water is brine or formation water.



Figure 27 Refractometer

A short summary of the accuracies related to the equipment used will be described in the next section.

Refractometers used by Expro:

Bellingham + Stanley Eclipse refractometer

Table 8 Refractometer specification[38]

Technical specification: industrial model 45-65		
Description	Range	Sacle division
Salinity (%NaCl)	0 - 28	0.2

Inaccuracies related to this measurement:

No relevant inaccuracies – salinity is also a rough measurement so no relevant unaccuracies is related to this measurement. The reading that is taken is to give an indication if it's formation water or brine that is produced. This can be of importancy in conjunction with the clean-up phase. A clean-up phase is considered done when the BS&W is less than 0.1%. If this can not be reached, the salinity can be tested to confirm which type of water it is.

7.1.7 H₂S and CO₂

H₂S, hydrogen sulfide, is a hazardous, toxic compound found in crude oil and natural gas. It is a colorless, flammable gas that can be identified in relative low concentrations by the characteristic rotten egg odor. At higher concentration the smells disappear because the gas paralyzes the olfactory nerves in the nose, and it will affect respiratory tissues that can lead to death.[9]

CO₂, carbon dioxide, is a slightly, odorless and colorless gas. At lower concentration the CO₂ affects the respiratory- and central nervous system. Higher concentration will make it difficult to eliminate the CO₂ and it can accumulate in the body. This can in the worst case cause death.[9]

Sampling and measurements for H₂S and CO₂ should at least be conducted twice during a flow period. Equipment that is necessary is

- Dräger pump/hand pump
- Ampoules tubes (available in different sizes)

There are different scales and types of the tubes and the understanding of the correct selection process is important for accurate measurement. Inside the tubes there is a paper coated with a chemical which reacts with the gas being measured. It can be measured in ppm or percentage.



Figure 28 Dreager tubes

A short summary of the accuracies related to the equipment used, will be described in the next section. The full technical specification can be found in Attachment IV.

H₂S measure devices used by Expro:

1. Ampoules tubes by Dreager

Table 9 Dreager tubes specification[39]

Technical specification						
Hazardous gas	Type	Range	Strokes	Time for measurement	Standard deviation	Color change
H ₂ S	0.5/a	0.5–15 ppm	10	Approx. 6 min	± 5 – 10%	White → brown
	5/b	5–60 ppm	10	Approx. 4 min	± 5 – 10%	White → brown
CO ₂	0.1%/a	0.5–6/0.1–1.2%	1/5	Approx. 30 s/ approx. 2.5 min	± 5 – 10%	White → violet
	1%/a	1-20%	1	Approx. 30 s	± 5 – 10%	White → violet

2. Hand pumps by Dreager

Inaccuracies related to this measurement:

Tube selection – when the content of a hazardous gas is to be measured, it is important to select the correct range. Normally the client will provide an estimate of what the expected content of that particular gas is, and the correct tube can be chosen. If a wrong tube is used, it can cause too low or high reading.

Number of strokes – each tube has a specified number of strokes that shall be applied by the handpump the tube is inserted to. The number of strokes shall be stamped on each tube, but can also be found in the specifications for each tube. It is important to apply the correct number of strokes since the scale on the tube is designed for a specific volume of gas sucked into the tube by the hand pump.

Hand pump – the hand pump should be checked for damage before use. If the bellow is damaged it will not suck in the correct volume of gas and it will give a wrong reading.

Sampling compartment – the measurement should be taken in a fairly closed chamber so it does not interfere with other gases. It is preferable to have the concentration as pure as possible to get most accurate reading. Since H₂S and CO₂ are heavier gases than air, it is important to have continuous flow from the separator to make sure they don't fall to the bottom of the compartment. The flow from the gas line on the separator should be controlled to make sure no condensate splashes into the compartment and goes into the ampoule tube. This will give wrong reading.

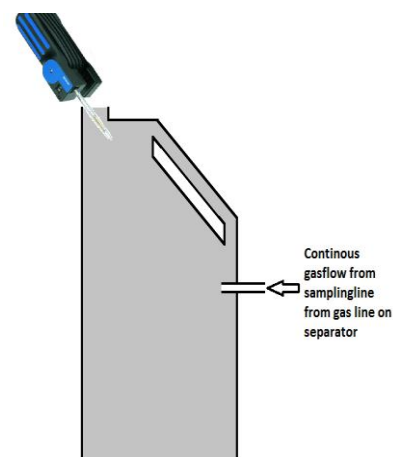


Figure 29 H₂S/CO₂ sampling compartment

Table 10 Dreager fluids properties[23]

GAS	MOLECULE WEIGHT	DENSITY(kg/m ³) Normal T and P
Air	29	1.205
Carbon dioxide	44.01	1.842
Hydrogen sulfide	34.08	1.434
NTP - 20°C and 1 atm		

Cross sensitivity – some gases may interfere with the H₂S or CO₂ and give wrong reading on the tube. The list of cases that may interfere can be found in the tube specifications in Attachment IV.

Procedure – the Expro procedure states that a gas balloon or a stainless steel cylinder should be used for measurement. This is not in conjunction with what is actually done offshore. Offshore supervisors use the method described above with continuous flow into a fairly closed chamber. After asking the Expro fluids manager what she recommended to use, she said that gas balloon and sampling cylinder should be avoided since the gas may absorb and give wrong reading.[24]

7.1.8 Oil gravity

The specific gravity of oil is calculated with reference to water. It is defined as the ratio of the density of the oil to the density of the water at a specific temperature and pressure.[13]

$$SG_{oil}(P, T) = \frac{\rho_{oil}}{\rho_{water}}$$

To measure the specific gravity Expro uses thermohydrometers. This is an equipment measuring both specific gravity and temperature of the oil. A hydrometer only measures specific gravity and temperature needs to be measured separate with a thermometer. From now on both will be described as hydrometer. The hydrometers are made with various ranges and both API and SG scales. To convert from specific gravity to API gravity, or vice versa, we need to use the following formulas

$$API\ gravity = \frac{141.5}{SG} - 131.5$$

$$SG = \frac{141.5}{API\ gravity + 131.5}$$

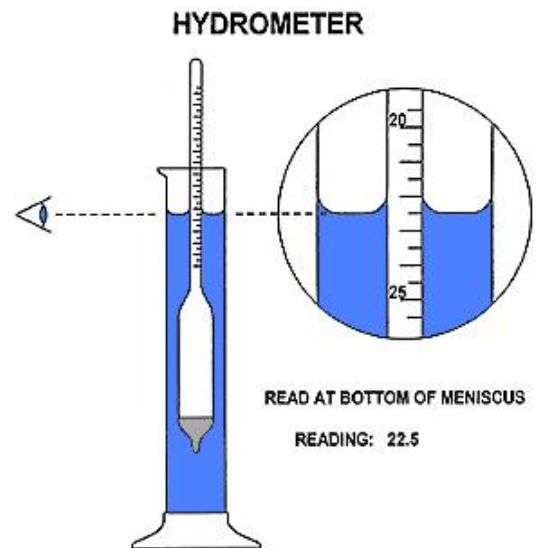


Figure 30 Hydrometer[22]

Another device to measure oil gravity is densimeter. A densimeter works by a drive coil that forces a tube to vibrate at some natural frequency which is a function of the tube's mass per unit length. When a fluid flows through the tube, the resonant frequency varies with the density of the fluid[5].

A short summary of the accuracies related to the equipment used will be described in the next section.

Oil gravity devices used by Expro:

1. Thermohydrometer

Table 11 Thermohydrometer specifications[40]

Technical specification		
ASTM no.	Range S.G.	Accuracy
82H	0.650 - 0.700	0.0005 SP.GR
83H	0.700 – 0.750	0.0005 SP.GR
84H	0.750 – 0.800	0.0005 SP.GR
85H	0.800 – 0.850	0.0005 SP.GR
86H	0.850 – 0.900	0.0005 SP.GR
87H	0.900 – 0.950	0.0005 SP.GR
88H	0.950 – 1.000	0.0005 SP.GR
89H	1.000 – 1.050	0.0005 SP.GR
90H	1.050 – 1.100	0.0005 SP.GR

Table 12 Aerometer specifications[41]

Technical specification - Areometer
Range S.G. (g/mL)
1,100 – 1,200
1,200 – 1,300
1,300 – 1,400
1,400 – 1,500

2. Cylinder

Table 13 Cylinder specification

Plactic cyliders	250 ml
	500 ml
	1000 ml

3. Densimeter

Table 14 Densimeter specification[42]

Technical specification	
Density range	0 – 1.999 g/cm^3
Accuracy	$\pm 0.001 g/cm^3$
Temperature range	0 – 40°C (32 – 104°F)
Accuracy	$\pm 0.2^\circ C$

Inaccuracies related to this measurement:

Hydrometer selection – it is important to select the right hydrometer when the measure of the oil gravity is to be performed. In Expro inventory two hydrometer types available. One is in conjunction with the ASTM standard, the other not. We see from the technical specification above that the ASTM hydrometer is in the range 0.05 while the other one is of range 0.1. With a larger scale range it can be assumed that the error will be larger since this is a reading done by the eye. There are no given accuracy from the manufacturer for these hydrometer.

Cylinder – there is requirement to the clearance between the cylinder bottom and walls when the hydrometer is installed. 1" between the hydrometer and the bottom of the cylinder and the ID of the cylinder shall be 1" greater than the OD of the hydrometer. A cylinder of appropriate size shall therefore be chosen.

Corrections to standard condition – The correction of the oil gravity to standard conditions is either done by the software used for data acquisition or can be quick checked by an Excel spreadsheet created internally in Expro. The input values are uncorrected specific gravity of oil, temperature of the oil in the cylinder when the S.G. of oil is read, and the oil line temperature when the sample was taken. The output values are k factor and corrected specific gravity. See Attachment I for formulas used for correction to standard conditions.

Densimeter – Densimeter has a lower accuracy than hydrometers and should not be used for oil gravity measurements. A reading with densimeter is done to spot check the reading of the hydrometer. A densimeter will also have problems with measuring the density if you have a light oil with gas bubbles. Offshore supervisors states that in a situation like this you will most likely not get a reading at all. Hydrometer should therefore always be used.

Procedure – the procedure given by Expro is very brief compared to the ones given by ASTM D287-12b and ASTM D6822-12b. The ASTM standards recommend to take two measurements and have requirements about how small the variation in temperature should be. The Expro procedure does not say anything about this.

7.1.9 Gas gravity

The specific gravity of gas is normally calculated with reference to air. It is defined as the ratio of the density of the gas to the density of the air, at a specific temperature and pressure.[10]

$$SG_{gas}(P, T) = \frac{\rho_{gas}}{\rho_{air}}$$

To measure the specific gravity we use a Gas gravimetric method, a Ranarex. The Ranarex consists of two cylindrical, gas-tight measuring chambers, each having a separate inlet and outlet connection. In each chamber there is an impeller and an impulse wheel, both with axial vanes. These wheels are mounted on separate shafts, facing each other but not touching.

An electrical motor and drive belt rotate the impellers at the same speed and in the same direction. The impellers draw continuous flow of gas sample into upper chamber, and reference air into the lower chamber. They spin the gas and air against the vanes of the corresponding impulse wheels. As the spinning gas and air impinge against the vanes, they create torque on the wheels that are proportional to the density of the gas and of the air.

The torque is transmitted from the chambers to two external measuring wheels. A flexible tape is wrapped on the measuring wheels so that the torque creates two opposing forces as shown in the schematic below. The measuring wheels are restrained from continuous rotation, but a difference between the torque forces allows limited motion of the entire system. The measuring system divides the torque of the gas divided by the density of the air, and thereby measures specific gravity[31]. See schematic below. This description is taken from the Ranarex gravitometer datasheet.

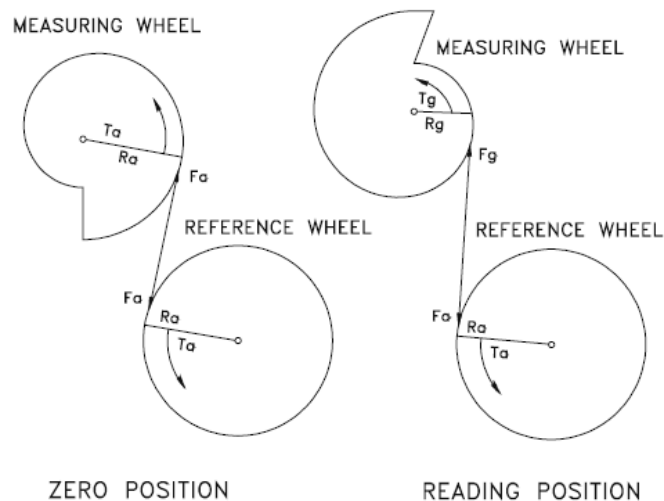


Figure 31 Ranarex measuring wheels schematics[32]

At the inlet there is a compartment with silica gel to remove moisture in the gas before the specific gravity is measured.

A short summary of the accuracies related to the equipment used will be described in the next section. The full technical specification can be found in Attachment IV.



Figure 32 Ranarex gravitometer[12]

Gas gravity devices used by Expro:

1. Ranarex gravitometer

Table 15 Ranarex specifications[31]

Technical specification	
S.G range	Dual scale: 0.52 – 1.03 & 0.97 – 1.90
Accuracy	$\pm 0.5\%$ of actual value

2. Gas bladder

Inaccuracies related to this measurement:

Ranarex gravitometer – the accuracy related to the specific gravity measurement of gas is the accuracy related to the gravitometer itself. The device measures the density of the gas related to the density of the air at same pressure and temperature. So temperature and pressure will have no effect on the reading. The gas bladder that is used for sampling do not hold pressure or temperature, so as soon the bladder is removed from the sampling point at the separator and carried to the lab container, the atmospheric conditions will in theory work upon the gas.

Silica gel compartment – the silica gel can only remove small amounts of moisture in the gas. If larger amounts of liquids in the gas enter the Ranarex the silica gel will not be able to handle the amount and the measurement will be wrong. In worst case it may damage the Ranarex gravitometer as well. This is especially related to wet gas and gas condensate systems.

7.1.10 Oil flow rate

Oil rates are normally measured by turbine meters. The turbine meter normally consist of a moving part, an impeller held in place by high pressure, low drag bearings. A magnetic transducer is installed in the meter body to count revolutions as the flow passes. The pulses from the transducer are determined for a known volume passing through the meter. This factor can be in pulses per gallon or other desired unit volume[5].

A picture of the components in a turbine meter is shown below.

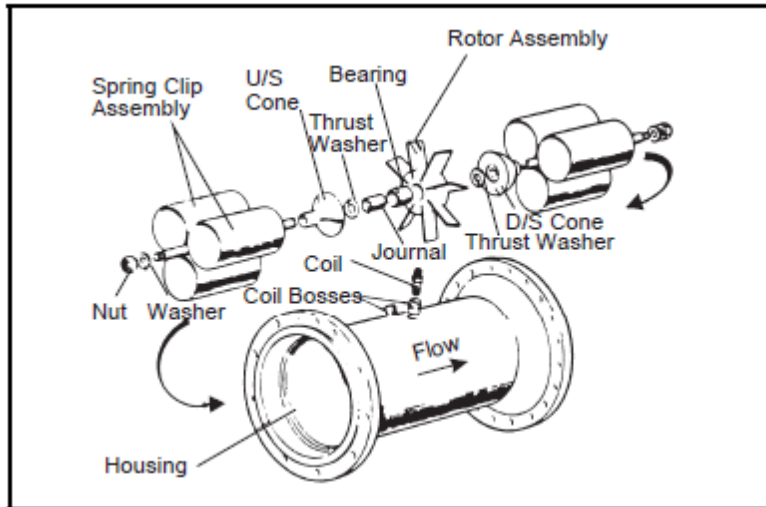


Figure 33 Turbine meter internal components[5]

Due to pressure loss from the turbine meter to the calibration tank, a meter factor needs to be taken. The pressure loss is created by the level control valve downstream the turbine meter and regular pressure drop in pipe. A decrease in pressure can cause changes in the oil and give precipitations of gas. The phase envelope below illustrates what happens when the pressure decreases for oil.

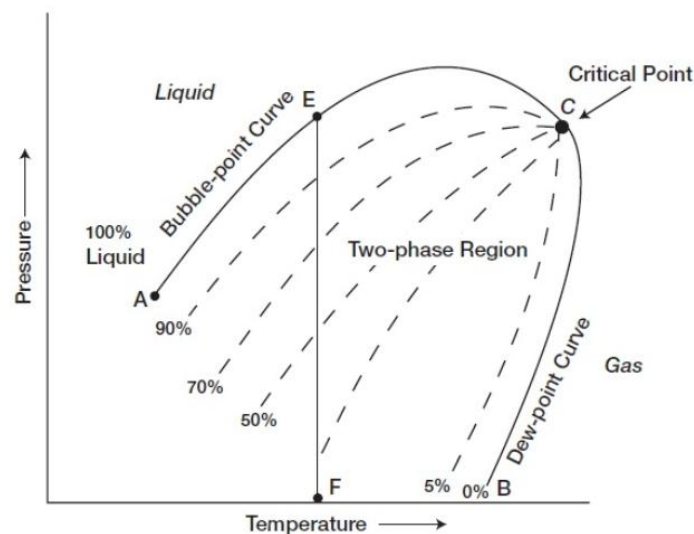


Figure 34 Phase envelope[26]

The meter factor is given as the relationship between the volume that passes through the turbine meter and a measured volume in the calibration tank. These two readings need to be done at the same time.

To be able to give the oil flow rate at standard condition a shrinkage factor need to be added. This is a measurement done in the calibration tank where you take a known volume of oil and bleed the pressure to zero and record the shrinkage of oil. The oil will shrink due to gas precipitation when the pressure decreases.

The formula used to measure the oil rate is

$$Q_{oil} \left(\frac{Sm^3}{Day} \right) = V_s * MF * \left(1 - \frac{Shr}{100} \right) * \left(1 - \frac{BS\&W}{100} \right) * VCF$$

$V_s = \text{Uncorrected flow rate} \left(\frac{M^3}{Day} \right)$ taken at the meter

$MF = \text{meter factor}$

$Shr = \text{shrinkage factor}$

$BS\&W = \text{base sediment and water}$

$VCF = \text{volum correction factor}$ (also called k-factor)

The formula above is given by the Expro procedure for manual calculations.

Devices used by Expro to measure oil flow rate:

1. Cameron Nuflu turbin meters

Table 16 Turbin meter specification[43]

Flow meter size	mm	GPM	M3/Hr	BPD	Nominal cal. factor	Max. output frequency	DP at max flow
					Pulses Gallon	Pulses/sec	psi
½	13	0.75-7.5	0.17-1.70	25-250	14500	1815	12.0
¾	19	2-15	0.45-3.41	68-515	2950	740	18.0
7/8	22	3-30	0.68-6.81	100-1000	2350	1175	20.0
1	25	5-50	1.14-11.36	170-1700	900	750	20.0
1 ½	38	15-180	3.41-40.88	515-6000	325	975	16.0
2	51	40-400	9.09-90.85	1300-13000	55	365	22.0
3	76	80-800	18.16-181.66	2750-27500	57	760	20.0

2. Expro calibration tank
3. Expro shrinkage tester
4. Software to calculate flowrate (IDEA or Edge-X)

Inaccuracies related to this measurement:

Turbine meter – for the turbine meter we will have the accuracy related to the meter.

Table 17 Accuracies turbin meter[43]

Meter grade	Linearity	Repeatability
Industrial	±0.05 of reading	±0.02%

Another small accuracy that might be mentioned, which in most cases has a very small impact on the reading, is the hydrostatic pressure from the separator and down to the pipe line where the meter is installed. If you have an oil that is at bubblepoint conditions in the separator, the pressure drop down to the meter might cause a release of solution gas that will contribute to higher meter reading. This effect is dependent on which type of oil you have. Dead oil will not have this effect, while light oil and condensate that is already at bubblepoint pressure in the separator, can start create small gas bubbles with a small decrease in pressure.

Meter factor – the meter factor is taken in two different ways in Expro. One regular meter factor and one combined meter and shrinkage factor. The combined meter and shrinkage factor is the most common today in Norwegian sector. Each method, and inaccuracies related to them, will be described below.

1. Meter factor

Meter factor is determined by taking reading from the turbine meter and a reading from the tank at the same time. The calibration tank shall have a sideglass with a calibrated measuring scale on it. The duration can vary from 15 to 50 minutes, or for a fixed volume. Either way, it is important to note duration and volume. The meter factor is given by the following equation

$$MF = \frac{\text{Volume measured in tank}}{\text{Volume measured by meter}}$$

The meter factor is multiplied with the volume measured by the meter to give the corrected metered volume at separator conditions.

2. Combined meter and shrinkage factor

A combined meter and shrinkage factor is the meter factor described above including the change in volume of a liquid phase caused by the release of solution gas and temperature expansion of the liquid. The equation for combined meter and shrinkage factor is given by the following equation

$$CMSF = MF * \left(1 - \frac{Shr_{oil}}{100}\right) * VCF$$

It is important to have good communication between the person taking the reading at the meter and the person taking the reading at the tank to get the same start and finish time. For the combined meter and shrinkage factor it is important to give the oil in the tank sufficient time to settle and release gas.

A more rare inaccuracy related to the meter factor, is installation of wrong sideglass on the calibration tank. Each calibration tank will have different diameter, height and number of installed nozzles. That means that the sideglass with measuring scale is unique for that particular tank. Switching sideglasses on tanks due to small time frames or other issues shall never be done.

Shrinkage factor – the shrinkage is describe as a decrease in volume of a liquid caused by the relase of solution gas due to thermal contraction of the liquid and reduction in pressure to standard pressure, 1 bar or 14,5 psi. The shrinkage can be measured in two different ways.

1. Shrinkage tester

The shrinkage tester is installed at the separator and has one gas inlet and one oil inlet. A known volume of liquid is transferred to the shrinkage tester at separator pressure and de-pressurised. The gas can be vented under controlled conditions. An example is given below

$$\begin{aligned} \text{intial reading} - \text{final reading} &= 100\% - 95\% \\ &= 5\% \text{ shrinkage} \end{aligned}$$

2. Combined meter and shrinkage factor

This is the same as described in the section for meter factor.

The accuracies of the shrinkage tester are related to possibility to fill the shrinkage tester to the top of the scale. This might be a problem if you have a well with low liquid production. If high liquid level in the separator can't be obtained, then the shrinkage tester should be filled as high as possible and the shrinkage in procentage be calculated from that point .

Another remark is not to vent off too quickly, as this can cause “flash off” of heavier components and give too great reduction in volume.

It is most common to the shrinkage on the calibration tank and verify that shrinkage with the result from the shrinkage tester.

Volume correction factor due to temperature– a volume correction factor is the change in volume caused by change in temperature to standard, 15°C or 60°F. The calculation of a VCF requires three input variables

- Final shrinkage temperature
- Oil SG temperature
- Oil SG

In Expro the VFC calculated in the software is used with the variables mentioned above as input parameters. There is also an Excel spreadsheet provided to calculate the VCF and the specific gravity of oil at standard conditions. The formulas used for calculating the VCF in the Excel spreadsheet is given in Attachment I.

During the investigation on how to calculate the volume correction factor various methods have come up. Calculations provided by Expro can be found in Attachment I- Expro procedures, while the one given by ASTM can be found in Attachment II – New procedures and Attachment III – Tables used for calculations. The different calculations for volume correction factor will be compared under the section 7.2 – Field evaluation.

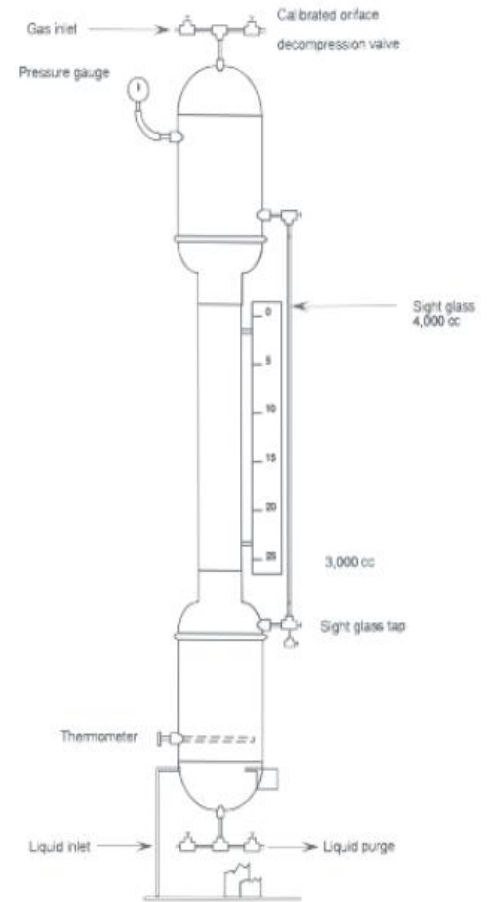


Figure 35 Shrinkage tester

In Attachment III a table for volume correction factor from GPSA can also be found. Here are the factors given for each 10th celsius with interpolation necessary to get a correct value. This method is not described in this thesis.

Flow rate equation – the flow equation will contain all uncertainties and inaccuracies related to the factors above. Since the volume correction factor is the factor that requires the greatest calculation, this will contribute to the largest error. Since this factor is calculated by the software we can assume that the error related to this factor is reduced significantly. Still some inaccuracies related to the specific gravity measurement will be included since this value is a part of the VCF calculation.

The BS&W can also be a factor that contributes to an error. Procedures that explain the flow rate calculation do not explain that this is the BS&W reading taken on the oil line. This is a measurement that is rarely taken on well tests Expro performs. In the software this factor is set as zero, and the BS&W from downstream choke is typed manually into the tables.

Below are illustrations with three different methods on how to find the total volume correction factor for oil flow rate. The fewer steps to correct to standard conditions, the more accurate the total correction factor will be.



Figure 36 Total volume correction factor

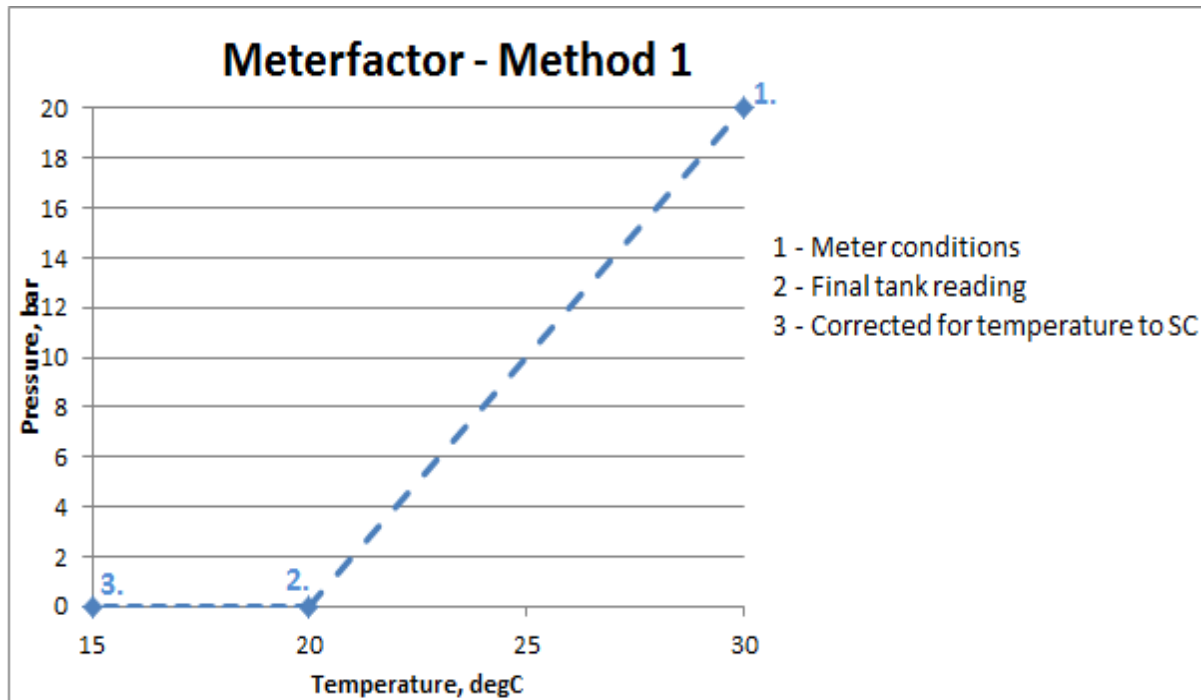


Figure 37 Meter factor method 1

In method 1 the first reading is taken at the turbine meter with oil line properties. A certain amount of oil flows through the meter for a period of time and is diverted to the calibration tank. The initial tank level before oil is diverted to tank needs to be known. The second reading is taken after the oil flow has been diverted back to the flare and the pressure in the calibration tank has been bled down to zero. The oil should get some time to settle before the second reading is taken. Even if the pressure is at standard conditions, the temperature might be above or below 15 degC. A correction for temperature needs to be added, and this is done by calculations. In Expro the temperature correction is included in the CMSF term, but this creates some confusion. I would like to use following terms

Combined meter & shrinkage factor:

$$CMSF = \frac{\text{final tank reading} - \text{initial tank reading}}{\text{final meter reading} - \text{initial meter reading}}$$

Volume correction factor due to temperature:

$$VCF_T = 1 - \left\{ \left[T_{\text{°C}} * \left(\frac{9}{5} \right) + 32 \right] - 60 \right\} * 0.0005$$

Total volume correction factor:

$$TVCF = CMSF * VCF_T$$

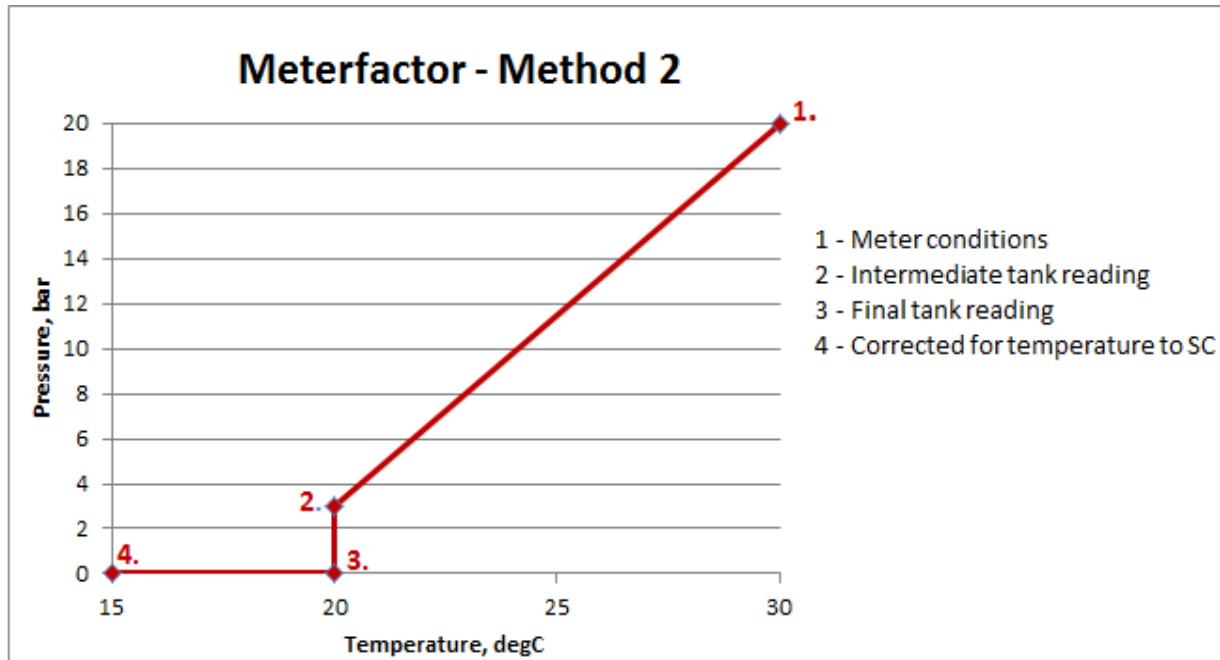


Figure 38 Meter factor method 2

In method 2 the first reading will also be at the turbine meter with a certain amount of oil flowing through the meter for a period of time. Immediately after the flow has been diverted back to the flare, is a reading taken at the tank. This reading divided by the meter reading gives the so-called meter factor

$$MF = \frac{\text{intermediate tank reading} - \text{initial tank reading}}{\text{final meter reading} - \text{initial meter reading}}$$

After the intermediate reading is taken, the pressure in the tank is bled down to zero. The oil should settle for a time before the final tank reading is done. This is the combined meter and shrinkage factor as described in method 1 and these two factors shall in theory be similar.

$$CMSF = MF * \left(1 - \frac{\text{Intermediate tank reading} - \text{final tank reading}}{100}\right)$$

Since two calculations are done in this method to find the CMSF, compared to method 1, this will give a bigger error for method 2 than for method 1. The correction due to temperature will also need to be added to find total volume correction factor

$$TVCF = CMSF * VCF_T$$

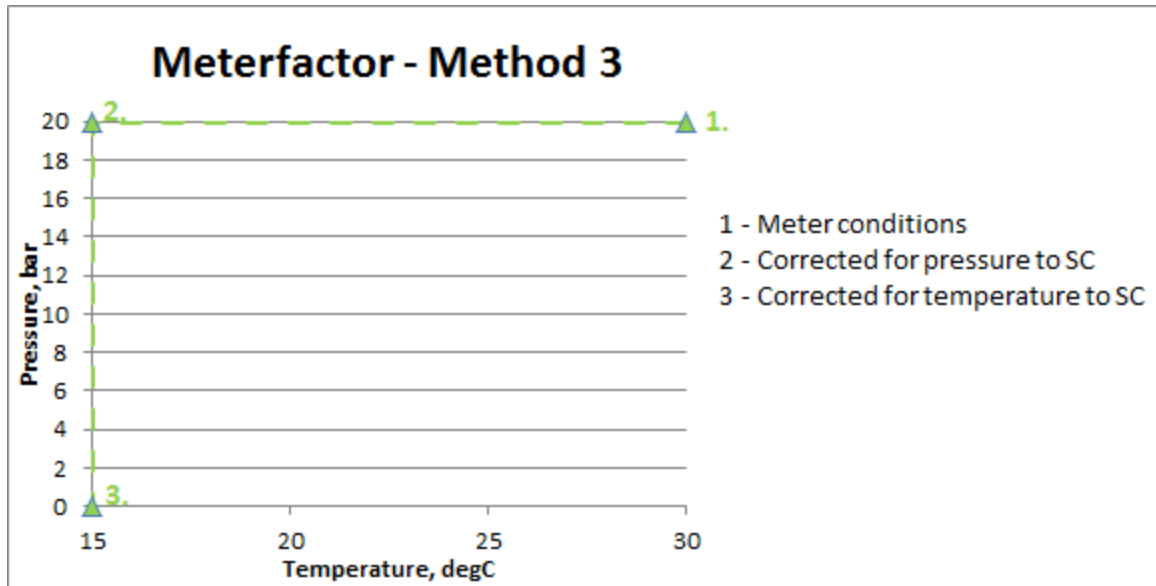


Figure 39 Meter factor method 3

In method 3 the volume that passes through the meter is corrected for both pressure and temperature. No calibration tank and meter factors are measured. This is a theoretical method and not recommended.

The best practice for use offshore will be to use a combination of method 1 and 3. With method 3 you will have an estimate of what the expected volume at standard conditions should be, while with method 1 you are measuring actual volume with only temperature correction as an error. We know for a fact that theory and practice not always are equal to each other, but they should at least be similar.

7.1.11 Gas flow rate

Gas flow rate has normally been measured by a orifice meter, but coriolis meter has recently taken more and more over. Coriolis meter will be described briefly in the next section.

An orifice meter is a fluid flow measuring device that gives a differential pressure due to a reduction in pipe size created by an orifice plate. The gas flow rate is given by the following equation. This equation is the one given by Expro procedure for manual calculation.

$$Q_g \left(\frac{scf}{hr} \right) = C' * \sqrt{h_w * P_f}$$

C' = Orifice flow constant

H_w = differential flow in inches of water

P_f = flowing pressure in psia

$$C' = F_b * F_r * Y * F_{pb} * F_{tb} * F_{tf} * F_{gr} * F_{pv}$$

F_b = Basic orifice factor

F_r = Reynolds number factor

Y = Expansion factor

F_{pb} = Pressure base factor

F_{tb} = Temperature base factor

F_{tf} = Flowing temperature factor

F_{gr} = Specific gravity factor

F_{pv} = Super compressibility factor

Some of these factors require measurements to calculate while some can be found in tables. When calculating these factors it is important to know which units the formulas are given for. The factors described above is taken from the internal Expro manual calculation procedure based upon AGA 3. and customary units is used. GPSA gives formulas and tables in Metric units, and these are only included in the comparison of factors in section 7.2.

Below I will describe the orifice meter and which measurements are taken. In the section *Inaccuracies related to these measurement* I will describe each factor that is included in the calculation and the inaccuracies related to them.

Today software is calculating most of the factors and giving the final flow rate. Under section 7.2 I will compare the factors and flow rate given by the software, with calculations done with equations given for each factor. A calculation based upon the GPSA is also included in section 7.2.

Devices used by Expro to measure oil flow rate:

1. Orifice meter – Daniels box

The orifice meter consists of two pressure gauges connected to an orifice flange recording the static pressure and the differential pressure. The orifice meter is usually installed in the gas line at the separator. A orifice plate with a smaller ID than the pipe is lowered to form a differential pressure. The plate is held perpendicular to the flow by flanges. The thickness of the orifice plates depends on the nominal diameter of the pipe the orifice meter is installed in. The upstream face of the plate shall be flat and perpendicular to the axis of the pipe, while the downstream face shall have a chamfer between 30-45°. See picture below. "Inlet" and "outlet" should be stamped on the plate to indicate how it shall be installed. If this is not the case, then flat end is the inlet and the one with the chamfer the outlet[5].

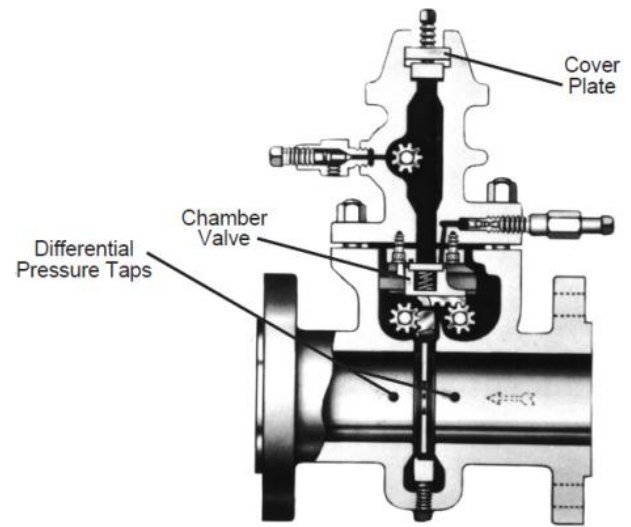


Figure 40 Daniel box[5]

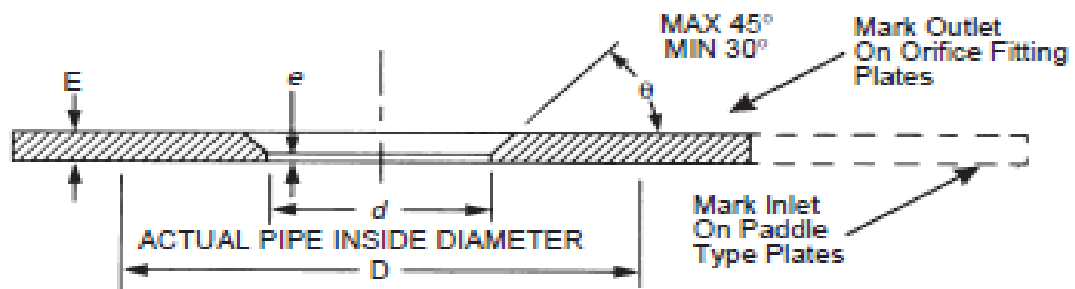


Figure 41 Orifice plate[5]

2. Pressure transmitters

Described in section 7.1.2

3. Temperature transmitters

Described in section 7.1.3

4. Straightening vanes

Straightening vanes should be installed upstream to the orifice meter to eliminate swirls and create laminar flow. The straightening vanes consists of a number of parallel passages of relative small transverse dimensions installed in the pipe. The vanes should not have an area greater than 1/16 of the cross section area of the inside of the pipe to give maximum efficiency[27].

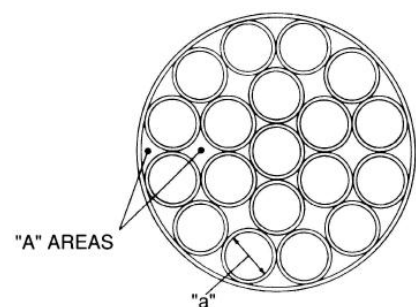


Figure 42 Straightening vanes[5]

Inaccuracies related to this measurement:

Pressures – for the pressures used for static, differential and factor calculations the accuracies for Rosemount pressure transmitters and process described in section 7.1.2 will be relevant.

Temperature – for temperature used to calculate factors the accuracies for Rosemount pressure transmitters and process described in section 7.1.3 will be relevant

Orifice plate – any deformation to the edge in the orifice plate can cause an increase in the flow measurement inaccuracy. The plate should therefore be treated with care and be kept clean at all times.

Meter tubes - “meter tubes” is the term for straight upstream and downstream pipe of the orifice meter. There are requirements on how the meter tubes should be when it comes to measuring the gas rate. For further explanations will A be the upstream pipe and B the downstream pipe. For upstream pipe it is a requirement that A should be at least 10 times the meter tube diameter. In elbows turbulent flow is created and sufficient length after an elbow and straightening vanes help to create laminar flow before the gas reaches the orifice meter. An orifice meter installed too close to an elbow will therefore create an inaccurate differential pressure, thus a wrong gas flow rate.

Units – it is important to insert data with correction unit into the different equations. The equations will vary depending if it is customary units or metric units that are used.

Orifice flow constant – for the orifice flow constant I will describe each factor and the accuracies related to them. These equations is for customary units. Full calculations for each can be found in Attachment VI.

1. F_b – Basic orifice factor

The basic orifice factor can be found from a table given in Attachment III or by using the following equation

$$F_b = 338,178 * d^2 * K_o$$

Correct values on the ID of pipe and orifice need to be known to get an accurate basic orifice factor. There should also be mention if flanged or pipe taps orifice meter is used. In Expro flanged taps are most common, and for further factors this is the type that is evaluated.

2. F_r – Reynolds number factor

The Reynolds number factor can be found from a table given in Attachments III or by use of the following equation

$$F_r = 1 + \frac{E}{12835 * d * K * \sqrt{h_w * P_f}}$$

Any inaccuracy related to the pressure and differential pressure transmitter will give an inaccuracy in the Reynolds number factor.

3. Y – expansion factor

The expansion factor can be found from a table given in Attachment III or by use of the equation for Y given in Attachment VI. The equation varies depending on flange or pipe taps meter and if the measurement of static pressure is taken upstream or downstream.

For the expansion factor correct value for ID's on pipe and orifice, differential pressure and flowing gas pressure are necessary to get a correct value. It should also be mentioned whether the static pressure is taken upstream or downstream of the orifice meter.

4. F_{pb} – Pressure base factor

Pressure base factor is calculated by the following equation

$$F_{pb} = \frac{14,73}{P_b}$$

$P_b = \text{base pressure}$

The base pressure is the standard pressure in customary units and is set to 14.699 psi. In Norway the standard pressure is normally considered as 1 atm.

5. F_{tb} – Temperature base factor

The temperature base factor is given by the following equation

$$F_{tb} = \frac{T_b + 459,67}{519,67}$$

$t_b = \text{base temperature}$

The base temperature is the standard temperature in customary units and is set to 59 degF. In Norway the standard temperature is normally considered as 15 degC.

6. F_{tf} – Flowing temperature factor

The flowing temperature factor is given by the following equation

$$F_{tf} = \left(\frac{519,67}{T_f + 459,67} \right)^{0,5}$$

$T_f = \text{Temperature at orifice meter}$

The inaccuracy will be related to the temperature transmitter installed in the orifice meter.

7. F_{gr} – Specific gravity factor

The specific gravity factor is given by the following equation

$$F_{gr} = \sqrt{\frac{1}{S.G}}$$

$S.G = \text{gas specific gravity}$

The inaccuracy will be related to the Ranarex gravitometer.

8. F_{pv} – Supercompressibility factor

The supercompressibility factor is given by equations given in Attachment VI.

The input data for the super compressibility factor is gas gravity, H₂S, CO₂ and N₂ content. N₂ is not a measurement that is commonly taken, so this input falls out of the equation. The three other parameters can be measured and used in the calculations. As we can see from the

attachment there are several equations that are calculated before the compressibility, Z can be found.

One of the parameters that needs to be calculated, and I consider as critical for the final compressibility, is the pseudocritical density. This value needs to be found by iteration, but the procedure does not give an acceptance value for when the iteration can be considered done.

The Expro procedure is based on the Dranchuk et al calculation, and I tried to get hold of this procedure to see if they had any acceptance criteria for the iteration. I did not manage to find this.

The procedure for gas calculations was based on the AGA. 3 standard, but the standard did not give the derivation of the supercompressibility factor either.

Another method is to find the Z value from graphs, see Attachment IV. One graph is based on pseudocritical pressure and temperature. This will be the most accurate one, but for exploration wells the critical pressure and temperature are not normally known. In such case the other graphs that are based upon mole weights can be used. These graphs are only given for a few mole weights so unless you have the exact weight there will be an inaccuracy related to this factor.

Orifice thermal expansion factor, F_a – in the GPSA handbook an additional factor is added to the equation, the orifice thermal expansion factor. This is a factor that is not included in the Expro manual calculation procedure. If this is a factor that is implemented in the software is unknown. The factor is given by the following equation in metric units

$$F_a = 1 + [0.0000333 * (T_f - T_b)]$$

This will be a small number with only changes in 3rd decimal, but it will still contribute to a change in final flow rate.

7.1.12 Coriolis meter

Coriolis meter measures mass flow, density and temperature of gas and liquids that pass through a process control pipe. This is an alternative to turbine meter and orifice meter. The mass flow rate is captured by sensing the vibrations of the tubes caused by the coriolis force on the medium that passes through the meter. For installation the orientation of the coriolis meter depends on which fluids are going to flow through it. A illustration is shown below

Fluid being measured	Preferred orientation
Liquids	Tubes down Horizontal pipeline
Gases	Tubes up Horizontal pipeline

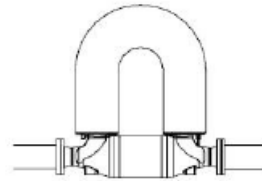
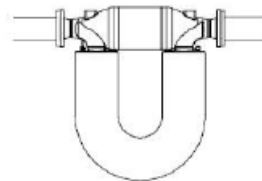


Figure 43 Coriolis meter orientation

Coriolis meter can measure both mass flow and volumetric flow. If volumetric flow is to be measured, the specific gravity of the fluid needs to be included. For Liquids the density can be measured by the coriolis, but this is not recommended for gas by manufacturers. Expro is therefor always measuring mass flow when coriolis meter is used. Below is a illustration of how the coriolis meter works

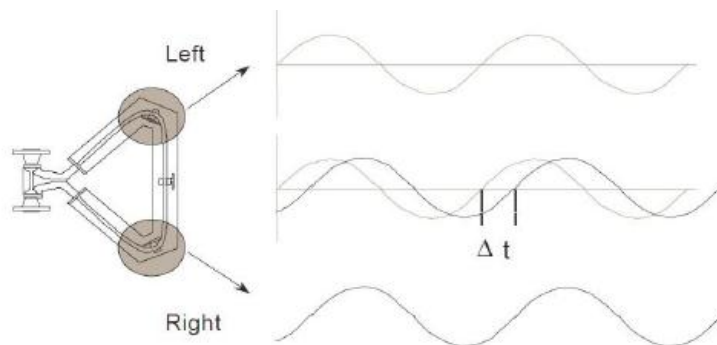


Figure 44 Coriolis meter function

Coriolis meter used by Expro:

Table 18 Coriolis meter specification[44]

MicroMotion ELITE High Capacity flow and density meters					
Liquid flow performance					
		Mass flow			Zero stability
		Lb/min	Metric tons/hr	Kg/h	Lb/min
Maximum flow rate	CMFHC2	54000	1470	1470000	2.5
	CMFHC3	94000	2550	2550000	5.0
Mass flow accuracy		±0.10% of rate			
Repeatability		±0.05% of rate			
When flow rate is less then zero stability(0.001), $accuracy = \pm \left[\left(\frac{zero\ stability}{flowrate} \right) * 100 \right] \%$ of rate and $repeatability = \pm \left[\frac{1}{2} * \left(\frac{zero\ stability}{flow\ rate} \right) * 100 \right] \%$					
Gas flow performance					
		Massflow		Zero stability	
Typical flowrates		Lb/min	Kg/hr	Lb/min	
Air	CMFHC2	1215	33067	2.5	
	CMFHC3	1900	51818	5.0	
Natural gas	CMFHC2	4450	121109	2.5	
	CMFHC3	8500	231353	5.0	
Mass flow accuracy		±0.35% of rate			
Repeatability		±0.20% of rate			
When flow rate is less then zero stability(0.0035), $accuracy = \pm \left[\left(\frac{zero\ stability}{flowrate} \right) * 100 \right] \%$ of rate and $repeatability = \pm \left[\frac{1}{2} * \left(\frac{zero\ stability}{flow\ rate} \right) * 100 \right] \%$					
Density performance (LIQUID ONLY)					
		g/cm ³		Kg/m ³	
Accuracy		±0.0005		±0.5	
Repeatability		±0.0002		±0.2	
Range		Up to 5		Upt o 5000	

Inaccuracies related to this measurement:

Orientation – the coriolis meter can be used to measure both oil rate and gas rate. Since liquid is heavier than air and gas lighter, the orientation needs to be different when the coriolis meter is installed.

Density – only density for liquids can be measured with a coriolis meter according to manufacturers data sheets. For gas density the gas gravitometer described earlier should be used.

Flow rate equation – the conversion from frequency of vibration to flow rate is a part of the software connected to the coriolis meter. There will be some uncertainties related to this, but since the software is a limitation, no inaccuracies are available to discuss.

7.2 Evaluation of test data

In this subchapter three different field cases will be investigated with the focus on flow rate calculations. Flow rates is one of the most important surface data that the client wants to collect. As mention above, most of these calculations are done by softwares today, but formulas implemented in softwares should come from an approved standard.

Issues that came up when investigating real data compared to procedures and standards will also be discussed.

7.2.1 Case 1 - Gas well, DST

The software that was used for handling data for this project was IDEA.

WELL TEST SUMMARY								
	Date	Time	Gas Q SM ³ /Day	C Gas V SM ³	Oil Q SM ³ /Day	C Oil V SM ³	Sep P Bar	Sep T Deg C
Flow period 1 - Initial flow	xx.xx.xx	15:30 18:10	0.00 965574.30	0 8863	0.00 0.00	0.00 0.00	0.1 16.8	16.50 11.79
Flow period 2 - Cleanup flow	xx.xx.xx	22:00 02:20	73260.86 1148916.00	0 131445	0.00 0.00	0.00 0.00	7.3 19.4	13.21 13.72
Flow period 3 - Main flow	xx.xx.xx	11:45 17:55	0.00 1034179.00	0 974201	0.00 0.00	0.00 0.00	4.7 14.0	16.70 15.35
Flow period 4 - Sampling flow	xx.xx.xx	00:00 06:30	0.00 1223758.00	0 239312	0.00 0.00	0.00 0.00	3.9 16.3	14.05 13.01

GAS CALCULATION										
	Date	Time	Gas DP mbar	Gas P Bar	Gas T Deg C	Gas SG	Hw "wg	Pf Psia	CO ₂ %	H ₂ S ppm
Flow period 1 - Initial flow	xx.xx.xx	18:10	384	16.03	-4.82	0.564	154.1	247.3	0.00	0.00
Flow period 2 - Cleanup flow	xx.xx.xx	02:20	548	18.21	28.75	0.564	219.9	278.8	0.00	0.00
Flow period 3 - Main flow	xx.xx.xx	17:55	579	12.82	9,82	0.564	232.6	200.6	0.00	0.00
Flow period 4 - Sampling flow	xx.xx.xx	06:30	745	14.83	24.55	0.564	299.0	229.8	0.00	0.00

OIL CALCULATION										
	Date	Time	2" Oil Meter MF	3" Oil Meter MF	Oil SG corr	Oil SG uncorr	ODCT Deg C	BS&W %	Shrink age %	K factor
Flow period 1 - Initial flow	xx.xx.xx	18:10	0.875	0.875	0.849	0.853	20.00	0.00	0.00	1.00299
Flow period 2 - Cleanup flow	xx.xx.xx	02:20	0.875	0.875	0.849	0.853	20.00	0.00	0.00	1.00146
Flow period 3 - Main flow	xx.xx.xx	17:55	0.875	0.875	0.849	0.853	20.00	0.00	0.00	1.00017
Flow period 4 - Sampling flow	xx.xx.xx	06:30	0.875	0.875	0.849	0.853	20.00	0.00	0.00	1.00216

Below is a comparison of factors used in the gas equation calculated by the IDEA software and manual calculated factors. The equations are taken from Expro manual calculation procedure. This procedure was based upon AGA 3. Standard. The GPSA factors include both calculated and table values. The tables can be found in Attachment III and Mathcad calculations in Attachment VI. Remember that the GPSA calculates factors in metric unit, and this will of course give a difference in some of the factors.

Software vs. manual gas calculations							
MEASURED VALUES							
Date	Time	Gas dP mBar	GasP Bar	GasT Deg C	Gas SG	Hw "wg	Pf Psia
xx.xx.xx	20:30:30	645	14.23	29.7	0.564	259.1	221,1
Pipe OD	Pipe ID	Orifice size					
6"	5.761"	4.5"					
CALCULATED VALUES							
	Fb	Fpb	Ftb	Fg	Ftf	Fr	Y
Software	5136	1.002	0.998	1.332	0.9779	1.0003	1.0037
AGA 3.	5136	1.002	0.998	1.332	0.9760	1.0000	1.0120
GPSA	10.488	1.013	1.000	1.332	0.97504	1.0000	1.0066
	Fpv	Fa	Gas Q (scf/hour)	Gas Q (Sm ³ /day)			
Software	1.0140			1105735			
AGA 3.	1.0580		1712000	1163483	Calculated with customary units		
GPSA	1.417	1.0005		1496000	Calculated with metric units		

From the results above can we see that the flowrate is higher for the values by AGA.3 and GPSA method than for the software. The super compressibility factor will have a huge impact on the final result and we see that this is the factor that varies the most.

The supercompressibility factor will be the most critical value in the flow equation. In the GPSA method only correlated tables based upon mole weights are given. In the Expro manual calculation procedure iterations is used, but no convergence criterion was given. The criterion that is given in the Mathcad file was taken from another Expro procedure, but this procedure had no references, thus not suited for use.

Another method that would give a more accurate supercompressibility factor is to get the Z value from a chart based upon pseudo-reduced pressure and temperature, see Attachment III. These are calculated by the following equations

$$P_r = \frac{P}{P_c}$$

$$T_r = \frac{T}{T_c}$$

where P_c and T_c are critical pressure and temperature. To find these values the composition must be known and for exploration wells this is not common information to have. If other wells have been drilled at the same field and the composition is known these critical values can be used.

7.2.2 Case 2 - Gas/condensate well, Clean-up

The software that was used for handling data for this project was EDGE-X.

WELL TEST SUMMARY										
	Date	Time	Choke size 64th	BHP Bara	BHT Deg C	WHP Barg	WHT Deg C	Standard conditioans		
								Gas rate MMm3/ d	Oil rate M3/d	W rate M3/d
Flow period 1 - Cleanup flow	xx.xx.xx	23:41 02:41	103	527.0	127.0	381.1	34.0	2.400	2500	0.00
Flow period 2 - Multirate flow	xx.xx.xx	04:04 06:10	55	538.0	126.8	408.0	18.6	0.700	600	0.00
Flow period 3 - Multirate flow	xx.xx.xx	06:20 08:30	59	536.0	127.1	404.0	22.0	0.900	950	0.00
Flow period 4 - Multirate flow	xx.xx.xx	08:35 16:00	63	528.2	127.6	395.1	29.0	1.300	1200	10.00
WELL PARAMETERS					EMISSIONS INFORMATION					
CO2(max)	2	%			Metered gas	2.981	MMm3			
H2S(max)	4	Ppm			Metered oil	2846.8	M3			
Gas SG(average)	0.679				Metered Water	141.6	M3			
Oil SG(average)	0.793	@20.2°C			Injected MEG	2.8	M3			
					Slop returns	81	M3			

In gas condensate field phase changes and two-phase flow will be the biggest issues. Measurements like BS&W, oil gravity, gas gravity, H₂S and CO₂ can be affected if gas is dissolved in oil or oil dissolved in gas.

For BS&W we might have too little condensate to be able to take a full sample of 100 ml. Here the outdated 15ml cylinders with hand operated cetrifuged might be of use.

When oil samples are taken from the separator to measure oil gravity this oil will most likely be at the bubblepoint pressure. When the oil gravity is measured the pressure will be at atmospheric pressure. Before the reading is taken the oil should get sufficient time to settle and release dissolved gas. If the measurement is done immideately after the sample is taken gas may still be dissolved in oil and give a lighter oil gravity.

For H₂S and CO₂ measurements the statement mentioned in section 7.1.7 about controlled flow from gas line to closed chamber compartment is important. Since reduction in pressure and temperature will create condensate we need to assure that no liquids splashes in the compartment and enter the dreager tube.

The same will occur when you take samples for gas gravity measurement. If you have a heavy gas condensate system, a large liquid slug may be created in the gas bladder balloon. If this is held with the inlet down when you transport the balloon from the sampling point to the laboratoy container, the water will be collected at the inlet. This amount of liquid the silica gel at the inlet will not be able to handle and this may damage the Ranarex gravitometer.

7.2.3 Case 3 - Oil well, DST

The software that was used for handling data for this project was IDEA.

WELL TEST SUMMARY										
	Date	Time	Choke size 64th	BHP Bara	BHT Deg C	WHP Barg	WHT Deg C	Standard conditions		
								Gas rate MMm3/d	Oil rate M3/d	W rate M3/d
DST1 – Main flow period	xx.xx.xx	10:00 10:00	32	56.80	79.9	8.8	13.3	n/a	100	0.0
DST2 – Main flow period	xx.xx.xx	15:28 15:30	36	189.40	83.2	60.7	20.0	41700	480	0.0
DST1										
WELL PARAMETERS					EMISSIONS INFORMATION					
CO2(max)	0.2	%			Metered gas	n/a		MMm3		
H2S(max)	0	ppm			Metered oil	50.21		M3		
Gas SG(average)	0.804				Metered Water	14.0		M3		
Oil SG(average)	0.853	@60°F			Injected MEG	0.8		M3		
DST2										
WELL PARAMETERS					EMISSIONS INFORMATION					
CO2(max)	0.2	%			Metered gas	43959.3		m3		
H2S(max)	0	ppm			Metered oil	592.3		M3		
Gas SG(average)	0.732				Metered Water	10.6		M3		
Oil SG(average)	0.849	@60°F			Injected MEG	4.2		M3		

Below is a comparison of correction of oil density back to standard conditions. Calculations of these values can be found in Attachment VI. The calculations below is based upon the CMSF spreadsheet for this job in Attachment V.

Oil calculations comparison					
MEASURED VALUES ON OIL LINE					
Date	Time	Meter	Oil SG	Oil SG T, °C	Oil line T, °C
xx.xx.xx	18:20:00	1.5"	0.852	8.6	36.4
OIL DENSITY CALCULATED VALUES					
	VCF	OilAPICorr	OilSGcorr		
ASTM	1.006	35.558	0.847		
Excel	0.982	35.456	0.848		
Manual	0.995	32.901	0.861		
METER FACTOR CALCULATION – mathcad files Attachment VI					
	Tank1	Tank2	Oil line	Shrink1	Shrink2
DegC	13.40	18.75	34.70	21.00	13.00
VCF1	0.972	0.967	0.953	0.965	0.972
VCF2	0.98	0.979	0.974	0.978	0.980
VCF3	1.002	0.997	0.983	0.995	1.002
VCF - API	1.002	0.997	0.984	0.995	1.002

The volume correction factor includes in most cases only the temperature correction since all measurements and readings are taken at atmospheric pressure. As mentioned earlier the specific gravity of oil is corrected to standard conditions by the software used, but Excel calculations and manual calculation procedures are still available within Expro. From the oil temperature above we should expect a volume correction factor above 1 to correct the temperature up to 15 degC and a decrease in specific gravity.

We see that this only occurs for the ASTM method. The Excel spreadsheet gives a decrease in specific gravity, but the correction factor is below one. In the Excel spreadsheet this is separately calculated. The correction factor that is calculated in the Excel spreadsheet is apparently the correction factor for the Oil line temperature. This Excel spreadsheet has no references attached to it and no named author. This is therefor not a reliable tool to calculate the corrected gravity and correction factor.

The correction factor given by Expro manual calculation procedure has reference in ASTM D1250-80. This standard has expired and the procedure should have been updated with the new ASTM standard D6822-12b and API 11.1. All the output values from this procedure are opposite of what is expected, so this procedure should not be used as a reliable source for calculating VCF.

A correction due to temperature is also necessary when the combined meter & shrinkage factor is taken. There is no procedure given by Expro on how to measure the meter factor or how to correct it to standard conditions. Due to lack of procedures different methods have been used. The DAQ personel offshore have used an Excel spreadsheet created locally to calculate the final meter and shrinkage factor that is used to correct the flow rate measured at the turbine meter. In Attachment I a template of the excelsheet they use for calculation CMSF can be found. The yellow cells are for input values and red cells for output values. There is no protection on the red cells with formulas, so anybody can change the formulas if they want.

When I checked one of the meter factors taken for Case 3, three different formulas for VCF were inserted in the spreadsheet. A document like this should be protected with only input cells open for changes. In the table above all correction factors for all the three formulas found in the spreadsheet have been calculated and VCF calculated according to API 11.1. We see that the first two correction factors are wrong and the last is identical to the one given by API 11.1. The formula for VCF3 is simple compared to the one given by API 11.1, and no reference about where the formula comes from is given. If this formula should be used in further calculation it needs to be approved by lead engineers in Expro.

7.3 Plots

In this last section history plots and critical flow plots for all case will be given. History plot are to illustrate how the job was performed. The critical flow plot are used to see if critical flow was maintained during the whole job. As mentioned earlier it is important to have critical flow throughout so that changes downstream of the choke don't effect upstream pressures and flowrates. In expro is a rule of thumb that the downstream pressure shall be at least half of upstream pressure or below. The theoretical value is 55 % of upstream pressure[33]. Both of these is illustrated in the critical flow check plot.

7.3.1 Case 1 – Gas well, DST

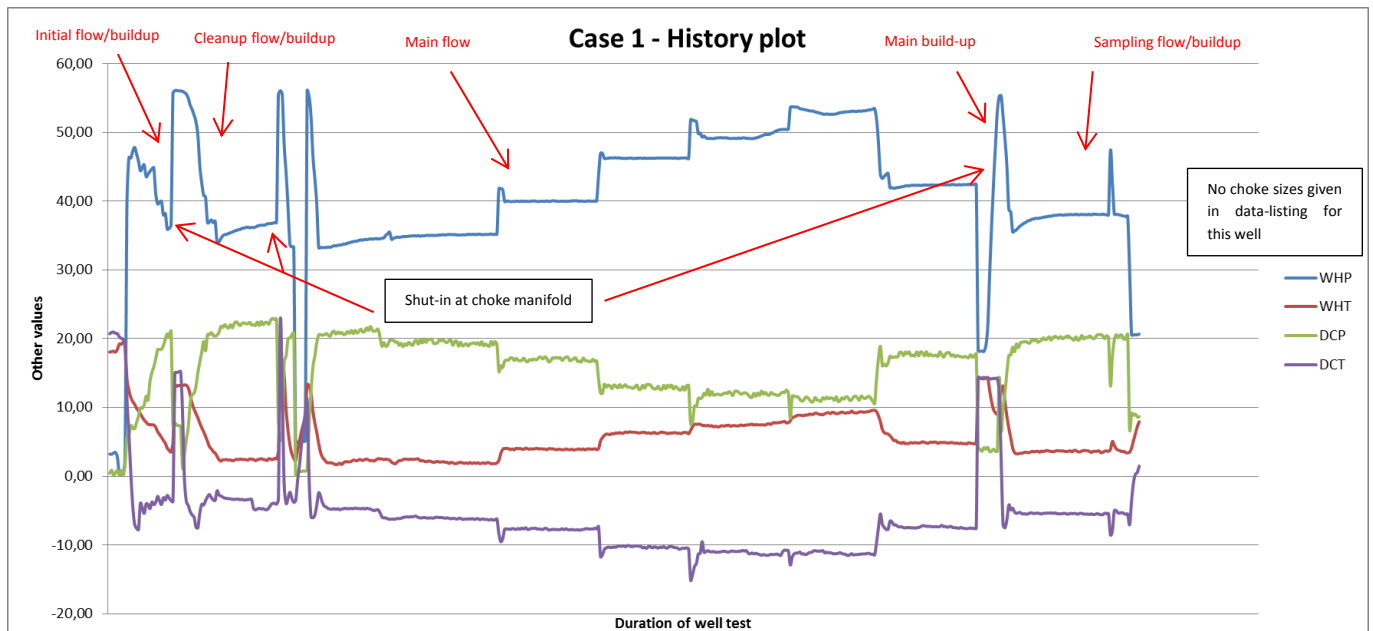


Figure 45 Case 1 - History plot

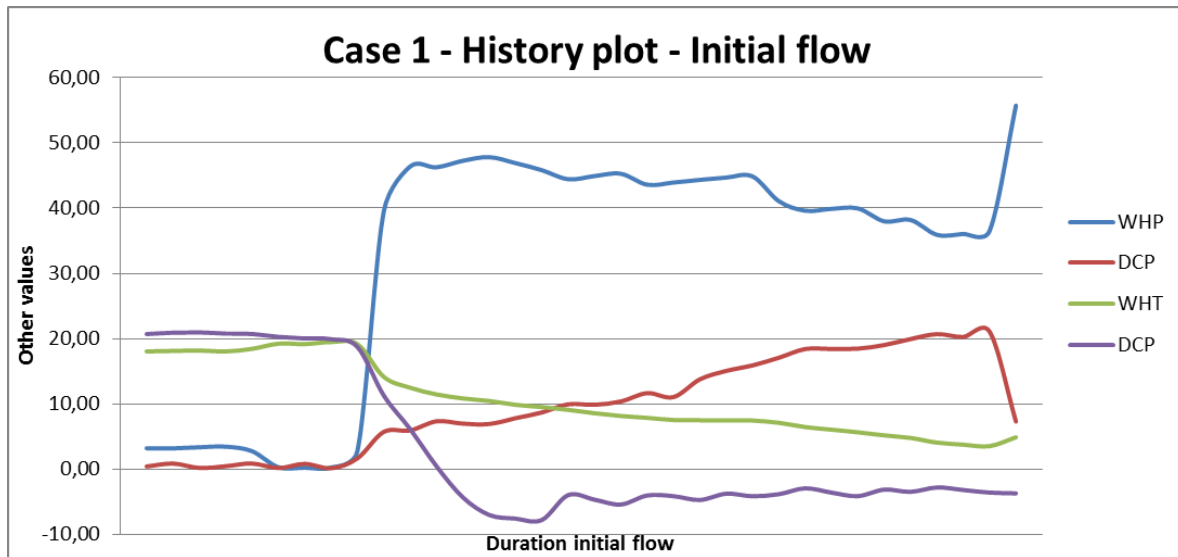


Figure 46 Case 1 - Initial flow plot

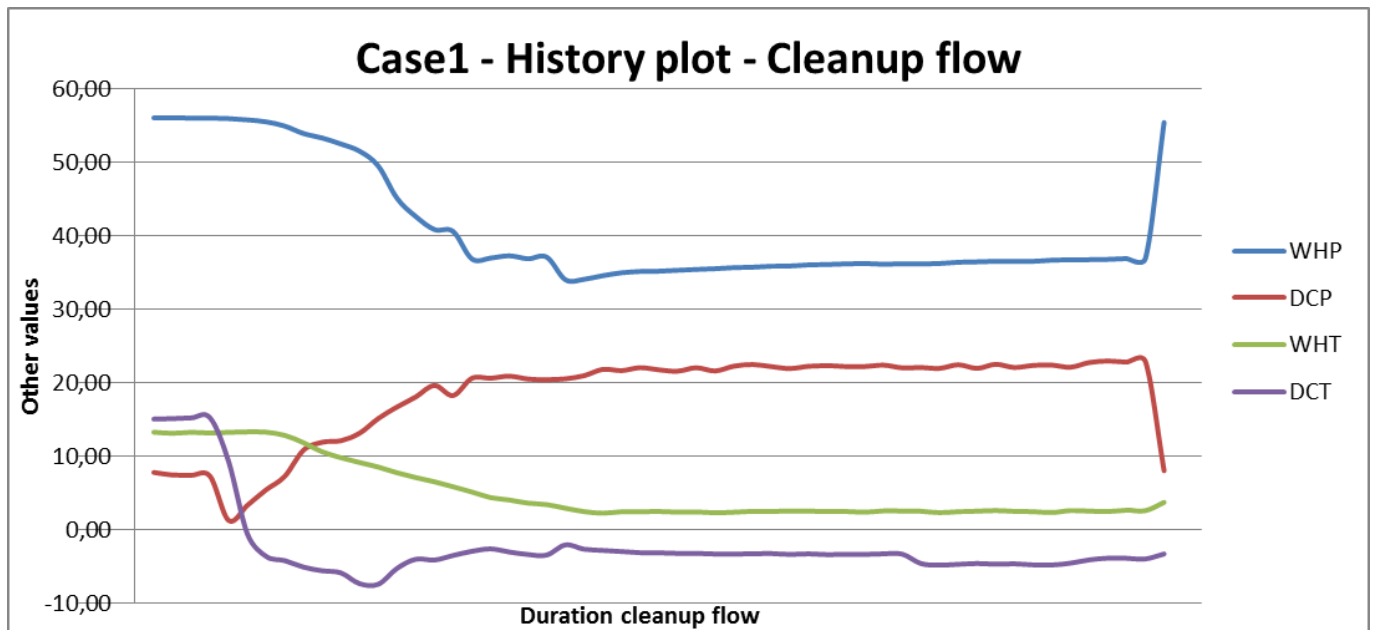


Figure 47 Case1 - Cleanup flow plot

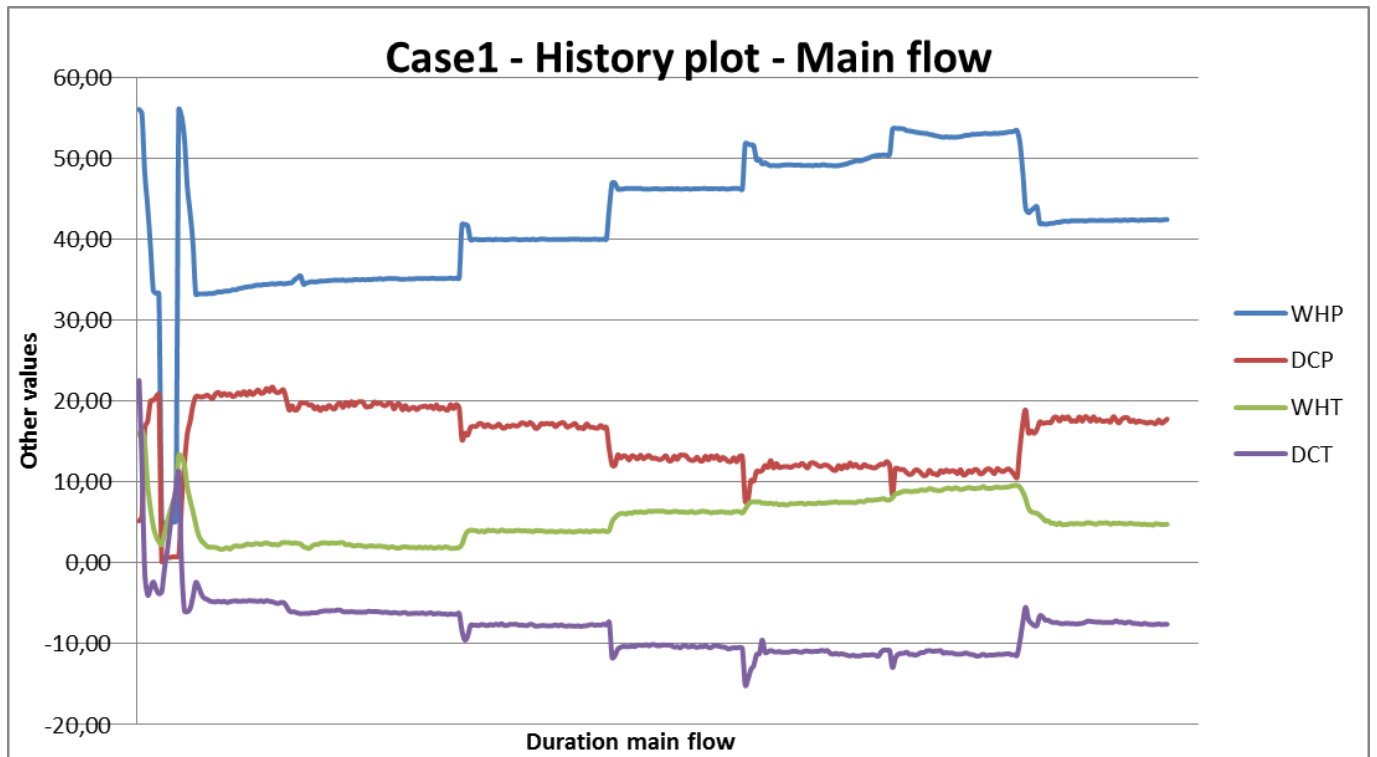


Figure 48 Case1 - Main flow plot

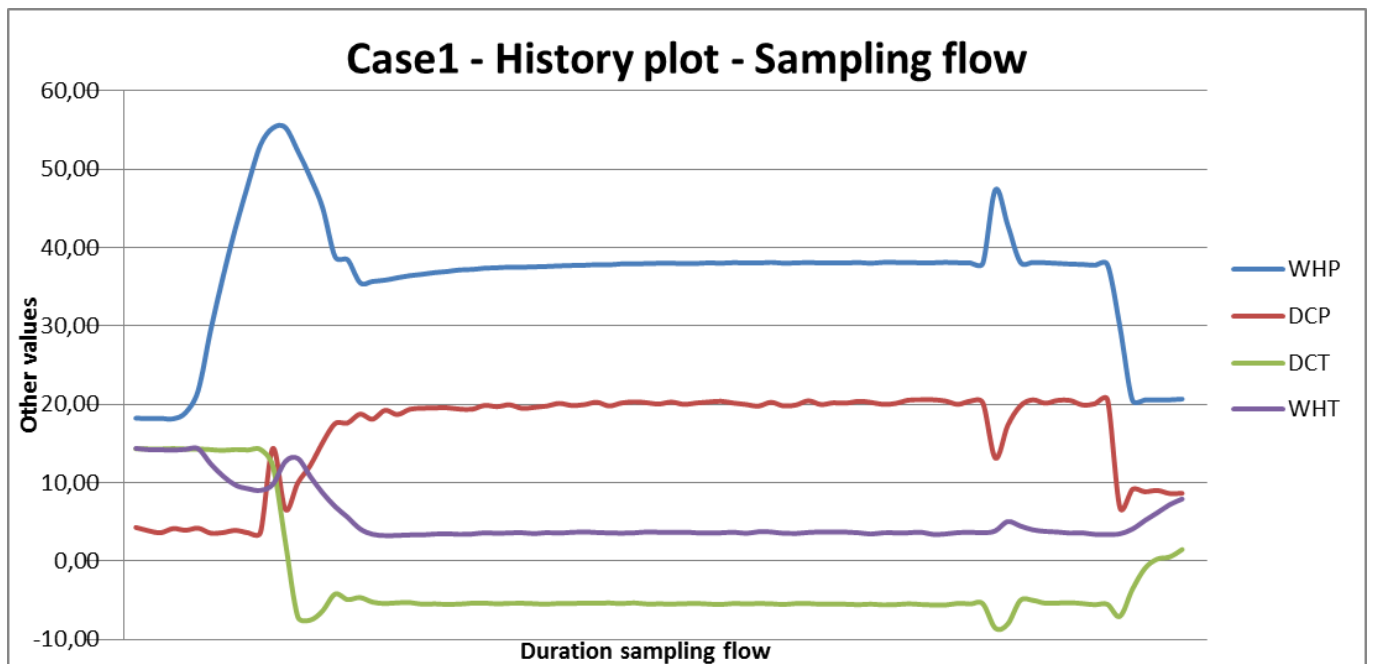


Figure 49 Case1 - Sampling flow plot

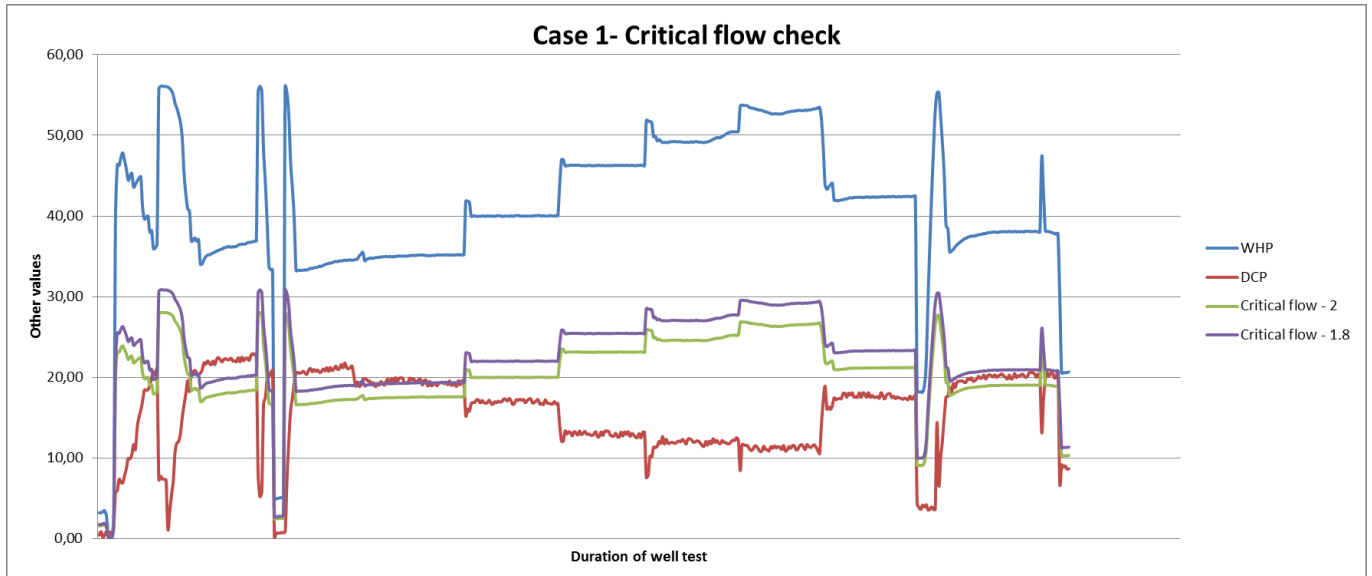


Figure 50 Case1 - Critical flow check plot

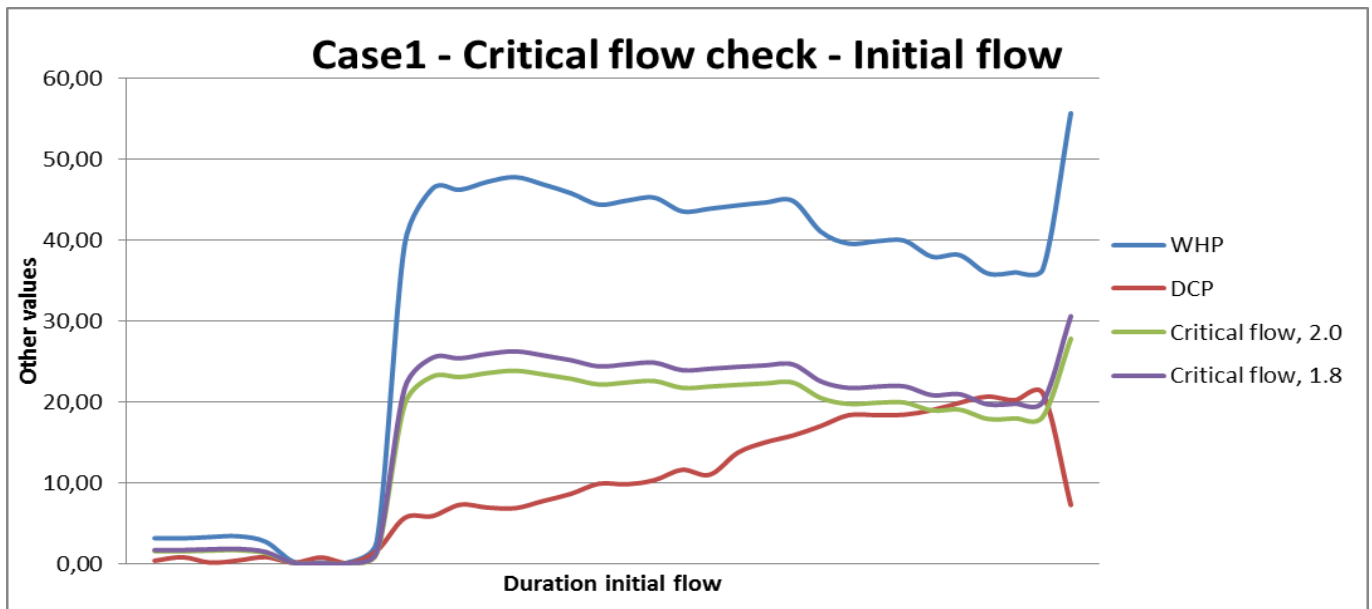


Figure 51 Case1 - Critical flow check plot - Initial flow

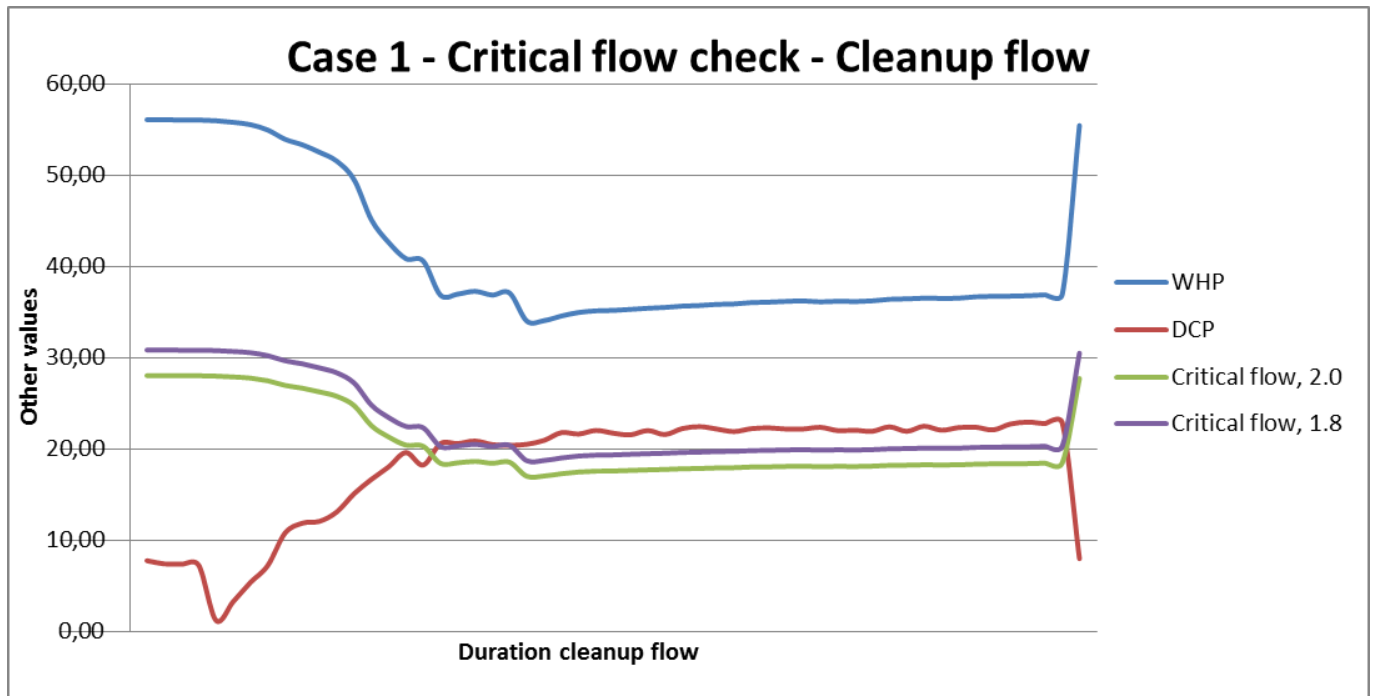


Figure 52 Case1 - Critical flow check plot - Cleanup flow

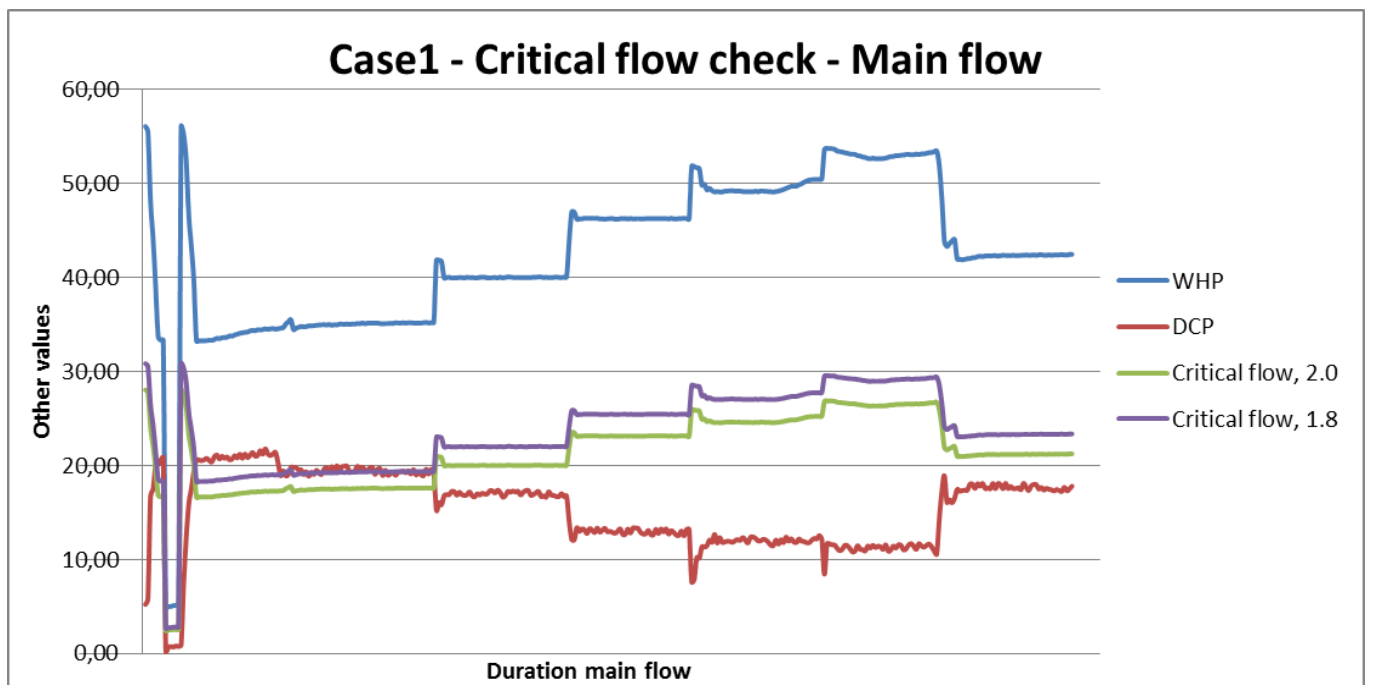


Figure 53 Case1 - Critical flow check plot - Main flow

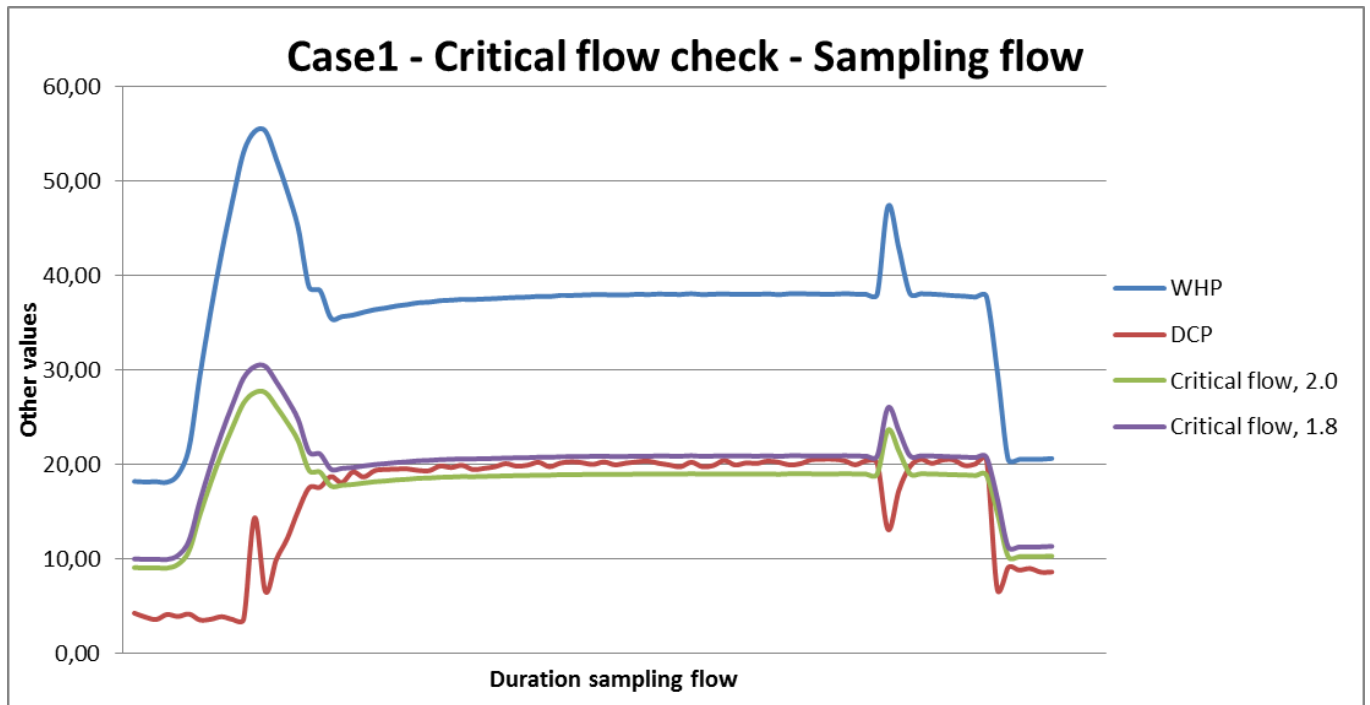


Figure 54 Case1 - Critical flow check plot - Sampling flow

The critical flow was not maintained during the whole test.

7.3.2 Case2 – Gas/condensate well, clean up

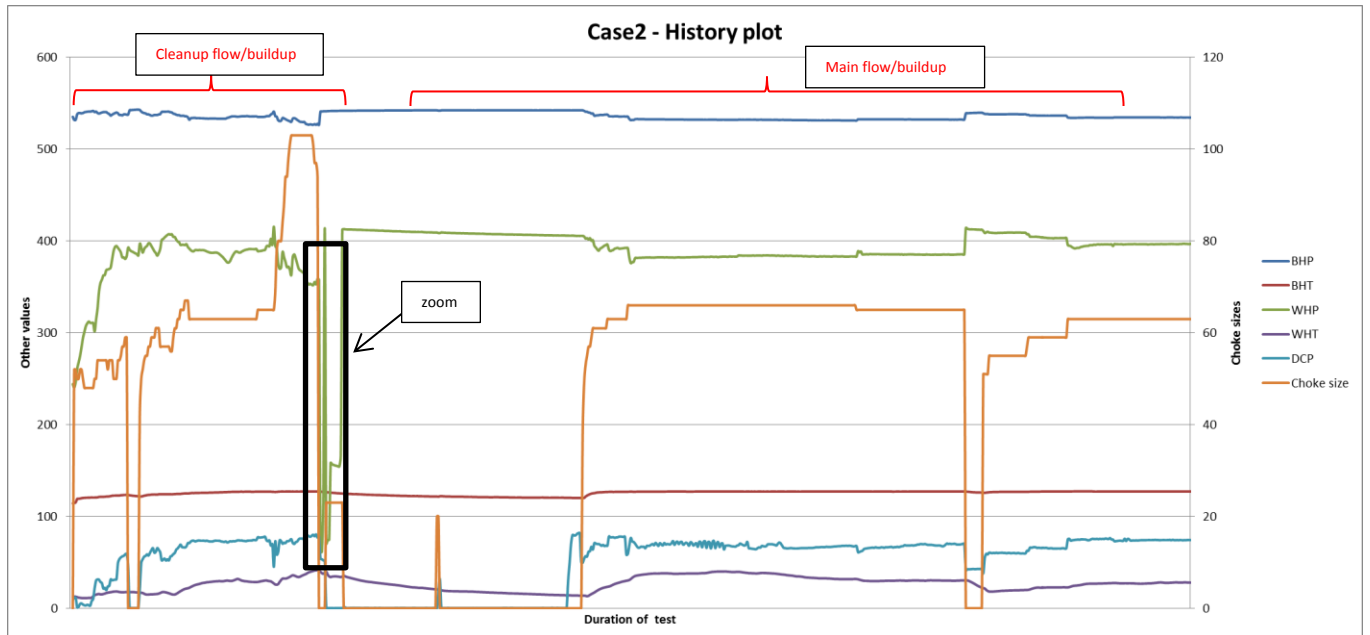


Figure 55 Case 2 - History plot

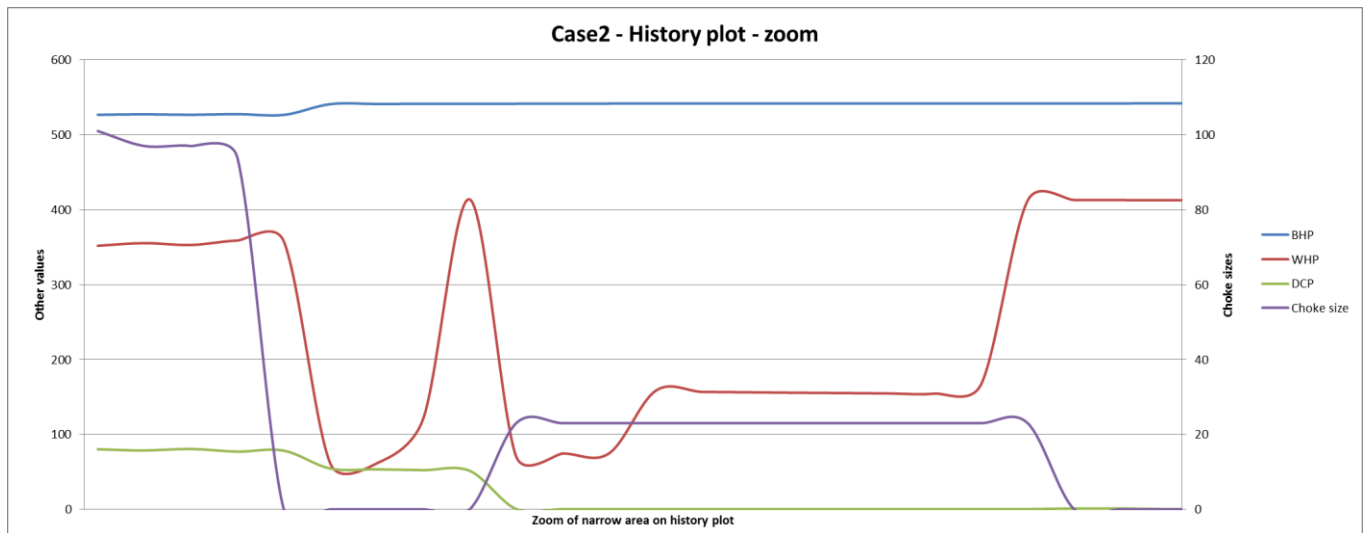


Figure 56 Case 2 – History plot - zoom

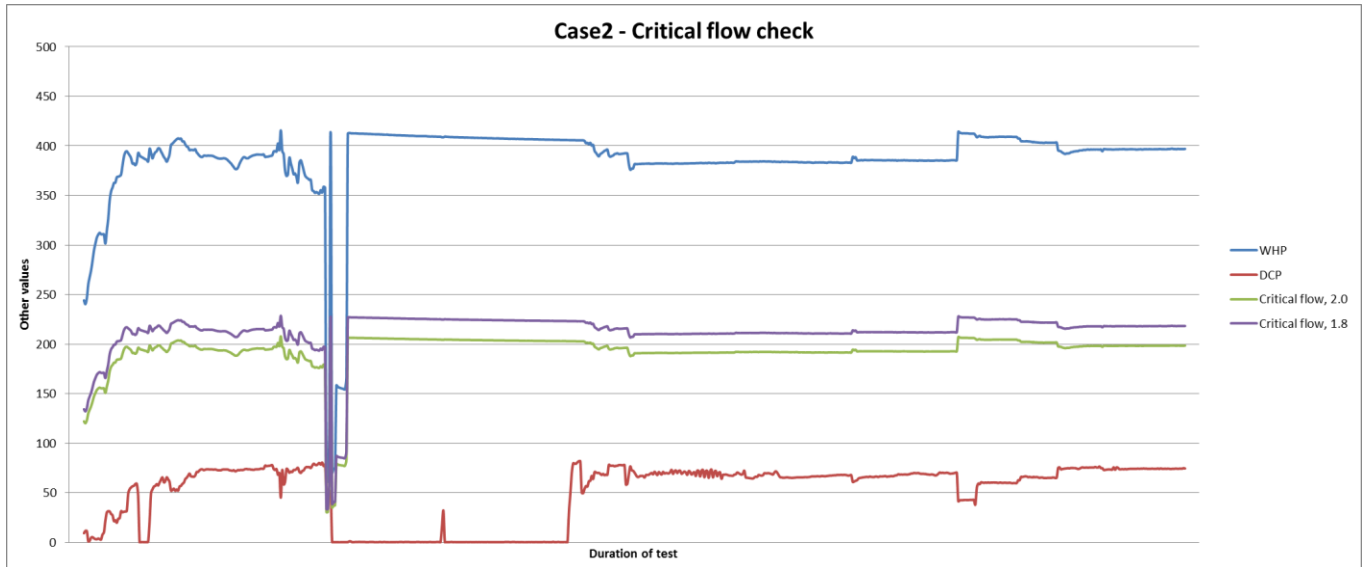


Figure 57 Case2 - Critical flow check plot

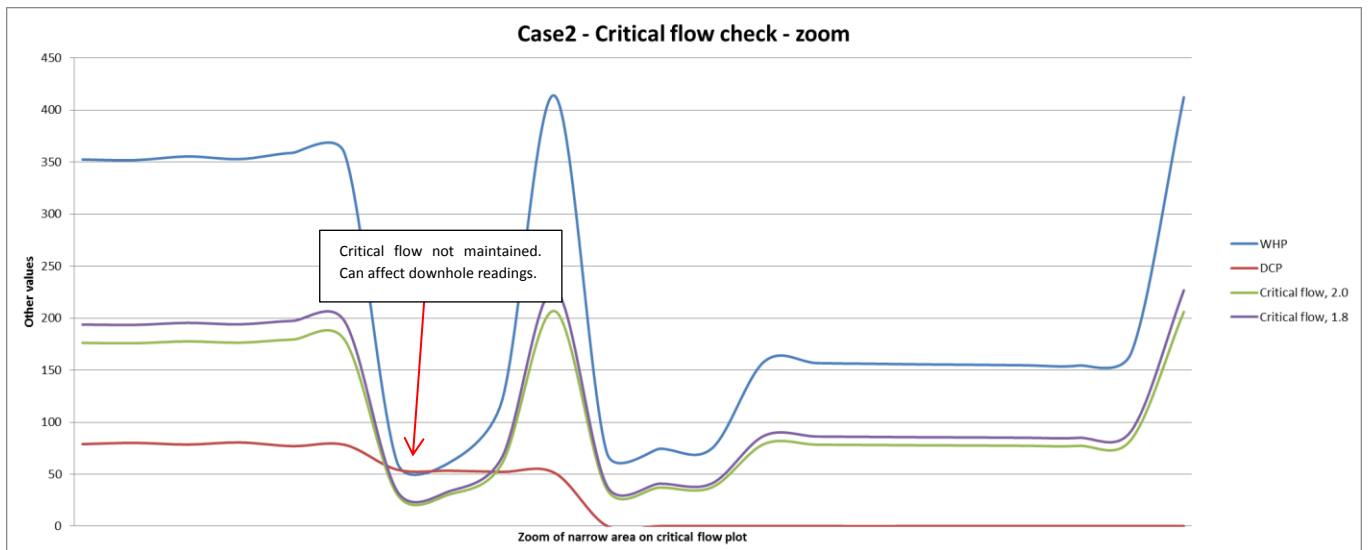


Figure 58 Case2 - Critical flow check plot - zoom

7.3.3 Case3 – Oil well, DST 1

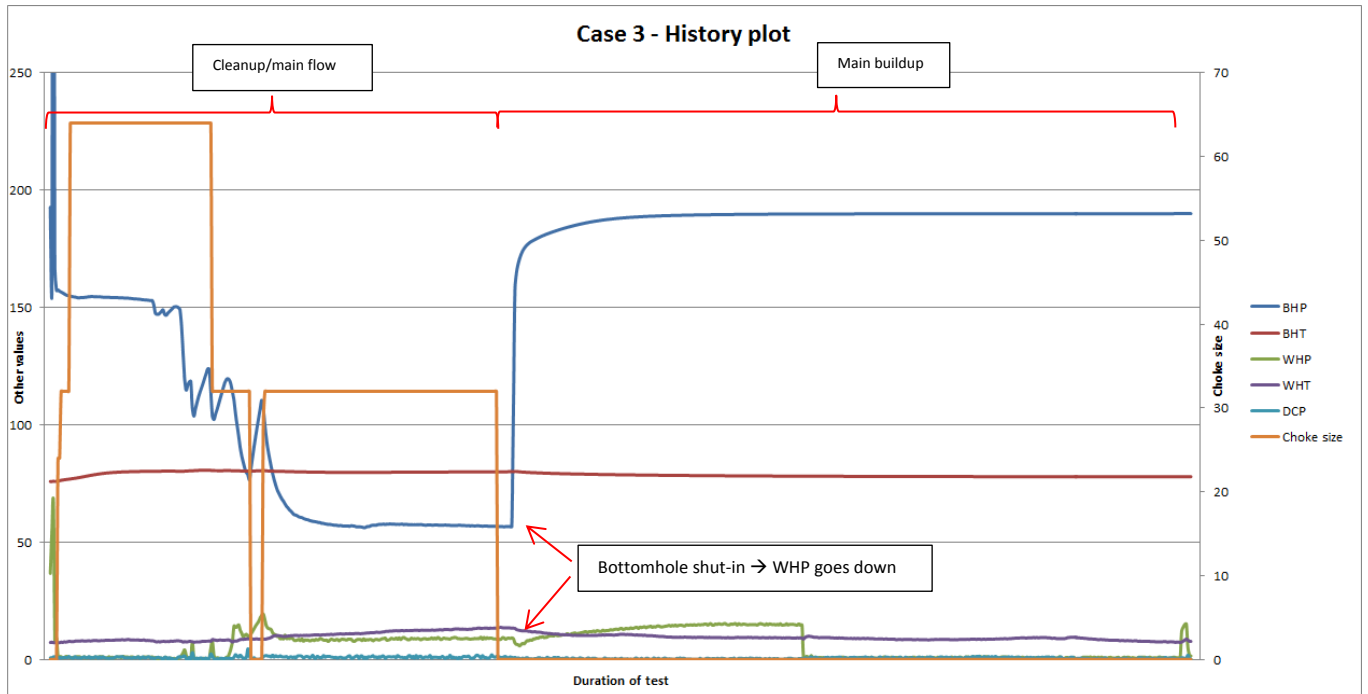


Figure 59 Case3, DST1 - History plot

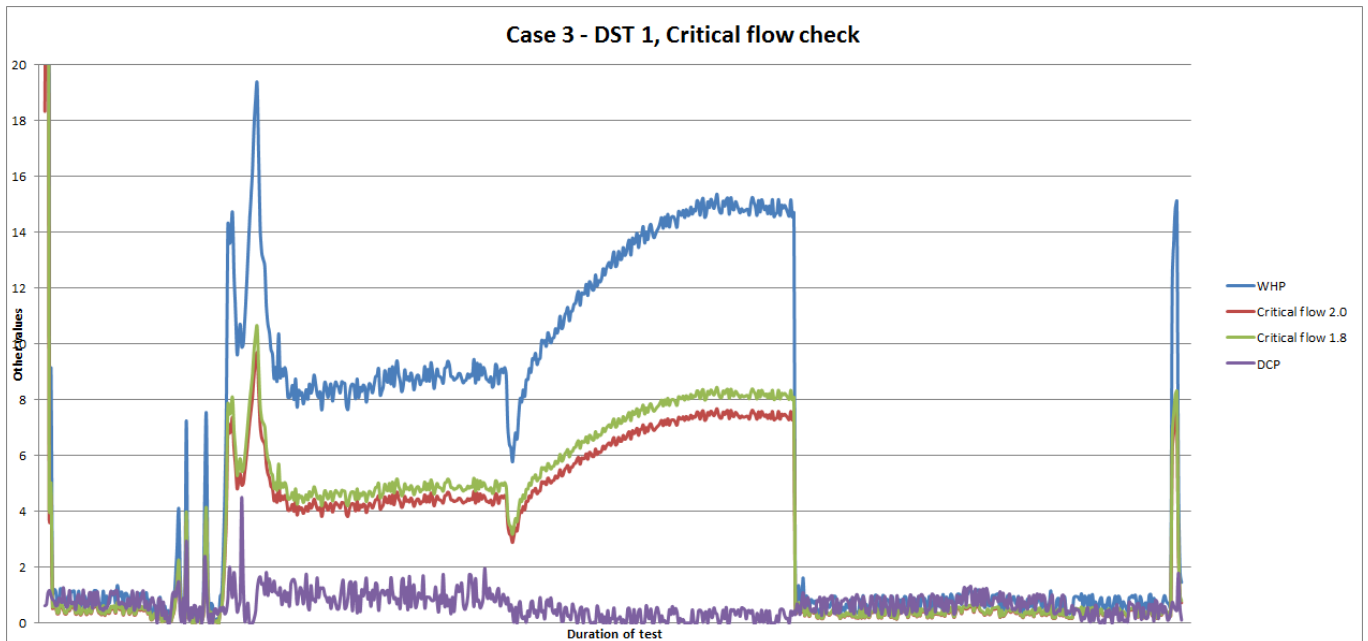


Figure 60 Cas3, DST1 - Critical flow check plot

This plot fluctuates a lot and in some sections is it difficult to see if critical flow is maintained or not.

7.3.4 Case3 – Oil well, DST 2

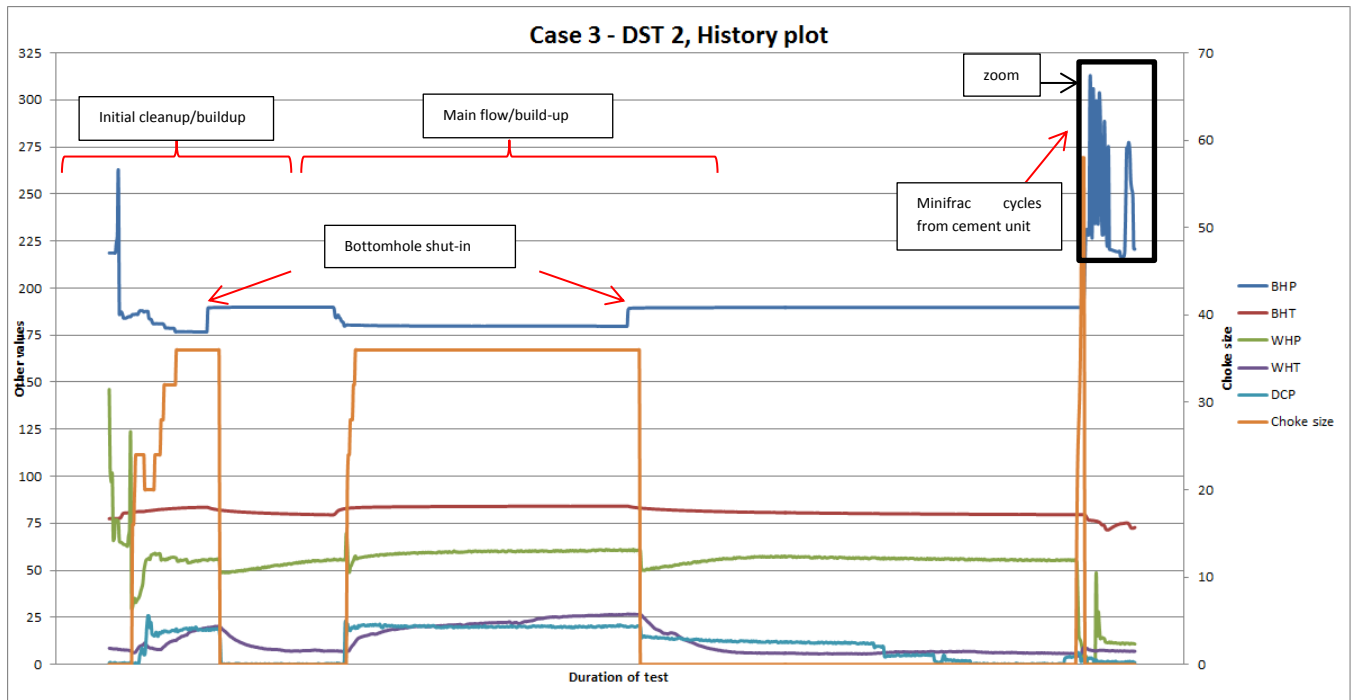


Figure 61 Case3, DST2 - History plot

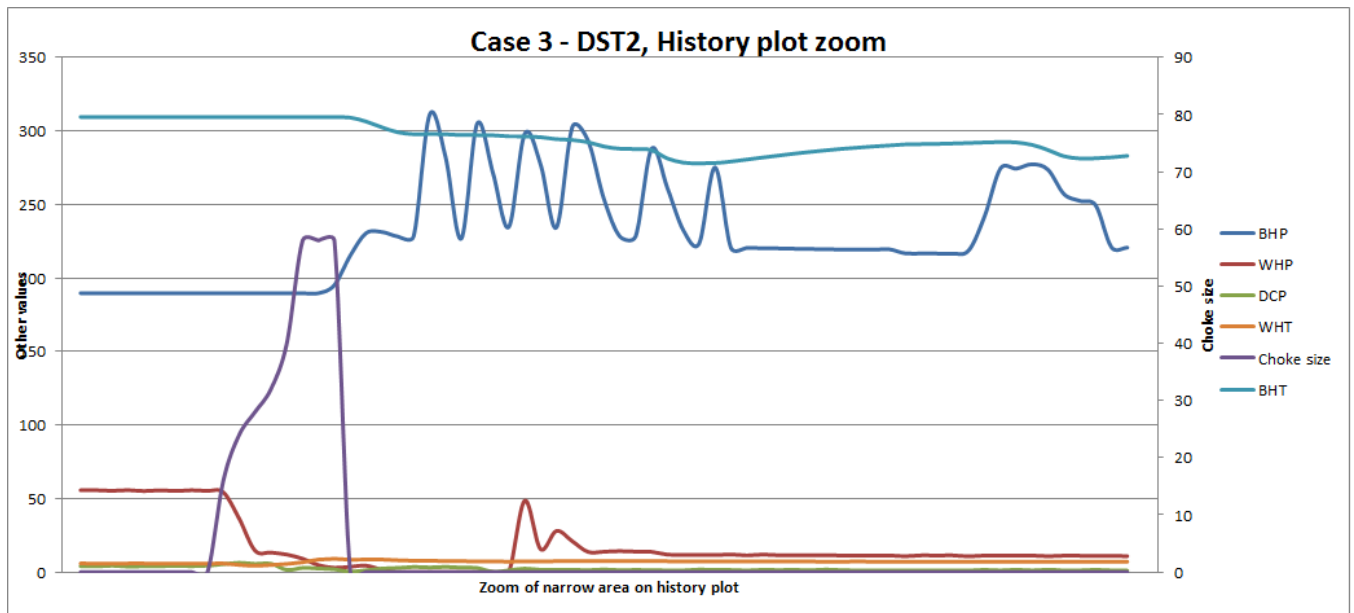


Figure 62 Case3, DST2 - History plot - zoom

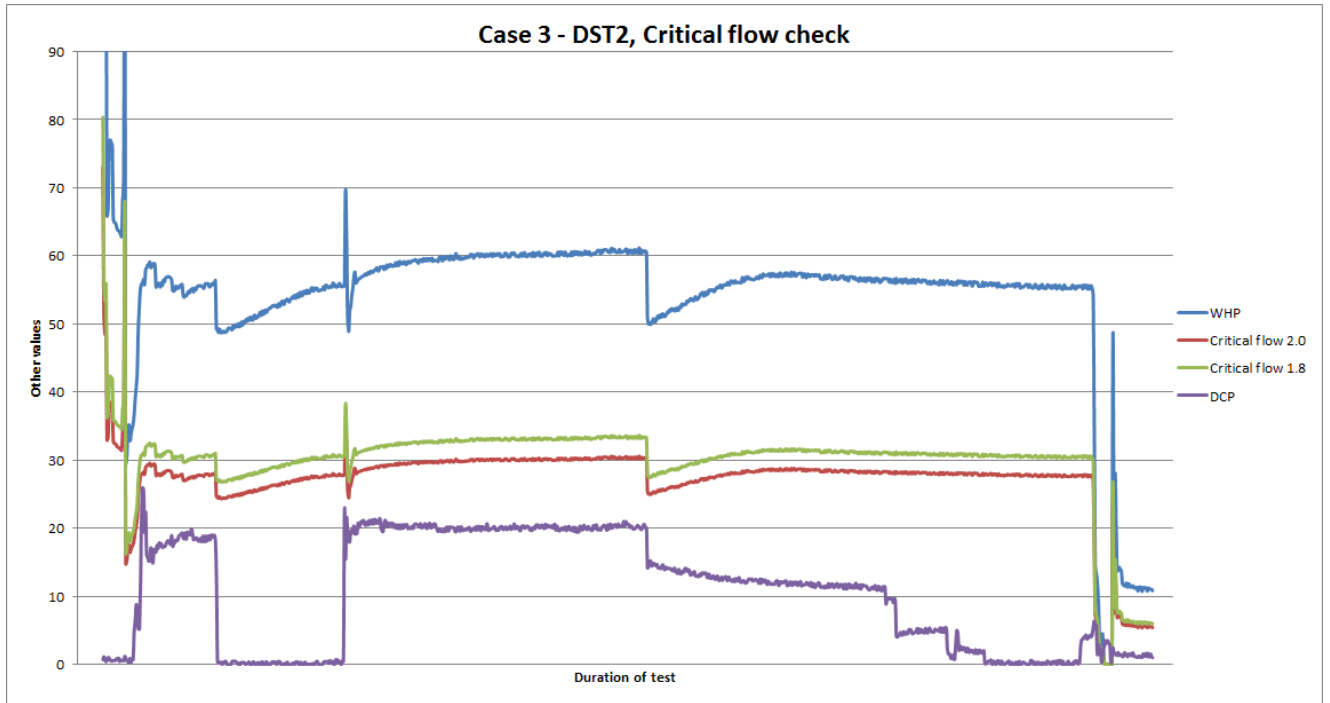


Figure 63 Case3, DST2 - Critical flow check plot

Critical flow almost maintained during the entire test.

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Attachment I

Expro procedures

Expro procedure for BS&W measurements

Procedure:

- Pour 50ml of a solvent into a clean centrifuge tube
- Add 1-3 drops of demulsifier and shake tube until solvent and demulsifier are well mixed
- Shake sample container vigorously and pour in 50 ml of crude oil into centrifuge tube with the solvent and demulsifier (if used)
- Shake the centrifuge by hand, for several minutes to mix thoroughly the sample with demulsifier and solvent (if used)
- Repeat this procedure for a second centrifuge tube if enough collected sample
- If required, heat the centrifuge tubes until the sample temperature is 140°F
- Once the sample has been heated, shake well and place in the centrifuge

NOTE: when shaking the sample, ensure that none of the sample is spilled

- Spin the sample for approximately 3-10 minutes
- Reand the BS&W content

NOTE: Read to the nearest .05 ml (between 0.1 and 1 ml) and to the neares 0.1 ml when over 1 ml. If the two samples (for comparison) agree, or are very close, add the precentages together to achieve the true BS&W

NOTE: If only one sample was taken then the result should be multiplied by two since halve the sample was solvent. If the sample was not cut with solvent (e.g. for light crude's or condensates) the percentage of BS&W should be read directly. If two samples were taken, the results should be added toghether and the combined total divided by two

- On comletion of the test, all equipment should be washed and cleaned ready for the next

NOTE: On HPHT wells, no samples should be taken from upstream of the choke manifold apart from monophasic samples. On every well test we should always be aware of the potential dangers when taking samples from upstream of the choke manifold. The potential from problems (valve washouts etc.) increases in the following circumstances

- High flowing pressures
- Gas wells
- Rat hole at surface (mud)

Expro procedure for pH measurements

Expro procedure to measure pH:

- A sample from of produced water is separated from the oil
- pH paper is dipped into the fluid
- Compare colour reaction on the paper and pH scale on the packet that comes with the paper
- Roughly estimate pH value

Expro procedure for salinity measurements

Expro procedure for measure the salinity:

- Apply a drop of distilled water to the prism end of the refractometer and close lid
- While viewing towards a light source, use the zero adjustment screw to line up the base line with 0 on the scale
- Clean the prism and apply a drop of the produced water to the pricem and of the refractometer and close lid
- While viewing towards a light source, determine the point on the scale that a color change occurs.

NOTE: using the refractometer's calibration table found inside the units box determine the ppm value of the salinity found in the produced water and report

Expro procedure for H₂S & CO₂ measurements

Procedure:

- Select tube of correct type and range
- Squeeze Dräger body to compress bellows and insert unbroken tube into valve aperture

NOTE: If Bellows do not expand then integrity of bellows is assured and sampling can continue. If bellows expand then the bellows are leaking and false results will ensure of that tester is used. REPLACE the bellows unit.

- Collect gas sample in bladder/stainless steel cylinder

NOTE: Ensure bladder/cylinder is purged adequately to obtain a representative sample

The sample must be at atmospheric pressure for the purpose of reading the Dräger tube, if the sample bladder contains pressure this will create an artificially high reading.

- Break open both ends of the Dräger tube
- Compress body to expel air from bellows and insert tube in valve aperture

NOTE: Check arrow on tube side of correct end to install – arrow indicates direction of flow (from sample to tester).

- Once tube secure in valve aperture, release bellow and allow chain to go taut

NOTE: The chain MUST be allowed to go taut for a correct reading to be obtained. This is because the volume of the bellows is a calibrated amount which is related to the reagent used in the tubes and any differing volume will cause errors.

- Repeat compression/relaxation sequence as required for 'n' times

NOTE: The value of 'n' is indicated on the tube and will be dependant on the tube and scale used (for multi scale tube)

- Once all compression/relaxation sequences completed, remove the bladder and tube from the valve aperture and read off the discoloration from tube against the relevant scale
- Once the sample has been sucked through the tube 'n' times, the tube should be broken at the breaking point (between the two dots) so that the inner reagent ampoule breaks
- Shake out the content of the ampoule in the direction of the indicating layer and suck the solution through the layer

NOTE: The indication layer should be completely wetted by the solution

TAKE CARE THAT THE CONTENTS OF THE AMPOULE DOES NOT ENTER THE PUMP

- Read the off the discoloration against the scale in PPM

Expro procedure for Oil gravity measurements

Procedure:

NOTE: the cylinder should have enough height to allow for a 1" clearance between the bottom of the hydrometer and the bottom of the measuring cylinder. The ID of the cylinder should be at least 1" greater than the OD of the hydrometer.

- Allow any foam on the top of the sample to settle (or skim off) and place the sample in an area free from air currents
- Lower the hydrometer carefully into the sample to a point 2 of the smallest divisions above that at which it will float. Release the hydrometer
- When the hydrometer comes to a rest, the gravity should be read at the point at which the surface of the sample cuts the scale

NOTE: the hydrometer should not touch the side of the measuring cylinder, if the scale cannot be read properly, deduct 0.1 from the reading

- Take the temperature of the sample and note the results on the data sheet

NOTE: it is preferable to use a hydrometer that combines the thermometer and hydrometer functions

Expro procedure for Gas gravity measurements

Expro procedure to measure Gas Gravity:

- 'Blow down' gas sample line (normally taken from the top of the separator gas outlet)

This will ensure that a representative sample is collected and any condensation etc, that has accumulated in the sample line is blown clear prior collection the gas sample

- Once sample line has been 'blown down', place bladder over fitting, or connect the sample bottle to the end of the sample line
- Open the isolation valve on the sample line and fill the bladder or bottle

NOTE: do not over-pressurise the bladder as it is not a pressure containing device and will rupture if excess pressure is applied

- Vent the gas in the bladder or bottle in order to purge the container
- Repeat the above so that at least three purge cycles have been completed

- Fill the bladder or bottle with gas and measure the specific gravity using the RANAREX gravitometer
- Purge through the oil sample line on the separator until the contents of the line has been displaced twice
- Collect a sample from the oil line on the separator into a measuring cylinder

Expro excel sheet – correction Oil SG to Standard Conditions

Standard conditions: 1 atm and 15.0 °C

Input values:

- Oil SG uncorrected
- ODCT – oil density cylinder temperature, °C
- Oil line temperature, °C

Fixed values:

- $k.0 = 341,096$
- $k.1 = 0$

Calculated values:

- **Conversion from S.G. to API gravity**

$$Oil\ API_{uncorr} = \left(\frac{141,5}{Oil\ SG_{uncorr}} \right) - 131,5$$

- **Conversion from °C to °F**

$$ODCT(^{\circ}F) = \left(\frac{9}{5} * ODCT(^{\circ}C) \right) + 32$$

$$Oil\ line\ temp(^{\circ}F) = \left(\frac{9}{5} * Oil\ line\ temp(^{\circ}C) \right) + 32$$

Notations:

- $API.0 = Oil\ API_{uncorr}$
- $T.0f = ODCT(^{\circ}F)$
- $TankT = Oil\ line\ temp (^{\circ}F)$

API equation:

$$A1 = \frac{141360,198}{API.0 + 131,5}$$

$$A2 = 1 - [0.00001278 * (T.0f - 59)] - [0,0000000062 * (T.0f - 59)^2]$$

$$A3 = A1 * A2$$

$$A4 = \frac{341,0957}{A3^2}$$

$$A5 = A4 * (T.0f - 59)$$

$$A6 = 0,8 * A5$$

$$A7 = A5 * A6$$

$$A8 = -(A5 + A7)$$

$$A9 = EXP(A8)$$

$$A10 = IF \left(A9 = 0; 10 * 10^{10}; \frac{A3}{A9} \right)$$

$$API_c = \left(\frac{141360,198}{A10} \right) - 131,5$$

K-factor equation:

$$B1 = \frac{141360,198}{API_c + 131,5}$$

$$B2 = \frac{k.0}{B1}$$

$$B3 = \frac{B2}{B1}$$

$$B4 = \frac{k.1}{B1}$$

$$B5 = B3 + B4$$

$$B6 = B5 * (TankT - 60)$$

$$B7 = 0,8[B5 * (TankT - 60)]$$

$$B8 = B7 * B6$$

$$B9 = B6 - B8$$

$$B10 = EXP(B9)$$

Results:

- $k - factor = B10$
- $API_{corr} = API_c$
- $Oil SG_{corr} = \frac{141,5}{API_{corr} + 131,5}$

Attachment II

New procedures - drafts:

- BS&W
- Salinity
- H₂S & CO₂
- Oil gravity
- Gas gravity
- Oil flow rate
- Gas flow rate
- Meterfactor spreadsheet



EXPRO

Document Number:

<Document Number >

Revision:

B

Product Line / Function

Surface Well Test

Level:

<Classification>

Document Type:

Procedure

Title:

Basic Sediment & Water
-
(BS&W measurement)

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Revision List

Revision	Date	Prepared by	Reviewed by	Approved by
A	29.Sep.2015	Ida S. Gundersen	Kristian Sletthaug	
Revision Comment: First release				
B	27.Nov.2015	Ida S. Gundersen		
Revision Comment:				
Revision Comment:				
Revision Comment:				
Revision Comment:				
Revision Comment:				

DRAFT

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1. Purpose

The objective of this measurement is to find the percentage content of water and sediments produced from the well.

2. Scope

This procedure describes the equipment used for this measurement and how to take the most accurate reading.

3. Responsibilities & Authorities

All personnel that have passed the Well Test 1 Course are authorised to perform this kind of measurement. This procedure should be followed at all times.

In the case of personnel which have not passed Well Test 1, the measurement should be done under supervision of the Well Test supervisor.

This document originated as part of a master thesis that looked into data accuracy in association with well test operations. Expro's engineers in Norway have the authority to revise this procedure.

4. References

ASTM D4007-11e1 – Standard Test Method for Water and Sediment in Crude Oil by Centrifuge Method(Laboratory Procedure)

Well Test Standard, section 4.4 – Surface sampling

5. Apparatus

5.1 Centrifuge tube

Centrifuge tube specification		
ASTM D4007-11e1 – Standard test method for water and sediments in crude oil by the centrifuge method(laboratory procedure)		
<ul style="list-style-type: none"> Each tube shall be a 203 mm, cone shaped and be made of thoroughly tempered glass Graduation on tube shall be clear and distinct Accuracy of graduations on the tube shall be volumetrically verified before use of the tube 		
Centrifuge tube calibration tolerance for 203 mm tube		
Range, mL	Subdivision, mL	Volume tolerance, mL
0.0 - 0.10	0.05	±0.02
0.10 – 0.3	0.05	±0.03
0.3 – 0.5	0.05	±0.05
0.5 – 1.0	0.10	±0.05
1.0 2.0	0.10	±0.10
2.0 – 3.0	0.20	±0.10
3.0 – 5.0	0.5	±0.20
5.0 – 10	1.0	±0.50
10 – 25	5.0	±1.00
25 - 100	25.0	±1.00

Comment: even though this is a laboratory procedure, Expro employs the same tubes for offshore use

5.2 Centrifuge

5.2.1 Air operated centrifuge

Expro uses air operated centrifuges for testing of BS&W in the field. Below are specifications on this piece of equipment, as given by ASTM.

Centrifuge specifications	
ASTM D4007-11e1 – Standard test method for water and sediments in crude oil by the centrifuge method(laboratory procedure)	
<ul style="list-style-type: none">• Be able to spin two or more filled cone shaped 203mm centrifuge tubes• Revolving head, trunnion rings, and trunnion cups, including the cushions, shall all be constructed to withstand the maximum centrifugal force capable of being delivered by the power source.• The centrifuge shall be heated and controlled thermostatically to avoid unsafe conditions.• Shall be able to maintain the sample temperature during entire run at 60 ±3°C.	

5.2.2 Hand operated centrifuge

For smaller samples a hand operated centrifuge might be used. However, its use in the field has declined in later years.



5.3 Solvent

5.3.1 Toluene

Toluene is a reagent added to the system to lower the interfacial tension between oil and water, thus ensuring greater separation of the two. This facilitates a more accurate reading of the BS&W.

WARNING – Toluene is flammable. Keep away from heat, sparks and open flame.

Other solvents might be used, but shall have following characteristics:

Characteristics of reagents	
Assay(ingredient and quality)	+99.5%
Colour (APHA standard)	10
Boiling range (Recorded boiling point 110.6°C)	2.0°C
Residue after evaporation	0.001 max – wt./wt.
Substances darkened by H ₂ SO ₄	Pass test
Sulphur compounds (as S)	0.003% max – wt./wt.
Water (H ₂ O)	0.03% max – wt./wt.

5.3.2 Demulsifier

The purpose of a demulsifier is to promote the separation of water from the sample and to prevent it clinging to the walls of the centrifuge tube.

Recommended stock solution is 75% toluene and 25% demulsifier.

A different ratio may be required for some crude oils.

6. Step procedure

1. Pour 50 mL \pm 0.05mL of solvent into a clear centrifuge tube
2. Add 0.2 mL of demulsifier and shake tube until solvent and demulsifier are well mixed
3. Pour 50 mL of crude oil into centrifuge tube with the solvent and demulsifier.

Note – when shaking the sample, ensure that none of the sample is spilled.

4. Shake the tube by hand for several minutes to mix the sample with solvent and demulsifier.

Note – repeat this procedure for a second centrifuge tube if required.

Note – if required, heat the centrifuge tubes until the sample temperature is 140°F.

5. Place the tube in the centrifuge

Note – if only one sample is about to be centrifuged, make sure you have a tube with similar weight at the opposite side to ensure balance.

6. Spin the sample for approximately 3-10 minutes.
7. Read the BS&W content

Note – read to the nearest 0.05 mL between 0.1 – 1 mL, and to the nearest 0.1 mL when over 1 mL.

Note – if only one sample is taken, the result needs to be multiplied by two since half of the sample consists of solvent.

Note – if two samples are taken, and they are very similar, add the percentages together to achieve the true BS&W.

8. On completion of the test, all equipment should be washed and cleaned ready for the next test

Special cases:

Light crudes and gas condensates – for cases like this no solvent is used and 100 mL sample added instead. The percentage of BS&W can then be read directly on the tube.

Note – always be aware of the potential danger when taking samples from upstream of the choke manifold. This is to be avoided if possible, the samples should preferably be taken downstream of the choke manifold.

Sampling point:

There should be two valves in place with the inside valve fully open. The outside valve should be used when taking samples to control flow.

If the outside valve is washed out, the inside valve should be immediately closed. To continue sampling another valve need to be added, alternatively, the sample point may be plugged.



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Product Line / Function

Surface Well Test

Level:

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Document Type:

Procedure

Title:

Salinity determined by Refractometer

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1. Purpose

The objective of this determination is to see whether any water produced during a clean-up phase is brine or formation water.

The amount of salt mixed in the brine is often a known amount. By measuring the salt content of the water produced, it can be observed whether the salt content deviates from amount in the brine. This can help us determine if the clean-up phase is done or not.

2. Scope

This procedure describes the equipment used for this measurement and how to take the most accurate reading.

3. Responsibilities & Authority

All personnel that have passed the Well Test 1 Course are authorised to perform this kind of measurement. This procedure should be followed at all times.

In the case of personnel which have not passed Well Test 1, the measurement should be done under supervision of the Well Test supervisor.

This document originated as part of a master thesis that looked into data accuracy in association with well test operations. Expro's engineers in Norway have the authority to revise this procedure.

4. References

ASTM D4542-07 – Standard Test Method for Pore Water Extraction and Determination of the Soluble Salt Content of Soils by refractometer

PRODUCT DATASHEET – refractometer, Bellingham + Stanley Ltd.

EQUIPMENT DESCRIPTION -

https://en.wikipedia.org/wiki/Traditional_handheld_refractometer

5. Apparatus

5.1 Refractometer

A handheld refractometer is an analogue instrument used to measure a liquid’s refractive index. It works on the critical angle principle by which lenses and a prism project a shadow line onto a small glass reticule inside the instrument, which is then viewed by the user through a magnifying eyepiece.



A sample drop is placed between the prism and a flap. Light travelling through the sample is either passed through the reticule or totally internally reflected. The net effect is that a shadow line forms between the illuminated area and the dark area. The reading is taken at the point where the shadowy line crosses the scale. Because refractive index is very temperature dependent, corrections for temperature need to be taken.

A correction table for a sugar based sample is shown below.

International Temperature Correction Table for °Brix (% Sucrose) scale
Correct the readings by the following factors (refractometer must be calibrated correctly at 20°C)

Temperature °C	Reading °Brix		15.0	20.0	25.0	30.0	35.0	40.0	45.0	50.0	55.0	60.0	65.0	70.0	75.0	80.0	85.0
	0.0	5.0															
10.0	-0.53	-0.56	-0.59	-0.62	-0.65	-0.67	-0.69	-0.71	-0.72	-0.73	-0.74	-0.75	-0.75	-0.75	-0.75	-0.74	-0.73
11.0	-0.49	-0.52	-0.54	-0.57	-0.59	-0.61	-0.63	-0.64	-0.65	-0.66	-0.67	-0.68	-0.68	-0.68	-0.67	-0.67	-0.66
12.0	-0.44	-0.47	-0.49	-0.51	-0.53	-0.55	-0.56	-0.57	-0.58	-0.59	-0.60	-0.60	-0.61	-0.61	-0.60	-0.60	-0.59
13.0	-0.40	-0.41	-0.43	-0.45	-0.47	-0.48	-0.50	-0.51	-0.52	-0.53	-0.53	-0.53	-0.53	-0.53	-0.53	-0.52	-0.52
14.0	-0.34	-0.36	-0.38	-0.39	-0.40	-0.42	-0.43	-0.44	-0.44	-0.45	-0.45	-0.46	-0.46	-0.46	-0.45	-0.45	-0.44
15.0	-0.29	-0.31	-0.32	-0.33	-0.34	-0.35	-0.36	-0.37	-0.37	-0.38	-0.38	-0.38	-0.38	-0.38	-0.37	-0.37	-0.37
16.0	-0.24	-0.25	-0.26	-0.27	-0.28	-0.28	-0.29	-0.30	-0.30	-0.30	-0.31	-0.31	-0.31	-0.31	-0.30	-0.30	-0.30
17.0	-0.18	-0.19	-0.20	-0.20	-0.21	-0.21	-0.22	-0.22	-0.23	-0.23	-0.23	-0.23	-0.23	-0.23	-0.23	-0.23	-0.22
18.0	-0.12	-0.13	-0.13	-0.14	-0.14	-0.14	-0.15	-0.15	-0.15	-0.15	-0.15	-0.15	-0.15	-0.15	-0.15	-0.15	-0.15
19.0	-0.06	-0.06	-0.07	-0.07	-0.07	-0.07	-0.07	-0.08	-0.08	-0.08	-0.08	-0.08	-0.08	-0.08	-0.08	-0.08	-0.07
20.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21.0	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.07
22.0	0.13	0.14	0.14	0.14	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.15
23.0	0.20	0.21	0.21	0.22	0.22	0.23	0.23	0.23	0.24	0.24	0.24	0.24	0.24	0.23	0.23	0.23	0.22
24.0	0.27	0.28	0.29	0.29	0.30	0.30	0.31	0.31	0.32	0.32	0.32	0.32	0.32	0.31	0.31	0.31	0.30
25.0	0.34	0.35	0.36	0.37	0.38	0.38	0.39	0.39	0.40	0.40	0.40	0.40	0.40	0.39	0.39	0.39	0.38
26.0	0.42	0.43	0.44	0.45	0.46	0.46	0.47	0.48	0.48	0.48	0.48	0.48	0.48	0.47	0.47	0.46	0.46
27.0	0.50	0.51	0.52	0.53	0.54	0.55	0.55	0.56	0.56	0.56	0.56	0.56	0.56	0.55	0.55	0.55	0.52
28.0	0.58	0.59	0.60	0.61	0.62	0.63	0.64	0.64	0.65	0.65	0.65	0.65	0.64	0.64	0.63	0.62	0.60
29.0	0.66	0.67	0.68	0.69	0.70	0.71	0.72	0.73	0.73	0.73	0.73	0.73	0.72	0.71	0.70	0.69	0.68
30.0	0.74	0.75	0.77	0.78	0.79	0.80	0.81	0.81	0.81	0.82	0.81	0.81	0.81	0.80	0.79	0.78	0.75

The procedure on how to correct for temperature can be found in the next section.

5.2 Additional equipment

- Distilled water or alcohol for cleaning
- Pipette

6. Step procedure

1. Thoroughly wash the refractometer with distilled water and then dry the instrument.
2. Place one or two drops of liquid onto the semicircle of the white plastic area, which is held firmly against the glass platform. Only allow the liquid to escape under the white plastic area.
3. Hold the refractometer at a right angle to a light source and read the salinity. If the liquid is properly introduced, there should be a distinct black/white boundary. Read off the value where the bottom of the hairline touches the beginning of the black boundary. Round up or down to the nearest whole number.
4. After use, clean the prism and flap immediately with water or other suitable solvent and dry with a clean tissue.

Note – The prism surface can get damaged by strong alkaloids or acids if left in contact with it over long periods of time. Therefore, clean samples off of the prism as soon as possible. Wiping the prism surface occasionally with alcohol will remove any build-up of oils left from the sample.

Note – Salinity is given in parts per thousand parts (0/00). Salinity is the total amount of solids material, in grams, contained in 1 kg of sea water when all the carbonates has been converted to oxide, the bromine and iodine replaced by chlorine, and all organic matter completely oxidized

Note – Error in reading directly from the salinity scale is ± 0.3 ppt.

Note – Actual sea water samples may have a black/yellow/white boundary when reading the refractometer. Readings are always taken at beginning of the black boundary. Two to three readings should always be taken to ensure accuracy and precision.

Correcting the reading for temperature:

The eclipse refractometer is calibrated to read correctly at 20°C. The refractive index of the measured sample will vary with temperature and the reading must be corrected to take account of this.

Correction for sugar based samples measured on BRIX(%sucrose) scale are shown in the table in the previous section and can be used with the following method:

1. Stabilise the instrument at 20°C.
2. Apply a sample of known value to the prism and adjust to read correctly as described above.
3. Add/subtract factors from the table for measurements at other temperatures.



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Title:

H2S and CO2 measured
with
Draeger tubes

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1. Purpose

The objective of this measurement is to find the content of H₂S and CO₂ in the gas produced. These gases can be hazardous for both people and the environment.

2. Scope

This procedure describes the equipment used for this measurement and how to take the most accurate readings.

3. Responsibilities

All personnel that have passed the Well Test 1 Course are authorised to perform this kind of measurement. This procedure should be followed at all times.

In the case of personnel which have not passed Well Test 1, the measurement should be done under supervision of the Well Test supervisor.

This document originated as part of a master thesis that looked into data accuracy in association with well test operations. Expro's engineers in Norway have the authority to revise this procedure.

4. References

- Draeger website:

http://www.draeger.com/sites/en_uk/Pages/Chemical-Industry/Draeger-Tube-pump-accuro.aspx

- Expro internal documents

Pictures:

Measuring tube – Expro internal documents

Handpump -

https://www.google.co.uk/search?q=hand+pump+H2S&source=Inms&tbm=isch&sa=X&ved=0CAcQAUoAWoVChMI0dOI6KWcyAIVBy4aCh25OwP8&biw=1376&bih=723#tbm=isch&q=draeger+hand+pump&imgsrc=K9MwblL_deQ9pM%3A

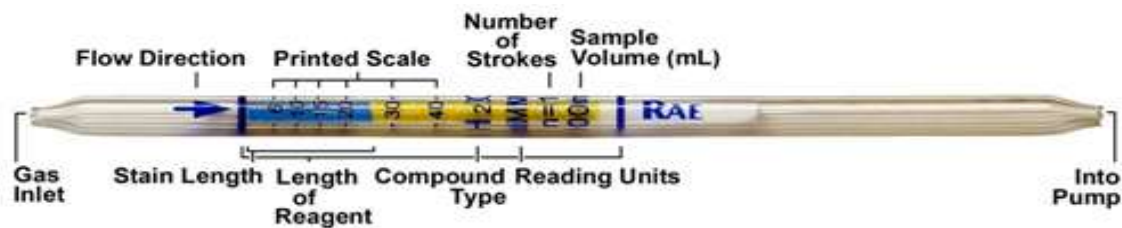
5. Apparatus

5.1 Measuring tube

These tubes are so-called short term tubes. They are intended for the measurement of momentary concentrations. The duration of a short term measurement is in the range of 10 seconds to 15 minutes. There are several types of short-term tubes:

- Tubes with a single indication layer
- Tubes with one or more pre-layers plus an indication layer
- Combinations of two tubes
- Tubes with connection hoses
- Tubes with a built-in reagent ampoule
- Tubes for simultaneous measurement

Most common used in Expro is tubes with a built-in reagent ampoule.

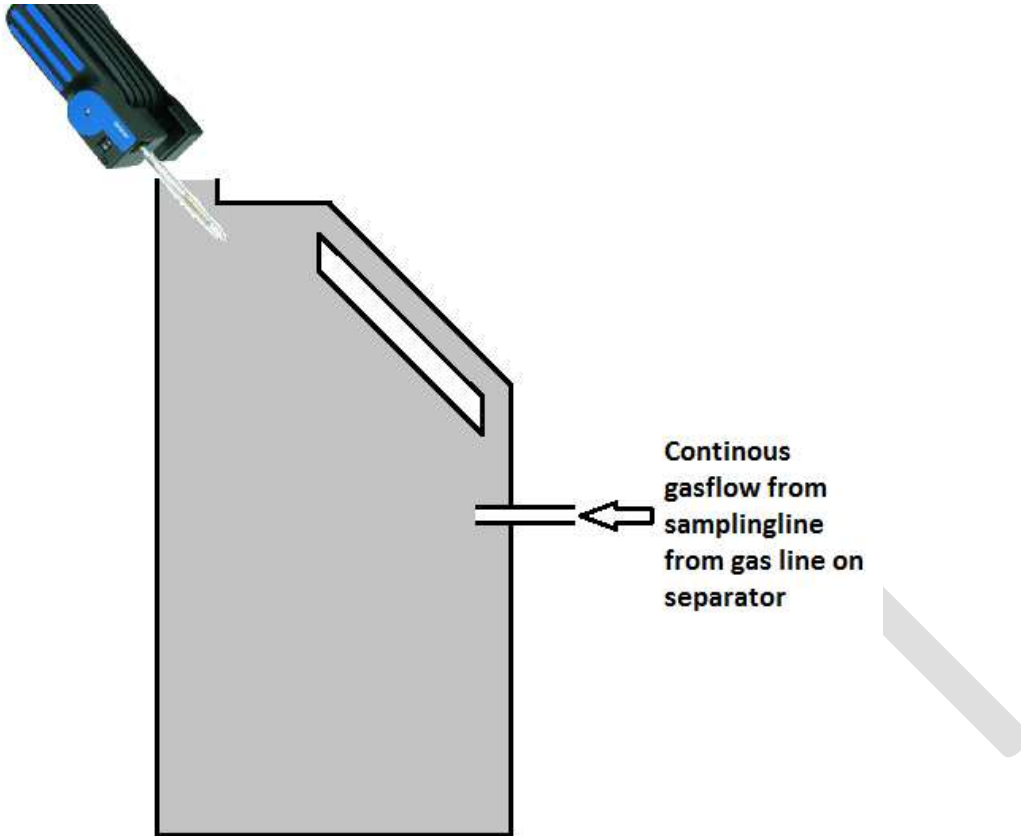


5.2 Hand pump

A Draeger tube hand pump draws in 100 ml per stroke. For measuring, the bellow is pressed together. The exhaust valve is closed during the opening phase of the bellow so that the gas sample flows through the connected Draeger tube into the pump. After complete opening of the pump body into its original position the suction process is finished. The end of stroke is visible by a pressure-controlled end of stroke indication, located in the pump head.



5.3 Sampling compartment



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6. Step procedure

1. Select tube of correct type and range.

Note - there might be tubes with different scales and accuracies. If available, use the tubes with smallest subscaling since this gives most accurate reading.

2. Squeeze Draeger body to compress the bellows and insert unbroken tube into valve aperture.

Note – if the bellows do not expand then integrity of the bellows is assured and sampling can continue. If the bellows expand then the bellows are leaking and false results will be experienced if that tester is used.

3. Open flow from gas line to sampling compartment.

Note –make sure the flow is continuous and controlled. If condensate occurs, make sure it not splashes into the compartment

4. Break open both ends of the Draeger tube.
5. Compress body to expel air from bellow and insert tube in valve aperture.

Note - check arrow on tube side for correct end to install – arrow indicates direction of flow (from sample to tester).

6. Insert the tube into the hole in the top off the sampling compartment
7. Once the tube is secure in the valve aperture, release bellows and allow chain to go taut.

Note - the chain MUST be allowed to go taut for a correct reading to be obtained. This is because the volume of the bellows is a calibrated amount which is related to the reagent used in the tubes and any differing volume will cause errors.

8. Repeat compression/relaxation sequence as required for 'n' times.

Note - the value of 'n' is indicated on the tube and will be dependent on the tube and scale used (for multi scale tubes).

9. Once all compression/relaxation sequences are completed, remove the bladder and tube from the valve aperture and read off the discoloration from tube against the relevant scale.
10. Once the sample has been sucked through the tube 'n' times, the tube should be broken at the breaking point (between the two dots) so that the inner reagent ampoule breaks.
11. Shake out the contents of the ampoule in the direction of the indication layer and suck the solution through the layer.

Note - the indication layer should be completely wetted by the solution.

Note - take care that the contents of the ampoule do not enter the pump.

12. Read the off the discoloration against the scale on PPM or %.



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Specific Gravity of Crude Petroleum (Thermohydrometer & Hydrometer)

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1. Purpose

The objective of this procedure is to give guidance on how to measure the specific gravity of oil (API gravity) as accurately as possible with the equipment used in the field. Specific gravity is a measurement taken to describe the property of the oil produced from the reservoir.

2. Scope

This procedure describes the equipment used for this measurement and how to take the most accurate reading.

Since thermohydrometers are most commonly used in the field, the procedure on how to use this will be described step by step.

If a hydrometer is used, the procedure is approximately the same, but the temperature readings are taken with a thermometer right before and after you have taken the hydrometer reading.

3. Responsibilities & Authority

All personnel that have passed the Well Test 1 Course are authorised to perform this kind of measurement. This procedure should be followed at all times.

In the case of personnel which have not passed Well Test 1, the measurement should be done under supervision of the Well Test supervisor.

This document originated as part of a master thesis that looked into data accuracy in association with well test operations. Expro's engineers in Norway have the authority to revise this procedure.

4. References

ASTM D287-12b – Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)

ASTM D6822-12b – Test Method for Density, Relative Density, or API Gravity of Crude Petroleum and Liquid Petroleum Products by Thermohydrometer Method

The standard below is similar to ASTM D-287-12B but covers laboratory measurements with hydrometers. Since thermohydrometers are recommended for field testing, it is the procedure for these that is described in this document.

ASTM D1293-12b – Test Method for Density, Relative Density, or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method

Step 5 in the calculations is verified by *Master thesis – Data accuracy from well test operations*.

Pictures:

Hydrometer -

https://www.google.co.uk/search?q=ASTM+hydrometer&source=lnms&tbm=isch&sa=X&ved=0CAcQ_AUoAWoVChMlxZXhuKGcyAIVSwgaCh2zPwfB&biw=1376&bih=723#imgrc=RstZ5FCbKMBmdM%3A

Thermometer -

https://www.google.co.uk/search?q=ASTM+hydrometer&source=lnms&tbm=isch&sa=X&ved=0CAcQ_AUoAWoVChMlxZXhuKGcyAIVSwgaCh2zPwfB&biw=1376&bih=723#tmb=isch&q=ASTM+thermometer&imgrc=Zgk4C787U0CzeM%3A

Thermohydrometer -


https://www.google.co.uk/search?q=ASTM+hydrometer&source=lnms&tbm=isch&sa=X&ved=0CAcQ_AUoAWoVChMlxZXhuKGcyAIVSwgaCh2zPwfB&biw=1376&bih=723#tmb=isch&q=ASTM+thermohydrometer&imgrc=Op47nKtuZLfP2M%3A

Hydrometer cylinder -


https://www.google.co.uk/search?q=glass+cylinder&biw=1376&bih=723&source=lnms&tbm=isch&sa=X&ved=0CAYQ_AUoAWoVChMlnpqY7KKcyAIVTNlaCh13mwzy#tmb=isch&q=hydrometer+cylinder&imgrc=P7MaaqCA0MRUnM%3A

5. Apparatus

5.1 Thermohydrometer

Thermohydrometer						
ASTM E100 - Standards Specification for ASTM Hydrometers						
	<ul style="list-style-type: none"> • Same specifications as regular hydrometer with some additional requirements: <ul style="list-style-type: none"> - The thermometer shall be of the mercury in glass type - When the thermometer scale is located in the stem of hydrometer, the scale shall be in red to distinguish it from the hydrometer scale. - Capillary stem shall be essentially parallel to the hydrometer axis <p>In Expro, following thermohydrometers are accepted:</p>					
	Thermohydrometer No.		Hydrometer dimensions and scale		Thermometer scale	
	ASTM Hydrometer No.	Nominal Rel. Density range (Sp. Gr)	Total length, mm	374–387	Range, °C	-20 to +65
	300H-82	0.600 – 0.650	Body diam., mm	18–25		0 to +85
	301H-82	0.650 – 0.700	Stem diam., mm	4.0		+20 to +105
	302H-82	0.700 – 0.750	Standard temp, °C	15	Immersion	Total
	303H-82	0.750 – 0.800	Subdivision, kg/m3	0.5	Subdivision, °C	1.0
	304H-82	0.800 – 0.850	Short interm. line at, kg/m3	1	Intermediate lines at, °C	5
	305H-82	0.850 – 0.900	Long interm. line at, kg/m3	5	Main lines at, °C	10
	306H-82	0.900 – 0.950	Main lines at, kg/m3	10	Scale error at any point not to exceed, °C	1.0
	307H-62	0.950 – 1.000	Scale error at any point not to exceed, kg/m3	0.5	Scale length, mm	80 - 100
	308H-82	1.000 – 1.050	Length of nominal scale, mm	125-145		
	309H-82	1.050 – 1.100	Scale extension beyond nominal range limit, kg/m3	2.5		

5.2 Hydrometer

Hydrometer Specification																																																																
ASTM E100 – Standards Specification for ASTM Hydrometers																																																																
	<ul style="list-style-type: none"> Shall be of constant-mass, variable-displacement type and it shall be made of glass. The outer surface of the stem and body shall be symmetrical about the vertical axis and it shall always float with this axis in liquids. Shall be thoroughly dry on the inside when sealed. The glass shall be smooth, transparent, and free of bubbles, cracks, strain patterns, or other imperfections that might interfere with the use of the hydrometer. Graduation lines and inscriptions shall be in a permanent black marking material. Special Inscription: Standard temperature and reference temperature(ex. 60/60°F), hydrometer number(ex. 1H). <p>In Expro, the following hydrometers are accepted:</p> <table border="1" style="width: 100%; border-collapse: collapse; margin-top: 10px;"> <thead> <tr> <th colspan="2" style="text-align: center;">Light liquids</th> <th style="width: 10%;"></th> <th colspan="2" style="text-align: center;">Heavy liquids</th> </tr> <tr> <th style="font-size: small;">ASTM Hydrometer No.</th> <th style="font-size: small;">Nominal Rel. Density range (Sp. Gr)</th> <th></th> <th style="font-size: small;">ASTM Hydrometer No.</th> <th style="font-size: small;">Nominal Rel. Density range (Sp. Gr)</th> </tr> </thead> <tbody> <tr><td style="text-align: center;">82H-62</td><td style="text-align: center;">0.650 – 0.700</td><td></td><td style="text-align: center;">111H-62</td><td style="text-align: center;">1.000 – 1.050</td></tr> <tr><td style="text-align: center;">83H-62</td><td style="text-align: center;">0.700 – 0.750</td><td></td><td style="text-align: center;">112H-62</td><td style="text-align: center;">1.050 – 1.100</td></tr> <tr><td style="text-align: center;">84H-62</td><td style="text-align: center;">0.750 – 0.800</td><td></td><td style="text-align: center;">113H-62</td><td style="text-align: center;">1.100 – 1.150</td></tr> <tr><td style="text-align: center;">85H-62</td><td style="text-align: center;">0.800 – 0.850</td><td></td><td style="text-align: center;">114H-62</td><td style="text-align: center;">1.150 – 1.200</td></tr> <tr><td style="text-align: center;">86H-62</td><td style="text-align: center;">0.850 – 0.900</td><td></td><td style="text-align: center;">115H-62</td><td style="text-align: center;">1.200 – 1.250</td></tr> <tr><td style="text-align: center;">87H-62</td><td style="text-align: center;">0.900 – 0.950</td><td></td><td style="text-align: center;">116H-62</td><td style="text-align: center;">1.250 – 1.300</td></tr> <tr><td style="text-align: center;">88H-62</td><td style="text-align: center;">0.950 – 1.000</td><td></td><td style="text-align: center;">117H-62</td><td style="text-align: center;">1.300 – 1.350</td></tr> <tr><td style="text-align: center;">89H-62</td><td style="text-align: center;">1.000 – 1.050</td><td></td><td style="text-align: center;">118H-62</td><td style="text-align: center;">1.350 – 1.400</td></tr> <tr><td style="text-align: center;">90H-62</td><td style="text-align: center;">1.050 – 1.100</td><td></td><td style="text-align: center;">119H-62</td><td style="text-align: center;">1.400 – 1.450</td></tr> <tr><td></td><td></td><td></td><td style="text-align: center;">120H-62</td><td style="text-align: center;">1.450 – 1.500</td></tr> </tbody> </table> <p style="margin-top: 10px;">Comment: Expro mostly use hydrometers for light liquids</p>				Light liquids			Heavy liquids		ASTM Hydrometer No.	Nominal Rel. Density range (Sp. Gr)		ASTM Hydrometer No.	Nominal Rel. Density range (Sp. Gr)	82H-62	0.650 – 0.700		111H-62	1.000 – 1.050	83H-62	0.700 – 0.750		112H-62	1.050 – 1.100	84H-62	0.750 – 0.800		113H-62	1.100 – 1.150	85H-62	0.800 – 0.850		114H-62	1.150 – 1.200	86H-62	0.850 – 0.900		115H-62	1.200 – 1.250	87H-62	0.900 – 0.950		116H-62	1.250 – 1.300	88H-62	0.950 – 1.000		117H-62	1.300 – 1.350	89H-62	1.000 – 1.050		118H-62	1.350 – 1.400	90H-62	1.050 – 1.100		119H-62	1.400 – 1.450				120H-62	1.450 – 1.500
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Specification related to design:	
Standard temp. °F	60/60
Subdivisions	0.0005
Intermediate lines at	0.001
Main lines at	0.005
Scale error at any point not to exceed	0.0005
Total length, mm	325 – 335
Length of nominal scale, mm	125 – 145
Scale extension beyond nominal range limits, max	0.0025
Body diameter, mm	23 – 27
Stem diameter min, mm	5.0

Recommended Hydrometers by ASTM					
ASTM D1298-12B – Standard Test Method for Density, Relative Density, or API Gravity of crude Petroleum an Liquid Petroleum Products by Hydrometer Method					
Units	Range		Scale		Meniscus
	Total	Each unit	Interval	Error	Correction
Density, Kg/m3 at 15°C	600-1100	20	0.2	±0.2	+0.3
	600-1100	50	0.5	±0.3	+0.7
	600-1100	50	1.0	±0.6	+1.4
Rel. density, 60/60°F	0.600-1.100	0.020	0.0002	±0.0002	+0.0003
	0.600-1.100	0.050	0.0005	±0.0003	+0.0007
	0.600-1.100	0.050	0.001	±0.0006	+0.0014
	0.650-1.100	0.050	0.0005	±0.0005	+0.0007
API gravity	-1 to +101	12	0.1	±0.1	-0.1

Comment: Expro uses hydrometers marked in blue.

5.3 Thermometers
Thermometers
ASTM E1 – Specification for ASTM Liquid-in-glass Thermometers



- Specifications to come


Range, °C	-20 to +65 L
	0 to +85 M
	+20 to +105 H
Immersion	Total
Subdivision, °C	1.0
Intermediate lines at, °C	5
Main lines at, °C	10
Scale error at any point not to exceed, °C	1.0
Scale length, mm	80 - 100



Recommended Thermometers			
ASTM D1298-12B – Standard Test Method for Density, Relative Density, or API Gravity of crude Petroleum an Liquid Petroleum Products by Hydrometer Method			
Scale	Range	Graduation Interval	Scale Error
°C	-1 to +38	0.1	±0.1
°C	-20 to +102	0.2	±0.15
°F	-5 to +215	0.5	±0.25

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5.4 Hydrometer cylinder

Hydrometer cylinder	
<p>ASTM D0287-12B – Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products(Hydrometer Method), section 6.3</p>	
	<ul style="list-style-type: none"> • Shall be of clear glass, plastic or metal Comment: plastic cylinder shall be resistant to discoloration or attack by oil samples and shall not affect the material being tested. • Inside diameter of cylinder shall be at least 25 mm greater than the outside diameter of the hydrometer. • Height shall be such that the appropriate hydrometer floats in the test position with at least 25 mm clearance between the bottom of the hydrometer and bottom of cylinder

6. Step procedure – Thermohydrometer

WARNING – EXTREMELY FLAMMABLE

1. Test temperature should be between -18°C and 90°C (0°F and 195°F)

Note – the density will be most accurate at or near reference temperature of 15°C(60°F)

2. Transfer a sample into a clean hydrometer cylinder without splashing.

Note – the hydrometer cylinder shall be at approximately the same temperature as the sample to be tested.

3. Place the cylinder containing the sample in a vertical position in a location free from air current.

Note – take precautions to prevent the temperature of the sample from changing during the time necessary to complete the test. The temperature of the surrounding medium should not change more than 3°C(5°F).

Note - Let the oil settle for a period of time to let gas dissolved in the oil evaporate. A sampling cabinet shall be used if the measurement is done inside the laboratory container.

4. Lower and raise the thermohydrometer no more than two scale division in the sample cylinder.

Note - Keep the rest of the stem dry, as unnecessary liquid on the stem changes the effective weight of the instrument.

Note – Allow sufficient time for the hydrometer to come to rest, usually 3 to 5 min.

5. Read and record the thermohydrometer scale reading with meniscus correction to the nearest 0.5 kg/m³ and the thermometer reading to the nearest 0.5°C(1.0°F).

Note - The correct reading is that point on the hydrometer scale at which the surface of the liquid cuts the scale. Determine this point by placing the eye slightly below the level of the liquid and slowly raising it until the surface, first seen as a distorted ellipse, appears to become a straight line cutting the hydrometer scale

6. Two successive determinations of density and gravity need to be taken to ensure temperature of the thermohydrometer and liquid has stabilized. The two successive corrected values should be within 0.5 kg/m³. If this cannot be obtained, the temperature may not have stabilized, or loss of light hydrocarbons may be occurring.

Take a new reading when temperature has stabilized.

7. Calculations – Hydrometer & thermohydrometer

1. Apply any relevant thermometer corrections to the temperature readings and record the average of those two temperature to the nearest 0.1°C.
2. Apply any hydrometer correction identified in a calibration certificate to the observed reading and record the correct hydrometer scale to the nearest 0.1 kg/m³ for density(0.0001 g/mL, kg/L or rel. density, or 0.1 °API).

Step 1 – Convert the correct hydrometer scale reading to density in kg/m³ if necessary

$$\text{Density} \left(\frac{\text{kg}}{\text{m}^3} \right) = \frac{141.5 * 999.016}{131.5 + \text{API}}$$

$$\text{Density} \left(\frac{\text{kg}}{\text{m}^3} \right) = R.D * 999.016$$

Step 2 – Calculate hydrometer thermal glass expansion correction factor using appropriate equation

- Correction for a Base Temperature T_b of 15°C:

$$HYC = 1.0 - [0.000023(T - 15)] - [0.00000002(T - 15)^2]$$

- Correction for a Base Temperature T_b of 60°F:

$$HYC = 1.0 - [0.00001278(T - 60)] - [0.0000000062(T - 60)^2]$$

Alternative equation:

- Correction for a Base Temperature T_b of 20°C:

$$HYC = 1.0 - [0.000023(T - 20)] - [0.00000002(T - 20)^2]$$

Step 3 – Multiply density from Step 1 with correction of base temperature

$$\text{Density}(\text{kg}/\text{m}^3)_{HYC} = \text{Density} \left(\frac{\text{kg}}{\text{m}^3} \right) * HYC$$

Step 4 – Convert densities to relative densities R.D.

$$R.D. = \frac{\text{Density} \left(\frac{\text{kg}}{\text{m}^3} \right)_{HYC}}{999.016}$$

Step 5 – Correct the density for liquid temperature to selected base temperature

$$VCF = 1 - (T_F - 60) * 0.0005$$

Step 6 – Corrected density

$$\text{Density}(\text{kg}/\text{m}^3)_{\text{Corr}} = \text{Density}(\text{kg}/\text{m}^3)_{HYC} * VCF$$



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Document Number:

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Product Line / Function

Surface Well Test

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Document Type:

Procedure

Title:

Gas Specific Gravity with Ranarex Gravimeter

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Revision List

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B	27.Nov.2915	Ida S. Gundersen		
Revision Comment:				
Revision Comment:				
Revision Comment:				
Revision Comment:				

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1. Purpose

The objective of this measurement is to find the specific gravity of the gas. This value is used by oil companies to perform various task and simulations, but is also used during well testing to calculate flow rate for gas.

2. Scope

This procedure describes the equipment used for this measurement and how to take the most accurate reading.

3. Responsibilities & Authority

All personnel that have passed the Well Test 1 Course are authorised to perform this kind of measurement. This procedure should be followed at all times.

In the case of personnel which have not passed Well Test 1, the measurement should be done under supervision of the Well Test supervisor.

This document originated as part of a master thesis that looked into data accuracy in association with well test operations. Expro's engineers in Norway have the authority to revise this procedure.

4. References

ASTM D1070-03(Reapproved 2010) – Standard Test Method for Relative Density of Gaseous Fuels

Product datasheet – RANAREX Gas Gravitometers

Pictures:

Gas bladder –

https://www.google.co.uk/search?q=stainless+steel+gas+sample+bottle&biw=1376&bih=723&source=lnms&tbm=isch&sa=X&ved=0CAYQ_AUoAWoVChMI96WciKCcyAIVSdgaCh3WjQ5t#bm=isch&q=gas+sampling+bladder&imgsrc=UQPA-tjK3K2UnM%3A

Gas sampling bottle -

https://www.google.co.uk/search?q=stainless+steel+gas+sample+bottle&biw=1376&bih=723&source=lnms&tbm=isch&sa=X&ved=0CAYQ_AUoAWoVChMI96WciKCcyAIVSdgaCh3WjQ5t#imgsrc=5V9M_NbVdHsKDM%3A

Ranarex measuring wheels schematics -

https://www.google.co.uk/search?q=dr%C3%A4ger+tubes&source=lnms&tbm=isch&sa=X&ved=0CAcQ_AUoAWoVChMIhITh8L3HxwIVCdlACh0fZA4C&biw=894&bih=880#tbm=isch&q=Ranarex&imgsrc=Q2Xti36SLjX_SM%3A

5. Apparatus

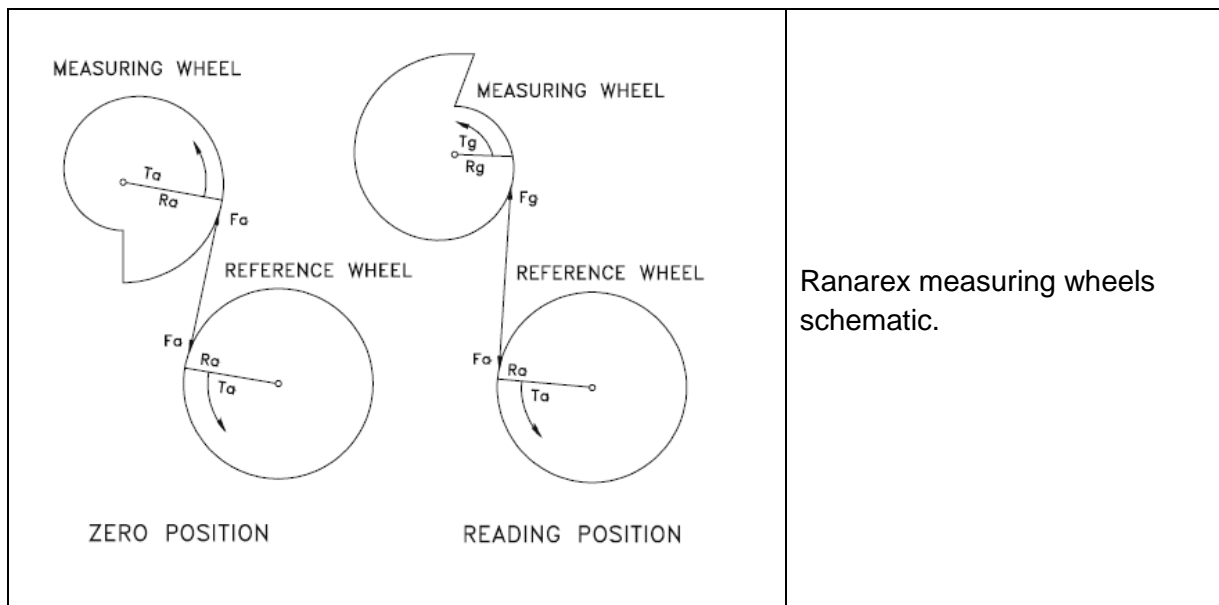
5.1 Ranarex Gravimeter


The principles and design behind a Ranarex gravimeter are simple.

The gravimeter contains two cylindrical, gas-tight measuring chambers with each having a separate inlet and outlet connection. Each chamber contains an impeller and an impulse wheel, both with axial vanes. These wheels are mounted on separate shafts, facing each other but not touching.

An electrical motor and drive belt rotate the impellers at the same speed and in the same direction. The impellers draw continuous flow of gas sample into upper chamber, and reference air into the lower chamber. They spin the gas and air against the vanes of the corresponding impulse wheels. As the spinning gas and air impinge against the vanes, they create torque on the wheels that are proportional to the density of the gas and of the air.

The torque is transmitted from the chambers to two external measuring wheels. A flexible tape is wrapped on the measuring wheels so that the torque creates two opposing forces as shown in the schematic below. The measuring wheels are restrained from continuous rotation, but a difference between the torque forces allows limited motion of the entire system. The measuring system divides the torque of the gas divided by the density of the air, and thereby measures specific gravity.



Ranarex Gravitometer	
Model specification:	
<ul style="list-style-type: none">• Accuracy - $\pm 0.5\%$ of actual value• Readings – indicating only• Sample flow rate – 10-15 scf/h• Specific gravity range – 0.52 to 1.03 and 0.97 to 1.90• Ambient Air Reference dryer – Silica Gel	

5.2 Other Equipment

- Gas bladder



- Stainless steel sample bottle



Note – if sample bottles are to be used, they should have an approved pressure rating and third party certification. They are not commonly used in the Norwegian sector.

6. Step procedure

Preparation

1. Dried air standard – Install a drier at the air inlet. The instrument must use air at normal CO₂ content as the reference standard
2. Temperature – The air and the gas should be at the same temperature. The installation of a sample line of reasonable length relative to diameter, will allow sufficient rapid heat transfer for the gas sample to reach ambient temperature before it is drawn into the reference chamber.
3. Pressure – reduce the gas sample to atmospheric pressure. The reference air is also at atmospheric pressure.
4. Power supply – by maintaining the voltage and line frequently between the limits specified in the manufacturer's manual, the speed of the electric motor remains sufficiently constant that minor variations have no effect on measurements.

Measurement

1. "Blow down" gas sample line (normally taken from the top of the separator gas outlet)

Note – this will ensure that a representative sample is collected and any condensation etc. that has accumulated in the sample line is blown clear prior collecting the gas sample.

2. Once sample line has been "blown down", place bladder over fitting, or connect the sample bottle to the end of the sample line
3. Open the isolation valve on the sample line and fill the bladder or bottle.

Note – do not over pressurise the bladder as it is not a pressure containing device and will rupture if excess pressure is applied.

4. Vent the gas in the bladder in order to purge the container.
5. Repeat the above so that at least three cycles have been completed.
6. Fill the bladder and measure the specific gravity using the RANAREX gravimeter

Note - Prior to connection the instrument to gas, turn on the motor and check the zero point when the Ranarex contains only air.

Note – If large amounts of condensate may be formed in the bladder, make sure to held the inlet of the balloon upward to keep it free from liquids.

Notes – more than one reading should be done for wet gas or gas/condensate system to ensure correct reading. Large amounts of liquids in the gas, may give wrong reading of gas gravity and may damage Ranarex gravimeter.



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Oil flow rate
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Measurements and calculations

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1. Purpose

The objective of this procedure is to give guidance on how to perform all tests and measurements necessary to find an accurate oil flow rate.

2. Scope

This document will describe which tests and readings which are required to calculate an accurate oil flow rate.

3. Responsibilities

These days, all oil and gas flow rates are determined by the use of advanced software. However, oil rates require that a correction to standard conditions are taken into account.

This document is meant to provide guidance to the factors and equations which lie behind the calculation of the oil flow rate.

4. References

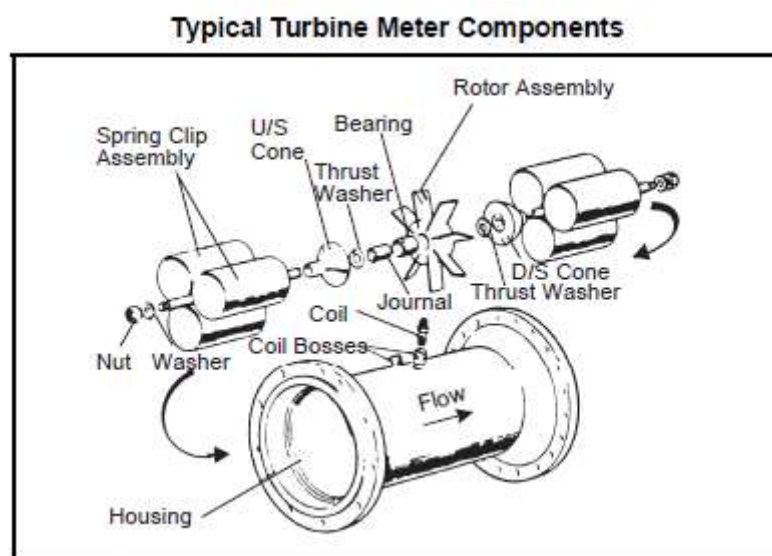
GPSA Engineering Data book – 11th Edition (Electronic) SI Volumes I & II

5. Equipment

Turbine meters

A turbine meter normally consists of one moving part, which is an impeller held in place by high pressure, low drag bearings. A magnetic transducer installed in the meter body is used to count revolutions as a medium passes through the meter body. The pulses from the transducer are determined for a known volume passing through the meter to develop a factor in pulses per litre, or any other desired volumetric unit.

A schematic of a typical turbine meter and its components are shown below



An expected accuracy of 0.25% can be attained where proper stream conditions are maintained and the meter is installed correctly.

Things to consider regarding installation of turbine meters:

- Different meters are only applicable for certain flow ranges, make sure the right meter for the expected flow rate is used.
- Upstream strainers should be installed to protect meter internals from foreign materials (sand, debris and solids)
- Expected pulsation and vibration of the meter should be considered
- Proper upstream flow conditioning
- Significant rate changes can damage the meter
- Change in flow temperature, pressure and density should be considered
- Minimum back-pressure: 2 times the pressure drop across meter, plus 1.25 times separator pressure is the minimum recommended back pressure. This is often not a practical solution in well testing, which is why a calibration tank etc. is used to correct the readings acquired through the meter.
- Separate equipment to prove the meter (i.e. calibration tank, shrinkage tester)

Meter prover system (Calibration tank)

A calibration tank is used to correct the oil flow measurement through the meter. The act of calibration consists of verifying how much gas goes through the meter and what the shrinkage to standard conditions are. A picture of a calibration tank is shown below.

A calibration tank should have a known volume and sight glasses with calibrated volume measurement strips on it.

NOTE: Each tank shall have a unique measuring strip for that specific tank. Sight glasses should never be removed and put on another tank. This will give the wrong volume reading.

It is also required to have pressure and temperature gauges installed on the calibration tank, in order to be able to make corrections to standard conditions.

The standard requirements to a prover system is listed below:

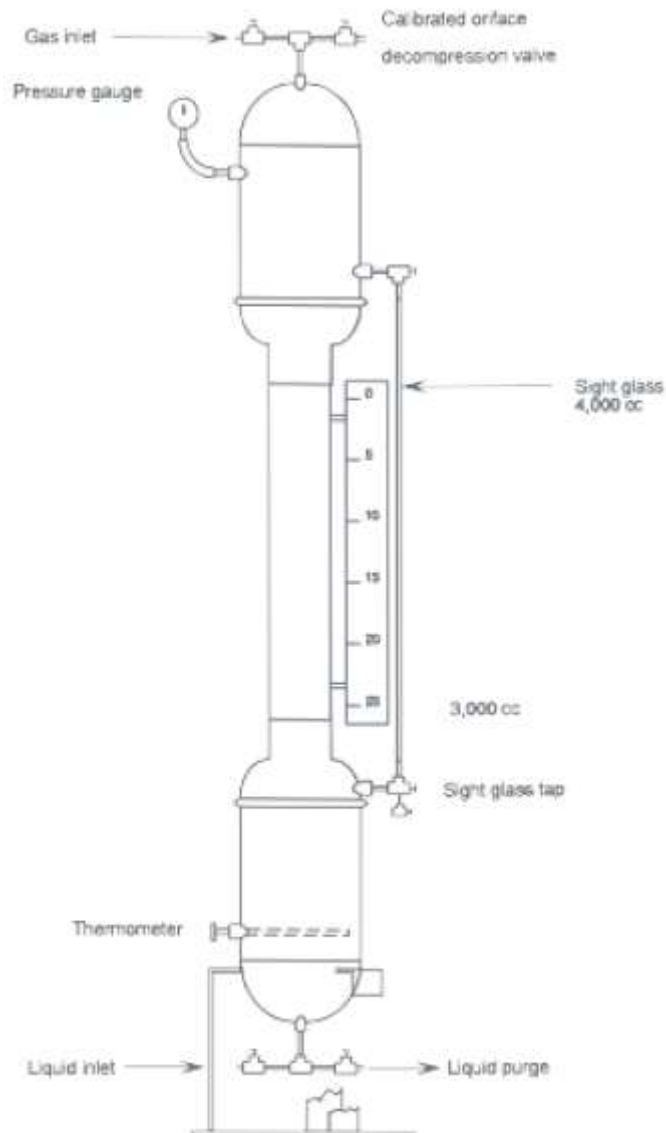
- All prover vessels should be calibrated by qualified personnel using test measures certified by the U.S Bureau of Standards and be issued a *Certificate of Calibration*.
- All meter prover systems should be equipped with a thermometer and pressure gauges located near the meter. Prover vessel shall have pressure gauges and thermometers on the inlet and outlet. Gauges and thermometers should be checked periodically against a deadweight tester and certified thermometer to verify accuracy.
- All valves in the proving system which affect the accuracy of the proving should provide for observation of valve integrity, e.g., double block and bleed valves.
- Proving conditions should approximate operating conditions.



Shrinkage tester

The shrinkage tester is used to verify that the shrinkage measured by using the calibration tank is within an acceptable range.

A shrinkage tester works by receiving oil/condensate at separator pressure, the tester is then isolated from the separator and slowly bled off to atmospheric pressure. The shrinkage is the decrease in volume of a liquid phase caused by the release of solution of gas and/or the thermal contraction of the liquid and is expressed as a percentage



6. Measurements

Meter reading

1. Note oil line temperature
2. Take meter reading at time 0
3. Allow a known amount of volume pass through the meter. Alternatively, allow a certain volume pass through the meter for a known amount of time

NOTE: if it is decided to take a meter reading for a certain length of time, make sure the tank has the capacity to handle the volume expected during this time.

4. Note oil line temperature when reading is finished
5. Calculate volume passing through the meter
6. Proceed with calculating the corrected meter reading

Calibration tank reading

1. Take initial tank reading and temperature reading
2. Open inlet valve to tank
3. Divert fluid flow to tank using oil manifold
4. Take reading as and when it is required (at the same time as for meter reading) from the sight glass over timed periods
5. At the end of the flow period, divert flow from tank to burner using oil manifold
6. Close tank inlet valve
7. Note pressure and temperature in tank
8. Note intermediate level at tank compartment.
9. Bleed off tank slowly to atmospheric pressure
10. Note temperature at atmospheric pressure
11. Note final level in tank at atmospheric pressure
12. Calculate shrinkage
13. Proceed with calculations for correction for temperature

Shrinkage tester

1. Level in the separator should be higher the top scale on the shrinkage tester.

NOTE: if the separator has a low liquid level, calculate shrinkage from the point the liquid level reaches in the sight glass.

2. With the shrinkage tester empty, open the gas equalising line from separator to pressure the shrinkage tester to separator pressure.
3. Open liquid inlet line slowly to allow the shrinkage tester to fill with oil

NOTE: be careful when approaching the top mark on the scale, so the tester is not overfilled.

4. Once sample is at "zero level", close oil and gas line
5. Record pressure and temperature of sample in tester

NOTE: time to bleed sample to atmospheric should be ± 30 minutes

6. Open bleed-off valve slowly
7. Once the sample is at atmospheric pressure, record reduction from scale
8. Repeat operation as required to obtain the average
9. When completed, close bleed-off valve and open gas line to enable the tester to reach separator pressure
10. Open drain valve to blow down level via drain line

7. Calculations

7.1 Total volum correction factor

1. Calculate combined meter and shrinkage factor

$$CMSF = VCF_{pressure} = \frac{\text{Final tank reading} - \text{initial tank reading}}{\text{final meter reading} - \text{initial meter reading}}$$

Note – final tank reading is the reading after pressure is bled to zero and the oil has been settled for a period of time.

2. Correct for temperature deviation from standard temperature

$$VCF_{temp} = 1 - [T_{\circ F} - 60] * 0.0005$$

3. Total volume correction factor

$$TVCF = VCF_{pressure} * VCF_{temp}$$

7.2 Corrected meter reading

$$\text{Corrected meter reading} = Q_{meter} * TVCF$$

8. Meter Proving Reports

A meter proving report shall as a minimum contain the information stated below:

- Prover report number
- Date and time
- Meter owner
- Company of person responsible for proving
- Fluid used
- Fluid specific gravity
- Fluid vapour pressure (at operation pressure)
- Meter size
- Totalizer pulses
- Prover size
- Pulses per unit volume
- Uncorrected prover volume
- Temperature of fluid at meter and prover
- Pressure of fluid at meter and prover
- Operator's name and signature



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Procedure

Title:

Gas flow rate
-
Measurements & Calculations

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1. Purpose

The objective of this document is to give guidance on which measurements that are necessary to be able to calculate the gas flow rate, additionally, the equation behind the flow rate will be outlined.

2. Scope

This document describes which measurements are needed to calculate the gas flow rate, where the measurements should be taken, factors that need to be calculated, and the tables which have to be used.

Important note: all measured inputs shall be in metric units. If measured values is in imperial units they need to be converted before the can be used in the following equations in this document.

3. Responsibilities

These days, all oil and gas flow rates are determined by use of advanced software. This document is meant to provide guidance to the factors and equations which lie behind the calculation of the gas flow rate.

4. References

GPSA handbook – Measurement

5. Apparatus

1. Pressure transmitter
2. Temperature transmitter
3. Ranarex Gravimeter

6. Measurements

- h_w - Differential pressure, inch water
 - Pressure transmitter at Daniel box
- P_f - Static pressure, kPa
 - Pressure transmitter at Daniel box
- P_b – Base pressure, kPa
 - Pressure in separator
- T_f – Flowing temperature, °C
 - Temperature transmitter on separator
- T_b – Base temperature, °C
 - Temperature in separator
- Gas S.G – specific gravity of gas
 - Ranarex Gas Gravitometer

7. Calculation

- F_b - Basic orifice factor
 - Table
- F_{bp} – Pressure base factor
 - $F_{bp} = \frac{101.325}{P_b}$
- F_{tb} – Flowing temperature factor
 - $F_{tb} = \frac{273+T_b}{288}$
- F_{tf} – Flowing temperature factor
 - $F_{tf} = \sqrt{\frac{288}{273+T_f}}$
- F_{pv} – Supercompressibility factor
 - $F_{pv} = \frac{1}{Z^2}$
 - Z from Table
- F_g – Relative density factor
 - $F_g = \sqrt{\frac{1.00}{S.G}}$
- F_r – Reynolds Number
 - Table
- Y – Expansion factor
 - Table
- F_a – Orifice thermal expansion
 - $F_a = 1 + [0.0000333(T_f - T_b)]$

Gas flow rate:

$$Q_{gas} \left(\frac{m^3}{h} \right) = \sqrt{h_w} * \sqrt{P_f} * F_b * F_{bp} * F_{tb} * F_{tf} * F_{pv} * F_g * F_r * Y * F_a$$



8. Tables

FIG. 3-16
Flange Taps, Basic Orifice Factors, $F_b - m^3/h$

		Pipe Sizes, Nominal and Standard ID, mm										
Nominal Diameter	Standard ID, mm	50	75	100	150	200	250	300	400	500	600	750
Orifice Diameter, mm	Orifice Diameter, inches											
6.35	0.250	0.0272	0.0272	0.0271								
9.53	0.375	0.0608	0.0607	0.0607								
12.70	0.500	0.1081	0.1076	0.1075	0.1074							
15.88	0.625	0.1697	0.1683	0.1678	0.1675							
19.05	0.750	0.2464	0.2430	0.2420	0.2412							
22.23	0.875	0.3391	0.3320	0.3301	0.3286	0.3281						
25.40	1.000	0.4499	0.4356	0.4323	0.4298	0.4289						
28.58	1.125	0.5815	0.5543	0.5486	0.5448	0.5433	0.5425					
31.75	1.250	0.7386	0.6892	0.6793	0.6735	0.6715	0.6703	0.6695				
34.93	1.375	0.9277	0.8412	0.8250	0.8162	0.8133	0.8117	0.8106				
38.10	1.500	1.1605	1.0122	0.9861	0.9728	0.9690	0.9668	0.9654				
41.28	1.625		1.2040	1.1633	1.1436	1.1384	1.1356	1.1338	1.1320			
44.45	1.750		1.4197	1.3576	1.3287	1.3217	1.3181	1.3158	1.3135			
47.63	1.875		1.6632	1.5701	1.5284	1.5189	1.5143	1.5115	1.5087			
50.80	2.000		1.9389	1.8022	1.7429	1.7302	1.7244	1.7209	1.7175	1.7148		
53.98	2.125		2.252	2.0555	1.9725	1.9557	1.9483	1.9440	1.940	1.9367		
57.15	2.250		2.618	2.332	2.218	2.195	2.186	2.181	2.176	2.172		
60.33	2.375			2.636	2.479	2.450	2.438	2.432	2.426	2.421	2.418	
63.50	2.500			2.969	2.757	2.718	2.704	2.696	2.689	2.684	2.681	
66.68	2.625			3.335	3.052	3.002	2.984	2.974	2.966	2.960	2.956	
69.95	2.750			3.738	3.365	3.301	3.278	3.267	3.257	3.250	3.246	
73.03	2.875			4.185	3.697	3.615	3.586	3.573	3.562	3.554	3.549	
76.20	3.000			4.697	4.049	3.945	3.910	3.894	3.881	3.871	3.865	3.860
79.40	3.125				4.421	4.291	4.247	4.228	4.213	4.202	4.196	4.189
82.55	3.250				4.817	4.654	4.600	4.577	4.559	4.547	4.540	4.532
85.73	3.375				5.236	5.033	4.968	4.940	4.919	4.906	4.897	4.889
88.90	3.500				5.682	5.431	5.350	5.317	5.293	5.278	5.268	5.259
92.08	3.625				6.155	5.846	5.749	5.709	5.681	5.664	5.653	5.643
95.25	3.750				6.658	6.280	6.163	6.116	6.084	6.064	6.052	6.041
98.43	3.875				7.194	6.735	6.593	6.537	6.500	6.478	6.464	6.452
101.60	4.000				7.765	7.209	7.039	6.973	6.930	6.905	6.890	6.876
107.95	4.250				9.024	8.223	7.983	7.891	7.834	7.802	7.784	7.767
114.30	4.500				10.488	9.332	8.997	8.872	8.795	8.754	8.732	8.712
120.65	4.750					10.546	10.086	9.916	9.814	9.763	9.736	9.712
127.00	5.000					11.880	11.253	11.026	10.893	10.828	10.795	10.767
133.35	5.250					13.346	12.506	12.205	12.032	11.950	11.910	11.877
139.70	5.500					14.963	13.850	13.457	13.232	13.129	13.081	13.042
146.05	5.750					16.757	15.295	14.783	14.495	14.366	14.308	14.262
152.40	6.000						16.848	16.189	15.823	15.661	15.592	15.538
158.75	6.250						18.522	17.678	17.216	17.016	16.932	16.869
165.10	6.500							20.326	19.258	18.678	18.431	18.329
171.45	6.750							22.275	20.933	20.211	19.906	19.784
177.80	7.000							24.383	22.712	21.82	21.44	21.297
184.15	7.250							26.68	24.601	23.50	23.04	22.868
190.50	7.500							29.224	26.61	25.26	24.71	24.50
196.85	7.750								28.75	27.10	26.44	26.19

FIG. 3-16 (Cont'd)
Flange Taps, Basic Orifice Factors, $F_b - m^3/h$

		Pipe Sizes, Nominal and Standard ID, mm										
Nominal Diameter		50	75	100	150	200	250	300	400	500	600	750
Standard ID, mm		52.50	77.93	102.26	154.05	202.72	254.51	307.09	387.35	488.95	590.55	742.95
Orifice Diameter, mm	Orifice Diameter, inches											
203.20	8.000							31.03	29.03	28.24	27.94	27.75
209.55	8.250							33.45	31.05	30.10	29.75	29.54
215.90	8.500							36.05	33.17	32.04	31.63	31.38
222.25	8.750							38.84	35.39	34.05	33.57	33.27
228.60	9.000							41.87	37.72	36.13	35.57	35.23
234.95	9.250							40.17	38.30	37.63	37.24	
241.30	9.500							42.73	40.54	39.77	39.32	
247.65	9.750							45.43	42.86	41.97	41.45	
254.00	10.000							48.27	45.28	44.24	43.65	
260.35	10.250							51.25	47.78	46.58	45.91	
266.70	10.500							54.39	50.37	49.00	48.22	
273.05	10.750							57.70	53.07	51.49	50.60	
279.40	11.000							61.20	55.86	54.05	53.05	
285.75	11.250							64.94	58.77	56.70	55.55	
292.10	11.500							61.78	59.42	59.42	58.13	
298.45	11.750								64.91	62.23	60.77	
304.80	12.000								68.17	65.12	63.47	
317.50	12.500								75.08	71.18	69.09	
330.20	13.000								82.57	77.61	74.99	
342.90	13.500								90.68	84.46	81.18	
355.60	14.000								99.56	91.75	87.67	
368.30	14.500									99.52	94.49	
381.00	15.000									107.81	101.63	
393.70	15.500									116.66	109.13	
406.40	16.000									126.12	117.00	
419.10	16.500									136.26	125.26	
431.80	17.000									147.22	133.94	
444.50	17.500										143.06	
457.20	18.000										152.65	
469.90	18.500										162.74	
482.60	19.000										173.37	
495.30	19.500										184.57	
508.00	20.000										196.37	
520.70	20.500										208.83	
533.40	21.000										222.04	
546.10	21.500										236.13	



FIG. 3-17

"b" Values for Reynolds Number Factor, F_r – Flange Taps

Pipe Sizes, Nominal and Standard ID, mm												
Nominal Diameter	50	75	100	150	200	250	300	400	500	600	750	
Standard ID, mm	52.50	77.93	102.26	154.05	202.72	254.51	307.09	387.35	488.95	590.55	742.95	
Orifice Diameter, mm	Orifice Diameter, inches											
6.35	0.250	1.225	1.336	1.394								
9.53	0.375	0.960	1.106	1.200								
12.70	0.500	0.778	0.919	1.031								
15.88	0.625	0.669	0.771	0.886	1.180							
19.05	0.750	0.623	0.659	0.764	0.950							
22.23	0.875	0.632	0.579	0.664	0.851	0.976						
25.40	1.000	0.681	0.532	0.585	0.762	0.894						
28.58	1.125	0.759	0.511	0.524	0.684	0.818	0.927					
31.75	1.250	0.855	0.513	0.481	0.614	0.749	0.863	0.950				
34.93	1.375	0.946	0.537	0.455	0.554	0.685	0.802	0.894				
38.10	1.500	1.023	0.577	0.445	0.504	0.627	0.745	0.840				
41.28	1.625		0.631	0.447	0.460	0.576	0.692	0.790	0.905			
44.45	1.750		0.693	0.463	0.426	0.528	0.642	0.741	0.860			
47.63	1.875		0.759	0.490	0.401	0.484	0.597	0.696	0.818			
50.80	2.000		0.826	0.523	0.381	0.450	0.554	0.651	0.777	0.894		
53.98	2.125		0.885	0.565	0.368	0.417	0.515	0.613	0.738	0.859		
57.15	2.250		0.934	0.611	0.363	0.390	0.479	0.574	0.700	0.823		
60.33	2.375			0.663	0.363	0.368	0.446	0.538	0.664	0.790	0.885	
63.50	2.500			0.714	0.369	0.349	0.417	0.505	0.630	0.758	0.855	
66.68	2.625			0.766	0.380	0.335	0.392	0.474	0.598	0.726	0.826	
69.95	2.750			0.814	0.397	0.324	0.368	0.445	0.566	0.696	0.798	
73.03	2.875			0.856	0.415	0.318	0.348	0.419	0.537	0.667	0.770	
76.20	3.000			0.890	0.439	0.315	0.331	0.394	0.509	0.639	0.744	0.863
79.40	3.125				0.467	0.316	0.316	0.373	0.483	0.611	0.717	0.839
82.55	3.250				0.496	0.320	0.304	0.352	0.458	0.585	0.692	0.815
85.73	3.375				0.529	0.328	0.295	0.335	0.434	0.560	0.667	0.792
88.90	3.500				0.564	0.337	0.288	0.319	0.411	0.536	0.643	0.770
92.08	3.625				0.598	0.351	0.283	0.304	0.390	0.512	0.619	0.749
95.25	3.750				0.634	0.365	0.282	0.292	0.372	0.490	0.597	0.728
98.43	3.875				0.703	0.394	0.282	0.282	0.353	0.468	0.576	0.706
101.60	4.000				0.766	0.402	0.283	0.274	0.336	0.448	0.554	0.685
107.95	4.250				0.818	0.447	0.294	0.262	0.307	0.410	0.513	0.646
114.30	4.500					0.496	0.312	0.257	0.282	0.374	0.476	0.609
120.65	4.750					0.550	0.336	0.257	0.262	0.344	0.441	0.573
127.00	5.000					0.605	0.366	0.263	0.247	0.316	0.407	0.538
133.35	5.250					0.658	0.401	0.275	0.237	0.291	0.377	0.505
139.70	5.500					0.708	0.439	0.292	0.230	0.270	0.349	0.475
146.05	5.750					0.753	0.480	0.314	0.228	0.253	0.324	0.446
152.40	6.000						0.524	0.337	0.229	0.237	0.302	0.418
158.75	6.250						0.568	0.366	0.234	0.225	0.280	0.392
165.10	6.500						0.611	0.397	0.242	0.216	0.262	0.366
171.45	6.750						0.652	0.430	0.254	0.208	0.245	0.344
177.80	7.000						0.692	0.464	0.267	0.204	0.230	0.323
184.15	7.250						0.728	0.501	0.286	0.202	0.218	0.303
190.50	7.500						0.757	0.538	0.304	0.204	0.208	0.284
196.85	7.750							0.574	0.325	0.206	0.200	0.267

FIG. 3-17 (Cont'd)

 "b" Values for Reynolds Number Factor, F_r – Flange Taps

Pipe Sizes, Nominal and Standard ID, mm											
Nominal Diameter	50	75	100	150	200	250	300	400	500	600	750
Standard ID, mm	52.50	77.93	102.26	154.05	202.72	254.51	307.09	387.35	488.95	590.55	742.95
Orifice Diameter, mm	Orifice Diameter, inches										
203.20	8.000						0.610	0.349	0.212	0.193	0.251
209.55	8.250						0.644	0.374	0.218	0.188	0.237
215.90	8.500						0.676	0.401	0.228	0.185	0.225
222.25	8.750						0.706	0.429	0.238	0.184	0.213
228.60	9.000						0.732	0.458	0.251	0.185	0.202
234.95	9.250							0.487	0.266	0.187	0.193
241.30	9.500							0.516	0.282	0.191	0.187
247.65	9.750							0.545	0.299	0.194	0.180
254.00	10.000							0.574	0.318	0.201	0.175
260.35	10.250							0.602	0.337	0.209	0.169
266.70	10.500							0.628	0.357	0.217	0.167
273.05	10.750							0.655	0.378	0.228	0.165
279.40	11.000							0.679	0.401	0.239	0.164
285.75	11.250								0.423	0.251	0.164
292.10	11.500								0.447	0.265	0.165
298.45	11.750								0.470	0.279	0.168
304.80	12.000								0.493	0.295	0.171
317.50	12.500								0.540	0.328	0.180
330.20	13.000								0.585	0.362	0.192
342.90	13.500								0.627	0.400	0.208
355.60	14.000								0.664	0.438	0.226
368.30	14.500									0.476	0.247
381.00	15.000									0.516	0.270
393.70	15.500									0.553	0.296
406.40	16.000									0.590	0.323
419.10	16.500									0.623	0.352
431.80	17.000									0.654	0.381
444.50	17.500										0.413
457.20	18.000										0.443
469.90	18.500										0.474
482.60	19.000										0.505
495.30	19.500										0.534
508.00	20.000										0.564
520.70	20.500										0.593
533.40	21.000										0.618
546.10	21.500										0.642



FIG. 3-18 Expansion Factors – Flange Taps, Y2 (static downstream)

hw/P ₁ Ratio	β = d/D												
	.1	.2	.3	.4	.45	.50	.52	.54	.56	.58	.60	.61	.62
0.00	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
0.50	1.0007	1.0007	1.0007	1.0007	1.0008	1.0008	1.0008	1.0008	1.0008	1.0008	1.0008	1.0008	1.0008
1.00	1.0014	1.0014	1.0014	1.0014	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015
1.50	1.0027	1.0027	1.0027	1.0026	1.0025	1.0025	1.0025	1.0025	1.0025	1.0025	1.0025	1.0025	1.0025
2.00	1.0036	1.0036	1.0036	1.0035	1.0034	1.0033	1.0033	1.0033	1.0033	1.0033	1.0033	1.0033	1.0033
2.50	1.0045	1.0045	1.0045	1.0044	1.0043	1.0041	1.0041	1.0040	1.0040	1.0040	1.0040	1.0040	1.0040
3.00	1.0055	1.0054	1.0054	1.0053	1.0051	1.0050	1.0049	1.0048	1.0047	1.0046	1.0044	1.0044	1.0043
3.50	1.0064	1.0064	1.0063	1.0061	1.0060	1.0058	1.0057	1.0056	1.0055	1.0053	1.0052	1.0051	1.0050
4.00	1.0073	1.0073	1.0072	1.0070	1.0069	1.0066	1.0065	1.0064	1.0063	1.0061	1.0060	1.0059	1.0058
4.50	1.0082	1.0082	1.0081	1.0079	1.0077	1.0075	1.0073	1.0072	1.0071	1.0069	1.0067	1.0066	1.0065
5.00	1.0091	1.0091	1.0090	1.0088	1.0086	1.0083	1.0082	1.0080	1.0078	1.0077	1.0074	1.0073	1.0072
5.50	1.0100	1.0100	1.0099	1.0097	1.0095	1.0092	1.0090	1.0088	1.0086	1.0084	1.0082	1.0081	1.0079
6.00	1.0110	1.0109	1.0108	1.0106	1.0103	1.0100	1.0098	1.0096	1.0094	1.0092	1.0090	1.0088	1.0087
6.50	1.0119	1.0118	1.0117	1.0114	1.0112	1.0108	1.0107	1.0105	1.0102	1.0100	1.0097	1.0096	1.0094
7.00	1.0128	1.0128	1.0127	1.0123	1.0121	1.0117	1.0115	1.0113	1.0110	1.0108	1.0105	1.0103	1.0102
7.50	1.0137	1.0137	1.0136	1.0132	1.0129	1.0125	1.0123	1.0121	1.0118	1.0116	1.0112	1.0111	1.0109
8.00	1.0146	1.0146	1.0145	1.0141	1.0138	1.0134	1.0132	1.0129	1.0126	1.0123	1.0120	1.0118	1.0116
8.50	1.0156	1.0156	1.0154	1.0150	1.0147	1.0142	1.0140	1.0137	1.0133	1.0131	1.0128	1.0126	1.0124
9.00	1.0165	1.0165	1.0163	1.0159	1.0156	1.0151	1.0148	1.0146	1.0143	1.0139	1.0135	1.0133	1.0131
9.50	1.0174	1.0174	1.0172	1.0168	1.0164	1.0159	1.0157	1.0154	1.0151	1.0147	1.0143	1.0141	1.0139
10.00	1.0184	1.0183	1.0181	1.0177	1.0173	1.0168	1.0166	1.0162	1.0159	1.0155	1.0151	1.0149	1.0146
10.50	1.0193	1.0192	1.0191	1.0186	1.0182	1.0176	1.0174	1.0170	1.0167	1.0163	1.0159	1.0156	1.0154
11.00	1.0202	1.0202	1.0200	1.0195	1.0191	1.0185	1.0182	1.0179	1.0175	1.0171	1.0166	1.0164	1.0161
11.50	1.0211	1.0211	1.0209	1.0204	1.0200	1.0193	1.0190	1.0187	1.0183	1.0179	1.0174	1.0172	1.0169
12.00	1.0221	1.0220	1.0218	1.0213	1.0208	1.0202	1.0199	1.0195	1.0191	1.0187	1.0182	1.0179	1.0177
12.50	1.0230	1.0230	1.0228	1.0222	1.0217	1.0211	1.0207	1.0204	1.0199	1.0195	1.0190	1.0187	1.0184
13.00	1.0239	1.0239	1.0237	1.0231	1.0226	1.0219	1.0216	1.0212	1.0208	1.0203	1.0198	1.0195	1.0192
13.50	1.0249	1.0248	1.0246	1.0240	1.0235	1.0228	1.0224	1.0220	1.0216	1.0211	1.0205	1.0202	1.0199
14.00	1.0258	1.0258	1.0255	1.0249	1.0244	1.0236	1.0233	1.0229	1.0224	1.0219	1.0213	1.0210	1.0207
14.50	1.0267	1.0267	1.0265	1.0258	1.0253	1.0245	1.0241	1.0237	1.0232	1.0227	1.0221	1.0218	1.0215
15.00	1.0277	1.0276	1.0274	1.0267	1.0262	1.0254	1.0250	1.0245	1.0240	1.0235	1.0229	1.0226	1.0222

FIG. 23-4
Compressibility Factors for Natural Gas¹

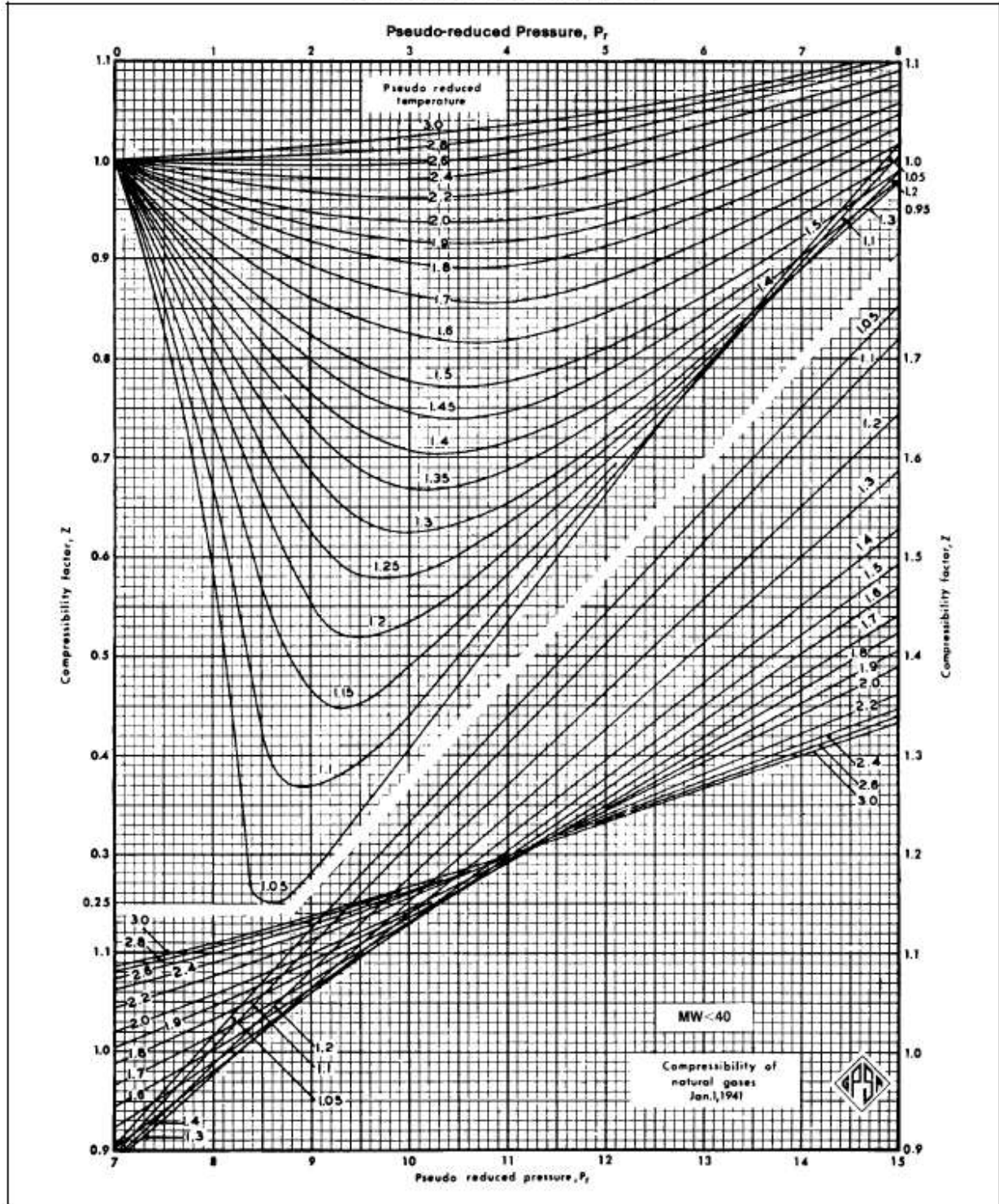


FIG. 23-5
Compressibility of Low-Molecular-Weight Natural Gases¹¹

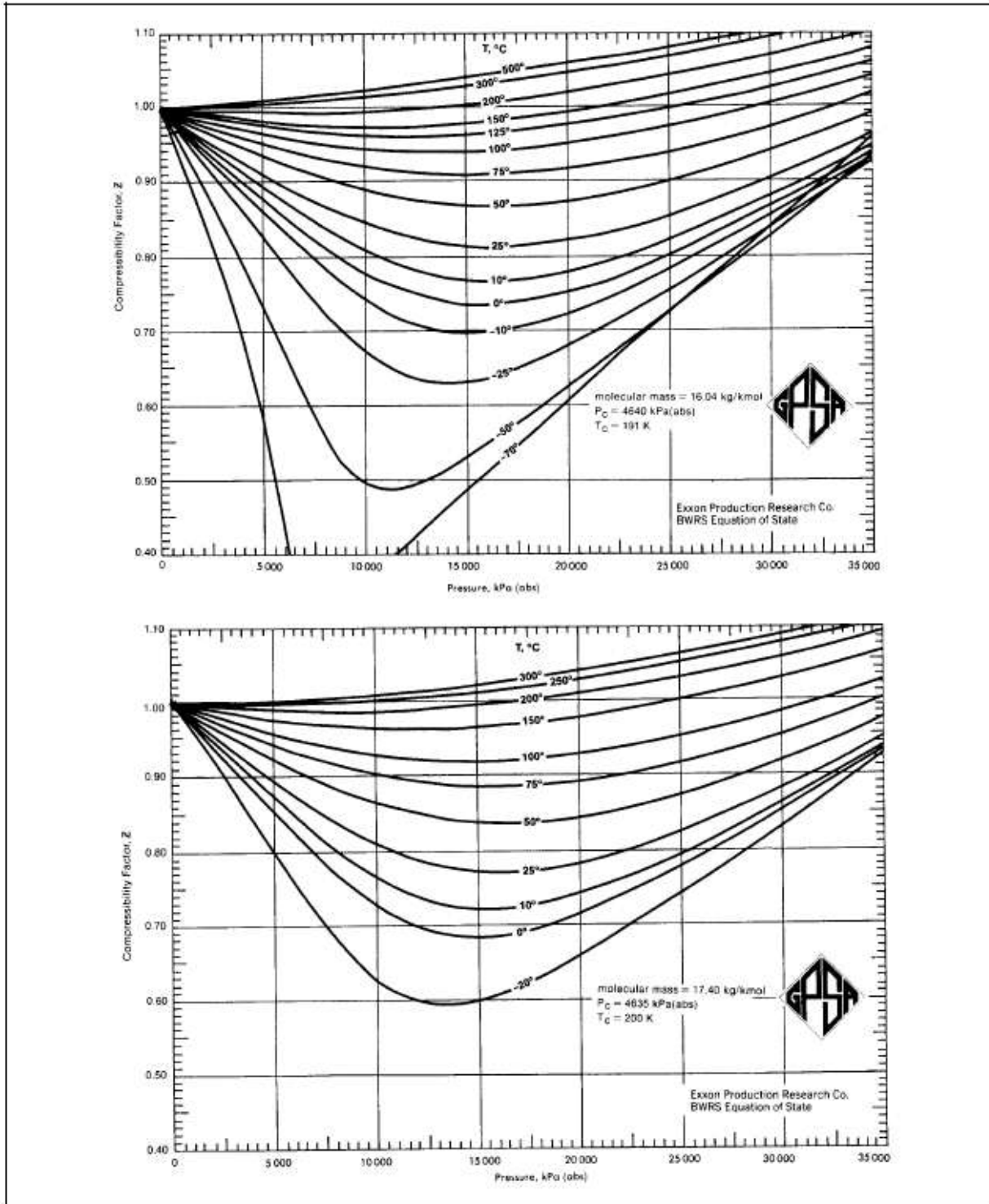


FIG. 23-6
Compressibility of Low-Molecular-Weight Natural Gases¹¹

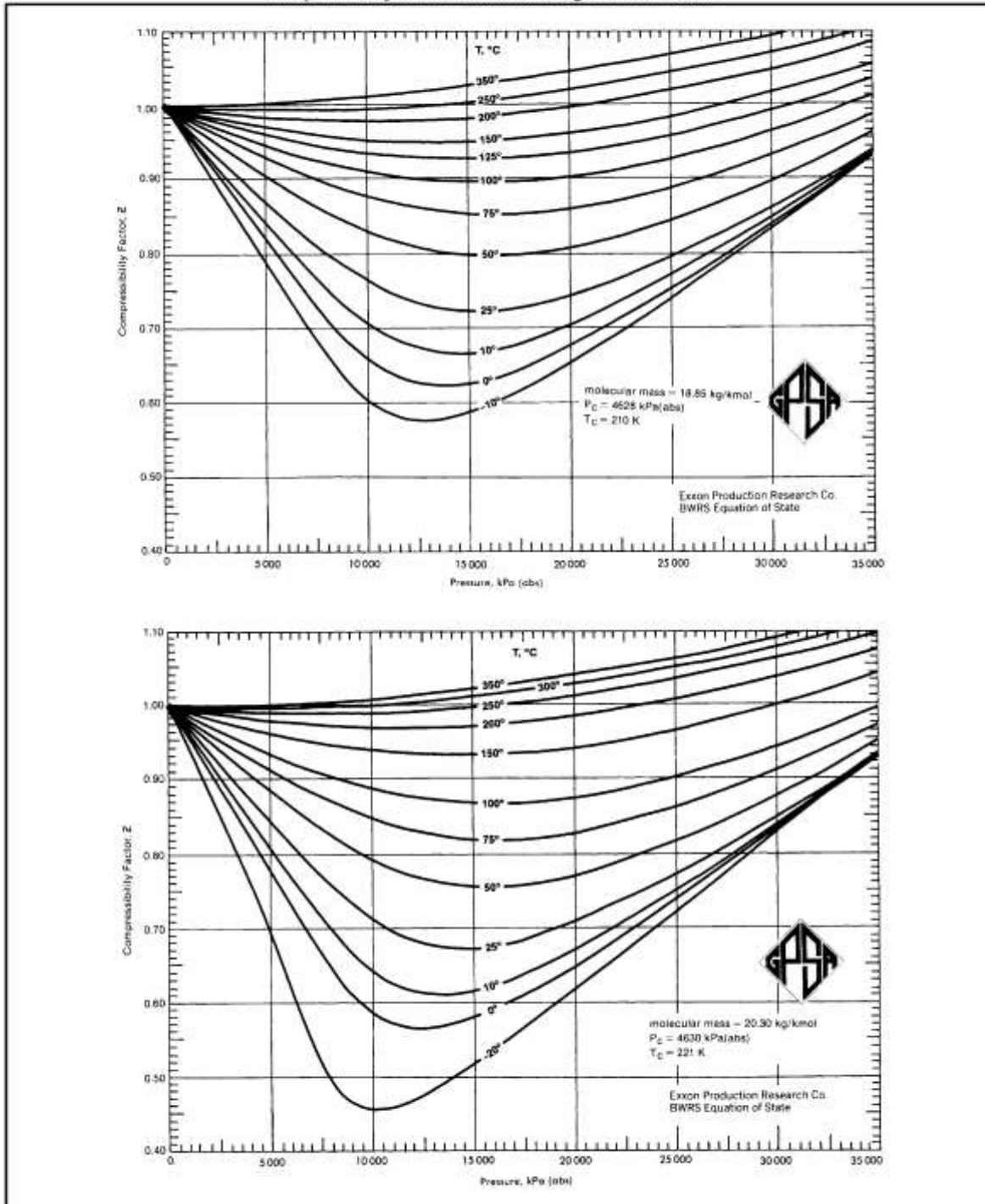
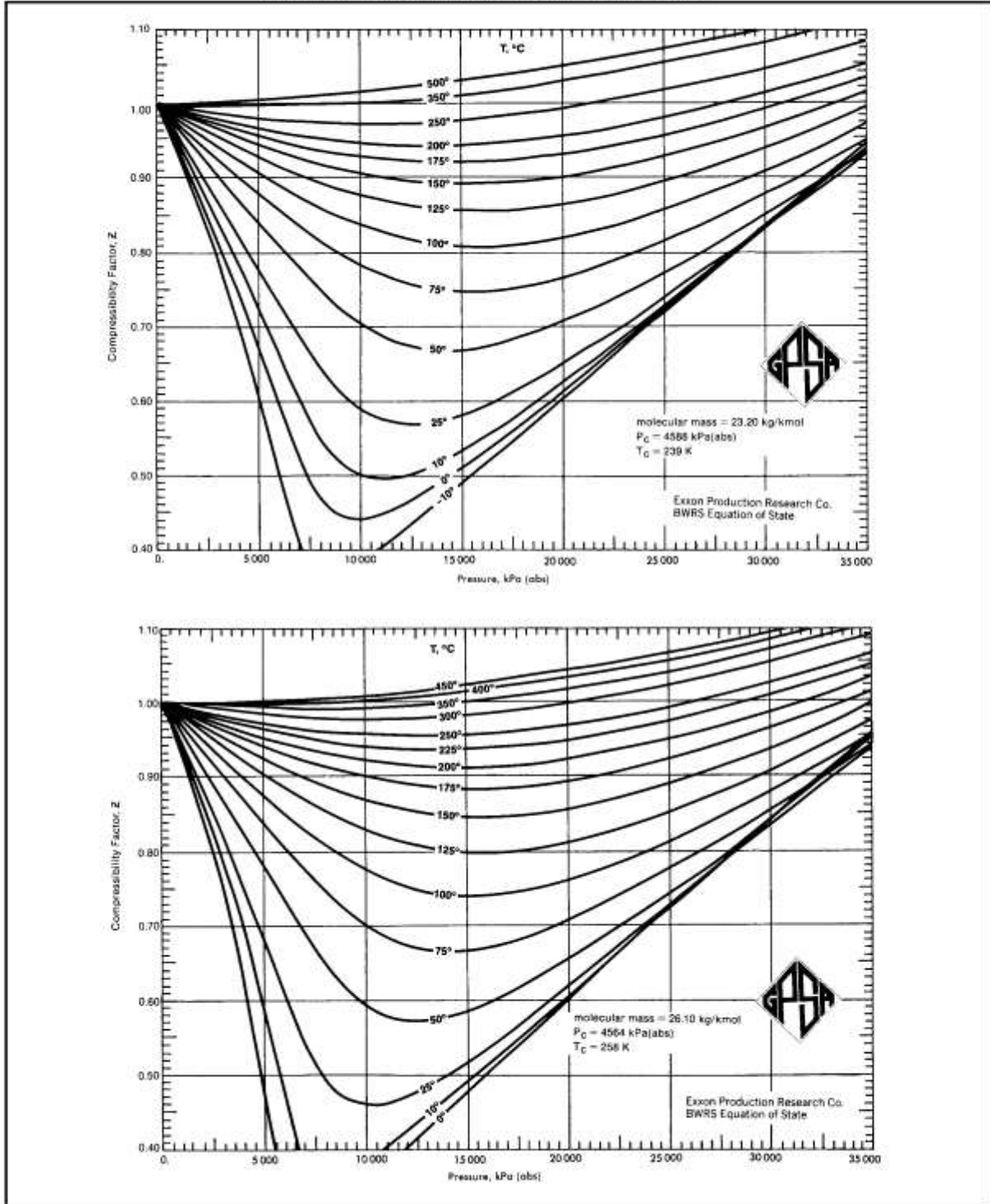


FIG. 23-7

Compressibility of Low-Molecular-Weight Natural Gases¹¹





Client: Example
 Field: Example
 Well: Example
 Date: Example

Draft

TOTAL VOLUME CORRECTION FACTOR - OIL

Details

Choke size	n/a	/64ths	Start time	n/a	Hrs
Separator pressure	n/a	Barg	Finish time	n/a	Hrs
Separator temperature	n/a	°C	Final reading time	n/a	Hrs
Meter used	n/a				
Observed oil gravity	0,860		VCF	0,996	
Oil temp @ gravity	20	°C	Oil gravity @ SC	0,857	

Meter reading

Initial meter reading	2	m ³	Oil line temperature	50	°C
Final meter reading	10	m ³			
Volume through meter	8	m ³			

Tank reading

Initial tank reading	2	m ³	Intermediate tank reading	9,8	m ³
Initial tank temperature	15	°C	Intermediate tank temperature	30	°C
Final tank reading	9	m ³	Time allowed for shrinkage	157	mins
Final tank temperature	10	°C			

Shrinkage factor

Tank shrinkage			Shrinkage tester		
Intermediate tank reading	9,8	m ³	Initial reading	100	%
Final tank reading	9	m ³	Final reading	91,59	%
Shrinkage factor	8,16	%	Shrinkage factor	8,41	%

Total volume correction factor

VCF - Pressure	0,875		Total volume correction factor	0,91875	
VCF - Temperature	1,05		Volume through meter @ SC	7,35	Sm ³

MF	0,975	Standard conditions	P	14,5037 psi
CMSF	0,875		T	15 °C
TVCF	0,919			

Use total volume correction factor marked green

VCF = 1 - (((9/5)*T°C+32)-60)*0.0005

Date & Signature: _____

Attachment III

Tables used for calculations

- API 11.1
- GPSA Engineering Data book 11th edition (Electronic)

11.1.7.2 Method to Correct Volume and Density from Metric Observed Conditions to Metric Base Conditions

Note: For liquids with an equilibrium vapor pressure greater than atmospheric, see 11.1.3.4.

Outline of Calculations

This procedure calculates the density at the metric base conditions (15°C or 20°C and 0 kPa (gauge)) that is consistent with an observed density measured at the observed temperature and pressure conditions. Because the VCF expressions were developed and expressed in terms of a base density at 60°F, this calculation must be done as a two part process:

1. Calculate the density at 60°F and 0 psig consistent with the observed density.
2. Calculate the density at the metric base temperature and pressure conditions.

The procedure has been written assuming that the input values are all in the proper units (°C, kPa or bar (gauge), and kg/m³). If they are not in the proper units then apply the procedures in 11.1.5.1. The density values calculated by this procedure are in kg/m³. If these units do not match the original input units, then the calculated density value(s) should be converted to that of the original input value's units using the procedures in 11.1.5.1.

Input Values

Commodity group describing liquid (if α_{60} not input)

α_{60} Pre-calculated 60°F thermal expansion factor (if commodity group not given)

ρ_o Observed density (kg/m³)

T Base temperature (15°C or 20°C)

t_o Temperature at which the observed density was measured (°C)

P_o Pressure at which the observed density was measured (kPa or bar (gauge))

Optional Input Values

V_o Volume at observed conditions (any valid set of units, such as liters, cubic metres, and barrels)

Output Values

ρ_T Density at metric base conditions (15°C or 20°C and 0 kPa (gauge)) (kg/m³)

C_{TL} Volume correction factor due to temperature

C_{PL} Volume correction factor due to pressure

F_P Scaled compressibility factor (kPa⁻¹ or bar⁻¹)

C_{TPL} Combined volume correction factor due to temperature and pressure

Optional Output Values

V_T Volume at base conditions (same set of units as V)

ρ_{60} Density at 60°F and 0 psig (kg/m³)

Intermediate Values

$T_{,F}$	Base temperature T converted to units of °F (°F)
$t_{o,°F}$	Temperature t_o converted to units of °F (°F)
$P_{o,psig}$	Pressure P_o converted to units of psig (psig)
$C_{TL,60}^*$	CTL value correcting ρ_{60} to ρ_T
C_{TL}^*	CTL value correcting ρ_{60} to the observed temperature
C_{TPL}^*	CTPL value correcting ρ_{60} to the observed temperature and pressure
$F_{P,psig}$	Scaled compressibility factor (psi^{-1})

Calculation Procedure

- Step 1: Convert the base temperature, observed temperature, and observed pressure into customary units using equations in 11.1.5.1. Call these variables $T_{,F}$, $t_{o,°F}$, and $P_{o,psig}$.
- Step 2: Calculate the correction factors for the density at 60°F, ρ_{60} , corresponding to the observed density ρ_o at conditions $t_{o,°F}$ and $P_{o,psig}$ using the procedure in 11.1.6.2. If this procedure returns with an error condition, exit this procedure. There are associated factors that must be adjusted to take into account that the reference temperature is not 60°F and the pressure is not in customary units. Call these factors C_{TL}^* , C_{PL} , C_{TPL}^* , and $F_{P,psig}$.
- Step 3: Using this value of ρ_{60} , calculate the associated metric base density value ρ_T at $T_{,F}$ using the procedure in 11.1.6.1. The pressure correction need not be calculated since the metric base pressure (0 kPa (gauge)) is the same as the base pressure in 11.1.6.1 (0 psig). Call the CTL associated with this step $C_{TL,60}$.
- Step 4: Calculate the correction factors for the metric base temperature by combining the correction factors for 60°F. The temperature correction factor is:

$$C_{TL} = \frac{C_{TL}^*}{C_{TL,60}}$$

and the combined temperature and pressure correction factor is:

$$C_{TPL} = C_{TL} \cdot C_{PL}$$

Round this value of C_{TPL} consistent with 11.1.5.4.

Modify the scaled compressibility factor for the metric pressure units:

$$F_P = \frac{F_{P,psig}}{6.894757} \text{ for kPa}$$

$$F_P = \frac{F_{P,psig}}{0.06894757} \text{ for bar.}$$

Step 5: Calculate the volume at the base conditions:

$$V_T = V_o \cdot C_{TPPL}$$

Step 6: Exit from this procedure.

these examples are used to test one's own computer implementation of the procedures, it is required that at least eight of the significant digits be matched.

11.1.5.1 Method to Convert Units of Temperature, Pressure, Thermal Expansion Factor, and Density-Related Values

Note: For liquids with an equilibrium vapor pressure greater than atmospheric, see 11.1.3.4.

Outline of Calculations

This procedure accepts the density, temperature, and pressure values in units as entered and converts them to the units required by the calculation procedure.

Relative density & API gravity values are *in vacuo*.

Possible Input and Output Values

t_{C}	Temperature value ($^{\circ}\text{C}$)
P_{kPa}	Pressure value (kPa (gauge))
P_{bar}	Pressure value (bar (gauge))
γ_T	Relative density value based upon water at temperature T
γ_{60}	Relative density value based upon water at 60°F
G	API gravity ($^{\circ}\text{API}$)
$\alpha_{60,^{\circ}\text{C}}$	60°F thermal expansion factor ($^{\circ}\text{C}^{-1}$)
ρ	Density value (kg/m^3)
t	Temperature value ($^{\circ}\text{F}$)
P	Pressure value (psig)
α_{60}	60°F thermal expansion factor ($^{\circ}\text{F}^{-1}$)

Calculation Procedure

Step 1: Convert the units of the input variables to those required by the procedure: kg/m^3 for density, $^{\circ}\text{F}$ for temperature, psig for pressure, and $^{\circ}\text{F}^{-1}$ for the 60°F thermal expansion factor.

Temperature

If the input temperature variable is in $^{\circ}\text{F}$ units then no processing is required.

If the input temperature variable is in $^{\circ}\text{C}$ units then:

$$t = 1.8 \cdot t_{\text{C}} + 32$$

Pressure

If the input pressure variable is in units of psig then no processing is required.

If the input pressure variable is in units of kPa then:

$$P = \frac{P_{\text{MPa}}}{6.894757}$$

If the input pressure variable is in units of bar then:

$$P = \frac{P_{\text{bar}}}{0.06894757}$$

Density

If the input density variable is relative density then:

$$\rho = \gamma_T \cdot \rho_{w,T}$$

where $\rho_{w,T}$ is the density of water consistent with the reference temperature T . The only water density needed in this Standard is for 60°F. The accepted value for the density of water at 60°F is 999.016 kg/m³ (see Appendix D).

If the input density variable is API gravity then:

$$\rho = \frac{141.5}{G+131.5} \cdot \rho_{w,60} = \frac{141.5}{G+131.5} \cdot 999.016$$

If the input density variable is already in units of kg/m³ then no processing is required. However, there are instances in this Standard that the density in units of kg/m³ must be converted back to API gravity or relative density. If the 60°F relative density is required, then:

$$\gamma_{60} = \frac{\rho}{\rho_{w,60}} = \frac{\rho}{999.016}$$

or if the API gravity is required, then:

$$G = \frac{141.5}{\rho/999.016} - 131.5 = \frac{141.5}{\rho/999.016} - 131.5$$

60°F Thermal Expansion Factor

If the input 60°F thermal expansion factor variable is in units of °F⁻¹ and the output is also °F⁻¹ then no processing is required.

If the input 60°F thermal expansion factor variable is in units of °C⁻¹ and the output is also °C⁻¹ then no processing is required.

If the input 60°F thermal expansion factor variable is in units of °C⁻¹ and the output is °F⁻¹ then:

$$\alpha_{60} = \frac{\alpha_{60,^{\circ}\text{C}}}{1.8}$$

If the input 60°F thermal expansion factor variable is in units of °F⁻¹ and the output is °C⁻¹ then:

$$\alpha_{60,^{\circ}\text{C}} = 1.8 \cdot \alpha_{60}$$

Step 2: Exit from this procedure.

11.1.5.3 Method to Convert Temperature from ITS-90 to IPTS-68 Basis

Outline of Calculations

This procedure converts temperature from ITS-90 to IPTS-68 basis. This correction is necessary because of the change in the standard procedure to calibrate temperature measurement devices. The change in the temperatures between the two scales is small. The equation presented here is from the original paper describing the ITS-90 temperature scale.²

Input Values

$t_{F,90}$ Temperature consistent with ITS-90 (°F)

$t_{C,90}$ Temperature consistent with ITS-90 (°C)

Output Values

$t_{F,68}$ Temperature consistent with IPTS-68 (°F)

$t_{C,68}$ Temperature consistent with IPTS-68 (°C)

Intermediate Values

Δ_t Correction to ITS-90 temperature to give IPTS-68 temperature (°C)

τ Scaled temperature value.

Calculation Procedure

Step 1: Accept input temperature value, either in units of °F, $t_{F,90}$, or °C, $t_{C,90}$.

Step 2: If input temperature was in units of °F, calculate the temperature in units of °C:

$$t_{C,90} = \frac{t_{F,90} - 32}{1.8}$$

Step 3: Calculate the scaled temperature value:

$$\tau = \frac{t_{C,90}}{630}$$

and use this to calculate the temperature correction:

$$\Delta_t = \left(a_1 + \left(a_2 + \left(a_3 + \left(a_4 + \left(a_5 + \left(a_6 + (a_7 + a_8\tau)\tau\right)\tau\right)\tau\right)\tau\right)\tau \right) \tau \right) \tau.$$

The a_i coefficients are given in the following table.

² "The International Temperature Scale of 1990, ITS-90," NPL Special Report QU S45, National Physical Laboratory, Teddington, Middlesex, November 1989.

i	a_i
1	-0.148759
2	-0.267408
3	1.080760
4	1.269056
5	-4.089591
6	-1.871251
7	7.438081
8	-3.536296

Step 4. Determine the equivalent IPTS-68 temperature:

$$t_{C,68} = t_{C,96} - \Delta_t$$

If the input temperature was in units of °F, also calculate the equivalent IPTS-68 temperature in customary units:

$$t_{F,68} = 1.8t_{C,68} + 32$$

Step 5: Exit from this procedure.

11.1.5.4 Rounding of Values

Outline of Calculations

This procedure gives instructions and increments for rounding density, temperature, pressure, thermal expansion coefficient, and volume correction factor values. These rounding rules are needed to generate the final volume correction factor due to temperature and pressure and to generate the tables in printed tabular (historical) format. All input values must be rounded when generating the tables in historical format.

Calculation Procedure

Step 1: The following table shows acceptable units for the input and calculated variables and the increment to which they should be rounded.

Variable Type	Units	Rounding Increment (δ)
Density	°API	0.1
	Relative Density	0.0001
	kg/m ³	0.1
Temperature	°F	0.1
	°C	0.05
Pressure	psig	1
	kPa (gauge)	5
	bar (gauge)	0.05
Thermal Expansion Coefficient (α_{60})	°F ⁻¹	0.0000001 (0.1×10^{-6})
	°C ⁻¹	0.0000002 (0.2×10^{-6})
CTL		0.00001
Scaled Compressibility Factor (F_p)	psi ⁻¹	0.001

	kPa ⁻¹	0.0001
	bar ⁻¹	0.01
CPL		0.00001
CTPL		0.00001

Step 2: Normalize the input variable.

$$Y = \frac{|X|}{\delta}$$

where X is the value to be rounded, $|X|$ is its absolute value, δ is the rounding increment, and Y is the normalized variable.

Step 3: Find the integer closest to the normalized variable. If the decimal portion of Y is not exactly equal to 0.5 then use the following equation for rounding:

$$I = \text{trunc}(Y + 0.5)$$

where trunc is the truncation function and I is the rounded value for the normalized variable. However, if the decimal portion of Y is exactly equal to 0.5 then use the following equation for rounding:

$$I = \begin{cases} \text{trunc}(Y) + 1 & \text{if } \text{trunc}(Y) \text{ is odd} \\ \text{trunc}(Y) & \text{if } \text{trunc}(Y) \text{ is even} \end{cases}$$

Step 4: Rescale the integer from Step 3:

$$X_{\text{round}} = \pm \delta \cdot I$$

where X_{round} is the rounded variable. The sign of the rounded value is chosen to match that of the original value.

Step 5: Exit from this procedure.

Examples

A temperature of 5.34°C is rounded as:

$$Y = \frac{|5.34|}{0.05} = 106.8$$

$$I = \text{trunc}(106.8 + 0.5) = \text{trunc}(107.3) = 107$$

$$X_{\text{round}} = +0.05 \cdot 107 = +5.35$$

A temperature of -5.34°C is rounded as:

$$Y = \frac{|-5.34|}{0.05} = 106.8$$

$$I = \text{trunc}(106.8 + 0.5) = \text{trunc}(107.3) = 107$$

$$X_{\text{round}} = -0.05 \cdot 107 = -5.35$$

A temperature of 10.05°F should be rounded as follows:

$$Y = \frac{\lceil 10.05 \rceil}{0.1} = 100.5$$

$$I = \text{trunc}(100.5) = 100 \quad (\text{rounding towards the even integer})$$

$$X_{\text{round}} = +0.1 \cdot 100 = 10.0$$

11.1.5.5 Other Implementation Considerations

- CTPL should be substituted for $CTL \times CPL$, where a standard specifies a serial multiplication of correction factors.
- Where a calculation within an existing standard makes use of a CTL factor alone, an equivalent value CTPL is calculated with observed gauge pressure set to zero.
- The discrimination rules for the input parameters should comply with the appropriate Standard (Chapters 12.1 and 12.2) prior to implementation of API MPMS Chapter 11.1. Verification data has been completed up to eight decimal places. In this document, the final VCF (CTPL) is rounded to five decimal places. Different rounding precisions may be used to accommodate other standards, however they should not exceed eight decimal places.

11.1.6 Implementation Procedures for Customary Units (60°F and 0 psig Base Conditions)

11.1.6.1 Method to Correct a Measured Volume to Base Conditions and Density from Base Conditions to an Alternate Temperature and Pressure

Note: For liquids with an equilibrium vapor pressure greater than atmospheric, see 11.1.3.4.

Outline of Calculations

This procedure calculates the Volume Correction Factor (VCF) for correcting from the density at the base conditions (60°F and 0 psig) to alternate temperature and pressure conditions. The parameters used in this procedure depend upon the commodity group to which the liquid belongs. This calculation is done as a two-part process:

1. A thermal correction is applied to the liquid to account for the change from the base temperature (60°F) to the alternate temperature at a constant base pressure.
2. A pressure correction is applied to the liquid to account for the change from the base pressure (0 psig) to the alternate pressure at the alternate temperature.

The procedure has the flexibility of accepting a pre-calculated 60°F thermal expansion factor or calculating one based upon the commodity type of the liquid.

The calculation routine is depicted in Figure 11.1.6.1.A.

The procedure has been written assuming that the input values are all in the proper units (°F, psig, and kg/m³). If they are not in the proper units then apply the procedures in 11.1.5.1 before entering this procedure. The density values calculated by this procedure are in the units of kg/m³. If these units do not match the original input units, then the output densities should be converted to that of the original input value's units using the procedures in 11.1.5.1.

Input Values

Commodity group describing liquid (if α_{60} not input)

α_{60} Pre-calculated 60°F thermal expansion factor (if commodity group not given) (°F⁻¹)

ρ_{60} Density at base conditions (60°F and 0 psig) (kg/m³)

t Alternate temperature ($^{\circ}\text{F}$)

P Alternate pressure (psig)

Optional Input Values

$V_{t,P}$ Volume at alternate conditions (t and P) (any valid set of units, such as barrels, liters, and cubic metres)

Output Values

C_{TL} Volume correction factor due to temperature

C_{PL} Volume correction factor due to pressure

F_p Scaled compressibility factor (psi^{-1})

C_{TPL} Combined volume correction factor due to temperature and pressure

Optional Output Values

ρ Density at alternate conditions (kg/m^3)

V_{60} Volume at base conditions (60°F and 0 psig) (same units as $V_{t,P}$)

Intermediate Values

δ_{60} Temperature shift value (a constant, $0.01374979547^{\circ}\text{F}$)

t^* Alternate temperature shifted to IPTS-68 basis ($^{\circ}\text{F}$)

ρ^* Base density shifted to IPTS-68 60°F basis (kg/m^3)

Δt Alternate temperature minus the base temperature of 60°F ($^{\circ}\text{F}$)

α_{60} Thermal expansion factor at 60°F ($^{\circ}\text{F}^{-1}$) (if not input)

K_0 Coefficient in correlation for α_{60} ($\text{kg}^2/\text{m}^6 \text{ }^{\circ}\text{F}$)

K_1 Coefficient in correlation for α_{60} ($\text{kg}/\text{m}^3 \text{ }^{\circ}\text{F}$)

K_2 Coefficient in correlation for α_{60} ($^{\circ}\text{F}^{-1}$)

A, B Variables used in calculation of ρ^* .

Calculation Procedure

Step1: Unless otherwise directed, check the input values to determine if they are in the range of this Standard. The following are the valid limits.

$$-58.0^{\circ}\text{F} \leq t \leq 302.0^{\circ}\text{F}$$

$$0 \leq P \leq 1500 \text{ psig}$$

$$\rho_{60,\text{min}} \leq \rho_{60} \leq \rho_{60,\text{max}} \quad (\text{if commodity type is specified})$$

$$230.0 \times 10^{-6} \text{ }^{\circ}\text{F}^{-1} \leq \alpha_{60} \leq 930.0 \times 10^{-6} \text{ }^{\circ}\text{F}^{-1} \quad (\text{if } \alpha_{60}, \text{ not commodity type, is specified})$$

The following table gives the ρ_{60} limits for the various commodity groups. This check does not have to be done if α_{60} , not the commodity group, is specified.

Commodity Type	$\rho_{60, \min}$	$\rho_{60, \max}$
Crude Oil	610.6 kg/m ³	1163.5 kg/m ³
Refined Products		
Lubricating Oil	800.9 kg/m ³	

If $P < 0$ psig then set $P = 0$ psig and continue with the procedure.

If any of the other conditions are not true then one or more of the input variables is out of range. Set an error condition (such as setting all output values to zero) and exit procedure.

Step 2: Shift the input temperature t to the IPTS-68 basis t^* following the procedure in 11.1.5.3.

Step 3: Shift the input ρ_{60} value to the IPTS-68 basis ρ^* . If a pre-calculated α_{60} value has been input, use:

$$\rho^* = \rho_{60} \cdot \exp[0.5\alpha_{60}\delta_{60}(1 + 0.4\alpha_{60}\delta_{60})]$$

If the commodity group has been specified, then compute the ρ^* value using:

$$\rho^* = \rho_{60} \left\{ 1 + \frac{\exp[A(1+0.8A)] - 1}{1 + A(1+1.6A)B} \right\}$$

where:

$$A = \frac{\delta_{60}}{2} \left[\left(\frac{K_0}{\rho_{60}} + K_1 \right) \frac{1}{\rho_{60}} + K_2 \right]$$

$$B = \frac{2K_0 + K_1\rho_{60}}{K_0 + (K_1 + K_2\rho_{60})\rho_{60}}$$

The K_i coefficients used in these equations depend upon the commodity group. The following table gives the coefficients to be used.

		Density Range(kg/m ³)	K_0	K_1	K_2
Crude Oil		610.6 ≤ ρ_{60} < 1163.5	341.0957	0.0	0.0
Products	Fuel Oils	838.3127 ≤ ρ_{60} ≤ 1163.5	103.8720	0.2701	0.0
	Jet Fuels	787.5195 ≤ ρ_{60} < 838.3127	330.3010	0.0	0.0
	Transition Zone	770.3520 ≤ ρ_{60} < 787.5195	1489.0670	0.0	-0.00186840
	Gasolines	610.6 ≤ ρ_{60} < 770.3520	192.4571	0.2438	0.0
Lubricating Oil		800.9 ≤ ρ_{60} < 1163.5	0.0	0.34878	0.0

Step 4: In preparation of calculating the correction factor due to temperature, C_{TL} , determine the coefficient of thermal expansion at the base temperature of 60°F, α_{60} . If a pre-calculated α_{60} value has been input, proceed to Step 5.

If the commodity group has been specified, then compute the α_{60} value using:

$$\alpha_{60} = \left(\frac{K_0}{\rho^*} + K_1 \right) \frac{1}{\rho^*} + K_2$$

The coefficients used in this equation depend upon the commodity group. Use the same coefficients that were used in Step 3.

Step 5: Calculate the difference between the alternate temperature and the base temperature as:

$$\Delta t = t^* - 60.0068749.$$

Use this value to calculate the correction factor due to temperature, C_{TL} :

$$C_{TL} = \exp \left\{ -\alpha_{60} \Delta t \left[1 + 0.8 \alpha_{60} (\Delta t + \delta_{60}) \right] \right\} \quad \text{where } \delta_{60} = 0.01374979547.$$

Step 6: Calculate the scaled compressibility factor F_p . Use the equation:

$$F_p = \exp \left(-1.9947 + 0.00013427 \cdot t^* + \frac{793920 + 2326.0 \cdot t^*}{\rho^{*2}} \right).$$

Step 7: Calculate the correction factor due to pressure, C_{PL} . Use the equation:

$$C_{PL} = \frac{1}{1 - 10^{-5} \cdot F_p \cdot P}.$$

Step 8: Calculate the VCF, the combined temperature and pressure correction, C_{TPL} :

$$C_{TPL} = C_{TL} \cdot C_{PL}.$$

Round this value of C_{TPL} consistent with 11.1.5.4.

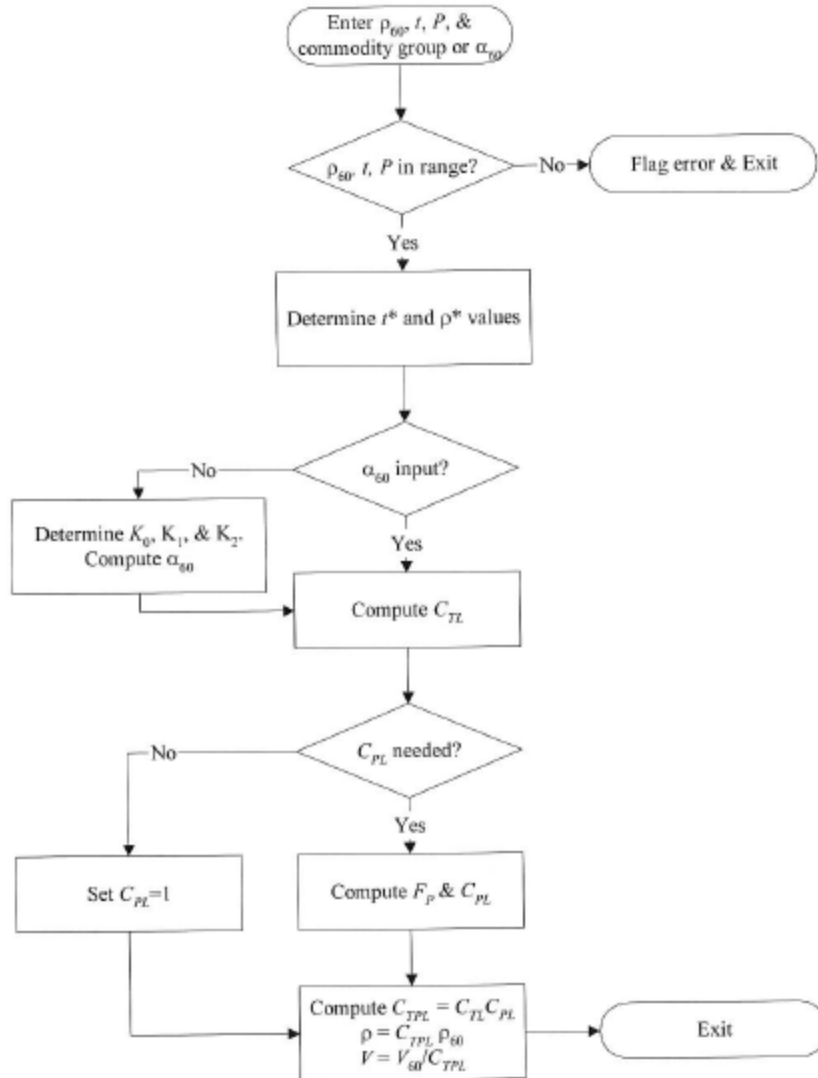
Step 9: Optionally, correct a volume measured at alternate conditions to base conditions and/or correct base density to alternate conditions.:

$$\rho = C_{TL} \cdot C_{PL} \cdot \rho_{60}.$$

$$V_{60} = V_{t,P} * C_{TPL}$$

Step 10: Exit from this procedure.

Figure 11.1.6.1.A Flow Chart Of Procedure Correcting Volume and Density to an Alternate Temperature and Pressure from Base Conditions



11.1.6.2 Method to Correct Volume and Density from Observed Conditions to Customary Base Conditions

Note: For liquids with an equilibrium vapor pressure greater than atmospheric, see 11.1.3.4.

Outline of Calculations

This procedure calculates the density at the base conditions (60°F and 0 psig) that is consistent with an observed density at its temperature and pressure condition. The procedure has the flexibility of accepting a pre-calculated 60°F thermal expansion factor or calculating one based upon the commodity type of the liquid.

The equations for the temperature and pressure correction factors are direct functions of the base density. In this procedure, however, this base density is unknown. So, the base density must be calculated using iteration. This basic procedure is:

- 1) Estimate a value for the 60°F density.
- 2) Calculate the observed density via the procedure outlined in 11.1.6.1.
- 3) Compare this result with the given observed density.
- 4) If the calculated observed density is acceptably close to the given observed density, then the iterations are complete.
- 5) If the calculated and given observed densities are not acceptably close, then the value for the 60°F density is changed and we repeat the process, starting at step 2.

This final iterative value of the 60°F density is the desired output from this procedure.

A Newton's method of iteration procedure is outlined here. The Newton's method is a specific way to determine how the value for the 60°F density is changed in step 5 above. However, this method need not be used to comply with the implementation procedure. Other initial guesses or iterative solution techniques could be used and still be deemed compliant with this Standard provided the process is continued until the calculated and given observed densities are acceptably close— this criterion is Step 4 of this procedure. See 11.1.3.4 and Appendix F for further discussions about this iteration scheme.

Note that when using the Generalized Refined Products group (the B Tables), the sub-group may change depending upon the iterative value of the base density, ρ_{60} . This sub-group switching is automatically performed as part of this iteration procedure. Other iterative procedures may not be able to do this.

The calculation steps are depicted in Figure 11.1.6.2.A.

The procedure has been written assuming that the input values are all in the proper units (°F, psig, and kg/m³). If they are not in the proper units then apply the procedures in 11.1.5.1 before entering this procedure. The density values calculated by this procedure are in the units of kg/m³. If these units do not match the original input units, then the output densities should be converted to that of the original input value's units using the procedures in 11.1.5.1.

Input Values

Commodity group describing liquid (if α_{60} not input)

- | | |
|---------------|---|
| α_{60} | Pre-calculated 60°F thermal expansion factor (if commodity group not given) |
| ρ_o | Observed density (kg/m ³) |
| t_o | Temperature at which the observed density was measured (°F) |
| P_o | Pressure at which the observed density was measured (psig) |

Optional Input Values

V_o Volume at observed conditions (any valid set of units, such as barrels, liters, and cubic metres)

Output Values

ρ_{60} Density at base conditions (60°F and 0 psig) (kg/m³)

C_{TL} Volume correction factor due to temperature

C_{PL} Volume correction factor due to pressure

F_P Scaled compressibility factor (psi⁻¹)

C_{TPL} Combined volume correction factor due to temperature and pressure

Optional Output Values

V_{60} Volume at base conditions (60°F and 0 psig) (same set of units as V)

Intermediate Values

$\rho_{60}^{(m)}$ Value of ρ_{60} on the m -th iteration

$\rho_{60,max}$ Maximum value allowed for ρ_{60} on any iteration

$\rho_{60,min}$ Minimum value allowed for ρ_{60} on any iteration

$C_{TL}^{(m)}$ Volume correction factor due to temperature on the m -th iteration

$C_{PL}^{(m)}$ Volume correction factor due to pressure on the m -th iteration

$C_{TPL}^{(m)}$ Value of the combined VCF due to temperature and pressure on the m -th iteration

$F_P^{(m)}$ Scaled compressibility factor on the m -th iteration (psi⁻¹)

ΔT Temperature difference from the base temperature of 60°F (°F)

$\delta\rho_a^{(m)}$ Deviation between the value of the observed density ρ_o and the estimate of ρ_{60} on the m -th iteration

$\Delta\rho_{60}^{(m)}$ Change applied to the value of $\rho_{60}^{(m)}$ on the m -th iteration to get the value on the next iteration (kg/m³)

$D_a^{(m)}$ Coefficient needed to perform iteration on ρ_{60}

$D_T^{(m)}$ Correction factor due to temperature used in iterative procedure

$D_P^{(m)}$ Correction factor due to pressure used in iterative procedure

$E^{(m)}$ Correction factor due to density used in iterative procedure

Calculation Procedure

Step 1: Check the input values to determine if they are in the range of this Standard. The following are the valid limits:

$$-58.0^{\circ}\text{F} \leq t_o \leq 302.0^{\circ}\text{F}$$

$$0 \leq P_o \leq 1500 \text{ psig}$$

$$\rho_{\min} \leq \rho_o \leq \rho_{\max} \text{ (if commodity type is specified)}$$

$$230.0 \times 10^{-6} \text{ }^{\circ}\text{F}^{-1} \leq \alpha_{60} \leq 930.0 \times 10^{-6} \text{ }^{\circ}\text{F}^{-1} \text{ (if } \alpha_{60} \text{, not commodity type, is specified)}$$

The following table gives the largest possible ρ_o limits for the various commodity groups. This check does not have to be done if α_{60} , not the commodity group, is specified. Note that even if a ρ_o value is within these limits it may still not correspond to a valid ρ_{60} value.

Commodity Type	ρ_{\min}	ρ_{\max}
Crude Oil	470.5 kg/m ³	1201.8 kg/m ³
Refined Products	470.4 kg/m ³	1209.5 kg/m ³
Lubricating Oil	714.3 kg/m ³	1208.3 kg/m ³

If $P_o < 0$ psig then set $P_o = 0$ psig and continue with the procedure.

If any of the input variables are out of range set an error condition (such as setting all output values to zero) and exit procedure.

Step 2: Use the observed density ρ_o as the initial guess for the density at base conditions, $\rho_{60}^{(0)}$

$$\rho_{60}^{(0)} = \rho_o$$

Limit this initial guess to remain in the range of this Standard. Set:

$$\rho_{60}^{(0)} = \begin{cases} \rho_{60,\min} & \text{if } \rho_o < \rho_{60,\min} \\ \rho_{60,\max} & \text{if } \rho_o > \rho_{60,\max} \end{cases}$$

The following table gives the ρ_{60} limits for the various commodity groups. This check does not have to be done if α_{60} , not the commodity group, is specified.

Commodity Type	$\rho_{60,\min}$	$\rho_{60,\max}$
Crude Oil	610.6 kg/m ³	1163.5 kg/m ³
Refined Products		
Lubricating Oil	800.9 kg/m ³	

Consider the iteration counter to be set at $m = 0$ and start the iterative procedure.

Step 3: Following the procedure in 11.1.6.1, calculate the correction factor due to temperature and pressure, $C_{TPL}^{(m)}$, using the current guess for the density at base conditions, $\rho_{60}^{(m)}$. Do not check the input values for being in the proper range. Do not round the value of $C_{TPL}^{(m)}$. Retain the value of α_{60} as $\alpha_{60}^{(m)}$.

Step 4: Determine if the result of this current estimate for the density at base conditions and the corresponding CTPL reproduces the observed density. If it does then the calculation has converged and the iterations should halt. The estimate is considered as "good enough" if:

$$|\delta\rho_a^{(n)}| < 0.000001 \text{ kg/m}^3 \text{ where } \delta\rho_a^{(n)} = \rho_a - \rho_{60}^{(n)} \cdot C_{TPL}^{(n)}.$$

If this condition is true, go to Step 7.

Step 5: Revise the estimate for the density at base conditions. The general recursion equation is:

$$\rho_{60}^{(n+1)} = \rho_{60}^{(n)} + \Delta\rho_{60}^{(n)}.$$

Newton's iteration method to determine $\Delta\rho_{60}^{(n)}$ is:

$$\Delta\rho_{60}^{(n)} = \frac{E^{(n)}}{1 + D_T^{(n)} + D_P^{(n)}}.$$

where:

$$E^{(n)} = \frac{P_a}{C_{TL}^{(n)} C_{PL}^{(n)}} - \rho_{60}^{(n)}$$

$$D_T^{(n)} = D_a^{(n)} \cdot \alpha_{60}^{(n)} \Delta t (1 + 1.6 \alpha_{60}^{(n)} \Delta t) \text{ and } \Delta t = t_a - 60$$

$$D_P^{(n)} = -\frac{2C_{PL}^{(n)} P_a P_r^{(n)} (7.93920 + 0.02326 t_a)}{\rho_{60}^{(n)2}}.$$

The $D_a^{(n)}$ values depend upon the commodity group and are obtained from the following table. If the α_{60} value has been specified as an input value, then $D_a^{(n)} = 0$ (meaning that $D_T^{(n)} = 0$). Note that when dealing with Generalized Refined Products the sub-group could change during the course of the iterations (depending on the current $\rho_{60}^{(n)}$ value) resulting in different $D_a^{(n)}$ values from one iteration to the next.

Commodity Groups (Table)		Density Range(kg/m ³)	D_a
Crude Oil (A)		$610.6 \leq \rho_{60} < 1163.5$	2.0
Refined Products (B)	Fuel Oils	$838.3127 \leq \rho_{60} \leq 1163.5$	1.3
	Jet Fuels	$787.5195 \leq \rho_{60} < 838.3127$	2.0
	Transition Zone	$770.3520 \leq \rho_{60} < 787.5195$	8.5
	Gasolines	$610.6 \leq \rho_{60} < 770.3520$	1.5
Lubricating Oil (D)		$800.9 \leq \rho_{60} < 1163.5$	1.0
Special Applications (C)		All ρ_{60} values	0.0

There are cases where the Newton's method $\Delta\rho_{60}^{(n)}$ value should not be directly used:

- If the Newton's method gives a value outside of the valid range for this Standard, constrain the $\Delta\rho_{60}^{(n)}$ value to go only to the boundary:

$$\text{If } \rho_{60}^{(a)} + \Delta\rho_{60}^{(n)} < \rho_{60,\min} \text{ then reset } \Delta\rho_{60}^{(n)} = \rho_{60,\min} - \rho_{60}^{(n)}.$$

$$\text{If } \rho_{60}^{(a)} + \Delta\rho_{60}^{(n)} > \rho_{60,\max} \text{ then reset } \Delta\rho_{60}^{(n)} = \rho_{60,\max} - \rho_{60}^{(n)}.$$

Step 6: Increment the iteration counter to $m+1$. If this value for the iteration counter is less than or equal to 15 continue the iterative procedure with Step 3. Otherwise set an error condition for non-convergence (such as setting all output values to zero) and exit procedure.

(Note: If the commodity class is Refined Products with a density near the boundary of a product group, there may be rare instances where convergence may fail due to a mathematical anomaly. In these instances, the resulting density should be within acceptable tolerance after 15 iterations. The density from the last iteration may be used to calculate the CTPL and the result should be flagged with a note that it did not converge. This resulting CTPL should be within acceptable tolerance.)

Step 7: After the convergence criterion in Step 4 is met, set the value of ρ_{60} to the last $\rho_{60}^{(w)}$ value and set the value of C_{TP_L} to the last $C_{TP_L}^{(m)}$ value. Check this ρ_{60} value to determine if it is in the range of this Standard. If $\rho_{60} < \rho_{60,\min}$ or $\rho_{60} > \rho_{60,\max}$ then this ρ_{60} value is out of range. Set an error condition (such as setting all output values to zero) and exit the procedure. Round this value of C_{TP_L} consistent with 11.1.5.4.

Step 8: If volume V_o has been input and the temperature and pressure for the density are the same as those for V_o , the volume at base conditions is calculated:

$$V_{60} = V_o \cdot C_{TP_L}.$$

Step 9: Exit from this procedure.

Figure 11.1.6.2.A Flow Chart Of Procedure For Correcting Volume and Density from Observed Conditions to Base Conditions

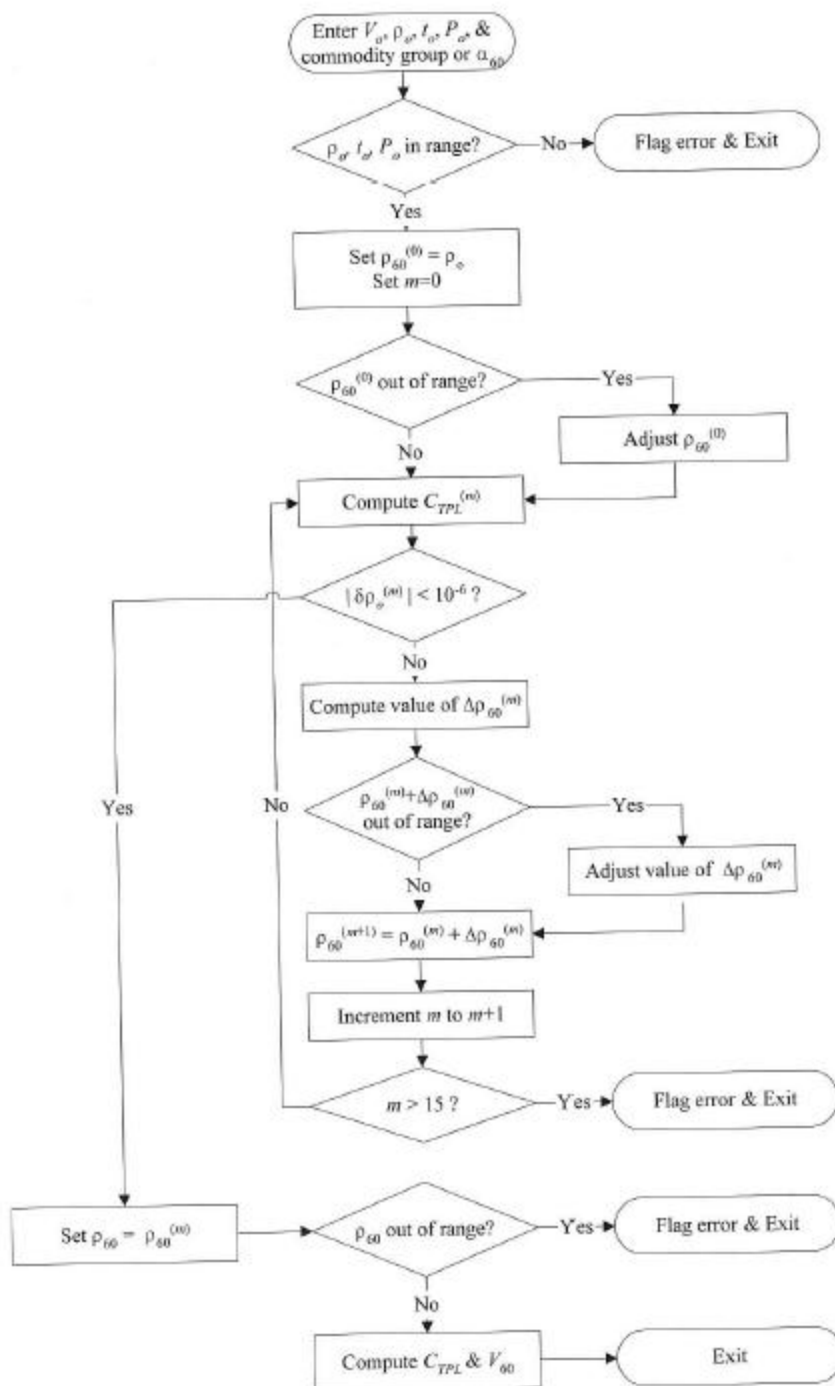


FIG. 3-16
Flange Taps, Basic Orifice Factors, $F_b - m^3/h$

Pipe Sizes, Nominal and Standard ID, mm												
Nominal Diameter	50	75	100	150	200	250	300	400	500	600	750	
Standard ID, mm	52.50	77.93	102.26	154.05	202.72	254.51	307.09	387.35	488.95	590.55	742.95	
Orifice Diameter, mm	Orifice Diameter, inches											
6.35	0.250	0.0272	0.0272	0.0271								
9.53	0.375	0.0608	0.0607	0.0607								
12.70	0.500	0.1081	0.1076	0.1075	0.1074							
15.88	0.625	0.1697	0.1688	0.1678	0.1675							
19.05	0.750	0.2464	0.2430	0.2420	0.2412							
22.23	0.875	0.3391	0.3320	0.3301	0.3286	0.3281						
25.40	1.000	0.4499	0.4356	0.4323	0.4298	0.4289						
28.58	1.125	0.5815	0.5543	0.5486	0.5448	0.5433	0.5425					
31.75	1.250	0.7386	0.6892	0.6793	0.6735	0.6715	0.6703	0.6695				
34.93	1.375	0.9277	0.8412	0.8250	0.8162	0.8133	0.8117	0.8106				
38.10	1.500	1.1605	1.0122	0.9861	0.9728	0.9690	0.9668	0.9654				
41.28	1.625		1.2940	1.1633	1.1436	1.1384	1.1356	1.1338	1.1320			
44.45	1.750		1.4197	1.2676	1.2387	1.2217	1.2181	1.2158	1.2135			
47.63	1.875		1.6632	1.5701	1.5284	1.5189	1.5143	1.5115	1.5087			
50.80	2.000		1.9389	1.8022	1.7429	1.7302	1.7244	1.7209	1.7175	1.7148		
53.98	2.125		2.252	2.0555	1.9725	1.9557	1.9483	1.9440	1.940	1.9367		
57.15	2.250		2.618	2.332	2.218	2.195	2.186	2.181	2.176	2.172		
60.33	2.375			2.636	2.479	2.450	2.438	2.432	2.426	2.421	2.418	
63.50	2.500			2.969	2.757	2.718	2.704	2.696	2.689	2.684	2.681	
66.68	2.625			3.335	3.052	3.002	2.984	2.974	2.966	2.960	2.956	
69.85	2.750			3.738	3.365	3.301	3.278	3.267	3.257	3.250	3.246	
73.03	2.875			4.185	3.697	3.615	3.586	3.573	3.562	3.554	3.549	
76.20	3.000			4.697	4.049	3.945	3.910	3.894	3.881	3.871	3.865	3.860
79.40	3.125				4.421	4.291	4.247	4.228	4.213	4.202	4.196	4.189
82.55	3.250				4.817	4.654	4.600	4.577	4.559	4.547	4.540	4.532
85.73	3.375				5.236	5.033	4.968	4.940	4.919	4.906	4.897	4.889
88.90	3.500				5.682	5.431	5.350	5.317	5.293	5.278	5.268	5.259
92.08	3.625				6.155	5.846	5.749	5.709	5.681	5.664	5.653	5.643
95.25	3.750				6.658	6.280	6.163	6.116	6.084	6.064	6.052	6.041
98.43	3.875				7.194	6.735	6.593	6.537	6.500	6.478	6.464	6.452
101.60	4.000				7.765	7.209	7.039	6.973	6.930	6.905	6.890	6.876
104.76	4.125				8.224	7.623	7.423	7.347	7.291	7.244	7.218	7.202
107.93	4.250				8.765	8.082	7.852	7.756	7.688	7.630	7.582	7.554
111.10	4.375				9.277	8.552	8.292	8.176	8.096	8.026	7.966	7.916
114.28	4.500				9.860	9.102	8.812	8.676	8.584	8.504	8.432	8.372
117.45	4.625				10.415	9.612	9.292	9.136	9.032	8.940	8.866	8.806
120.63	4.750				10.942	10.092	9.742	9.566	9.442	9.330	9.246	9.186
123.80	4.875				11.442	10.542	10.162	9.966	9.822	9.690	9.586	9.506
126.98	5.000				11.915	11.022	10.612	10.396	10.242	10.090	9.966	9.866
130.15	5.125				12.362	11.422	10.982	10.746	10.572	10.400	10.256	10.136
133.33	5.250				12.782	11.852	11.382	11.126	10.932	10.750	10.586	10.446
136.50	5.375				13.182	12.252	11.752	11.476	11.262	11.060	10.876	10.716
139.68	5.500				13.562	12.622	12.092	11.796	11.562	11.340	11.136	10.956
142.85	5.625				13.922	12.962	12.402	12.086	11.832	11.590	11.366	11.156
146.03	5.750				14.262	13.272	12.682	12.346	12.072	11.810	11.566	11.336
149.20	5.875				14.582	13.552	12.932	12.576	12.282	12.000	11.736	11.486
152.38	6.000				14.892	13.802	13.182	12.806	12.492	12.180	11.886	11.616
155.55	6.125				15.182	14.022	13.382	12.986	12.652	12.320	12.006	11.716
158.73	6.250				15.462	14.212	13.552	13.136	12.782	12.430	12.086	11.766
161.90	6.375				15.732	14.372	13.702	13.266	12.892	12.520	12.156	11.816
165.08	6.500				15.992	14.502	13.822	13.366	12.972	12.580	12.206	11.846
168.25	6.625				16.242	14.602	13.912	13.436	13.022	12.610	12.216	11.856
171.43	6.750				16.482	14.682	14.002	13.506	13.072	12.640	12.226	11.866
174.60	6.875				16.712	14.742	14.072	13.566	13.112	12.660	12.236	11.876
177.78	7.000				16.932	14.782	14.122	13.616	13.142	12.690	12.256	11.886
180.95	7.125				17.142	14.802	14.152	13.656	13.162	12.710	12.276	11.896
184.13	7.250				17.342	14.812	14.162	13.686	13.172	12.720	12.286	11.906
187.30	7.375				17.532	14.812	14.162	13.706	13.172	12.720	12.286	11.906
190.48	7.500				17.712	14.802	14.152	13.726	13.162	12.710	12.276	11.896
193.65	7.625				17.882	14.782	14.132	13.746	13.142	12.690	12.256	11.876
196.83	7.750				18.042	14.752	14.102	13.766	13.112	12.660	12.226	11.846

FIG. 3-17
"b" Values for Reynolds Number Factor, F_r – Flange Taps

Pipe Sizes, Nominal and Standard ID, mm													
Nominal Diameter	50	75	100	150	200	250	300	400	500	600	750		
Standard ID, mm	52.50	77.93	102.26	154.95	202.72	254.51	307.09	387.35	488.95	590.55	742.96		
Orifice Diameter, mm	Orifice Diameter, inches												
6.35	0.250	1.225	1.396	1.394									
9.53	0.375	0.960	1.106	1.200									
12.70	0.500	0.778	0.919	1.031									
15.88	0.625	0.669	0.771	0.886	1.180								
19.05	0.750	0.623	0.659	0.764	0.950								
22.23	0.875	0.632	0.579	0.664	0.851	0.976							
25.40	1.000	0.681	0.532	0.585	0.762	0.894							
28.58	1.125	0.759	0.511	0.524	0.684	0.818	0.927						
31.75	1.250	0.855	0.513	0.481	0.614	0.749	0.863	0.950					
34.93	1.375	0.946	0.537	0.455	0.554	0.685	0.802	0.894					
38.10	1.500	1.023	0.577	0.445	0.504	0.627	0.745	0.840					
41.28	1.625		0.631	0.447	0.460	0.576	0.692	0.790	0.905				
44.45	1.750		0.693	0.463	0.426	0.528	0.642	0.741	0.860				
47.63	1.875		0.759	0.490	0.401	0.484	0.597	0.696	0.818				
50.80	2.000		0.826	0.523	0.381	0.450	0.554	0.651	0.777	0.894			
53.98	2.125		0.886	0.565	0.368	0.417	0.515	0.613	0.738	0.859			
57.15	2.250		0.934	0.611	0.363	0.390	0.479	0.574	0.700	0.823			
60.33	2.375			0.663	0.363	0.368	0.446	0.538	0.664	0.790	0.885		
63.50	2.500			0.714	0.369	0.349	0.417	0.505	0.630	0.758	0.855		
66.68	2.625			0.766	0.380	0.335	0.392	0.474	0.598	0.726	0.826		
69.85	2.750			0.814	0.397	0.324	0.368	0.445	0.566	0.696	0.798		
73.03	2.875			0.856	0.415	0.318	0.348	0.419	0.537	0.667	0.770		
76.20	3.000			0.899	0.439	0.315	0.331	0.394	0.509	0.639	0.744	0.863	
79.40	3.125				0.467	0.316	0.316	0.373	0.483	0.611	0.717	0.839	
82.55	3.250				0.496	0.320	0.304	0.352	0.458	0.585	0.692	0.815	
85.73	3.375				0.529	0.328	0.295	0.335	0.434	0.560	0.667	0.792	
88.90	3.500				0.564	0.337	0.288	0.319	0.411	0.536	0.643	0.770	
92.08	3.625				0.598	0.351	0.283	0.304	0.390	0.512	0.619	0.749	
95.25	3.750				0.634	0.365	0.282	0.292	0.372	0.490	0.597	0.728	
98.43	3.875				0.703	0.394	0.282	0.282	0.353	0.468	0.576	0.706	
101.60	4.000				0.766	0.402	0.283	0.274	0.336	0.448	0.554	0.685	
107.95	4.250				0.818	0.447	0.294	0.262	0.307	0.410	0.513	0.646	
114.30	4.500					0.496	0.312	0.257	0.282	0.374	0.476	0.609	
120.65	4.750					0.550	0.336	0.257	0.262	0.344	0.441	0.573	
127.00	5.000					0.605	0.366	0.263	0.247	0.316	0.407	0.538	
133.35	5.250					0.658	0.401	0.275	0.287	0.291	0.377	0.505	
139.70	5.500					0.708	0.439	0.292	0.290	0.270	0.349	0.475	
146.05	5.750						0.753	0.480	0.314	0.228	0.253	0.324	0.446
152.40	6.000							0.524	0.337	0.229	0.237	0.302	0.418
158.75	6.250							0.568	0.366	0.234	0.225	0.289	0.392
165.10	6.500							0.611	0.397	0.242	0.216	0.262	0.366
171.45	6.750							0.652	0.430	0.254	0.208	0.245	0.344
177.80	7.000							0.692	0.464	0.267	0.204	0.230	0.323
184.15	7.250							0.728	0.501	0.286	0.202	0.218	0.303
190.50	7.500							0.757	0.538	0.304	0.204	0.208	0.284
196.85	7.750								0.574	0.325	0.206	0.200	0.267

FIG. 3-18
Expansion Factors – Flange Taps, Y2 (static downstream)

hw/P ₂ Ratio	$\beta = d/D$										hw/P ₂ Ratio	$\beta = d/D$											
	1	2	3	4	45	50	52	54	56	58		60	61	62	63	64	65	66	67	68	69	70	71
0.00	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
0.50	1.0009	1.0018	1.0027	1.0036	1.0045	1.0053	1.0061	1.0069	1.0077	1.0085	1.0093	1.0101	1.0109	1.0117	1.0125	1.0133	1.0141	1.0149	1.0157	1.0165	1.0173	1.0181	1.0189
1.00	1.0018	1.0037	1.0056	1.0075	1.0094	1.0113	1.0132	1.0151	1.0170	1.0189	1.0208	1.0227	1.0246	1.0265	1.0284	1.0303	1.0322	1.0341	1.0360	1.0379	1.0398	1.0417	1.0436
1.50	1.0027	1.0057	1.0087	1.0117	1.0147	1.0177	1.0207	1.0237	1.0267	1.0297	1.0327	1.0357	1.0387	1.0417	1.0447	1.0477	1.0507	1.0537	1.0567	1.0597	1.0627	1.0657	1.0687
2.00	1.0036	1.0076	1.0116	1.0156	1.0196	1.0236	1.0276	1.0316	1.0356	1.0396	1.0436	1.0476	1.0516	1.0556	1.0596	1.0636	1.0676	1.0716	1.0756	1.0796	1.0836	1.0876	1.0916
2.50	1.0045	1.0095	1.0145	1.0195	1.0245	1.0295	1.0345	1.0395	1.0445	1.0495	1.0545	1.0595	1.0645	1.0695	1.0745	1.0795	1.0845	1.0895	1.0945	1.0995	1.1045	1.1095	1.1145
3.00	1.0055	1.0064	1.0073	1.0082	1.0091	1.0100	1.0109	1.0118	1.0127	1.0136	1.0145	1.0154	1.0163	1.0172	1.0181	1.0190	1.0199	1.0208	1.0217	1.0226	1.0235	1.0244	1.0253
3.50	1.0064	1.0063	1.0062	1.0061	1.0060	1.0059	1.0058	1.0057	1.0056	1.0055	1.0054	1.0053	1.0052	1.0051	1.0050	1.0049	1.0048	1.0047	1.0046	1.0045	1.0044	1.0043	1.0042
4.00	1.0073	1.0072	1.0071	1.0070	1.0069	1.0068	1.0067	1.0066	1.0065	1.0064	1.0063	1.0062	1.0061	1.0060	1.0059	1.0058	1.0057	1.0056	1.0055	1.0054	1.0053	1.0052	1.0051
4.50	1.0082	1.0081	1.0080	1.0079	1.0078	1.0077	1.0076	1.0075	1.0074	1.0073	1.0072	1.0071	1.0070	1.0069	1.0068	1.0067	1.0066	1.0065	1.0064	1.0063	1.0062	1.0061	1.0060
5.00	1.0091	1.0090	1.0089	1.0088	1.0087	1.0086	1.0085	1.0084	1.0083	1.0082	1.0081	1.0080	1.0079	1.0078	1.0077	1.0076	1.0075	1.0074	1.0073	1.0072	1.0071	1.0070	1.0069
5.50	1.0100	1.0100	1.0099	1.0098	1.0097	1.0096	1.0095	1.0094	1.0093	1.0092	1.0091	1.0090	1.0089	1.0088	1.0087	1.0086	1.0085	1.0084	1.0083	1.0082	1.0081	1.0080	1.0079
6.00	1.0109	1.0108	1.0107	1.0106	1.0105	1.0104	1.0103	1.0102	1.0101	1.0100	1.0099	1.0098	1.0097	1.0096	1.0095	1.0094	1.0093	1.0092	1.0091	1.0090	1.0089	1.0088	1.0087
6.50	1.0119	1.0118	1.0117	1.0116	1.0115	1.0114	1.0113	1.0112	1.0111	1.0110	1.0109	1.0108	1.0107	1.0106	1.0105	1.0104	1.0103	1.0102	1.0101	1.0100	1.0099	1.0098	1.0097
7.00	1.0128	1.0128	1.0127	1.0126	1.0125	1.0124	1.0123	1.0122	1.0121	1.0120	1.0119	1.0118	1.0117	1.0116	1.0115	1.0114	1.0113	1.0112	1.0111	1.0110	1.0109	1.0108	1.0107
7.50	1.0137	1.0137	1.0136	1.0135	1.0134	1.0133	1.0132	1.0131	1.0130	1.0129	1.0128	1.0127	1.0126	1.0125	1.0124	1.0123	1.0122	1.0121	1.0120	1.0119	1.0118	1.0117	1.0116
8.00	1.0146	1.0146	1.0145	1.0144	1.0143	1.0142	1.0141	1.0140	1.0139	1.0138	1.0137	1.0136	1.0135	1.0134	1.0133	1.0132	1.0131	1.0130	1.0129	1.0128	1.0127	1.0126	1.0125
8.50	1.0155	1.0155	1.0154	1.0153	1.0152	1.0151	1.0150	1.0149	1.0148	1.0147	1.0146	1.0145	1.0144	1.0143	1.0142	1.0141	1.0140	1.0139	1.0138	1.0137	1.0136	1.0135	1.0134
9.00	1.0165	1.0165	1.0163	1.0162	1.0161	1.0160	1.0159	1.0158	1.0157	1.0156	1.0155	1.0154	1.0153	1.0152	1.0151	1.0150	1.0149	1.0148	1.0147	1.0146	1.0145	1.0144	1.0143
9.50	1.0174	1.0174	1.0172	1.0171	1.0170	1.0169	1.0168	1.0167	1.0166	1.0165	1.0164	1.0163	1.0162	1.0161	1.0160	1.0159	1.0158	1.0157	1.0156	1.0155	1.0154	1.0153	1.0152
10.00	1.0184	1.0183	1.0181	1.0179	1.0177	1.0175	1.0173	1.0171	1.0169	1.0167	1.0165	1.0163	1.0161	1.0159	1.0157	1.0155	1.0153	1.0151	1.0149	1.0147	1.0145	1.0143	1.0141
10.50	1.0193	1.0192	1.0191	1.0189	1.0187	1.0185	1.0183	1.0181	1.0179	1.0177	1.0175	1.0173	1.0171	1.0169	1.0167	1.0165	1.0163	1.0161	1.0159	1.0157	1.0155	1.0153	1.0151
11.00	1.0202	1.0202	1.0200	1.0198	1.0196	1.0194	1.0192	1.0190	1.0188	1.0186	1.0184	1.0182	1.0180	1.0178	1.0176	1.0174	1.0172	1.0170	1.0168	1.0166	1.0164	1.0162	1.0160
11.50	1.0211	1.0211	1.0209	1.0207	1.0205	1.0203	1.0201	1.0199	1.0197	1.0195	1.0193	1.0191	1.0189	1.0187	1.0185	1.0183	1.0181	1.0179	1.0177	1.0175	1.0173	1.0171	1.0169
12.00	1.0221	1.0220	1.0218	1.0216	1.0214	1.0212	1.0210	1.0208	1.0206	1.0204	1.0202	1.0200	1.0198	1.0196	1.0194	1.0192	1.0190	1.0188	1.0186	1.0184	1.0182	1.0180	1.0178
12.50	1.0230	1.0230	1.0228	1.0226	1.0224	1.0222	1.0220	1.0218	1.0216	1.0214	1.0212	1.0210	1.0208	1.0206	1.0204	1.0202	1.0200	1.0198	1.0196	1.0194	1.0192	1.0190	1.0188
13.00	1.0239	1.0239	1.0237	1.0235	1.0233	1.0231	1.0229	1.0227	1.0225	1.0223	1.0221	1.0219	1.0217	1.0215	1.0213	1.0211	1.0209	1.0207	1.0205	1.0203	1.0201	1.0199	1.0197
13.50	1.0249	1.0248	1.0246	1.0244	1.0242	1.0240	1.0238	1.0236	1.0234	1.0232	1.0230	1.0228	1.0226	1.0224	1.0222	1.0220	1.0218	1.0216	1.0214	1.0212	1.0210	1.0208	1.0206
14.00	1.0258	1.0258	1.0256	1.0254	1.0252	1.0250	1.0248	1.0246	1.0244	1.0242	1.0240	1.0238	1.0236	1.0234	1.0232	1.0230	1.0228	1.0226	1.0224	1.0222	1.0220	1.0218	1.0216
14.50	1.0267	1.0267	1.0265	1.0263	1.0261	1.0259	1.0257	1.0255	1.0253	1.0251	1.0249	1.0247	1.0245	1.0243	1.0241	1.0239	1.0237	1.0235	1.0233	1.0231	1.0229	1.0227	1.0225
15.00	1.0277	1.0276	1.0274	1.0272	1.0270	1.0268	1.0266	1.0264	1.0262	1.0260	1.0258	1.0256	1.0254	1.0252	1.0250	1.0248	1.0246	1.0244	1.0242	1.0240	1.0238	1.0236	1.0234

FIG. 23-4
Compressibility Factors for Natural Gas¹

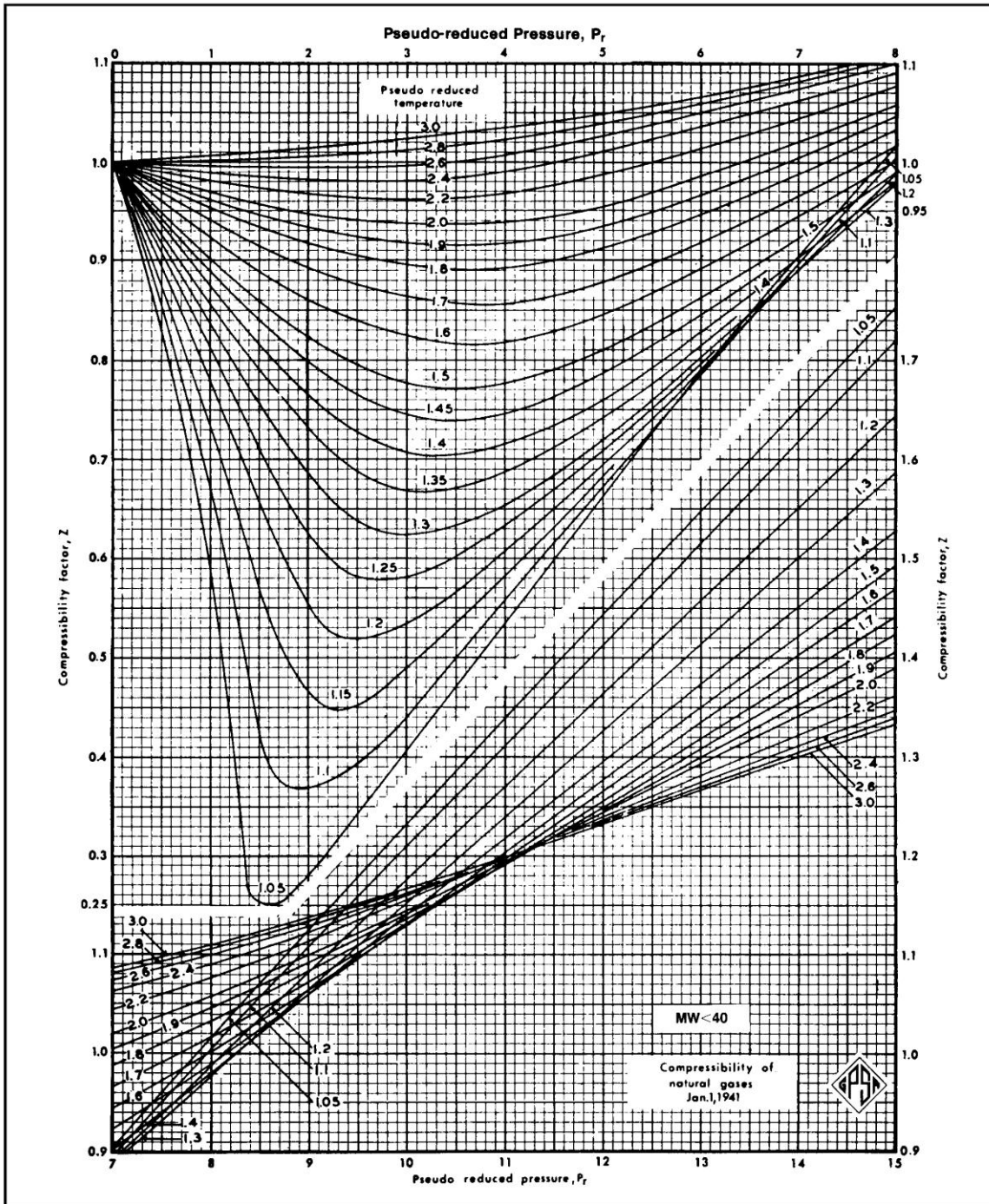


FIG. 23-5
Compressibility of Low-Molecular-Weight Natural Gases¹¹

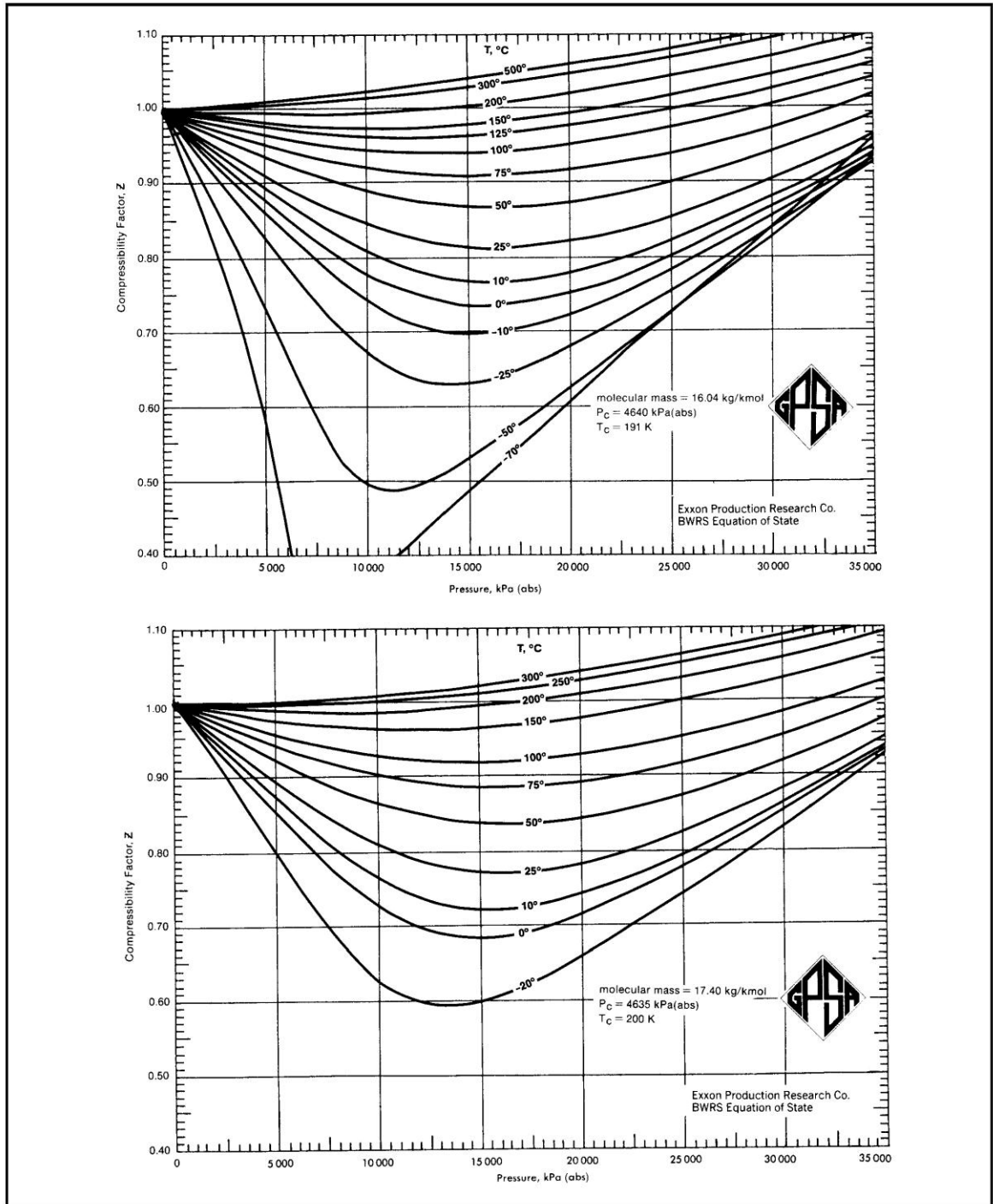


FIG. 23-6
Compressibility of Low-Molecular-Weight Natural Gases¹¹

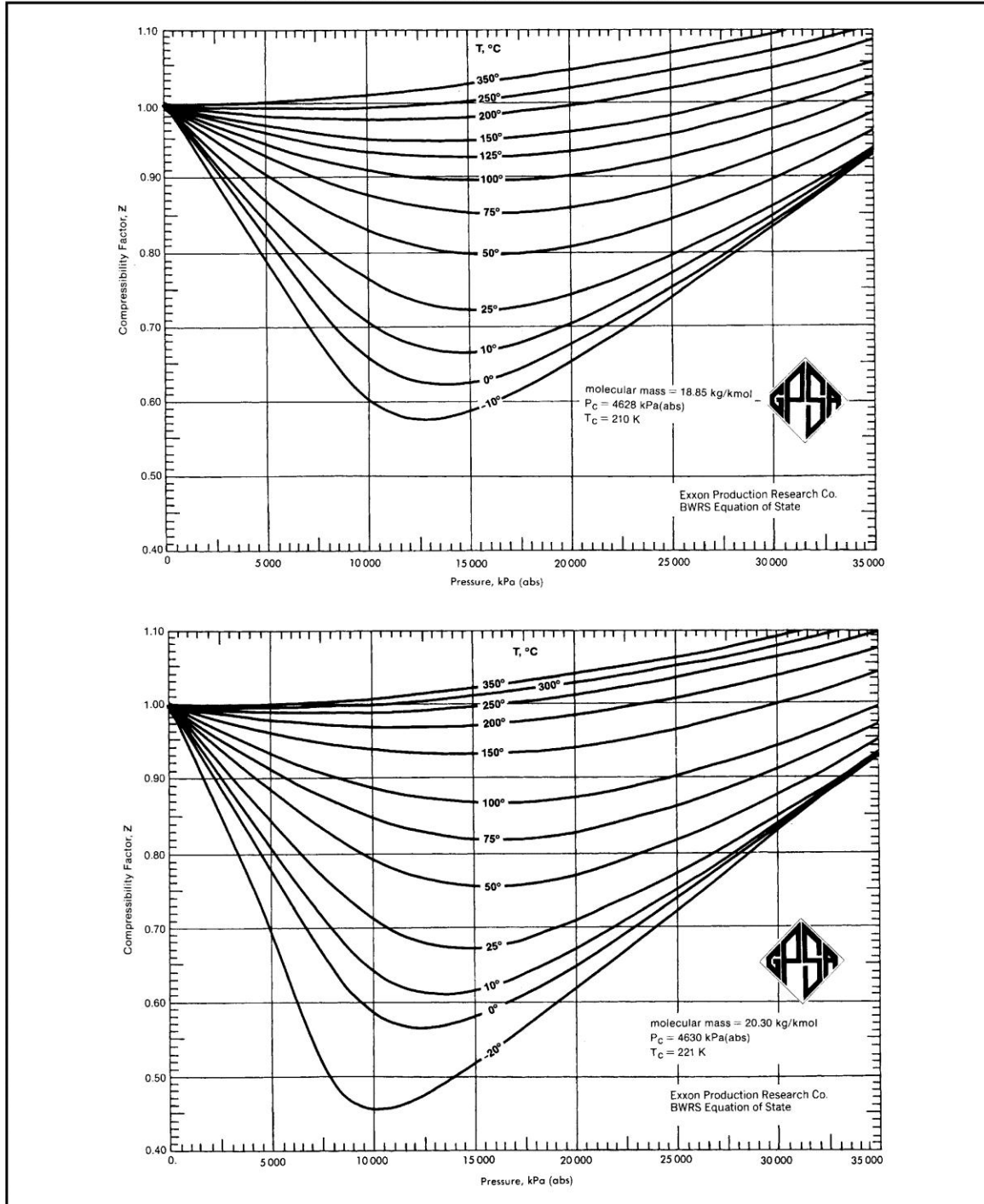
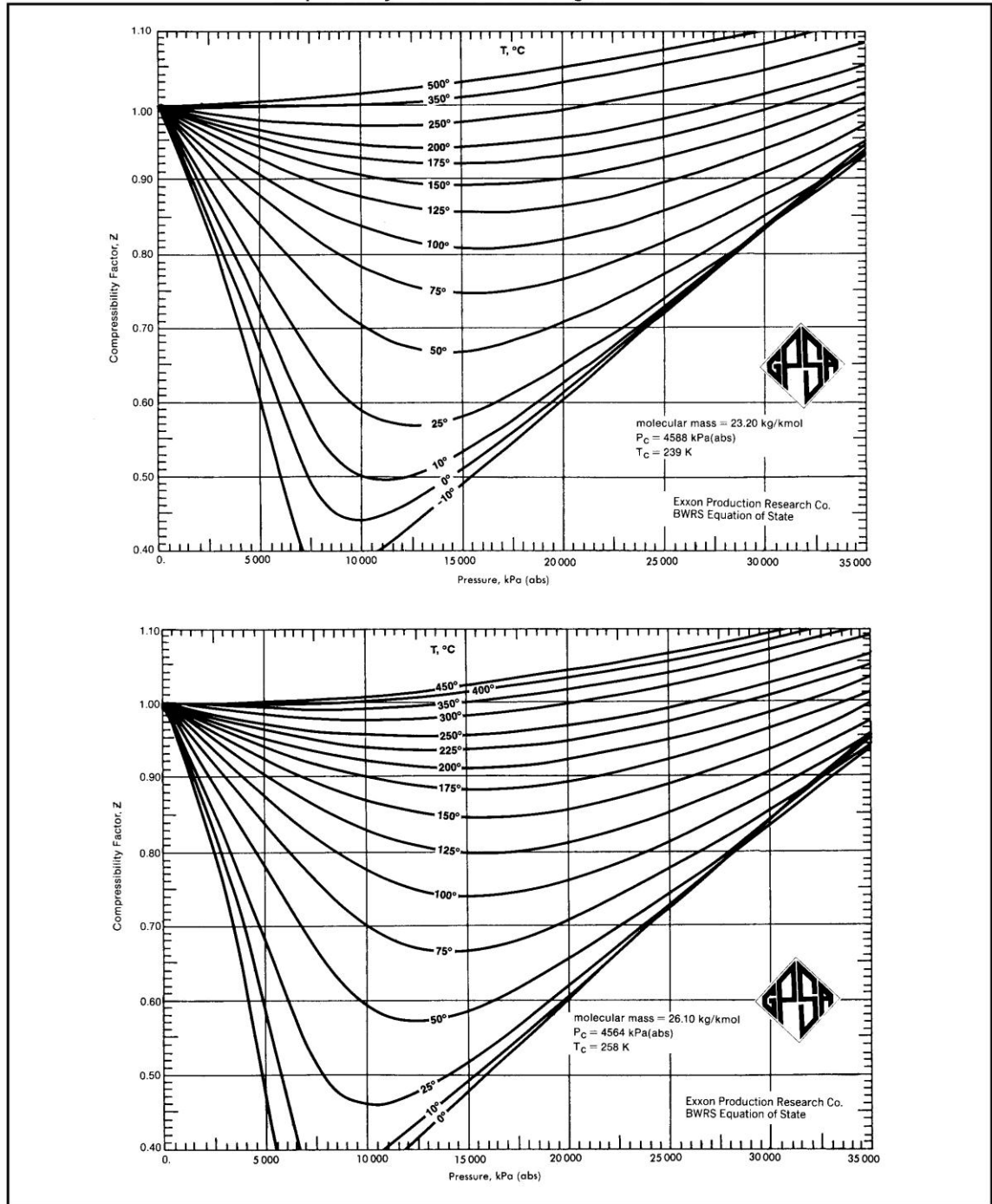


FIG. 23-7
Compressibility of Low-Molecular-Weight Natural Gases¹¹



**Volume Correction Factors for Temperature, C_{ti}
Paraffinic Hydrocarbon Mixtures**

Liquid Relative Density at 15.5°C	Temperature of flowing fluid, °C								
	-10	0	10	20	30	40	60	80	100
0.50	1.072	1.045	1.016	0.986	0.954	0.919			
0.51	1.069	1.043	1.015	0.987	0.957	0.924			
0.52	1.066	1.041	1.014	0.988	0.959	0.929			
0.53	1.062	1.038	1.014	0.988	0.962	0.933			
0.54	1.059	1.036	1.013	0.989	0.963	0.937			
0.55	1.056	1.035	1.012	0.990	0.966	0.940			
0.56	1.053	1.033	1.012	0.990	0.967	0.944			
0.57	1.051	1.031	1.011	0.991	0.970	0.947			
0.58	1.048	1.029	1.010	0.991	0.971	0.949			
0.59	1.046	1.028	1.010	0.992	0.973	0.954			
0.60	1.044	1.0269	1.0096	0.9922	0.9746	0.9569	0.9211		
0.61	1.042	1.0259	1.0093	0.9825	0.9756	0.9586	0.9242		
0.62	1.040	1.0246	1.0088	0.9930	0.9768	0.9605	0.9276	0.8943	
0.63	1.039	1.0239	1.0086	0.9931	0.9775	0.9618	0.9299	0.8977	
0.64	1.038	1.0232	1.0083	0.9933	0.9781	0.9629	0.9320	0.9009	
0.65	1.037	1.0225	1.0081	0.9936	0.9789	0.9641	0.9342	0.9040	
0.66	1.036	1.0218	1.0078	0.9937	0.9794	0.9651	0.9362	0.9069	
0.67	1.035	1.0211	1.0075	0.9939	0.9801	0.9662	0.9381	0.9098	
0.68	1.0336	1.0205	1.0073	0.9941	0.9807	0.9672	0.9399	0.9124	
0.69	1.0326	1.0199	1.0071	0.9942	0.9813	0.9682	0.9417	0.9150	
0.70	1.0317	1.0194	1.0069	0.9944	0.9818	0.9691	0.9434	0.9174	
0.71	1.0308	1.0189	1.0067	0.9946	0.9823	0.9699	0.9450	0.9197	
0.72	1.0300	1.0183	1.0065	0.9947	0.9828	0.9707	0.9466	0.9221	
0.73	1.0293	1.0179	1.0064	0.9948	0.9832	0.9716	0.9480	0.9242	
0.74	1.0284	1.0173	1.0062	0.9951	0.9837	0.9724	0.9494	0.9263	
0.75	1.0277	1.0169	1.0061	0.9951	0.9842	0.9730	0.9507	0.9282	
0.76	1.0270	1.0165	1.0059	0.9952	0.9845	0.9738	0.9520	0.9301	
0.77	1.0263	1.0161	1.0057	0.9954	0.9849	0.9744	0.9533	0.9320	
0.78	1.0256	1.0156	1.0056	0.9955	0.9853	0.9751	0.9545	0.9337	0.9128
0.79	1.0249	1.0152	1.0054	0.9956	0.9857	0.9757	0.9556	0.9354	0.9151
0.80	1.0244	1.0149	1.0053	0.9957	0.9861	0.9763	0.9567	0.9370	0.9171

Ref: API Manual of Petroleum Measurement Standards, Chapter 11 (API 2540, ASTM D-1250, ANSI 211-83, IP 200, ISO R91).

Temperature Correction Factors for Mild Steel, C_{ts}

C_{ts} for mild steel having a cubical coefficient of expansion of 3.34×10^{-5} per $^{\circ}\text{C}$

Observed Temperature, $^{\circ}\text{C}$	C_{ts} Value	Observed Temperature, $^{\circ}\text{C}$	C_{ts} Value
(-21.8) - (-18.8)	0.9988	23.0 - 26.0	1.0003
(-18.7) - (-15.8)	0.9989	26.1 - 29.0	1.0004
(-15.7) - (-12.8)	0.9990	29.1 - 31.9	1.0005
(-12.7) - (- 9.8)	0.9991	32.0 - 34.9	1.0006
(- 9.7) - (- 6.9)	0.9992	35.0 - 37.9	1.0007
(- 6.8) - (- 3.9)	0.9993	38.0 - 40.9	1.0008
(- 3.8) - (- 0.9)	0.9994	41.0 - 43.9	1.0009
(- 0.8) - 2.1	0.9995	44.0 - 46.9	1.0010
2.2 - 5.0	0.9996	47.0 - 49.9	1.0011
5.1 - 8.0	0.9997	50.0 - 52.9	1.0012
8.1 - 11.0	0.9998	53.0 - 55.9	1.0013
11.1 - 14.0	0.9999	56.0 - 58.8	1.0014
14.1 - 17.0	1.0000	58.9 - 61.8	1.0015
17.1 - 20.0	1.0001	61.9 - 64.8	1.0016
20.1 - 23.0	1.0002	64.9 - 67.8	1.0017

Note: This table is suitable for application in meter proving; in prover calibration use the formulas. For the formula used to derive the tabulated values and to calculate values, see Section 12 of the API Manual.

Pressure Correction Factors for Steel, C_{ps}

All measurements are in kPa (psi)

Prover Dimensions									
Factor, C_{ps}	150 mm pipe 6.35 mm wall	150 mm pipe 7.11 mm wall	200 mm pipe 8.18 mm wall	200 mm pipe 9.525 mm wall	250 mm pipe 9.27 mm wall	250 mm pipe 9.525 mm wall	300 mm pipe 9.525 mm wall	350 mm pipe 7.92 mm wall	350 mm pipe 9.525 mm wall
1.0000	0-420	0-476	0-413	0-490	0-372	0-386	0-317	0-234	0-290
1.0001	421-1262	477-1427	414-1248	491-1476	373-1124	387-1158	318-965	235-717	291-876
1.0002	1263-2110	1428-2386	1249-2082	1477-2462	1125-1882	1159-1937	966-1613	718-1200	877-1462
1.0003	2111-2950	2387-3337	2083-2917	2463-3441	1883-2634	1938-2710	1614-2262	1201-1682	1463-2048
1.0004	2951-3799	3338-4296	2918-3751	3442-4427	2635-3385	2711-3489	2263-2903	1683-2165	2049-2634
1.0005	3800-4640	4297-5247	3752-4585	4428-5413	3386-4144	3490-4261	2904-3551	2166-2648	2635-3213
1.0006	4641-5482	5248-6206	4586-5419	5414-6399	4145-4833	4262-5040	3552-4199	2649-3130	3214-3799
1.0007	5483-6330	6207-7157	5420-6254	6400-7385	4834-5647	5041-5812	4200-4847	3131-3613	3800-4385
1.0008	6331-7171		6255-7088		5648-6399	5813-6592	4848-5488	3614-4096	4386-4971
1.0009					6400-7157	6593-7364	5489-6137	4097-4578	4972-5557
1.0010							6138-6785	4579-5061	5558-6143
1.0011							6786-7433	5062-5544	6144-6730
1.0012								5545-6026	6731-7316
1.0013								6027-6509	
1.0014								6510-6992	

Factor, C_{ps}	400 mm pipe 9.525 mm wall	450 mm pipe 9.525 mm wall	500 mm pipe 9.525 mm wall	600 mm pipe 9.525 mm wall	650 mm pipe 9.525 wall	650 mm pipe 12.7 mm wall	750 mm pipe 12.7 mm wall	900 mm pipe 12.7 mm wall
1.0000	0-248	0-221	0-200	0-165	0-152	0-207	0-172	0-145
1.0001	249-758	222-669	201-600	166-496	153-455	208-614	173-531	146-441
1.0002	759-1269	670-1124	601-1007	497-827	456-765	615-1034	532-889	442-738
1.0003	1270-1779	1125-1572	1008-1407	828-1165	766-1069	1035-1441	890-1248	739-1027
1.0004	1780-2282	1573-2020	1408-1806	1166-1496	1070-1379	1442-1862	1249-1600	1028-1324
1.0005	2283-2792	2021-2468	1807-2213	1497-1834	1380-1689	1863-2268	1601-1958	1325-1620
1.0006	2793-3303	2469-2917	2214-2613	1835-2165	1690-1993	2269-2689	1959-2317	1621-1917
1.0007	3304-3813	2918-3372	2614-3020	2166-2496	1994-2303	2690-3096	2318-2668	1918-2213
1.0008	3814-4323	3373-3820	3021-3420	2497-2834	2304-2606	3097-3516	2668-3027	2214-2510
1.0009	4324-4827	3821-4268	3421-3827	2835-3165	2607-2917	3517-3923	3028-3385	2511-2806
1.0010	4828-5337	4269-4716	3828-4227	3166-3503	2918-3220	3924-4344	3386-3744	2807-3103
1.0011	5338-5847	4717-5164	4228-4633	3504-3834	3221-3530	4345-4751	3745-4096	3104-3392
1.0012		5165-5619	4634-5033	3835-4165	3531-3834	4752-5171	4097-4454	3393-3689
1.0013		5620-6067	5034-5433	4166-4502	3835-4144	5172-5578	4455-4813	3690-3985
1.0014		6068-6516	5434-5840	4503-4833	4145-4454	5579-5999	4814-5171	3986-4282
1.0015		6517-6964	5841-6240	4834-5164	4455-4758	6000-6405	5172-5523	4283-4578
1.0016			6241-6647	5165-5502	4759-5068	6406-6826	5524-5881	4579-4875
1.0017			6648-7047	5503-5833	5069-5371	6827-7233	5882-6240	4876-5164
1.0018				5834-6171	5372-5681		6241-6592	5165-5461
1.0019				6172-6502	5682-5985		6593-6950	5462-5757
1.0020				6503-6833	5986-6295			5758-6054
1.0021				6834-7171	6296-6599			6055-6350
1.0022					6600-7047			6351-6647
1.0023								6648-6943

Note: This table is based on the equation:

$$C_{ps} = 1 + \frac{P_2 - P_1 D}{E_m}$$

Attachment IV

Technical specifications

- Expro memory gauges
- SPARTEK memory gauges
- Rosemount 3051T
- Rosemount 644
- Rosemount 3144
- Dreager 6728041
- Dreager CH29801
- Dreager CH23501
- Dreager CH25101
- Oil densiometer
- Ranarex gravitometer

Expro Memory Gauges – Specifications

Technical specification			
	CT1000	MT 1000	HT 1000
Pressure sensor	Shear Quartz Resonator	Digital shear quartz resonator	Digital shear quartz resonator
Pressure range	0-16,000 psi	0-16,000 psi	0-20,000 psi
Accuracy	± 3.2 psi	± 3.2 psi	± 3.2 psi
Transducer resolution	0.008 psi	0.008 psi	0.008 psi
Stability (per month)	0.1 psi	0.1 psi	0.1 psi
Temperature sensor	Quartz crystal	Digital Quartz crystal	Digital Quartz crystal
Temperature range	32 - 350°F (0-177°C)	32 - 350°F (0-177°C)	32 - 392°F (0-200°C)
Accuracy	=/- 1.8°F	=/- 1.8°F	=/- 1.8°F
Resolution	0.09°F (0.05°C)	0.09°F (0.05°C)	0.09°F (0.05°C)
Memory type	Non-volatile flash	Non-volatile flash	Non-volatile flash
Memory capacity	1 million data sets	1 million data sets	800,000 data set
Fastest sample rate	0.1 seconds	1 second	1 second
Programmable intervals	15	15	15
Length c/w battery pack	60" (1524mm)	30.5" (775mm)	30.5" (775mm)
Outside diameter	1.25" (2.8mm) or 1.5" (38mm)	1.25" (32mm)	1.25" (32mm)
Weight	5.5kg (12lb)	5.0kg (11lb)	5.0kg (11lb)

SPARTEK Memory Gauge – Specifications

Technical specification - Quartz gauge			
	SS5063	SS5067	SS5200
Pressure sensor	Quartz	Quartz	Quartz
Pressure range	10,000 – 16,000 psi	10,000 – 25,000 psi	16,000 – 25,000 psi
		30,000 – 35,000 psi	30,000 – 35,000 psi
Accuracy (% FS)	0.020 %	0.020 %	0.020 %
		0.025 %	0.025 %
Resolution	0.00006 % FS	0.00006 % FS	0.00006 % FS
Stability (per year)	<0.020 % FS/year	<0.020 % FS/year	<0.020 % FS/year
Temperature range	77°F - 350°F (25°C - 177°C)	77°F - 350°F (25°C - 177°C)	77°F - 392°F (25°C - 200°C)
Accuracy	0.9°F (0.5°C)	0.9°F (0.5°C)	0.9°F (0.5°C)
Resolution	<0.009°F (0.005°C)	<0.009°F (0.005°C)	<0.009°F (0.005°C)
Power requirements			
Voltage (min)	3 V	3 V	3 V
Current (sleep)	0.2 mA	0.2 mA	4 mA
Current (sample)	7 mA	7 mA	10 mA

Data acquisition			
Channels	Pressure	Pressure	Pressure
	Temperature	Temperature	Temperature
	Time	Time	Time
Fastest sample rate	10 sample/sec	10 sample/sec	1 sample/sec
Memory capacity	2,000,000 samples	2,000,000 samples	2,000,000 samples
Optional	4,000,000 samples	4,000,000 samples*	
Redundant Memory	2x, 4x	2x, 4x	2x, 4x
Gauge			
Material	Inconel 718-NACE/17-4PH MP35N (as req.)	Inconel 718-NACE MP35N (as required)	Inconel 718-NACE MP35N (as required)
Diameter (inch)	0.750"(19 mm)	1.27"(32.3 mm)	1.27"(32.3 mm)
Length	Varies with configuration	Varies with configuration	Varies with configuration
Seal configuration	2x O-ring/Backup	Metal C-Ring, 2x O-ring/backup	Metal C-Ring, 2x O-ring/backup
Communications	RS 232/USB	RS 232/USB	RS 232/USB
Software compatibility	Windows 8/7/Vista/XP/NT/2000		
Surface readout	yes	yes	yes

Technical specification - Sapphire			
	SS2300	SS2500	SS2700
Pressure sensor	Sapphire	Sapphire	Sapphire
Pressure range	750, 1500, 3k, or 6k psi	10k, 15k, or 20k*	10k, 15k, or 20k*
Accuracy (% FS)	0.3 psi or 0.03 %	0.3 psi or 0.03 %	0.3 psi or 0.05 %
Resolution	0.0003% FS	0.0003% FS	0.0003% FS
Stability (per year)	< 0.03 % FS/year	< 0.03 % FS/year	< 0.03 % FS/year
Temperature range	32 - 275°F (135°C)	32 - 302°F (150°C)	32 - 338°F (170°C)
Power requirements			
Voltage (min)	3 V	3 V	3 V
Current (sleep)	0.10 mA	0.10 mA	0.20 mA
Current (sample)	4.50 mA	4.50 mA	4.80 mA
Data acquisition			
Channels	Pressure	Pressure	Pressure
	Temperature	Temperature	Temperature
	Time	Time	Time
Fastest sample rate	1 sample/sec	1 sample/sec	1 sample/sec
Memory capacity	2,000,000 samples	2,000,000 samples	2,000,000 samples
*Optional	4,000,000 samples	4,000,000 samples	4,000,000 samples
Pressure Trigger	yes	yes	yes
Redundant Memory	2x, 4x	2x, 4x	2x, 4x
Gauge			
Material	17-4 PH	17-4 PH	17-4 PH
Options*	Inconel 718-NACE	Inconel 718-NACE	Inconel 718-NACE
Diameter (inch)	0.75", 1.00", or 1.25"	0.75", 1.00", or 1.25"	0.75", 1.00", or 1.25"

Length	Varies with configuration	Varies with configuration	Varies with configuration
Communications	RS 232/USB	RS 232/USB	RS 232/USB
Software compatibility	Windows 8/7/Vista/XP/NT/2000		
Surface readout	yes	yes	yes

- * - 20k only with 1.0" or 1.25" OD

Rosemount 3051T – specifications

Range and sensor limit				
Range	Minimum Span	Upper (URL)	Lower (LRL)	Lower Gauge (LRL)
1	0.3 psi (20.6 mbar)	30 psi (2.07 bar)	0 psi (0 bar)	-14.7 psig (-1.01 barg)
2	1.5 psi (0.103 bar)	150 psi (10.3 bar)	0 psi (0 bar)	14.7 psig (-1.01 barg)
3	8 psi (0.55 bar)	800 psi (55.2 bar)	0 psi (0 bar)	14.7 psig (-1.01 barg)
4	40 psi (2.76 bar)	4000 psi (257.8 bar)	0 psi (0 bar)	14.7 psig (-1.01 barg)
5	2000 psi (137.9 bar)	10 000 psi (689.4 bar)	0 psi (0 bar)	14.7 psig (-1.01 barg)

Total performance	
Range 2 – 4	$\pm 0.15\%$ of span

Note - For $\pm 50^\circ\text{F}$ (28°C) temperature changes, up to 1000 psi (6,9 MPa) line pressure, from 1:1 to 5:1 range down

Long term stability	
Range 1 – 4	$\pm 0.125\%$ of URL for 5 years $\pm 50^\circ\text{F}$ (28°C) temperature changes, and up to 1000 psi line pressure

Reference accuracy - standard	
Range 1 – 4	$\pm 0.065\%$ of span
For spans less than 10:1	$\pm \left[0.0075 \left(\frac{\text{URL}}{\text{Span}} \right) \right] \% \text{ of span}$
Range 5	$\pm 0.075\%$ of span
For spans less than 10:1	$\pm \left[0.0075 \left(\frac{\text{URL}}{\text{Span}} \right) \right] \% \text{ of span}$

Reference accuracy - high	
Range 2 – 4	$\pm 0.04\%$ of span
For spans less than 5:1	$\pm \left[0.0075 \left(\frac{\text{URL}}{\text{Span}} \right) \right] \% \text{ of span}$

Dynamic Performance – total response time ($T_d + T_c$) @ 75°F (24°C)

	4 – 20 mA (HART protocol)	Fieldbus protocol
Total response time ($T_d + T_c$) @ 75°F (24°C)	100 ms	152 ms
Dead time (T_d)	45 ms (nominal)	97 ms
Update Rate	22 times per second	22 times per second

Ambient Temperature Effect per 50°F (28°C)	
Range 1	$\pm(0.025\% \text{ URL} + 0.125\% \text{ span})$ from 1: 1 to 10: 1
	$\pm(0.05\% \text{ URL} + 0.125\% \text{ span})$ from 10: 1 to 100: 1
Range 2 – 4	$\pm(0.025\% \text{ URL} + 0.125\% \text{ span})$ from 1: 1 to 30: 1
	$\pm(0.035\% \text{ URL} + 0.125\% \text{ span})$ from 30: 1 to 100: 1
Range 5	$\pm(0.1\% \text{ URL} + 0.15\% \text{ span})$

Rosemount 644 – specifications

Accuracy									
Sensor option	Sensor reference	Input range		Recomendend min. span		Digital Accuracy		D/A Accuracy	
2-,3-,4-wire RTDs		°C	°F	°C	°F	°C	°F		
Pt100	IEC 751, 1995($\alpha=0.00385$)	-200 to 850	-328 to 1562	10	18	± 0.15	± 0.27	$\pm 0.03\%$ of span	
Pt100	JIS 1604, 1981 ($\alpha=0.003916$)	-200 to 645	-328 to 1193	10	18	± 0.15	± 0.27	$\pm 0.03\%$ of span	

Ambient Temperature Effect				
Sensor option	Sensor reference	Temp. Effect per 1.0°C (1.8°F) change in ambient temp	Range	D/A Effect
2-,3-,4-wire RTDs				
Pt100	IEC 751, 1995($\alpha=0.00385$)	0.003°C (0.0054°F)	Entire Sensor input range	0.001% of span
Pt100	JIS 1604, 1981 ($\alpha=0.003916$)	0.003°C (0.0054°F)	Entire Sensor input range	0.001% of span

Rosemount 3144 – specifications

Accuracy									
Sensor option	Sensor reference	Input range		Recomendend min. span		Digital Accuracy		D/A Accuracy	
2-,3-,4-wire RTDs		°C	°F	°C	°F	°C	°F		
Pt100	IEC 751, 1995($\alpha=0.00385$)	-200 to 850	-328 to 1562	10	18	± 0.10	± 0.18	$\pm 0.02\%$ of span	
Pt100	JIS 1604, 1981 ($\alpha=0.003916$)	-200 to 645	-328 to 1193	10	18	± 0.10	± 0.18	$\pm 0.02\%$ of span	

Ambient Temperature Effect				
Sensor option	Sensor reference	Temp. Effect per 1.0°C (1.8°F) change in ambient temp	Range	D/A Effect
2-,3-,4-wire RTDs				
Pt100	IEC 751, 1995($\alpha=0.00385$)	0.0015°C	Entire Sensor input range	0.001% of span
Pt100	JIS 1604, 1981 ($\alpha=0.003916$)	0.0015°C	Entire Sensor input range	0.001% of span

Hydrogen Sulfide 0.5/a

Order No. 67 28 041

Application Range

Standard Measuring Range:	0.5 to 15 ppm
Number of Strokes n:	10
Time for Measurement:	approx. 6 min
Standard Deviation:	± 5 to 10 %
Color Change:	white → pale brown

Ambient Operating Conditions

Temperature:	0 to 40 °C
Absolute Humidity:	3 to 30 mg H ₂ O / L

Reaction Principle



Cross Sensitivity

No interference by:	100 ppm sulfur dioxide
	100 ppm hydrochloric acid
	100 ppm ethyl mercaptan



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Hydrogen Sulfide 5/b

Order No. CH 29 801

Application Range

Standard Measuring Range:	5 to 60 ppm
Number of Strokes n:	10
Time for Measurement:	approx. 4 min
Standard Deviation:	± 5 to 10 %
Color Change:	white → brown

Ambient Operating Conditions

Temperature:	0 to 60 °C
Absolute Humidity:	< 40 mg H ₂ O / L

Reaction Principle

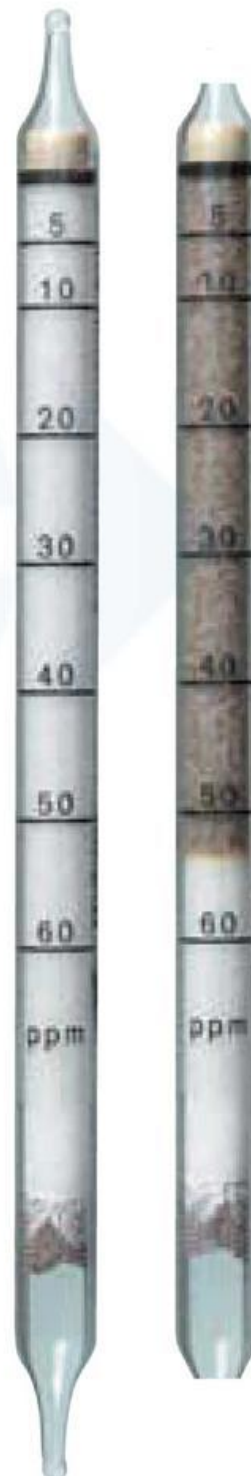


Cross Sensitivity

Sulfur dioxide can cause plus errors of up to 50%. Sulfur dioxide alone does not discolor the indicating layer.

Extension of the Measuring Range

Using n = 1, multiply the reading by 10; the measuring range will be 50 to 600 ppm.



ST-125-2001



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Carbon Dioxide 0.1%/a

Order No. CH 23 501

Application Range

Standard Measuring Range:	0.5 to 6 / 0.1 to 1.2 Vol.-%
Number of Strokes n:	1 / 5
Time for Measurement:	approx. 30 s / approx. 2.5 min
Standard Deviation:	± 5 to 10 %
Color Change:	white to pale violet → blue violet

Ambient Operating Conditions

Temperature:	0 to 30 °C
Absolute Humidity:	max. 30 mg H ₂ O /L

Reaction Principle

CO₂ + Amine → blue violet reaction product

Cross Sensitivity

Hydrogen sulfide and sulfur dioxide in the TLV range do not interfere.



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Carbon Dioxide 1%/a

Order No. CH 25 101

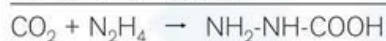
Application Range

Standard Measuring Range:	1 to 20 Vol.-%
Number of Strokes n:	1
Time for Measurement:	approx. 30 s
Standard Deviation:	± 5 to 10 %
Color Change:	white to pale violet → blue violet

Ambient Operating Conditions

Temperature:	0 to 40 °C
Absolute Humidity:	max. 40 mg H ₂ O / L

Reaction Principle



Cross Sensitivity

Hydrogen sulfide in the TLV range does not interfere. In a range comparable to the calibrated range for carbon dioxide, sulfur dioxide is indicated. The sulfur dioxide sensitivity is approximately $\frac{1}{3}$ (e.g. 6 Vol.% sulfur dioxide gives an indication of 2 Vol.%).



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Oil Densimeter – Specifications

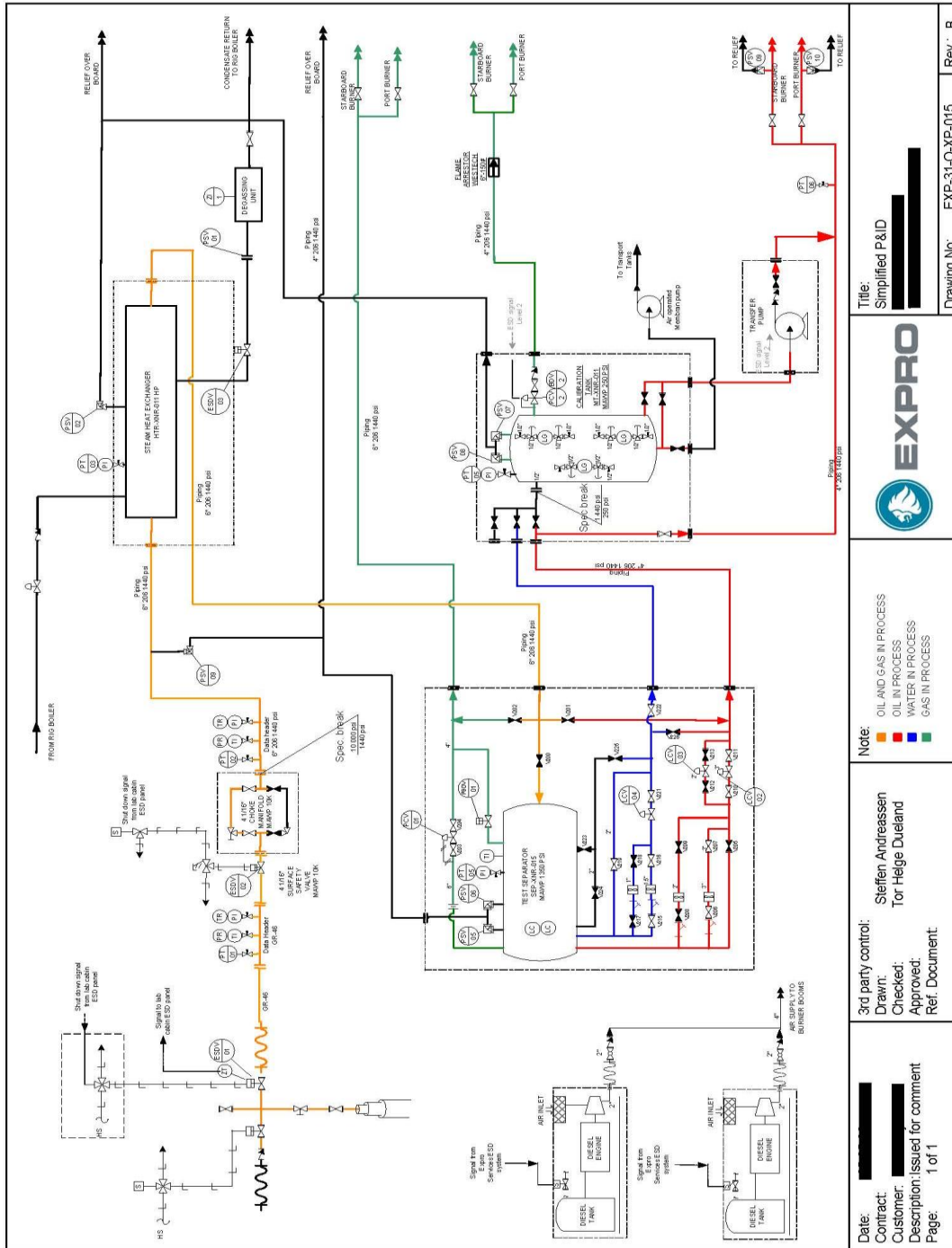
Technical specification – Anton Paar	
Measuring range	Density: 0 – 1.999 g/cm ³
	Temperature: 0 - 40°C (32 - 104°F)
Accuracy	Density: ±0.001 g/cm ³
	Temperature: ±0.2°C
Repeatability, s.d.	Density: 0.0005 g/cm ³
	Temperature: 0.1 °C
Resolution	Density: 0.0001 g/cm ³
	Temperature: 0.1°C or 0.1°F
Permanently stored tables and customer functions	°Brix, %alcohol, Proof, °Baume, °Plato, API Gravity, API SG, API density, SG at ref.temp., %H ₂ SO ₄ , programmable customer functions
Data memory	1024 measuring values
Power supply	Two 1.5V alkaline batteries (Micro LR03 AAA)
Sample volume	Approximately 2 mL
Dimensions	140 x 130 x 25mm (5.5 x 5.1 x 1 inches)
Weight	275 g (10 ounces)
Interface	Optional RS 232 interface with infrared data port

Ranarex Gravitometer – Specifications

Technical specifications – Portable model	
Accuracy	±0.5 % of actual value
Readings	Indicating only
Drive motor	115 VAC, 60 Hz or 230 VAC, 50 Hz
Sample flow rate	10 – 15 scf/hour
Sample pressure	20 psig maximum
Specific gravity range	Dual scale: 0.52 – 1.03 and 0.97 – 1.90
Ambient air reference dryer	Silica gel
Ship weight	50 lb (23 kg)
Case	Portable with carrying handle

Attachment V

Case 1 – Gas Well



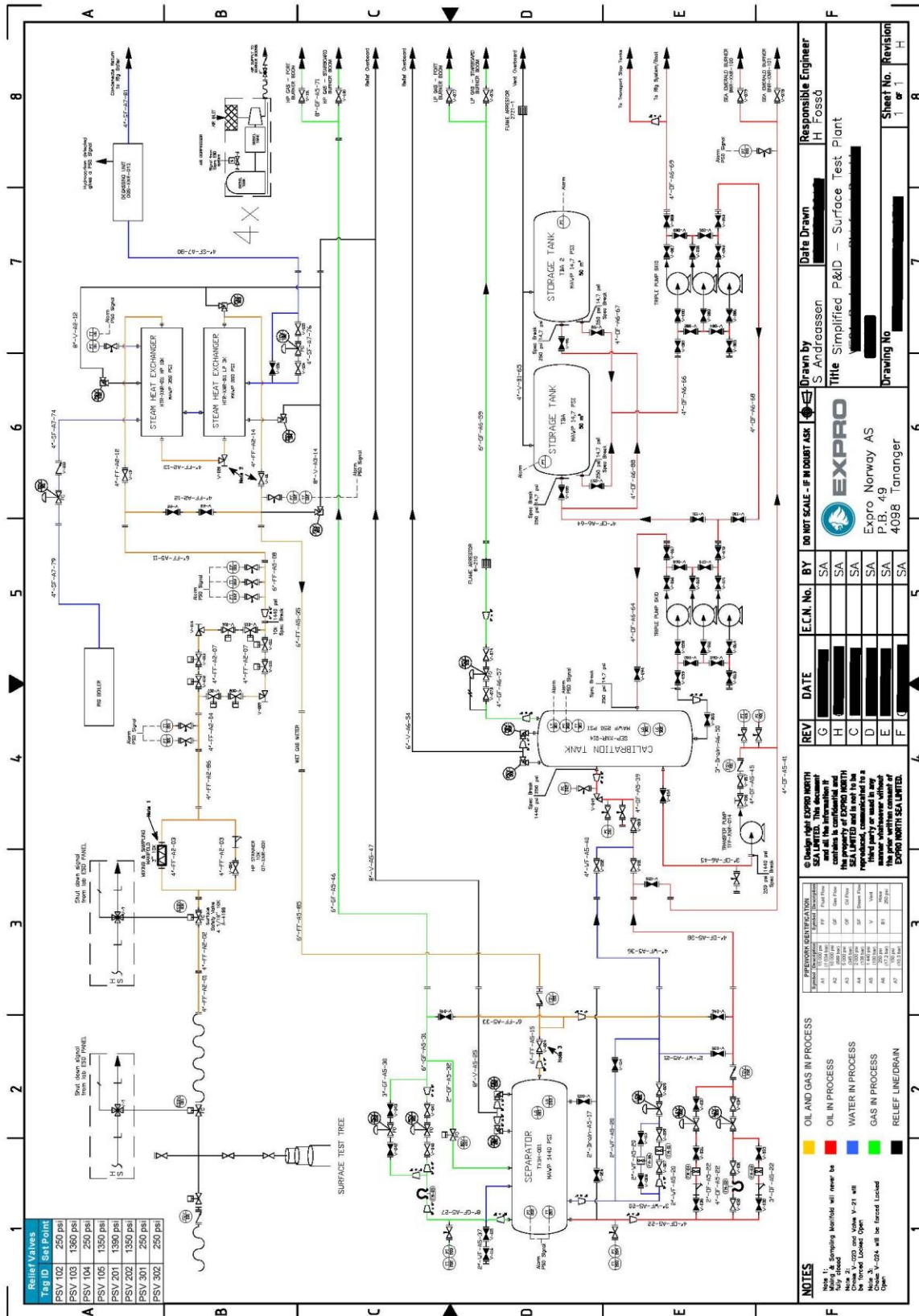
Drawing Legend					
PT	Pressure Transmitter		TCV	Temperature Controlled Valve	
PR	Pressure Recorder		LCV	Level Controlled Valve	
PI	Pressure Indicator		PCV	Pressure Controlled Valve	
TT	Temperature Transmitter		BDV	Blow Down Valve	
TR	Temperature Recorder		S	Signal	
TI	Temperature Indicator		LC	Level Controller	
ZI	Position Indicator		LG	Level Glass	
ZT	Position Transmitter				
ESDV	Emergency Shut Down Valve				
PSV	Pressure Safety Valve (relief valve)				

Date: Contract: Customer: Description: Page:	3rd party control: Drawn: Steffen Andreassen Checked: Approved: Ref. Document:	Note:		Title: Legend Page 2 of 3	Drawing No.	Rev.:
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Drawing Legend					
	Normally open Valve			Liquid Turbine Meter	
	Normally close valve			Y - Strainer	
	Hydraulic operated valve			Daniel Box	
	Needle valve			Pump	
	Fixed Choke			Rupture Disc	
	Adjustable Choke			Mixing Manifold	
	Relief Valve				
	Check Valve				
	Pressure Control Valve				

Date: Contract: Customer: Description: Page:	3rd party control: Drawn: Steffen Andreassen Checked: Approved: Ref. Document:	Note:		Title: Legend Page 3 of 3	Drawing No.	Rev.:
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Case 2 – Gas/condensate field



Case 3 – Combined Meter & Shrinkage factor



Client : ██████
 Field : ██████
 Well : ██████
 Date : ██████

COMBINED METER & SHRINKAGE FACTOR

DETAILS

Choke size	36	[64th] Meter Used	1.5" Oil
Separator Pressure	20	[Bar] Observed Oil Gravity	0,856
Separator Temperature	34,8	[°C] Oil Temp @ above gravity	48,2 °F
Start time	17:33	Hrs	Oil SG @ 60°F
Finish time	20:10	Hrs	0,850

METER READINGS

Initial Tank Reading	2,80	M3	Initial Meter Reading	3,1	M3
Initial Tank Temperature	13,4	[°C]	Final Meter Reading	8,2	M3
VCF	0,9719		Volume through meter	5,1	M3
Initial Volume @ Std Conditions	2,7	M3			
Time allowed for Shrinkage	157	mins			
Final Tank Reading	8,7	M3	Oil Line Temperature	34,7	[°C]
Final Tank Temperature	18,75	[°C]	VCF	0,9832	
VCF	0,9788		Vol. through meter @ Std Conditions	5,0	M3
Final Volume @ Std Conditions	8,5	M3			
Volume to tank @ Std Conditions	5,8	M3			

CMSF = Combined Meter & Shrinkage Factor
 SF = Shrinkage Factor
 MF = Meter Factor

SHRINKAGE FACTOR

Initial Shrinkage Reading	100	%	Final Shrinkage Reading	94	%
Initial Shrinkage Temperature	21	DegC	Final Shrinkage Temperature	13	DegC
VCF	1,0195		VCF	1,0235	
Initial Reading @ Std Conditions	102,0	%	Final Reading @ Std Conditions	96,2	%
SF =	$\frac{\text{Corrected Final Reading}}{\text{Corrected Initial Reading}}$	=	5,6%	or	0,9437

METER FACTOR

CMSF =	$\frac{\text{Corrected Tank Volume}}{\text{Corrected Meter Volume}}$	=	1,1555
MF =	$\frac{\text{CMSF}}{\text{SF}}$	=	$\frac{1,1555}{0,9437} = 1,2245$

Attachment VI

Mathcad calculations

Density correction & Volume correction factor - Expro excel sheet

Standard conditions: 1 atm and 15degC

Input values:

OilSG:= 1 uncorrected oil density, SG
 ODCTC:= 1 oil density cylinder temperature, degC
 LineTC:= 1 oil line temperature, degC

k0:= 341.096
 k1:= 0

Conversion:

OilAPI:= $\left(\frac{141.5}{\text{OilSG}}\right) - 131.5$ uncorrected oil density, API
 ODCTF:= $\left[\left(\frac{9}{5}\right)\text{ODCTC}\right] + 32$ oil density cylinder temperature, degF
 LineTF:= $\left[\left(\frac{9}{5}\right)\cdot\text{LineTC}\right] + 32$ oil line temperature, degF

Output values:

Corrected density

A1:= $\frac{141360.298}{\text{OilAPI} + 131.5}$
 A2:= $1 - [0.00001278(\text{ODCTF} - 59)] - [0.000000062(\text{ODCTF} - 59)^2]$
 A3:= A1·A2
 A4:= $\frac{341.0957}{A3^2}$
 A5:= A4 (ODCTF - 59)
 A6:= 0.8·A5
 A7:= A5·A6
 A8:= -(A5 + A7)
 A9:= ln(A8)
 A10 = IF(A9=0;10*10^10;A3/A9)
 OilAPIcorr:= $\left(\frac{141360.198}{A10}\right) - 131.5$

Red values due to no input parameter in this sheet. Formulas for illustration only.

Volume correction factor

$$B1 := \frac{141360.198}{\text{OilAPIcorr} + 131.5}$$

$$B2 := \frac{k0}{B1}$$

$$B3 := \frac{B2}{B1}$$

$$B4 := \frac{k1}{B1}$$

$$B5 := B3 + B4$$

$$B6 := B5 \cdot (\text{LineTF} - 60)$$

$$B7 := 0.8 \cdot [B5 \cdot (\text{LineTF} - 60)]$$

$$B8 := \frac{B7}{B6}$$

$$B9 := -B6 - B8$$

$$B10 := e^{B9}$$

Density correction & Volume correction factor - ASTM 1250-04 section 1.1.6.2

All input values shall be in metric unit, or conversion from customary to metric is necessary.

Limitation for calculating procedures:

- OilSGT shall be between -58.0 and 302.0 degF
- Pressure, P_o at which measurement was taken between 0 and 1500 psig
- If $P_o < 0$ psig, set $P_o = 0$ and continue procedure
- Density between min and max density

Commodity type specified - crude oil:

$D_{min} := 610.6$
 $D_{max} := 1163.5$
 $K_0 := 341.0957$
 $K_1 := 0$
 $K_2 := 0$

Input values:

OilSGT - temperature of OilSG measured - degF
OilSGP - pressure of OilSG measurement - psig
BaseT - base temperature - degF
OilSG - oil specific gravity

OilSGT := 1 Values for illustration only
OilSGP := 0
BaseT := 1
OilSG := 1

Conversion temperature from ITS-90 to IPTS-68

This correction is necessary because of the change in standard procedure to calibrate temperature measurement devices. The change in temperatures between the two scales is small.

Temperature:

$$\begin{aligned} TF90 &:= OiISGT && \text{temperature in degF} \\ TC90 &:= \frac{TF90 - 32}{1.8} && \text{temperature converted to degC} \\ \tau &:= \frac{TC90}{630} \end{aligned}$$

$$\begin{aligned} a1 &:= -0.148759 \\ a2 &:= -0.267408 \\ a3 &:= 1.080760 \\ a4 &:= 1.269056 \\ a5 &:= -4.089591 \\ a6 &:= -1.871251 \\ a7 &:= 7.438081 \\ a8 &:= -3.536296 \end{aligned}$$

$$\Delta t := [a1 + [a2 + [a3 + [a4 + [a5 + [a6 + (a7 + a8 \cdot \tau)]\tau]\tau]\tau]\tau]$$

$$\begin{aligned} TC68 &:= TC90 + \Delta t && \text{corrected temperature from ITS-90 to IPTS-68 in degC} \\ dotT &:= 1.8 \cdot TC68 + 32 && \text{corrected temperature from ITS-90 to IPTS-68 in degF} \end{aligned}$$

Density due to thermal glass expansion:

Hydrometer thermal glass expansion if base temperature is 60 degF:

$$HYC1 := 1.0 - [0.00001278(OiISGT - 60)] - [0.000000062(OiISGT - 60)^2]$$

Hydrometer thermal glass expansion if base temperature is 15 degC:

$$HYC2 := 1.0 - [0.000023(T - 15)] - [0.00000002(T - 15)^2]$$

Density corrected for glass thermal expansion:

$$DHYC := Dtp \cdot HYC1$$

EVERYTHING BELOW NEEDS TO BE CALCULATED FOR EACH ITERATION STEP**Conversion density from ITS-90 to IPTS-68**

$D60 := D_{tp}$ density at base conditions, kg/m³ at 60degF and 0 p

$$A := \left(\frac{D60}{2} \right) \cdot \left[\left[\left(\frac{K0}{D60} \right) + K1 \right] \cdot \left(\frac{1}{D60} \right) + K2 \right]$$

$$B := \frac{2K0 + K1 \cdot D60}{K0 + (K1 + K2 \cdot D60) \cdot D60}$$

$$\text{dotD} := D60 \cdot \left[1 + \frac{e^{[A \cdot (1+0.8 \cdot A)]} - 1}{1 + A \cdot (1 + 1.6A) \cdot B} \right] \quad \text{corrected density from ITS-90 to IPTS-68 in kg/m}^3$$

Volume correction factor due to temperature:

$$\alpha_{60} := \left(K1 + \frac{K0}{\text{dotD}} \right) \cdot \left(\frac{1}{\text{dotD}} \right) + K2$$

$$\Delta T := \text{dotT} - 60.00688749$$

$$C_{tl} := e^{[-\alpha_{60} \cdot \Delta T \cdot [1 + 0.8 \cdot \alpha_{60} \cdot (\Delta T + 0.01374979547)]]}$$

Volume correction factor due to pressure:

$$F_{pv} := e^{\left(-1.9947 + 0.00013427 \cdot \text{dotT} + \frac{793929 + 2326 \cdot \text{dotT}}{\text{dotD}} \right)}$$

$$C_{pl} := \frac{1}{1 - 10^{-5} \cdot F_{pv} \cdot \text{OilSGP}}$$

Combined temperature and pressure volume correction factor:

$$C_{tpl} := C_{tl} \cdot C_{pl}$$

Iterate the following steps until difference <0.000001:

$$D0 := \text{DHYC}$$

$$D1 := \text{DHYC} \cdot C_{tpl}$$

$$\Delta D1 := D0 - D1$$

Volume correction factor - Expro manual calculation sheet - ASTM 1250-80

Input values:

shrT - final shrinkage temperature - degF
 OilSGT - temperature of OilSG measured - degF
 BaseT - base temperature - degF
 BaseP - base pressure - psig
 OilSG - oil specific gravity

shrT := 1
 OilSGT := 1
 BaseT := 1
 BaseP := 1
 OilSG := 1

Correct input values to SI units:

$$T_{obs} := \frac{(shrT - 32)}{1.8}$$

$$T_{\omega} := \frac{(OilSGT - 32)}{1.8}$$

$$T_{base} := \frac{(BaseT - 32)}{1.8}$$

$$P_{base} := \frac{(BaseP - 14.73)}{14.5038}$$

$$D_{tp} := OilSG \cdot 999.012$$

Calculation of volum correction factor:

$$B := e^{-\left[1.38315 + (T - 0.00343804) - \left[3.02909 + (T - 0.0161654) \cdot \ln\left(\frac{D_{tp}}{1000}\right)\right]\right]}$$

Compressibility factor

$$C_{pl} := \frac{1}{1 - (P_{base} \cdot B \cdot 10^{-5})}$$

Correction for pressure on liquid

$$D_{to} := \frac{D_{tp}}{C_{pl}}$$

Density corrected for pressure

$$\delta := T - T_{base}$$

Difference in temp from base temp

$$HYC := 1 - (0.000023 \cdot \delta) - (0.00000002 \cdot \delta^2)$$

Hydrometer correction

$$derivD_{to} := D_{to} \cdot HYC$$

Density at atm pressure - still at temp.

$$D_{15} := derivD_{to}$$

Initialising base temp density

Iterate the following steps until difference < 0.05:

$$\alpha := \frac{613.9723}{D15^2}$$

Coefficient of thermal expansion

$$VCF := e^{[(\alpha \cdot \text{delta}) - (0.8 \cdot \alpha \cdot \alpha \cdot \text{delta} \cdot \text{delta})]}$$

Volume correction fact

$$\text{derivD15} := \frac{\text{derivDto}}{VCF}$$

Density at standard temp & pressure

$$\text{Difference} := \text{derivD15} - D15$$

Convergence check

$$\text{newD15} := \text{derivD15}$$

Gas flow rate calculations

This calculation is based upon Expro manually calculation procedure. The procedure is based on AGA 3. standard

Fb - Basic orifice factor

Input values:

line bore size - D

$$D := 1$$

orifice size - d

$$d := 0.5$$

$$\beta := \frac{d}{D}$$

Flange taps:

$$\begin{aligned} Ke1 := & 0.5993 + \left(\frac{0.007}{D}\right) + \left[0.364 + \left(\frac{0.076}{D^{0.5}}\right)\right] \cdot \beta^4 + 0.4 \left[1.6 - \left(\frac{1}{D}\right)\right]^5 \cdot \left[0.07 + \left(\frac{0.5}{D}\right) - \beta\right]^{2.5} \dots \\ & + \left[0.009 + \left(\frac{0.034}{D}\right)\right] \cdot (0.5 - \beta)^{1.5} + \left[\left(\frac{65}{D^2}\right) + 3\right] \cdot (\beta - 0.7)^{2.5} \\ B1 := & \frac{530}{D^{0.5}} \end{aligned}$$

Pipe taps:

$$\begin{aligned} Ke2 := & 0.5925 + \left(\frac{0.0182}{D}\right) + \left[0.44 - \left(\frac{0.06}{D}\right)\right] \cdot \beta^2 + \left[0.935 + \left(\frac{0.225}{D}\right)\right] \cdot \beta^5 + 1.35 \cdot \beta^{14} \dots \\ & + \left(\frac{1.43}{D^{0.5}}\right) \cdot (0.25 - \beta)^{2.5} \\ B2 := & \left(\frac{875}{D}\right) + 75 \end{aligned}$$

Some values for β might give negative terms in the Ke equation. In such cases should the value be treated as zero and where these terms are a factor of another term, the whole product is to be treated as zero.

Will use the terms for flange taps for further calculations

Output values:

$$E := d \cdot (830 - 5000 \cdot \beta + 9000 \cdot \beta^2 - 4200 \cdot \beta^3 + B1)$$

$$Ko := \frac{Ke1}{1 + \frac{15 \cdot E}{1000000 \cdot d}}$$

$$F_b := 338.178 \cdot d^2 \cdot K_o$$

Fr - reynolds number factor

Input values:

$$h_w := 1$$

$$P_f := 1$$

Output values:

$$K_w := K_o + \frac{\sqrt{K_o^2 - 4 \cdot \left(\frac{-E \cdot K_o}{12835 \cdot d \cdot \sqrt{h_w \cdot P_f}} \right)}}{2}$$

$$K_w := K_o + \frac{\sqrt{K_o^2 - 4 \cdot \left(\frac{-E \cdot K_o}{12835 \cdot d \cdot \sqrt{h_w \cdot P_f}} \right)}}{2}$$

Solving for K above will give two solutions, the positive solutions should be chosen.

$$F_r := 1 + \frac{E}{12835 \cdot d \cdot K_w \cdot \sqrt{h_w \cdot P_f}}$$

Y - Expansion factor

Flange taps:

Absolute static pressure taken at the upstream tap

$$k := 1.3$$

$$P_{f1} := 1$$

$$x_{f1} := \frac{h_w}{27.707 \cdot P_{f1}}$$

$$Y_{f1} := 1 - \left(0.41 + 0.35 \cdot \beta^4 \right) \cdot \left(\frac{x_{f1}}{k} \right)$$

Absolute static pressure taken at the downstream tap

$$P_{f2} := 1$$

$$x_{f2} := \frac{h_w}{27.707 \cdot P_{f2}}$$

$$Y_{f2} := \sqrt{(1 + x_{f2}) - \left(0.41 + 0.35 \cdot \beta^4 \right) \cdot \left[\frac{x_{f2}}{k \cdot \sqrt{(1 + x_{f2})}} \right]}$$

Pipe taps:

Absolute static pressure taken at the upstream tap

$$xp1 := \frac{hw}{27.707 \cdot Pf1}$$

$$Yp1 := 1 - \left[0.333 + 1.145 \cdot (\beta^2 + 0.7 \cdot \beta^5 + 12 \cdot \beta^{13}) \right] \cdot \left(\frac{xp1}{k} \right)$$

Absolute static pressure taken at the downstream tap

$$xp2 := \frac{hw}{27.707 \cdot Pf2}$$

$$Yp2 := \sqrt{(1 + xp2) - \left[0.333 + 1.145 \cdot (\beta^2 + 0.7 \cdot \beta^5 + 12 \cdot \beta^{12}) \right] \cdot \left[\frac{xp2}{k \cdot \sqrt{(1 + xp2)}} \right]}$$

Fpb - Pressure base factor

$$Pb := 1$$

$$Fpb := \frac{14.73}{Pb}$$

Ftb - Temperature base factor

$$Tb := 1$$

$$Ftb := \frac{Tb + 459.67}{519.67}$$

Ftf - Flowing temperature factor

$$Tf := 1$$

$$Ftf := \left(\frac{519.67}{Tf + 459.67} \right)^{0.5}$$

Fgr - specific gravity factor

$$GasSG := 1$$

$$Fgr := \left(\frac{1}{GasSG} \right)^{0.5}$$

F_{pv} - super compressibility factor

Input values:

$$\text{GasSG} := 1$$

$$\text{N}_2 := 1$$

$$\text{CO}_2 := 1$$

$$\text{H}_2\text{S} := 1$$

Output values:

$$y_{\text{N}_2} := \frac{\text{N}_2}{100}$$

$$y_{\text{CO}_2} := \frac{\text{CO}_2}{100}$$

$$y_{\text{H}_2\text{S}} := \frac{\text{H}_2\text{S}}{1000000}$$

$$G_1 := \frac{\text{GasSG} - 0.9672 \cdot y_{\text{N}_2} - 1.5195 \cdot y_{\text{CO}_2} - 1.1765 \cdot y_{\text{H}_2\text{S}}}{1 - y_{\text{N}_2} - y_{\text{CO}_2} - y_{\text{H}_2\text{S}}}$$

$$T_{c1} := 168 + 325G_1 - 12.5G_1^2$$

$$P_{c1} := 677 + 15G_1 - 37.5G_1^2$$

$$T_c := (1 - y_{\text{N}_2} - y_{\text{CO}_2} - y_{\text{H}_2\text{S}}) \cdot T_{c1} + 227.3y_{\text{N}_2} + 547.6y_{\text{CO}_2} + 672.4y_{\text{H}_2\text{S}}$$

$$P_c := (1 - y_{\text{N}_2} - y_{\text{CO}_2} - y_{\text{H}_2\text{S}}) \cdot P_{c1} + 493y_{\text{N}_2} + 1071y_{\text{CO}_2} + 1306y_{\text{H}_2\text{S}}$$

$$\text{CWA} := 120 \left[(y_{\text{CO}_2} + y_{\text{H}_2\text{S}})^{0.9} - (y_{\text{CO}_2} + y_{\text{H}_2\text{S}})^{1.6} \right] + 15 (y_{\text{H}_2\text{S}}^{0.5} - y_{\text{H}_2\text{S}}^4)$$

$$T_{c2} := T_c - \text{CWA}$$

$$P_{c2} := \frac{P_c \cdot (T_c - \text{CWA})}{T_c + y_{\text{H}_2\text{S}} \cdot (1 - y_{\text{H}_2\text{S}}) \cdot \text{CWA}}$$

$$p_{\text{Pr}} := \frac{P_f}{P_{c2}}$$

$$p_{\text{Tr}} := \frac{T_f}{T_{c2}}$$

Pseudocritical density - dr

$$A := 0.0642$$

$$B := 0.5353 \cdot p_{\text{Tr}} - 0.6123$$

$$C := 0.3151 \cdot p_{\text{Tr}} - 1.0467 - \frac{0.5783}{p_{\text{Tr}}^2}$$

$$D := p_{\text{Tr}}$$

$$E := \frac{0.6816}{p_{\text{Tr}}^2}$$

$$F := 0.6845$$

$$\overline{G} := 0.27 \cdot pPr$$

$$dr0 := \frac{0.27 \cdot pPr}{pTr}$$

Iteration to find pseudocritical density:

$$fdr0 := A \cdot dr0^6 + B \cdot dr0^3 + C \cdot dr0^2 + D \cdot dr0 + E \cdot dr0^3 (1 + F \cdot dr0^2) \left[e^{(-F \cdot dr0^2)} - G \right]$$

$$dotfdr0 := 6 \cdot A \cdot dr0^5 + 3 \cdot B \cdot dr0^2 + 2 \cdot C \cdot dr0 + D + E \cdot dr0^2 \cdot [3 + F \cdot dr0^2 (3 - 2 \cdot F \cdot dr0^2)] \cdot e^{(-F \cdot dr0^2)}$$

$$dr1 := dr0 - \frac{fdr0}{dotfdr0}$$

Continue with dr2, dr3, dr4

$$Z := \frac{0.27 \cdot pPr}{dr \cdot pTr}$$

$$Fpv := \frac{1}{Z^{0.5}}$$

Gas flow rate:

$$Q_g := Fb \cdot Fr \cdot Y \cdot Fpb \cdot Ftb \cdot Fft \cdot Fgr \cdot Fpv \cdot \sqrt{hw \cdot Pf}$$

Gas flow rate calculations - Case 1

All data inserted in the equations shall be given in customary units

Fb - Basic orifice factor

Input values:

$$D := 5.761 \quad \text{line bore size ID in inches}$$

$$d := 4.5 \quad \text{orifice size ID in inches}$$

$$\beta := \frac{d}{D} = 0.781$$

Flange taps:

$$\begin{aligned} K_{e1} := & 0.5993 + \left(\frac{0.007}{D}\right) + \left[0.364 + \left(\frac{0.076}{D^{0.5}}\right)\right] \cdot \beta^4 + 0.4 \left[1.6 - \left(\frac{1}{D}\right)\right]^5 \cdot \left[0.07 + \left(\frac{0.5}{D}\right) - \beta\right]^{2.5} \dots \\ & + \left[0.009 + \left(\frac{0.034}{D}\right)\right] \cdot (0.5 - \beta)^{1.5} + \left[\left(\frac{65}{D^2}\right) + 3\right] \cdot (\beta - 0.7)^{2.5} = 0.757 + 0.73i \end{aligned}$$

$$B1 := \frac{530}{D^{0.5}} = 220.814$$

Some values for β might give negative terms in the K_e equation. In such cases should the values be treated as zero and where these terms are a factor of another term, the whole product is to be treated as zero.

Will use the terms for flange taps for further calculations.

Output values:

$$E := d \cdot (830 - 5000 \cdot \beta + 9000 \cdot \beta^2 - 4200 \cdot \beta^3 + B1) = 2.857 \times 10^3$$

$$K_o := \frac{K_{e1}}{1 + \frac{15 \cdot E}{1000000d}} = 0.75 + 0.723i$$

$$F_b := 338.178d^2 \cdot K_o = 5.136 \times 10^3 + 4.95i \times 10^3$$

Fr - reynolds number factor

Input values:

$$h_w := 259.1 \quad \text{inches water gauge}$$

$$P_f := 221.1 \quad \text{flowing gas pressure at orifice meter (static pressure) in psia}$$

Output values:

$$K_{f1} := \frac{K_o + \sqrt{K_o^2 - 4 \left(\frac{-E \cdot K_o}{12835d \cdot \sqrt{h_w \cdot P_f}} \right)}}{2} = 0.75 + 0.723i$$

$$K_2 := \frac{K_o - \sqrt{K_o^2 - 4 \cdot \left(\frac{-E \cdot K_o}{12835 \cdot d \cdot \sqrt{hw \cdot Pf}} \right)}}{2} = -2.066 \times 10^{-4} - 2.843i \times 10^{-8}$$

Solving for K above will give two solutions, the positive solutions should be chosen.

$$Fr := 1 + \frac{E}{12835 \cdot d \cdot K_1 \cdot \sqrt{hw \cdot Pf}} = 1 - 1.376i \times 10^{-4}$$

Y - Expansion factor

$$k := 1.3 \quad \text{isentropic exponent}$$

Flange taps:

Absolute static pressure taken at the upstream tap

$$xf1 := \frac{hw}{27.707 \cdot Pf} = 0.042$$

$$Yf1 := 1 - \left(0.41 + 0.35 \cdot \beta^4 \right) \cdot \left(\frac{xf1}{k} \right) = 0.982$$

Absolute static pressure taken at the downstream tap

$$xf2 := \frac{hw}{27.707 \cdot Pf} = 0.042$$

$$Yf2 := \sqrt{(1 + xf2) - \left(0.41 + 0.35 \cdot \beta^4 \right) \cdot \left[\frac{xf2}{k \cdot \sqrt{(1 + xf2)}} \right]} = 1.012$$

There is no information given on whether the static pressure was installed upstream or downstream orifice meter. I calculated for both and found that the value for abs. static pressure taken downstream tap was the one closest to the value calculated by the software. Yf2 is the value that is used in the final gas equation.

Fpb - Pressure base factor

$$P_b := 14.699 \quad \text{base pressure, psia}$$

$$F_{pb} := \frac{14.73}{P_b} = 1.002$$

Ftb - Temperature base factor

$$T_b := 59 \quad \text{base temperature, degF}$$

$$F_{tb} := \frac{T_b + 459.67}{519.67} = 0.998$$

Ftf - Flowing temperature factor

$$T_f := 85.76 \quad \text{temperature at orificemeter, degF}$$

$$F_{tf} := \left(\frac{519.67}{T_f + 459.67} \right)^{0.5} = 0.976$$

F_{gr} - specific gravity factor

GasSG := 0.564 gas specific gravity measured by Ranarex

$$F_{gr} := \left(\frac{1}{\text{GasSG}} \right)^{0.5} = 1.332$$

F_{pv} - super compressibility factor

See separate mathcad file

$$F_{pv} := 1.058$$

Gas flow rate

$$Q_g := F_b \cdot F_r \cdot Y_f \cdot F_{pb} \cdot F_{tb} \cdot F_{tf} \cdot F_{gr} \cdot F_{pv} \cdot \sqrt{h_w \cdot P_f} = 1.712 \times 10^6 + 1.65i \times 10^6$$

Gas rate incl. Orifice thermal expansion factor

$$F_a := 1 + 0.0000333 \cdot (T_f - T_b) = 1.001$$

$$Q_{ga} := F_a \cdot Q_g = 1.714 \times 10^6 + 1.651i \times 10^6$$

Super compressibility factor - Case 1

Fpv - super compressibility factor

Input values:

GasSG := 0.564	gas density in SG
Pf := 206.3887	flowing gas pressure at the orifice meter in psi(psia-atm)
Tf := 85.46	flowing gas temperature at the orifice meter in degF
BaseP := 14.53	standard pressure in psi
N2 := 0	
CO2 := 0	
H2S := 0	

Output values:

$$y_{N2} := \frac{N2}{100} = 0$$

$$y_{CO2} := \frac{CO2}{100} = 0$$

$$y_{H2S} := \frac{H2S}{1000000} = 0$$

$$G1 := \frac{GasSG - 0.9672y_{N2} - 1.5195y_{CO2} - 1.1765y_{H2S}}{1 - y_{N2} - y_{CO2} - y_{H2S}} = 0.564$$

$$Tc1 := 168 + 325G1 - 12.5G1^2 = 347.324$$

$$Pc1 := 677 + 15G1 - 37.5G1^2 = 673.531$$

$$Tc := (1 - y_{N2} - y_{CO2} - y_{H2S}) \cdot Tc1 + 227.3y_{N2} + 547.6y_{CO2} + 672.4y_{H2S} = 347.324$$

$$Pc := (1 - y_{N2} - y_{CO2} - y_{H2S}) \cdot Pc1 + 493y_{N2} + 1071y_{CO2} + 1306y_{H2S} = 673.531$$

$$CWA := 120 \left[(y_{CO2} + y_{H2S})^{0.9} - (y_{CO2} + y_{H2S})^{1.6} \right] + 15(y_{H2S}^{0.5} - y_{H2S}^4) = 0$$

$$Tc2 := Tc - CWA = 347.324$$

$$Pc2 := \frac{Pc \cdot (Tc - CWA)}{Tc + y_{H2S} \cdot (1 - y_{H2S}) \cdot CWA} = 673.531$$

$$pPr := \frac{Pf + BaseP}{Pc2} = 0.328$$

$$pTr := \frac{Tf + 460}{Tc2} = 1.57$$

Pseudocritical density - dr

$$\underline{A} := 0.0642$$

$$B := 0.5353 \cdot pTr - 0.6123 = 0.228$$

$$\underline{C} := 0.3151 \cdot pTr - 1.0467 - \frac{0.5783}{pTr^2} = -0.786$$

$$D := pTr = 1.57$$

$$E := \frac{0.6816}{pTr^2} = 0.276$$

$$\underline{F} := 0.6845$$

$$\underline{G} := 0.27 \cdot pPr = 0.089$$

Iteration to find pseudocritical density:**Step 0:**

$$dr0 := \frac{GasSG}{pTr} = 0.359$$

$$fdr0 := A \cdot dr0^6 + B \cdot dr0^3 + C \cdot dr0^2 + D \cdot dr0 + E \cdot dr0^3 (1 + F \cdot dr0^2) \left[e^{(-F \cdot dr0^2)} \right] - G = 0.397$$

$$dfdr0 := 6 \cdot A \cdot dr0^5 + 3 \cdot B \cdot dr0^2 + 2 \cdot C \cdot dr0 + D + E \cdot dr0^2 \cdot [3 + F \cdot dr0^2 (3 - 2 \cdot F \cdot dr0^2)] \cdot e^{(-F \cdot dr0^2)} = 1.202$$

$$dr1 := dr0 - \left(\frac{fdr0}{dfdr0} \right) = 0.029$$

$$\delta dr0 := \frac{dr1}{dr0} = 0.0795$$

Step 1:

$$dr1 = 0.029$$

$$fdr1 := A \cdot dr1^6 + B \cdot dr1^3 + C \cdot dr1^2 + D \cdot dr1 + E \cdot dr1^3 (1 + F \cdot dr1^2) \left[e^{(-F \cdot dr1^2)} \right] - G = -0.044$$

$$dfdr1 := 6 \cdot A \cdot dr1^5 + 3 \cdot B \cdot dr1^2 + 2 \cdot C \cdot dr1 + D + E \cdot dr1^2 \cdot [3 + F \cdot dr1^2 (3 - 2 \cdot F \cdot dr1^2)] \cdot e^{(-F \cdot dr1^2)} = 1.527$$

$$dr2 := dr1 - \left(\frac{fdr1}{dfdr1} \right) = 0.058$$

$$\delta dr1 := \frac{dr2}{dr0} = 0.1604$$

Step 2:

$$dr2 = 0.058$$

$$fdr2 := A \cdot dr2^6 + B \cdot dr2^3 + C \cdot dr2^2 + D \cdot dr2 + E \cdot dr2^3(1 + F \cdot dr2^2) \left[e^{(-F \cdot dr2^2)} \right] - G = -6.152 \times 10^{-4}$$

$$dfdr2 := 6 \cdot A \cdot dr2^5 + 3 \cdot B \cdot dr2^2 + 2 \cdot C \cdot dr2 + D + E \cdot dr2^2 \cdot [3 + F \cdot dr2^2(3 - 2 \cdot F \cdot dr2^2)] \cdot e^{(-F \cdot dr2^2)} = 1.485$$

$$dr3 := dr2 - \left(\frac{fdr2}{dfdr2} \right) = 0.058$$

$$\delta dr2 := \frac{dr3}{dr0} = 0.1615$$

Step 3:

$$dr3 = 0.058$$

$$fdr3 := A \cdot dr3^6 + B \cdot dr3^3 + C \cdot dr3^2 + D \cdot dr3 + E \cdot dr3^3(1 + F \cdot dr3^2) \left[e^{(-F \cdot dr3^2)} \right] - G = -1.2 \times 10^{-7}$$

$$dfdr3 := 6 \cdot A \cdot dr3^5 + 3 \cdot B \cdot dr3^2 + 2 \cdot C \cdot dr3 + D + E \cdot dr3^2 \cdot [3 + F \cdot dr3^2(3 - 2 \cdot F \cdot dr3^2)] \cdot e^{(-F \cdot dr3^2)} = 1.484$$

$$dr4 := dr3 - \frac{fdr3}{dfdr3} = 0.058$$

$$\delta dr3 := \frac{dr4}{dr0} = 0.1615 \quad \text{ACCEPTABLE VALUE}$$

Final pseudocritical density value:

$$newdr := dr3 = 0.058$$

$$Z := \frac{0.27 \cdot pPr}{newdr \cdot pTr} = 0.972$$

$$Fpv := \frac{1}{Z^2} = 1.058$$

Case1 - Gas flow rate - GPSA

All input data shall be in metric units

Input values:

$$\text{GasP} := 1423 \text{ kPa}$$

$$\text{GasT} := 29.7 \text{ degC}$$

$$\text{GasSG} := 0.564$$

$$\text{hw} := 259.1 \text{ "water}$$

$$\text{GasPf} := 221.1 \text{ psia}$$

$$\text{PipeID} := 5.761 \text{ "}$$

$$\text{Orifice} := 4.5 \text{ "}$$

$$\text{BaseP} := 100 \text{ kPa}$$

$$\text{BaseT} := 15 \text{ degC}$$

Conversion to metric unit:

$$\text{Pf} := \left(\frac{\text{GasPf}}{14.53} \right) \cdot 10^2 = 1.522 \times 10^3 \text{ kPa}$$

Intermediate calculations:

$$\text{Fpb} := \frac{101.325}{\text{BaseP}} = 1.0132$$

$$\text{Ftb} := \frac{273 + \text{BaseT}}{288} = 1$$

$$\text{Ftf} := \sqrt{\frac{288}{273 + \text{GasT}}} = 0.9754$$

$$\text{Fg} := \sqrt{\frac{1}{\text{GasSG}}} = 1.332$$

$$\text{Fa} := 1 + [0.0000333(\text{GasT} - \text{BaseT})] = 1.0005$$

$$\beta := \frac{\text{Orifice}}{\text{PipeID}} = 0.781 \quad \text{highest beta value in table is 0.62.}$$

$$\text{hwmm} := \text{hw} \cdot 25.4 = 6.581 \times 10^3$$

$$\text{ratio} := \frac{\text{hwmm}}{\text{Pf}} = 4.325$$

Table values:

$$\text{Fb} := 10.488$$

$$\text{MWGas} := 0.564 \cdot 28.966 = 16.337$$

$$\text{Z} := 0.84$$

$$\text{Fpv} := \frac{1}{\text{Z}^2} = 1.417$$

$$\text{Fr} := 1$$

$$\text{Y} := 1.0066$$

Gas flow rate:

$$Q_g := \sqrt{h_{wmm} \cdot P_f \cdot F_b \cdot F_{pb} \cdot F_{fb} \cdot F_{tf} \cdot F_g \cdot F_{pv} \cdot F_r \cdot Y \cdot F_a} = 6.234 \times 10^4 \text{ m}^3/\text{h}$$

$$Q_{g\text{days}} := Q_g \cdot 24 = 1.496 \times 10^6$$

Case3 - Density iteration - ASTM 1205-04 (API 11.1)

Limitation of standard:

$$-58.0 \text{ degF} \leq T_0 \leq 302.0 \text{ degF}$$

$$0 \leq P_0 \leq 1500 \text{ psig}$$

$$\rho_{\min} \leq \rho_0 \leq \rho_{\max}$$

Commodity group: Crude oil

$$\rho_{\min} = 470.5 \text{ kg/m}^3$$

$$\rho_{\max} = 1201.8 \text{ kg/m}^3$$

$$K_0 := 341.0957$$

$$K_1 := 0$$

$$K_2 := 0$$

$$D_{\alpha} := 2.0$$

Input data:

$$TC := 8.6 \quad \text{temperature of OilSG measured in degC}$$

$$\text{OilSGP} := 14.5037 \quad \text{pressure of OilSG measured in psig}$$

$$\text{BaseT} := 15 \quad \text{standard temperature in degC}$$

$$\text{OilSG} := 0.852 \quad \text{specific gravity of oil}$$

Conversion temperature from ITS-90 to IPTS-68 (API 11.1.5.3):

$$\tau := \frac{TC}{630} = 0.014$$

$$a_1 := -0.148759$$

$$a_2 := -0.267408$$

$$a_3 := 1.080760$$

$$a_4 := 1.269056$$

$$a_5 := -4.089591$$

$$a_6 := -1.871251$$

$$a_7 := 7.438081$$

$$a_8 := -3.536296$$

$$\Delta t := [a_1 + [a_2 + [a_3 + [a_4 + [a_5 + [a_6 + (a_7 + a_8 \cdot \tau) \tau] \tau] \tau] \tau] \tau] \tau = -2.078 \times 10^{-3}$$

$$TC_{68} := TC + \Delta t = 8.598 \quad \text{converted measured temperature in degC}$$

$$dT := 1.8 \cdot TC_{68} + 32 = 47.476 \quad \text{converted measured temperature in degF}$$

Conversion from specific gravity to kg/m3:

$$D_{\text{meas}} := \text{OilSG} \cdot 999.012 = 851.158$$

Density corrected for hydrometer thermal glass expansion:

$$\text{HYC} := 1.0 - [0.000023(8.6 - 15)] - [0.00000002(8.6 - 15)^2] = 1$$

$$D := D_{\text{meas}} \cdot \text{HYC} = 851.283$$

Iteration process

Step 0:

$$D0 := D = 851.283$$

$$A0 := \left(\frac{0.01374979547}{2} \right) \cdot \left[\left(\frac{K0}{D0} \right) + K1 \right] \cdot \left(\frac{1}{D0} \right) + K2 = 3.236 \times 10^{-6}$$

$$B0 := \frac{2K0 + K1 \cdot D0}{K0 + (K1 + K2 \cdot D0) \cdot D0} = 2$$

$$dD0 := D0 \cdot \left[1 + \frac{e^{[A0 \cdot (1+0.8 \cdot A0)]} - 1}{1 + A0 \cdot (1 + 1.6A0) \cdot B0} \right] = 851.286 \quad \text{converted density to ITPS-68}$$

$$\alpha0 := \left(K1 + \frac{K0}{dD0} \right) \cdot \left(\frac{1}{dD0} \right) + K2 = 4.707 \times 10^{-4} \quad \text{thermal expansion factor}$$

$$\Delta T0 := dT - 60.00688749 = -12.531 \quad \text{will be constant for all iterations}$$

$$Ct0 := e^{[-\alpha0 \cdot \Delta T0 \cdot (1+0.8 \cdot \alpha0 \cdot (\Delta T0+0.01374979547))]} = 1.006$$

$$Fpv0 := e^{\left(-1.9947+0.00013427 \cdot dT + \frac{793929+2326 \cdot dT}{dD0^2} \right)} = 0.477$$

$$Cpl0 := \frac{1}{1 - 10^{-5} \cdot Fpv0 \cdot OilSGP} = 1$$

$$Ctp0 := Ct0 \cdot Cpl0 = 1.006$$

$$\delta D0 := D - dD0 \cdot Ctp0 = -5.074$$

$$Dp0 := - \left[\frac{2 \cdot Cpl0 \cdot OilSGP \cdot Fpv0 \cdot (7.93920 + 0.02326 \cdot dT)}{dD0^2} \right] = -1.727 \times 10^{-4}$$

$$Dt0 := D \cdot \alpha0 \cdot \Delta T0 \cdot (1 + 1.6 \cdot \alpha0 \cdot \Delta T0) = -0.012$$

$$E0 := \left(\frac{D}{Ctp0} \right) - dD0 = -5.044$$

$$\Delta D0 := \frac{E0}{1 + Dt0 + Dp0} = -5.104$$

$$D1 := D0 + \Delta D0 = 846.179$$

Step 1:

$$D1 = 846.179$$

$$A1 := \left(\frac{0.01374979547}{2} \right) \cdot \left[\left[\left(\frac{K0}{D1} \right) + K1 \right] \cdot \left(\frac{1}{D1} \right) + K2 \right] = 3.275 \times 10^{-6}$$

$$B1 := \frac{2K0 + K1 \cdot D1}{K0 + (K1 + K2 \cdot D1) \cdot D1} = 2$$

$$dD1 := D1 \cdot \left[1 + \frac{e^{[A1 \cdot (1+0.8 \cdot A1)]} - 1}{1 + A1 \cdot (1 + 1.6A1) \cdot B1} \right] = 846.181$$

$$\alpha1 := \left(K1 + \frac{K0}{dD1} \right) \cdot \left(\frac{1}{dD1} \right) + K2 = 4.764 \times 10^{-4}$$

$$\Delta T1 := dT - 60.00688749 = -12.531$$

$$Ct11 := e^{[-\alpha1 \cdot \Delta T1 \cdot [1+0.8 \cdot \alpha1 \cdot (\Delta T1+0.01374979547)]]} = 1.006$$

$$Fpv1 := e^{\left(-1.9947+0.00013427 \cdot dT + \frac{793929+2326 \cdot dT}{dD1^2} \right)} = 0.484$$

$$Cp11 := \frac{1}{1 - 10^{-5} \cdot Fpv1 \cdot OilSGP} = 1$$

$$Ctp11 := Ct11 \cdot Cp11 = 1.006$$

$$\delta D1 := D - dD1 \cdot Ctp11 = -2.063 \times 10^{-4}$$

$$Dp1 := - \left[\frac{2 \cdot Cp11 \cdot OilSGP \cdot Fpv1 \cdot (7.93920 + 0.02326 \cdot dT)}{dD1^2} \right] = -1.774 \times 10^{-4}$$

$$Dt1 := D \alpha \alpha1 \cdot \Delta T1 \cdot (1 + 1.6 \alpha1 \cdot \Delta T1) = -0.012$$

$$E1 := \left(\frac{D}{Ctp11} \right) - dD1 = -2.05 \times 10^{-4}$$

$$\Delta D1 := \frac{E1}{1 + Dt1 + Dp1} = -2.075 \times 10^{-4}$$

$$D2 := D1 + \Delta D1 = 846.178$$

Step 2:

$$D2 = 846.178$$

$$A2 := \left(\frac{0.01374979547}{2} \right) \cdot \left[\left[\left(\frac{K0}{D2} \right) + K1 \right] \cdot \left(\frac{1}{D2} \right) + K2 \right] = 3.275 \times 10^{-6}$$

$$B2 := \frac{2K0 + K1 \cdot D2}{K0 + (K1 + K2 \cdot D2) \cdot D2} = 2$$

$$dD2 := D2 \cdot \left[1 + \frac{e^{[A2 \cdot (1 + 0.8 \cdot A2)]} - 1}{1 + A2 \cdot (1 + 1.6A2) \cdot B2} \right] = 846.181$$

$$\alpha2 := \left(K1 + \frac{K0}{dD2} \right) \cdot \left(\frac{1}{dD2} \right) + K2 = 4.764 \times 10^{-4}$$

$$\Delta T2 := dT - 60.00688749 = -12.531$$

$$Ctl2 := e^{[-\alpha2 \cdot \Delta T2 \cdot [1 + 0.8 \cdot \alpha2 \cdot (\Delta T2 + 0.01374979547)]]} = 1.006$$

$$Fpv2 := e^{\left(-1.9947 + 0.00013427 \cdot dT + \frac{793929 + 2326 \cdot dT}{dD2^2} \right)} = 0.484$$

$$Cpl2 := \frac{1}{1 - 10^{-5} \cdot Fpv2 \cdot OilSGP} = 1$$

$$Ctpl2 := Ctl2 \cdot Cpl2 = 1.006$$

$$\delta D2 := D - dD2 \cdot Ctpl2 = -7.025 \times 10^{-10} \quad \text{ACCEPTABLE VALUE fDOR DENSITY}$$

New density value:

$$\text{newD} := D2 = 846.178 \quad \text{corrected density in kg/m}^3$$

$$\text{newOilSG} := \frac{\text{newD}}{999.016} = 0.847 \quad \text{corrected density in SG}$$

$$\text{newOilAPI} := \left(\frac{141.5}{\text{newOilSG}} \right) - 131.5 = 35.558 \quad \text{corrected density in API}$$

Case3 - Density correction and Volume correction factor - Expro excel sheet

Standard conditions: 1 atm adn 15degC

Input values:

OilSG := 0.852 uncorrected oil density, SG
 ODCTC := 8.6 oil density cylinder temperature, degC
 LineTC := 36.4 oil line temperature, degC
 k0 := 341.096
 k1 := 0

Conversion:

OilAPI := $\left(\frac{141.5}{\text{OilSG}}\right) - 131.5 = 34.58$ uncorrected oil density, API
 ODCTF := $\left[\left(\frac{9}{5}\right)\text{ODCTC}\right] + 32 = 47.48$ oil density cylinder temperature, degF
 LineTF := $\left[\left(\frac{9}{5}\right)\cdot\text{LineTC}\right] + 32 = 97.52$ oil line temperature, degF

Output values:**Corrected density**

$$A1 := \frac{141360.298}{\text{OilAPI} + 131.5} = 851.159$$

$$A2 := 1 - [0.00001278(\text{ODCTF} - 59)] - [0.000000062(\text{ODCTF} - 59)^2] = 1$$

$$A3 := A1 \cdot A2 = 851.277$$

$$A4 := \frac{341.0957}{A3^2} = 4.707 \times 10^{-4}$$

$$A5 := A4 \cdot (\text{ODCTF} - 59) = -5.422 \times 10^{-3}$$

$$A6 := 0.8 \cdot A5 = -4.338 \times 10^{-3}$$

$$A7 := A5 \cdot A6 = 2.352 \times 10^{-5}$$

$$A8 := -(A5 + A7) = 5.399 \times 10^{-3}$$

$$A9 := e^{A8} = 1.005$$

$$A10 = \text{IF}(A9=0; 10 \cdot 10^{10}; A3/A9)$$

$$A10 := \frac{A3}{A9} = 846.694$$

$$\text{OilAPI}_{\text{corr}} := \left(\frac{141360.198}{A10}\right) - 131.5 = 35.456$$

$$\text{OilSG}_{\text{corr}} := \frac{141.5}{\text{OilAPI}_{\text{corr}} + 131.5} = 0.848$$

Volume correction factor

$$B1 := \frac{141360.198}{\text{OilAPIcorr} + 131.5} = 846.694$$

$$B2 := \frac{k0}{B1} = 0.403$$

$$B3 := \frac{B2}{B1} = 4.758 \times 10^{-4}$$

$$B4 := \frac{k1}{B1} = 0$$

$$B5 := B3 + B4 = 4.758 \times 10^{-4}$$

$$B6 := B5 \cdot (\text{LineTF} - 60) = 0.018$$

$$B7 := 0.8 \cdot [B5 \cdot (\text{LineTF} - 60)] = 0.014$$

$$B8 := B7 \cdot B6 = 2.55 \times 10^{-4}$$

$$B9 := -B6 - B8 = -0.018$$

$$B10 := e^{B9} = 0.982$$

Case3 - Density correction and Volume correction factor - Expro manual calculation Procedure - ASTM 1250-80

All input values shall be in metric units for this VCF procedure

Input values:

shrT := 8.6	final shrinkage temperature, degC
OilSGT := 8.6	temperature at measurement of SG, degC
BaseT := 15	standard temperature, degC
BaseP := 1	standard pressure, 1 bara
OilSG := 0.856	specific gravity, SG

Correct input values to Metric units:

$$D_{tp} := \text{OilSG} \cdot 999.012 = 855.154 \text{ kg/m}^3$$

Calculation of volum correction factor:

Compressibility factor

$$B := e^{-\left[1.38315 + (\text{OilSGT} \cdot 0.00343804) - \left[3.02909 + (\text{OilSGT} \cdot 0.0161654) \cdot \ln\left(\frac{D_{tp}}{1000}\right)\right]\right]} = 6.743$$

$$C_{pl} := \frac{1}{1 - (\text{BaseP} \cdot B \cdot 10^{-5})} = 1$$

Correction for pressure on liquid

$$D_{to} := \frac{D_{tp}}{C_{pl}} = 855.097$$

Density corrected for pressure

$$\text{delta} := \text{OilSGT} - \text{BaseT} = -6.4$$

Difference in temp from base temp

$$\text{HYC} := 1 - (0.000023 \cdot \text{delta}) - (0.00000002 \cdot \text{delta}^2) = 1$$

Hydrometer correction

$$\text{derivD}_{to} := D_{to} \cdot \text{HYC} = 855.222$$

Density at atm pressure - still at temp.

$$D_{15} := \text{derivD}_{to} = 855.222$$

Initialising base temp density

Iterate the following steps until difference < 0.05:

Step 0:

$$D_0 := D_{15} = 855.222$$

$$\alpha_0 := \frac{613.9723}{D_0^2} = 8.394 \times 10^{-4}$$

Coefficient of thermal expansion

$$\text{VCF}_0 := e^{[(\alpha_0 \cdot \text{delta}) - (0.8 \cdot \alpha_0 \cdot \text{delta} \cdot \text{delta})]} = 0.995$$

Volume correction factor

$$dD_0 := \frac{D_{15}}{\text{VCF}_0} = 859.849$$

Density at standard temp & pressure

$$\text{Difference} := dD_0 - D_{15} = 4.627$$

Convergence check

$$D_1 := dD_0 = 859.849$$

Step 1:

$$D1 = 859.849$$

$$\alpha 1 := \frac{613.9723}{D1^2} = 8.304 \times 10^{-4}$$

$$VCF1 := e^{[(\alpha 1 \cdot \text{delta}) - (0.8 \cdot \alpha 1 \cdot \alpha 1 \cdot \text{delta} \cdot \text{delta})]} = 0.995$$

$$dD1 := \frac{D15}{VCF1} = 859.799$$

$$\text{Difference} := dD0 - D15 = 4.627$$

$$D1 := dD0 = 859.849 \quad \text{ACCEPTABLE VALUE}$$

Corrected oil density:

$$\text{OilSGcorr} := \frac{D1}{999.012} = 0.861$$

$$\text{OilAPIcorr} := \left(\frac{141.5}{\text{OilSGcorr}} \right) - 131.5 = 32.901$$

Case3 - Expro Combined Meter & Shrinkage Factor excel sheet - :

Below is input parameters used to calculate combined meter and shrinkage factor by Expro. When I checked formulas that was inserted in the excel sheet for Case3 could I find three different formulas for the same calculation and all of them wrong. The template used for calculation is not a protected sheet so all cells can be modified.

Input data - details:

- Choke size
- Separator pressure, bar
- Separator temperature, degC
- Start time
- Finish time
- Meter size
- Oil SG
- Oil SG temperature, degC
- Corrected Oil SG

Input data - meter reading:

- Initial meter reading, M3
- Final meter reading, M3
- Oil line temperature, degC
- Initial tank reading, M3
- Initial tank temperature, degC
- Final tank reading, M2
- Final tank temperature, degC

Input data - shrinkage reading:

- Initial shrinkage reading, %
- Initial shrinkage temperature, degC
- Final shrinkage reading, %
- Final shrinkage temperature, degC

Output data - meter reading:

$$VCF1 := 1 - \left[T \cdot \left(\frac{9}{5} \right) + 32 \right] \cdot 0.0005$$

$$VCF2 := 1 - \left[T \cdot \left(\frac{5}{9} \right) + 32 \right] \cdot 0.0005$$

$$VCF3 := 1 - (T - 60) \cdot 0.0005$$

Three different formulas for volume correction factor is used!

Reading @ SC = reading x VCF

SF = corrected final reading/corrected initial reading

CMSF = corrected tank volume/corrected meter volume

MF = CMSF/SF

See template for calculating meterfactor in Attachment 1

Case3 - Expro Combined Meter & Shrinkage Factor excel sheet:

Input data - details:

Choke := 36
 SepP := 20 bar
 SepT := 34.8 degC
 Δt := 157 min
 Meter := 1.5
 OilSG := 0.852
 OilSGT := 8.6 degC

Input data - meter reading:

Tank1 := 2.28	M3	Initial tank reading
Tank1T := 13.4	degC	Initial tank temperature
Tank2 := 8.7	M3	Final tank reading
Tank2T := 18.75	degC	Final tank temperature
Meter1 := 3.1	M3	Initial meter reading
Meter2 := 8.2	M3	Final meter reading
OilLineT := 34.7	degC	Oil line temperature

Input data - shrinkage reading:

Shrink1 := 100	%	Initial shrinkage reading
Shrink1T := 21	degC	Initial shrinkage temperature
Shrink2 := 94	%	Final shrinkage reading
Shrink2T := 13	degC	Final shrinkage temperature

Output data - meter reading - Expro sheet:

$$\text{Tank1TVCF} := 1 - \left[\text{Tank1T} \cdot \left(\frac{9}{5} \right) + 32 \right] \cdot 0.0005 = 0.972$$

$$\text{Tank1TVCF} := 1 - \left[\text{Tank1T} \cdot \left(\frac{5}{9} \right) + 32 \right] \cdot 0.0005 = 0.98$$

$$\text{Tank1TVCF} := 1 - \left[\left[\text{Tank1T} \cdot \left(\frac{9}{5} \right) + 32 \right] - 60 \right] \cdot 0.0005 = 1.002$$

$$\text{Tank2TVCF} := 1 - \left[\text{Tank2T} \cdot \left(\frac{9}{5} \right) + 32 \right] \cdot 0.0005 = 0.967$$

$$\text{Tank2TVCF} := 1 - \left[\text{Tank2T} \cdot \left(\frac{5}{9} \right) + 32 \right] \cdot 0.0005 = 0.979$$

$$\text{Tank2TVCF} := 1 - \left[\left[\text{Tank2T} \cdot \left(\frac{9}{5} \right) + 32 \right] - 60 \right] \cdot 0.0005 = 0.997$$

$$\text{OilLineTVCF} := 1 - \left[\text{OilLineT} \cdot \left(\frac{9}{5} \right) + 32 \right] \cdot 0.0005 = 0.953$$

$$\text{OilLineTVCF} := 1 - \left[\text{OilLineT} \cdot \left(\frac{5}{9} \right) + 32 \right] \cdot 0.0005 = 0.974$$

$$\text{OilLineTVCF} := 1 - \left[\left[\text{OilLineT} \cdot \left(\frac{9}{5} \right) + 32 \right] - 60 \right] \cdot 0.0005 = 0.983$$

$$\text{Shrink1TVCF} := 1 - \left[\text{Shrink1T} \cdot \left(\frac{9}{5} \right) + 32 \right] \cdot 0.0005 = 0.965$$

$$\text{Shrink1TVCF} := 1 - \left[\text{Shrink1T} \cdot \left(\frac{5}{9} \right) + 32 \right] \cdot 0.0005 = 0.978$$

$$\text{Shrink1TVCF} := 1 - \left[\left[\text{Shrink1T} \cdot \left(\frac{9}{5} \right) + 32 \right] - 60 \right] \cdot 0.0005 = 0.995$$

$$\text{Shrink2TVCF} := 1 - \left[\text{Shrink2T} \cdot \left(\frac{9}{5} \right) + 32 \right] \cdot 0.0005 = 0.972$$

$$\text{Shrink2TVCF} := 1 - \left[\text{Shrink2T} \cdot \left(\frac{5}{9} \right) + 32 \right] \cdot 0.0005 = 0.98$$

$$\text{Shrink2TVCF} := 1 - \left[\left[\text{Shrink2T} \cdot \left(\frac{9}{5} \right) + 32 \right] - 60 \right] \cdot 0.0005 = 1.002$$

Reading @ SC = reading x VCF

SF = corrected final reading/corrected initial reading

CMSF = corrected tank volume/corrected meter volume

MF = CMSF/SF

Output data - meter reading - API 11:

$$\text{OilID} := \text{OilSG} \cdot 999.016 = 851.162$$

$$\alpha_{60} := \frac{341.0951}{\text{OilID}^2} = 4.708 \times 10^{-4}$$

So small change in alpha60 with large change in densiti
Will be used as a constant for calculations for VCF

$$\text{TF} := \text{OilSGT} \cdot \left(\frac{9}{5} \right) + 32 = 47.48$$

$$\Delta\text{TSG} := \text{TF} - 60 = -12.52$$

$$\text{VCFSG} := e^{[-\alpha_{60} \cdot \Delta\text{TSG} \cdot [1 + 0.8 \cdot \alpha_{60} \cdot (\Delta\text{TSG} + 0.01374979547)]]} = 1.006$$

$$\text{Tank1TF} := \text{Tank1T} \cdot \left(\frac{9}{5}\right) + 32 = 56.12$$

$$\Delta\text{TTank1} := \text{Tank1TF} - 60 = -3.88$$

$$\text{VCFTank1} := e^{[-\alpha 60 \cdot \Delta\text{TTank1} \cdot [1+0.8 \cdot \alpha 60 \cdot (\Delta\text{TTank1}+0.01374979547)]]} = 1.002$$

$$\text{Tank2TF} := \text{Tank2T} \cdot \left(\frac{9}{5}\right) + 32 = 65.75$$

$$\Delta\text{TTank2} := \text{Tank2TF} - 60 = 5.75$$

$$\text{VCFTank2} := e^{[-\alpha 60 \cdot \Delta\text{TTank2} \cdot [1+0.8 \cdot \alpha 60 \cdot (\Delta\text{TTank2}+0.01374979547)]]} = 0.997$$

$$\text{OilLineTF} := \text{OilLineT} \cdot \left(\frac{9}{5}\right) + 32 = 94.46$$

$$\Delta\text{TOilLine} := \text{OilLineTF} - 60 = 34.46$$

$$\text{VCFOilLine} := e^{[-\alpha 60 \cdot \Delta\text{TOilLine} \cdot [1+0.8 \cdot \alpha 60 \cdot (\Delta\text{TOilLine}+0.01374979547)]]} = 0.984$$

$$\text{Shrink1TF} := \text{Shrink1T} \cdot \left(\frac{9}{5}\right) + 32 = 69.8$$

$$\Delta\text{TShrink1} := \text{Shrink1TF} - 60 = 9.8$$

$$\text{VCFShrink1} := e^{[-\alpha 60 \cdot \Delta\text{TShrink1} \cdot [1+0.8 \cdot \alpha 60 \cdot (\Delta\text{TShrink1}+0.01374979547)]]} = 0.995$$

$$\text{Shrink1TF} := \text{Shrink1T} \cdot \left(\frac{9}{5}\right) + 32 = 69.8$$

$$\Delta\text{TShrink1} := \text{Shrink1TF} - 60 = 9.8$$

$$\text{VCFShrink1} := e^{[-\alpha 60 \cdot \Delta\text{TShrink1} \cdot [1+0.8 \cdot \alpha 60 \cdot (\Delta\text{TShrink1}+0.01374979547)]]} = 0.995$$

$$\text{Shrink2TF} := \text{Shrink2T} \cdot \left(\frac{9}{5}\right) + 32 = 55.4$$

$$\Delta\text{TShrink2} := \text{Shrink2TF} - 60 = -4.6$$

$$\text{VCFShrink2} := e^{[-\alpha 60 \cdot \Delta\text{TShrink2} \cdot [1+0.8 \cdot \alpha 60 \cdot (\Delta\text{TShrink2}+0.01374979547)]]} = 1.002$$