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A Study on the Impact of Instrument Measurement Uncertainty, Degradation, Availability and Reservoir and Fluid Properties Uncertainty on Calculated Rates of Virtual Metering Systems

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ABSTRACT

A virtual metering system is a tool that is used to infer the oil, water and gas production rates. The tool can be utilized for both production and injection wells in the upstream oil & gas space. A virtual meter provides an estimate of a well's production by utilizing a set of input measurement data and parameters that describe the system.

There are various classes of virtual meters which include model-driven, data-driven and transient multiphase flow simulation based systems. Regardless of class, these various systems require input data from instruments such as pressure and/or temperature sensors located throughout the production facility. Depending on the model, some will need additional input parameters such as reservoir properties, wellbore design, and fluid properties.

This paper explores how virtual metering systems respond to the measurement and parameter input uncertainty, measurement degradation and instrument availability. The first part of the study looks into the impact of instruments degradation and drift over time. The instruments that have the largest impact to the estimated rates are highlighted. The sensitivity to the parameter input uncertainty is also investigated. Second, the study inquires how the various input measurements uncertainties propagate through the models and into the estimated rates. Finally, the sensitivity of the inferred rate quality to data availability as affected by instrument failures is ascertained from the data.

The results presented contain some interesting findings in what may perhaps be the first of such inquiry posed on virtual metering systems. The study has revealed adaptive aspect of virtual metering systems that are able to detect certain input anomalies and respond with alternative solutions. The various systems studied offer a suite of models and some include an uncertainty-based model discrimination feature to arrive at a composite rate weighted by individual model uncertainties. Other systems provide estimate of other key input parameters such as water cut and reservoir pressure as well as pressure and temperature at different locations depending on the calculation methodology used. Finally, the study has shown that certain instruments are vital to virtual meters' functionality and thus, provides for a defensible argument for instrument redundancy in certain parts of the production facility. The latter can be a useful insight when negotiating instrument redundancy and accuracy philosophies, particularly with the wells and subsea communities.

1 INTRODUCTION

A virtual metering system is a tool that is capable of estimating oil, water and gas production from a well by utilizing measurement data from sensors located in the field and on the production facility. The system also requires input parameters such as reservoir and fluid properties and field description including wellbore design and thermal properties. A virtual metering system typically consists of a suite of models most common of which are well inflow, hydraulic-thermal and choke flow calculations. A system description is common to all the models but each model requires a different set of measurement and parameter inputs to estimate the well production rate. In some cases inference of other operating and performance parameters such as water cut and reservoir pressure is also made.

A virtual metering system, when properly calibrated and appropriate models applied for the given field conditions, can provide engineers with near real-time visibility of field-wide production rates. The information is useful for production allocation and optimization, subsurface and base management, and field surveillance and monitoring.

A virtual metering system can be used as a standalone method or in conjunction with physical meters. In subsea developments, for instance, subsea multiphase flow meters may be deployed in a manifold where wells are tested sequentially via a common test header. In some cases, the development may justify individual meters deployed on each well, providing dedicated and continuous measurement. In these examples, a virtual metering system can be deployed as second layer of measurement. The virtual meter, calibrated independent of the multiphase meters, can provide assurance of measurement integrity by comparing two independent production rates for trending and corroboration. In the event of meter failure, the virtual meter can provide backup measurement until the failed meter is replaced. This "***layered measurement***" philosophy has been deployed in a number of fields and continue to gain traction as a way to improve production measurement integrity and reliability, particularly in deepwater developments.

The increasing use of virtual meters, notwithstanding, there appears to be a general "black box" perception of their performance capabilities, features beyond rate estimation and requirements for sustainability. Perhaps even less understood is their sensitivity to measurement and parameter input uncertainties. There is also the question of a model hierarchy - what particular model to use for a given set of field properties and conditions. The hydraulic models also use multiphase flow or tubing correlation of which several correlations are included in virtual metering packages - which correlation applies when?

This paper presents a sensitivity study of three virtual metering systems. Two of the systems are based on well inflow, hydraulic-thermal and choke flow models and one based on transient and multiphase flow simulators. For a given set of perturbed input data, the resulting calculated production rate of each virtual metering system was compared against a baseline data to arrive at the sensitivities.

The aim of the study is to determine how the different systems respond to the sensor measurement uncertainties, degradation over time and availability due to failures. The sensitivity of the calculated rates on the parameter inputs of reservoir and fluid conditions uncertainty are also gleaned in the study from the initial systems calibration.

The study was conducted as part of a major project work scope with the objective of identifying and selecting the "best" virtual metering system. In the course of the work, the task of selecting winners and losers took a back seat to gaining a deeper understanding of the fundamentals and unlocking some of the features and capabilities available in virtual metering packages. These include uncertainty-based model discrimination and smart features that detect anomalies and provides alternative solutions. It is noted that the deep inner workings of the discriminatory and adaptive features are treated as proprietary by the vendors. It is not the intent of the study to delve into them as these are not available to the end user anyway.

The identities of the various systems and the development project are withheld to allow the reader to focus on the technical discourse - to encourage the users of virtual metering systems to ask similar questions posed in the study. The gain of a deeper understanding of the various systems and their sensitivities for a given application should inform the selection process. Last, the insights gained on instruments uncertainty and availability can result in a powerful conversation when negotiating instrument quality and redundancy in wells and the subsea facility.

2 VIRTUAL METERING SYSTEMS USED IN THE STUDY

Following is a brief description of the virtual metering systems that were used in the study. Two systems, referred to as A & B, are based on well inflow, hydraulic-thermal and choke flow models while the third system, C, uses a dynamic process simulator coupled with a transient multiphase flow simulator. Systems A & B are limited to individual well descriptions. Both utilize pseudo steady-state models which may not be applicable during transient conditions. Studies performed on A & B are limited to one well with typical wellbore design and instrumentation. System C, on the other hand, is a comprehensive wells and facility hydraulic network model. A dynamic process simulation model including 5 production wells, manifolds, flowlines, risers and topsides production and test separators was developed for this study.

The rate estimation models used by System A are choke flow, hydraulic-thermal and numerical models. The choke flow model uses the measured pressure drop across the production choke to estimate bulk rate. Additional input of reservoir fluid properties allows for the determination of changes in phase.

The hydraulic methods provided in system A comprise of various models based on reservoir inflow and tubing hydraulic models. Some utilize the classic vertical lift performance and reservoir inflow performance intersection (VLP/IPR) while others are based solely on tubing hydraulic models. The system combines the available measurements with inflow and tubing calculations of pressure and temperature in multiple combinations to estimate rate. System A offers 13 different tubing and inflow models plus the choke flow and numerical equations.

The numerical models in System A are user-defined equations that describe the measured wellhead or downhole pressure data. Apart from the rates and phase, System A provides additional output of "unused" parameters that were not required for a particular model. These could include combinations of wellhead pressure and temperature, downhole pressure, reservoir pressure, well productivity index (PI), water cut and gas-oil ratio.

System A reports the best-estimate rate from a user-defined model selection hierarchy. A "best rate" is selected from the models from which a convergent solution is obtained starting at the top of the hierarchy.

The second model used in the study, System B, is very similar to System A in terms of the hydraulic-thermal and chokes flow modes but differs in a number of key features. System B includes 4 types of rate estimation methods. These are inflow performance, wellbore flow, choke flow and well jumper flow models.

There are 9 distinct models provided each requiring various measurement and parameter input data. For each model, an associated uncertainty is estimated by perturbing the input measurements. The rate estimates from each model are then combined statistically using a proprietary algorithm that uses the associated uncertainties as the weighting factor to arrive at the best rate estimate. The overall uncertainty is also calculated and reported along with the reported best rate.

Both systems have the capability to detect anomalous measurement input but differ in the action taken when such an event is detected. System A disables the model/s where the anomalous input/s is/are required and the rate is determined from the remaining models in the hierarchy for which valid inputs are available. System B, on the other hand, reverts to an alternative solution for which valid input measurements are available. For example, if the input pressure measurements are all deemed invalid, then the system reverts to a temperature solution to estimate the well rate. System B does not output or calculate "unused" parameters. It is noted that the logic for valid measurement discrimination is often complex and can be system specific, a subject that is not covered in this paper.

Finally, the third System C used in the study is based on a dynamic process simulator, linked to transient multiphase flow simulator. A simulation model of the production facility from the wells to the topside separators was constructed. Two identical copies of the facilities model were used in the study. One represents the plant which generates the measurements. The other represents the virtual metering system which receives the plant measurements as input.

Any changes in the plant model state are conveyed to the virtual metering system via valve positions, pressures, temperatures and topsides total flow measurement changes. Independent wellbore and valve sub-models are included in the virtual metering model in order to calibrate the total flow rate and water cut for each well based on pressure and temperature input from the plant.

3 DESIGN BASIS FOR THE STUDY

The following section provides information on the well design and thermal properties, fluids thermodynamic properties, and certain modelling assumptions used in the study. This section is provided to highlight the input data needed in the construction of a typical virtual flow metering system.

3.1 Wellbore Completion Design

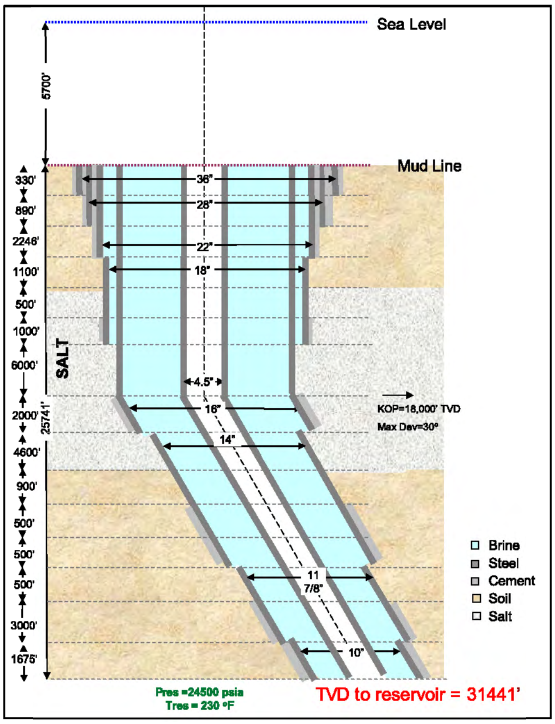

Fig. 1 - Wellbore Casing Design

The well that was used in the study is a subsea completion in 5,700 feet of water. The well is vertical up to 18,000 feet true vertical depth (TVD) at which point it deviates at a maximum of 30 degrees to a TVD of ca 31,500 feet and an equivalent measured depth of 33,500 feet. The tubing ID is 3.96 inches (4.5" OD) with an approximate roughness of 0.0006. The downhole pressure gauge was assumed to be located at 31,500 TVD. The well was modelled without a surface-controlled subsea safety valve (SCSSV). The wellbore casing design is shown below in Figure 1.

3.2 Wellbore Heat Transfer and Geothermal Properties

For the hydraulic-thermal based models A & B, the study was limited to steady state conditions. The wellbore heat transfer was sufficiently modelled by imposing a heat transfer coefficient (U value) distribution on the tubing (inner) wall. The U value distribution and the geothermal gradient for the wellbore used in the study are shown in Figure 2 and Table 1, respectively.

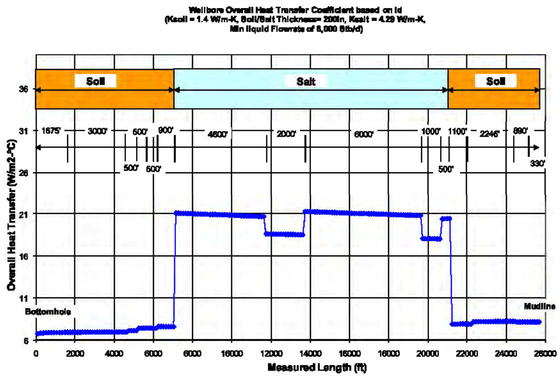

Fig. 2 - U Value Distribution Along Wellbore

Table 1 - Geothermal Gradient Data

Measured Depth (ft)	Temperature (ºF)
5,700	39.5
10,500	105
24,500	145
33,520	250

3.3 Reservoir Fluid Composition and Properties

The reservoir fluid composition is given in Table 2. It is useful to note that the baseline production rate data used in the study is derived from a forecast model and not from actual field production data. The equation of state (EOS) used for the fluid phase behaviour description in the forecast model was the Peng-Robinson (1978) with the temperature-dependent Peneloux volume translation [PR 78 Peneloux (T)].

Table 2 - Reservoir Fluid Composition

Component	Mol %	Mol wt	Crit T (°F)	Crit P (psia)
N2	0.554	28.01	-232.4	493
CO2	0.232	44.01	87.9	1071.6
C1	16.629	16.04	-116.63	667.8
C2	5.521	30.07	90.09	707.8
C3	7.059	44.1	206.01	616.3
iC4	1.025	58.12	274.98	529.1
nC4	3.624	58.12	305.65	550.7
iC5	1.619	72.15	369.1	490.4
nC5	2.781	72.15	385.7	488.6
C6	5.151	86.2	465.08	469.86
C7-10	15.55	113.95	582.45	389.52
C11-13	8.312	159.91	702.54	310.1
C14-19	10.634	224.06	834.87	259.93
C20-26	6.596	313.11	1019.76	211.45
C27+	14.713	680	1221.475	129.99

The modelling of the fluid phase behaviour with an EOS can be another source of uncertainty in virtual metering systems. The following illustrates this effect. System B used the Peng-Robinson Peneloux [PR Peneloux] (without the temperature dependency on the volume translation) for the phase behaviour model. The EOS models were both tuned to the same set of experimental PVT data. A comparison of the predicted fluid properties using the two EOS is given in Tables 3 and 4. The phase envelope predictions are shown in Figure 3.

Table 3 - Fluid Properties at Reservoir Condition (24,330 psia and 226 °F)

Property	PR78 with Peneloux (T)	PR (Peneloux)	Unit
Density	887.42	891.81	kg/m3
Oil Formation Volume Factor	1.061	1.054	bbl/stb
Viscosity	11.1	7.2	cP
GOR (single stage)	217	207.3	scf/stb

Table 4 - Fluid Properties at Saturation Condition

Property	PR78 with Peneloux (T)	PR (Peneloux)	Unit
Saturation Pressure	1074	1054	psia at 226 °F
Density	791.3	797.6	kg/m3
Oil Formation Volume Factor	1.192	1.179	bbl/ stb
Viscosity	2.3	1.61	cP

The difference in the thermodynamic and fluid properties predictions from the two EOS would result in variation in the estimated rates for the same set of measurement input. The percentage deviation of the estimated rate between the two EOS descriptions, for the same virtual metering system with identical set of input data would be around 2-5%.

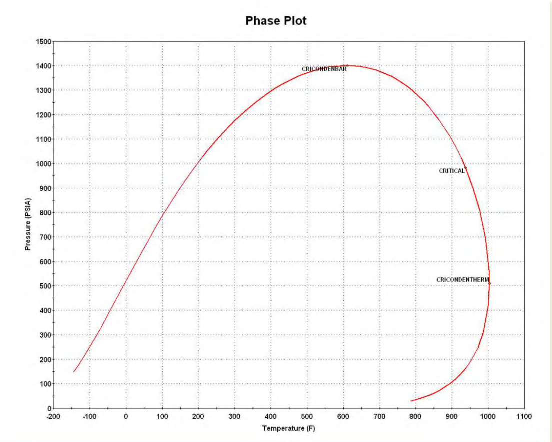

Fig. 3 - Phase Envelope Predictions for PR (Peneloux) and PR 78 Peneloux (T) EOS

Some of the EOS predicted properties are adjusted to obtain a match between the virtual meter and baseline rates during the initial calibration. In the case of system B, the liquid densities were tuned to match the baseline flow rates.

System A utilized a simple black oil model for the phase behavior description of the same fluid. The Petrovsky PVT correlation was used to estimate the bubble point, solution GOR and formation volume factor.

4 SENSITIVITY ANALYSIS METHODOLOGY

4.1 Baseline Production Profile (Study Cases)

Three production scenarios, representing the field production spectrum from early (high rate), mid to late life (low rate) were used as the baseline against which the sensitivity of the various virtual meters were tested. Table 5 provides details of the operating conditions for the three scenarios used in by Systems A and B.

Table 5 - Design data for three production scenarios

Scenario	Liquid Rate (stb/d)	Watercut (%)	Reservoir Pressure (psia)	WHP (psia)	WHT (ºF)	DHP (psia)	DHT (ºF)
Case 1 Year 0	14600	13	24200	2810	200.3	14174	285
Case 2 Year 4.28	7000	17	23200	2923.6	157.2	13268	285
Case 3 Year 20	500	66	16400	3023.1	84.6	14827	245

4.2 Selection of Applicable Methods and Initial Calibration

The reservoir and fluid properties for this particular field development produce flowing wellhead pressures that are about an order of magnitude less than the reservoir pressure. Notice also from Tables 4 and 5 that the saturation pressure at reservoir temperature is well below the flowing wellhead pressures over life of field. These conditions would result in no gas breakout in the subsea facility. For these types of wells, the production plan is to produce with the production choke valves fully open. This production scenario precludes the use of the choke flow models in systems A & B due to the very low pressure drops that would be generated across the choke. Thus, only the hydraulic-thermal models were applicable for these systems.

For system A, three hydraulic well models were developed representing each production scenario. The parameters within the models were then adjusted to get a match with the tubing flow correlations and the baseline conditions. For the tubing correlation, the parameters for the hydrostatic and friction effects were matched to each of the production scenario yielding three sets of values, shown in Table 6 below.

Table 6 - Tubing Correlation Match Parameters 1 and 2

Design Case	Tubing Correlation Match Parameters	
	Parameter 1 (Hydrostatic)	Parameter 2 (Friction)
Case 1- Year 0	1.00599	1.04150
Case 2 - Year 4.28	0.99627	0.95422
Case 3 - Year 20	0.99679	1.00000

The water salinity in the early life case was set to the field produced water salinity from downhole fluid samples. When this salinity value was used in the mid to late life cases, the frictional coefficient in the match parameters for the chosen tubing correlation was outside the expected range. The water salinity was adjusted in these two cases to obtain a frictional match coefficient in the expected range.

There were a total of seven hydraulic modes of calculation utilized in System A that are applicable to the three baseline cases. These modes are summarized in Table 7 below. The letters M, K and E in the table represent the measurement input, parameter input and additional estimated parameters output apart from the production rate (which can either be measurement or parameter).

Table 7 - System A Calculation Modes

Description	Measurements				Parameters			System A Modes
	WHP	WHT	DHP	DHT	Res P	WC	GOR	Method
Method 1	M	E	E	M	K	K	K	Tubing and inflow (VLP/IPR) intersection calculation
Method 2	E	E	M	M	K	K	K	
Method 3	M	E	M	M	K	E	K	
Method 4	M	M	E	M	K	E	K	
Method 5	M	E	M	M	E	K	K	Tubing gradient (VLP only) calculation
Method 6	M	M	E	M	E	K	K	
Method 7	M	M	M	M	E	E	K	

For example, the first calculation mode requires the well head pressure and bottomhole temperature for the measurement inputs plus the reservoir pressure, produced water cut and fluid gas-oil ratio for the parameters. The calculation mode then yields the estimated production rate and phase composition, along with the downhole pressure and wellhead temperature.

The estimated values of WHT and DHP output by this method are recorded for every calculation cycle. These values are then trended against the corresponding measurements. System B includes a trending feature that is configured for each well to make these comparisons against a user-defined deviation tolerance. In the event an estimated parameter exceeds the tolerance, then an alert is issued and a course of action is then taken as appropriate. For example, one or more of the following actions may be taken:

- Parameters inputs (GOR, watercut, reservoir pressure) are updated;
- The well model is reviewed;
- The method being used to estimate the production rate is reviewed;
- The well is prioritised for a well test and any changes discovered applied in the model and System B configuration.

However, even if the discrepancy exceeds the tolerance, if System B uses a different method then the rate estimates may still be good. For instance the if the discrepancy is caused by a change in reservoir pressure then the method that only involves tubing pressure drop will still be good (provided that the tubing pressure drop was calibrated to good data).

For system B, there were three hydraulic-thermal methods that were used to arrive at the composite best rate. These methods involve the combination of 2 measurement inputs of pressure and temperature from the reservoir, bottomhole and wellhead locations. Table 8 below shows the methods used in system B. For each method, both pressure and temperature input are required regardless of location.

Table 8 - Calculation Modes for System B

Method	Reservoir P & T	Bottomhole P & T	P & T before choke
1	x		x
2		x	x
3	x	x	

The liquid density in system B was increased by around 2% to account for the differences in the EOS phase behaviour predictions. Calibration of system B to the design cases were carried out and the resulting best estimated rates compared to the baseline data are shown in Table 9.

Table 9 - Comparison of System B Predicted and Baseline Rates Post Initial Calibration

Case	Oil Rate (stbpd)			Water Rate (stbpd)		
	Design	System B	% Error	Design	System B	% Error
1	12648	12726	0.6	1952	1960	0.4
2	5830	5777	-0.9	1170	1159	-0.9
3	168	207	23.2	332	405	22.0

Note that residual errors for the oil and water rates in the early (Case 1) to mid-life (Case 2) are within ±1.0% absolute error. For late life (Case 3), errors increase to as high as 20% due to the very low flow rates.

The initial calibration of the virtual metering system would absorb the baseline uncertainties from the input measurements and parameters required by the methods used. The study assumed that the conditions that generated the baseline data are known. Thus, the initial uncertainties from the input measurements and parameters are absorbed by the adjustable parameters in the models.

It is important, however, to be aware that the value of all operating condition parameters from instrumented processes on wells cannot always be determined. Even if valid estimates of certain parameters are available, there may still be a range of different combination of rates, phase composition and inflow parameter values that match the measured set of conditions. This raises the issue of uniqueness of solution.

The tubing pressure drop variation on a typical oil production well as a function of flow rate is shown in Figure 4.

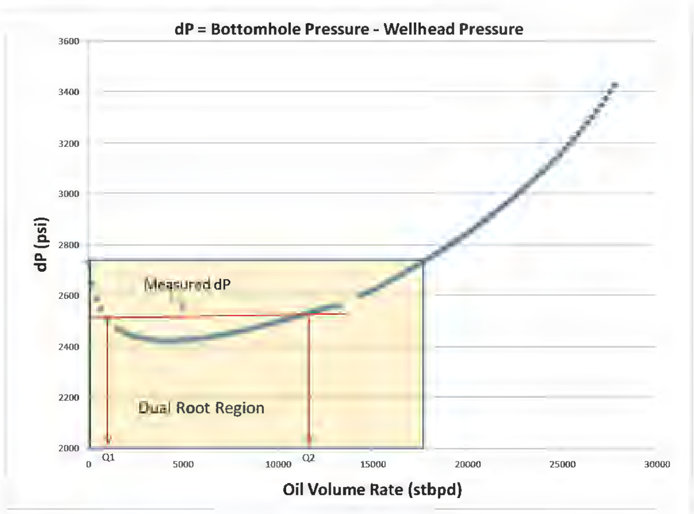

Fig. 4 - Pressure Drop versus Flow Rate for a Typical Oil Well

Note at the lower flow rates, two possible flow rates would generate the same differential pressure across the well. This is due to balance between the competing hydrostatic and frictional forces. This dual root problem is addressed in system B by using additional measured data. For the same well in Figure 4 above, the temperature drop across the well is a monotonic decreasing function of flow rate, shown in Figure 5. The measured temperature drop used in conjunction with the pressure drop ensures the correct rate solution is obtained.

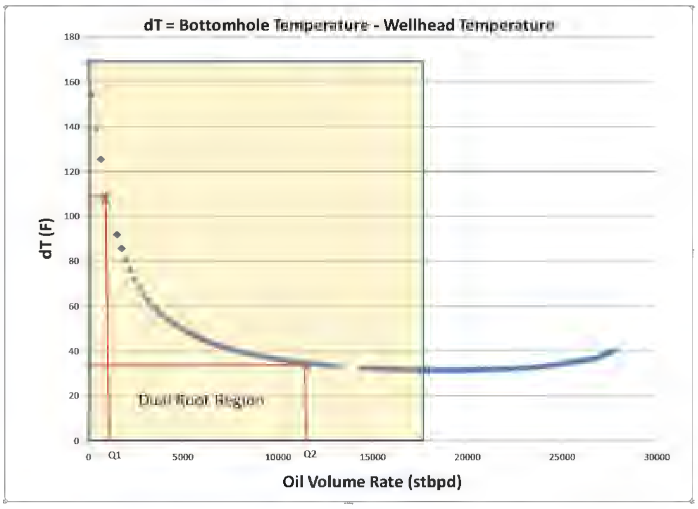

Fig. 5 - Temperature Drop versus Flow Rate for a Typical Oil Well

4.3 Test Matrix

The hydraulic-thermal models will be sensitive to the following measurements and parameters:

Measurement:

- Produced fluid pressure at the wellhead - WHP
- Produced fluid temperature at the wellhead - WHT
- Produced fluid pressure at the downhole gauge location - DHP (also called BHP)
- Produced fluid temperature at the downhole gauge location - DHT (also called BHT)

Parameters:

- Average reservoir pressure - Pres
- Inflow productivity index - PI
- Liquid phase watercut - WC

For each of the production scenarios, a number of cases were run to assess the impact of instrument uncertainty, degradation, and availability and the impact of the field input parameters to the calculated rates. In the case of uncertainty and degradation, the sensitivities were calculated by introducing an error to each of the measurements or parameters on an individual basis and then comparing the results with the base case.

System A reports the sensitivities on the basis of the oil rate while System B reports in terms of total mass rate deviation. Deviations are computed as a percentage of the difference between the calculated and base case rate divided by the base case rate, regardless of basis.

With different bases of reporting deviations for systems A and B, the absolute value of the deviations are not directly comparable but the resulting sensitivities would hold. The test matrix is summarized in Table 10.

Table 10 - Sensitivity Analysis Test Matrix

<table>
<tr><th>Instrument</th><th>Instrument [illegible]</th><th>Instrument [illegible]</th><th>Instrument [illegible]</th><th>Field Input Parameters</th></tr>
<tr><td>Bottom Hole Pressure</td><td rowspan="4">1 and 2 Transmitter Cases</td><td rowspan="4">1and 2 Transmitter Cases – base uncertainty of 1% and 25%</td><td rowspan="4">1 and 2 Transmitter Cases – measured value varied in 5% increment up to +/- 10%</td><td rowspan="4">N/A</td></tr>
<tr><td>Bottom Hole Temperature</td></tr>
<tr><td>Pressure Upstream of Choke</td></tr>
<tr><td>Temperature Upstream of Choke</td></tr>
<tr><td>Reservoir Pressure</td><td colspan="3" rowspan="3">N/A</td><td rowspan="3">Vary in 5% increment up to 10%</td></tr>
<tr><td>PI</td></tr>
<tr><td>Water Cut</td></tr>
</table>

4.4 System C Description

The virtual metering system C is fundamentally different from the other two used in this study that it warrants a separate treatment. System C uses a dynamic process simulator linked to a transient multiphase flow simulator. It utilizes pressure and temperature measurement, and valve positions from the field to estimate the production rates from all the wells in the hydraulic network.

4.4.1 Model Implementation

For system C, two copies of the same model are used in this study. One model represents the plant which generates the input and where all the tuners are off. The other is called virtual metering model, which receives the plant data. Data transfer between the models, located in different servers, is done by using Object Linking and Embedding for Process Control (OPC).

Independent wellbore and choke valve sub-models are part of the virtual metering model in order to calibrate total flow rate and water cut for each well based only on pressure and temperature measurements coming from the plant model. The simplified model schematic of the production facility used in the study is shown below.

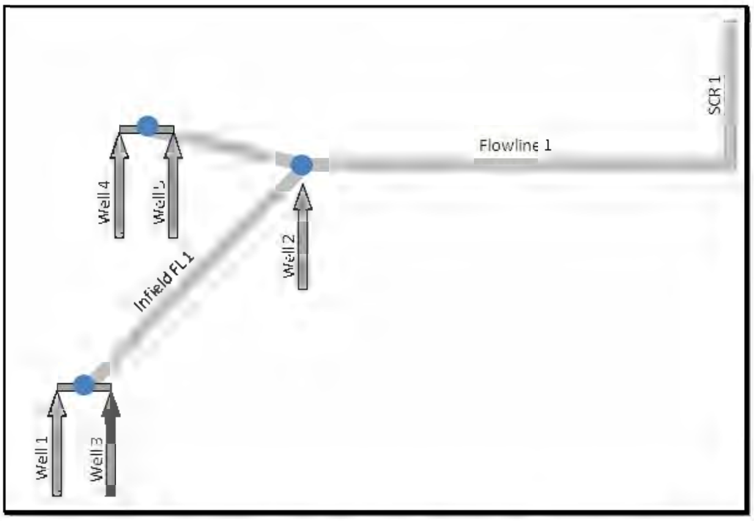

Fig. 6 - System C Wells and Flowlines Schematic

The scope of this study includes the following:

Subsea:

- 5 production wells
- Flowlines
- Risers
-

Topsides:

- Test separator inlet heater
- Cross exchanger
- Test separator
- Production separator

The table below lists the boundary conditions of the model which serve either as an inlet or an outlet boundary. In this study, the productivity index was chosen for calibration while the reservoir pressure was held constant to match the wellbore pressure measurements. This is based on the premise that during operations, the field reservoir engineer could better estimate of the reservoir pressure.

Note also from Table 11 the relative production rates of each of the 5 wells at different production scenarios. At the peak high stage, wells 3 and 5 have the lowest production rate. This will play a role in the sensitivity results presented in section 5.

Table 11 - System C Subsea Boundary Conditions

		Year			
		0 (Base)	Peak (High)	Late life	
				Low	High
Well 1	Presv (psia)	24200	23200	16500	21100
	WC (%)	15	15	35	50
	PI (Stb/d/psi)	1.43	0.73	0.2	0.58
	Q_{Liq} (stbpd)	14600	7000	500	3900
Well 2	Presv (psia)	-	23200	16400	21100
	WC (%)	-	30	60	60
	PI (Stb/d/psi)	-	0.57	0.3	0.45
	Q_{Liq} (stbpd)	-	5400	500	2900
Well 3	Presv (psia)	24100	22500	16100	20000
	WC (%)	15	15	35	25
	PI (Stb/d/psi)	1.41	0.49	0.24	0.3
	Q_{Liq} (stbpd)	13900	4300	500	1800
Well 4	Presv (psia)	-	22500	19300	20000
	WC (%)	-	15	50	50
	PI (Stb/d/psi)	-	0.7	0.1	0.65
	Q_{Liq} (stbpd)	-	6800	500	3700
Well 5	Presv (psia)		22300	15300	20900
	WC (%)	-	15	25	40
	PI (Stb/d/psi)	-	0.55	0.3	0.42
	Q_{Liq} (stbpd)	-	5000	500	2900

Table 12 - System C Topsides Boundary Conditions

	Prod'n separator	Test separator
Operating pressure (psig)	350	350
Water pressure downstream separator (psia)	200	200
Oil pressure downstream separator (psia)	200	200

4.4.2 Scenario Matrix

The sensitivity of system C to the well measurements and production parameter inputs for the entire network model would involve tremendous number of cases to run as to be practicable. There are 9 instruments per well and 3 production parameters used in the study for system C.

Measurements per well:

Pressure upstream of the Production Wing Valve (PWV):	UPWVP1
Temperature upstream of PWV:	UPWVT1
Pressure upstream of PCV	UPCVP1
Temperature upstream of PCV	UPCVT1
Pressure downstream of the PCV:	DPCVP1
Temperature downstream of PCV:	DPCVT1
Downhole pressure	DHP1
Downhole temperature transmitter	DHT1
Choke position	

Production parameters:

Productivity index	PI
Reservoir temperature	T_resv
Water cut	WC

A preliminary sensitivity study was conducted for 1 well to determine the critical measurements that will be tested in order to reduce the number of cases to be run. This exercise reduced the measurement input to 4. These transmitters are located upstream and downstream of the production control valve (PCV), upstream of the production wing valve and the downhole pressure gauge. The three production parameters were retained in the study. The reduction of measurement input from nine to four elements would still involve a large number of cases if each measurement and parameter input were perturbed one at a time per well per production scenario. A further step was taken to reduce the number of runs and still produce meaningful result.

The result from the single well sensitivity study was also used to inform the final selection of cases to be run. The resulting scenario matrix is shown in Table 13. Each tick mark is a run case, where 0 is for Year 0, PH is for Peak high, and LLH is for the Late life high scenarios. The assumptions used in landing the matrix are given below:

- At year 0, only wells 1 and 3 are producing.
- Do not perform the same test for identical transmitters in two different wells going to the same manifold. In this case, wells 1 and 3 go to same manifold and so do wells 4 and 5 (See Figure 6 for a schematic representation of wells and flowlines alignment)
- Do not repeat the same tests from the preliminary study.
- Pressure transmitters (21 cases): Since well 1 was already tested in the preliminary study for year 0, no cases for wells 1 and 3 at this life stage are considered. For the same offset, different stages are considered. All possible combinations are considered for well 2 for the last two life stages, but UPWVP1 is not considered since it has more or less the same errors as for UPCVP1
- Temperature transmitters: Since no considerable errors were found in the preliminary study, no temperature transmitters are considered here.
- Productivity index, water cut, reservoir temperature, and choke blockage (12 cases): For each parameter, 3 cases are proposed (one at each manifold). Higher offsets are reserved for the LLH stage.
- A scenario matrix with a total of 30 cases is summarised in Table 13 where only one single measurement or parameter is perturbed in each case (multiple combinations are not considered in this matrix).

Table 13 - System C Scenario Matrix

		Trans. offsets (%)		PI offset (%)		WC offset (%)		Choke bias (%)	
		2	5	5	10	10	20	2	5
Well 1	DPCVP1	PH							
	UPCVP1	LLH							
	UPWVP1	PH							
	DHP1	LLH							
	PI			0					
	WC								
	Choke bias								
Well 2	DPCVP1	PH							
	UPCVP1	LLH							
	UPWVP1								
	DHP1	PH							
	PI				LLH				
	WC					PH			
	Choke bias							PH	
Well 3	DPCVP1	LLH							
	UPCVP1	PH							
	UPWVP1	LLH							
	DHP1		LLH						
	PI								
	WC					0			
	Choke bias							0	
Well 4	DPCVP1	PH							
	UPCVP1	LLH							
	UPWVP1	PH							
	DHP1	PH	LLH						
	PI			PH					
	WC								
	Choke bias								LLH
Well 5	DPCVP1	LLH							
	UPCVP1	PH							
	UPWVP1	LLH							
	DHP1	LLH	PH						
	PI								
	WC						LLH		
	Choke bias								

5 SENSITIVITY ANALYSIS RESULTS

This section presents the sensitivity results for cases 1 and 2 production scenarios at ±5-10% perturbations (see Table 5).

Tornado plots are used to summarize the sensitivity calculations. The tornado plots for the three calculation modes in the System A hierarchy are presented below. These are Method 1, Method 2 and Method 5 in Table 7 above. System B reports only one best rate estimate as a result of the uncertainty based statistical discrimination technique employed.

5.1 Instrument Degradation Uncertainty Results for Systems A & B

All the measurement and parameter input values were kept fixed while the value of the measurement or parameter being investigated is perturbed from its base value. The calculated rate is then compared to the base rate from which the absolute deviation was determined as follows:

$$\%Deviation = \frac{Perturbed\ rate - Base\ case\ rate}{Base\ case\ rate} \times 100\%$$

5.1.1 Case 1 - Year 0 (High production rate case)

The sensitivities computed for the Case 1 production scenario correspond to the highest production rates at start-up. The results for Systems A and B are presented below.

5.1.1.1 Sensitivities to ±5% measurement and parameter uncertainty

For system A, the sensitivities to a ±5% adjustment to a measurement or parameter input depends on the particular mode of calculation used. Recall that for System A, seven methods are used and the study shows that Method 1 provides the least sensitivity for Case 1 at this level of perturbation.

System A sensitivity response for Method 1 is shown below. Method 1 is a tubing and inflow intersection method without any adjustments made. As can be expected, this method is most sensitive to the error in reservoir pressure, followed by the well productivity index, wellhead pressure, watercut and downhole temperature. Method 1 yields about a ±10% oil rate change with ±5% error in reservoir pressure.

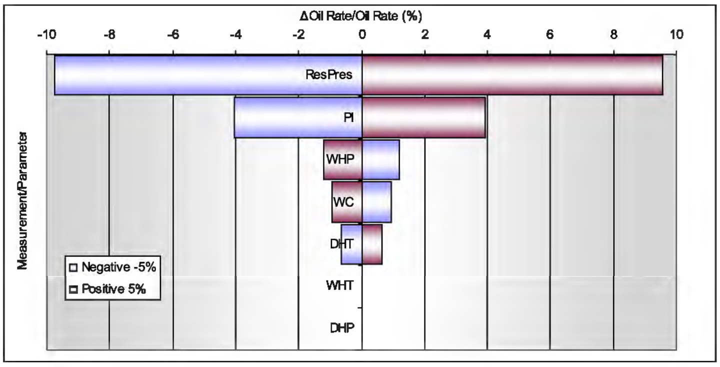

Fig. 7 - System A, Method 1, ±5% sensitivities for Case 1 (Year 0)

Note that for Method 1, the downhole pressure and wellhead temperature are not used and thus show 0% sensitivity on the tornado plot. This will be the case for any of the unused measurement or parameter input for a particular mode in System A.

The corresponding sensitivity responses for Methods 2 and 5 are shown in Figures 8 and 9. Method 2 is also based on tubing and inflow intersection calculation but where the wellhead pressure is adjusted to match the downhole pressure. The method is also very sensitive to reservoir pressure error.

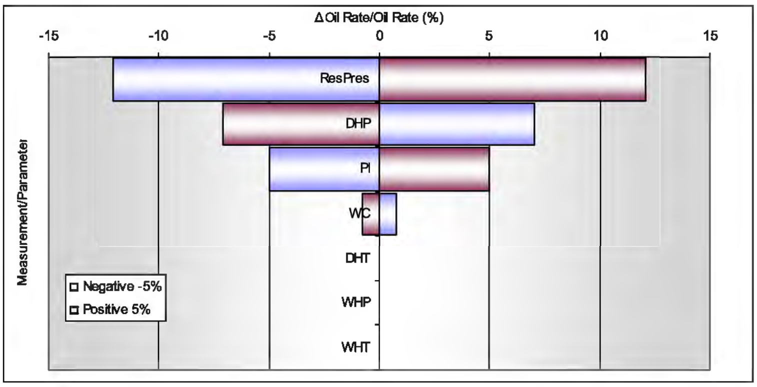

Fig. 8 - System A, Method 2, ±5% sensitivities for Case 1 (Year 0)

Method 5 was selected to represent a calculation based on tubing gradient only. The method adjusts the rate to match the downhole pressure. Method 5 might be a useful alternative if an accurate reservoir pressure is not available, but requires an accurate downhole pressure input.

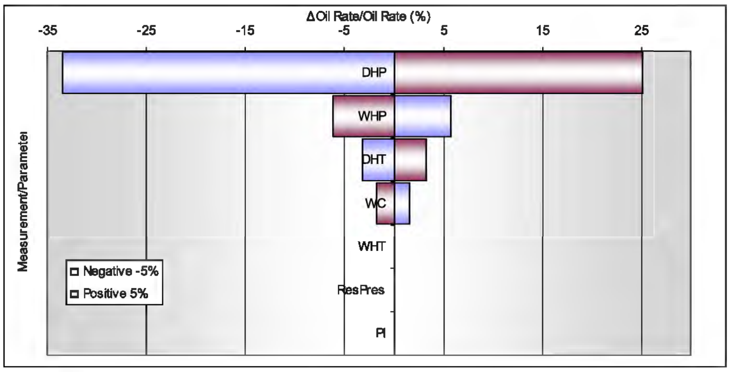

Fig. 9 - System A, Method 5, ±5% sensitivities for Case 1 (Year 0)

Figure 10 shows the sensitivity response of system B to ±5% injected error. Recall that for System B, three calculation modes were available. The rates estimate from each method is combined statistically to yield the reported rate value. The sensitivities shown in Figure 10 are the combined reported total mass rate error for each parameter or measurement perturbation.

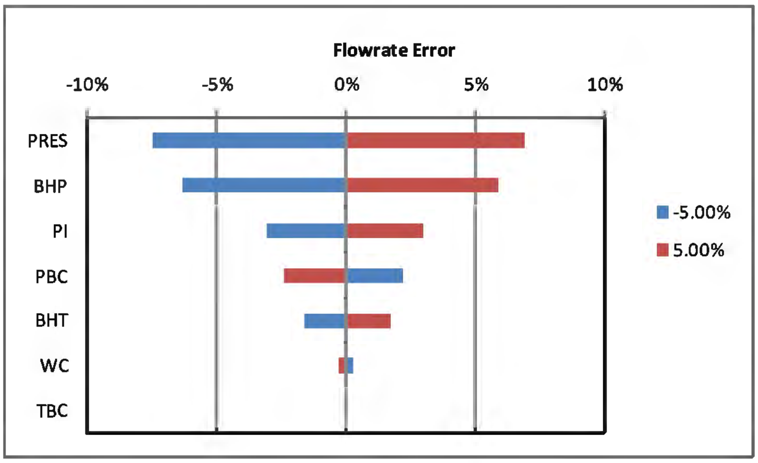

Fig. 10 - System B, ±5% sensitivities for Case 1 (Year 0)

Notice that at the ±5% perturbation level, the resulting error response of each of the measurement and parameter input is symmetrical and the system shows the highest sensitivity to reservoir pressure error. At this level of perturbation, the results are aligned with expectation based on the physics of the flow, e.g., a change in reservoir pressure produces a corresponding change in rate in the same direction.

5.1.1.2 Sensitivities to ±10% measurement and parameter uncertainty

The sensitivities of system A to ±10% injected errors, for the same methods 1, 2 and 5 are shown in Figure 11-13 below.

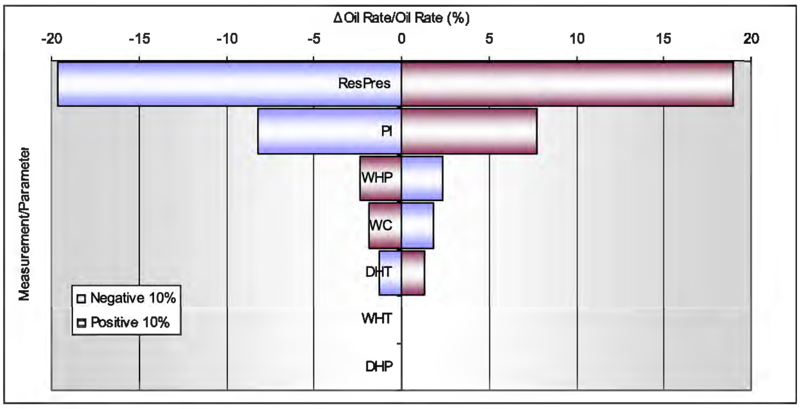

Fig. 11 - System A, Method 1, ±10% sensitivities for Case 1 (Year 0)

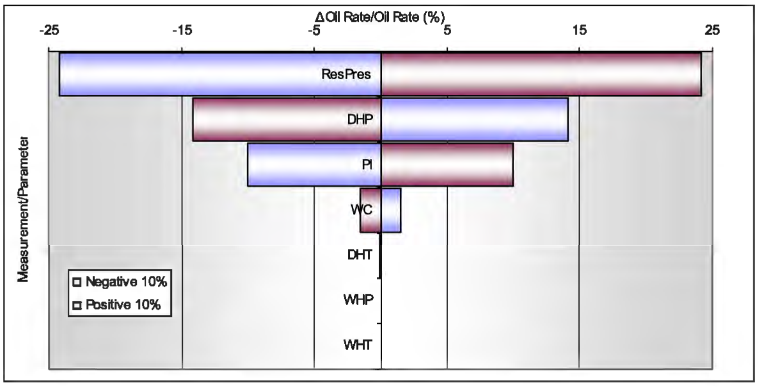

Fig. 12 - System A, Method 2, ±10% sensitivities for Case 1 (Year 0)

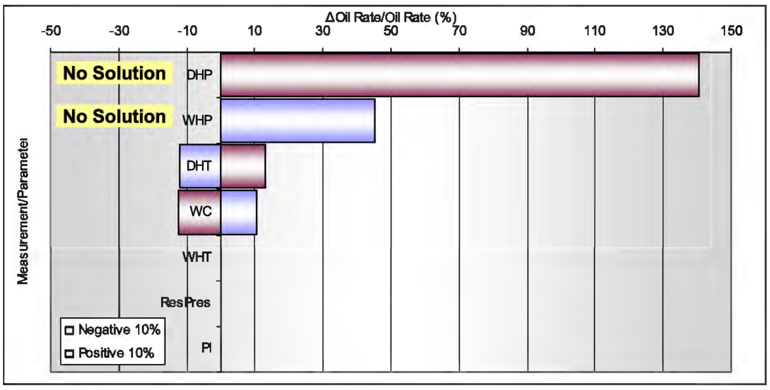

Fig. 13 - System A, Method 5, ±10% sensitivities for Case 1 (Year 0)

Methods 1 and 2 in System A show the highest sensitivity to reservoir pressure. Where these values are not known accurately and the downhole pressure gauge is working properly, then Method 5 based on tubing pressure drop would provide the best rate estimate.

It should be pointed out that some of the injected errors can be large enough that it is not physically possible for some combinations of measurement and parameter values to be achieved in practice. In these instances, system A, from physics standpoint is rightly not able to report results. These events are indicated by a label of **No Solution** in the plots as it first appears in Figure 13. In this case, the perturbed downhole pressure of 10% below the base value could not be supported by the hydrostatic column pressure in the well.

Figure 14 below shows the response of system B to a ±10% perturbation error. The first observation is that the rate is most sensitive to the reservoir pressure uncertainty. Second, the rate response to the downhole pressure is now asymmetrical and in the same direction of change. To understand the underlying cause, a deeper analysis of the System B response to bottomhole pressure changes is warranted.

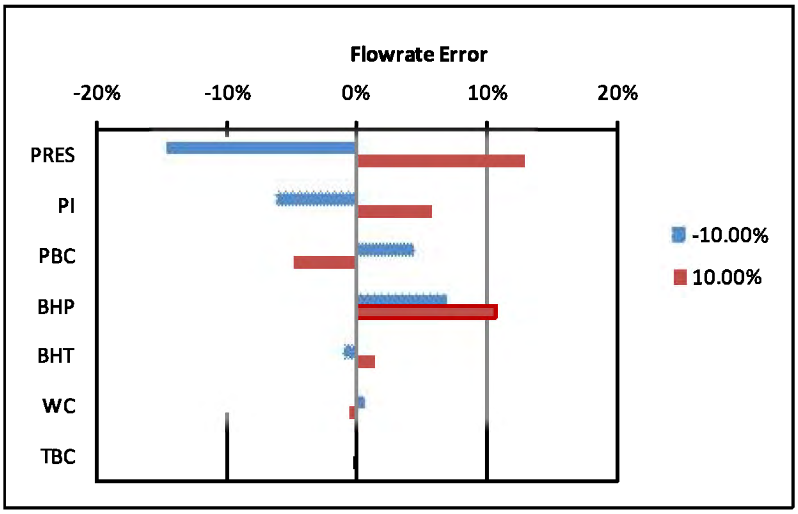

Fig.14 - System B, ±10% sensitivities for Case 1 (Year 0)

For system B, an increase in the bottomhole pressure causes the wellbore flow model to increase its predicted rate. Since the well differential pressure (bottomhole minus well head pressure) has increased, applying the statistical perturbation method results in a smaller method prediction uncertainty. For the PI method, increase in the bottomhole pressure results in a decreased predicted rate. The resulting lower differential pressure across the sandface causes the statistical perturbation to ascribe a larger uncertainty for the PI method as bottomhole pressure is increased. The resulting best rate reported by System B is increased from the baseline case as the statistical mixing rule gives a higher weight to the wellbore flow model. This outcome is identical for the +5 and +10% bottomhole pressure injected errors.

When the bottomhole pressure is decreased by 10%, the wellbore flow model does not behave as expected. The system finds that the frictional differential pressure (dP) in the well is very small and the resulting flow rate leads to a very low arrival temperature compared to reading. The system then “concludes” that either the bottomhole or wellhead pressures are invalid. The resulting lack of confidence in the wellbore pressure readings causes the system’s smart features to kick-in and seeks an alternative solution. The hydraulic-thermal model is solved by adjusting the rate that produces a consistent arrival temperature which yields a higher predicted rate. The PI model also predicts a higher rate with the lower bottomhole pressure. The overall system predicted rate therefore is higher than the baseline rate when the pressure is decreased by 10%. The smart system feature, thus, yields a rate sensitivity response that is in the same direction of change for a plus or minus change in bottomhole pressure from baseline value.

5.1.2 Case 2 - Year 4.28

The liquid rate for case 2 production scenario has been reduced to about half the level compared to case 1. The sensitivity results for system A shows that Method 1 is the least sensitive calculation, achieving better than ±11% for 5% uncertainty in measured and condition parameters.

5.1.2.1 Sensitivities to ±5% measurement and parameter uncertainty

Figure 15-17 present the results for Methods 1, 2 and 5 in system A with a ±5% perturbation. Note that the order of sensitivities for each method above is largely identical in cases 1 and 2.

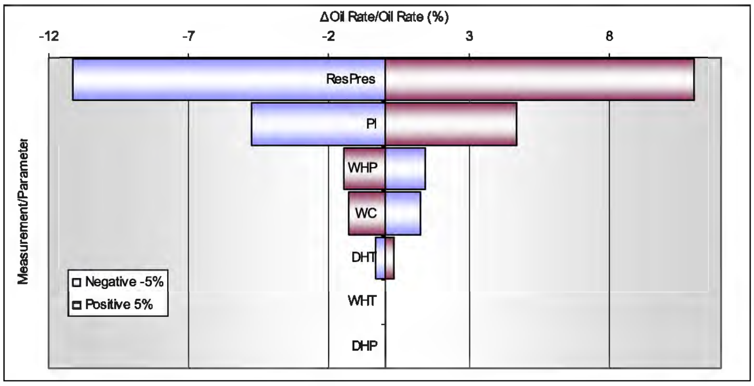

Fig. 15 - System A, Method 1, ±5% sensitivities for Case 2 (Year 4.48)

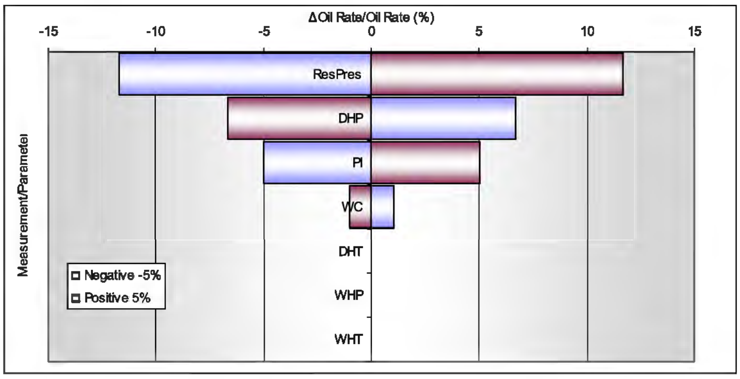

Fig. 16 - System A, Method 2, ±5% sensitivities for Case 2 (Year 4.48)

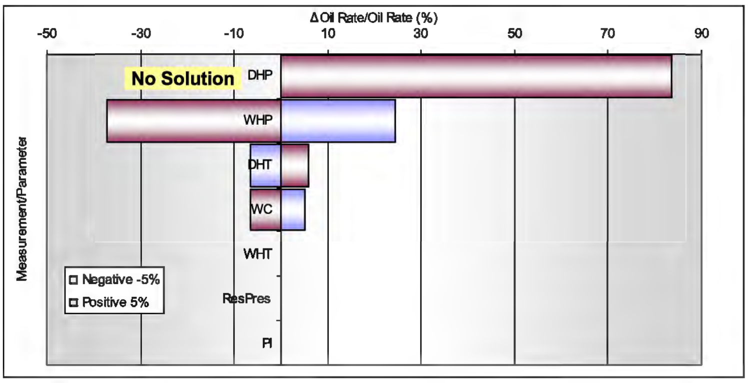

Fig. 17 - System A, Method 5, ±5% sensitivities for Case 2 (Year 4.48)

The sensitivities for system B at ±5% perturbation error for the case 2 production scenario is shown in Figure 18. Note that at the lower liquid rate, the bottomhole pressure asymmetry occurs at the lower perturbation.

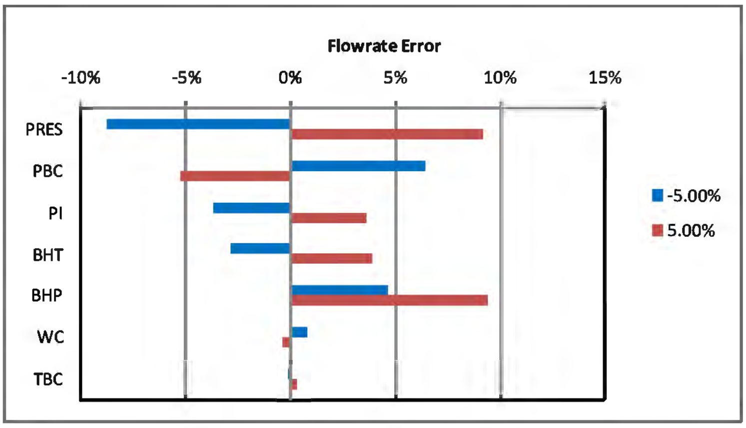

Fig. 18 - System B, ±5% sensitivities for Case 2 (Year 4.48)

Note also that the rate response to bottomhole temperature uncertainty is now asymmetrically pronounced. Increasing the inlet fluid temperature makes the fluid lighter resulting in a lower static head in the well. Hence method 6 in system predicts a higher flow rate needed to match a larger inferred frictional pressure drop. Similarly, lowering the inlet fluid temperature causes the predicted flow rate to decrease. However, the physics of the problem causes the effect to be asymmetric.

5.1.2.2 Sensitivities to ±10% measurement and parameter uncertainty

The sensitivities for system A using Methods 1, 2, and 5 at ±10% error are shown in Figures 19-21.

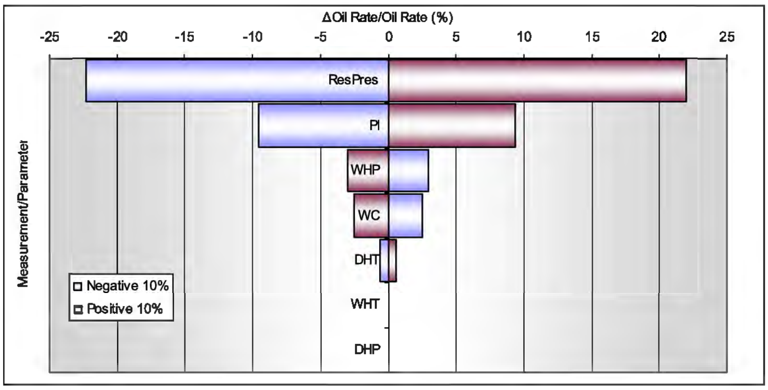

Fig. 19 - System A, Method 1, ±10% sensitivities for Case 2 (Year 4.48)

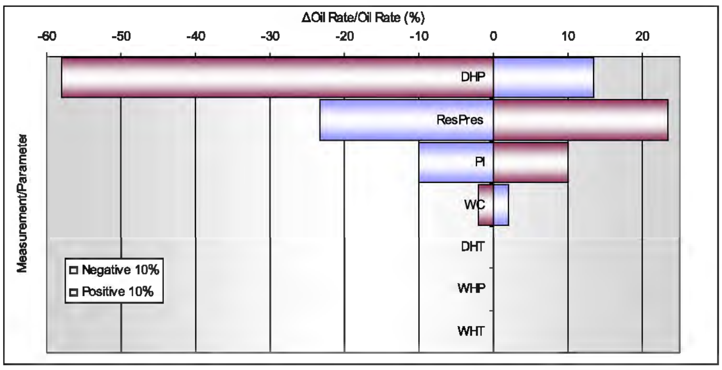

Fig. 20 - System A, Method 2, ±10% sensitivities for Case 2 (Year 4.48)

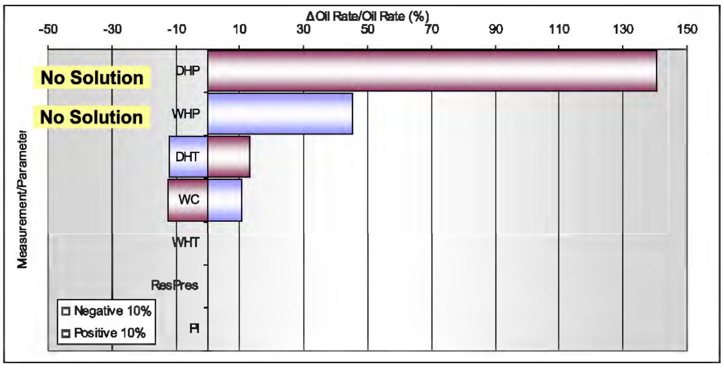

Fig. 21 - System A, Method 5, ±10% sensitivities for Case 2 (Year 4.48)

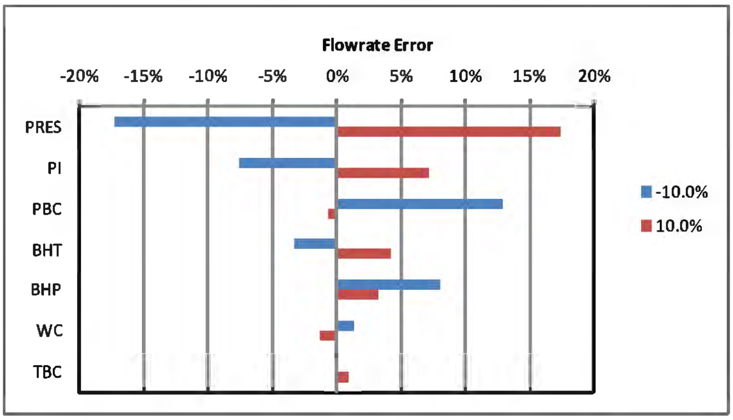

Fig. 22 - System B, ±10% sensitivities for Case 2 (Year 4.48)

Figure 22 shows the effect of the pressure before the choke (PBC - wellhead pressure) is highly asymmetric. At +10% PBC value from base case, the system finds that the frictional dP in the well is very small and the resulting low flow rate leads to a arrival temperature error that is unacceptable. Hence the system switches to a temperature solver for method 6 which yields a high flow rate estimate. As discussed previously, the effect of invoking a temperature solver approach is to produce an asymmetric rate response in the same direction of change for a given parameter perturbation.

5.2 Instrument Uncertainty Sensitivity Results

A virtual metering system, once properly described by the boundary conditions, needs to be calibrated against a reference well rate for which the corresponding measurement responses are known. In this part of the study, the sensitivity of the estimated rate uncertainty, post initial calibration, to the various instrument uncertainties is investigated. Another way to view the inquiry is how does the input measurement uncertainties propagate through the virtual metering system, measured by the resulting estimated rate uncertainty.

For example, if all the input pressure and temperature sensors have a base uncertainty of ±0.1%, then the estimated rate will have an overall uncertainty. This uncertainty will depend on the virtual metering system. The procedure used in this part of the study is to keep all measurements and user-input parameters fixed. Then, uncertainty of the instruments is increased one at a time, by an increment of 1% and 10%. The sensitivity of the predicted rate uncertainty to the perturbations of measurement input uncertainty is then ascertained. The results for System B are shown below.

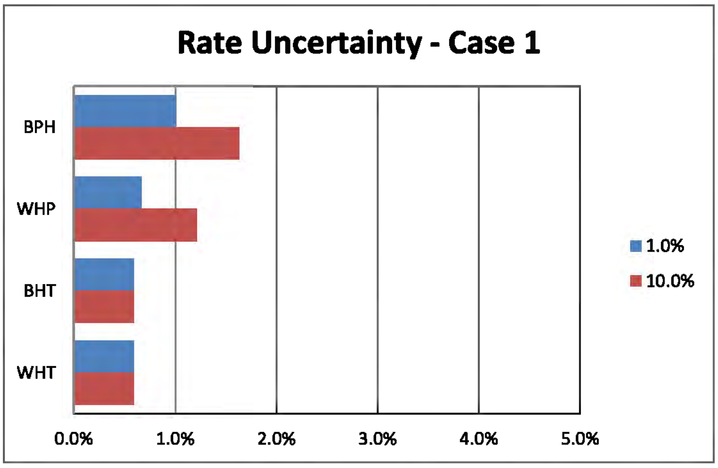

Fig. 23 - Impact of Instrument Uncertainty for Case 1 (Year 0)

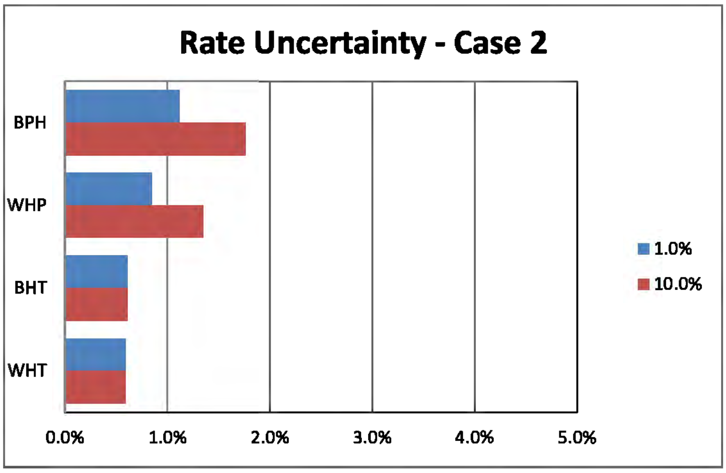

Fig. 24 - Impact of Instrument Uncertainty for Case 2 (Year 4.48)

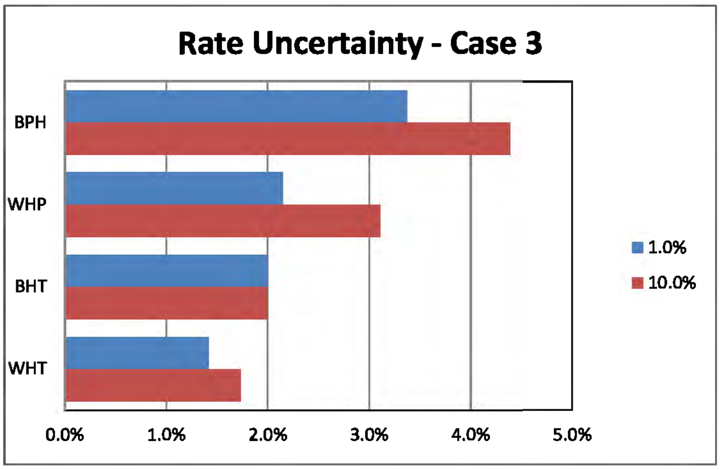

Fig. 25 - Impact of Instrument Uncertainty for Case 3 (Year 20)

Figures 23 to 25 show the impact of the manufacturer supplied instrument uncertainty on System B flow rate prediction uncertainty.

As the supplied uncertainty of a particular instrument is increased, the system is "smart" enough to start discounting the predictions of the methods that are affected by the instrument in question by increasing the uncertainty of those methods.

The results show that the predicted rate uncertainty for System B is most sensitive to the bottomhole pressure uncertainty for all the production cases in this study.

5.4 System C Sensitivity Study Results

5.4.1 Single Well Results

For this preliminary study, an offset of +2% for the transmitter readings in the plant model was introduced and analyzed how the error affects the parameters manipulated in the virtual metering model, and how it propagates topsides. Only the transmitters in well 1 were perturbed, and whenever redundant transmitters were available, all of them were given the same constant offset.

The sensitivities of the well rate, water cut, well PI , reservoir temperature and topside total rate to the input measurement perturbations, for the single well preliminary study, are shown in Figures 26-30.

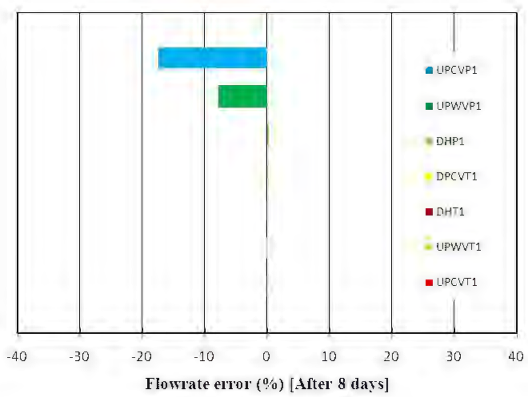

Fig. 26 - Well Rate Sensitivity

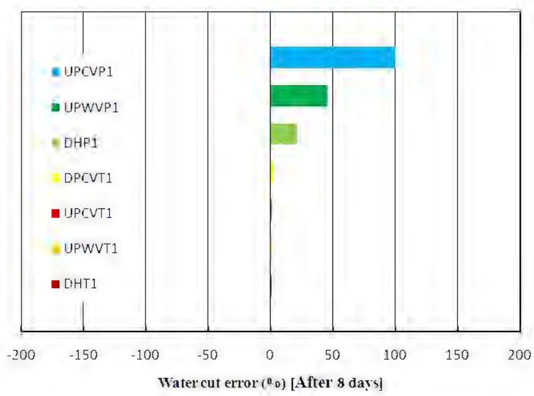

Fig. 27 - Water Cut Sensitivity

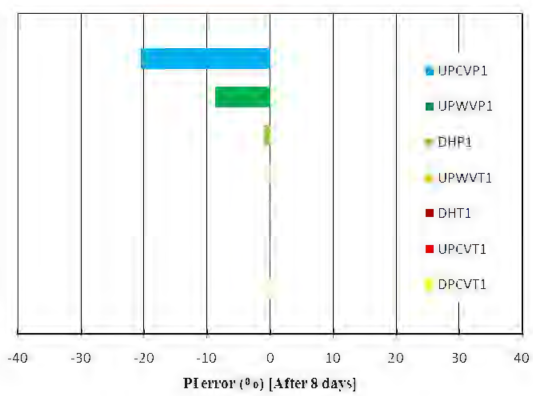

Fig. 28 - Well PI Sensitivity

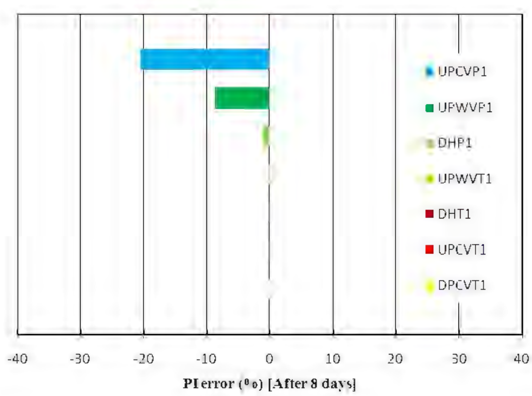

Fig. 29 - Reservoir Temperature Sensitivity

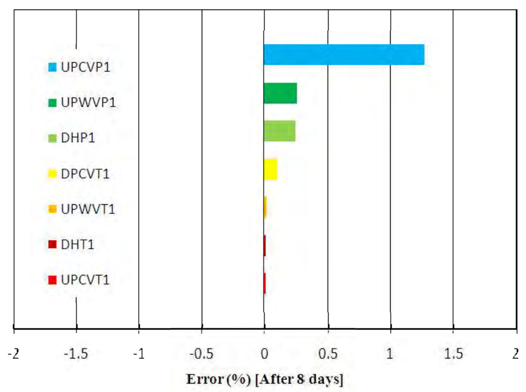

Fig. 30 - Total Topsides Flow Rate Sensitivity

As expected from the calibration scheme, the wellhead pressure measurements have the most influence in the prediction of the estimated outputs. This is because they are directly used to calibrate the choke opening, as well as the PI. In this case, the offset of temperature measurements do not have a significant effect. The pressure offsets have greater effect on the reservoir temperature than the temperature measurements themselves.

5.4.2 Instruments sensitivity analysis (Smart agents turned off)

The term "Smart agents" refers to the ability of the virtual metering model to detect possible faulty instruments and drop them from the calculation schemes. If the smart agent is active, the transmitters with the highest differences between measured and calculated values (of all the transmitters participating in the same tuning loop) are disabled if the differences are greater than a specified threshold. In this study, only one transmitter with the highest difference is disabled if the difference is greater than 1% after statistical analysis.

The nomenclature used in the tornado plots is as follows, XX_YY_ZZ, where XX represents the well where the transmitter is located, YY is the transmitter's name, and ZZ is the transmitter offset (given as percent of the current value). The sensitivity results for the Peak High case, for each well are presented below.

Figures 31-35 depicts the sensitivity of the rate response for each of the 5 wells in the network, to the input measurement perturbations. There were 10 cases run in the Peak High production scenario, as defined in Table 13. The topsides total rate sensitivity is shown in Figure 36.

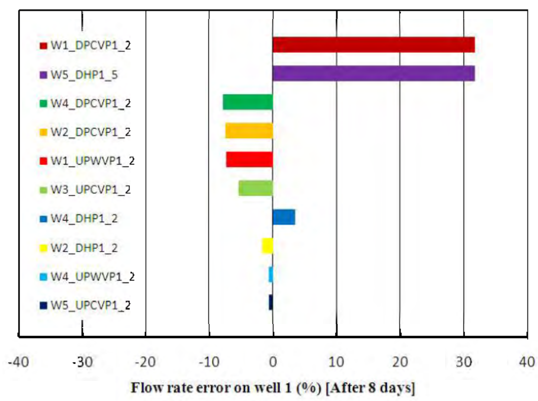

Fig. 31 - Well 1 Flow Rate Error

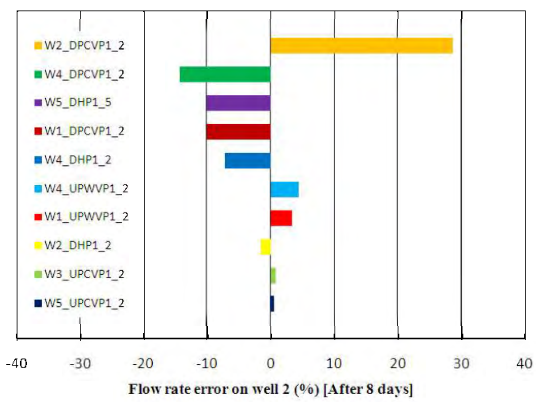

Fig. 32 - Well 2 Flow Rate Error

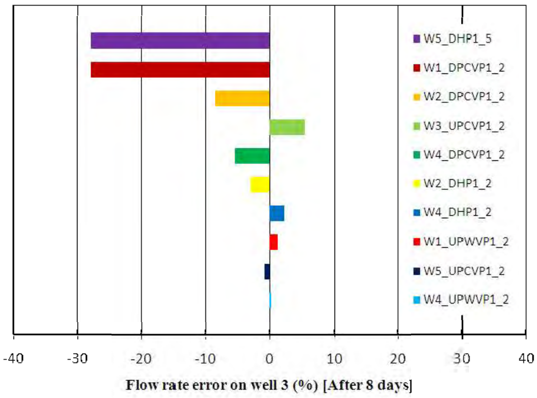

Fig. 33 - Well 3 Flow Rate Error

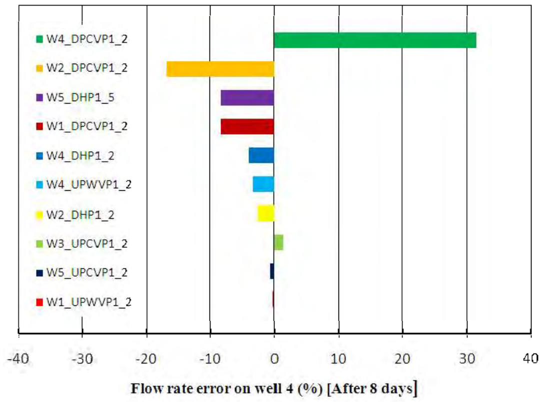

Fig. 34 - Well 4 Flow Rate Error

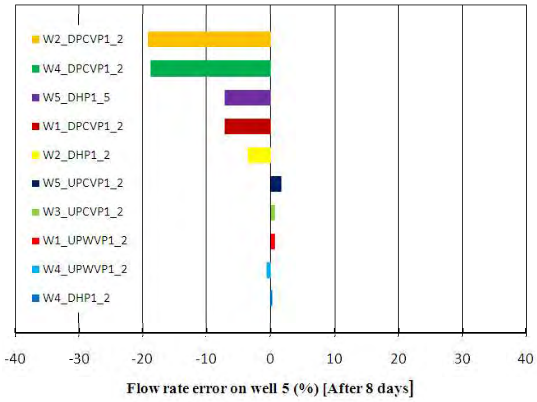

Fig. 35 - Well 5 Flow Rate Error

Note that for wells 1, 2 and 4, the rate responses were most sensitive to pressure gauge located downstream of the choke within the well itself. For wells 3 and 5, the sensitivities are on pressure gauges located on different wells. For well 3, the rate was most sensitive to downhole pressure gauge located on well 5. For well 5, the pressure input downstream of the choke on well 2 yielded the highest change in rate for that well.

The above well level measurement input sensitivities have to be viewed from a hydraulic network perspective. Note from Table 11 the relative rates of each well at the peak high scenario. Wells 3 and 5 are the lowest producers during this stage. Second, the same wells are located farthest from the floating facility. These two factors offer insights into the why wells 3 and 5 were most sensitive to external stimuli.

5.4.2 Instrument sensitivity analysis (Smart agents turned on)

The worst five cases from the previous section were selected to be used here. In this part of the study, the smart agents are active in the virtual flow metering system in order to identify and drop faulty measurements.

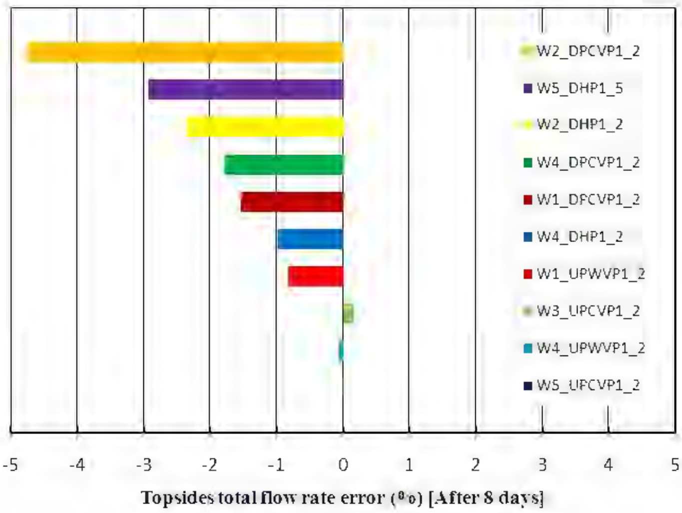

Fig. 36 - Total Topsides Flow Rate Error

1. Peak High: A 2% offset in the UPWVP1 transmitter located on well 1
2. Peak High: A 2% offset in the UPCVP1 transmitter located on well 3
3. Peak High: A 5% offset in the DHP1 transmitter located on well 5
4. Late Life High: A 5% offset in the DHP1 transmitter located on well 3
5. Late Life High: A 2% offset in the UPWVP1 transmitter located on well 5

In all the cases, the smart agents drop the faulty measurements after 20 minutes of being detected. After 4 days, the total flow rate, PI and water cut errors with respect to the plant model values are presented in the table below. The results when the smart agents are active give very low errors compared to the cases where the smart agents were off.

Table 14 - Impact of Smart Agents on Estimated Rate Error (after 4 days)

	Total Flow rate		PI		Water cut	
Smart agents	OFF (%)	ON (%)	OFF (%)	ON (%)	OFF (%)	ON (%)
Case 1	5.624	-0.042	5.894	-0.045	0.779	0.125
Case 2	-6.841	0.156	-6.960	-0.002	9.435	0.027
Case 3	-6.224	0.05	-6.117	0.042	-100.000	-0.186
Case 4	-92.652	2.222	-92.615	2.215	-95.201	-0.191
Case 5	-58.112	0.892	-58.185	0.908	7.287	-0.122

6 CONCLUSIONS AND RECOMMENDATIONS

A sensitivity study was conducted in order to gain insight and understanding on how virtual metering systems respond to measurement and parameter input uncertainty, measurement degradation and instrument availability. Three different virtual metering systems were used in the study. The first two, labelled A and B, are based in steady-state, hydraulic-thermal models. Both systems also included choke flow models. The third system, labelled C, is a full field virtual metering model based on a dynamic process simulator and linked to a transient multiphase flow simulation model.

The study was conducted as part of a major project work scope. The design premise for the study was based on the project parameters and was used as a common basis for all the three virtual meters. The succeeding comments, conclusions and recommendations are intended to raise the awareness of potential and current users of virtual metering systems, and to take into consideration the analytical process used when developing a holistic life cycle approach from selection to operation. At the risk of being repetitive, it is not the intent to differentiate amongst the systems used in this study.

In the course of the study, the following observations on the features of each virtual metering system, whilst secondary to the main objective, is worth outlining. Each system had a different approach or impact to the following:

- Methodology and modes of calculation for the same type of a well model
- Detection and treatment of anomalous measurement input
- Recovery from faulty or unavailable measurement input
- Calculation of and reporting the best estimated rate
- Use of automation versus operator judgement
- Organizational capability requirement for sustainability

In terms of sensitivities to the various measurement and parameter inputs, the study has shown that general conclusions can be made. While these conclusions are specific to the scope of the study, they are most likely applicable to other virtual metering systems in various field development scenarios.

- For virtual metering systems that utilize well inflow relationship (PI model) and hydraulic-thermal model, inaccuracies in the estimation of the reservoir pressure and the well PI have the greatest impact on flow rate prediction error.
- For the systems used in this study, errors in the wellhead and bottomhole pressures measurements have a large impact on flow rate prediction. The errors can be caused by instrument degradation or in some instances, due to issues in communication and transmission of information
- The temperature input, regardless of location has the least impact on flow rate estimation
- The rate estimation sensitivities for all input parameters increase as the production rate decreases. This effect, along with the instrument degradation over time could pose severe challenges to virtual metering in low production fields or late in field life.

In terms of input measurement uncertainty, the bottomhole pressure uncertainty gave the highest sensitivity to the predicted rate uncertainty, at least for System B.

In terms of availability,

- The wellhead pressure gauges are the most important for the virtual metering systems. There may be some distinction between the relative sensitivity to the pressure upstream or downstream of the production choke valve but it is methodology and rate dependent.

- The bottomhole pressure and temperature gauges are also important

Care must be taken to understand the impact of fluid properties and phase behaviour data uncertainty to the virtual metering system during calibration. The residual uncertainty in the estimated rates due to uncertainties in thermodynamic (PVT) and fluid properties, apart from the measurement and parameter input uncertainty may be difficult, if not impossible to quantify separately. Slow changes in fluid and PVT properties over time could still yield reasonable rate estimates but where the adjusted parameters now take on larger uncertainties compared to equivalent measured values.

Fluid samples may need to be obtained post first oil in order to update the fluid and PVT properties in the virtual metering systems to minimize their impact on estimated rates uncertainties.

Finally, certain smart features including fault detection, error recovery using alternative solutions and statistical based model discrimination are just a few examples of capabilities available in virtual metering systems. These features could bound the resulting uncertainty in the event of input device fault or failure and automate the model selection hierarchy to arrive at an estimated rate.

The following recommendations are made based on the findings in this study:

- Consider installing redundant pressure transmitters upstream of the subsea production choke. These redundant pressure transmitters should be completely independent, each with a separate connection to the well head.

- The downhole pressure and temperature gauges are also central to the various systems and so redundancy in these sensors should also be considered.

- Test the virtual metering system and the methods or modes hierarchy, particularly during the first year for production allocation and reconciliation and make any adjustments if required and continually calibrate this with production data.

- Determine a schedule for pressure transient analysis in order to ensure that the reservoir pressure value is updated. Consider a provision to automatically harvest downhole pressure data during unscheduled shut-downs as potential input data to routine pressure build-up analysis.

References

[1] Paper presented at the North Sea Flow Measurement Workshop, a workshop arranged by NFOGM & TUV-NEL