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Technical Paper

In-Situ Validation of ESMER MPFMs

Haluk Toral, Shiqian Cai and Bahar Hosgor, Petroleum Software Ltd

1 INTRODUCTION

This paper describes a project for the implementation of ESMER multiphase meters [1,2] for an entire oil field including the wellhead (one for each one of the 17 wells in the field) and the production lines (one for each one of the three production lines).

Badra oil field situated in the Wasit Province in Eastern Iraq and operated by Gazprom is estimated to hold reserves of over 3 billion barrels. Current production rate stands at 64,000 bpd from 9 wells. Gazprom aims to raise the production capacity to 170,000 bpd by the end of 2017 when all 17 wells will be producing.

Petroleum Software Ltd has designed manufactured and supplied twenty multiphase meters for the project comprising 17 off 6" well head MPFMs and 3 off 14" production line MPFMs.

The paper chronicles the highlights of the various stages of the full project cycle starting with the customer requirements and culminating with the field validation of the meters. We recount the comparison between competing technologies, an alliance with a potential competitor; recall the challenges in selection and procurement of materials and manufacturing against tight deadlines; narrate the testing, calibration, field validation of the MPFMs set against the background of customer expectations, industry guidelines and what's been found to be practical and possible.

2 ESMER MPFM FIELD IMPLEMENTATION PROJECT

2.1 Technical Specification

What was particularly noteworthy in the technical specification was the corrosive nature of the fluids (high H₂S and chlorides). Strict requirements were imposed for the selection and testing of the materials for pipes, flanges and transmitters. Otherwise, there was only one restriction about the MPFM technology itself; radioactive sensors were not permitted.

Of the many issues facing multiphase metering that of validation of its field performance ("accuracy") is the most challenging. In this instance, the requirement was stated as "matching 5% of true liquid flow rate, 10% of true gas flow rate within 95% confidence level". During many years of experience in the multiphase metering industry, we've found that accuracy is intensely debated prior to selection, rigorously treated during the flow loop test, and then finally abandoned to oblivion in the field. In this instance we took a bold step and raised the issue in the early stages of the bidding process. We asked our prospective customer: "How will you know that the MPFM you've selected will meet the accuracy targets in the field"? The question of course implicitly makes the point that an MPFM that works in the flow loop may not work (as well) in the field. We made the answer to this question the lynchpin of our technical proposal.

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Another argument which we put forward to the tender committee was that the effectiveness of each MPFM technology should be evaluated against specific fluid and process conditions and that it would be complacent to accept claims of “universally applicable plug-play devices” that would work equally well under all conditions. We’ve also pointed out that in some cases design features (such as dead T mixing) would give rise to serious side effects (large pressure loss) and/or cannot be maintained effectively (eg due to sand accumulation) even in the short term.

In the present project we were confident that esmerMPFM would satisfy the “performance requirement” because of two pre-requisites being in place; availability of PVT data (more of this later) and test separator for validation / recalibration (which was proposed as a part of our own scope of supply – more of this later also).

The corrosive nature of the fluids, maintenance and accessibility issues also favoured esmerMPFM’s robust industry standard skid.

2.2 ESMER Technology

ESMER MPFM comprises a mechanical skid (field unit) on which a set of transmitters are mounted specially selected as per process requirements. Measurements are processed in a flow computer which takes the form of a microprocessor inside an ExD enclosure or a rack mounted industrial PC for use from the safe area. Measurements can be displayed /stored on the flow computer or transmitted via serial / Ethernet ports.

Simplicity and technology leverage are the governing design principles of ESMER MPFMs. The ground rules of ESMER MPFM technology and its implementation can be expounded as follows:

- **ONE SIZE DOES NOT FIT ALL:** The solution of the multiphase metering problem requires multi-disciplinary collaboration between the instrumentation engineer, the petroleum engineer, the supplier and the end user. Present and future process conditions should be evaluated carefully together with the end users to provide the best fit solution
- **NOT A WIDGET:** An MPFM skid should comprise a selection of sensors ideally suited to given process conditions. It is not possible to develop a single device which can provide a shrink wrapped solution to all multiphase metering problems eg consider the fact that the physics of heavy oil and wet gas systems are incompatible
- **EXTRACTING MAXIMUM OUT OF INDUSTRY STANDARD SENSORS:** Sensors which respond to multiphase flow characteristics are commonly available already; they just need to be applied better to provide a multiphase metering solution eg ESMER MPMFs take advantage of high frequency components of commonly available pressure transmitters.
- **OVERCOMING THE NOT INVENTED HERE SYNDROME:** It helps to collaborate with the competitors where synergies can be identified. For example, in this instance we have included the Weatherford Red Eye sensors on the esmerMPFM skid in addition to our own impedance technology for water cut measurement.

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- NEURAL NETS CAN WORK UNDER THE RIGHT CONDITIONS: Digital signal processing techniques / algorithms will enhance the performance of MPFMs eg ESMER MPFMs' conventional fluid models are enhanced by neural net algorithms
- CLASSICAL FLUID / THERMO DYNAMIC MODELS CAN WORK UNDER THE RIGHT CONDITIONS- Thermodynamic (EOS) models will enhance the performance of MPFMs. ESMER MPFMs implement EOS models which take real time P,T inputs in order to predict GVF at actual pipeline conditions.
- NOT FIT AND FORGET. NOT OUT OF THE BOX: It is not possible to design / supply an out-of-the-box-fit-forget MPFM. An in-line MPFM has to be recalibrated/validated in the field against physical separation systems as per API recommendations. Petroleum Software Ltd will provide in-field calibration / validation services as an integral part of every project.

For the current project we considered that the following compliment of transmitters were the best match to customer / process / fluid requirements:

- Cone with AP, DP, Recovery DP and RTD transmitters
- Capacitance transmitter (embedded in the cone)
- Weatherford Red Eye

The above set of transmitters provided the required inputs into the hydrodynamic model described in Appendix A. In addition, pressure and temperature measurements were input into a thermodynamic model (founded on an EOS software package provided by Calsep of Denmark) for prediction of phase densities and gas volume fraction in real time. The TD model was fine tuned against PVT data provided by the customer in accordance with the procedure described in Appendix A. The output from the thermodynamic model was input directly into the hydrodynamic model. The data acquisition system, the flow models and the output (comprising a database on the local disk and MODBUS output to SCADA)

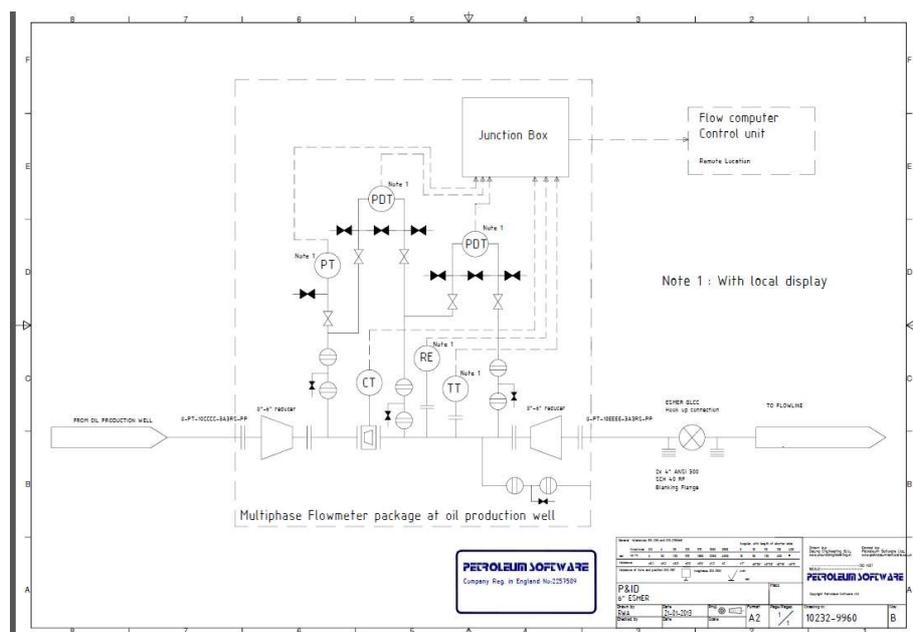


Fig.1 - ESMER C6+ PID

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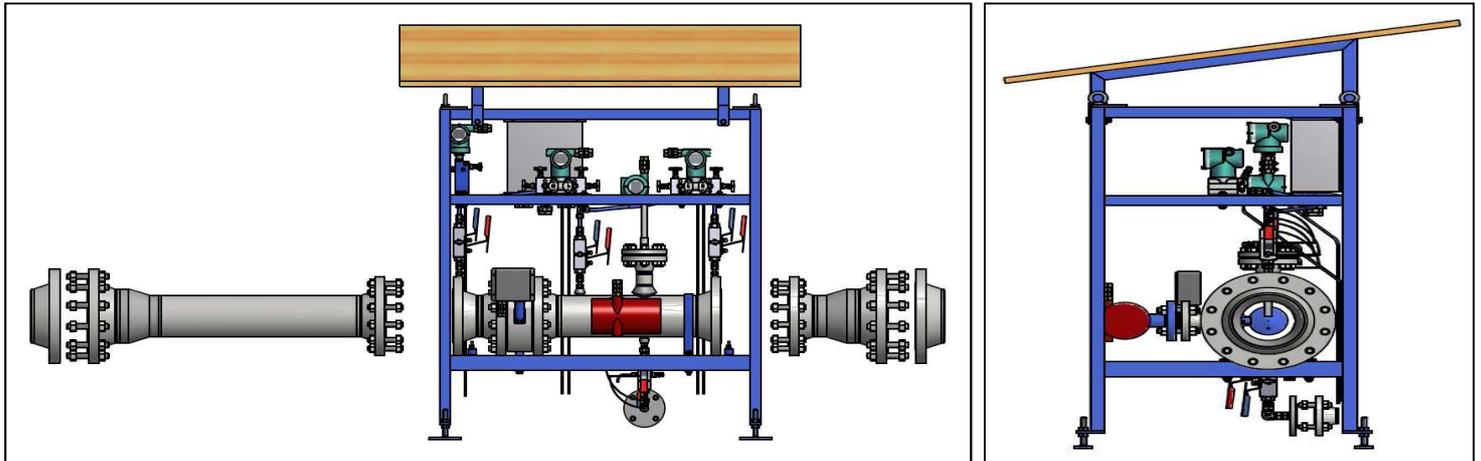


Fig.2 - ESMER C6+ General Arrangement Drawing



esmerMPFM C6+ at the Wellhead Badra Gazprom



esmerMPFM C14+ Installed at the Production Line Badra Gazprom

Fig.3 - ESMER C6+ at the Well Head and ESMER C14+ at the Production Line

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2.3 Project Chronicle

Competing Technologies

Several technical presentations were made to the tender technical committee during which we had a chance to express our opinion on competing technologies. For example, we expressed the opinion that it would be prudent to avoid:

- "Plug-and-play systems" based on mechanistic flow modelling and those based on empirical models calibrated in the flow loop
- Systems based on vertical flow, because they would
 - o Choke due to elbows
 - o Result in extra pressure drop of about 2 bar due to 4 elbows
 - o Be prone to strong flow induced vibrations, which would be especially risky for the larger production line MPFM
- Complex field electronics, because they are sensitive to harsh environmental conditions such as those which exist in hot/cold desert climate.

Some of the Issues Encountered

In the early days of our interaction with the customer, we spent a good deal of time on issues which turned out to be trivialities later on (such as the material for the sun shade, the drains and height of unit from the base).

Serious discussion started upon realisation that the length of upstream and downstream adaptors required (8 D and 3 D respectively) were not taken into account by the pipeline engineers and the fact that the diameter of the by-pass for the test separator could have been a bit larger than proposed.

Things got worse with the realisation that it was going to take much longer than initially anticipated to procure the pipes and flanges of special composition required for the highly corrosive process conditions. Materials tests required (HIC, SSC) would also add further two months before machining and assembly can start. This was a long time in view of the stringent delivery date of six months (first batch of six units) and nine months for another batch of fourteen units.

At the same time, the customer brought up another issue for discussion. How would we calibrate / flow loop test the production MPFMs (14")? Problem was a difficult one as no such flow loop exist to create the flow conditions mildly approaching those in the pipeline.

Flow Loop Selection

The prerequisites of the flow loop test, expected benefits and fine tuning of the "factory" calibration in the field were discussed within the framework of API 2566 State of the Art Multiphase Metering as per tender requirement [4]. API 2566 highlights regarding flow loop testing are quoted in Appendix B.

A multiphase flow loop which could simulate the process conditions for the 14" production line MPFMS could not be found. A decision was then made to test the 14" MPFMs in the single phase oil flow loop at NEL. This was not a wholly satisfactory match with the requirements of API 2566 but at least the exercise provided an opportunity to verify that the transmitters were in good working order prior to delivery to the field and

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allowed full characterisation of the coefficient of discharge of the cone under single phase conditions.

NEL multiphase loop also fell short of the required flow rates for testing 6" wellhead MPFMs (Fig. 4) but the wet gas loop offered a reasonable match for both the flow rates and pressure (but not temperature) Fig.5. However, the flow loop fluids were of course different to field and besides, no water/oil mixture can be employed in the wet gas loop. It was finally agreed to test the 6" wellhead MPFMs at the NEL Wet Gas Loop which showed reasonable overlap with the present flow conditions as shown in the operating envelope diagram below (Fig.5).

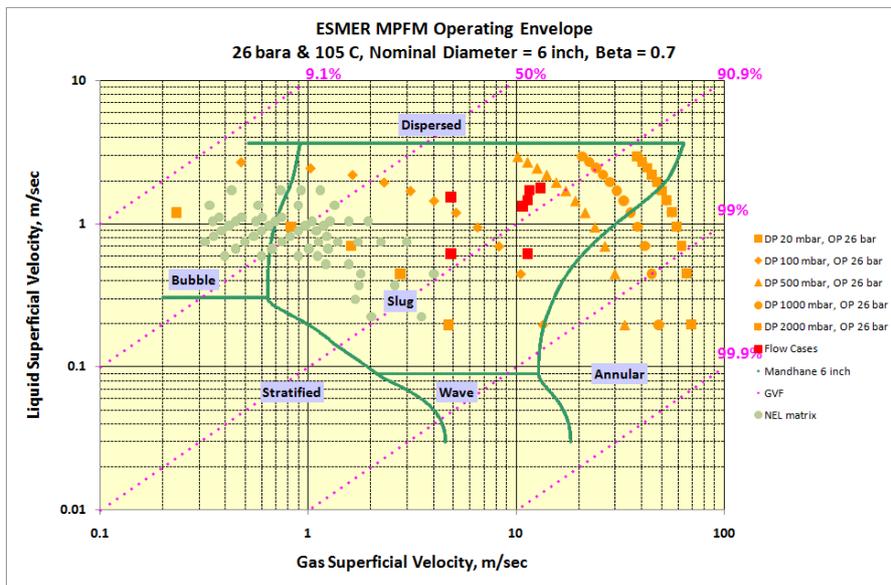


Fig.4 - NEL Multiphase Loop vs 6" Well Head MPFM

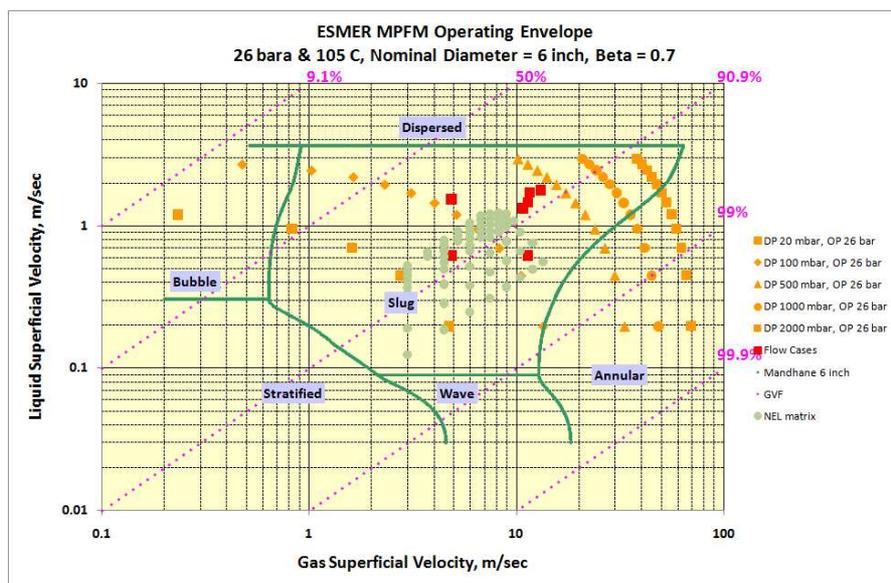


Fig.5 - NEL Wet Gas Loop vs 6" Well Head MPFM

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Flow Loop Test Results

Results of the NEL flow loop test are shown in the figures below giving a comparison of MPFM measurements against reference flow rates. The accuracy of the MPFM was demonstrated to be within the customer requirements of $\pm 10\%$ at 95% confidence level.

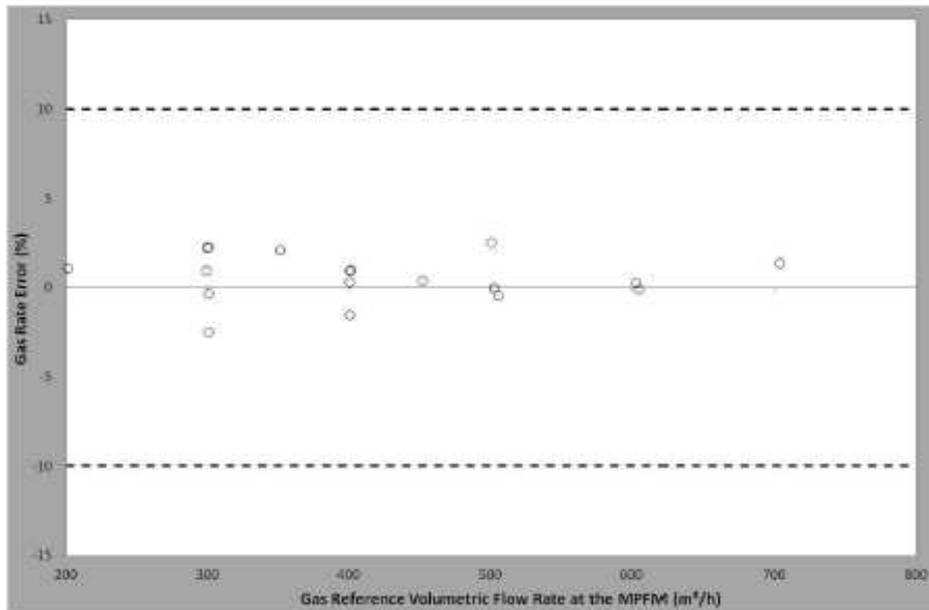


Figure A1.1 Gas Volumetric Flow Rate Error vs the Reference Gas Volumetric Flow Rate at the MPFM

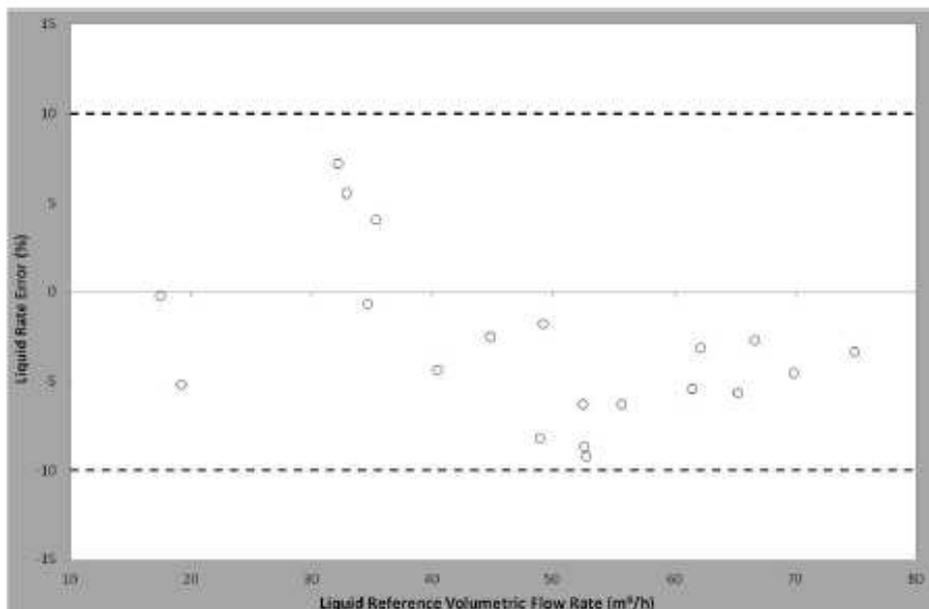


Figure A1.2 Liquid Volumetric Flow Rate Error vs the Reference Liquid Volumetric Flow Rate

Fig.6 - Flow loop test Results

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2.4 Field Implementation / Validation / Calibration

Installation and commissioning of first five units (3 off wellhead and 2 off production line MPFMs) took place in August 2014. Since then we have installed seven more systems as drilling progressed and more wells were brought online. Five further MPFMs are due to be installed by the end this year to complete the project.

Vertical Cyclonic Test Separator

As part of the project scope we had offered the customer a mobile test separator for validation and field calibration of the wellhead MPFMs. Initially seen as an optional tool, the importance of the test separator grew in time and became an indispensable tool.

We started by investigating the suitability of the GLCC technology (gas-liquid-compact-cyclone) as a test separator, an area subject to much research in recent years, considered by some to be an alternative to in-line multiphase metering. We had a choice of active and passive controlled systems. The latter sounded promising due to its simplicity. The passive controlled GLCC which we commissioned turned out to be 5 m tall column supported on a base of 4mx2m weighing and comprises a toroidal chamber of 40 cm diameter, as compact as it got.



We could have lived with the size but unfortunately the GLCC did not work as well as hoped! Experiments at the well head demonstrated that the separation efficiency was poor; too much liquid carried over with the gas and too much gas carried under with the liquid. Basically, the GLCC did not like the prevailing high GVF conditions and with hindsight its operating envelope turned out to favour a GVF range from 20% to 70% below.

Is it possible to extend the operating envelope to higher GVF by means of active controls? Worth an experiment another time, but on this occasion we thought it would be more prudent to go for a conventional horizontal separator described next.

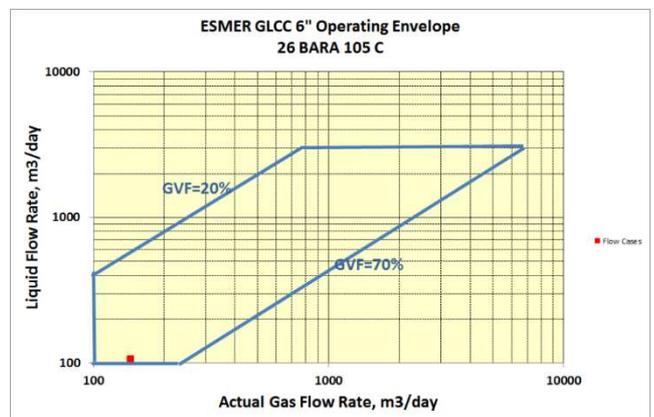
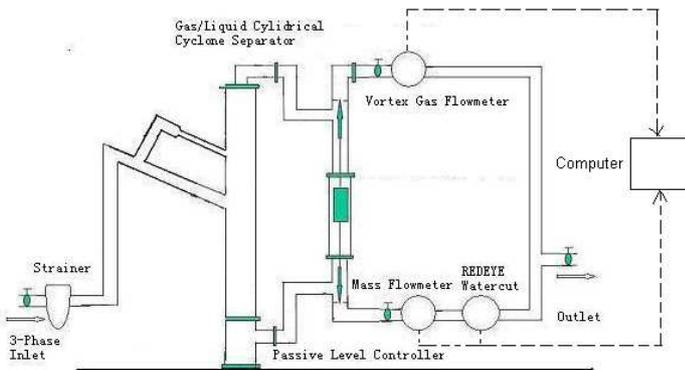


Fig 7. - Photo, Block Diagram and Operating Envelope of ESMER Passive GLCC

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Horizontal Conventional Separator

The horizontal separator turned out to be not as large as feared and could be transported “easily” between wells on the back of a trailer as shown on the photo below.



Fig.8 - MPFM and Test Separator Side by Side

	MPFM	GLCC	Horizontal Separator
Footprint LxWxH (m)	1.3 x 0.8 x 1.3	4.0 x 2.0 x 5.3	12.5 x 3.6 x 6
Empty Weight (kg)	273	7,500	38085
Full Weight (kg)	291	10,000	57419

**Table 1 Dimensions and Weight of MPFM vs GLCC vs Horizontal Separator
(For Same Duty of handling flow through a 6” pipeline – Appendix C)**

Separator Operation

Installation Effects

The test separator was connected in series and downstream of the MPFM. We had two concerns about the expected performance of the separator. Naturally the separation efficiency was foremost in our minds but we also worried about its back effect on the MPFM, ie whether the separator would contaminate the “normal” conditions in the MPFM.

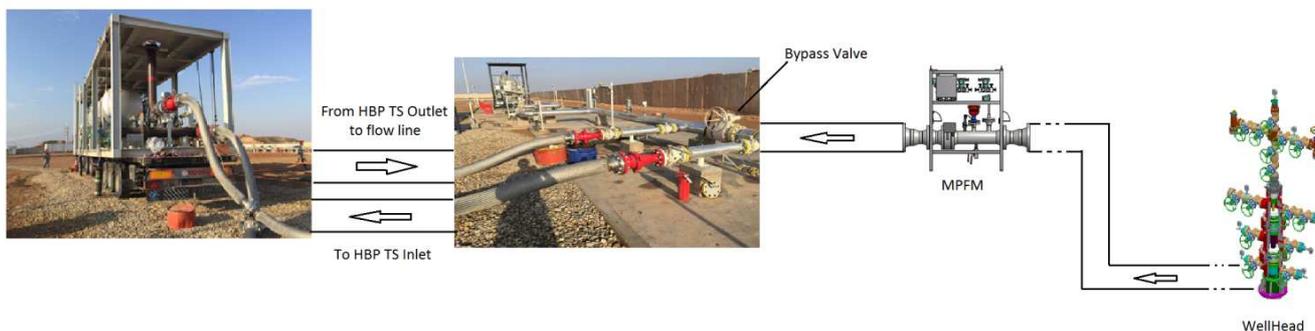


Fig.9 - Test Separator and MPFM in Series

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The pressure loss (ie increase in back pressure at the MPFM) was 5 bar at maximum flow rate. It was estimated that more than half this loss was caused by the reduction in the bypass pipe line diameter from 8" to 4". The effect of the pressure change on fluid properties and gas volume fraction was taken into account automatically by the MPFM via the thermodynamic model. The back effect of the separator on the MPFM is shown below. The back effect of the separator on pressure, temperature, DP and GVF change was in line with expectations.

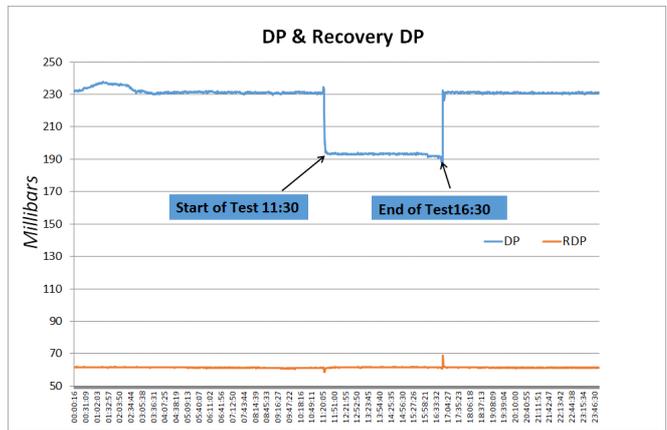
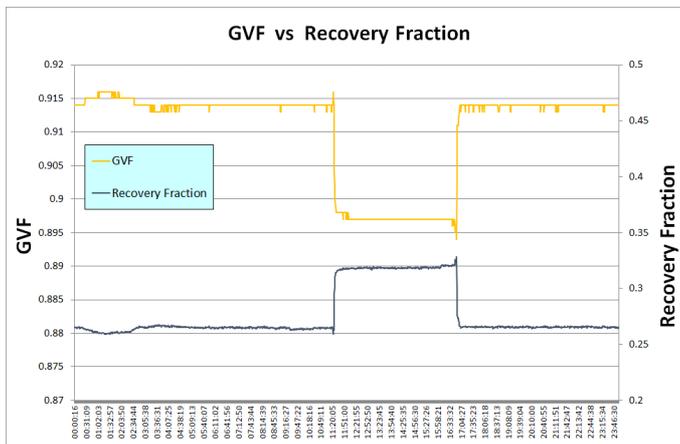
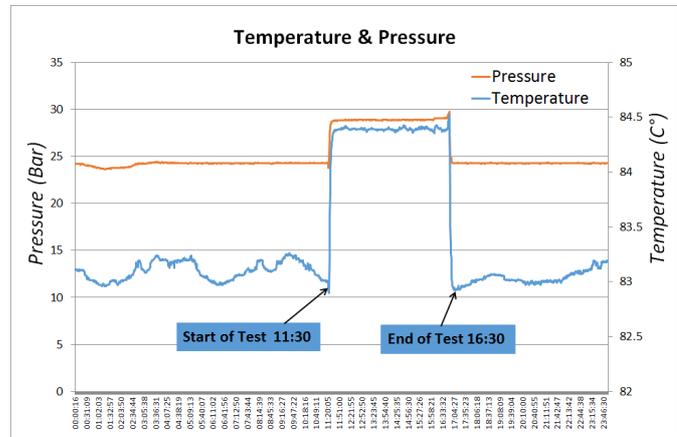


Fig.10 - Effect of the Test Separator on the MPFM

Separation Efficiency

Stable operation conditions could be reached within half an hour. It was not possible to quantify the separation efficiency but the stable operation of the system was encouraging and we believe that the design target efficiency (1% by mass liquid carry over in the gas leg and 1% gas carry under by volume in the liquid leg) was met. The trend of the influences can be reviewed as:

1. Gas carry under → underestimation of true gas
2. Gas carry under → turbine meter instrument error resulting in overestimation of oil
3. Liquid carry over → underestimation of true oil
4. Liquid carry over → orifice instrument error resulting in overestimation of gas

It appears that separation inefficiency results in two overestimations and two underestimations per phase. Hence, at least, the effects were counterbalancing.

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Validation & Calibration Results

Well Id	Start Time	Test Duration (hour)	Well Head			MPFM								HBP			Performance			
			WHP (Well head Pressure)	Well Head Temperature C	Choke Valve position (%)	Pressure At Flowline	Temperature at Flowline	Oil m3/h	Gas m3/h	GVF %	GOR Sm3/Sm3	Oil at Standard Sm3/h	Gas at Standard Sm3/h	Oil at Actual (m3/h)	Oil at Standard Condition	Total Gas at Standard Condition	GOR (Sm3/Sm3)	Oil (%)	Gas (%)	GOR (%)
P13	08/02/2016 12:00	4:00	50.0	84.4	53.7	28.9	84.4	79.1	693.9	89.7	223.9	70.4	15758.5	78.1	71.2	16065.3	225.6	-1.2	-1.9	-0.8
BD5	12/02/2016 10:30	4:30	52.0	81.9	52.2	26.6	82.3	74.2	703.5	90.5	221.8	66.5	14742.3	69.6	64.2	15203.5	236.8	3.5	-3.0	-6.3
P05	16/02/2016 11:30	4:00	54.6	85.4	51.2	30.2	86.0	81.3	679.9	89.3	224.2	72.1	16154.5	82.2	72.8	14872.3	204.2	-1.1	8.6	9.8
P04	18/02/2016 12:00	4:30	57.6	83.0	35.5	29.5	82.9	47.7	402.8	89.4	221.1	42.4	9369.1	56.7	50.4	10021.6	198.8	-16.0	-6.5	11.2

Table 2 Well Test Result with Test Separator (HBP) and MPFM Connected Inline

Table above summarises typical in-line test results comparing cumulative MPFM measurements versus the test separator over a four hour well test. Charts below show typical measurements on a minute by minute basis. The large fluctuation in the separator is due to the effect of the level controller.

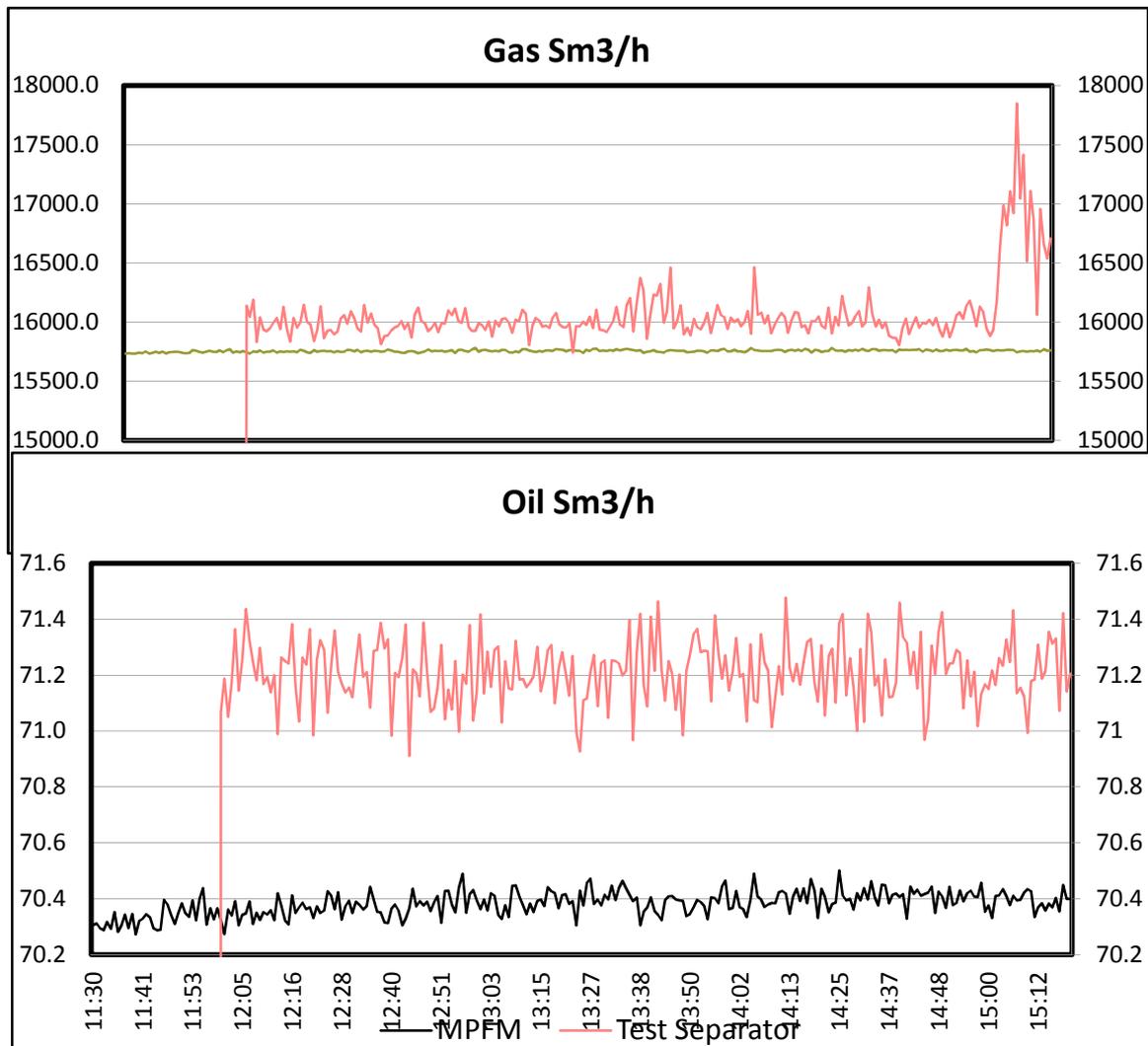


Fig.11 Typical Calibration Test Run – MPFM and Test Separator are Inline. Measurements are made on a minute-by-minute basis.

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Repeatability & Uncertainty

In order to qualify the uncertainty of the measurements, we've calculated the standard deviation of oil and gas flow rates at the test separator and the MPFM based on measurements averaged over a minute. The results are shown in the table below.

Well Test Information			MPFM						Test Separator					
Well_ID	Date	Test Time	Oil			Gas			Oil			Gas		
			Sd	avg	sd/avg(%)	Sd	avg	sd/avg(%)	Sd	avg	sd/avg(%)	Sd	avg	sd/avg(%)
P13	08.02.2016	12:00-16:30	0.04	70.39	0.06	8.93	15758.51	0.06	0.11	71.21	0.16	261.54	16065.32	1.63
BD4_1st	10.02.2016	10:00-14:30	0.18	14.90	1.24	37.56	3083.35	1.22	1.55	17.02	9.12	108.60	2674.75	4.06
BD5	12.02.2016	10:30-15:00	0.06	66.46	0.09	13.29	14742.34	0.09	0.66	64.22	1.03	24.21	15203.54	0.16
P08	14.02.2016	11:00-15:30	0.16	10.06	1.56	30.65	1996.20	1.54	0.65	11.62	5.64	6.67	2390.05	0.28
P05	16.02.2016	11:30-15:30	0.03	72.05	0.04	5.69	16154.51	0.04	0.16	72.85	0.22	16.29	14872.28	0.11
P04_1st	18.02.2016	12:00-16:30	0.09	42.37	0.21	19.84	9369.15	0.21	0.88	50.43	1.74	27.98	10021.64	0.28
P04_2nd	19.02.2016	09:00-13:00	0.07	45.81	0.16	18.50	10125.40	0.18	0.87	50.29	1.73	24.75	10040.67	0.25
BD4_2nd	20.02.2016	10:30-15:00	0.19	17.25	1.10	44.16	3564.66	1.24	2.03	16.99	11.92	75.25	3557.77	2.12
Average					0.56			0.57			3.94			1.11

Table 3. Typical Calibration Test Run – Standard Deviation of MPFM vs Separator Measurements Averaged over Each Minute

It is seen that the **experimental standard deviation** of the minute by minute measurements made by the test separator range from 11.9% (BD4) for the oil flow rate at low producing wells to 0.16% (P13) at high producing wells. The high value of the fluctuation is attributed to the activation of the level control mechanism of the separator. Repeatability of the measurements for the MPFM is better, ranging from 0.06% to 1.1%.

Experimental standard deviation was also repeated based on hourly averages. The results shown below are more representative of the "true" repeatability of the measurements (ie removal of the minute by minute influence of the level controller action). Maximum standard deviation encountered on an hourly basis was reduced to 2.73% (Well BD4).

Well Test Information			MPFM						Test Separator					
Well_ID	Date	Test Time	Oil			Gas			Oil			Gas		
			Sd	avg	sd/avg(%)	Sd	avg	sd/avg(%)	Sd	avg	sd/avg(%)	Sd	avg	sd/avg(%)
P13	08.02.2016	12:00-16:30	0.02	70.39	0.02	3.25	15758.51	0.02	0.02	71.21	0.03	109.74	16065.32	0.68
BD4_1st	10.02.2016	10:00-14:30	0.12	14.90	0.81	23.69	3083.35	0.77	0.46	17.02	2.73	119.30	2674.75	4.46
BD5	12.02.2016	10:30-15:00	0.05	66.46	0.07	11.52	14742.34	0.08	0.07	64.22	0.11	4.98	15203.54	0.03
P08	14.02.2016	11:00-15:30	0.16	10.06	1.60	31.13	1996.20	1.56	0.02	11.62	0.20	1.97	2390.05	0.08
P05	16.02.2016	11:30-15:30	0.01	72.05	0.01	2.58	16154.51	0.02	0.02	72.85	0.03	0.55	14872.28	0.00
P04_1st	18.02.2016	12:00-16:30	0.04	42.37	0.10	8.69	9369.15	0.09	0.14	50.43	0.29	17.36	10021.64	0.17
P04_2nd	19.02.2016	09:00-13:00	0.02	45.81	0.04	7.52	10125.40	0.07	0.07	50.29	0.13	3.92	10040.67	0.04
BD4_2nd	20.02.2016	10:30-15:00	0.15	17.25	0.88	37.80	3564.66	1.06	0.19	16.99	1.12	69.11	3557.77	1.94
Average					0.44			0.46			0.58			0.93

Table 3. Typical Calibration Test Run – Standard Deviation of MPFM vs Separator Measurements Averaged Hourly.

2.5 Routine Use

Measurements are transmitted directly to the SCADA at the central processing facility by MODBUS (averaged over a minute). The operators only need to visit the wellhead for special verification and maintenance actions. Downtime has been negligible (only one

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incident of shut down due to debris washed into the production line MPFM after pigging during two years of operation)

A number of checks (comparisons) are carried out daily for validating the measurements:

- Cumulative daily average of wellhead MPFMs (of which there are 17) vs Production Separator at the Central Processing Facility (CPF)
- Production line daily average MPFM measurement (for each one of the three production trains) vs CPF
- Cumulative of wellhead MPFMs vs production line MPFMs

Typically oil and gas rates agree to within 5% as shown in the sample charts from 20th March to 20th April 2016. We see that the daily average cumulative MPFM measurements over-state the production separator oil and gas flow rates (Fig 12) whereas production line MPFM under-state the production separator (Fig 13).

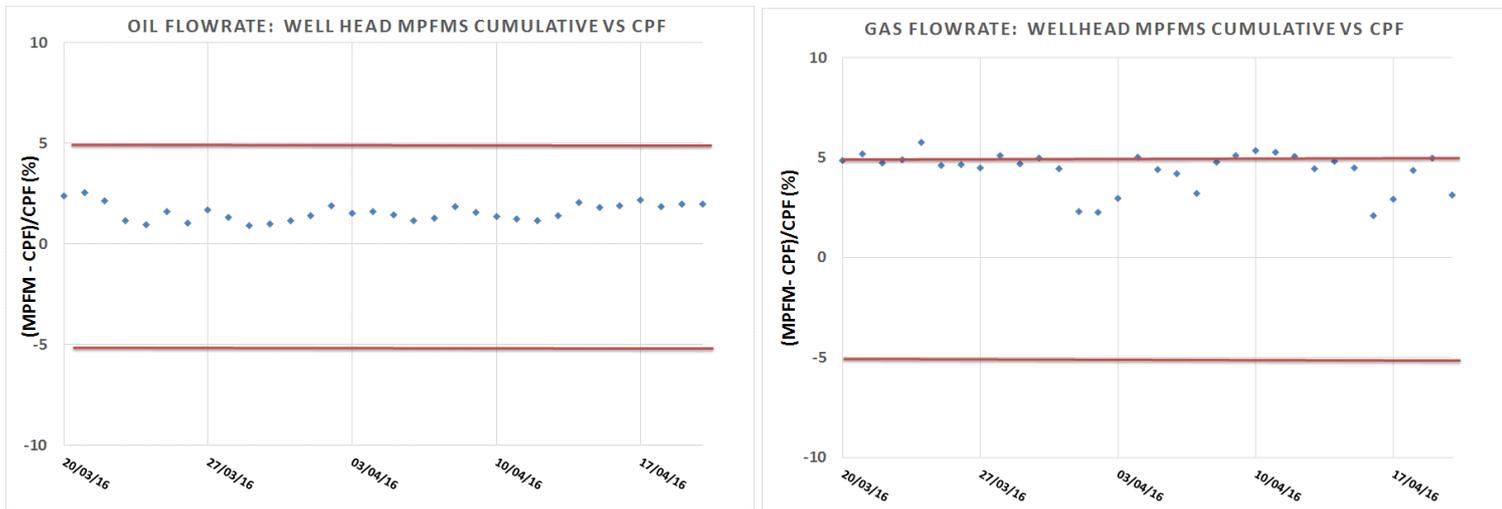


Fig.12 - Daily average cumulative measurement by Well Head MPFMs (6" MPFMs) compared against Central Processing Facility Separator Measurement 20.3.16 – 20.4.16

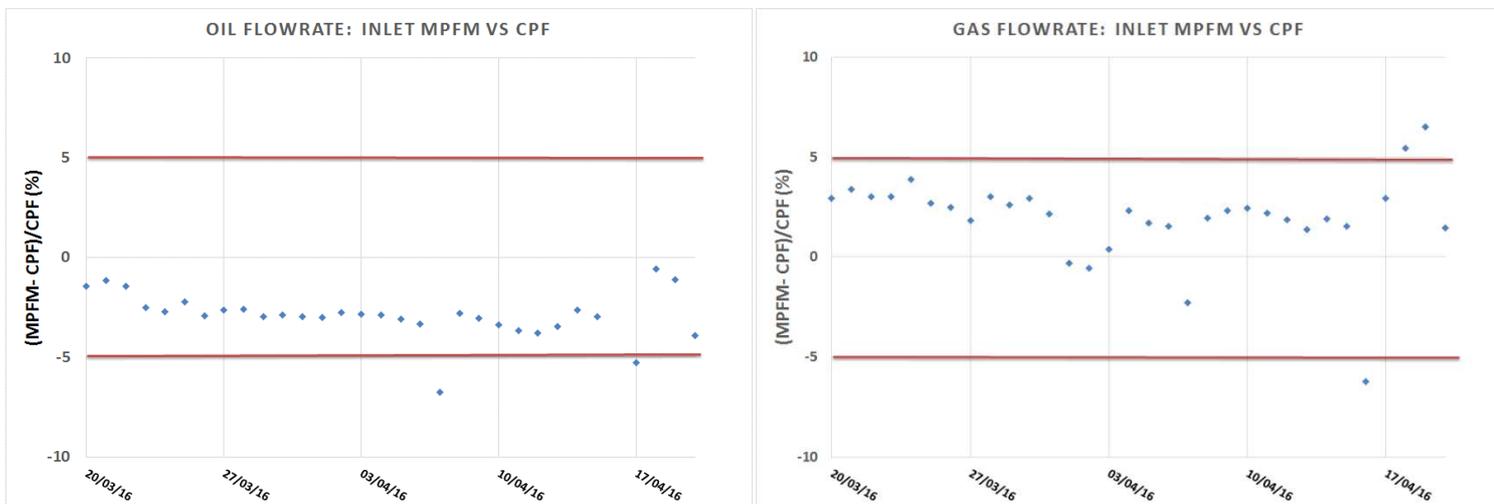


Fig.13 - Daily average Production Line MPFM (14" MPFM) compared against Central Processing Facility Separator Measurement 20.3.16 – 20.4.16

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3 CONCLUSIONS

- Project experience shows that fit-for-purpose multiphase meters deploying conventional transmitters and flow models can deliver a robust performance and a satisfactory level of accuracy /repeatability for wellhead and production line metering.
- Thermodynamic (phase equilibrium) model can provide an effective means of predicting / validating the gas volume fraction and physical properties of the phases in line.
- MPFMs can be effectively validated in-field and their calibration tuned up by means of a test separator
- A conventional horizontal separator is recommended in place of "compact cyclonic separators" under high GVF / high flow rate conditions.

4 REFERENCES

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Appendix A ESMER MPFM Theoretical Model

Like all flow meters, whether designed for single or multiphase measurement applications, ESMER MPM requires three stages of calibration:

1. Theoretical calibration
2. Flow loop calibration
3. Field adjustment

To understand the methodology of flow loop calibration and field adjustments we first need to understand the theoretical model underlying the ESMER MPM. The main parameters measured by ESMER MPM are the total flow rate and phase fractions (gas / liquid and water/liquid). The measurement is founded on **hydrodynamic_and thermodynamic models** as described below.

Overview

Thermodynamic Model is used to predict the GVF (a key parameter for the MPFM), density of phases at actual and standard conditions and shrinkage. The model is created by means of an EOS package provided by Calsep of Denmark named PVTsim.

The package takes the usual inputs such as feed composition (PVT lab), binary interaction coefficients (library), critical temperatures and pressure of components (library). Heavy end is characterised by means of proprietary models of Calsep. We use PVT data from the field (eg reservoir saturation pressure, multistage flash PVT) to tune up multi-stage flash model by iterative or regression methods for matching targets. The end result is a synthetic fluid composition. Using the synthetic fluid composition we perform multi-stage flash across a range of P,T and save the output (P,T,GVF, density of phases). We then train a neural net to create an algorithm which can be executed locally on-line on the MPFM flow computers.

What's described up to this point is the initial tune up of the Thermodynamic Model which takes place before installation. For field tune up the procedure is to be repeated against measurements obtained from the test separator after installation of the MPFMs. It should be noted that liquid / gas phase compositions, not measured at present, would be of additional value for field tune up.

The construction of the Hydrodynamic Model starts at the flow loop. This is an empirical exercise and involves essentially the characterisation of the *Discharge Coefficient* (Cd) which depends on flow regime, GVF, superficial velocities and densities of the phases (all inputs into the model are measured at the flow loop). The relationship between Cd and the parameters are non-linear and a neural network is used for implementation of the Hydrodynamic Model (as per Thermodynamic Model). The flow loop test was carried out at NEL for a range of flow rates and a test report was provided. The discharge coefficient model obtained from NEL measurements ("factory setting") will be tuned up empirically by comparing MPFM measurements against separator measurements. However, it is important to stress that the Hydrodynamic Model cannot be tuned up in isolation and must be tuned up in tandem with the Thermodynamic Model (eg Cd depends strongly on GVF which in turn depends on the Thermodynamic Model)

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ESMER HYDRODYNAMIC MODEL

The calculation starts with the conventional differential pressure equation (Bernoulli equation)

$$m_f = \frac{C_d \varepsilon_1 \beta^2 \sqrt{2}}{\sqrt{1 - \beta^4}} * A * \sqrt{\Delta p * \rho_m} \quad (1a)$$

Or

$$Q_f = \frac{C_d \varepsilon_1 \beta^2 \sqrt{2}}{\sqrt{1 - \beta^4}} * A * \sqrt{\Delta p / \rho_m} \quad (1b)$$

where:

m_f mass flow rate kg/sec

Q_f volume flow rate m³/sec

Δp DP across cone N/m² (Pa)

ρ_m fluid density (Kg/m³)

C_d discharge coefficient (including multiphase effect; ie function of gvf

ε_1 expansion factor

A flow area through full bore (m²)

β beta ratio where for a cone $\beta = \frac{\sqrt{(D^2 - d^2)}}{D}$

The Bernoulli equation presents a number of challenges in multiphase flow.

$$C_d = \text{fn}(\text{“Effective” Reynolds Number}). \quad (2)$$

Note: We propose the term “Effective Reynolds Number” in recognition of conventional fluid mechanics (the ratio of inertia and viscous forces). We do not profess to know / propose a deterministic equation here. The term can only be quantified empirically. For the sake of recognition of the influence parameters, we can propose the following “pseudo equation”:

$$\text{EffectiveReynoldsNo} = \text{fn}(m_f, \text{GVF}, \text{WaterCut}, \text{flow regime}, \text{physical properties}) \quad (3)$$

Note: physical properties include density, viscosity, salinity under actual conditions. Hence P,T effects are implicitly taken into account in this term

Next, we look at the water composition model. The principal input into the water composition model comes from one of the following sensors (signals):

- Capacitance
- Conductance
- Infra-red absorption spectroscopy
- Gamma ray absorption spectroscopy

The following general equation applies to any of the foregoing sensors.

$$\text{Output Signal (of Sensor)} = \Phi (\text{flow regime}, \text{GVF}, \text{Watercut}, \text{physical properties})$$

Hence inverting this equation, GVF and watercut can be (theoretically) obtained from:

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$$\text{GVF, WaterCut} = \Phi (\text{Signals, flow regime, physical properties}) \quad (4)$$

Where "Signals" stand for outputs of various transmitters on the MPFM skid; in this instance: impedance, DP, RecoveryDP, P, T

We now have four equations and four unknowns, mf, GVF, water composition, flow regime. A theoretical solution is possible but not probable !

Furthemore;

$$\text{Flow regime} = \Phi (\text{DP, RecoveryDP}) \quad (5)$$

Substituting 5 into 4 we get:

$$\{\text{GVF, WaterCut}\} = \Phi (\text{impedance, DP, RecoveryDP, P, T, salinity}) \quad (6)$$

The last relationship means that it is the combination of GVF and water cut that is correlated with the parameters on the right hand side. This relation cannot be expressed in the form of a linear mathematical correlation and an analytical solution is not possible.

However, neural nets can establish this relationship with relative ease given sufficient data. In neural networking terminology, the terms on the left hand side of relationship 6 represent the *joint targets* of a supervised network and those on the right hand side represent *the training inputs*.

Similarly, a separate neural net is trained with same inputs to predict the coefficient of discharge.

Substituting 5 into 3 and then into 2 we get:

$$\text{Cd} = \Phi (\text{impedance, DP, RecoveryDP, P, T, salinity}) \quad (7)$$

Once the mass flow rate is determined from equation 1 & 7 (Cd neural net); oil, water and gas flow rates can then be derived from GVF and Water cut given by 6 (GVF-Wcut neural net)

ESMER THERMODYNAMIC MODEL

ESMER theoretical model also comprises a thermodynamic (PVT) mathematical model which supplements the hydrodynamic core system described above. The PVT model, which runs on the flow computer in real time, permits the calculation of GOR from fluid composition and in-situ P,T measurement by flash calculation assuming equilibrium conditions. ESMER PVT model is based on the Soave Redlich Kwong Equation with Peneloux Correction. The EOS model is represented in the equations below. The model is tuned to field-fluid conditions by regression against GOR measurements made in the production separator train (multistage separation)

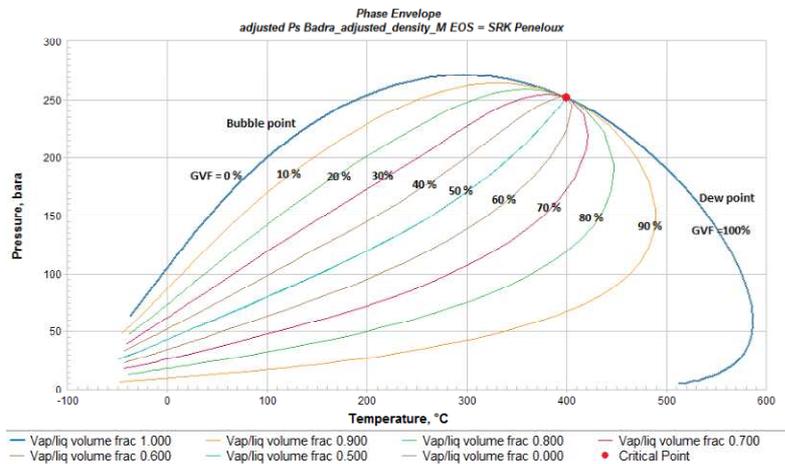
An example application of the thermodynamic model will be illustrated next. The phase envelope predicted by the thermodynamic model (based on fluid composition provided by the customer shown in table below) is shown below.

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	Doc. No. GB164-BD01-100-PR-DS-002 PROCESS DATA SHEET FOR MPFM (OIL PRODUCTION WELLS AND CPF INLET MANIFOLD)	Rev.: 0 Date: 19.12.12 Page: 8 / 10	
Component	% mole		
N ₂	0.28		
CO ₂	3.5		
H ₂ S	3.07		
C ₁	35.17		
C ₂	9.36		
C ₃	6.11		
iC ₄	1.06		
nC ₄	3.32		
iC ₅	1.49		
nC ₅	2.07		
C ₆	3.19		
C ₇	3.1		
C ₈	3.25		
C ₉	2.93		
C ₁₀	2.56		
C ₁₁	2.02		
C ₁₂	17.54		
Sum	100		
Molar mass reservoir oil, [g/mol]	93.87		
Reservoir pressure, [bara]	455.88		
Reservoir temperature, [°C]	118.96		
Saturation Pressure @ iPres, bar	214		
Dynamic Viscosity, [cP]			
at Pres	0.43		
at Ps	0.32		
Results of Multistage Separation:			
Formation Volume Factor (FVF), [m ³ /st m ³]	1.500855		
solution gas-oil ratio, [Sm ³ /Sm ³]	162.995		
solution gas-oil ratio, [Sm ³ /ton]	190.145		
stock-tank oil density, [kg/m ³]	854.5		

Note: 1. Maximum H₂S Content: 3.8 mol %; Maximum CO₂ Content: 3.7 mol %;
 Water content up to 25% should be considered.
 2. For sour service conditions, the materials shall comply with NACE MR0175 / ISO 15156.



The table shows the result of single stage flash calculation at 26bara and 105 C (upstream conditions where the 6" MPM will be installed). The GOR predicted under these conditions is 86.7% which ties up with the process data provided by the customer under these conditions.

The flash calculation was repeated at 16bara and 62C (downstream conditions where the 14" MPMs will be installed). The GOR predicted under these conditions is 90.3% which ties up with the process data provided by the customer under these conditions.

The predictions of the PVT model will be improved by tuning up against production separator GOR. The three steps of the tune up procedure are described next.

Step 1 Recombination

Recombination of the separator gas and separator liquid to one reported separator GOR will be initially conducted assuming a single stage separation (multi-stage separation is also possible).

Step 2 Fine Tuning of Fluid Composition

The recombined fluid from (1) will be flashed at separator conditions to check if the measured separator GOR is replicated by the simulation models. Only in the case of perfect separation and equilibration in the separator, perfect sampling, perfect fluid analysis and perfect modeling frame-work the measured and simulated separator GOR's will match perfectly. After this check the recombined fluid from (1) will be fine tuned so that the simulated separator GOR matches the measured separator GOR.

Step 3 Flash Calculation

The recombined fluid from (1) will be flashed at the pressure and temperature conditions of the MPM. The flash simulation provides the relative volume rates of gas and liquid at MPM conditions. The required information is: Pressure and temperature conditions of the MPM.

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Appendix B API 2566

"Section 19 TESTING GUIDELINES (factory acceptance – flow loop tests)

Section 19.1.8 pg 44: It should be pointed out that one cannot extrapolate performance between (flow loop) test points, mainly because the flow models are not linear solutions. These tests are not the final system calibration. For all multiphase measurement systems including Types II and III, the final calibration of the system is part of the field commissioning activity.

Section 20- FIELD TESTING GUIDELINES

Field tests may be conducted to qualify the meter performance under operating conditions, either as a precondition to the purchase or subsequent to the field installation, to verify the meter performance. The two types of field tests have to address a common problem – i.e. knowing the exact amount of multiphase fluid that flows through the meter.

There are three options for establishing the correct amount of fluid:

- Capturing fluids that flow through the system during the test and measuring them with secondary equipment except for the gas. This option requires extra equipment that must be calibrated and certified.*
- Proving all system components including the model, and then calculating an implied accuracy by inference. This option requires calibration of end devices under similar conditions of fluid properties, pressure, and temperature as well as flow modelling. These requirements make this option impractical.*
- Indexing the performance of the new system against an established multiphase measurement system such as a Type I gravity based test separator."*

Not surprisingly, the third option is the most common method employed in the field tests.

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Appendix C Process Data Sheet Well Head Production Lines Badra Oil Field

Flow rate range	Min	Normal	Max
Gas flow rate (Sm³/d)	2688	360000	432000
Gas flow rate (Am³/d)	151	20170	24205
Liquid flow rate (m³/d)	96	2400	2880
Water Cut (%)	0	25	100
Operating Pressure (barg)	15	22	35
Operating Temperature (C)	50	80	105
Design Pressure (barg)		43	
Design Temperature (C)		120	
Density at Standard conditions			
Oil density (kg/m³)	840	850	860
water density (kg/m³)	1001		1134
Gas (A Kg/m³)		24	
Viscosity at Actual conditions			
Oil viscosity (cP)		0.53	
Gas Viscosity (cP)		0.015	