Global Flow Measurement Workshop
24-26 October 2023

Technical Paper

Multiphase sampling system - Development and field experience from Gjøa

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1 INTRODUCTION

WHY DO WE NEED A MULTIPHASE SAMPLING SYSTEM?

The Neptune Energy Norway operated offshore platform Gjøa is located in the northern North Sea, approximately 45 kilometres west of the coastal city Florø. Gjøa production facility receives production from the Gjøa, Vega, Duva and Nova fields. Figure 1 gives an overview of the fields delivering production to Gjøa.

During the development of the Duva- and Nova tie-in projects, installation of a dedicated production separator for the Nova field was deemed technically and commercially unfeasible due to space- and weight capacity constraints. A development concept to install a test separator with corresponding test manifold was discarded for the same reasons.

Correct determination of flowrate and hydrocarbon composition is critical to ensure a fair allocation between the different license stakeholders. The allocation concept for Gjøa with tie-ins is a “mass-per-component” type allocation. Due to commingling of Duva, Nova and Gjøa oil well streams upstream of an inlet separator, flowrate and compositional data for the commingled streams must be acquired through the use of multiphase flowmeters and multiphase sampling equipment.

As part of the new tie-in projects, Nova and Duva, a multiphase sampling system was developed with the purpose of acquiring samples of gas, oil/ condensate and water to reduce the uncertainty in the metering system and to get compositional data to be used as input to the hydrocarbon field allocation. Sample data from the multiphase sampling system may then be compared with the calculated properties of the commingled well streams derived from the multiphase flowmeter measurements.

Please note that the multiphase sampling system is not designed with the intention to capture representative gas/oil/water phase fractions of a commingled hydrocarbon fluid. The multiphase sampling system is used to acquire separated gas, oil and water samples, which are analysed to characterise the gas and oil properties at the sample pressure and temperature conditions. Individual gas and oil compositions are then recombined mathematically using flowrate input to derive the total hydrocarbon composition.

This paper will address the following topics:

- why a multiphase sampling system was deemed necessary
- the development and design of the new multiphase sampling system
- the results from qualification testing done at K-Lab autumn 2021
- field experience since the system was put in use at Gjøa production platform early 2023

2 GJØA

The Gjøa field was discovered in 1989 and Equinor (Statoil) was the development operator. The operatorship was transferred to Neptune when production commenced in 2010. Operational performance and production levels have been outstanding since the start of production and good reservoir management has extended the field life. Gjøa is now set to produce 100 mmboe more than what was estimated when production started. Gjøa is predominantly a gas producer with reserves estimated at 58 mmboe per 1 January 2022, gas accounts for over ~90% of the reserves.

The semi-submersible production unit, which was jointly developed with nearby Vega field, has full processing and export capabilities. The floating production facility is designed to act as an area hub with a longer technical lifetime than the Gjøa/Vega fields and with additional space and weight capacity.

The gas is exported through the FLAGS pipeline to the St. Fergus gas terminal in Scotland. Oil is exported to the Mongstad crude oil terminal on the west coast of Norway.

Gjøa is the first floating production platform to be powered sustainably by onshore facilities. A 100 km submarine cable delivers hydropower-generated electricity from Mongstad.

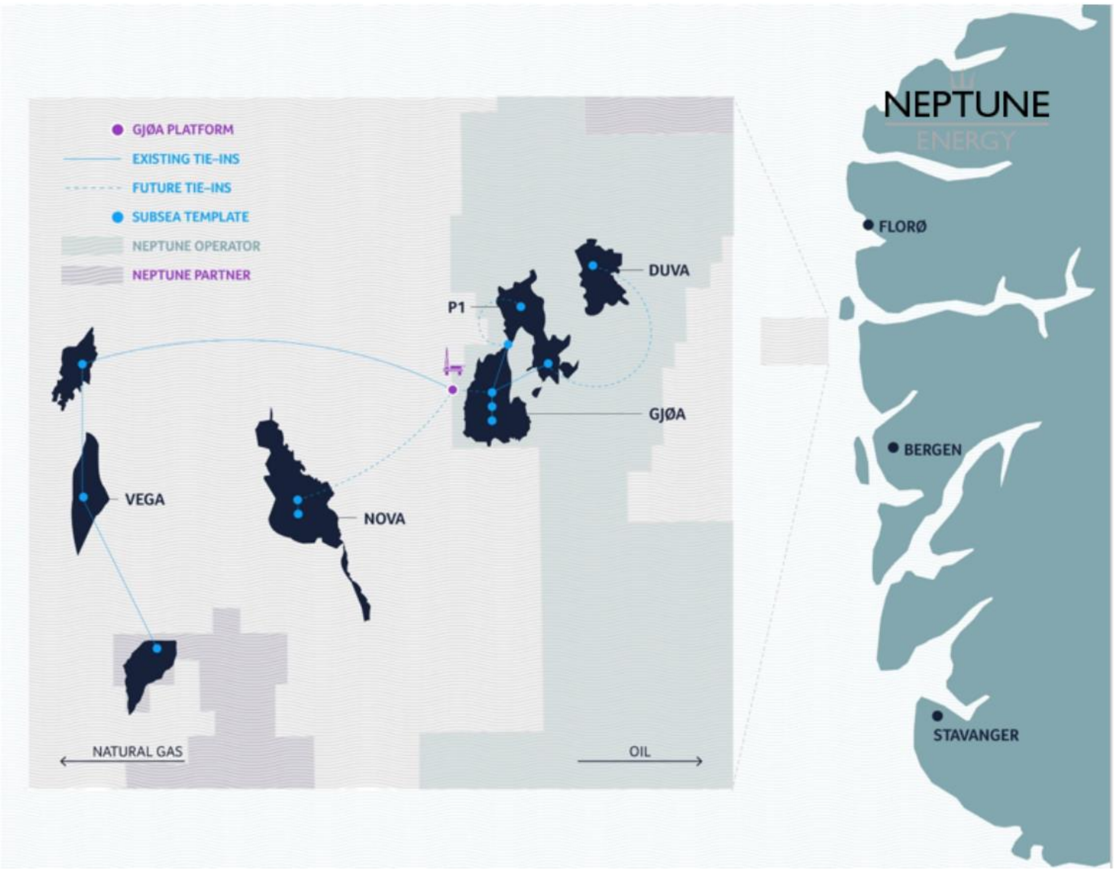

Figure 1: Field schematic, Gjøa platform with tie-in fields

2.1 Expansions and new tie-ins

To mitigate the decline of Gjøa's own production, the commitment was made to develop four projects (Gjøa P1, Vega infill wells, Duva and Nova) which make use of its processing capacity:

- **Gjøa P1 development (February 2021)**
  Extension of an existing reservoir in the northern part of the Gjøa field with startup of two new wells
- **Vega re-development (Q4 2021 – Q2 2022)**
  Extension of the Vega field with start-up of three new wells utilizing existing subsea infrastructure
- **Duva (August 2021)**
  Four-well subsea tieback in 14 km northeast of Gjøa
- **Nova (July 2022)**
  three-well subsea tieback development 17 km southwest of Gjøa

Figure 2: Lifting of the Nova production module onto Gjøa

2.2 Allocation concept

In this chapter, the original and the new allocation concepts are explained. This serves as background information to give a better understanding of why a multiphase sampling system is was deemed necessary. A schematic overview of the metering system on Gjøa can be found in Figure 3.

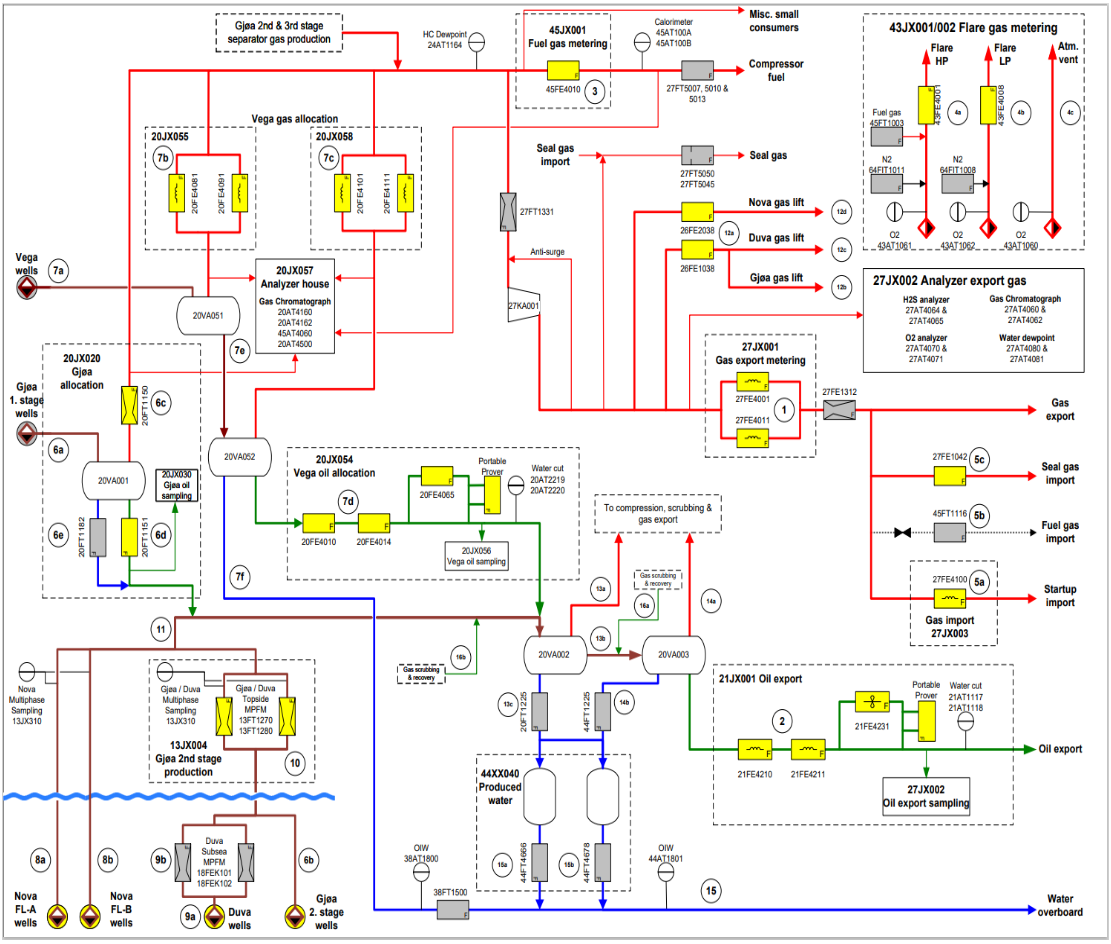

Figure 3: Metering schematic – Gjøa

2.2.1 Original metering and allocation concept, 2010 – 2021

The Gjøa field (host) started production in November 2010. The Gjøa and Vega fields were developed in parallel, and the Vega field came into production shortly after the Gjøa startup in November 2010. The original field allocation concept at Gjøa production facilities was based on fiscal metering and sampling of export gas, export oil, fuel and flare together with single phase metering and sampling of Vega separators.

By measuring and sampling the total production and the Vega field production, the Gjøa field would be allocated the difference between the two ("Gjøa by difference"). Production was allocated on a mass per component basis for hydrocarbon components C1-C6+, including the non-hydrocarbon components N2 and CO2. Oil recovery factors for each component ("CORF factors") were derived from process simulations, using the available metering and sampling data, and used to determine gas/oil fractions of the individual components produced by each field. This Gjøa allocation by difference system worked well for many years as Gjøa was the dominant producer in this period. A principle sketch of the original allocation system is shown to the left in Figure 4.

In the original allocation system, the total produced hydrocarbons must equal the sum of the two fields:

$$M_{Total}^{HC,alloc} = \sum_i M_{export,i}^{oil} + M_{export,i}^{gas} + M_{fuel,i}^{gas} + M_{flare,i}^{gas} \qquad (1)$$

$$= M_{Gjøa}^{HC} + M_{Vega}^{HC}$$

Vega would get its production allocated "as measured", corrected for CORF factors:

$$M_{Vega}^{HC,alloc} = M_{Vega}^{oil} + M_{Vega}^{gas} \qquad (2)$$

$$= \sum_i M_{Vega,i}^{HC} \cdot CORF_{Vega,i} + M_{Vega,i}^{HC} \cdot (1 - CORF_{Vega,i})$$

Gjøa was allocated the difference between the allocated total production and the allocated Vega production:

$$M_{Gjøa}^{HC,alloc} = M_{Total}^{HC,alloc} - M_{Vega}^{HC,alloc} \qquad (3)$$

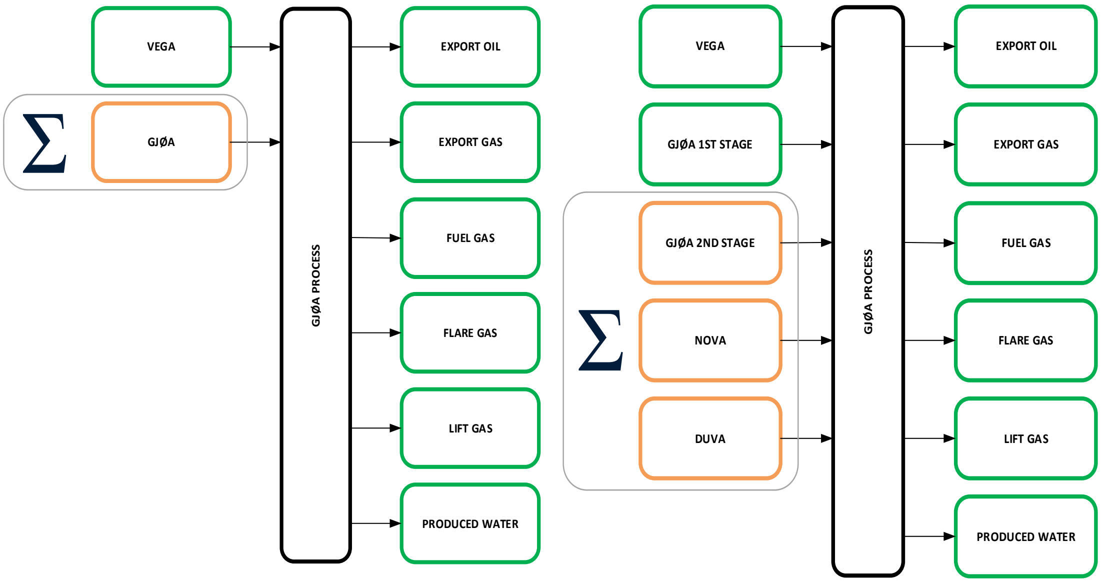

Figure 4: High level allocation principle sketch before (left) and after (right) tie in of Gjøa P1, Duva and Nova

2.2.2 Revised metering and allocation concept, 2021 –

To accommodate for tie-in of the new Nova- and Duva fields, with new license ownership structures, a change of allocation concept was required. Due to space- and weight capacity constraints at Gjøa topside facilities, it was not possible to install single phase metering systems for the new fields. Gjøa would no longer be the dominant field and the new allocation concept had to rely on the use of multiphase flow meters and multiphase samples. Multiphase flow meters have been used in the oil and gas industry for decades and are known to provide less accurate measurements when compared with conventional single phase metering systems. The added uncertainty is a consequence of the complex nature of multiphase flows and the ability of current technology to accurately measure the complex flow regimes occurring at upstream conditions (prior separation).

In the new setup, the production is allocated on a mass per component basis for hydrocarbon components C1-C10+[1], including the non-hydrocarbon components N2 and CO2. Total production and the Vega field is measured and sampled in the same way as before. Allocation of the Gjøa field has significantly changed in the new setup. Production from the new Gjøa P1 wells is routed to Gjøa 2nd stage separator via the oil production flowline, while the remaining production is routed to Gjøa 1st stage separator via the gas production flowline. The routing of Gjøa wells is flexible[2], and the routing of individual wells may change in the future for the purpose of optimizing production. Gjøa 1st stage separator production is measured single phase at the separator outlets, while remaining Gjøa production is commingled together with Duva and Nova prior entry to Gjøa 2nd stage separator.

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[1] Note that the heavy end is extended from C6+ to C10+.

[2] With the exception of Gjøa F1 satellite well, which can only produce to Gjøa 1st stage separator

Having measured and sampled the total production, then subtracted the Vega field production and Gjøa 1st stage separator production, the remaining production must come from the other producers (Gjøa oil line, Duva and Nova). This concept is further denoted as "Gjøa 2nd stage separator by difference". A further breakdown of the commingled Gjøa P1, Duva and Nova stream is required to determine the individual field productions. This subsequent allocation is carried out pro-rata, based on flowrate and compositions derived from the use of multiphase flow meters and sampling equipment. A principle sketch of the revised allocation system is shown to the right in Figure 4.

In the revised allocation system, the total produced hydrocarbons must equal the sum of the four fields:

$$M_{Total}^{HC,alloc} = \sum_i M_{export,i}^{oil} + M_{export,i}^{gas} + M_{fuel,i}^{gas} + M_{flare,i}^{gas} \tag{4}$$

$$= M_{Gjøa}^{HC} + M_{Vega}^{HC} + M_{Duva}^{HC} + M_{Nova}^{HC}$$

Vega will get its production allocated as measured, corrected for CORF factors:

$$M_{Vega}^{HC,alloc} = M_{Vega}^{oil} + M_{Vega}^{gas} \tag{5}$$

$$= \sum_i M_{Vega,i}^{HC} \cdot CORF_{Vega,i} + M_{Vega,i}^{HC} \cdot (1 - CORF_{Vega,i})$$

Similarly, Gjøa 1st stage separator will get its production allocated as measured, corrected for CORF factors:

$$M_{Gjøa\ 1st}^{HC,alloc} = M_{Gjøa\ 1st}^{oil} + M_{Gjøa\ 1st}^{gas} \tag{6}$$

$$= \sum_i M_{Gjøa\ 1st,i}^{HC} \cdot CORF_{Gjøa\ 1st,i} + M_{Gjøa\ 1st,i}^{HC} \cdot (1 - CORF_{Gjøa\ 1st,i})$$

The remaining production must come from Gjøa 2nd stage separator entrants (Gjøa oil line, Duva and Nova), which must equal the difference between the allocated total production, and the sum of production allocated to Gjøa 1st stage separator and Vega:

$$M_{Gjøa\ 2nd\ sep}^{HC,alloc} = M_{Total}^{HC,alloc} - \left(M_{Vega}^{HC,alloc} + M_{Gjøa\ 1st}^{HC,alloc}\right) \tag{7}$$

A sub-allocation is required in order to derive the individual field productions. Gjøa oil line, Duva and Nova will get the individual production allocated as their pro-rata share of the production allocated to Gjøa 2nd stage separator. The flowrate used in the pro-rata allocation is measured by multiphase flow meters.

Gjøa oil line production is calculated using:

$$M_{Gjøa\ oil\ line}^{HC,alloc} = \sum_i \frac{M_{Gjøa\ oil\ line,i}^{HC,meas}}{M_{Gjøa\ oil\ line,i}^{HC,meas} + M_{Duva,i}^{HC,meas} + M_{Nova,i}^{HC,meas}} \cdot M_{Gjøa\ 2nd\ sep,i}^{HC,alloc} \tag{8}$$

Duva production is calculated using:

$$M_{Duva}^{HC,alloc} = \sum_i \frac{M_{Duva,i}^{HC,meas}}{M_{Gjøa\ oil\ line,i}^{HC,meas} + M_{Duva,i}^{HC,meas} + M_{Nova,i}^{HC,meas}} \cdot M_{Gjøa\ 2nd\ sep,i}^{HC,alloc} \tag{9}$$

Nova production is calculated using:

$$M_{Nova}^{HC,alloc} = \sum_i \frac{M_{Nova,i}^{HC,meas}}{M_{Gjøa\ oil\ line,i}^{HC,meas} + M_{Duva,i}^{HC,meas} + M_{Nova,i}^{HC,meas}} \cdot M_{Gjøa\ 2nd\ sep,i}^{HC,alloc} \tag{10}$$

Once the produced oil and gas have been determined for each of the fields, there are further steps in the allocation sequence to allocate each field’s share of fuel gas and flare gas, and subsequently the export entitlements for each field. When export entitlements have been determined, rules for deferral adjustments will be used to calculate the final gas allocation for each field. After final gas allocation is concluded, line fill adjustments and value adjustments are calculated to conclude the final oil allocation for each field.

As seen from equations 8, 9 and 10, the hydrocarbon mass per component in the well streams have a direct impact on the quantity allocated to each of the fields, hence its correct determination is critical to ensure a correct allocation.

Samples for determination of hydrocarbon composition and value adjustment parameters will be collected using a multiphase sampling unit (MPSU) installed upstream of Gjøa 2nd stage separator as shown in Figure 3.

2.3 Licence partnerships

Gjøa:

Company name	Nation code	Company share [%]
Petoro AS	NO	30.000000
Neptune Energy Norge AS	NO	30.000000
Wintershall Dea Norge AS	NO	28.000000
OKEA ASA	NO	12.000000

Vega:

Company name	Nation code	Company share [%]
Wintershall Dea Norge AS	NO	56.700000
Petoro AS	NO	31.200000
Spirit Energy Norway AS	NO	5.500000
Neptune Energy Norge AS	NO	3.300000
INPEX Idemitsu Norge AS	NO	3.300000

DUVA:

Company name	Nation code	Company share [%]
INPEX Idemitsu Norge AS	NO	30.000000
PGNiG Upstream Norway AS	NO	30.000000
Neptune Energy Norge AS	NO	30.000000
Sval Energi AS	NO	10.000000

NOVA:

Navn, selskap	Nasjonskode	Selskapets andel [%]
Sval Energi AS	NO	45.000000
Wintershall Dea Norge AS	NO	39.000000
Pandion Energy AS	NO	10.000000
OKEA ASA	NO	6.000000

Reference: NPD Fact pages as of 20.09.2023

3 THE MULTIPHASE SAMPLING SYSTEM (MPSU)

Based on the project need to sample in a multiphase stream, and that no standard solution which met Neptune Energy's requirements was found, a new design was required. In close collaboration between Proserv, Rosenberg Worley Parsons, WintershallDEA and Neptune Energy a multiphase sampling system was designed and tested, see Figure 6.

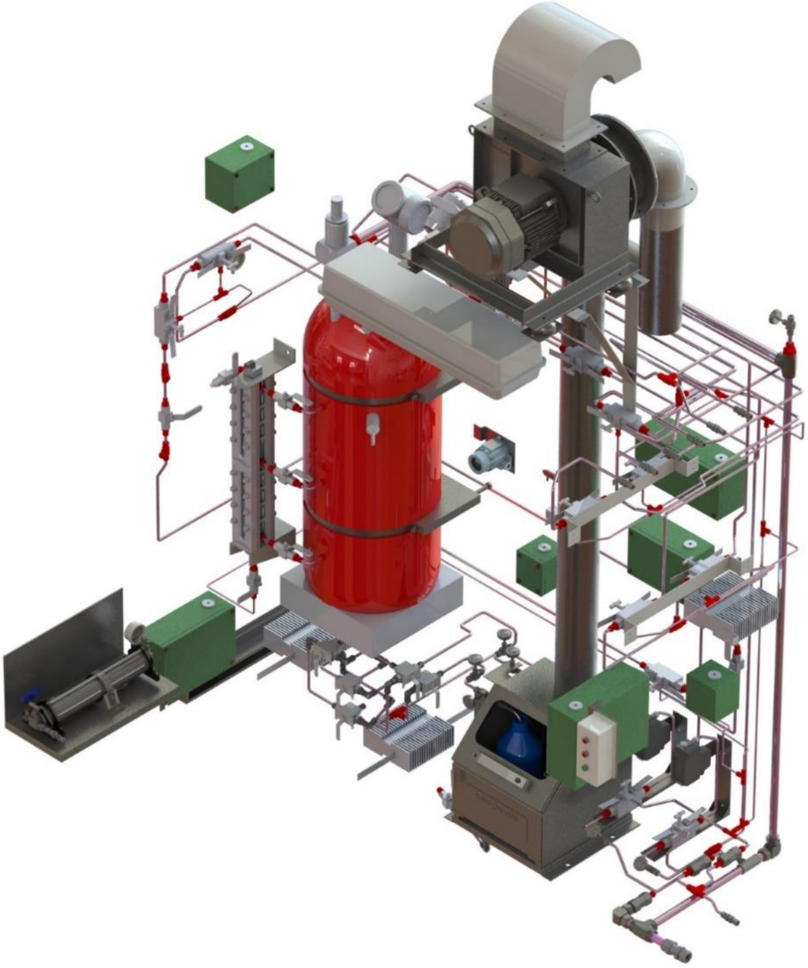


Figure 6 Multiphase sampling unit

The multiphase sampling unit comprise of:

- Two sample probes installed in Gjøa oil flowline
- Separate sampling probes installed in each Nova flowline (A and B)
- Two valve panels for selection of extraction point from each sample probe
- Separator inlet tubing and outlet tubing
- A mini separator which allows for separation of gas, oil and water to be sampled
- Level and interface (oil/water) measurement
- Heated cabinet with control valves, sample points and drain connections

Samples are taken by extracting multiphase fluids through the sample probe into a vertical mini separator. No pump is used in the sample extraction, and sample transport is driven solely by differential pressure between the flowline and closed drain connections at the separator outlets. The separator has outlets for gas (top), water (bottom) and oil (intrusive), through which the fluids can be transferred to pre-charged, pressurized piston cylinders.

The fluids may also be routed to a vented cabinet for atmospheric sampling. Moreover, it is possible to bypass the separator and route the multiphase fluid directly to a flow-through cylinder. The positions of the gas-oil interface and oil-water interface are monitored with a guided wave radar. The interfaces can also be visually inspected through a sight glass. The separator is equipped with a heating jacket for temperature control. Each outlet can be routed to drain/ flare.
Figure 7 shows the main components.

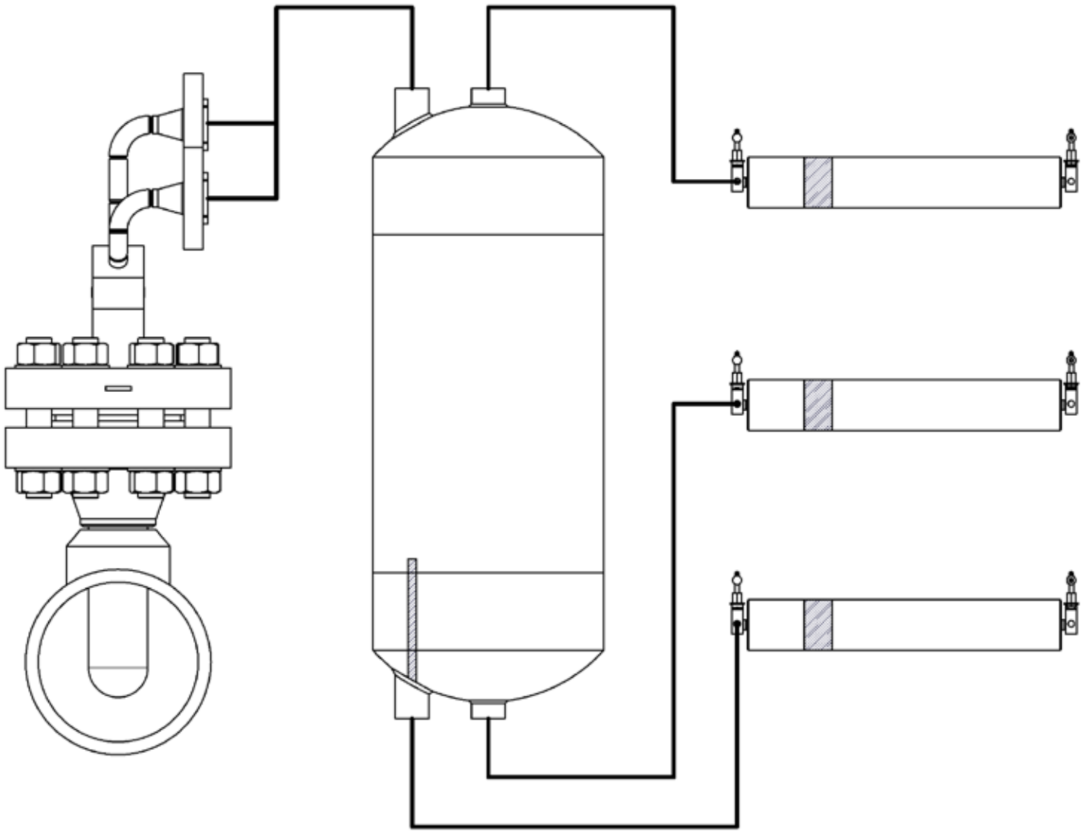


Figure 7: MPSU working principle sketch

CFD analyses ("Computational Fluid Dynamics") have been carried out to find the optimal locations of the sample probe with respect to bends, restrictions, valves, etc. As a result, the sample probes are placed such that a sufficient volume of each phase is collected and transferred to the mini separator.

The sample collection probes have three extraction points located at different pipe immersion lengths, with one extraction point located at the centre of the pipe, one located close to the pipe wall/edge and the third located between the centre point and edge point. The probes are mounted in a vertical position to limit the effect of phase separation due to gravity. See Figure 8**Feil! Fant ikke referansekilden.** for probe placement and Figure 8 for a sketch of the probe. The valve panel installed in the field is used to select which probe and extraction point to use for collecting the samples.

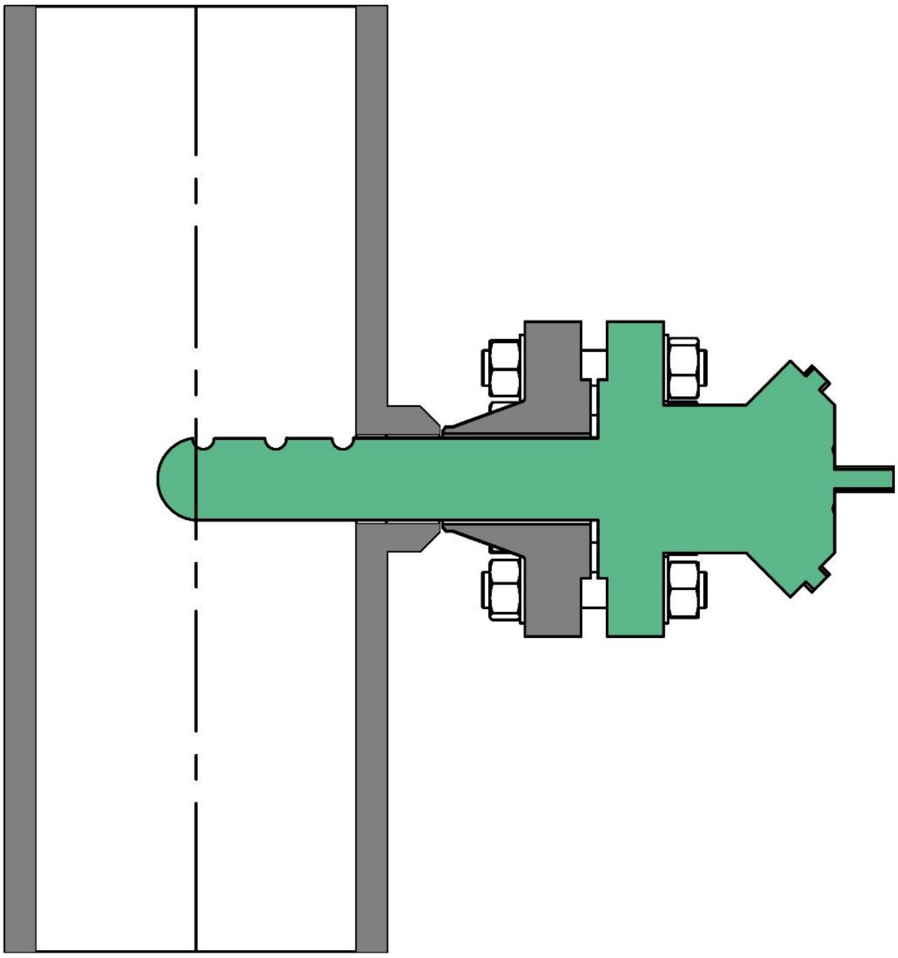


Figure 8: Probe installation details

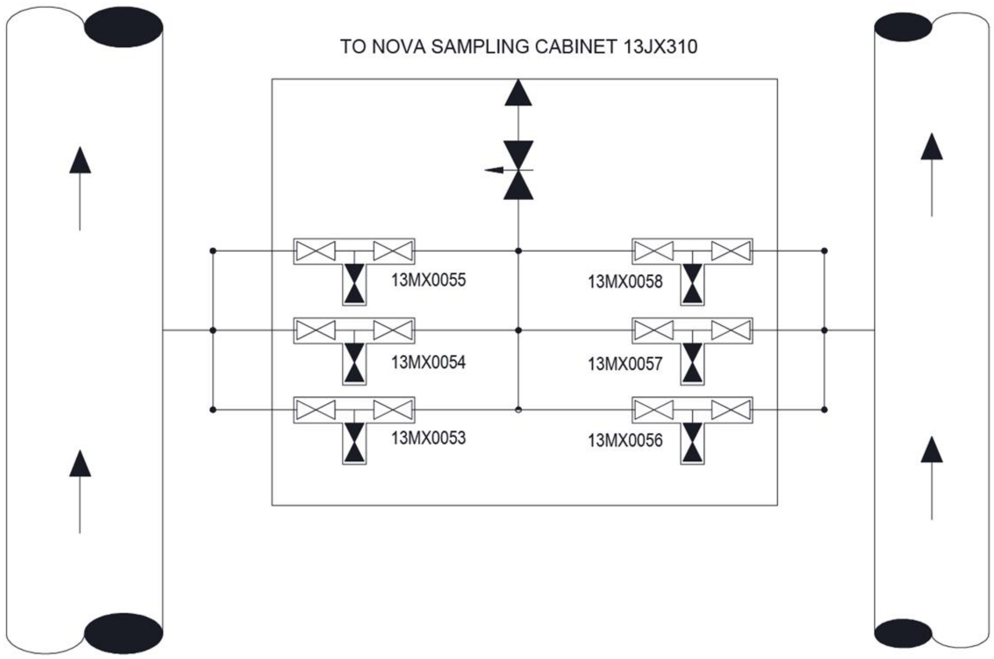


Figure 9: Gjøa oil flowlines valve manifold for multiphase sampling, 13JX003

The possibility to choose between different immersion lengths is there to enable the user to select a different extraction point should one extraction point fail to capture either of the gas or liquid phase, see Figure 9.

Samples collected using the MPSU should always be collected during stable production periods to provide the most representative results and samples should always be sampled in sets of one gas sample and one liquid sample with another sample pair as back-up if any of the samples are compromised for any reason. Sample pairs should be collected successively with as little downtime between samples as reasonably possible. This is to limit increased uncertainty in the sample data due to fluctuations in flow.

The gas and liquid sample pair is analysed in a laboratory for compositional analysis. The compositional analysis report contains information on the fluid properties and information on the mass fractions of each component.

The mass fractions of the gas sample and oil sample are recombined using the calculated mass flowrates at the time when the sample pair was collected. The procedure for recombining the gas sample composition and oil sample composition into a total hydrocarbon composition will be detailed in the chapter 6 "SAMPLE RECOMBINATION".

In addition to the sample pair required for N2, CO2, C1-C10+ compositional analysis, an additional liquid sample is analysed for true boiling point (TBP) analysis to determine the refinery cuts and oil quality as required for value adjustment.

4 MPFM CALIBRATION

The subsea multiphase meters provide important information used together with the information from the analysed MPSU samples. It is therefore useful to understand how the multiphase meters are verified and in-situ calibrated which is described in this chapter.

At Gjøa, all multiphase flowmeters (MPFMs) and virtual multiphase flowmeters (VFMs) are subject to periodic flowrate verification and in-situ calibrations two times pr year. Flowmeter calibrations are performed in the form of well deduction tests as there is no test separator available at Gjøa process facility. Normally one deduction test will last up to 36 hours.

The reference flowrates used during a well test depends on the well routing. MPFMs and VFMs measuring well streams entering Gjøa 1st stage separator and Vega well stream shall use dedicated separator instrumentation as reference for calibration purposes during well deduction testing. MPFMs and VFMs measuring well streams entering Gjøa 2nd stage separator use a calculated reference flowrate using the "by-difference" principle as described in chapter 2.2.2.

Mass factors are applied to each gas, oil and water phase to maintain a calibrated model at the normal operating point for the well. The tests are aligned with mandatory valve integrity tests to limit production downtime.

The Meter factors are established during a deduction test by comparing the meter flowrates against the calculated reference flowrates. A flowrate differential is introduced by shutting in the well. The flowrate differential of the subsea wellhead meter will be from normal flowrate to zero flowrate, while the calculated reference flowrate and any flowline meter flowrates, will decrease from a normal flowrate to a lower flowrate. This corresponding drop in reference flowrate is then used to deduce the flowrates of the well. Once the meter factors are established, the corresponding well PVT composition is updated.

The mass correction factors are calculated for each phase using:

$$k_m = \frac{M_{ref}^{A} - M_{ref}^{B}}{M_{meas}^{A} - M_{meas}^{B}} \qquad (11)$$

where,

- k_m is the mass correction factor
- M_{ref}^{A} is the calculated reference mass flowrate for period A (all wells flowing)
- M_{ref}^{B} is the calculated reference mass flowrate for period B (well shut in)
- M_{meas}^{A} is the measured mass flowrate for period A (all wells flowing)
- M_{meas}^{B} is the measured mass flowrate for period B (well shut in)

5 PVT

MPFMs measure the flow of gas, oil, and water at meter pressure and temperature conditions. Flash calculations are required to convert the input flowrates to standard conditions or any other reference conditions. A custom PVT-model, which is representative for the Gjøa separation process, is implemented in the metering control system. All production separators and gas scrubbers have been included in the model to allow for a multi-stage separation. Fluid compositions for each of the well streams, together with live flow, density, pressure, and temperature measurements from the process enable live PVT-calculations to determine flows at standard conditions and sampling/MPSU conditions. SRK-Peneloux equation of state is currently used in the flash calculations.

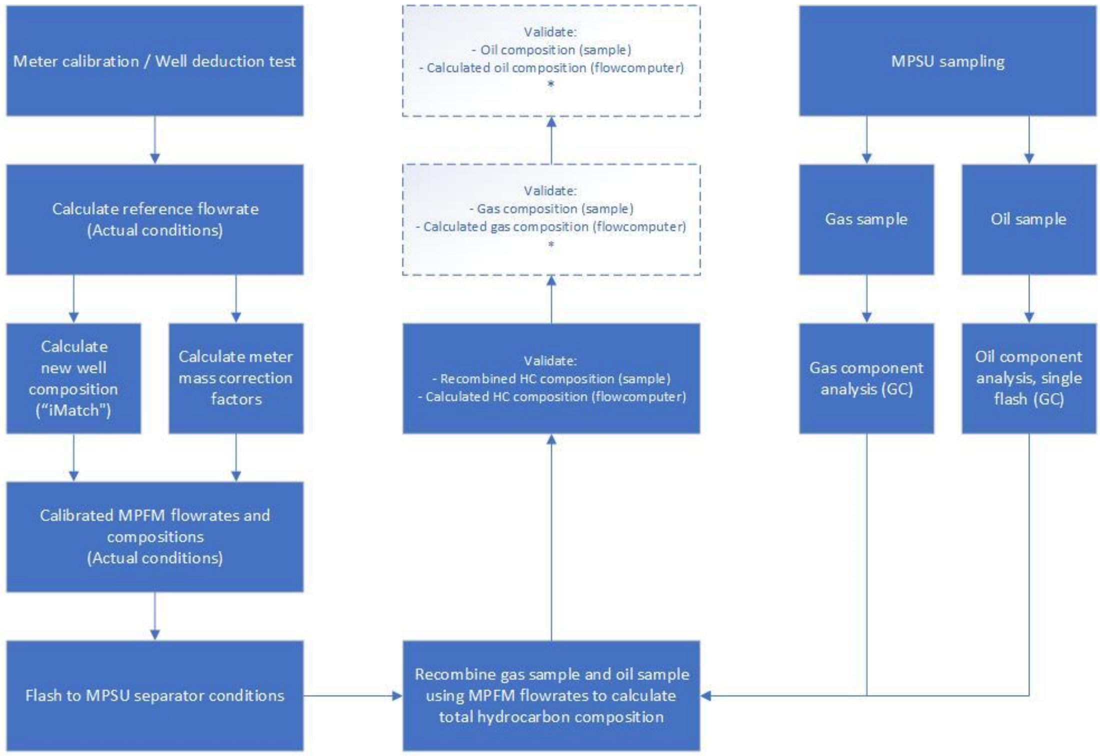
In normal operation the IMATCH routine is enabled. With this setting the Gjøa online MPM PVT package will correct the input C10+ fluid composition to match the measured gas and oil meter mass flow rates, accounting for possible long and short term fluctuations in the produced reservoir fluid composition. The composition adjustment is performed prior conversion of meter actual conditions flowrates to standard conditions flowrates. This ensures that the fluid composition used as input to the separation process calculation is representative of the fluid composition at the meter location.

IMATCH automatically adjust the input C10+ fluid composition to match the mass flow rates of gas and oil measured at the meter location. All input correction factors are applied in this calculation. The corrected reservoir fluid composition and the corrected total mass flow rate of oil and gas at meter location is calculated as follows:

1. Characterize input C10+ fluid composition and apply input density correction factors
2. Make a 2 phase PT-Flash at meter temperature and pressure conditions to determine the oil and gas compositions and the oil and gas molecular weights
3. Calculate the corrected reservoir fluid composition using the calculated oil and gas compositions from “2” and the input meter mass flow rates of oil and gas along with their respective mass flow rate correction factors
4. Calculate the total molar flow rate of reservoir fluid as and total mass flow rate as which are subsequently used in the separation process simulation to calculate the mass flow rates of oil and gas at standard conditions

6 SAMPLE RECOMBINATION

Samples obtained from the MPSU do not provide a direct representation of the individual gas, oil and water fractions found in the flowline at any time. To find the total hydrocarbon composition of the sampled wellstream, the individual gas and oil samples need to be recombined mathematically using a calibrated flowrate input. A block diagram of the process is shown in Figure 9.



* To be implemented

Figure 10. Block diagram of the composition validation process

Phase fractions of the sampled wellstream are determined by calculating the mass flowrates at sample conditions for each well contributing to the commingled wellstream. The sum of the individual well mass flowrates (@MPSU P&T), as produced into the flowline when sampled, is used to recombine the separate gas and oil analysis data provided by the accredited laboratory:

$$M_i^{HC} = M_i^{gas} + M_i^{oil} \tag{12}$$

$$= M^{gas} \cdot c_i^{gas} + M^{oil} \cdot c_i^{oil}$$

where:

- M_i^{HC} is the hydrocarbon mass per component i
- M_i^{gas} is the gas mass per component i
- M_i^{oil} is the oil mass per component i
- M^{gas} is the gas mass recombination flowrate
- M^{oil} is the oil mass recombination flowrate
- c_i^{gas} is the mass fraction of component i in the gas sample
- c_i^{oil} is the mass fraction of component i in the oil sample

When the component mass flows have been established, the hydrocarbon mass fraction of each component in the wellstream may be calculated:

$$c_i^{HC} = \frac{M_i^{HC}}{M^{HC}} \tag{13}$$

The PVT-pack is used to convert the MPFM mass flowrates at meter pressure and temperature conditions to MPSU pressure and temperature conditions. A single stage flash is used to calculate the flows as there is no separation between the wellhead metering point and sample extraction point.

6.1 Gjøa oil flowline samples

The gas mass flowrate of Gjøa oil flowline (including lift gas) at MPSU pressure and temperature conditions is used as the gas mass HC-fraction for the purpose of recombining the gas and oil compositions into a combined total hydrocarbon composition. The gas mass flowrate is calculated using:

$$Q_{m,GAS,GJØA\ OIL\ FLOWLINE,M}^{MPSU} = Q_{m,GAS,WELLS,GJØA\ OIL,M}^{MPSU} + Q_{m,GAS,WELLS,DUVA,M}^{MPSU}$$

where $Q_{m,GAS,WELLS,GJØA\ OIL,M}^{MPSU}$ is calculated using:

$$\begin{aligned} Q_{m,GAS,WELLS,GJØA\ OIL,M}^{MPSU} = {} & Q_{m,GAS,B1}^{MPSU} \cdot S_{B1} \cdot R_{B1} \\ & + Q_{m,GAS,B2}^{MPSU} \cdot S_{B2} \cdot R_{B2} \\ & + Q_{m,GAS,B3}^{MPSU} \cdot S_{B3} \cdot R_{B3} \\ & + Q_{m,GAS,C1}^{MPSU} \cdot S_{C1} \cdot R_{C1} \\ & + Q_{m,GAS,C2}^{MPSU} \cdot S_{C2} \cdot R_{C2} \\ & + Q_{m,GAS,C3}^{MPSU} \cdot S_{C3} \cdot R_{C3} \\ & + Q_{m,GAS,C4}^{MPSU} \cdot S_{C4} \cdot R_{C4} \\ & + Q_{m,GAS,D1}^{MPSU} \cdot S_{D1} \cdot R_{D1} \\ & + Q_{m,GAS,D3}^{MPSU} \cdot S_{D3} \cdot R_{D3} \\ & + Q_{m,GAS,E1}^{MPSU} \cdot S_{E1} \cdot R_{E1} \\ & + Q_{m,GAS,G1}^{MPSU} \cdot S_{G1} \cdot R_{G1} \\ & + Q_{m,GAS,G4}^{MPSU} \cdot S_{G4} \cdot R_{G4} \end{aligned}$$

S - 1 if the well is flowing, 0 if the well is closed
R - Routing (0=Gjøa gas line, 1=Gjøa oil line)

and $Q_{m,GAS,WELLS,DUVA,M}^{MPSU}$ is calculated using:

$$\begin{aligned} Q_{m,GAS,WELLS,DUVA,M}^{MPSU} = {} & Q_{m,GAS,K1}^{MPSU} \\ & + Q_{m,GAS,K2}^{MPSU} \\ & + Q_{m,GAS,K3}^{MPSU} \\ & + Q_{m,GAS,K4}^{MPSU} \end{aligned}$$

Similarly, the oil mass flowrate of Gjøa oil flowline at MPSU pressure and temperature conditions is used as the oil mass HC-fraction for the purpose of recombining the gas and oil compositions into a combined total hydrocarbon composition.

The oil mass flowrate is calculated using:

$$Q_{m,OIL,GJ\O A\ OIL\ FLOWLINE,M}^{MPSU} = Q_{m,OIL,WELLS,GJ\O A\ OIL,M}^{MPSU} + Q_{m,OIL,WELLS,DUVA,M}^{MPSU}$$

where $Q_{m,OIL,WELLS,GJ\O A\ OIL,M}^{MPSU}$ is calculated using:

$$\begin{aligned} Q_{m,OIL,WELLS,GJ\O A\ OIL,M}^{MPSU} = {} & Q_{m,OIL,B1}^{MPSU} \cdot S_{B1} \cdot R_{B1} \\ & + Q_{m,OIL,B2}^{MPSU} \cdot S_{B2} \cdot R_{B2} \\ & + Q_{m,OIL,B3}^{MPSU} \cdot S_{B3} \cdot R_{B3} \\ & + Q_{m,OIL,C1}^{MPSU} \cdot S_{C1} \cdot R_{C1} \\ & + Q_{m,OIL,C2}^{MPSU} \cdot S_{C2} \cdot R_{C2} \\ & + Q_{m,OIL,C3}^{MPSU} \cdot S_{C3} \cdot R_{C3} \\ & + Q_{m,OIL,C4}^{MPSU} \cdot S_{C4} \cdot R_{C4} \\ & + Q_{m,OIL,D1}^{MPSU} \cdot S_{D1} \cdot R_{D1} \\ & + Q_{m,OIL,D3}^{MPSU} \cdot S_{D3} \cdot R_{D3} \\ & + Q_{m,OIL,E1}^{MPSU} \cdot S_{E1} \cdot R_{E1} \\ & + Q_{m,OIL,G1}^{MPSU} \cdot S_{G1} \cdot R_{G1} \\ & + Q_{m,OIL,G4}^{MPSU} \cdot S_{G4} \cdot R_{G4} \end{aligned}$$

and $Q_{m,OIL,WELLS,DUVA,M}^{MPSU}$ is calculated using:

$$\begin{aligned} Q_{m,OIL,WELLS,DUVA,M}^{MPSU} = {} & Q_{m,OIL,K1}^{MPSU} \\ & + Q_{m,OIL,K2}^{MPSU} \\ & + Q_{m,OIL,K3}^{MPSU} \\ & + Q_{m,OIL,K4}^{MPSU} \end{aligned}$$

An accredited laboratory analyse the pressurized gas sample and pressurized liquid sample collected using the MPSU to provide two separate compositional analysis reports containing information on the component mass fractions in the gas sample, $C_{i,GAS,GJ\O A\ OIL\ FLOWLINE,M}^{MPSU}$, and the component mass fractions in the oil sample, $C_{i,OIL,GJ\O A\ OIL\ FLOWLINE,M}^{MPSU}$. The component mass flow based on analysis data may then be calculated using:

$$\begin{aligned} Q_{m,i,GJ\O A\ OIL\ FLOWLINE,M}^{MPSU} = {} & \left(Q_{m,GAS,WELLS,GJ\O A\ OIL,M}^{MPSU} + Q_{m,GAS,WELLS,DUVA,M}^{MPSU}\right) \cdot C_{i,GAS,GJ\O A\ OIL\ FLOWLINE,M}^{MPSU} \\ & + \left(Q_{m,OIL,WELLS,GJ\O A\ OIL,M}^{MPSU} + Q_{m,OIL,WELLS,DUVA,M}^{MPSU}\right) \cdot C_{i,OIL,GJ\O A\ OIL\ FLOWLINE,M}^{MPSU} \end{aligned}$$

Finally, the component mass fraction of the total hydrocarbon mass flow may be calculated:

$$C_{i,HC,GJ\O A\ OIL\ FLOWLINE,M}^{MPSU} = \frac{Q_{m,i,GJ\O A\ OIL\ FLOWLINE,M}^{MPSU}}{\sum_i Q_{m,i,GJ\O A\ OIL\ FLOWLINE,M}^{MPSU}}$$

Note that the equations provided in this section are valid regardless of which Gjøa oil header the fluid samples are obtained from.

6.2 Nova flowline A samples

The **gas mass flowrate** of Nova flowline A (including lift gas) at MPSU pressure and temperature conditions is used as the gas mass HC-fraction for the purpose of recombining the gas and oil compositions into a combined total hydrocarbon composition. The gas mass flowrate is calculated using:

$$\begin{aligned}Q_{m,GAS,WELLS,NOVA\ FLA,M}^{MPSU} &= Q_{m,GAS,X2} \cdot S_{X2} \cdot (1 - R_{X2}) \\ &+ Q_{m,GAS,X3} \cdot S_{X3} \cdot (1 - R_{X3}) \\ &+ Q_{m,GAS,X4} \cdot S_{X4} \cdot (1 - R_{X4})\end{aligned}$$

S - 1 if the well is flowing, 0 if the well is closed
R - Routing (0=Nova flowline A, 1=Nova flowline B)

Similarly, the **oil mass flowrate** of Nova flowline A at MPSU pressure and temperature conditions is used as the oil mass HC-fraction for the purpose of recombining the gas and oil compositions into a combined total hydrocarbon composition. The oil mass flowrate is calculated using:

$$\begin{aligned}Q_{m,OIL,WELLS,NOVA\ FLA,M}^{MPSU} &= Q_{m,OIL,X2} \cdot S_{X2} \cdot (1 - R_{X2}) \\ &+ Q_{m,OIL,X3} \cdot S_{X3} \cdot (1 - R_{X3}) \\ &+ Q_{m,OIL,X4} \cdot S_{X4} \cdot (1 - R_{X4})\end{aligned}$$

The accredited laboratory shall analyse the pressurized gas sample and pressurized liquid sample collected using the MPSU to provide two separate compositional analysis reports containing information on the component mass fractions in the gas sample, $C_{i,GAS,NOVA\ FLA,M}^{MPSU}$, and the component mass fractions in the oil sample, $C_{i,OIL,NOVA\ FLA,M}^{MPSU}$. The component mass flow based on analysis data may then be calculated using:

$$\begin{aligned}Q_{m,i,NOVA\ FLA,M}^{MPSU} &= Q_{m,GAS,WELLS,NOVA\ FLA,M}^{MPSU} \cdot C_{i,GAS,NOVA\ FLA,M}^{MPSU} \\ &+ Q_{m,OIL,WELLS,NOVA\ FLA,M}^{MPSU} \cdot C_{i,OIL,NOVA\ FLA,M}^{MPSU}\end{aligned}$$

Finally, the mass fraction of the total hydrocarbon mass flow may be calculated:

$$C_{i,HC,NOVA\ FLA,M}^{MPSU} = \frac{Q_{m,i,NOVA\ FLA,M}^{MPSU}}{\sum_i Q_{m,i,NOVA\ FLA,M}^{MPSU}}$$

6.3 Nova flowline B samples

The **gas mass flowrate** of Nova flowline B (including lift gas) at MPSU pressure and temperature conditions is used as the gas mass HC-fraction for the purpose of recombining the gas and oil compositions into a combined total hydrocarbon composition. The gas mass flowrate is calculated using:

$$\begin{aligned} Q_{m,GAS,WELLS,NOVA\ FLB,M}^{MPSU} = {} & Q_{m,GAS,X2} \cdot S_{X2} \cdot R_{X2} \\ & + Q_{m,GAS,X3} \cdot S_{X3} \cdot R_{X3} \\ & + Q_{m,GAS,X4} \cdot S_{X4} \cdot R_{X4} \end{aligned}$$

S	-	1 if the well is flowing, 0 if the well is closed
R	-	Routing (0=Nova flowline A, 1=Nova flowline B)

Similarly, the **oil mass flowrate** of Nova flowline B at MPSU pressure and temperature conditions is used as the oil mass HC-fraction for the purpose of recombining the gas and oil compositions into a combined total hydrocarbon composition. The oil mass flowrate is calculated using:

$$\begin{aligned} Q_{m,OIL,WELLS,NOVA\ FLB,M}^{MPSU} = {} & Q_{m,OIL,X2} \cdot S_{X2} \cdot R_{X2} \\ & + Q_{m,OIL,X3} \cdot S_{X3} \cdot R_{X3} \\ & + Q_{m,OIL,X4} \cdot S_{X4} \cdot R_{X4} \end{aligned}$$

The accredited laboratory analyse the pressurized gas sample and pressurized liquid sample collected using the MPSU to provide two separate compositional analysis reports containing information on the component mass fractions in the gas sample, $C_{i,GAS,NOVA\ FLB,M}^{MPSU}$, and the component mass fractions in the oil sample, $C_{i,OIL,NOVA\ FLB,M}^{MPSU}$. The component mass flow based on analysis data may then be calculated using:

$$\begin{aligned} Q_{m,i,NOVA\ FLB,M}^{MPSU} = {} & Q_{m,GAS,WELLS,NOVA\ FLB,M}^{MPSU} \cdot C_{i,GAS,NOVA\ FLB,M}^{MPSU} \\ & + Q_{m,OIL,WELLS,NOVA\ FLB,M}^{MPSU} \cdot C_{i,OIL,NOVA\ FLB,M}^{MPSU} \end{aligned}$$

Finally, the mass fraction of the total hydrocarbon mass flow may be calculated:

$$C_{i,HC,NOVA\ FLB,M}^{MPSU} = \frac{Q_{m,i,NOVA\ FLB,M}^{MPSU}}{\sum_i Q_{m,i,NOVA\ FLB,M}^{MPSU}}$$

7 MPSU TESTING AND QUALIFICATION

The MPSU system has been tested in three phases. First, it was sent to K-Lab (Kårstø) for initial qualification testing in 2021. Then, after being installed offshore, a field qualification test was performed with the same personnel as performed the test at K-lab (2022). Last, normal operational samples were taken by trained Neptune laborants (2023). These three tests are described in the following chapters.

7.1 SAT/ Qualification test at K-Lab (2021)

The purpose of the qualification test was to verify that the MPSU can collect representative pressurized oil and gas samples from a multiphase flowline. Hence, the composition of the MPSU oil and gas samples should be representative for the composition of the oil and gas phases in the multiphase flowline. K-Lab VGII Multiphase test loop at Kårstø provided reference data for the oil and gas composition with live fluids. A simplified flow loop diagram is shown in Figure 11.

At K-lab, the test section is located downstream the single phase reference metering stations and the mixing points. After flowing through the test section, the fluids return to the main separator vessel (Guard separator). Figure 12 shows a 3D drawing of the test section. The test section piping is 8'', hence similar to one of the flow lines at the Gjøa platform. The sample probe was located on a vertical pipe, downstream a blinded-T. The same piping was used for the FAT of one of the topside multiphase flow meter that is installed at Gjøa, except the spool piece where the sample probe is mounted. Here, a new spool piece was used with an ID that matched the sample probe dimensions.

In the SAT, the probe extraction port at the pipe wall was used for most test points. The motivation for choosing the port at the pipe wall was that a higher liquid fraction was expected close to the pipe wall, and it was considered advantageous to increase the amount of sampled liquid. In general, the port should be chosen such that a sufficient amount of liquid is sampled. For instance, if the GVF is high the liquid tend to flow along the pipe wall. If sufficient liquid can be sampled through either bore, use of the pipe centre bore hole is advised, as it consistent with best practice for single phase sampling.

The SAT test results are documented and discussed in detail in a report delivered by NORCE, only key highlights are included in this paper. The report can be made available upon request by Neptune Energy.

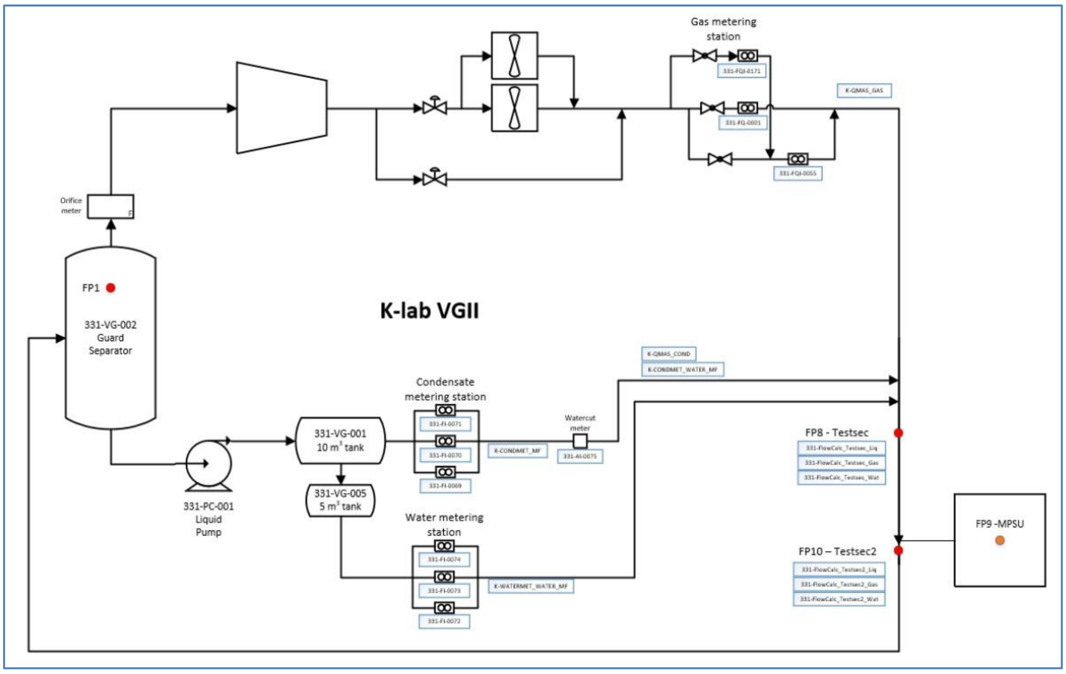


Figure 11. Simplified flow loop diagram of K-Lab VGII Multiphase test loop

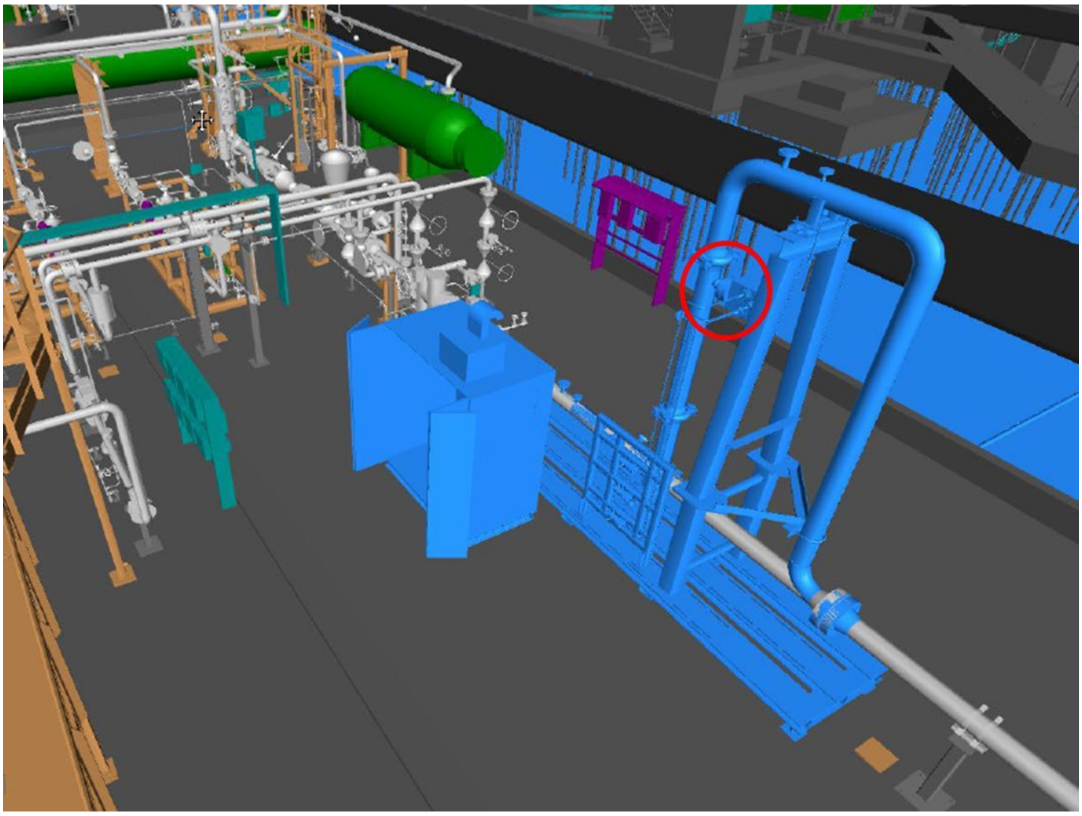


Figure 12. 3D model of MPSU and piping experimental set-up. The position of the sample probe is marked with a red oval. The direction of the flow is from left to right

The standard procedure for collecting single phase samples is listed below.

1. Wait for stabilized process conditions (flow rates, pressure, temperature, phase densities)
2. Allow for process fluid towards MPSU separator and wait for stabilized separator pressure (typically around 2 minutes). The reference data from K-lab is based on the reference measurements in this approximately 2 minutes long period. The valves between the separator and the sample probe are kept open after the pressure has stabilized, until the last point below when the separator is emptied for fluid after sampling. Hence, any loss of fluid/pressure from the separator due to draining, flaring and transferring of samples will be compensated by new process fluid flowing into the separator. The separator pressure is therefore maintained close to the process pressure until the separator is emptied for fluid.
3. Start 5 min flushing period. Liquid is sent to drain and gas is sent to flare. The drained/flared fluid will be replaced by new process fluid
4. Wait 5 minutes for separation and stabilization
5. Transfer gas sample to pressurized cylinder
6. If needed: Drain water and/or flare gas to secure that the oil layer is sufficiently thick, and that the oil layer is positioned at the same level as the oil probe
7. Transfer oil sample to pressurized cylinder
8. Transfer water sample to atmospheric sample container (if WLR is nonzero)
9. Drain liquid and flare gas until the separator is empty

7.1.1 Test matrix K-Lab

The test matrix was designed according to the following criteria and limitations

- Two different pressures. The operational envelope of the flow loop limited the maximum pressure to 60 bar and the final test matrix includes 4 points at this pressure level. The other pressure level used in the matrix is 30 bar, which is similar to the typical topside pressure range of the relevant flow lines at the Gjøa platform.
- Different flow velocities. This is done by changing the flow velocity and keeping the other parameters (pressure, GVF and WLR) constant. The maximum liquid flow rate of the flow loop is around 140 m^3/h and is the limiting parameter for the maximum velocity for most GVFs.
- Different GVF and WLR. The test matrix spans the expected range of GVF and WLR.

The test matrix spanned different GVF, WLR, velocities and pressures, as summarized in Table 1. In total, 61 pairs of oil and gas samples were collected. With 61 sample pairs, 122 pressurised sample cylinders were used for the duration of the test. The composition of the samples was measured up to C10+. Table 2 presents the final version of the SAT test matrix.

Table 1: Test envelope at K-Lab

Parameter	Range
GVF	20%-99%
WLR	0%-98%
Velocity	1 m/s - 25 m/s
Pressure	30 bar & 60 bar

Table 2 Final version SAT test matrix

Test point	Test section velocity (m/s)	Liquid flow rate (m^3/h)	GVF (%)	WLR (%)	Pressure [bar]	Repetitions	Single phase samples	Flow-through samples
Pro1	2	140	20	0	3	3	3	0
Pro2	1	70	20	0	3	3	3	0
Pro3	3	140	50	30	3	3	3	0
Pro4	1	70	50	70	3	2	2	0
Pro5	2	23	99	0	3	3	3	0
Pro6	1	12	99	0	3	3	3	0
Pro7	6	140	75	0	3	1	12	0
Pro8	3	70	74	0	3	7	7	0
Pro9	2	140	38	82	3	5	5	0
Pro10	1	70	37	81	3	5	5	0
Pro11	2	140	20	98	3	3	3	0
Pro13	2	140	20	5	3	5	0	5
Pro14	6	140	75	0	6	3	3	0
Pro15	3	70	74	0	6	3	3	0
Pro16	2	140	38	82	6	3	3	0
Pro17	1	70	37	81	6	8	3	5

7.1.2 Results qualification testing at K-Lab

For most samples, the observed deviations from the reference data are small, and the system also demonstrates a good repeatability. The key findings are:

- The overall results are considered to be satisfactory. For most samples good agreement with the reference data is achieved
- Some of the observed deviations from the reference data are believed to be related to lack of thermodynamic equilibrium in the MPSU separator at the time of sample transfer to the sample cylinders
- It was found that liquid-carry-over from the MPSU separator could contaminate the gas samples
- The observed deviations in the recombined hydrocarbon compositions are dominated by the deviations from the oil samples, since oil mass fraction of the hydrocarbon composition was high for most test points

The test gave valuable insights to the systems behaviour. The operation of the system was optimised and documented in the operation procedure to be used when the system is operated onboard Gjøa.

Results from all tests are not included here, Figure 13, Figure 14 and Figure 15 compare the measured gas compositions, measured oil composition and recombined HC composition with the corresponding K-lab reference data for test point Pro10. The results for Pro10 are rather typical for the SAT. Results from all test can be found in the attached SAT report

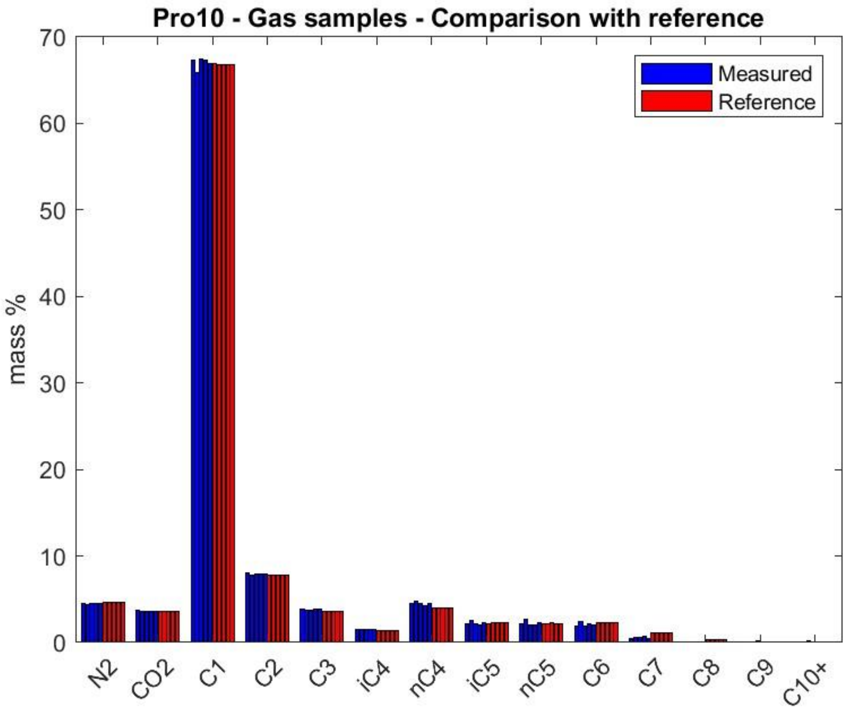


Figure 13: Pro10 measured gas samples compared with reference

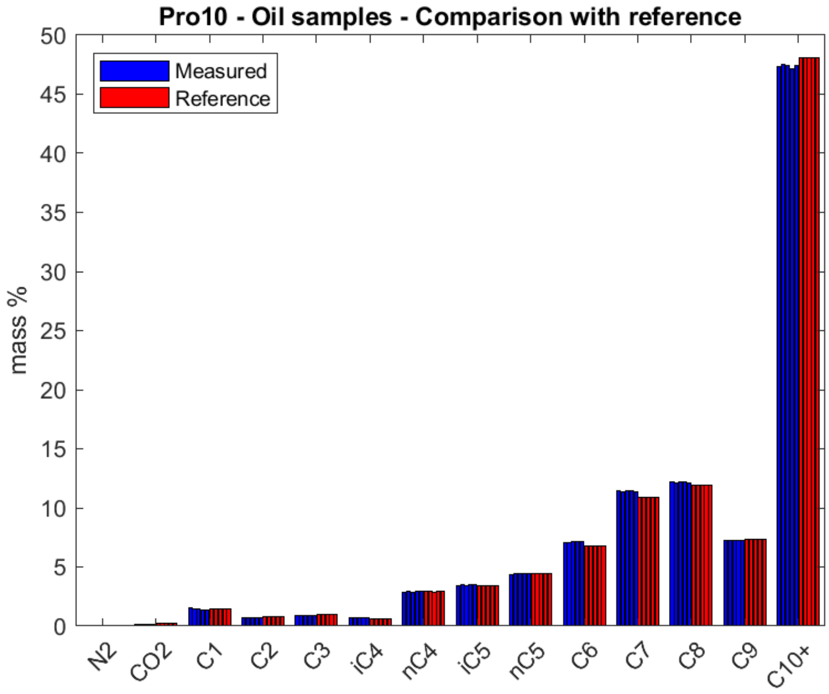


Figure 14: Pro10 measured oil sample compared with reference

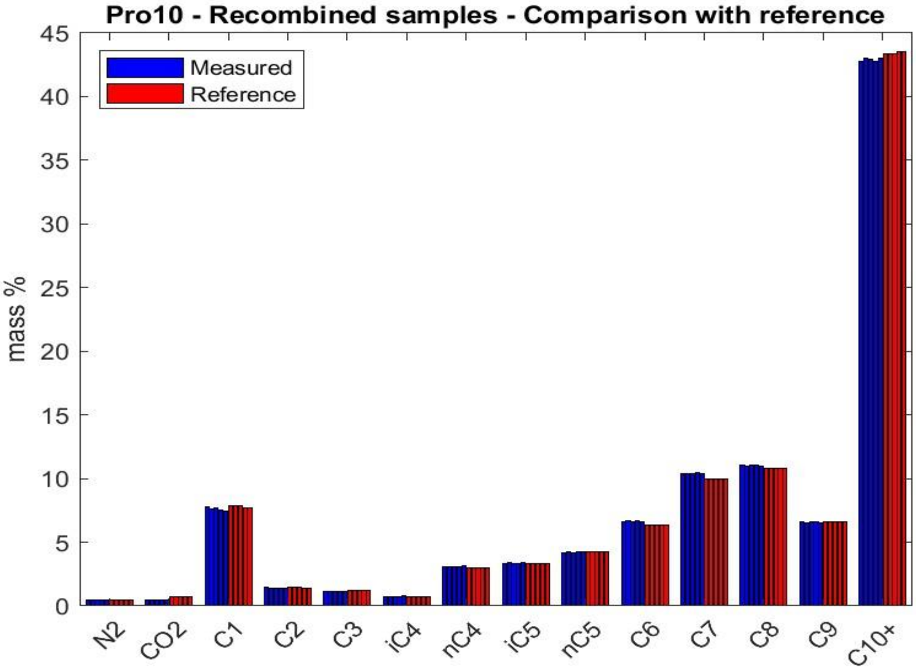


Figure 15: Pro 10 recombined HC composition compared with reference

Figure 16 and Figure 17 sum up the overall results for the SAT. The median value of the deviation from reference is plotted for each component for the gas samples, the oil samples and the recombined HC compositions. A positive value means the measured value is higher than the reference, and vice versa. The median deviations represent the typical observed deviations:

- The measured concentration of the light components in the oil samples is lower than reference. This is assumed to be caused by lack of thermodynamic equilibrium at the time of sample transfer to the cylinder
- The measured concentration of C6-C9 in the oil samples is higher than reference, while C10+ is lower than reference. These deviations are contended to be within the combined uncertainty of the reference data and the lab measurement uncertainty.
- The measured gas composition is lighter than the reference. Hence, the measured concentration of the heavier components is lower than reference, and the measured concentration of the lighter components is higher than reference. This is assumed to be caused by lack of thermodynamic equilibrium at the time of sample transfer to the cylinder.
- The deviations observed for the recombined HC composition are dominated by the deviations for the oil samples. This is due to high oil mass fraction for most test points.

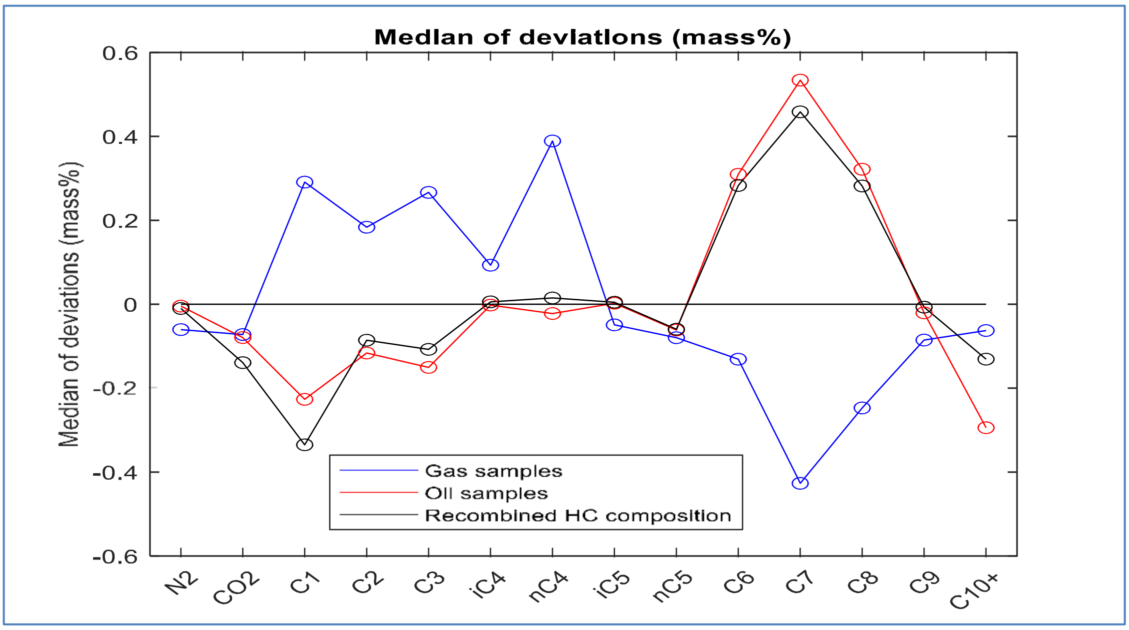


Figure 16. Median values of the deviation from reference is plotted for each component for the gas samples, the oil samples and the recombined HC compositions

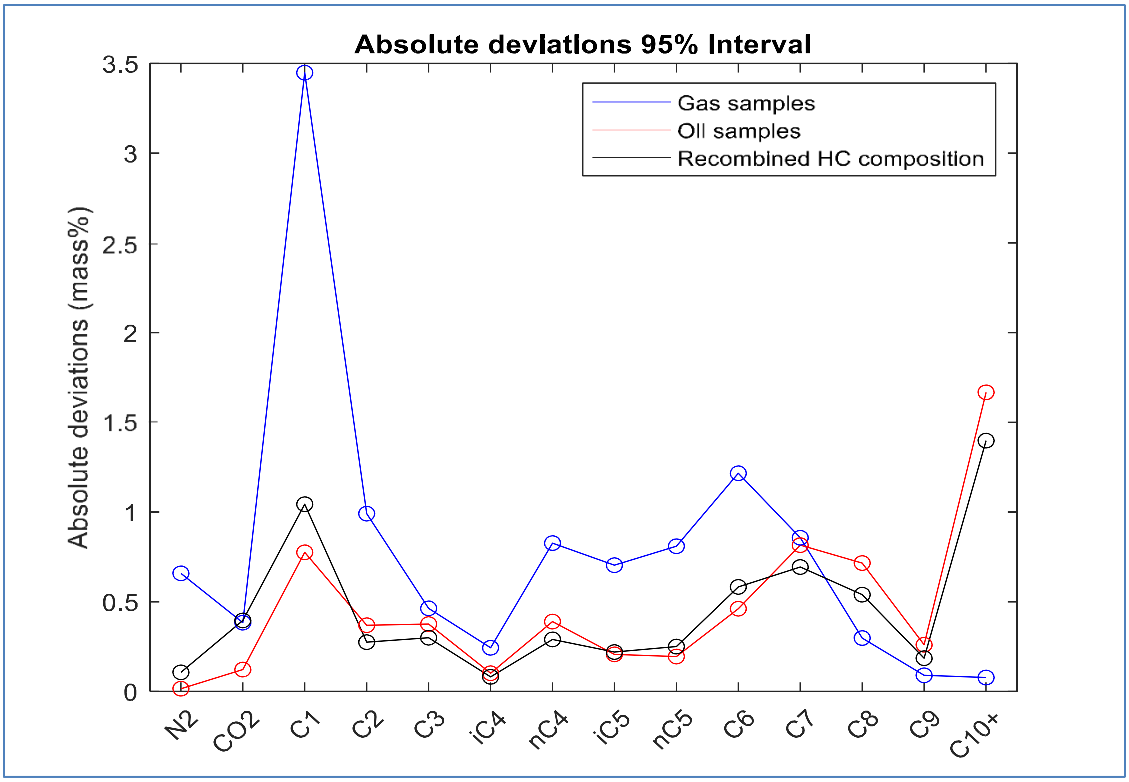


Figure 17: Absolute values which 95 % of the deviations are found, for gas samples, oil samples and recombined HC

7.1.3 K-Lab laboratory analysis

The gas samples were analysed by the laboratory at Kårstø Processing Plant. The samples were analysed according to a modified method of ASTM D 1945, ISO6975 and GPA2261, latest version. This is K-lab's standard procedure.

The oil samples were analysed by Expro Petrotech in Haugesund. The description given below is based on communication with Expro Petrotech. In order to find the composition of the sample, a number of procedures and measurements are necessary:

1. The sample is flashed to atmospheric pressure and room temperature. The volume of flashed gas and the weight and the density of the flashed oil are measured. The measured gas volume is corrected to standard conditions (1.01325 bara and 15 °C). The GOR can then be calculated. An internal, non-accredited method is used for the flash to atmospheric conditions and measurement of the flashed gas volume. The density of the flashed oil is measured according to ASTM D5002-19
2. The average molecular weight of the flashed oil is measured according to an internal, accredited method based on measurement of freezing-point depression
3. The composition of the flashed oil is measured according to a modified version of ASTM D5134-17. Both a pre-column and an analytical column is used. Pre-columns are often used in GC analysis to pre-separate the light and heavy components in the sample before the sample enters the analytical column. The analytical column separates the light fraction of the sample (up to n-C9), and a flame ionization detector (FID) is used for detection and quantification of the individual hydrocarbons up to n-C9. The heavier fraction (C10+) is backflushed to vent before it reaches the FID. In order to quantify the amount of the different components, including the C10+ fraction, a known weight fraction of i-C8 is added as an internal standard to the sample before injection to the GC.
4. The composition of the flashed gas is measured according to ASTM D1945-14
5. The flashed gas density is calculated from the measured flashed gas composition
6. Molecular weights of the C6-C9 pseudo components are found based on measurement of the PNA (paraffin-naphthene-aromatic) distribution and standard molecular weights for C6-C9 paraffins, naphthenes and aromatic pseudo components.

With these measurements the composition of the original sample can be recombined and expressed both in mole% and mass%.

The measured oil and gas compositions are recombined to a HC composition according to the following formula:

$$c_{HC}^{i} = c_{oil}^{i} * \left(\frac{q_{oil}}{q_{oil} + q_{gas}}\right) + c_{gas}^{i} * \left(\frac{q_{gas}}{q_{oil} + q_{gas}}\right)$$

Where:

- c_{HC}^{i} is the mass fraction of component i in the recombined HC composition
- c_{HC}^{i} is the measured mass fraction of component i in the oil sample
- c_{HC}^{i} is the measured mass fraction of component i in the gas sample
- q_{oil} is the reference oil mass flow rate at the MPSU sample probe conditions
- q_{gas} is the reference gas mass flow rate at the MPSU sample probe conditions

K-lab has a PVT model of the flow loop based on PVTsim Nova from Calsep. Based on knowledge of the total hydrocarbon composition in the flow loop, measured single phase flow rates of oil, gas and water, the PVT model can provide the phase (oil, gas and water) flow rates, compositions and densities for a given pressure and temperature. Hence, the PVT model can provide the oil and gas composition at MPSU sample probe conditions. The phase compositions given by the PVT model serve as the reference to which the measured oil and gas sample compositions are compared. The reference phase mass flow rates given by the PVT model can be used to recombine the measured oil and gas sample compositions to a HC composition, which in turn can be compared to the HC composition given by the PVT model.

7.1.4 Sample probe bore hole dependency

As mentioned earlier, the sample probes used in the MPSU system has three probe bores. For test point Pro7 twelve repetitions were carried out to examine if the choice of sample probe bore hole influenced the results. Three repetitions were carried out using the pipe centre bore hole, three repetitions using the off-centre or middle bore hole, three repetitions using the pipe wall bore hole, and finally three repetitions using all three bore holes simultaneously.

Figure 18 and Figure 19 compare the measured gas and oil compositions for Pro7 with the reference data. Different bar colours are used to distinguish which bore hole(s) that were used for sampling. The reference data were very stable through all twelve repetitions and are therefore plotted with the same colour (black).

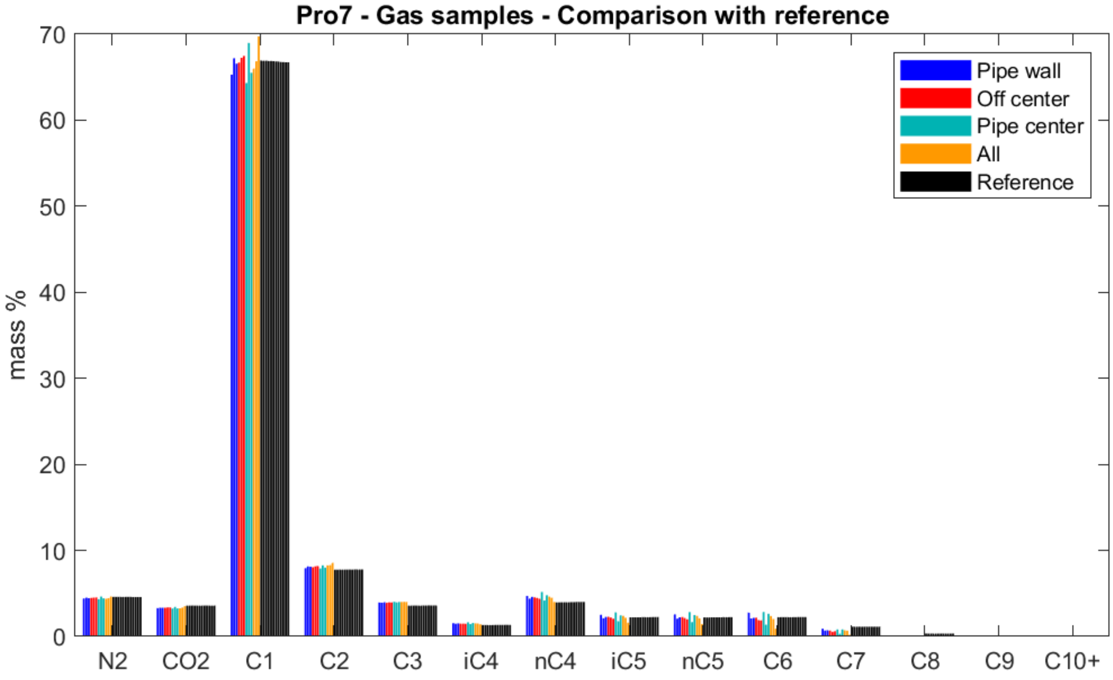


Figure 18: Pro7 measured gas samples compositions compared with reference

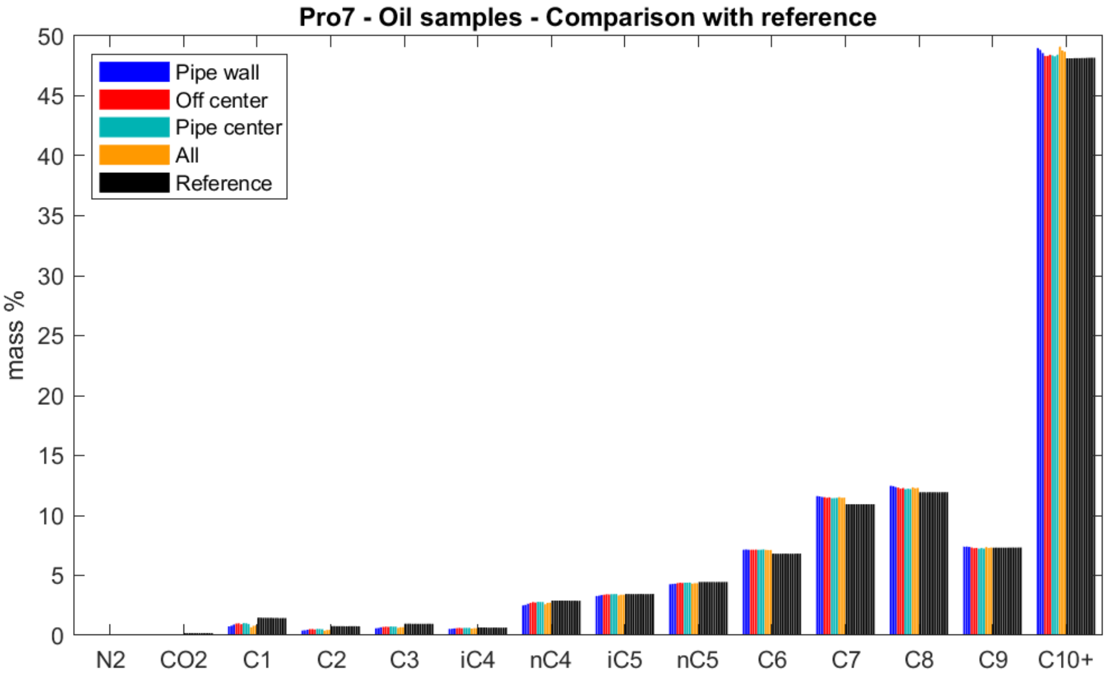


Figure 19: Pro7 measured oil samples compositions compared with reference

7.2 Field qualification test (2022-2023)

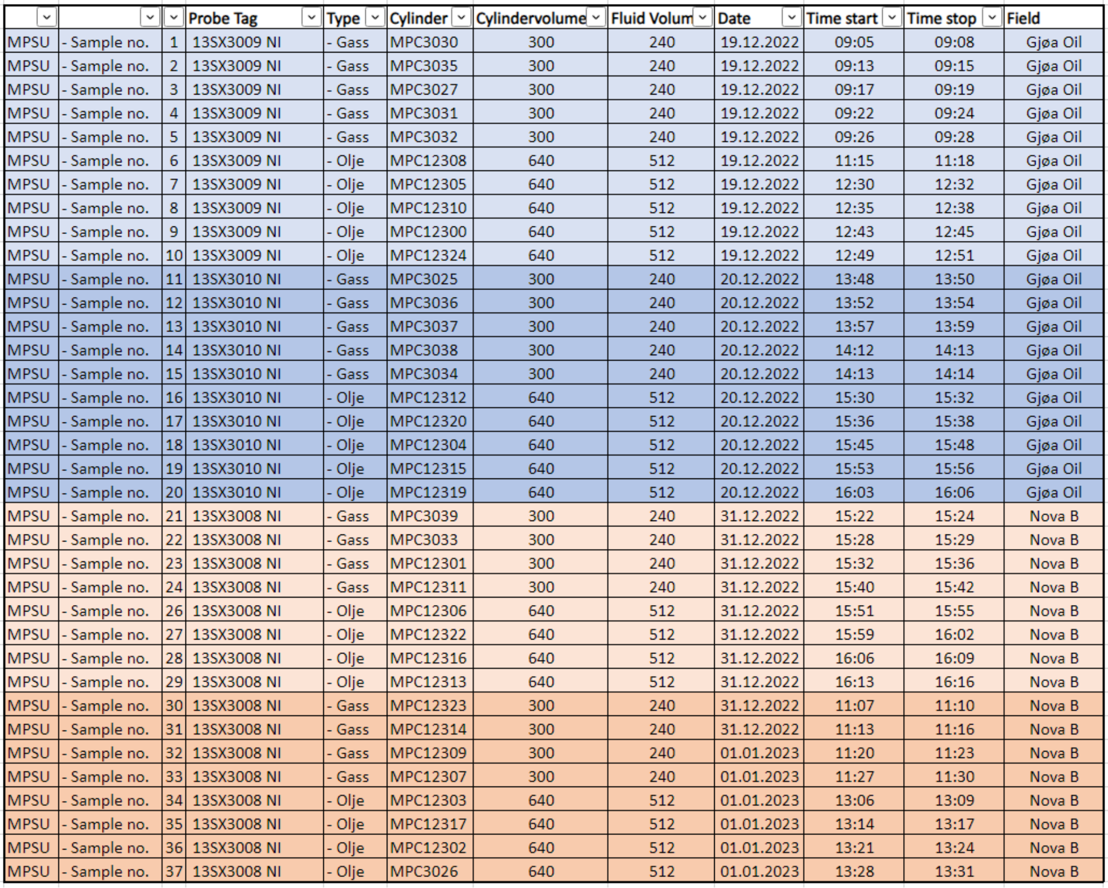
Once the MPSU system was commissioned and handed over to operations, the vendor was engaged to perform qualification tests offshore and to perform on site training for the laborants. The goal of this field test was to reproduce the results from the SAT test at K-lab and to verify the PVT flash calculations performed in the metering supervisory system towards the analysed samples.

The test program is listed in Table 3. At the time of testing, the 12" Nova riser was not operational, hence samples were taken from the Nova 8" riser. This test was performed by filling the MPSU mini separator was to the correct levels, then 4-5 gas samples and 4-5 oil samples were taken using pressurized cylinders while the valves to the flowline was open. This procedure was the same as used during the SAT test. Oil and gas samples were sent to third party laboratory for analysis.

Some key findings.

- Largest deviation is seen in the C1 and C10+ fraction
- Results matches the behaviour seen in both the qualification tests done offshore and at K-Lab

Table 3: MPSU Qualification test samples



			Probe Tag	Type	Cylinder	Cylindervolume	Fluid Volum	Date	Time start	Time stop	Field
MPSU	- Sample no.	1	13SX3009 NI	- Gass	MPC3030	300	240	19.12.2022	09:05	09:08	Gjøa Oil
MPSU	- Sample no.	2	13SX3009 NI	- Gass	MPC3035	300	240	19.12.2022	09:13	09:15	Gjøa Oil
MPSU	- Sample no.	3	13SX3009 NI	- Gass	MPC3027	300	240	19.12.2022	09:17	09:19	Gjøa Oil
MPSU	- Sample no.	4	13SX3009 NI	- Gass	MPC3031	300	240	19.12.2022	09:22	09:24	Gjøa Oil
MPSU	- Sample no.	5	13SX3009 NI	- Gass	MPC3032	300	240	19.12.2022	09:26	09:28	Gjøa Oil
MPSU	- Sample no.	6	13SX3009 NI	- Olje	MPC12308	640	512	19.12.2022	11:15	11:18	Gjøa Oil
MPSU	- Sample no.	7	13SX3009 NI	- Olje	MPC12305	640	512	19.12.2022	12:30	12:32	Gjøa Oil
MPSU	- Sample no.	8	13SX3009 NI	- Olje	MPC12310	640	512	19.12.2022	12:35	12:38	Gjøa Oil
MPSU	- Sample no.	9	13SX3009 NI	- Olje	MPC12300	640	512	19.12.2022	12:43	12:45	Gjøa Oil
MPSU	- Sample no.	10	13SX3009 NI	- Olje	MPC12324	640	512	19.12.2022	12:49	12:51	Gjøa Oil
MPSU	- Sample no.	11	13SX3010 NI	- Gass	MPC3025	300	240	20.12.2022	13:48	13:50	Gjøa Oil
MPSU	- Sample no.	12	13SX3010 NI	- Gass	MPC3036	300	240	20.12.2022	13:52	13:54	Gjøa Oil
MPSU	- Sample no.	13	13SX3010 NI	- Gass	MPC3037	300	240	20.12.2022	13:57	13:59	Gjøa Oil
MPSU	- Sample no.	14	13SX3010 NI	- Gass	MPC3038	300	240	20.12.2022	14:12	14:13	Gjøa Oil
MPSU	- Sample no.	15	13SX3010 NI	- Gass	MPC3034	300	240	20.12.2022	14:13	14:14	Gjøa Oil
MPSU	- Sample no.	16	13SX3010 NI	- Olje	MPC12312	640	512	20.12.2022	15:30	15:32	Gjøa Oil
MPSU	- Sample no.	17	13SX3010 NI	- Olje	MPC12320	640	512	20.12.2022	15:36	15:38	Gjøa Oil
MPSU	- Sample no.	18	13SX3010 NI	- Olje	MPC12304	640	512	20.12.2022	15:45	15:48	Gjøa Oil
MPSU	- Sample no.	19	13SX3010 NI	- Olje	MPC12315	640	512	20.12.2022	15:53	15:56	Gjøa Oil
MPSU	- Sample no.	20	13SX3010 NI	- Olje	MPC12319	640	512	20.12.2022	16:03	16:06	Gjøa Oil
MPSU	- Sample no.	21	13SX3008 NI	- Gass	MPC3039	300	240	31.12.2022	15:22	15:24	Nova B
MPSU	- Sample no.	22	13SX3008 NI	- Gass	MPC3033	300	240	31.12.2022	15:28	15:29	Nova B
MPSU	- Sample no.	23	13SX3008 NI	- Gass	MPC12301	300	240	31.12.2022	15:32	15:36	Nova B
MPSU	- Sample no.	24	13SX3008 NI	- Gass	MPC12311	300	240	31.12.2022	15:40	15:42	Nova B
MPSU	- Sample no.	26	13SX3008 NI	- Olje	MPC12306	640	512	31.12.2022	15:51	15:55	Nova B
MPSU	- Sample no.	27	13SX3008 NI	- Olje	MPC12322	640	512	31.12.2022	15:59	16:02	Nova B
MPSU	- Sample no.	28	13SX3008 NI	- Olje	MPC12316	640	512	31.12.2022	16:06	16:09	Nova B
MPSU	- Sample no.	29	13SX3008 NI	- Olje	MPC12313	640	512	31.12.2022	16:13	16:16	Nova B
MPSU	- Sample no.	30	13SX3008 NI	- Gass	MPC12323	300	240	31.12.2022	11:07	11:10	Nova B
MPSU	- Sample no.	31	13SX3008 NI	- Gass	MPC12314	300	240	31.12.2022	11:13	11:16	Nova B
MPSU	- Sample no.	32	13SX3008 NI	- Gass	MPC12309	300	240	01.01.2023	11:20	11:23	Nova B
MPSU	- Sample no.	33	13SX3008 NI	- Gass	MPC12307	300	240	01.01.2023	11:27	11:30	Nova B
MPSU	- Sample no.	34	13SX3008 NI	- Olje	MPC12303	640	512	01.01.2023	13:06	13:09	Nova B
MPSU	- Sample no.	35	13SX3008 NI	- Olje	MPC12317	640	512	01.01.2023	13:14	13:17	Nova B
MPSU	- Sample no.	36	13SX3008 NI	- Olje	MPC12302	640	512	01.01.2023	13:21	13:24	Nova B
MPSU	- Sample no.	37	13SX3008 NI	- Olje	MPC3026	640	512	01.01.2023	13:28	13:31	Nova B

Below are the results showing the average values from the repetitions and the associated deviation of the oil and gas samples

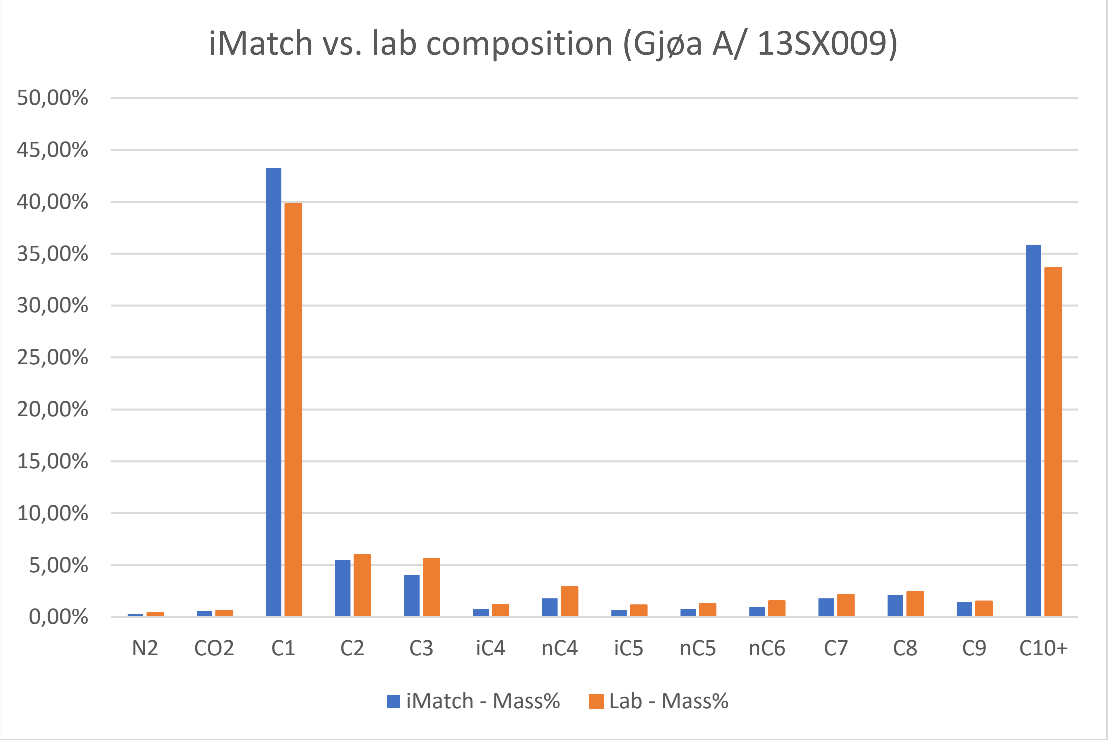


Figure 20: iMatch vs. lab composition Gjøa Flowlina A

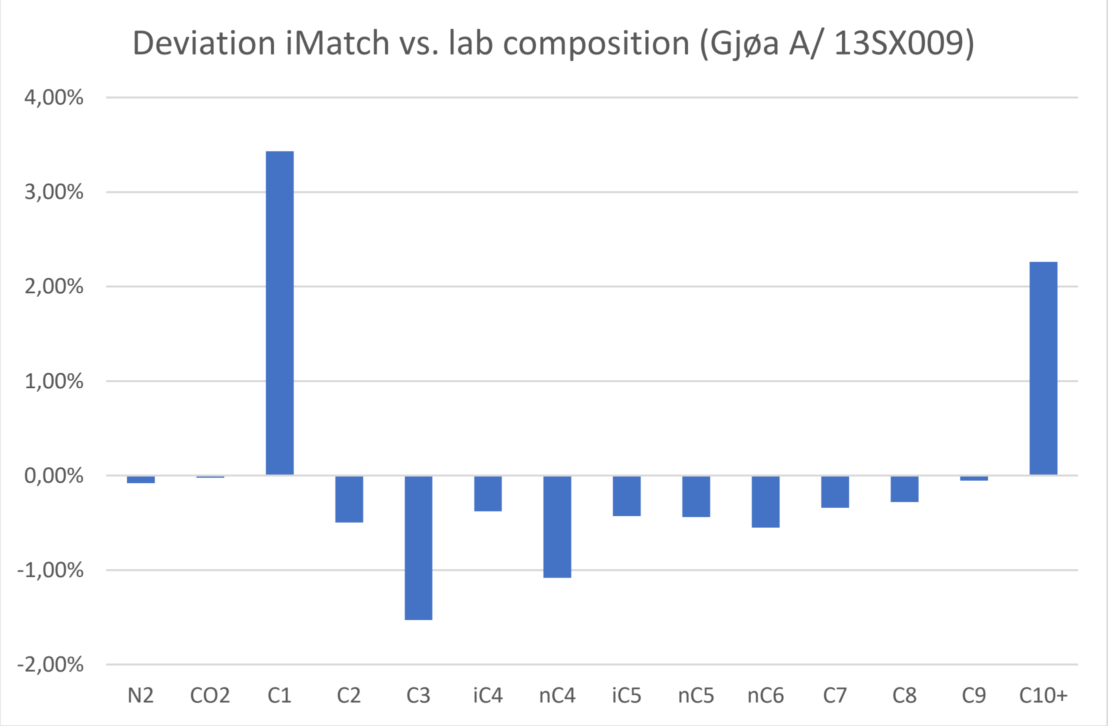


Figure 21: iMatch vs. lab deviation (Absolute) Gjøa Flowline A

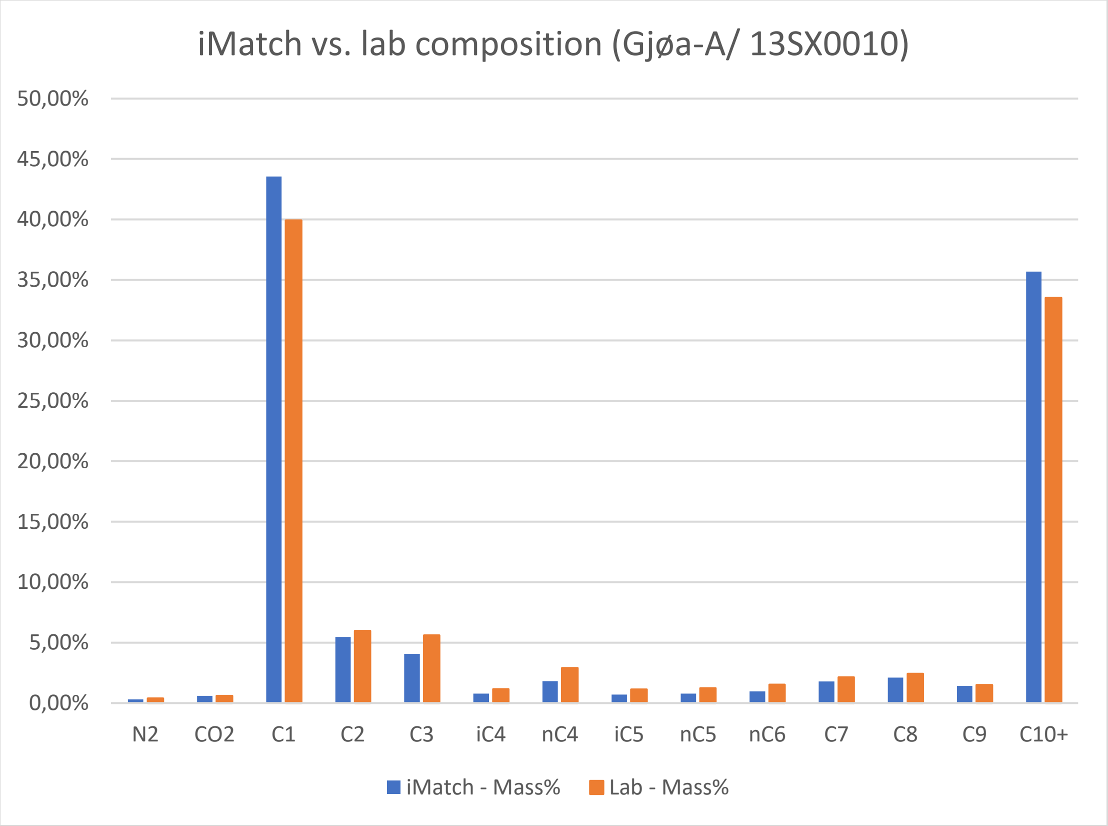


Figure 22: iMatch vs. lab composition Gjøa Flowline A

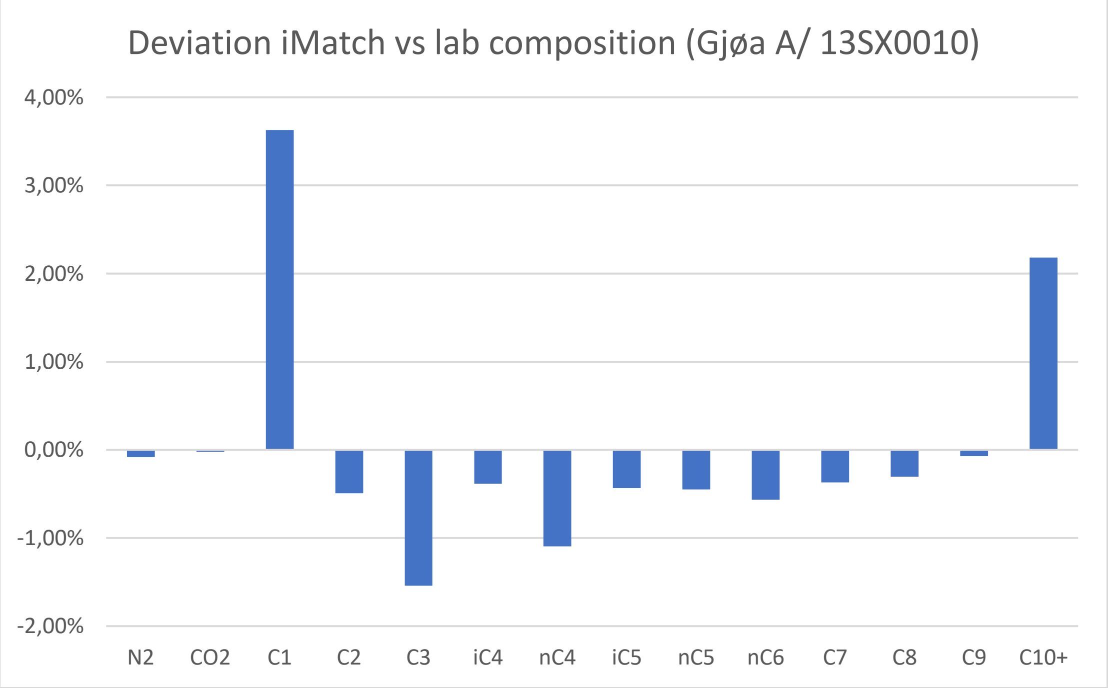


Figure 23: iMatch vs. lab deviation (absolute) Gjøa Flowline A

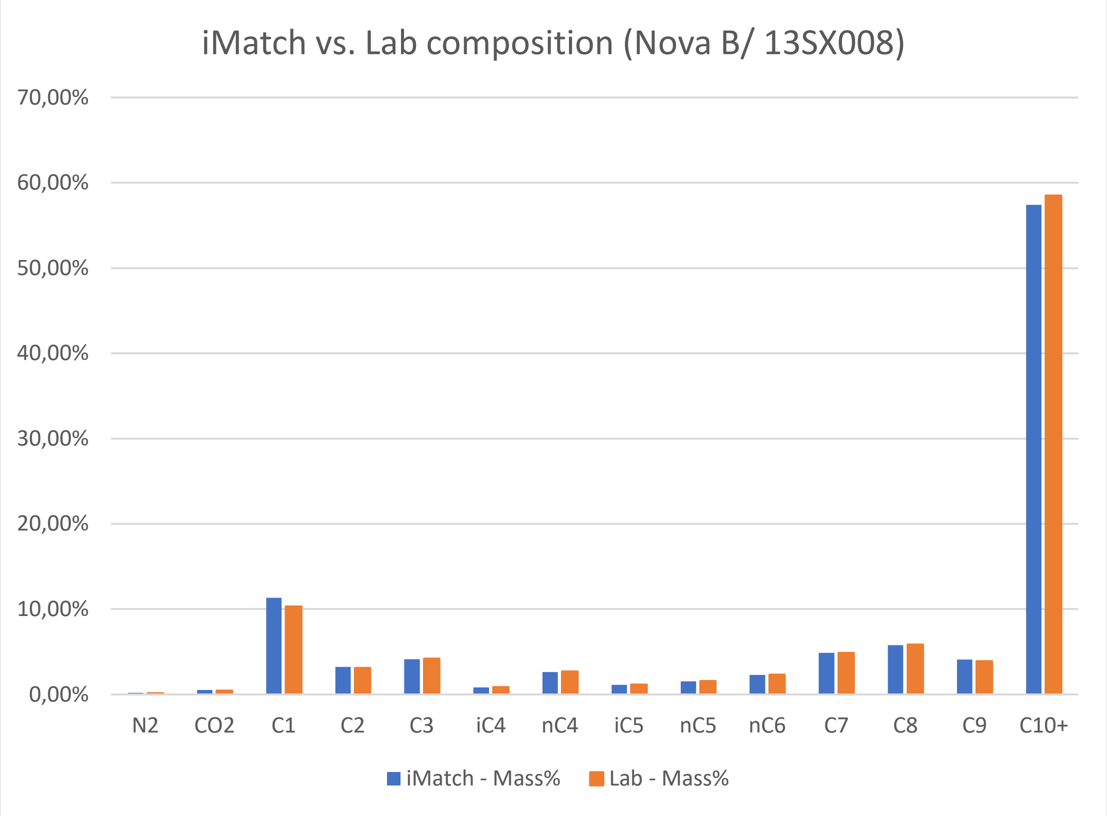


Figure 24: iMatch vs. lab composition Nova Flowline B

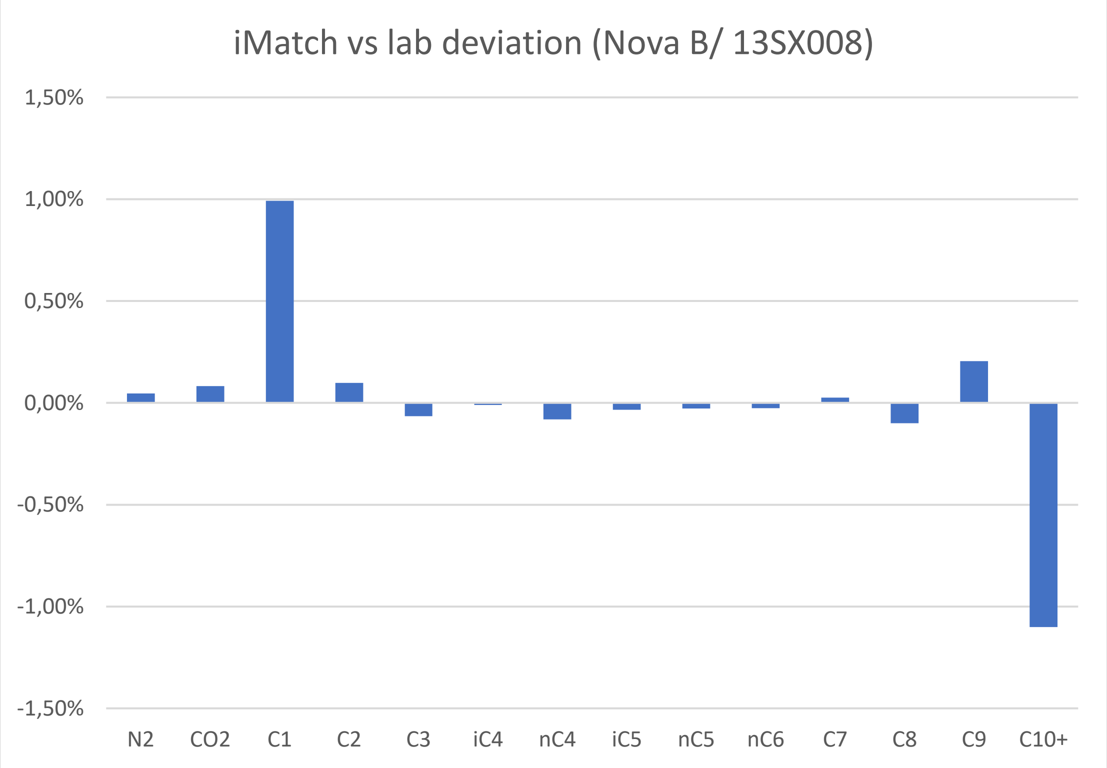


Figure 25: iMatch vs. lab deviation (absolute) Nova Flowline B

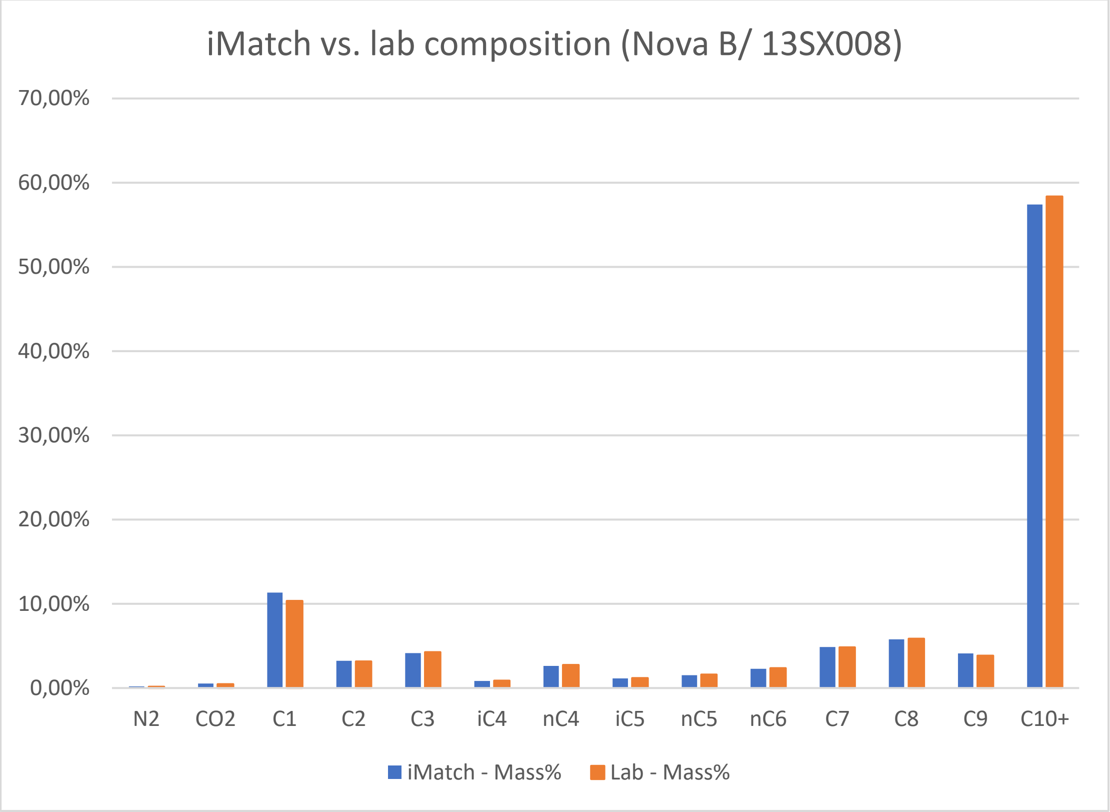


Figure 26: iMatch vs. lab composition Nova Flowline B

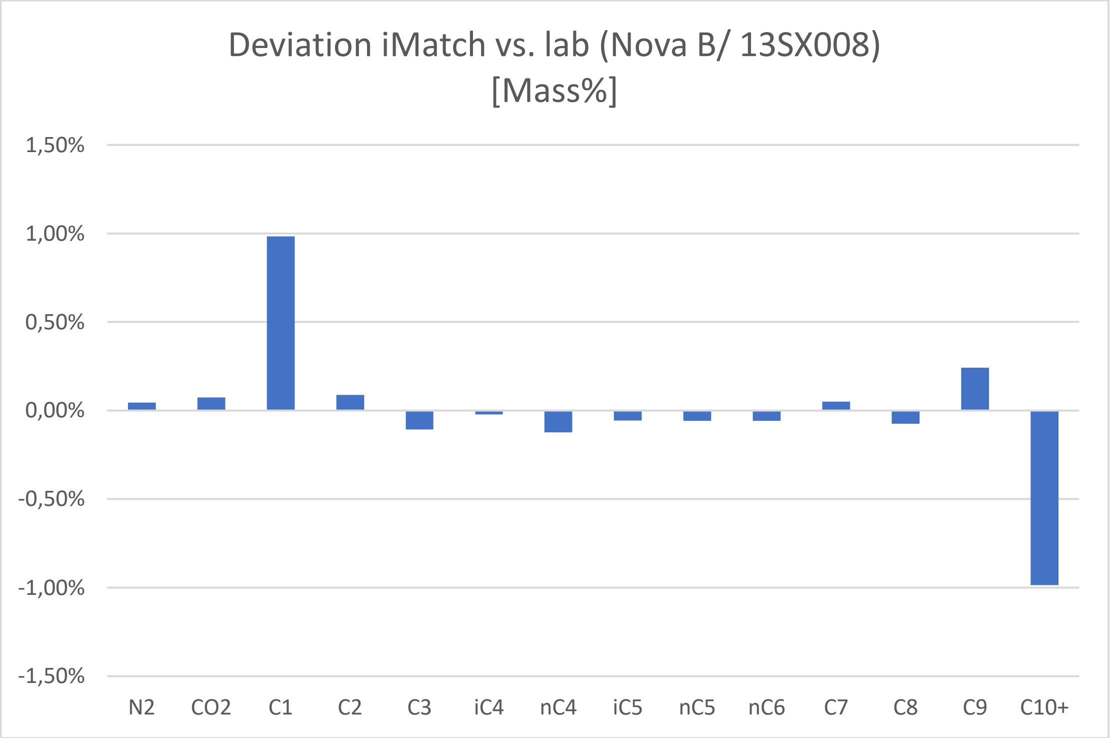


Figure 27: iMatch vs lab deviation Nova Flowline B

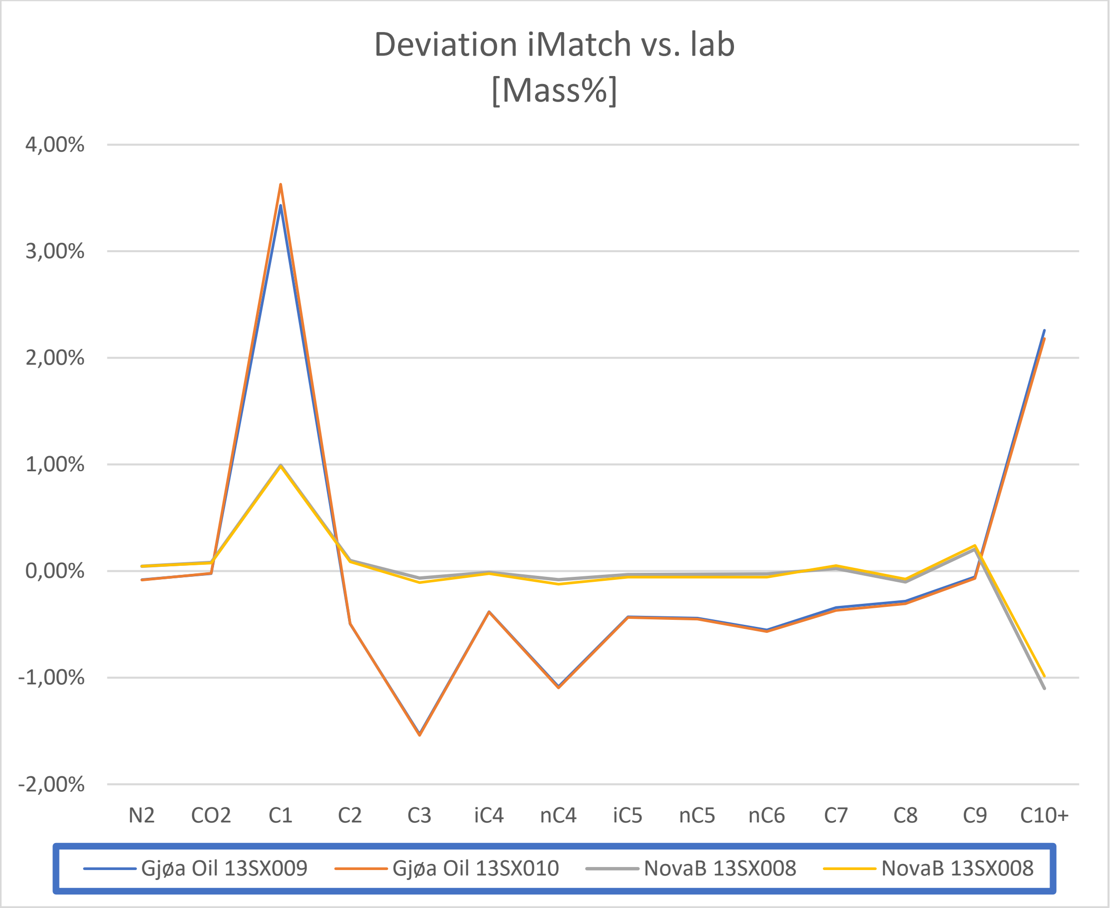


Figure 28: Absolute deviation [Mass%] from offshore qualification test subsea calculated composition VS analysed recombined HC composition from MPSU

7.3 Field test in normal operation (2023)

In this chapter, results from 10 analysed samples taken during normal operation is presented. The analysis is performed by a 3rd party laboratory and the recombination is done as described in earlier chapters.

The results from all 10 analysis are shown in the below diagrams which gives the mass% of each component for both the calculated composition through iMatch and the analysed results and absolute deviation.

Some key findings.

- Largest deviation is seen in the C1 and C10+ fraction
- Results matches the behaviour seen in both the qualification tests done offshore and at K-Lab

Note: No samples are taken from Gjøa flowline B, but the field qualification test shows that samples taken from flowline A repeats on flowline B

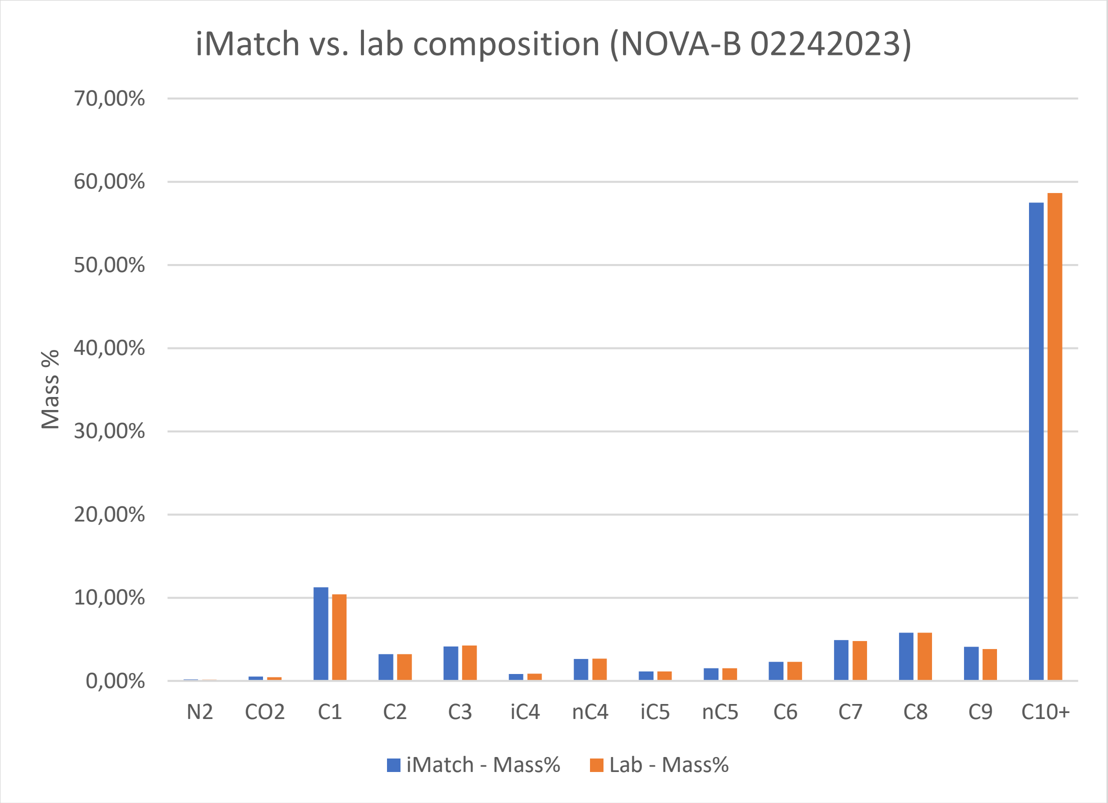


Figure 29: iMatch vs. lab composition from the Nova Flowline B

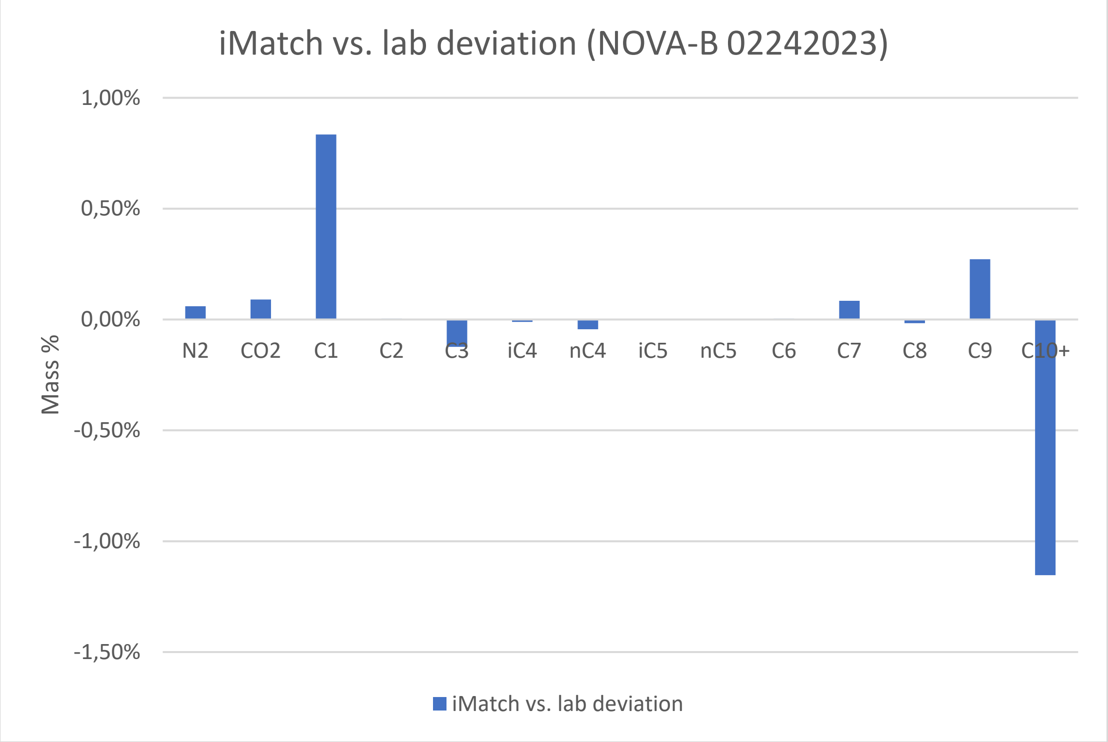


Figure 30: iMatch vs. lab deviation (Absolute) from the Nova Flowline B

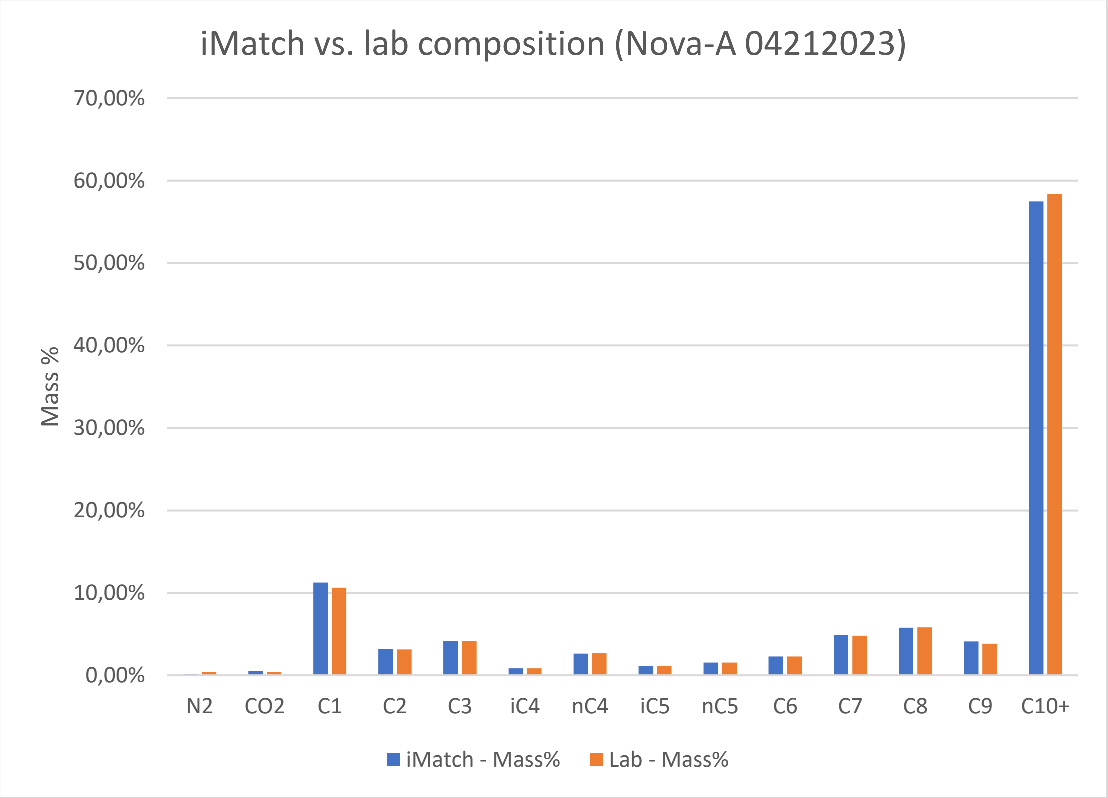


Figure 31: iMatch vs. lab composition from the Nova Flowline A

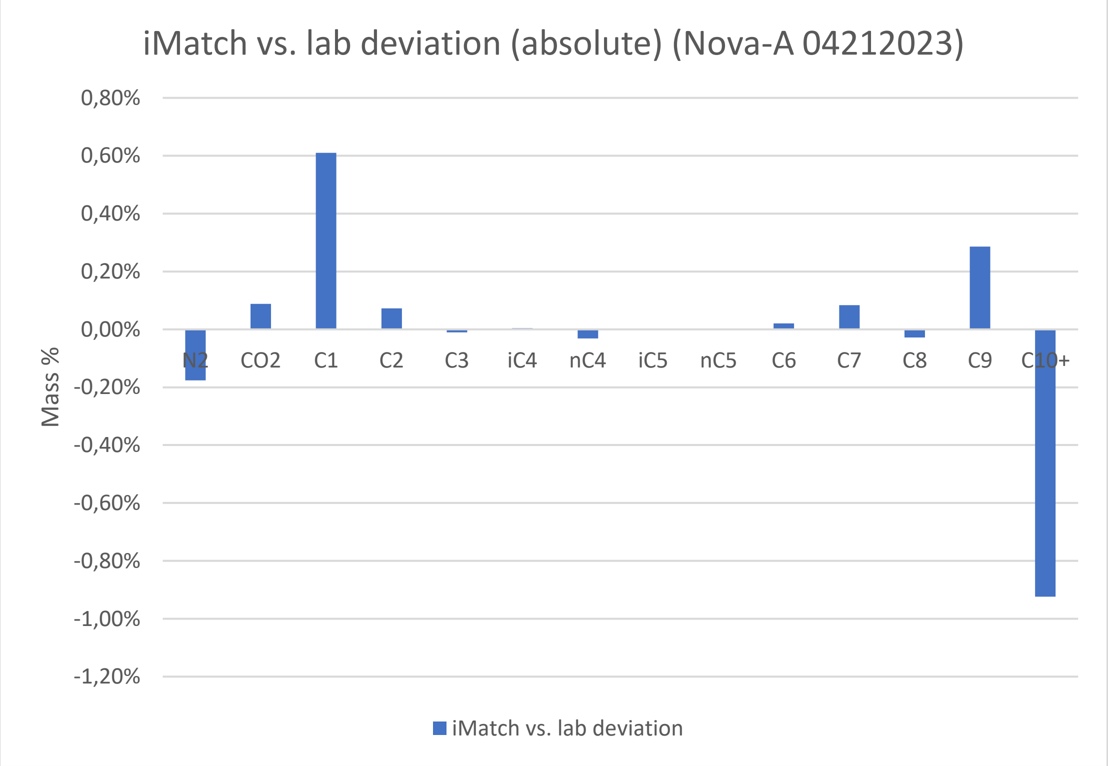


Figure 32: iMatch vs. lab deviation (absolute) Nova Flowline A

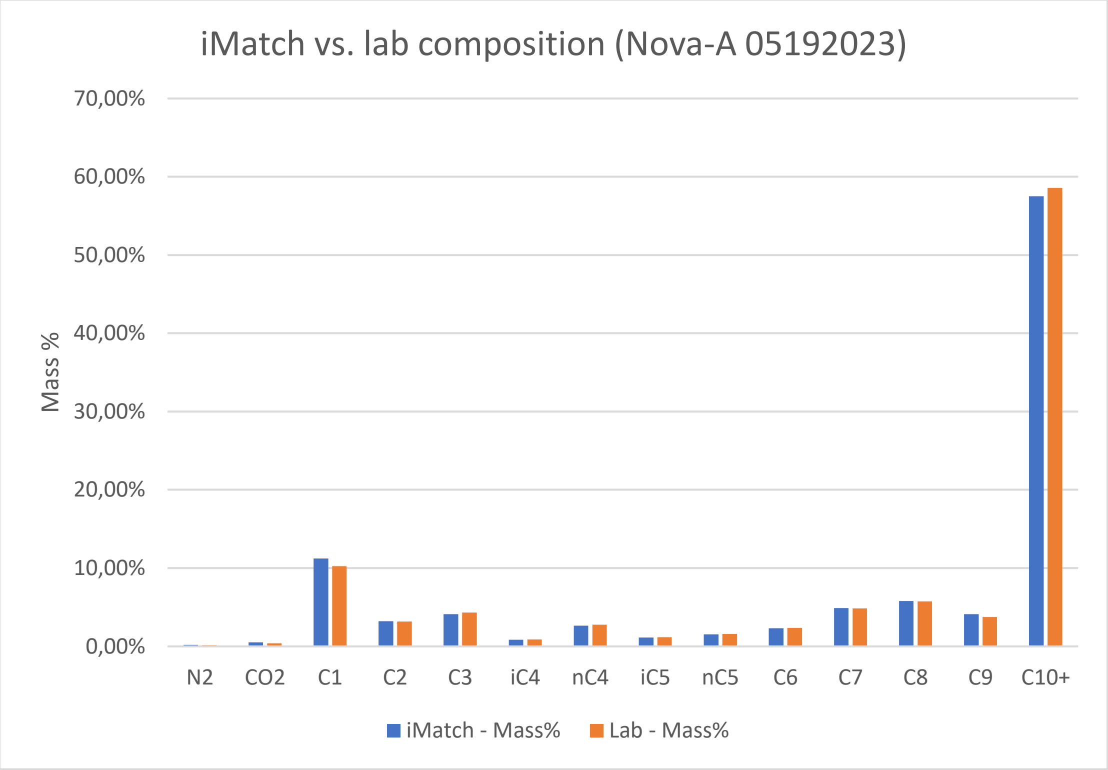


Figure 33: iMatch vs. lab composition from the Nova Flowline A

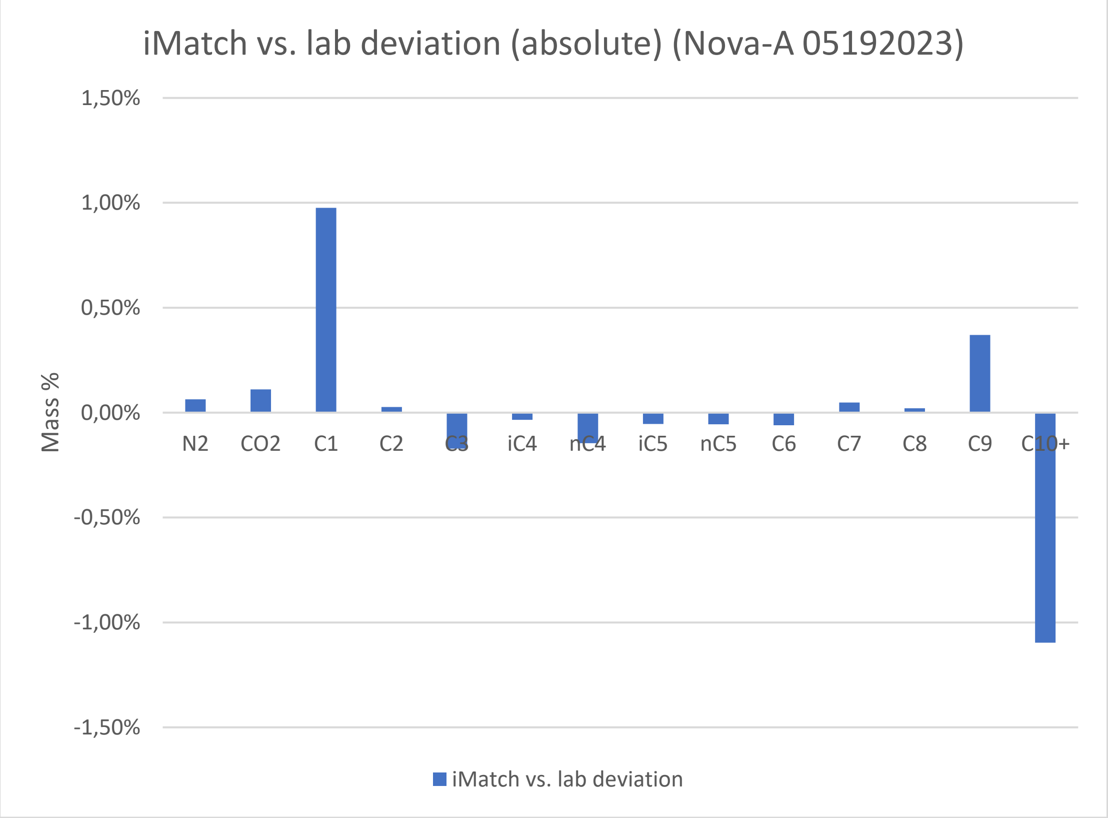


Figure 34: iMatch vs. lab deviation (absolute) Nova Flowline A

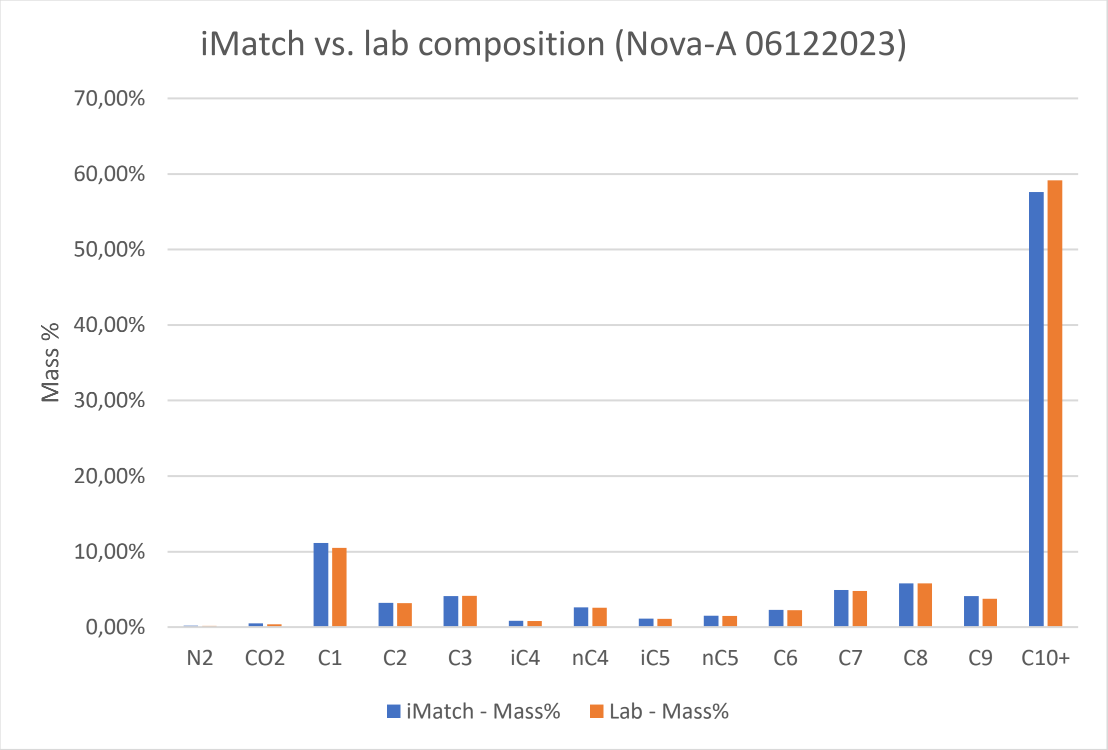


Figure 35: iMatch vs. lab composition from the Nova Flowline A

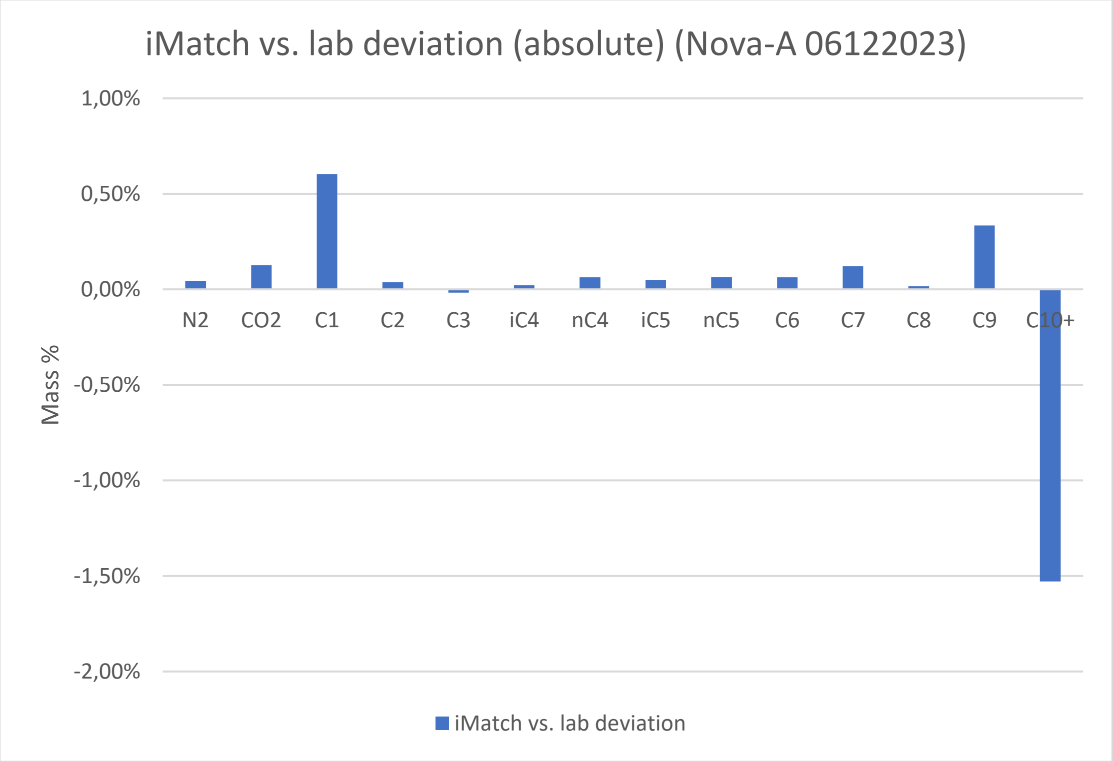


Figure 36: iMatch vs. lab deviation (absolute) Nova Flowline A

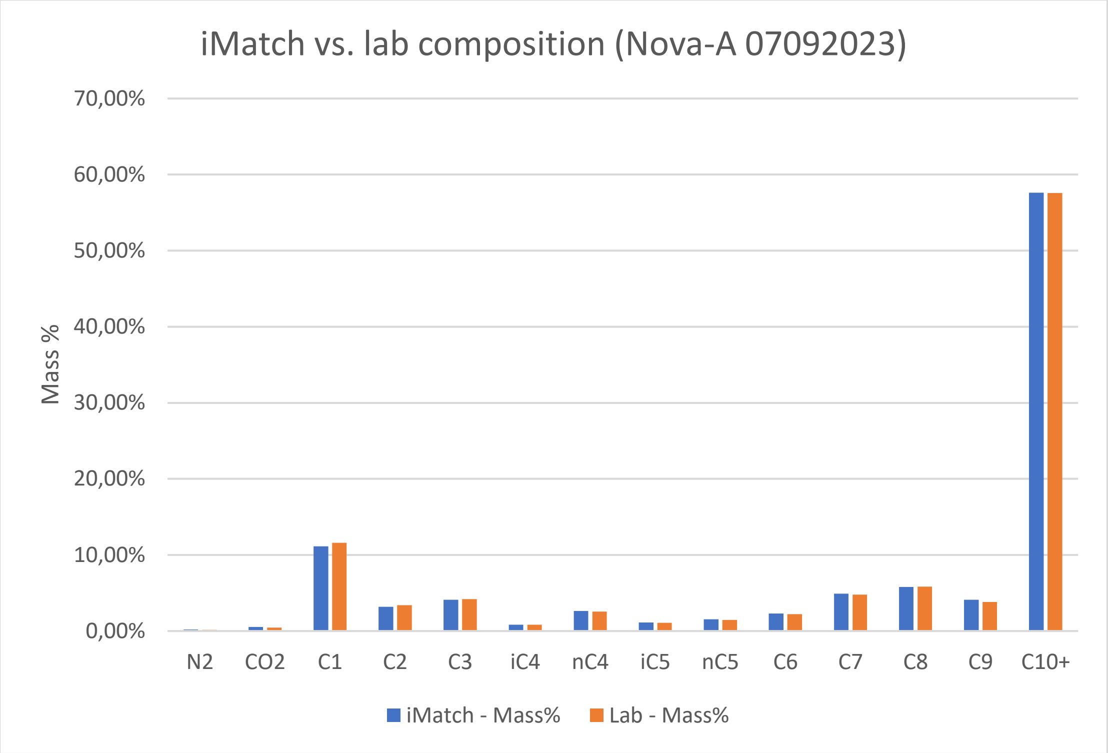


Figure 37: iMatch vs. lab composition from the Nova Flowline A

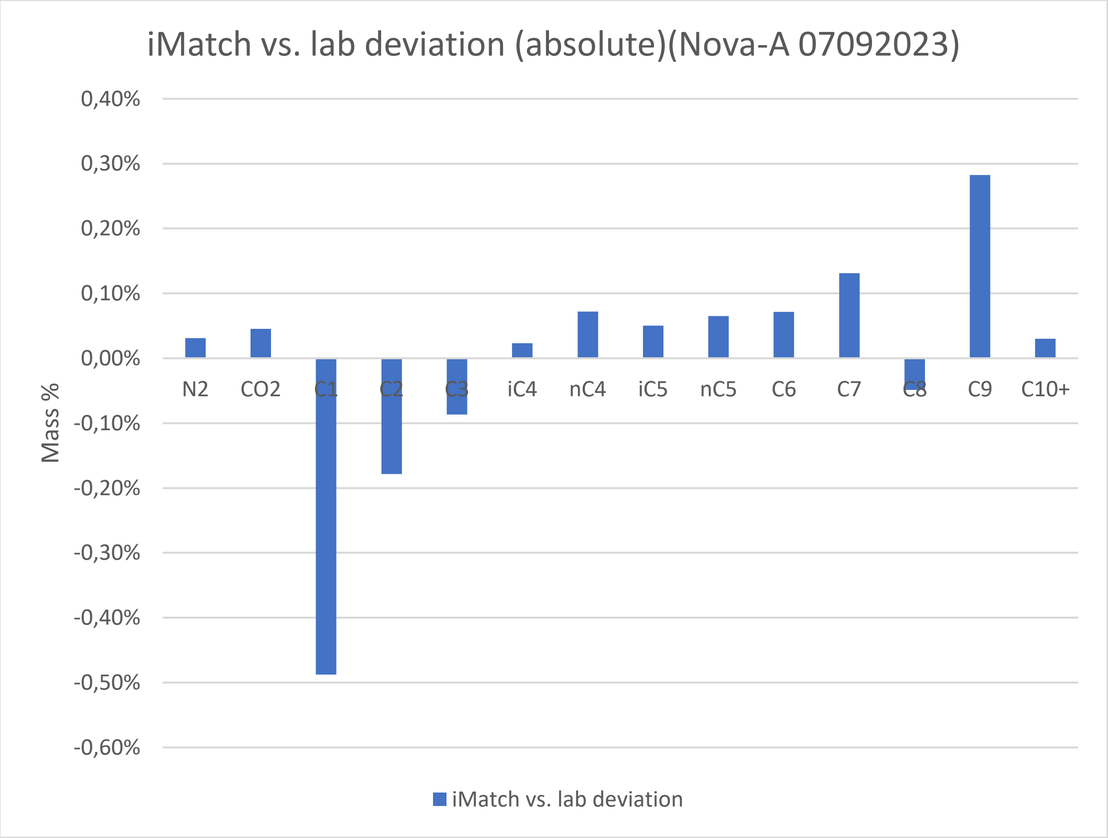


Figure 38: iMatch vs. lab deviation (absolute) Nova Flowline A

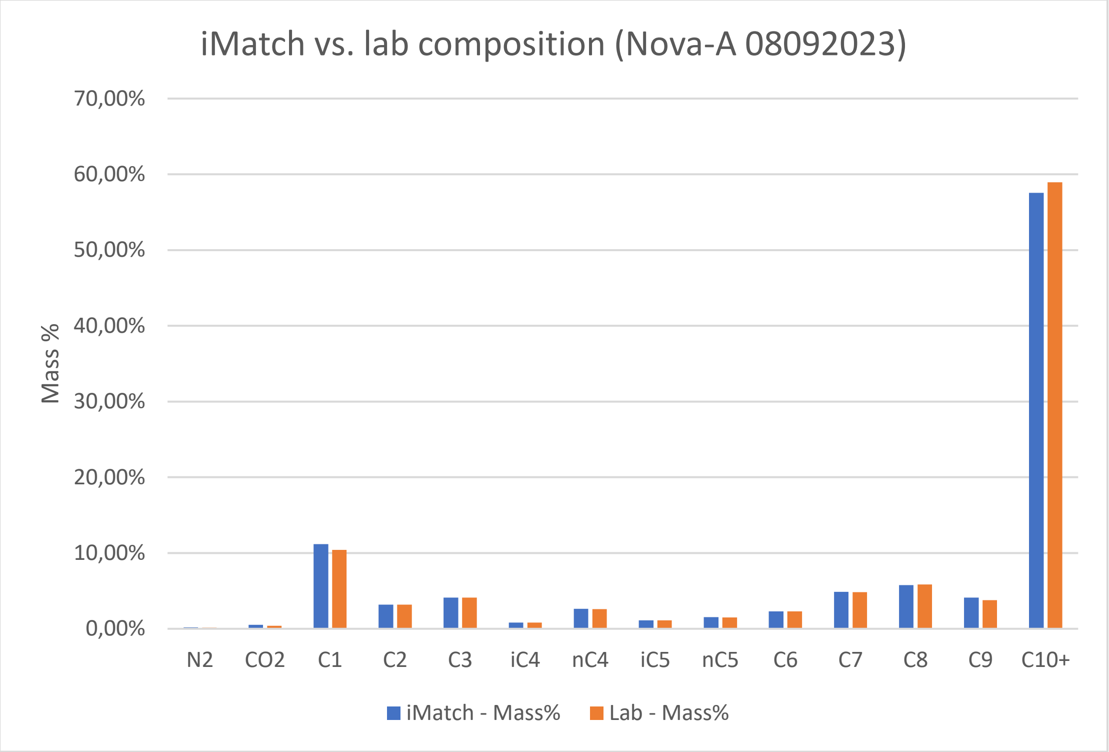


Figure 39: iMatch vs. lab composition from the Nova Flowline A

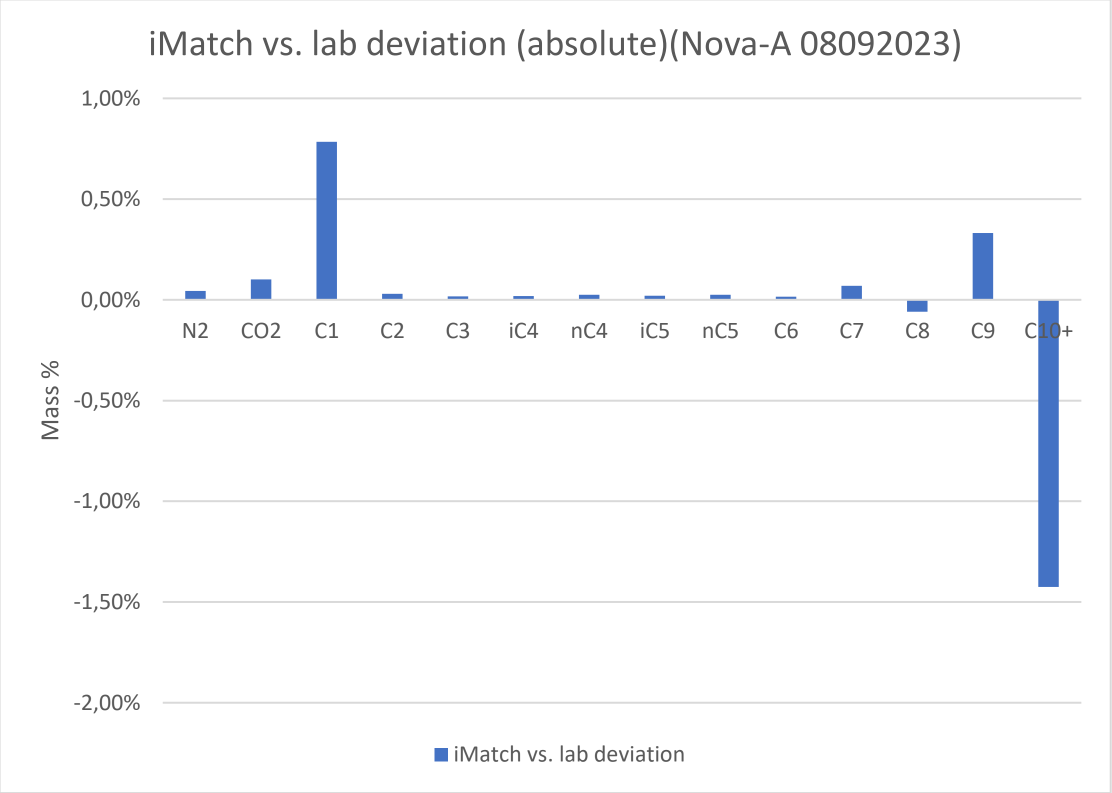


Figure 40: iMatch vs. lab deviation (absolute) Nova Flowline A

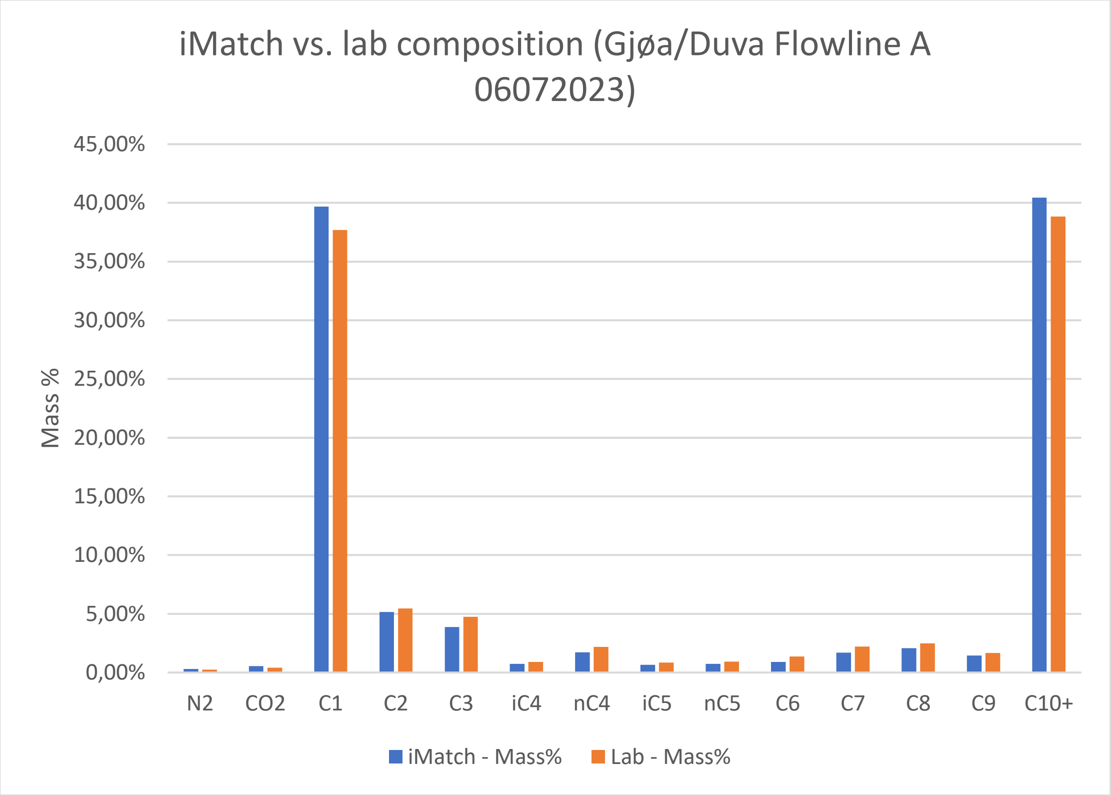


Figure 41: iMatch vs. lab composition from the Gjøa/ Duva Flowline A

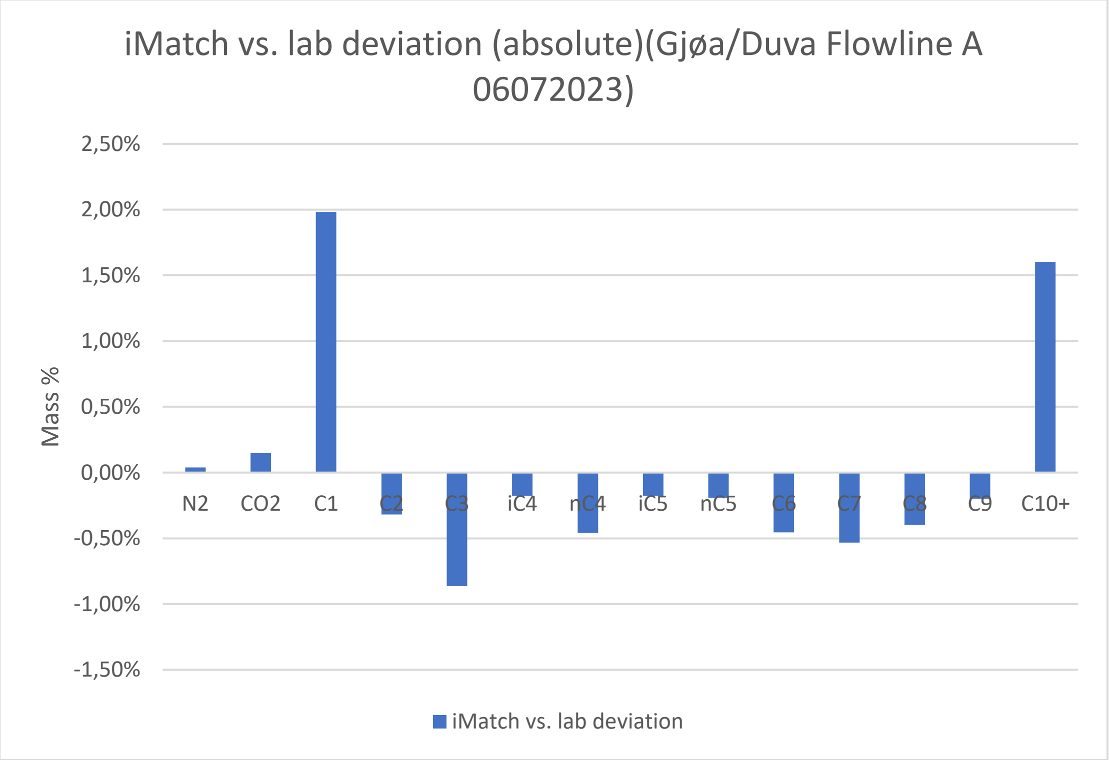


Figure 42: iMatch vs. lab deviation (absolute) Gjøa/ Duva Flowline A

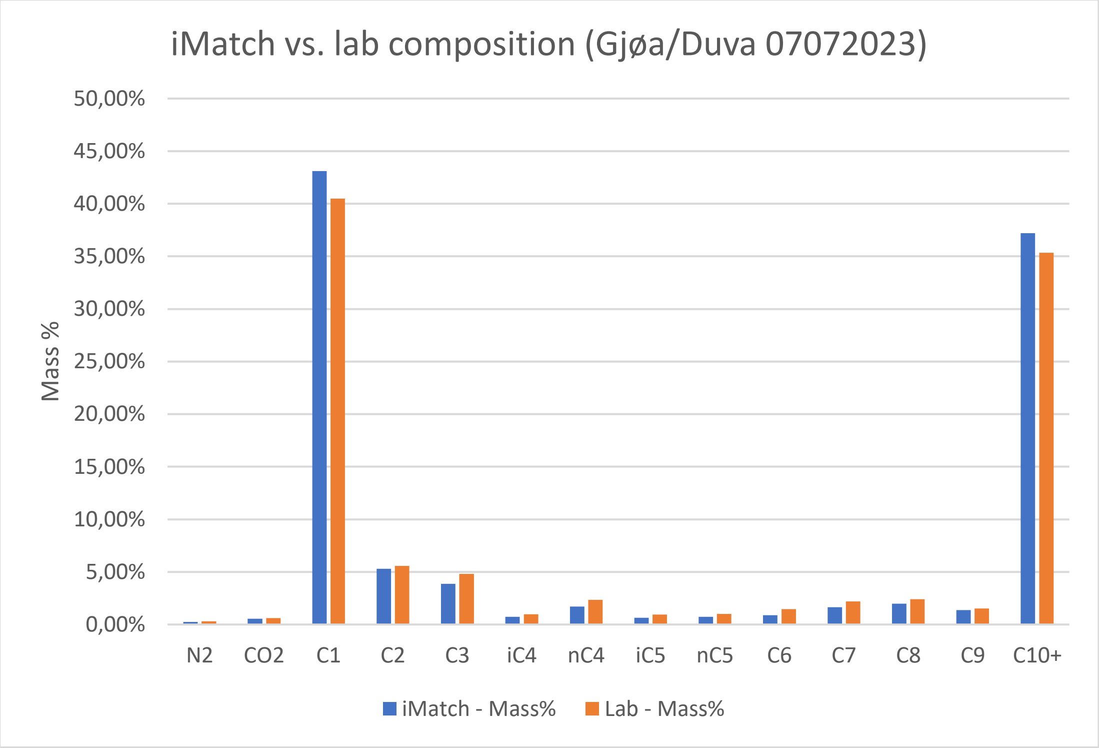


Figure 43: iMatch vs. lab composition from the Gjøa/ Duva flow line A

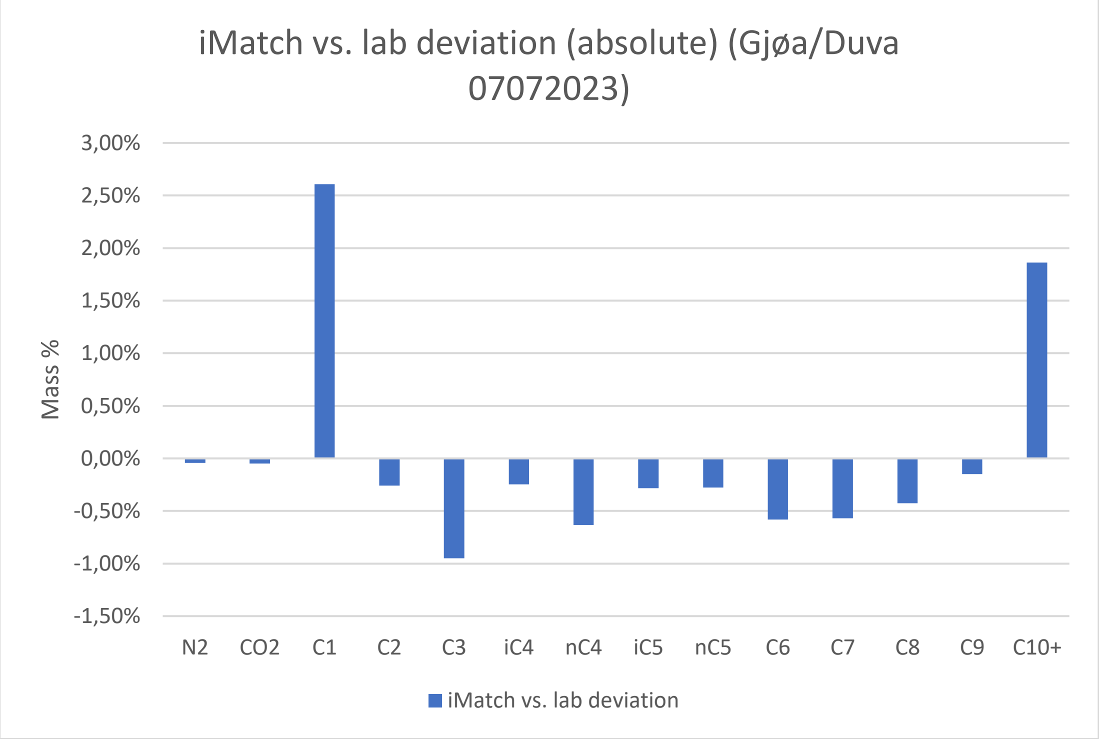


Figure 44: iMatch vs. lab deviation (absolute) Gjøa/ Duva Flowline A

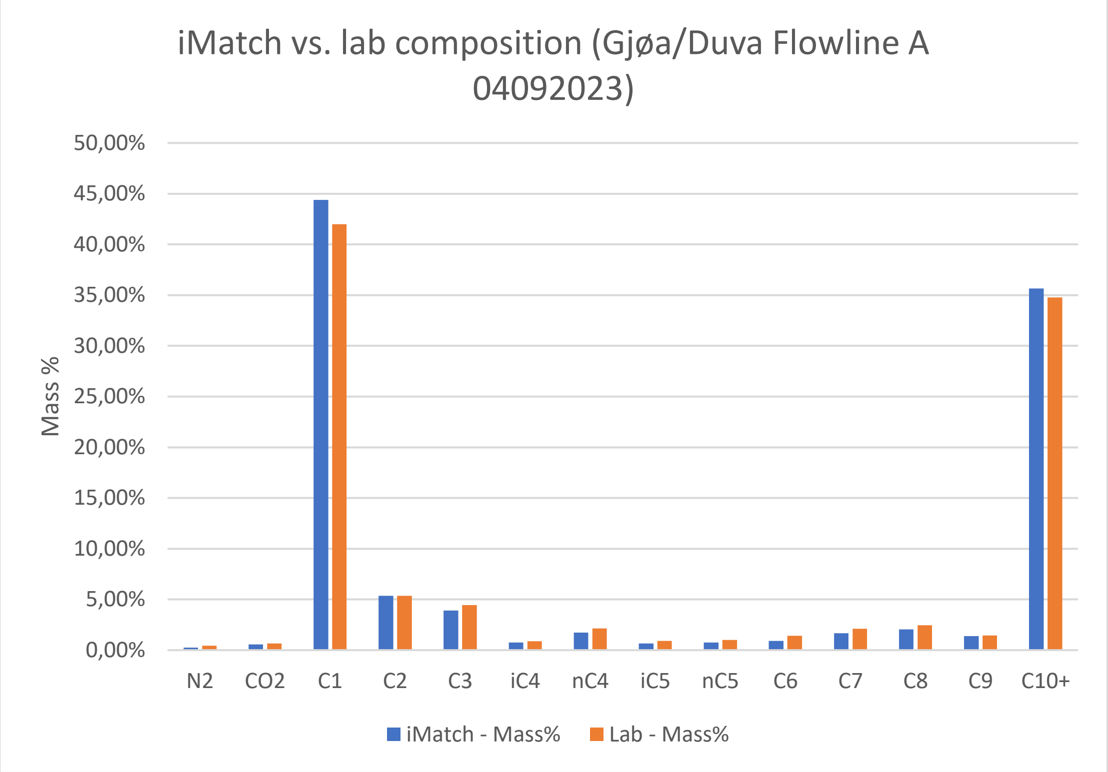


Figure 45: iMatch vs. lab composition from the Nova Flowline A

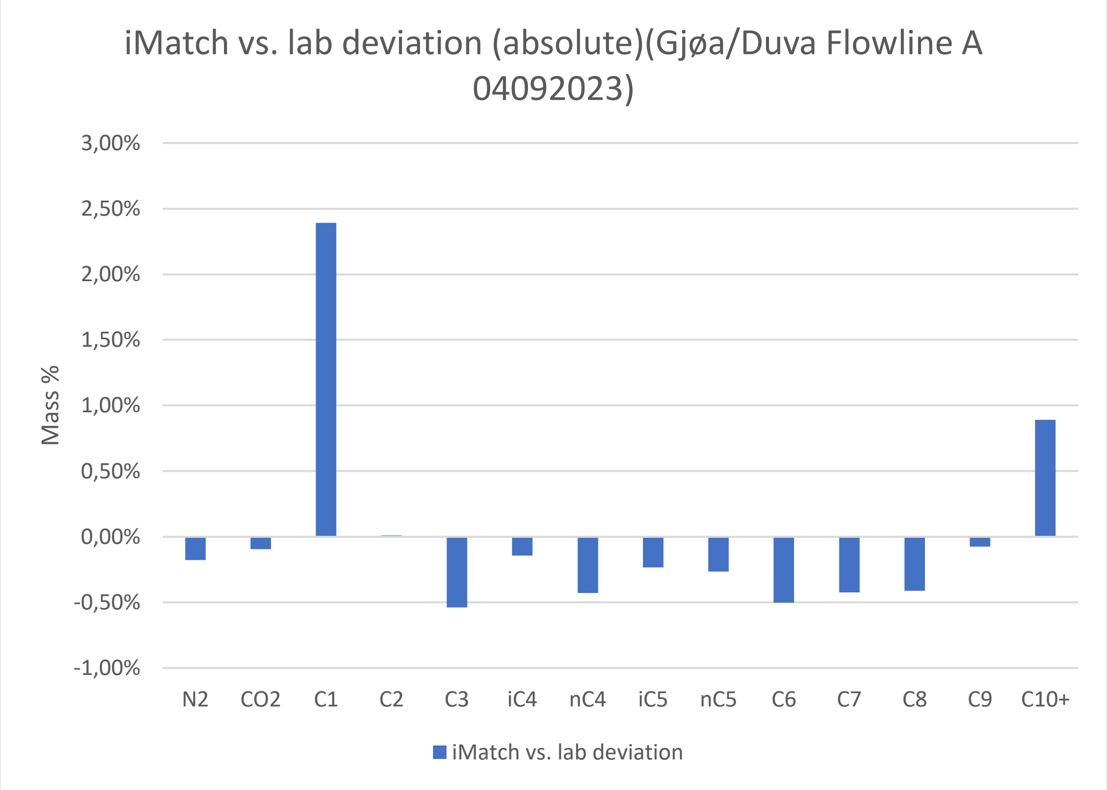


Figure 46: iMatch vs. lab deviation (absolute) Gjøa/ Duva Flowline A

8 CONCLUSION

Correct determination of flowrate and hydrocarbon composition is critical to ensure a fair allocation in a multi-field allocation system. At Duva- and Nova tie-in projects launch, no commercial product was available in the market that could acquire representative samples from a multiphase well stream, although some products have been attempted in the past, see reference [2], [3], and [4].

The multiphase sampling unit presented in this paper has been designed, constructed and tested onshore in a controlled test setup, and later in-situ at Gjøa through repeatability tests and with results from the device in normal operation. Although the results from the series of tests presented in this paper show deviations exceeding the uncertainty thresholds for a fiscal gas composition as defined in NORSOK I-106, and reproducibility thresholds specified in ASTM D-1945, the results show that it is possible to reproduce the hydrocarbon composition in a multiphase well stream using a multiphase sampling unit, procedures for sample handling and sample collection together with a calibrated system for recombination flowrates.

Due to the nature of multiphase flow, it is an impossible task capture a representative sample from a hydrocarbon fluid in a single sample. Even if we could capture entire pipe segments at a time, they would still only be spot samples representing the current conditions in the pipe at the time the sample was collected. The characteristics of a well stream changes continuously in the short term and long term, and therefore it is fundamental to capture these variations continuously through a calibrated flow measurement system. Modern multiphase flow metering systems allow for online composition calculation using a combination of measurements, input compositions and equations of state.

This study show that the multiphase sampling unit can be used to acquire samples which can be used to check consistency between "sampled" hydrocarbon composition and "calculated" hydrocarbon composition from a multiphase flow metering system. The multiphase sampling unit may also be used to acquire samples for value adjustment, as value adjustment information is normally provided for a stabilized sample.

Due to the change in well stream characteristics over the life of a field/well, the best estimation of hydrocarbon quantity and hydrocarbon quality is provided through the use of multiphase flowmeters with online PVT-calculations. Sampling, flowrate calibration and process simulation should be carried out regularly to maintain a calibrated system and to avoid systematic allocation bias. Outdated sample data in an allocation system may have a huge impact on the field allocation.

The component deviations observed during the onshore test is believed to originate mainly from the sample acquisition and sample handling operations, as the reference conditions at the test facilities are well known. Although the same difficulties related to sample acquisition and sample handling operations are as relevant with the device installed, the main source of error in-situ is believed to originate from the flowrate inputs used in the recombination of the gas- and oil sample. The in-situ results show that the component deviations are lower for the Nova samples, which have a low GVF as there are only oil producers, when compared with the commingled Gjøa/Duva samples, which have a significantly higher GVF due to commingling of gas wells and oil wells.

Authors believe that the field of multiphase sampling is still young and have much room for further improvement. Hopefully this technical paper has given the reader some insight to the design, testing and operational qualification process for the multiphase sampling unit installed at Gjøa production facilities, and that it may spark inspiration to others to further mature technology for multiphase metering and sampling.

9 REFERENCES

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2022 - Production Optimisation - Multiphase Sampling", Technical paper (white paper) (Available upon request to Neptune Energy)

[2] Carl Nilsson – Expro
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[3] Bruno Pinguet-Schlumberger
2006-19-Multiphase Sampling Kit to Improve Multiphase Flow Measurement

[4] Thomas F. Welker - Welker-Engineering
1996-06-Sampling 3-Phase Fluids for Quality Determination