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Monitoring Reservoir Pressure in the Groningen gasfield

Leendert Geurtsen and Quint de Zeeuw

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General Introduction

The production of gas from the reservoir causes a decline in the reservoir pressure. Prediction of the reservoir pressure decline in response to gas production and monitoring of the reservoir pressure is also of importance for the prediction and surveillance of compaction, subsidence and seismicity.

Reservoir pressure data is used to calibrate the reservoir model of the Groningen field (Ref. 1 to 4). The large dataset of Static Pressure Gradients (SPG) is primarily used for this. As these pressures are measured deep in the monitoring wells, at reservoir level, this data set is very accurate. The full data set covers the full history of the field.

However, for direct monitoring this data set is less appropriate as the data is obtained at for monitoring purposes considerable time intervals. In contrast, the pressures at the tubinghead of the well (the surface side of the well) are since 2011 continuously monitored and recorded. In this report it is investigated whether pressure data measured in the tubinghead of the well can be used to obtain an indication of reservoir pressure.

This document contains reports:

1. An overview paper on the better use of the available pressure data to history match the reservoir model and monitor the field pressure behavior.
2. Detailed report on the use of tubinghead pressures to estimate and monitor the reservoir pressure.

References

1. Technical Addendum to the Winningsplan Groningen 2013; Subsidence, Induced Earthquakes and Seismic Hazard Analysis in the Groningen Field, Nederlandse Aardolie Maatschappij BV (Jan van Elk and Dirk Doornhof, eds), November 2013.
2. Supplementary Information to the Technical Addendum of the Winningsplan 2013, Nederlandse Aardolie Maatschappij BV (Jan van Elk and Dirk Doornhof, eds), December 2013.
3. Groningen Field Review 2015 Subsurface Dynamic Modelling Report, Burkitov, Ulan, Van Oeveren, Henk, Valvatne, Per, May 2016.
4. Technical Addendum to the Winningsplan Groningen 2016 - Production, Subsidence, Induced Earthquakes and Seismic Hazard and Risk Assessment in the Groningen Field, PART I – Summary and Production,

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Improved Data Utilisation for history-matching and Monitoring Groningen

Improved Reservoir Management through increased data utilization.

Leendert Geurtsen and Quint de Zeeuw

Reservoir Engineering, Groningen asset, NAM

Introduction

The Groningen gas field in the northeast Netherlands is one of the biggest gas fields in the world with a GIIP just shy of 3,000 Bcm. Over the past 50 years some 75% has been produced by 256 wells in 29 clusters.

History matching of the Groningen dynamic reservoir model is primarily constrained by a set of roughly 1800 Static Pressure Gradient measurements of reservoir pressure. Until 2014, the offtake from the production clusters was managed such as to keep the reservoir pressure balanced across the field, resulting in a stable pressure decline across the field. In that light, the SPG surveillance frequency has been reduced over the last 20 years to about 1 survey per 5 years for each production cluster. The reservoir contains a dry gas (CGR around 1 Sm^3/mln $N.m^3$), and there is no free water production to date (condensed water only, currently WGR around 12 Sm^3/mln $N.m^3$). Consequently there is a dry gas column from tubinghead down to reservoir, and there has been a continuous challenge in the WRFM domain to stop taking SPG measurements and use THP data instead.

Due to production induced seismicity, since 2014 the Ministry of Economic Affairs has imposed a series of production caps, both for the total field as well as regionally for subsets of production clusters. Especially the most earthquake prone north-western region of the field was virtually shut-in completely, and a pressure gradient of some 25 bars has since established across the field. Consequently, the offtake distribution and regional flow patterns have changed drastically (Figure 1).

It is already firmly established in the Groningen earthquake research that reservoir pressure is an important parameter relating to seismicity. The field's dynamic response to the post-2014 changes in reservoir management offers a wealth of information about the reservoir connectivity and sealing capacity of these (intra-reservoir) faults. To maximize the learnings and to further calibrate the reservoir model, the reservoir pressure dataset has now been expanded with the Closed In Tubing Head Pressure data (CITHP), converted to bottom-hole pressures.

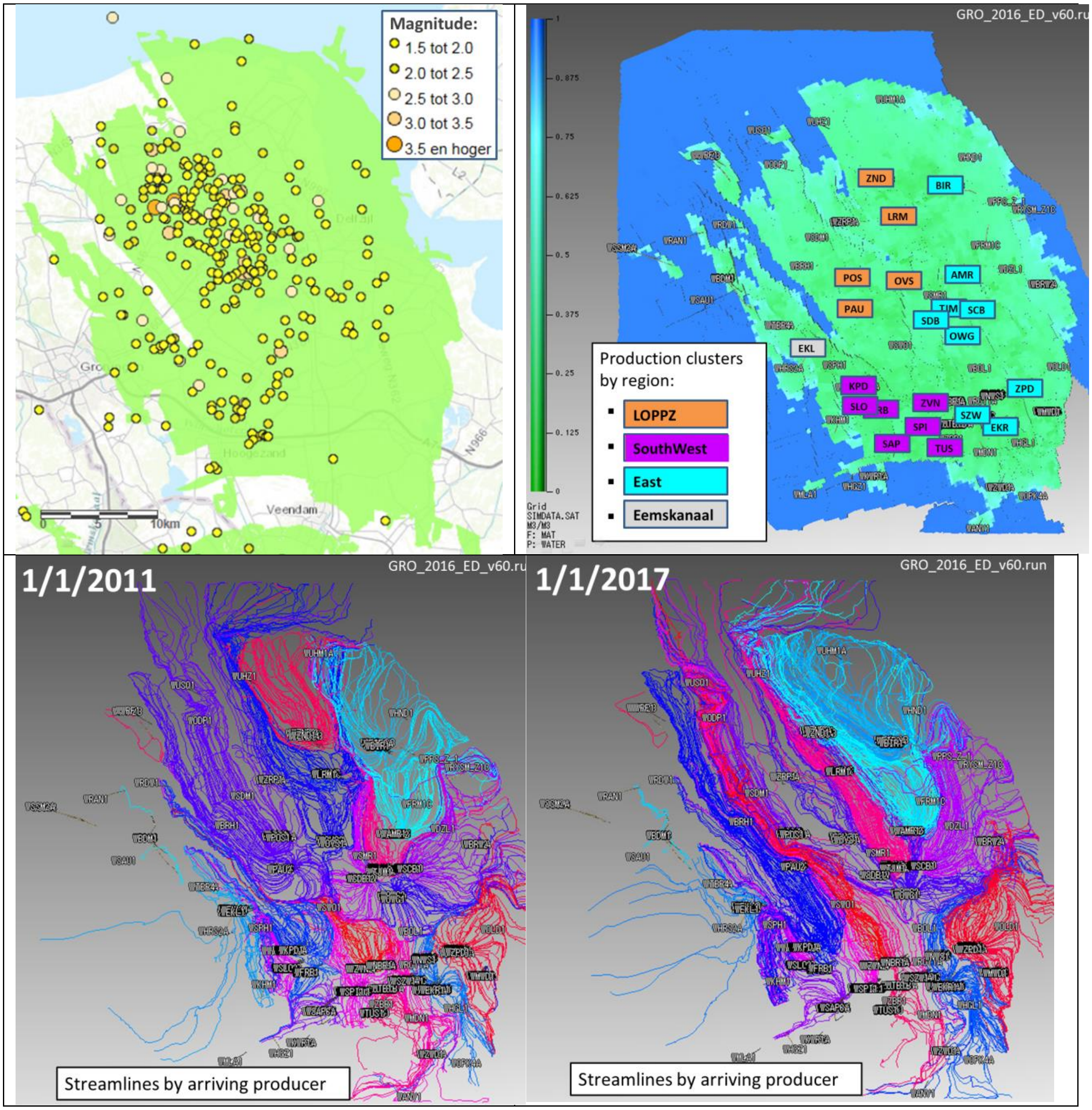

Figure 1: Impact of production induced seismicity on drainage of the Groningen field: historic earthquakes (M>1.5), the (current) production clusters grouped by their regional caps, and the change in drainage patterns due to the production caps.

Data availability and filtering

Since 2011, all production wells in Groningen are equipped with tubinghead pressure- and flow sensors that are continuously recording data which are stored in the PI[1] system. Although it is easy to filter the data for zero rate to obtain a CITHP dataset, there are a number of pitfalls that make this process non-trivial.

The Groningen field has the privilege of a dedicated Groningen Support Centre, which helps to facilitate unmanned production operations by providing an "advanced Process Control System". The SGC utilizes SAS software to analyse the Gigabytes of data coming in from the Distributed Control System (DCS). Big data models are run on the Groningen asset "SAS Wikker" platform to do condition monitoring and exception based surveillance of the installations, maintenance and operational activities, in order to prevent performance decline and unplanned shutdowns.

The SGC has setup a project on the SAS Wikker platform that does a fully automated retrieval of (daily) CITHP data points. The project processes the full PI THP dataset from all Groningen production wells since 2011, and applies a series of filtering steps including QC to avoid erroneous data:

- The well flowmeter (dedicated PI tag) should read zero (within meter calibration error) and the valves in the flowline should be open (dedicated PI tags for valve positions)
- Each well has two dedicated THP pressure gauges. Both have dedicated PI tags, which readings are compared to filter out periods of malfunctioning gauge readings or gauge drift
- It is checked whether the THP gauges are actually connected to the reservoir by evaluating the valve position settings on the Christmas tree (dedicated PI tags).

Note that these applied filters were largely developed as part of a more extensive SAS Wikker "big data" project, whereby stable PQ points are extracted from the DCS system for automated well deliverability calibration.

CITHP-CIBHP conversion method

Because there is a dry gas column from tubing head to reservoir, theoretically the conversion from CITHP to CIBHP should follow from

$$\frac{dp}{p} = \frac{M_{air}\,\gamma_g\,g}{Z\,R\,T}\,dh$$

Or, when assuming constant properties for the entire gas column:

$$CIBHP = CITHP\,\exp\left(\frac{M_{air}\,\gamma_g\,g\,h}{Z\,R\,T}\right)$$

Previous analysis work proved it only possible to calculate the CIBHP within an acceptable (1 bar) uncertainty after at least 10 days of shut-in, suggesting the conversion should account for time dependent errors.

[1] Actually, for Groningen the Exaquantum system is used, which is Yokogawa's equivalent of the PI system by OSISoft which is commonly used in Shell.

With over 50 years of production life the Groningen field offers a wealth of surveillance data. Out of the rich dataset of 1800 historic SPG's, a subset of 540 SPG's was found to include a full record of CIBHP, as well as CITHP and shut-in time. Plotting this dataset (colored by well shut-in time prior to measurement) clearly brings out the time dependent effect for the conversion. Acknowledging the fact that Groningen wells typically operate roughly between 7°C (shut-in) and 65°C (flowing), one can draw the associated operating envelope using the above equation. It can be observed from Figure 2 that the dataset nicely falls within the theoretical envelope, demonstrating the impact of wellbore cooling upon shut-in on the density of the gas column (and how much condensed water can be evaporated). Furthermore Figure 2 shows that the pressure dependency of the conversion factor is relatively limited (for Groningen).

Although there are analytical models for wellbore cooling, these models include parameters that still need to be calibrated with field data. Instead, it was decided to directly fit an empiric, time-dependent conversion factor for each Groningen cluster. Figure 3 shows as an example the function fitted on one of the Groningen clusters.

The accuracy of the new conversion is typically very good: within 1 bar of actual downhole SPG measurements, see Figure 4. Since most clusters are typically closed in at least a few times every year (for more than 1 day), this has created an abundant source of additional reservoir pressure data.

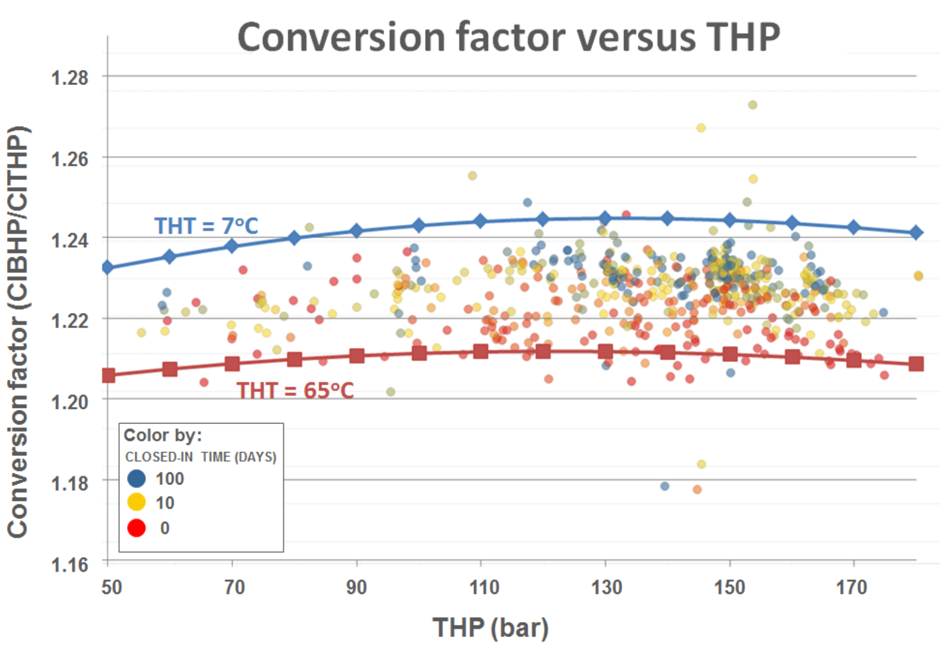

Figure 2: Conversion factor (CITHP/CIBHP) as a function of pressure, color-coded by shut-in time, including the theoretical operating envelope

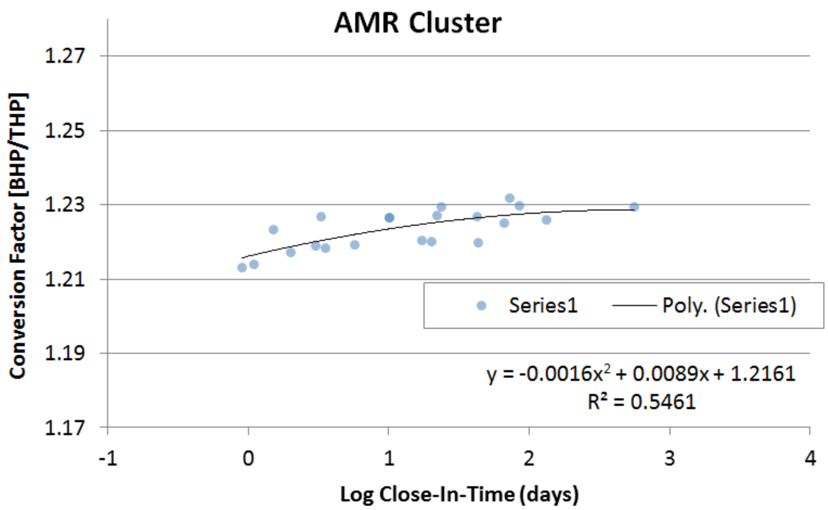

Figure 3: Function fitted on historic SPG data for the Amsweer cluster.

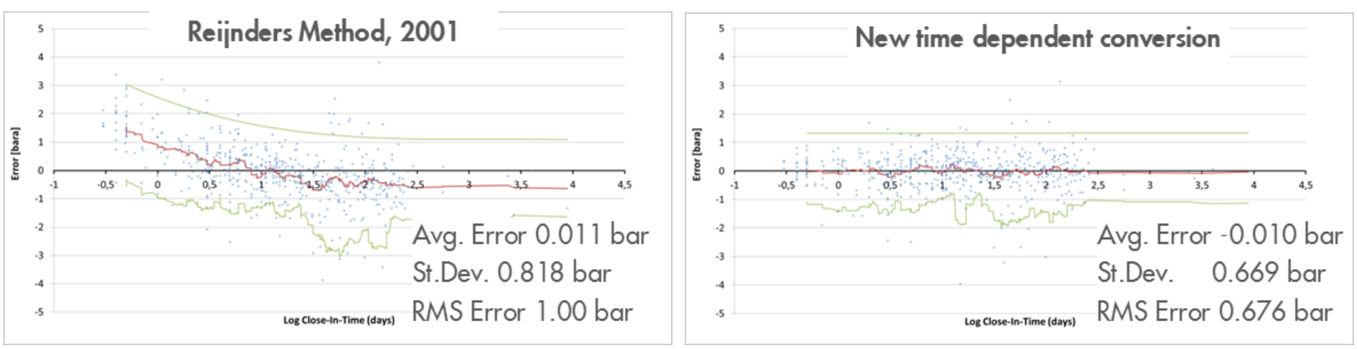

Figure 4: Error versus logarithm of shut-in time for Reijnders method (left) and the new time dependent conversion (right). The error is measured by converting known CITHPs from SPGs to CIBHP and comparing these against measured CIBHPs.

Impact

By combining the automated retrieval of CITHP data in SAS Wikker with the time dependent CITHP-to-CIBHP conversion method, the available dataset of reservoir pressure to constrain the reservoir model was dramatically increased. The decreasing trend in surveillance data (down to 6 BHP's in 2010) was turned upside down by adding some 16,000 datapoints per year from 2011 onwards (Figure 5). This workflow improves the Groningen reservoir management performance by a more effective utilization of data (for history matching), as well as a reduction in costs by decreasing the direct need for SPG data[2].

To accommodate for the CITHP to CIBHP dataset, the reservoir model was refined from monthly to daily history matching timesteps, and local gridblock refinement was applied around production clusters to ensure sufficient gridblock resolution between individual production wells.

[2] Some SPG's are still needed for calibration of the CITHP-CIBHP conversion, and to cover the observation wells in the periphery of the field which are not hooked up to the PI System.

Figure 6 gives a nice example of the impact of this additional data for well PAU-6. Instead of history matching the reservoir model to a single datapoint (SPG) over a 6 year time window, there are now dozens of reservoir pressure points to match to, capturing valuable transient effects (build-up upon 2014 shut-in eventually caught up by the total reservoir pressure decline. Hence the increase in data granularity truly switches on the lights while history matching Groningen!

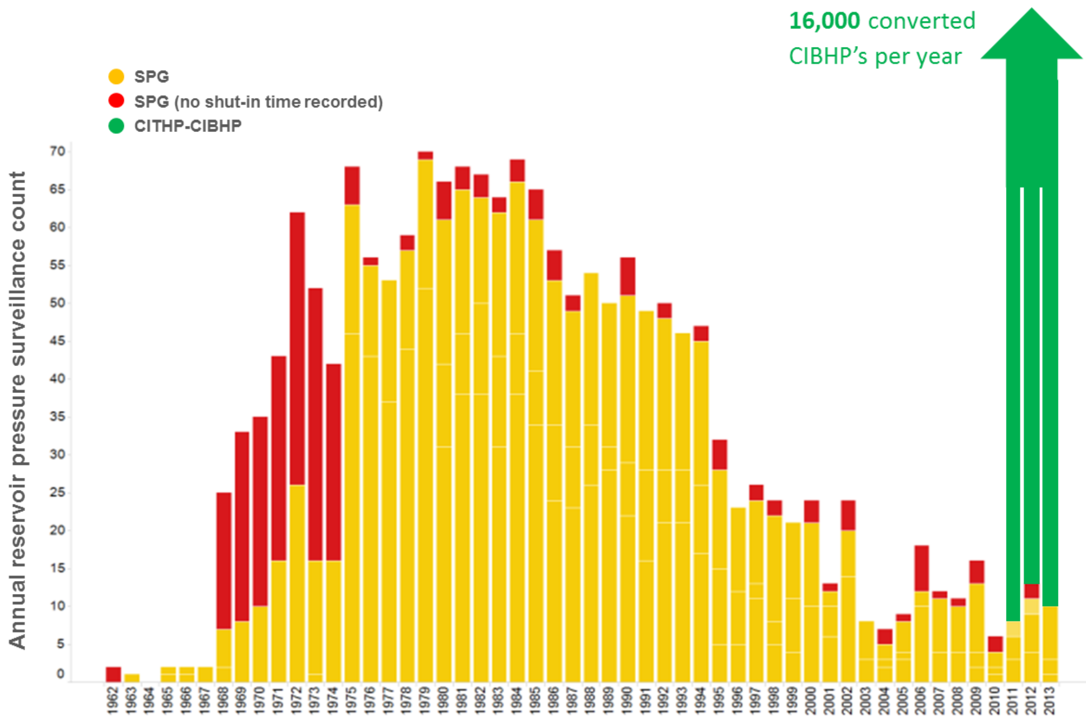

Figure 5: Annual count of reservoir pressures surveillance for the Groningen field.

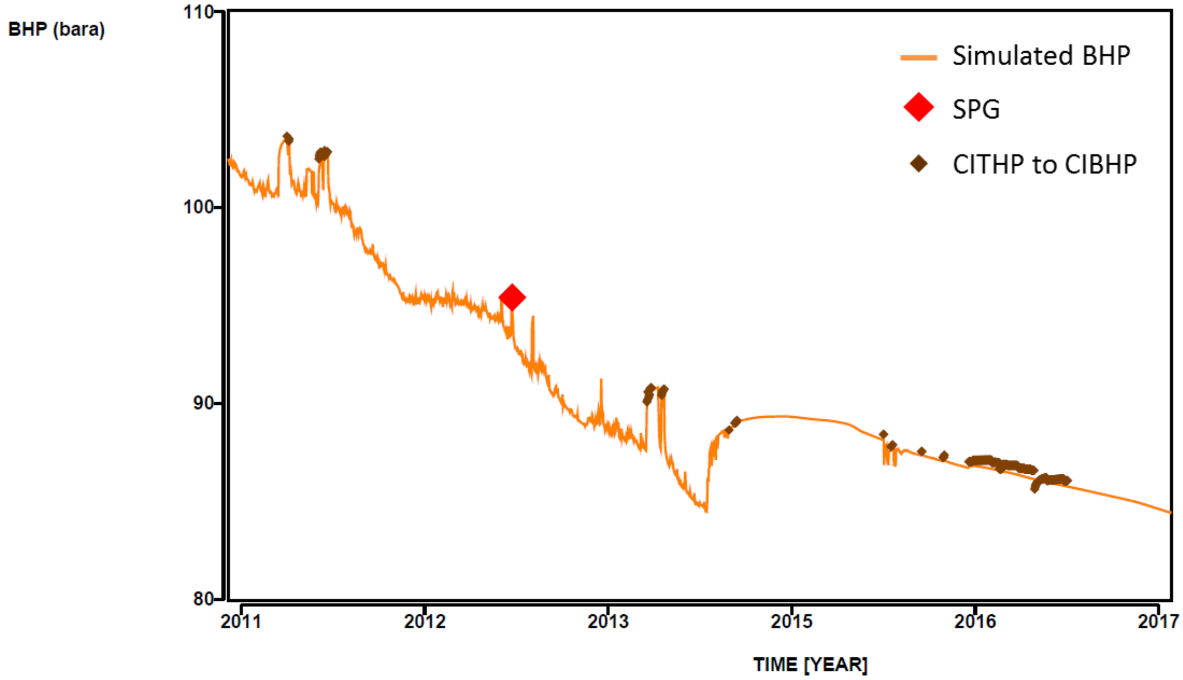

Figure 6: History match of reservoir pressure for well PAU-6: model outcome (orange) versus SPG (red) and CITHP-to-CIBHP (brown).

Nederlandse Aardolie Maatschappij B.V.

Shell UPO

CITHP to CIBHP conversion for the Groningen wells

Prepared by: Quint de Zeeuw

Contents

1. Context

Tubing Head Pressure (THP) data offers a wealth of information for reservoir surveillance. Full coverage of THP data is available for all producers on the Groningen field from Exaquantum/PI. Because the Groningen gas is a dry gas and the wells only produce condensed water (Figure 7), it is possible to obtain a pretty accurate estimate of Closed-In Bottom Hole Pressures (CIBHP) by converting Closed-In Tubing Head Pressure data (CITHP).

In the surveillance plan, CIBHP is measured by SPG once every 5 years for each production cluster. By building a filter in SAS Wikker to retrieve CITHP data of a minimum shut-in duration from PI, the data resolution of the CIBHP measurements can be greatly enhanced as depicted in Figure 8.

This note summarizes the various methodologies available to convert the CITHPs to CIBHPs, and establishes their respective accuracies as a function of shut-in-time. For quick use a field wide constant conversion factor of CIBHP = 1.2316 *CITHP can be used, yielding an RMS error of 1.39 bar (but increasing up to 3 or 4 bar for shut-in times < 10 days). A recommended best use is the newly proposed time dependent conversion factor per cluster yielding an RMS error of 0.73 bar which is constant over time (cluster specific functions to be found in chapter 7.2.1 on page 35).

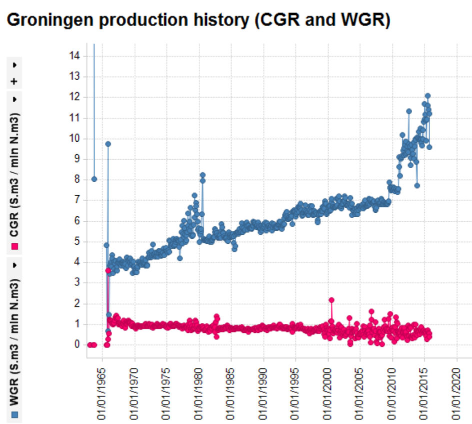

Figure 7: Groningen field historic Condensate Gas Ratio (CGR) and Water Gas Ratio (WGR) , source: R2D2 (Energy Components)

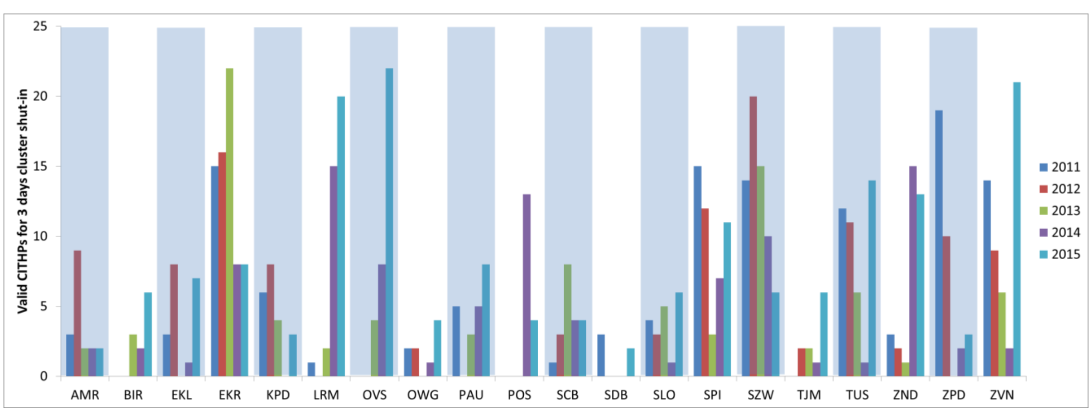

Figure 8: Valid CITHPs for clusters shut in longer than 3 days between May 2011 and December 2015 as obtained from PI.

2. THP to BHP conversion methods

Various methods have been established to convert THP to BHP for the Groningen field and can divided in 2 different categories; Conversion Factors and Integration Methods.

2.1. Conversion Factors

The conversion methods multiply the THP with a single factor, called M:

$$CIBHP = CITHP \times M$$

Where

$CIBHP$	Closed-In Bottom Hole Pressure at datum level [bara]
$CITHP$	Closed-In Tubing Head Pressure [bara]

2.1.1. Constant conversion factor

The simplest conversion is being used by production technologists:

$$M = \sqrt{1.44},$$

This is an empirical conversion used by most PTs and originates from the B factor as per the Modified Cullender Smith wellbore performance equation (Appendix 6). It is loosely in line with observations from the SPG dataset.

2.1.2. Averaged conversion factor

Alternatively, the CIBHP can be obtained from using a direct conversion factor between actual observed CITHP and CIBHP values from historic data:

$$M = \frac{1}{n}\sum_{i=1}^{n}\frac{CIBHP_i}{CITHP_i},$$

Where

$CIBHP_i$	CIBHP at datum level[3], as obtained from an actual SPG measurement i, [bara]
$CITHP_i$	CITHP associated with SPG measurement i, [bara][4]
n	number of wells.

This factor can be calculated for the full field, but also on a per cluster basis.

[3] Datum level for the Groningen field is 2875mTVDSS

[4] Note that PI stores THP data in [barg], whereas SPG and FBU data are stored in Siesta in [bara], and also the MoReS model was set up in [bara]. Consequently, the THP from PI are converted from [barg] to [bara], prior to usage in the conversions.

2.2. Integration Methods

2.2.1. Single-step integral

A more sophisticated method is proposed by Reijnders and modelled in MoReS*:*

$$CIBHP = C \times CITHP \times \exp\left(\frac{M_{air} \times SG_{gas} \times g \times h}{Z \times R \times T}\right)$$

Where:

C	correction factor
M_{air}	molecular mass of air (0.028966 kg/mol)
SG_{gas}	specific gas gravity (0.644 for Groningen Gas)
g	gravity constant (9.81 m/s^2)
h	depth to datum (2875 mTVDSS)
Z	gas deviation factor (compressibility factor)
R	Gas constant (8.3144621 J/mol·K)
T	Temperature (K)

The physical background of this equation can be found in Appendix 1. In this method one guesstimates an initial CIBHP, assumes a constant Z-factor (at p=($CITHP$+$CIBHP$)/2) and constant temperature T (at h/2) over the well and calculates a new CIBHP. The CIBHP converges within 3 iterations.

The additional correction factor C was introduced to improve the calculated CIBHP against the measured SPG data:

$$C = \frac{1}{n}\sum_{i=1}^{n}\frac{CIBHP_{SPG,i}}{CIBHP_{calc,i}}$$

This factor can be calculated for the full field, but also on a per cluster basis. In the GFR 2012 this factor C was set as 1, therefore this report investigates both the method from Reijnders with and without this correction factor.

2.2.2. Multiple-step integral

Further sophistication can be added by using Runga-Kuta numerical integration to solve the differential equation:

$$\frac{dp}{p} = \frac{M_{air} \times SG_{gas} \times g}{Z \times R \times T} \times dh$$

In this method the well is split in a number of intervals, pressures are calculated at the end of each interval to end up at datum depth and thus CIBHP.

3. THP data source

3.1. Location of measurement sensors

THP data is measured at each wellhead with digital gauges that are hooked up to the Distributed Control System, or DCS. The THP is monitored at the PIZA-002DC.PV and PI-007.PV gauges as depicted in Figure 9.

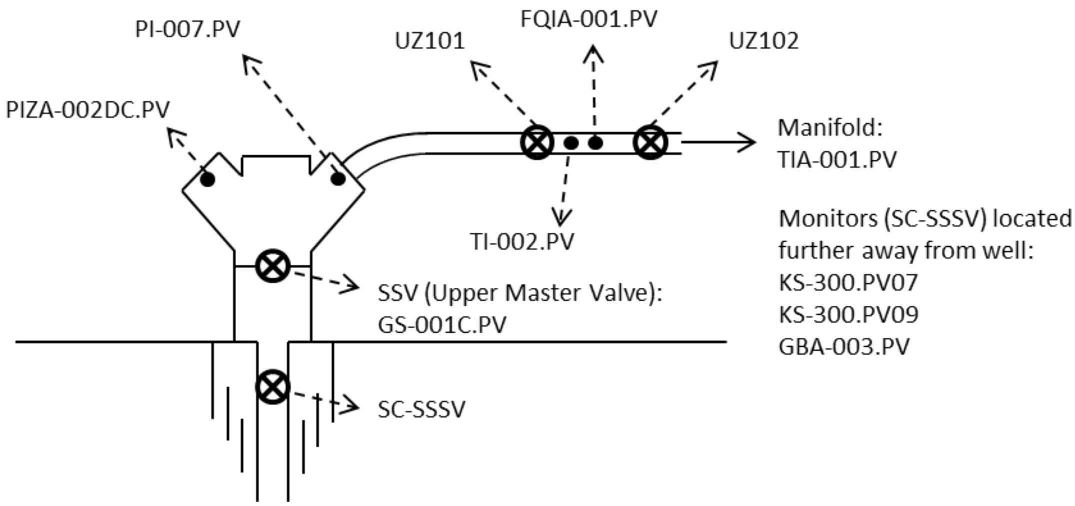

Figure 9: Schematic drawing of wellhead and relevant gauges and valves. Note that before each valve/gauge code the well name should be added to retrieve data from PI. (E.g. POS.09PI-007.PV). Also note that temperature sensor TI-002.PV is only available for a few wells.

3.2. Accuracy of sampled THP value

Pressures at the PIZA-002DC.PV and PI-007.PV gauges are recorded with transmitters which make use of a piezo element. This results in an accuracy of 0.25% of the transmitter range (in practice the accuracy is found at 0.1% of the transmitter range however).

Specifically for the Groningen field, there is a set-up with Exaquantum[5], which is a database that stores a filtered version of all data from the DCS. Subsequently, the data from Exaquantum is read-in by the PI System[6], which is NAM's standard.

As a result of the DCS- Exaquantum set-up, the THP's stored in PI are filtered in Exaquantum with a dead band as illustrated in Figure 10. In this current set-up, field values from both PI-007.PV and PIZA-002.PV are stored in Exaquantum after data compression. The data compression parameters are a dead band of ±0.2% of the transmitter range (both 0-140 barg) and dead band periodicity time of 5 s. So every 5 seconds the system evaluates if the field exceeds previous stored value plus or minus the dead band (0.2% of 140 barg = 0.28 bar). The principle is illustrated in Figure 11. The dead-band settings for DCS and Exaquantum can be changed on request. If data is stored directly into PI without the use of

[5] Exaquantum is a Plant Information Management System by Yokogawa
[6] Infrastructure for management of real-time data and events by OSIsoft

Exaquantum, a dead-band filter exists for data compression in PI as well. For the data used in this study, this is not the case such that Exaquantum and PI have the same compressed data.

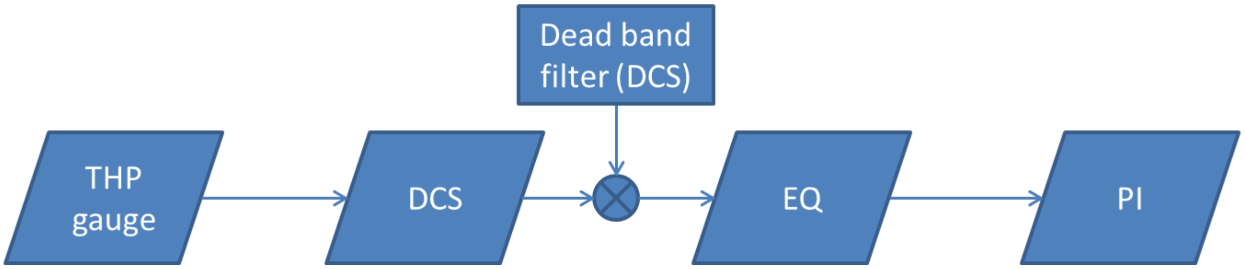

Figure 10: Schematic of moments filters are applied on measured THP before data is stored in PI.

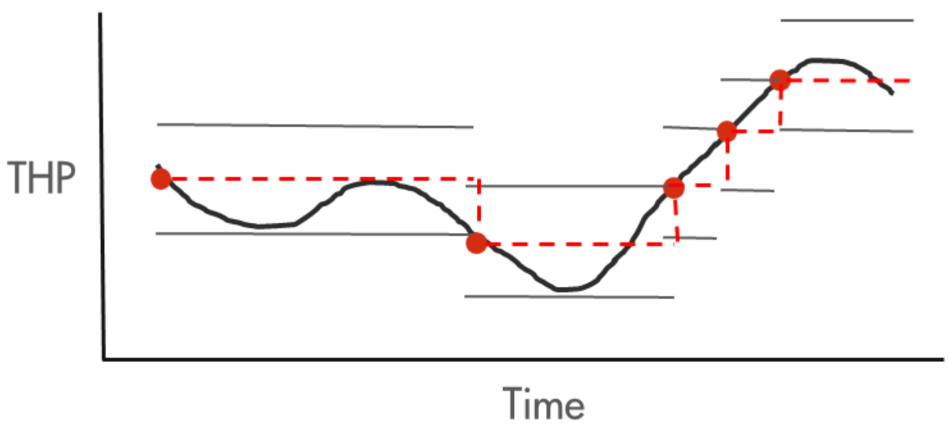

Figure 11: Dead-band principle. The black curve is real pressure, red dots are the stored pressure which are measured outside the dead-band. The dotted red line is the extrapolated pressure between stored values. The thin black lines are the dead-bands corresponding to stored pressure points. Note that a value is not stored if the dead-band is exceeded within the dead band periodicity of 5 s.

On average the difference between PIZA-002.PV and PI-007.PV is very small, in the range of 0.01 to 0.4 bar (partly caused by the dead banding). The table below shows an overview of the average absolute difference at different moments after shut-in for some wells:

Table 1: Mean absolute difference between PI-007.PV and PIZA-002.PV for LRM-7 and TUS-10

Well name	Shut-in Time										
	0 days [bar]	0,5 days [bar]	1 days [bar]	1,5 days [bar]	2 days [bar]	2,5 days [bar]	3 days [bar]	3,5 days [bar]	4 days [bar]	4,5 days [bar]	5 days [bar]
LRM-7	0.08	0.11	0.12	0.12	0.42	0.14	0.1	0.11	0.11	0.1	0.11
TUS-10	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.29	0.29	0.29	0.06

3.3. Measurement units

Note that PI stores THP data in [barg], whereas BHP data are stored in Siesta in [bara], and also the MoReS model was set up in [bara]. Consequently, the THP data from PI were converted from [barg] to [bara] by adding atmospheric pressure (1.01325 bar), prior to usage in the conversions.

3.4. THP validity filters

Because the data collection, storage and retrieval is fully automated, various QC checks are required to avoid erroneous data. CITHP data can be used for CIBHP conversion if the following QC steps are met.

- The well CITHP used to calculate CIBHP's is obtained as the average of the values of the PIZA-002DC.PV and PI-007.PV gauges. If the values differ significantly (>0.7 bar[7]), the data is flagged as not valid.

- Only if the THP gauges are actually connected to the reservoir the CITHP readings are valid. For connection to the reservoir this means that the Surface Safety Valve (SSV) – also called Upper Master Valve(UMV) – and Surface Controlled Sub-Surface Safety Valve (SC-SSSV) must be open (Figure 9). There is a dedicated PI tag to monitor the SSV position: if the PI monitor GS-001C.PV reads 0, the SSV is closed. The SC-SSSV position is indirectly monitored: if GBA-003.PV reads 0, and KS-300.PV07 is 1 OR KS-300.PV09 read 1, the SC-SSSV is open (Please note the reverse is not true). See Table 3 for the definition of these monitors.

- The flow in the well is monitored in PI by the flow meter FQIA-001.PV, which should read flow < 0.1 mln NM^3 . The reading <0.1 mln NM^3 is set as flowmeters might show a signal if the well has actually stopped flowing. Also the position of the UZ101.PV and UZ.102 valves should both read 0 if the well is not flowing. For the position of these valves and gauge around the well see Figure 9.

All quality checks for a valid CITHP reading are summarized in Table 2. The flags used for the quality checks are defined in Table 3. They have been implemented accordingly as filters in SAS Wikker.

[7] based on 2* dead band (=0.28 bar) + margin

Table 2: Summary of all quality checks on THP from PI.

QC	Good quality THP(value = 1)
Open Reservoir	SSV=1 and SC-SSV=1[8]
Closed-in Well	Open Reservoir = 1 or UZ101= 0 or UZ102 = 0 or (Open Reservoir = 1 and UZ101 = 1 and UZ102 = 1 and Well producing = 0)
Working Gauges	Absolute difference PIZA-002.PV & PI-007.PV < 0,7 bar

Table 3: Definition of flags used for THP quality check. See Figure 9 for the valve and gauge positions around the well.

Flag	PI monitor	Description	Open (value=1)	Closed (value=0)
SSV	GS-001C.PV	Status closed position	0	1
SC-SSSV	GBA-003.PV KS-300.PV09 KS-300.PV07	Position alarm (not open) Well ready Well online(=1)	0 1 1	Reverse is not true
UZ101	UZ101.PV UZ101.MV	Position feedback Open/close signal valve	1 1	0 0
UZ102	UZ102.PV UZ102.MV	Position feedback Open/close signal valve	1 1	0 0
Well producing	FQIA-001.PV	Flowrate	≥ 0.1 mln NM3/day	< 0.1 mln NM3/day

An example of a well which does not satisfy the QC is depicted in Figure 12: the THP shows a materially different trend from the BHP. The Surface Safety Valve turned out to be closed during this test.

Figure 13 shows the behavior for a well which does satisfy the QC. The reservoir pressure build-up outweighs the effect of tubing gas column cooling, consequently CITHP rises as well. It also shows that pressure build up is slow as CIBHP still increases after 6.6 days.

There are some wells which do satisfy the QC but show a THP behavior which does not follow the trend in BHP. Such an example is depicted in Figure 14: although the measured downhole pressure shows a build-up upon shut-in, the CITHP is dropping. This CITHP behavior can be explained by the cooling effect on the gas column with shut-in time: gas density decreases with temperature, leading to a heavier gas column. This effect can outweigh a small increase in CIBHP for a high quality well like POS-2, where the drawdown (and consequent build-up) is minimal (some 0.3 bar). The wellbore cooling effect is discussed in more detail in Chapter 5.

[8] For data retrieval without SPGs note that the status open reservoir is best covered by using KS-300.PV09=1 for CITHP (no well flow and well status “ready”) from the DCS. This status is based on the Hydraulic Well Control Unit, or HWCU, status. Especially for SC-SSSV this is more reliable than only using valve position information. It is used to exclude most of the well maintenance activities.

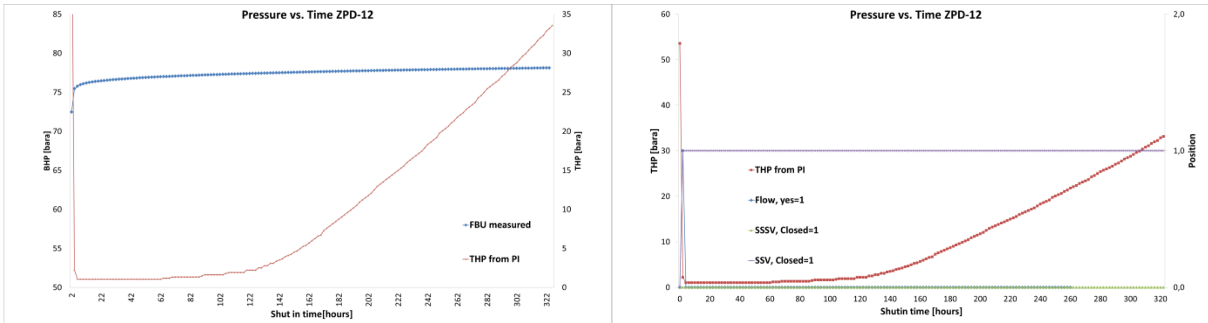

Figure 12: Example of CITHP behavior for ZPD-12 which is not representative for the reservoir. The SSV is closed during the test. The data shown is between 10-06-2014 and 23-06-2014.

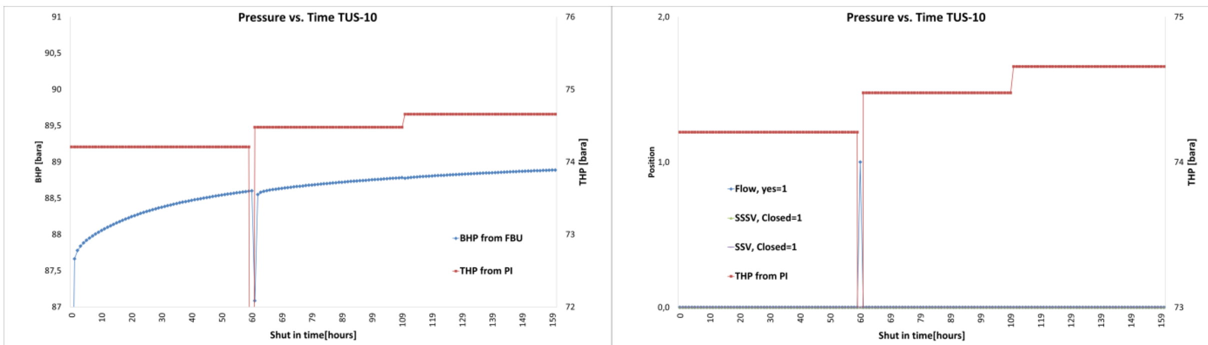

Figure 13: Expected CITHP behavior for TUS-10 with open SSV and SC-SSV and no flow. The data shown is between 30-10-2012 and 06-11-2012.

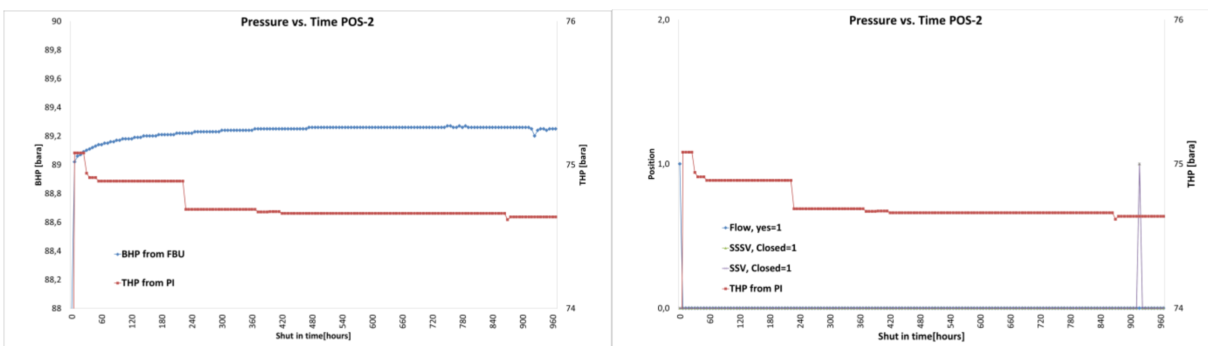

Figure 14: The CIBHP (measured from downhole gauge) for POS-2 increases due to pressure recovery/build-up whereas the verified CITHP (obtained from PI) decreases as a result of the cooling of the gas column. The data shown is between 15-09-2014 and 25-10-2014.

4. BHP data source

There are two sources of BHP data available for calibrating the CITHP to CIBHP conversion:

- Static Pressure Gradients (SPG)
- Long Term Memory Gauge (LTMG) data from Flowing Build-Up (FBU) tests.

4.1. SPG data

Various subsets of the available SPG data have been used in this study:

- There is a total of 2350 SPGs in the Groningen field
- There are 879 SPGs which have a reported THP value.
- There are 540 SPGs which also have a reported shut-in time[9].
- There are 31 SPGs which have valid THPs from PI.

4.2. FBU data

The wells with FBU tests between 2002-2015 are summarized in Table 4. In total 24 FBU tests from 8 different clusters, which have valid CITHP data from PI are used in the conversion accuracy study.

Note that the BHP obtained from FBU tests are at gauge depth and not at reservoir datum (difference can be 100s of meters). The FBU data is therefore only used for a well-by-well analysis and not on the full error study on all methods.

[9]Shut-in time of the well is registered and not equal to 0 days. Note that does not filter out shut-in times between 0 and 1 day.

Table 4: Groningen FBU tests between 2002 and 2015 according to WRFM surveillance sheet. .

Cluster	year													
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
AMR														
BIR	BIR-13		BIR-5							FBU	FBU			
EKL					EKL-13					EKL-4, -6, -12				
EKR	EKR-210			EKR-11, -209							FBU			
FRB	FBU													
KPD														
LRM												LRM-7		
MWD														
NBR	FBU													
NWS														
OVS	OVS-4,-5													
OWG	OWG-6											OWG-7		OWG-3
PAU		PAU-6						PAU-3, -4		PAU-3	PAU-3,-6		PAU-2	
POS													POS-2,-9	
SAP										SAP-12	SAP-6, -15			
SCB							FBU							
SDB	SDB-7				SDB-10									SDB-11
SLO			SLO-6											
SPI	SPI-103													
SZW	SZW-6	SZW-209			SZW-2, -204			FBU						
TJM						TJM-09								
TUS										TUS-6, -9, -10	TUS-4, -10			
UTB														
ZND	ZND-1							ZND-3						
ZPD	ZPD-9												ZPD-12	
ZVN		ZVN-10										ZVN-4,-12		
AAA-#	FBU registered in surveillance sheet, but not found in Siesta													
AAA-#	Unusable PI data: No data in PI (yet) or no valid data													
AAA-#	FBU with usable PI data													
AAA	No usable FBU data on cluster													

4.3. BHP accuracy

Downhole pressures (at reservoir datum) from SPG tests after the year 2000 are either obtained from electrical gauges (Micro Automatic or Sentinal gauges) resulting in 0.6 bar accuracy, although the gauges typically give an accuracy of 0.4 bar[10]. Before the year 2000 a variety of mechanical gauges were used. These mechanical gauges have different accuracies, which are not all captured in this report. It should be noted however that the downhole pressures measured from these mechanical gauges will be less accurate than the more recent downhole pressures measured in the more recent SPGs after the year 2000.

The standard accuracy of the premier quartz gauges used in FBU tests is 0.2 bar, although the gauges typically give an accuracy of 0.1 bar.[11]

[10] http://www.alsglobal.com/Our-Services/Energy/Oil-and-Gas/Well-and-Pipeline-Monitoring/Memory-Gauge-Monitoring/Piezo-Gauges/Micro-Automatic-Gauge and http://www.alsglobal.com/en/Our-Services/Energy/Oil-and-Gas/Well-and-Pipeline-Monitoring/Memory-Gauge-Monitoring/Piezo-Gauges/Sentinel-Tool

[11] According to Omega well monitoring: http://www.omegawell.com/media/011-ds-premier-v2-07-14.pdf

5. BHP and THP measurement error summary

As described in chapter 3. THP data source and in chapter 4.BHP data source, the data used in this error study contains already a measurement error resulting from gauge accuracy and dead-banding. Table 5 provides an overview of the measurement errors in THP and BHP for different sources.

Table 5: Summary of error in measured BHP and THP as described in chapter 4 and 5.

THP error [bar]		BHP error [bar]	
SPG	0.045	SPG_pre2000	0.3-3.3
PI gauges	0.14	SPG_post2000	0.6
PI dead-band	0.28	FBU	0.2

6. Wellbore temperature

The *single-step integral* method assumes that temperature over the full wellbore can be represented by a single (constant) value. The simplest approach is to take the average value of Tubing Head Temperature (THT) and Bottom Hole Temperature (BHT). The *multiple-step integral* method assumes the temperature over the full wellbore can be represented by a straight line between THT and BHT.

6.1. Bottom Hole Temperature

The reservoir temperature varies strongly across the field, mainly due to thickness variations of the over/underlying salt bodies. The temperature at datum level shows a spread of up to 20^{o}C. Consequently, the geothermal gradient as a function of depth also varies across the field. For each well the average BHT from its corresponding cluster is used.

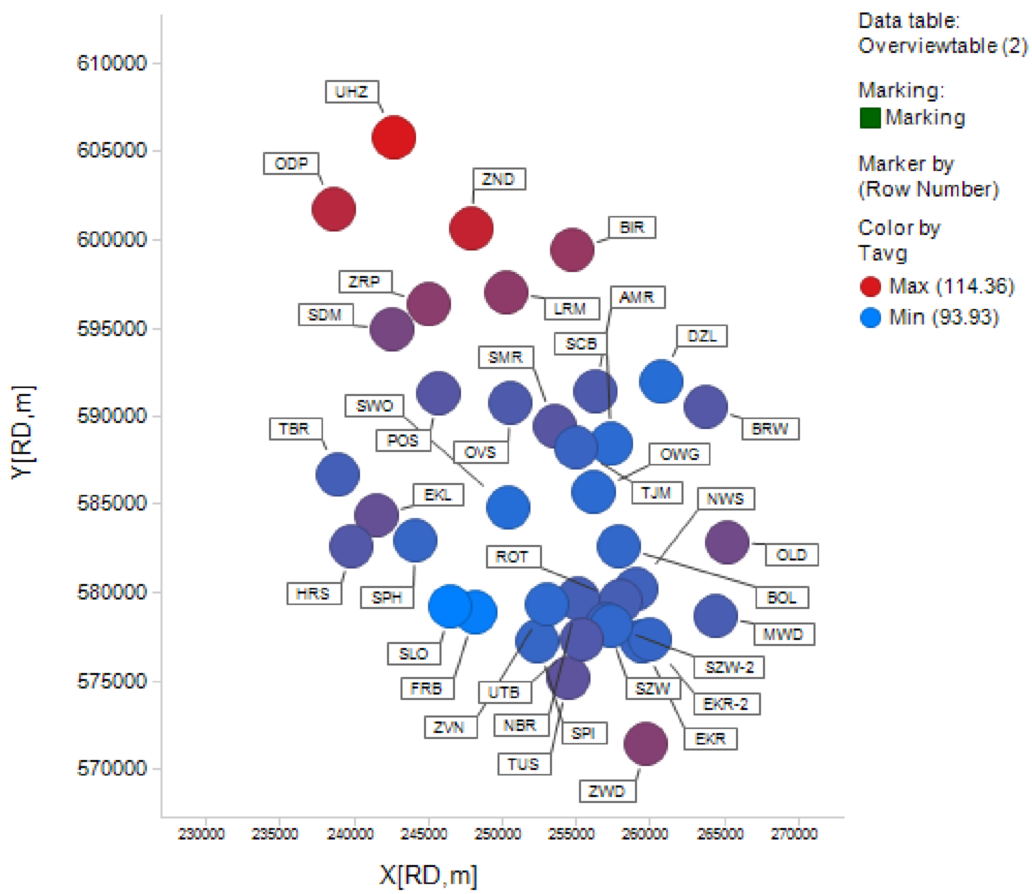

Figure 15: Variance in reservoir temperature (in °C).

6.2. Tubing Head Temperature

By assuming that the temperature profile is linear between the wellhead and reservoir datum, the THT is directly used in the integral methods.

Upon shut-in, the Tubing Head Temperature will be driven by the ambient temperature, which is varying between day/night and summer/winter. However, this change is only affecting the geothermal gradient very close to the surface: 1 meter during one day cycle. Hence given that the CITHT as measured at surface does not affect the temperature profile along the wellbore, it was kept in line with previous work by Jort van Jaarsveld who used a standard THT for static conditions which is approximately 7 degree C.

The THT effect is analyzed in more detail in Appendix 7.

6.3. Average wellbore temperature uncertainty

6.3.1. Wellbore heating

The wellbore temperature warms up significantly as a function of flow rate. It is calculated that the temperature half-way down the wellbore (SDB-10) varies from 60°C to 85°C when varying the rate from 0.1 to 0.78 mln m^3/d. Figure 16 shows this effect.

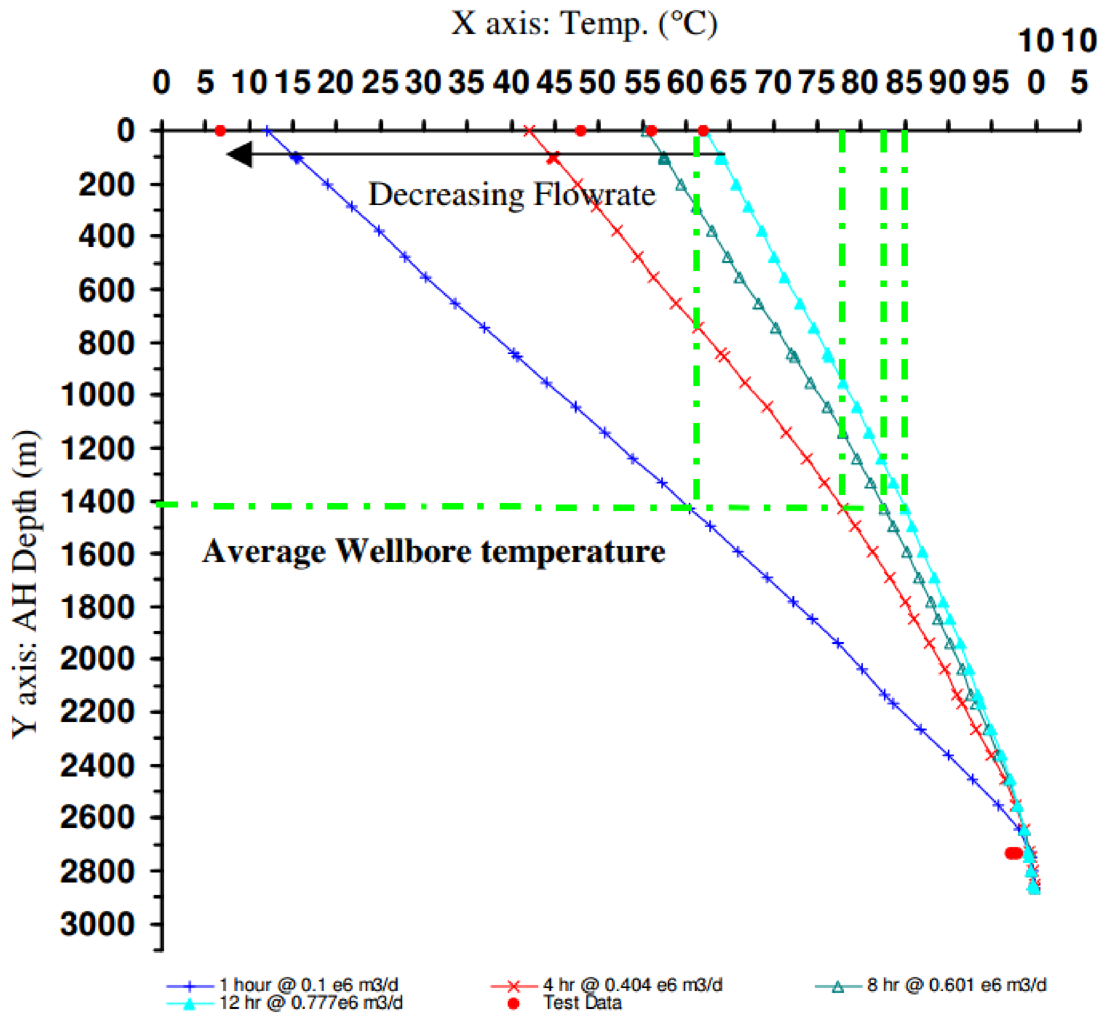

Figure 16: Modelled temperature profile along SDB-10 during an FBU as shown in.

6.3.2. Wellbore cooling

After shut-in, the cooling of a wellbore back to the geothermal gradient takes a significant amount of time. This can be observed in observation well Zeerijp-3, where Distributed Temperature Sensor (DTS) data is available. Although this well was never produced, a temperature disturbance was introduced with respect to the geothermal gradient, when the well was drilled. Drilling mud is heated up at the bottom of the well, and then circulated upwards through the drilling annulus, heating up the top of the borehole.

The DTS sensors become operational 44 days after the well was drilled[12]. In the next 89 days , the top 800 m of the wellbore still cools down by about 3 ^{o}C (Figure 17) . This demonstrates that the heat

[12] Zeerijp-3 was completed on August 30th 2015 and DTS data collection started on October 12th 2015, thus 44 days after completion of the well.

dissipation into the ambient rock to restore the wellbore temperature to the geothermal gradient can be a slow process. The cooling effect in the earlier shut-in times (< 44 days) is expected to be much larger when Newtonian cooling (exponential temperature decline) is assumed.

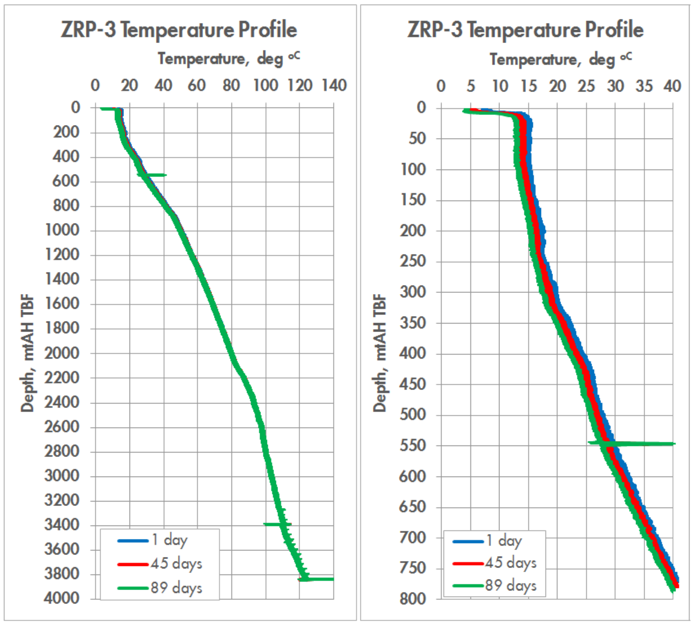

Figure 17: Distributed Temperature Sensor data for Zeerijp-3. 3 curves are shown for a different number of days after the initial start of DTS measurements 44 days after completion of the well.

6.4. Shut-in time as proxy for average wellbore temperature

As shown in the previous section on page 28 the cooling of the wellbore to geothermal gradient can be a slow process. The expected THT envelope spans roughly from 7°C (shut-in well) to 65°C (flowing well). Using the single-step integral calculation, theoretical boundaries associated with these THT limits can be established for the conversion factor (CIBHP/CITHP) across the historic THP operating range. It turns out that the theoretical boundaries do nicely enclose the SPG historic dataset, see Figure 18. By color coding the data points by their respective shut-in duration (in days), it becomes obvious that there is a clear trend between shut-in duration and wellbore temperature. Again, using the single-step integral calculation, the conversion factor (CIBHP/CITHP) can be calculated across the THT range between the established limits for THT. It turns out the calculated THT dependent trend matches the historic time dependent trend in the conversion factor (CIBHP/CITHP) versus logarithmic shut-in time for the historic SPG dataset, see Figure 19. This makes physical sense: as the wellbore cools down, the gas column gets heavier, resulting in a bigger delta between THP and BHP, and consequently the conversion factor (CIBHP/CITHP) becomes bigger. The increasing conversion factor for longer shut-in times due to cooling of the wellbore, results in a difference of about 3 bar[13] for converted CIBHP's within the first 10 days of shut-in.

[13]At THP=100 bar, the conversion factor at THT=7 is some 1.24, whereas at THT=65 it is around 1.21. The associated difference in calculated BHP is (1.24-1.21)x100 bar = 3 bar.

Note that the theoretical curves (for THT 7°C and 65°C) show a curvature across the THP range associated with the Gas Deviation Factor (or rather $\exp(1/Z)$, see section 2.2.1), which seems to be reflected in the dataset as well.

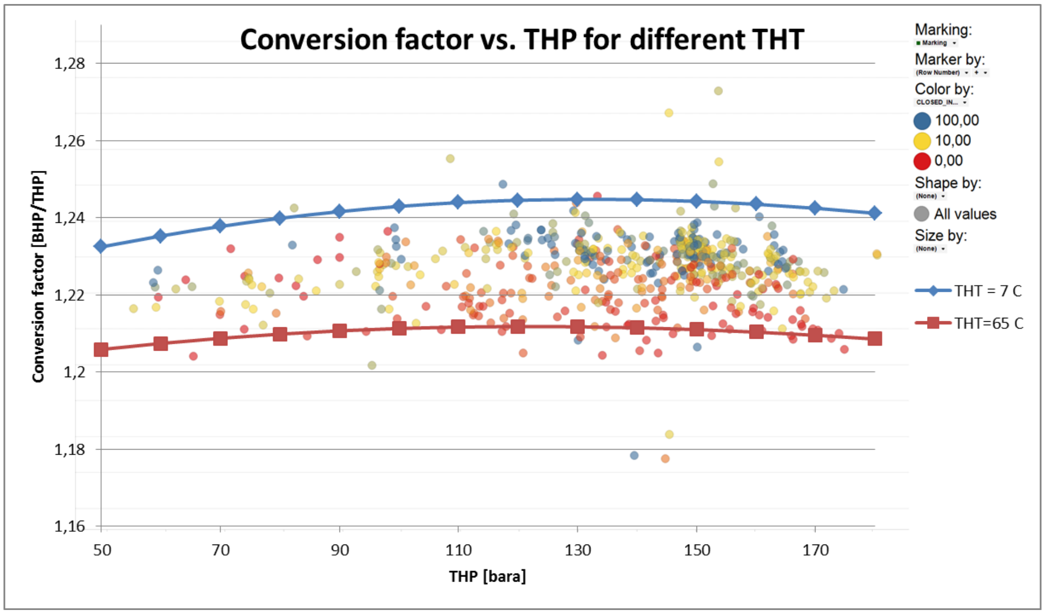

Figure 18: Artificial conversion factors from the single-step integral versus real conversion factors from historic SPG data. Shut-in time (in days) and THT are ranging from red to blue as an indication of a warmer/colder well.

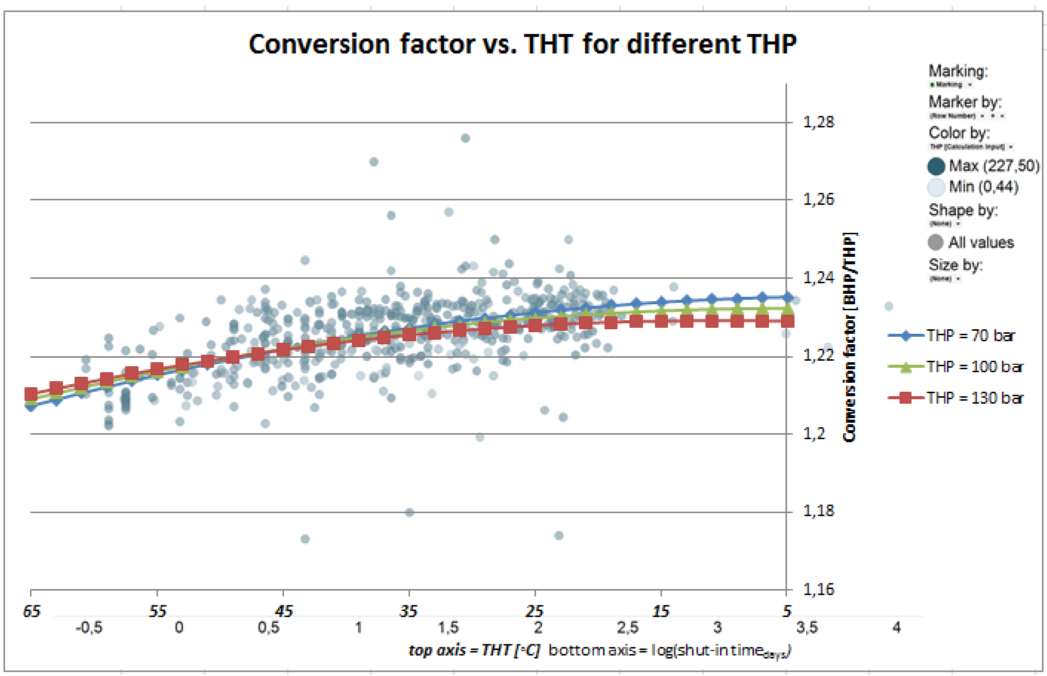

Figure 19: Artificial conversion factors from the single-step integral versus THT and real conversion factors from historic SPG data versus logarithmic shut-in time.

7. Time dependent conversion methods

Upon shut-in of a well, the pressure and temperature in the wellbore will change as a result of wellbore storage, because the well cools off to the geothermal gradient, and because the draw-down pressure dissipates. Consequently, the validity of the various CITHP-CIBHP conversions are a function of the shut-in time.

The dependency on time (as a proxy for wellbore temperature) of the conversion factor as shown in Figure 18 provides the basis to design new time-dependent conversion methods. This chapter provides a new *conversion factor* and a new *single-step integral correction factor* as a function of the shut-in time of a well. These functions are derived for the full field dataset, as well as for the data per cluster.

7.1. Full field functions

7.1.1. Time dependent conversion factor (CIBHP/CITHP)

Figure 20 shows a plot of the conversion factor versus the logarithmic shut-in time as obtained from filtered[14] historic SPG data. A 3rd order polynomial is fitted on the 37-point moving average of the data[15] and results in the following full field time dependent conversion factor:

$$M = \frac{CIBHP}{CITHP} = 0.000375 \times \log(t_{day})^3 - 0.00380 \times \log(t_{day})^2 + 0.0128 \times \log(t_{day}) + 1.22$$

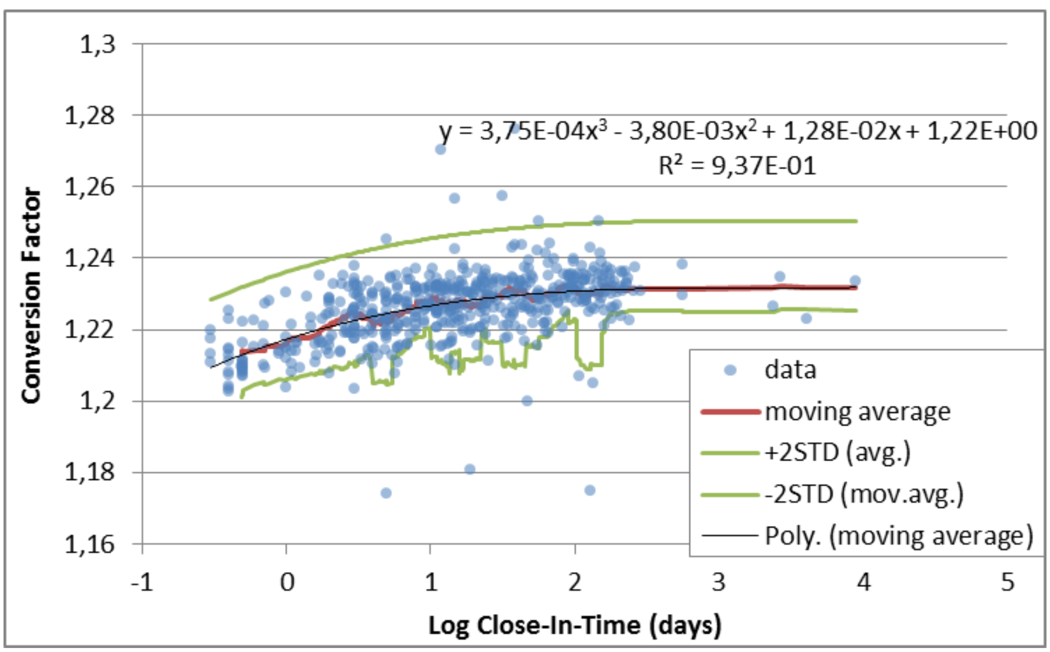

Figure 20: Curve fitted through moving average of conversion factors versus logarithmic shut-in time from filtered historic SPG data.

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[14] Shut-in time > 0 days and conversion factor between 0 and 1.5 to remove extreme outliers.

[15] Bins of 36 data points are used to ensure unbiased statistics.

7.1.2. Time dependent correction factor

Figure 21 shows a plot of the correction factor for the single-step integral versus the logarithmic shut-in time as obtained from filtered[16] historic SPG data. A curve is fitted on the moving average of the data[17] and results in the following full field time dependent conversion factor:

$$C = 0.000261 \times \log(t_{day})^3 - 0.00272 \times \log(t_{day})^2 + 0.00948 \times \log(t_{day}) + 0.979$$

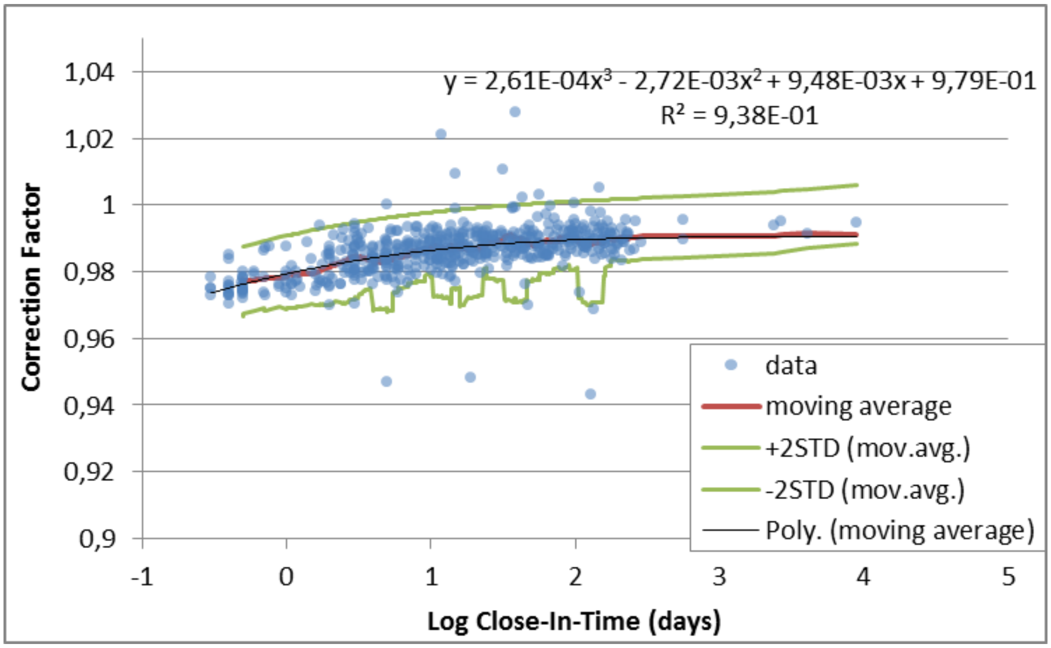

Figure 21: Curve fitted through moving average of correction factors versus logarithmic shut-in time from filtered historic SPG data.

7.2. Individual cluster functions

Given that there is a significant spread in the geothermal gradient across the clusters, the time dependent functions can be further improved by fitting them on SPG data grouped per cluster.

7.2.1. Time dependent conversion factor (CIBHP/CITHP)

Figure 22 shows a plot of the conversion factor versus the logarithmic shut-in time as obtained from filtered[18] historic SPG data only for the Amsweer cluster. A parabolic polynomial trend line is fitted on the data, yielding a time dependent, cluster specific conversion factor. On some clusters the polynomial trend lines result in non-physical behavior for very short or very long shut-in times[19]. Third order polynomial trend lines, or linear trend lines are fitted on these clusters to resemble correct physical

[16] Shut-in time > 0 days and conversion factor between 0 and 1.5.
[17] Bins of 36 data points are used to ensure unbiased statistics.
[18] Shut-in time > 0 days and conversion factor between 0 and 1.5.
[19] That is the conversions factor increases for shorter shut-in time or decreases for longer shut-in time, which is not in line with a cooling gas column.

behavior. This process is repeated for all clusters in the Groningen field (Appendix 4), resulting in the equations per cluster as summarized in Table 6.

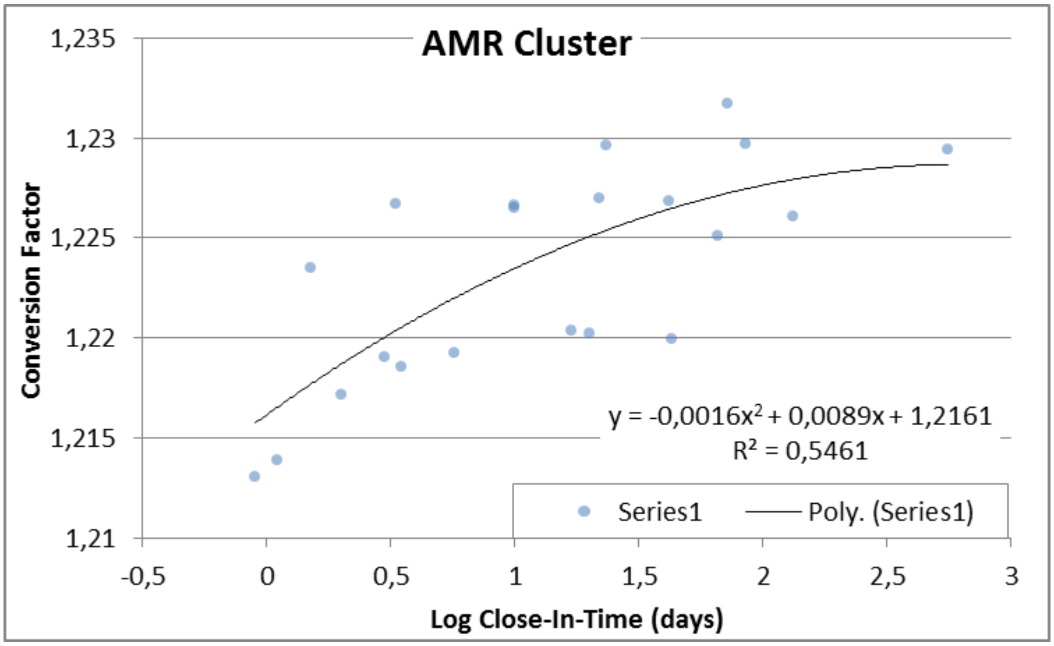

Figure 22: Curve fitted through conversion factors versus logarithmic shut-in time from filtered SPG data for Amsweer cluster.

Table 6: Time dependent conversion functions per cluster and full field.

Cluster	Time Dependent Conversion Function t = shut-in time (days)
FIELD	M = 0.000375*log(t)^3 -0.0038*log(t)^2 + 0.0128*log(t) + 1.22
AMR	M = -0.0016*log(t)^2 + 0.0089*log(t) + 1.2161
BIR	M = -0.0016*log(t)^2 + 0.0071*log(t) + 1.2114
EKL	M = 0.0022*log(t)^3 -0.0117*log(t)^2 + 0.0216*log(t) + 1.2189
EKR	M = -0.0003*log(t)^2 + 0.0033*log(t) + 1.2272
FRB	M = -0.0015*log(t)^2 + 0.0068*log(t) + 1.2237
KPD	M = -0.0019*log(t)^2 + 0.0081*log(t) + 1.2249
LRM	M = 0.0065*log(t) + 1.2066
MWD	M = -0.0019*log(t)^2 + 0.0126*log(t) + 1.2158
NBR	M = 0.0108*log(t) + 1.21
NWS	M = -0.0045*log(t)^2 + 0.0192*log(t) + 1.214
OVS	M = -0.0015*log(t)^2 + 0.0093*log(t) + 1.2128
OWG	M = -0.0015*log(t)^2 + 0.0076*log(t) + 1.219
PAU	M = -0.0029*log(t)^2 + 0.0117*log(t) + 1.2165
POS	M = -0.00007*log(t)^2 + 0.0066*log(t) + 1.214
ROT	M = 0.0089*log(t) + 1.21[20]
SAP	M = -0.0055*log(t)^2 + 0.0241*log(t) + 1.2108
SCB	M =- 0.0027*log(t)^2 + 0.0152*log(t) + 1.21
SDB	M = -0.0048*log(t)^2 + 0.0172*log(t) + 1.2153
SLO	M = -0.0024*log(t)^2 + 0.0098*log(t) + 1.2224
SPI	M = -0.0026*log(t)^2 + 0.0123*log(t) + 1.22
SZW	M = -0.0028*log(t)^2 + 0.0095*log(t) + 1.2238
TJM	M = -0.0005*log(t)^2 + 0.0108*log(t) + 1.21
TUS	M = -0.002*log(t)^2 + 0.0112*log(t) + 1.2188
UTB	M = -0.0018*log(t)^2 + 0.0084*log(t) + 1.2263
ZND	M = -0.0016*log(t)^2 + 0.0109*log(t) + 1.2085
ZPD	M = -0.0033*log(t)^2 + 0.0132*log(t) + 1.2185
ZVN	M = -0.002*log(t)^2 + 0.0101*log(t) + 1.2211

7.2.2. Time dependent correction factor

Figure 23 shows an example of the correction factor for the single-step integral versus the logarithmic shut-in time as obtained from filtered[21] historic SPG data for the Amsweer cluster. A parabolic polynomial trend line is fitted on the data, yielding a time dependent, cluster specific correction factor. On some clusters the polynomial trend lines result in non-physical behavior for very short or very long

[20] Bad fit on 2 conflicting data points, see Appendix 4.
[21] Shut-in time > 0 days and conversion factor between 0 and 1.5.

shut-in time[22]. Third order polynomial trend lines, or linear trend lines are fitted on these clusters to resemble correct physical behavior. This process is repeated for all clusters in the Groningen field (Appendix 4), resulting in different equations for each cluster as summarized in Table 7.

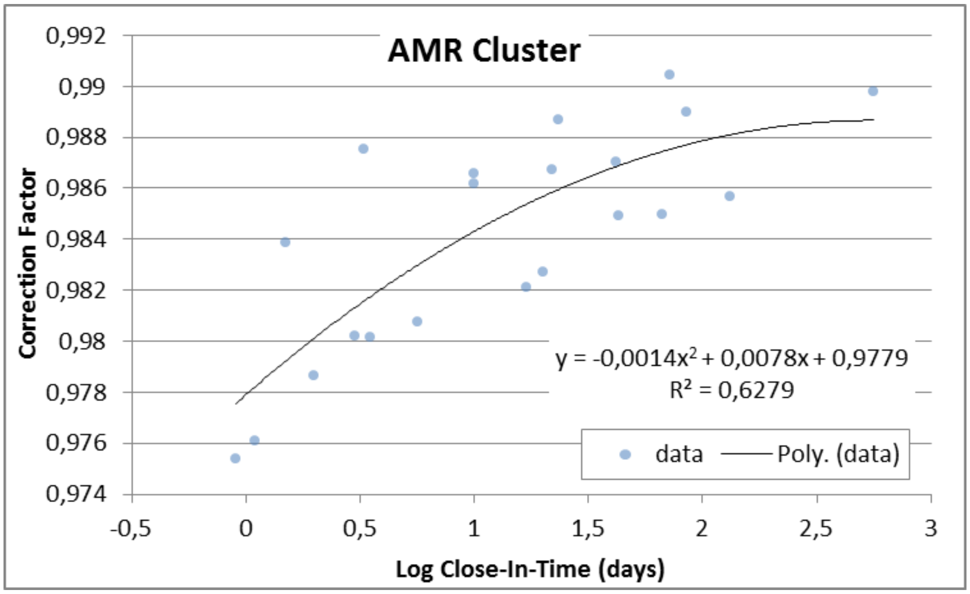

Figure 23: Curve fitted through correction factors versus logarithmic shut-in time from filtered SPG data for Amsweer cluster.

[22] The conversions factor increases for shorter shut-in time or decreases for longer shut-in time, which is not in line with a cooling gas column.

Table 7: Time dependent correction functions per cluster and full field.

Cluster	Time Dependent Correction Function t = shut-in days
FIELD	C = 0.000261*log(t)^3 - 0.00272*log(t)^2 + 0.00948*log(t) + 0.979
AMR	C = -0.0014*log(t)^2 + 0.0078*log(t) + 0.9779
BIR	C = -0.0013*log(t)^2 + 0.0059*log(t) + 0.9777
EKL	C = 0.001*log(t)^3 - 0.0072*log(t)^2 + 0.0164*log(t) + 0.9814
EKR	C = -0.0013*log(t)^2 + 0.0061*log(t) + 0.984
FRB	C = -0.0006*log(t)^2 + 0.0048*log(t) + 0.9798
KPD	C = -0.0014*log(t)^2 + 0.0063*log(t) + 0.9823
LRM	C = 0.0055*log(t) + 0.9739
MWD	C = -0.0016*log(t)^2 + 0.0102*log(t) + 0.9778
NBR	C = 0.0046*log(t) + 0.98
NWS	C = -0.0031*log(t)^2 + 0.0137*log(t) + 0.977
OVS	C = -0.0012*log(t)^2 + 0.0078*log(t) + 0.9755
OWG	C = -0.0012*log(t)^2 + 0.006*log(t) + 0.9796
PAU	C = -0.0025*log(t)^2 + 0.0102*log(t) + 0.9763
POS	C = -0.0002*log(t)^2 + 0.0065*log(t) + 0.9759
ROT	C = 0.0086*log(t) +0.97[23]
SAP	C = -0.0046*log(t)^2 + 0.0195*log(t) + 0.9717
SCB	C = -0.0011*log(t)^2 + 0.0082*log(t) + 0.9755
SDB	C = -0.0037*log(t)^2 + 0.0133*log(t) + 0.977
SLO	C = -0.0023*log(t)^2 + 0.0088*log(t) + 0.9796
SPI	C = -0.0015*log(t)^2 + 0.0073*log(t) + 0.983
SZW	C = -0.0023*log(t)^2 + 0.0074*log(t) + 0.9838
TJM	C = -0.0007*log(t)^2 + 0.0103*log(t) + 0.971
TUS	C = -0.0017*log(t)^2 + 0.0094*log(t) + 0.9808
UTB	C = -0.0016*log(t)^2 + 0.0069*log(t) + 0.9864
ZND	C = -0.001*log(t)^2 + 0.0082*log(t) + 0.9781
ZPD	C = -0.003*log(t)^2 + 0.011*log(t) + 0.9798
ZVN	C = -0.0016*log(t)^2 + 0.0076*log(t) + 0.9815

[23] Bad fit on 2 conflicting data points, see Appendix 4.

8. Analysis

QC of the various conversion methodologies was done using all available FBU data between 2002-2015[24], and using all SPG data in the Groningen field.

8.1. FBU dataset (well-by-well analysis)

The FBU data for which there are also PI THP data available provide the opportunity not only to evaluate the various conversion methods, but also their validity over time. Because FBU data is recorded at gauge depth and not at reservoir datum, this well-by-well analysis is only used for a comparison between the different integral methods (which can be used for any specified depth).

Figure 24, Figure 25 and Figure 26 give a specific analysis for wells TUS-10, PAU-06 and POS-2 (all with validated, but different CITHP behavior). The full analysis on all wells with valid CITHP and CIBHP data as mentioned in Table 4 can be found in Appendix 2.

Correction factor

What can be observed from the plots on the left of Figure 24, Figure 25 and Figure 26 (and the figures in Appendix 2) is that both integral methods without correction factors result in worse CIBHP's than the corrected integral methods (consistently 1-2 bar too high CIBHP). Therefore the **corrected integral methods** are preferred.

Single versus Multi-step integral

What can be observed from the plots on the right of Figure 24, Figure 25 and Figure 26 (and the figures in Appendix 2) is that the **corrected multi-step integral** can result in either a higher or lower CIBHP (up to 0.2 bar) as compared to the **corrected single-step** integral. This difference does not consistently improve or worsen the results. Given that the **corrected multi-step integral** does not provide a consistently better match, it is recommended to limit the complexity of the conversion, and use the simpler **corrected single-step integral**.

Time dependency

Finally in the plots on the right of Figure 24, Figure 25 and Figure 26 the time dependent correction has been applied to the single-step integral. It can be observed that whereas the other methods do not correct for the cooling of the gas column in the wellbore, the time corrected single-step integral does correct for this cooling.

[24] The PI monitoring system was started from 2002. Before there are no continuous measurements of THP's.

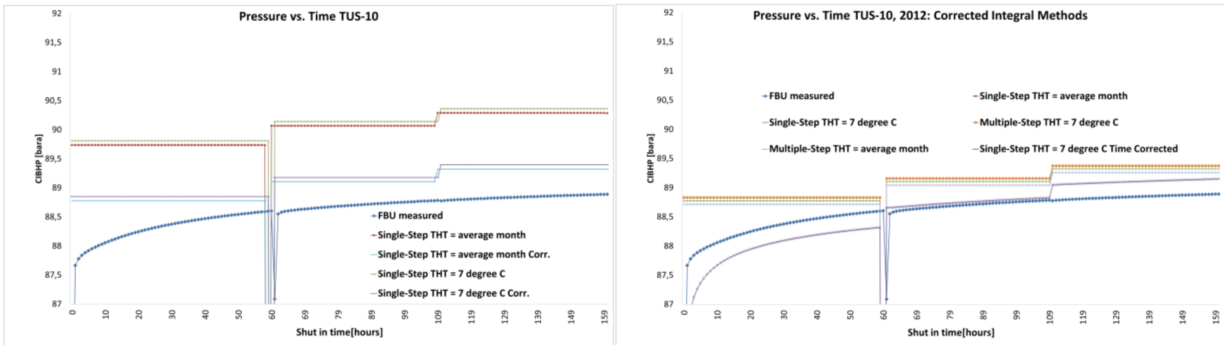

Figure 24: Measured CIBHP from TUS-10 and calculated CIBHP's from different integral conversion methods.

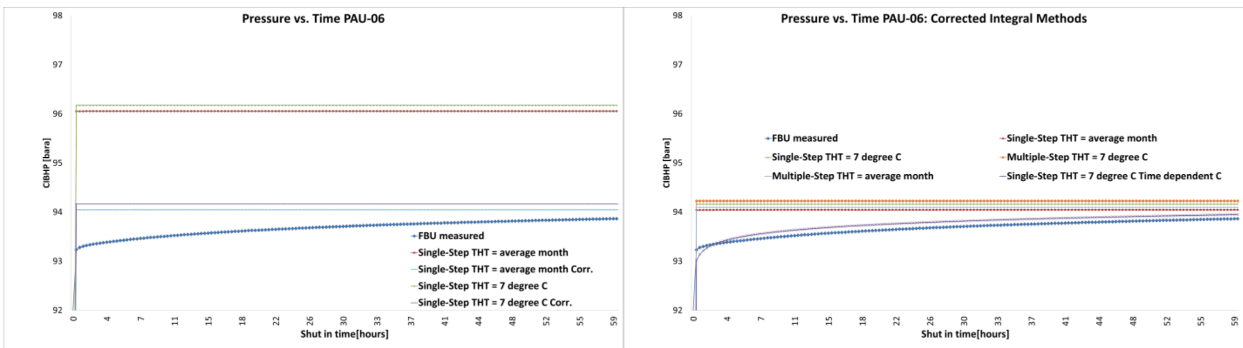

Figure 25: Measured CIBHP from PAU-06 and calculated CIBHP's from different integral conversion methods.

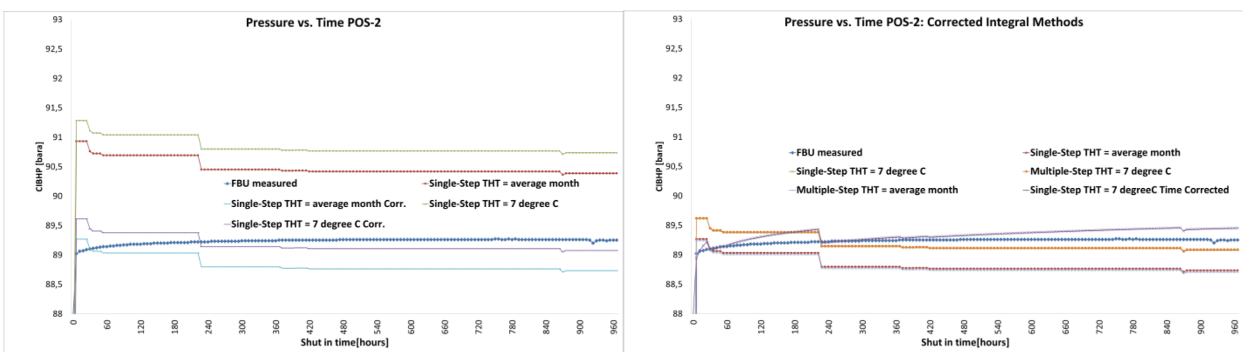

Figure 26: Measured CIBHP from POS-02 and calculated CIBHP's from different integral conversion methods.

8.2. SPG dataset

8.2.1. Accuracy of the THP associated with an SPG

The associated THP for an SPG measurement is typically reported from either a Dead Weight Test (DWT) or lubricator stop pressure. To be consistent, only the DWT and lubricator pressures as directly obtained from SPG tests are used in this analysis. DWT data is considered more accurate than lubricator pressures data[25] and has a standard accuracy of 0.015% (see Appendix 3).

For more recent wells THPs from PI are also available (starting for some wells in 2002 and all wells in 2008). As a QC step, these THP's as obtained from PI were compared to those obtained from DWT and lubricator pressures. Table 8 shows that the THP's are within a 0.3 bar range of THP from DWT pressures and within 0.49 bar range of lubricator stop pressures. Note here that the dead band already causes a 0.28 bar uncertainty in the THP and the pressure sensors themselves have an accuracy of 0.1%

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[25] Regulatory agencies often indicate that pressures should be measured with DWT, see Appendix 3.

Table 8: QC on THP obtained from PI vs. DWT and lubricator pressures for all SPG's, given that the THP from PI are valid. Note that the pressure from PI were converted from barg to bara.

Well-name	Date SPG	THP from PI	THP from DWT	THP lubricator	Error PI-DWT	Error PI-lubricator	Comment
		bara	bara	bara	bara	bara	
POS-09	3-6-2008	96.78		97.9		1.12	Possibly lubricator atmospheric pressure added to bara lubricator pressure
BIR-02	6-5-2009	93.94	95.01		1.07		Exact test time 11:37: showing non-valid THP
OWG-07	16-2-2004	104.33	104.17	103.84	0.16	0.49	DWT shows good conversion with PI data
OWG-02	4-5-2007	95.85	95.59	95.38	0.26	0.47	DWT shows good conversion with PI data
PAU-06	10-4-2003	110.57	110.27	110.24	0.30	0.33	
BIR-13	26-8-2002	112.08	111.8	111.91	0.28	0.17	
EKL-06	9-10-2006	116.58	116.31	116.67	0.27	0.09	
ZVN-04	11-3-2013	69.06		69.31		0.25	
KPD-11	22-5-2006	101.05	101.11	101.28	0.06	0.23	
ZPD-05	13-4-2007	96.36	96.18	96.14	0.18	0.22	
SDB-10	31-3-2006	99.06		99.27		0.21	
TUS-02	27-8-2012	73.87		74.08		0.21	
BIR-03	26-7-2002	112.52	112.32	112.5	0.20	0.02	
PAU-02	24-6-2008	96.53		96.34		0.19	
SPI-01	9-6-2010	82.75		82.58		0.17	
SDB-07	25-11-2002	111.49		111.35		0.14	
SCB-10	20-7-2012	74.94		74.80		0.14	
SDB-10	27-3-2006	98.61	98.52	98.75	0.09	0.14	
LRM-02	15-5-2006	102.38	102.51	102.32	0.13	0.06	
EKL-06	20-10-2011	101.44		101.57		0.13	
PAU-03	27-1-2009	94.13	94.02	94.01	0.11	0.12	
ZND-09	23-9-2014	78.64		78.75		0.11	
OWG-02	22-5-2012	73.67		73.57		0.10	
SLO-06	27-6-2012	74.71		74.61		0.10	
TUS-04	9-11-2012	73.21		73.30		0.09	
SLO-05	17-8-2015	58.09		58.17		0.08	
BIR-03	16-7-2015	69.2		69.13		0.07	
SPI-03	23-9-2015	54.47		54.52		0.05	

ZVN-04	25-5-2012	74.20		74.15		0.05	
SDB-02	11-8-2009	89.53		89.5		0.03	
LRM-02	20-9-2013	76.51		76.53		0.02	
OWG-02	18-3-2013	69.13		69.16		0.03	

8.2.2. Time independent conversions

Based on the available SPG dataset (producing wells, observation wells and closed-in wells) a *field wide average conversion factor* was established to be 1.2316, with *average conversion factor per cluster* as per Table 9.

And finally a *correction factor C for the single-step integral* conversion and a *correction factor C for the multiple-step integral conversion* were obtained from this dataset and are shown in Table 9.

For both the conversion factor and for the correction factor C there is a time dependency, as is explained in chapter 7.

Table 9: Average conversion factors for full field and per cluster and correction factors for the single-step and multiple-step integral conversions assuming THT = 7 ^{o}C. All based on 879 SPG tests from the Groningen field.

Cluster Name	Average SPG conversion factor [BHP/THP]	Correction Factor Single-Step THT = 7 degree C	Correction Factor Multiple-Step THT = 7 degree C
	[bara/bara]	[bara/bara]	[bara/bara]
Field			
FIELD	1.231683993	0.991052978	0.988551806
Producing Clusters			
AMR	1.221796887	0.983459645	0.982609671
BIR	1.218883733	0.984037867	0.982662709
EKL	1.228226244	0.989340065	0.988418346
EKR1	1.230152026	0.988217152	0.989781052
EKR2	1.230035846	0.988685859	0.989971095
FRB	1.227315295	0.984287321	0.985128875
KPD	1.229689683	0.986382499	0.98718107
LRM	1.212319099	0.978751447	0.977378629
MWD	1.226288819	0.986422852	0.985719136
NBR	1.229541205	0.988987184	0.988287611
NWS	1.22995823	0.98867361	0.989437739
OVS	1.218114268	0.979971302	0.979266471
OWG	1.223189356	0.982781249	0.983905203
PAU	1.218782375	0.979095366	0.962234235
POS	1.219477592	0.981701897	0.983155998

SAP	1.232870362	0.989251569	0.974228346
SCB	1.225610975	0.984738851	0.949784084
SDB	1.224586416	0.984296164	0.972016628
SLO	1.229872262	0.985808614	0.96081653
SPI1	1.231943306	0.990541892	0.960697234
SPI2	1.231368538	0.989441597	1.011623712
SZW1	1.229747774	0.988426386	0.98784917
SZW2	1.230870048	0.988681612	0.988225465
TJM	1.222389016	0.982456963	0.981903742
UTB	1.231030172	0.991169535	0.961111501
ZND	1.216824295	0.984906069	0.983044908
TUS	1.228469722	0.98931858	0.988386179
ZPD	1.225158567	0.985022276	0.984403994
Observation wells			
BOL	1.238528318	0.995040152	0.994545326
BRH	1.237852917	0.996791147	0.995900443
BTA	nodata	nodata	nodata
DZL	1.250085388	1.00390516	1.003475754
FRM	1.03726012	0.838649093	0.837264032
HGL	1.317127163	1.055142492	1.059899021
HND	1.253750496	1.014490523	1.009082681
HGZ	1.243403634	0.931632293	0.940082636
HRS	1.235237029	0.999186507	1.000348978
KHM	1.24577576	1.002736686	1.023227957
MDN	nodata	nodata	nodata
MLA	nodata	nodata	nodata
ODP	1.231494161	0.99664398	0.998954733
OLD	1.253445326	1.010451728	1.019218863
ROT	1.239847871	0.997447383	1.006463242
SDM	1.240290969	0.99957026	0.998505892
SMR	1.242131991	0.999552438	1.000083235
SPH	1.236939044	0.993821148	1.008003982
SWO	1.240630626	0.996112972	1.000874711
TBR	1.23642393	0.994375979	0.997455317
UHM	1.236030125	1.000754981	0.998792618
UHZ	1.228414896	0.99517367	0.99461916
ZBR	incorrect data	incorrect data	incorrect data
ZRP	1.235194487	0.996799007	0.995479494
ZWD	1.245767953	1.00512287	1.00475013
Injection wells			

BRW	incorrect data	incorrect data	incorrect data
Other abandoned clusters			
GLH	nodata	nodata	nodata
VLV	nodata	nodata	nodata
WBL	1.244338636	0.996967575	0.999392583

8.2.3. Time dependent conversions

From the well-by-well analysis using the FBU data the **single-step** integral with THT = 7 °C was found to be the most accurate integral method. This method is further investigated using the (bigger) SPG data set. The constant multiplier methods (**constant factor** conversion 1.20, field wide **average conversion factor** conversion 1.2316 and the **average cluster conversion factors**) and newly proposed time dependent multiplier methods are then only investigated on their accuracy on historic SPG data.

The **non-corrected single-step** integral with THT = 7 °C, **corrected single-step** integral with THT = 7 °C, **constant conversion factor** conversion of 1.20, **average cluster conversion factors** and newly proposed **time dependent** multiplier methods are investigated on their accuracy on historic SPG data.

Part of the error is caused by the uncertainty resulting from the gauges as explained in Chapter Accuracy of sampled THP value on page 19 and Chapter Accuracy of the THP associated with an SPG on page40.

The error is therefore plotted as the difference in [bara] between measured CIBHP and calculated CIBHP and not as percentage. The error plots in Figure 27 until Figure 35 show the error as obtained from all historic SPG data, historic SPG data after 2000 and from THPs from PI. The Root Mean Squared, or RMS, error is summarized for all different methods and datasets in Table 10.

Note the accuracy of the single-step integral conversion is <0.7% when the shut-in time is longer than 10 days. This conclusion was derived from a similar plot to Figure 28 .

Table 10: Root Mean Squared (RMS) error summarized for all conversion methods on different datasets.

Method	Dataset	RMS Error [bara]	Comment
Single-Step integral non-corrected	All SPGs	2.52	Error larger for shorter shut-in time
	Post 2000 SPGs	2.00	
	PI THP	2.08	
Single-Step integral corrected (fixed value per cluster)	All SPGs	1.01	Error larger for shorter shut-in time
	Post 2000 SPGs	0.66	
	PI THP	0.55	
Single-Step integral time corrected (per cluster)	**All SPGs**	**0.71**	
	Post 2000 SPGs	**0.52**	
	PI THP	**0.41**	
Single-Step integral time corrected (field wide)	All SPGs	0.80	
	Post 2000 SPGs	0.72	
	PI THP	0.51	
Constant conversion ($M=\sqrt{(1.44)}=1.2$)	All SPGs	3.54	Error larger for shorter shut-in time
	Post 2000 SPGs	2.48	
	PI THP	1.76	
Constant conversion (per cluster)	All SPGs	0.97	Error larger for shorter shut-in time
	Post 2000 SPGs	0.67	
	PI THP	0.65	
Constant conversion (field wide = 1.2316)	All SPGs	1.39	Error larger for shorter shut-in time
	Post 2000 SPGs	1.16	
	PI THP	1.29	
Time dependent conversion (per cluster)	**All SPGs**	**0.73**	
	Post 2000 SPGs	**0.63**	
	PI THP	**0.56**	
Time dependent conversion (field wide)	All SPGs	0.97	
	Post 2000 SPGs	0.87	
	PI THP	0.91	

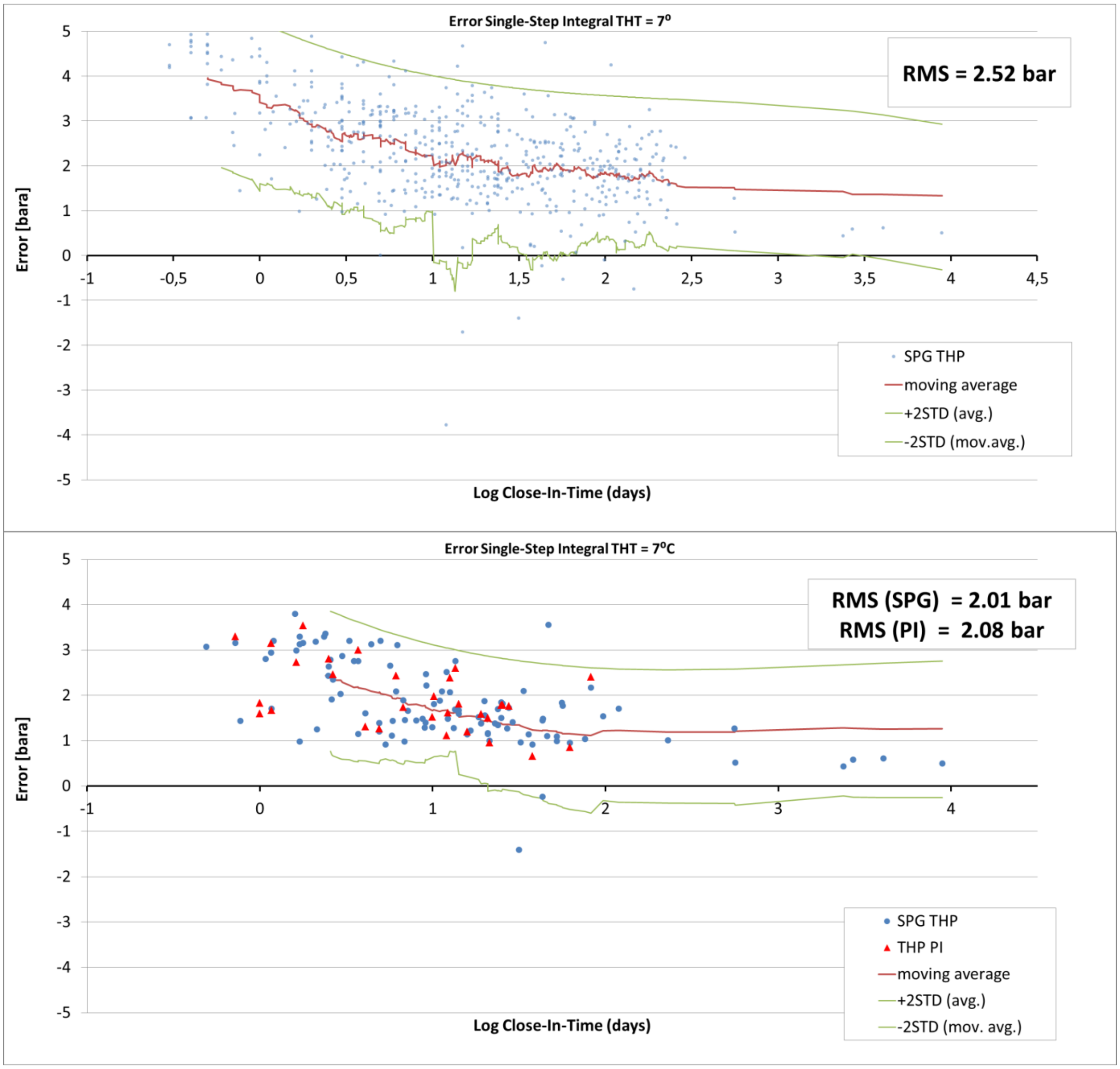


Figure 27: Error behavior of Single-Step integral conversion with THT = 7 degree C versus log (days shut-in time). Note that moving average and STD are only based on SPG data.

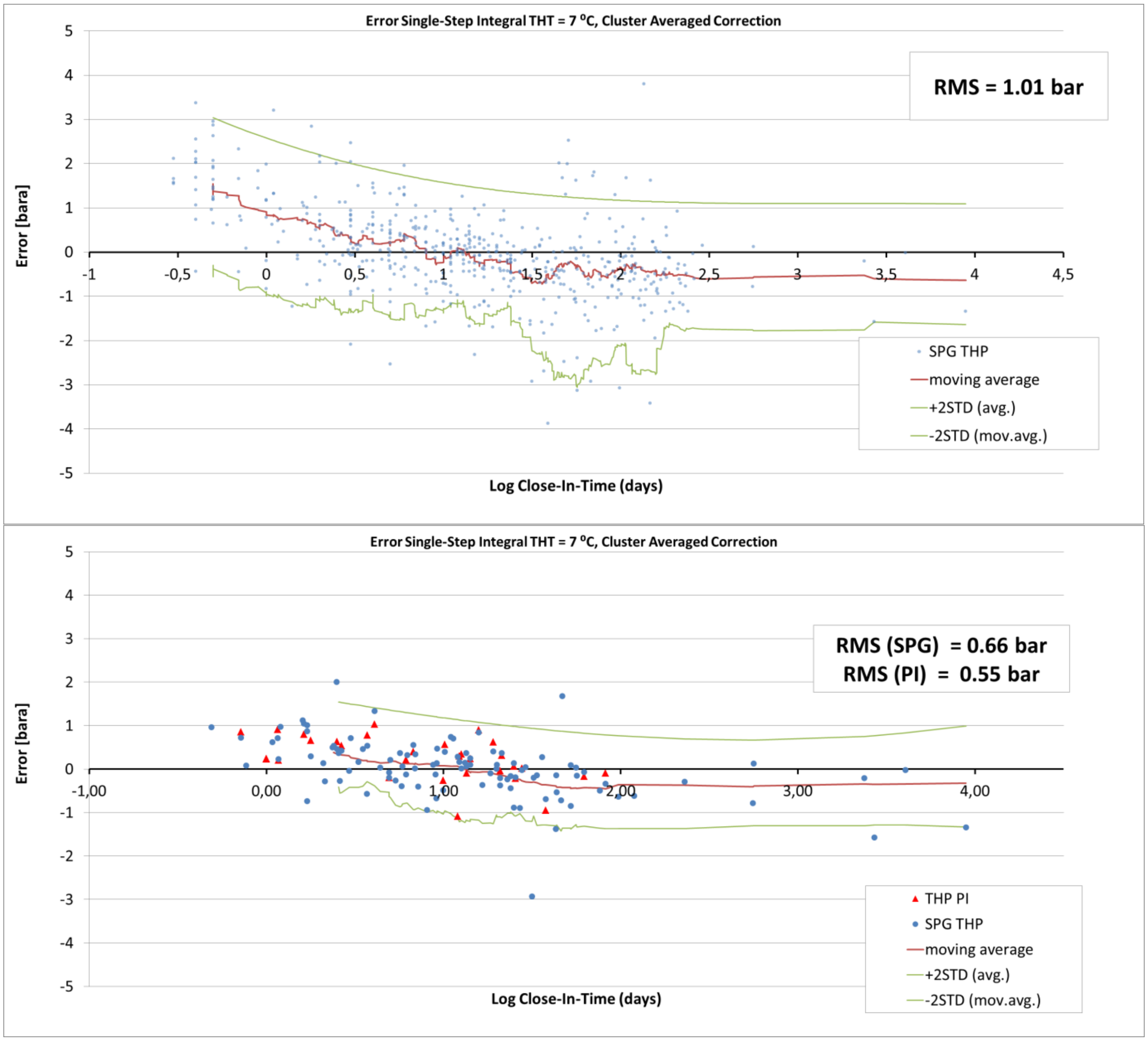


Figure 28: Error behavior of Cluster based Corrected Single-Step integral conversion with THT = 7 degree C versus log (days shut-in time). Method is equal to the method used in *Proposal for DWT campaign southern clusters Groningen field,G.J.C.A. Reijnders, June 2001, NAM200106100013.* Note that moving average and STD are only based on SPG data.

Figure 29: Error behavior of Field Based Time Corrected Single-Step integral conversion with THT = 7 degree C versus log (days shut-in time). Note that moving average and STD are only based on SPG data.

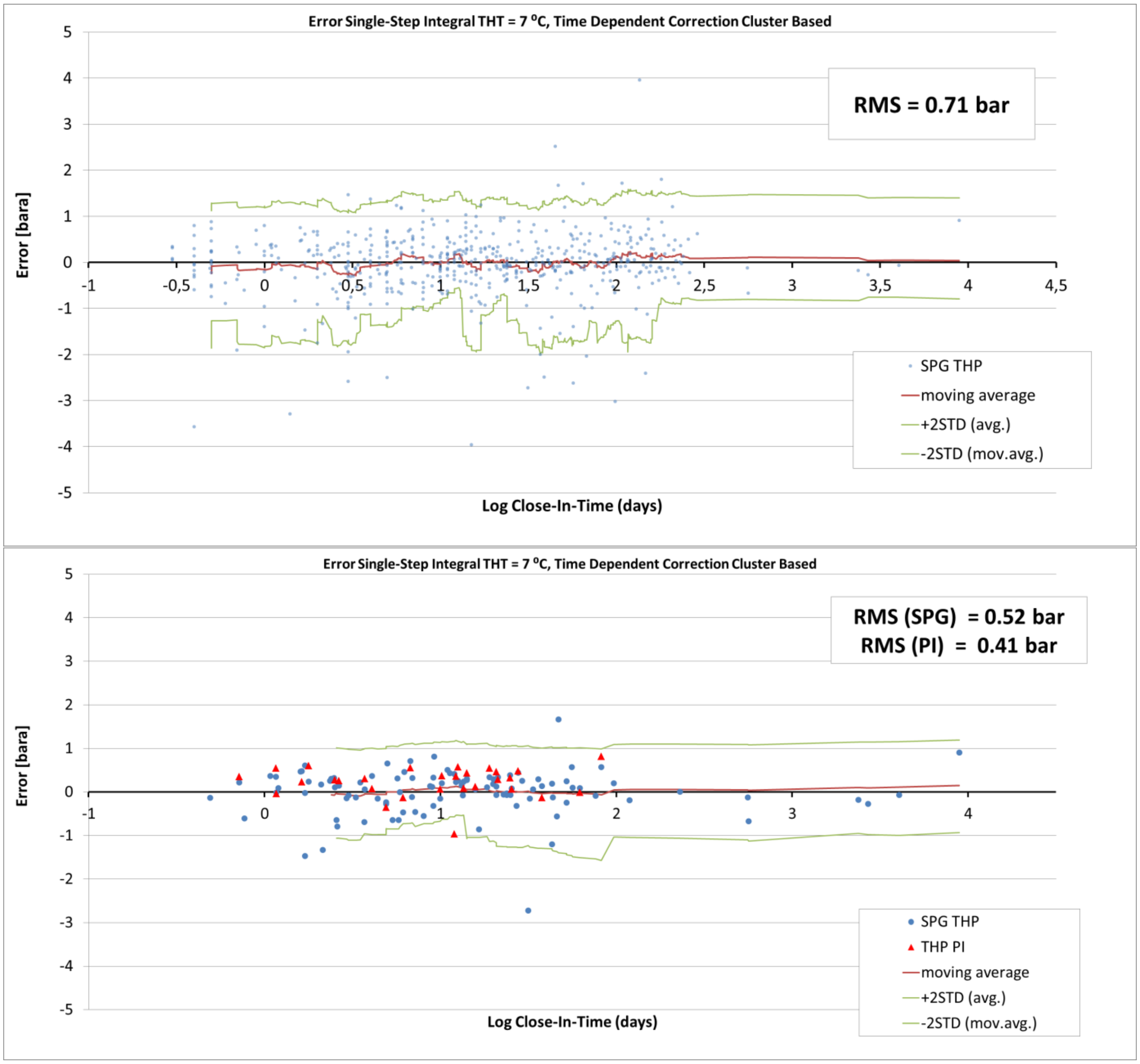


Figure 30: Error behavior of Cluster Based Time Corrected Single-Step integral conversion with THT = 7 degree C versus log (days shut-in time). Note that moving average and STD are only based on SPG data.

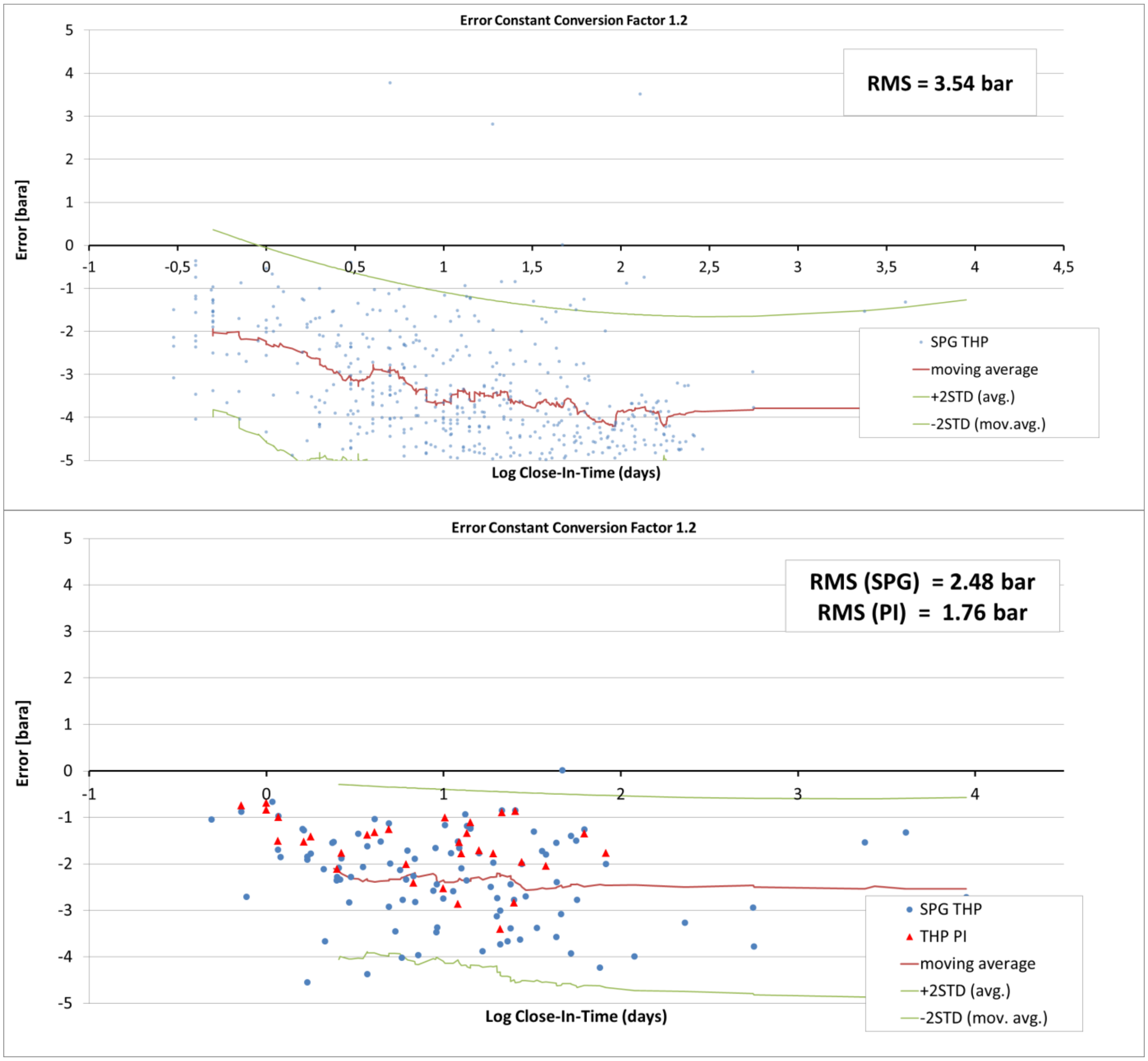
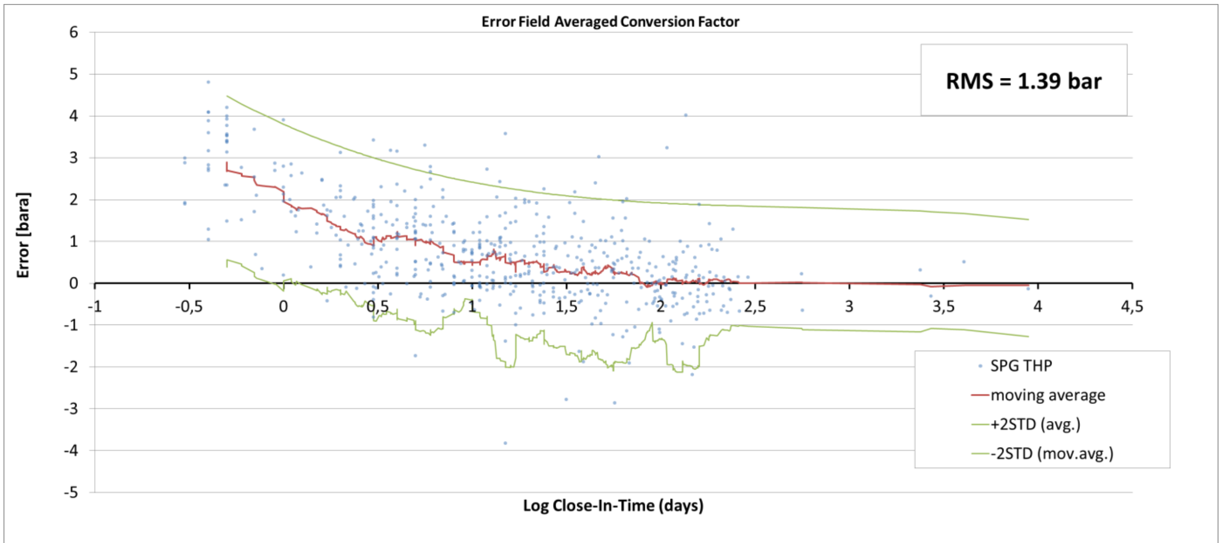


Figure 31: Error behavior of Constant Conversion Factor versus log (days shut-in time). Note that moving average and STD are only based on SPG data.



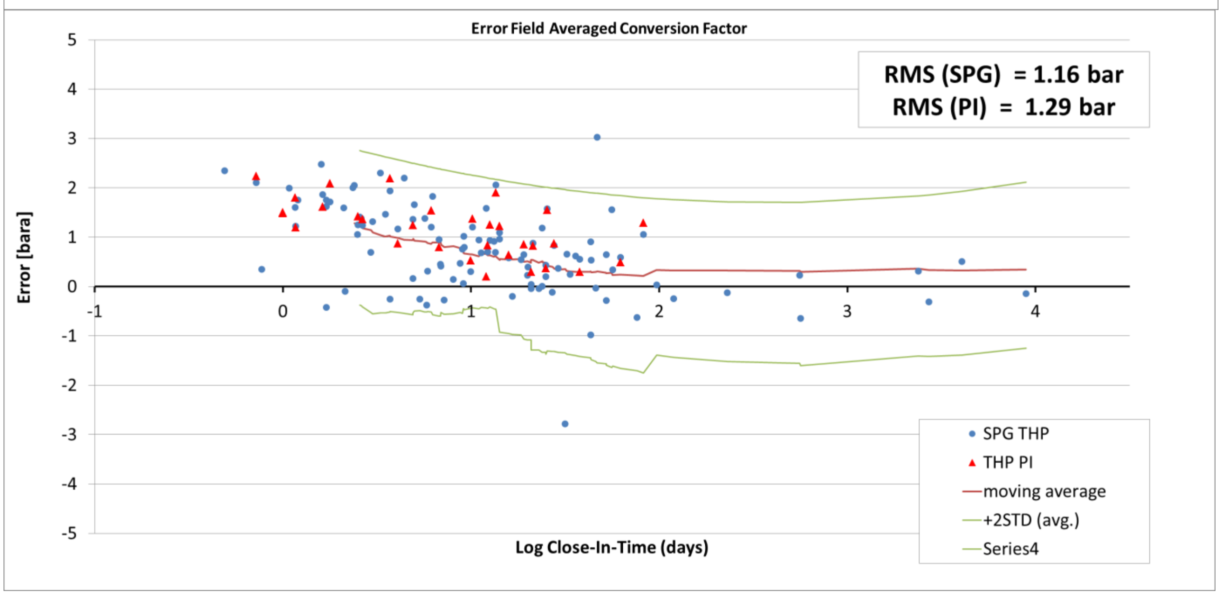


Figure 32: Error behavior of Average Conversion Factor from full field SPG data versus log (days shut-in time). Note that moving average and STD are only based on SPG data.

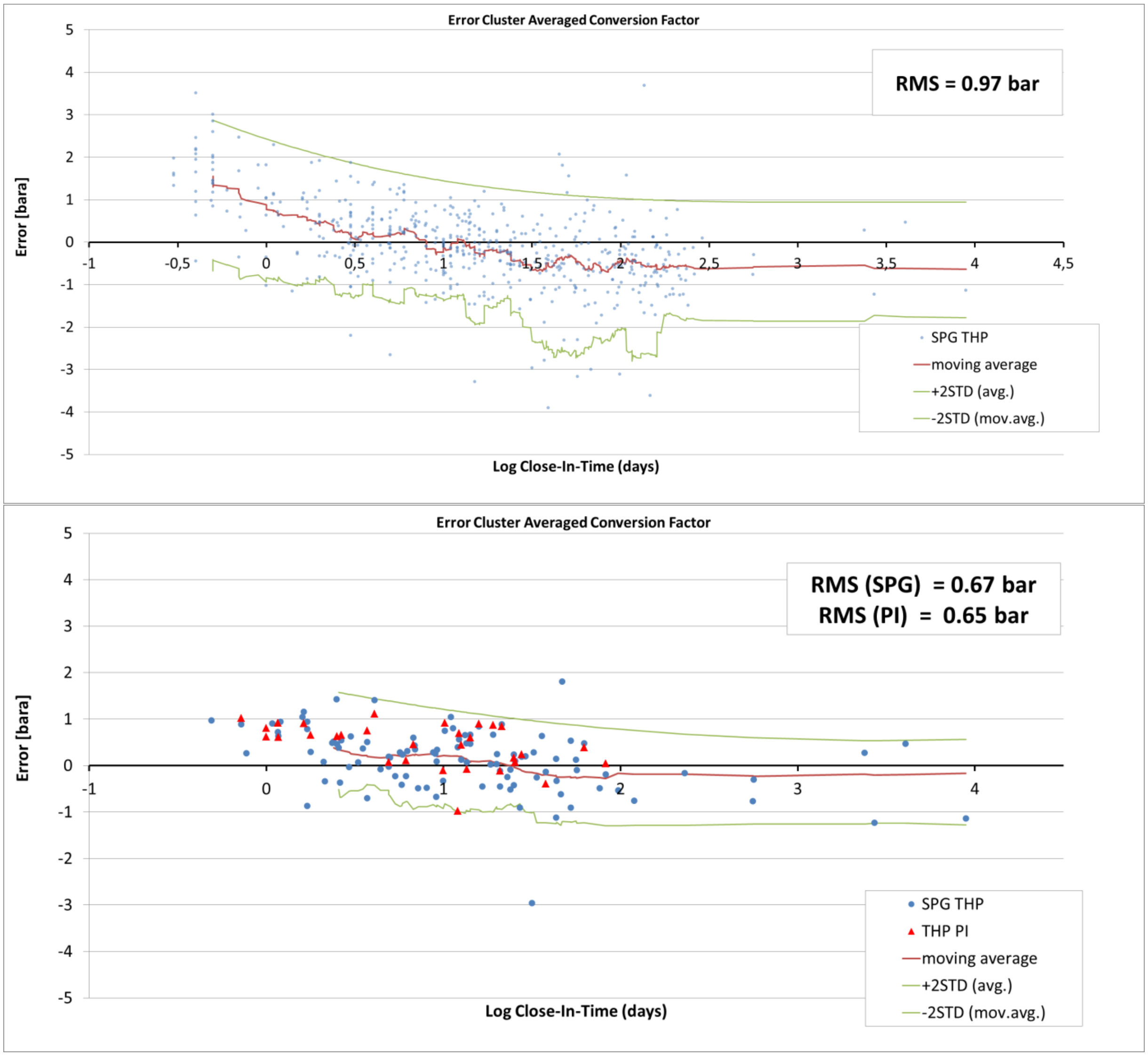


Figure 33: Error behavior of Average Conversion Factor from cluster SPG data versus log (days shut-in time). Note that moving average and STD are only based on SPG data.

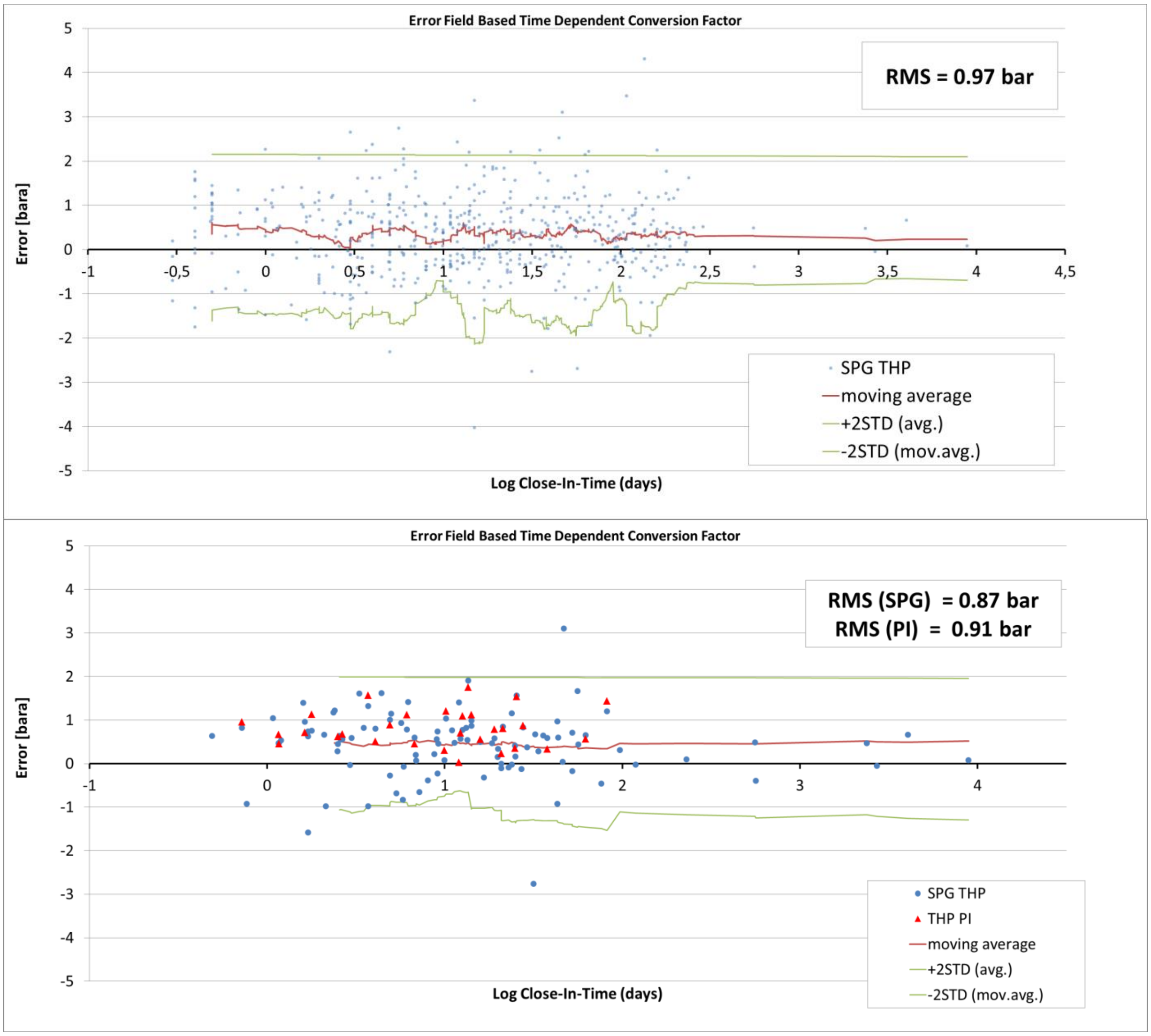


Figure 34: Error behavior of Field Based Time Dependent Conversion Factor versus log (days shut-in time). Note that moving average and STD are only based on SPG data.

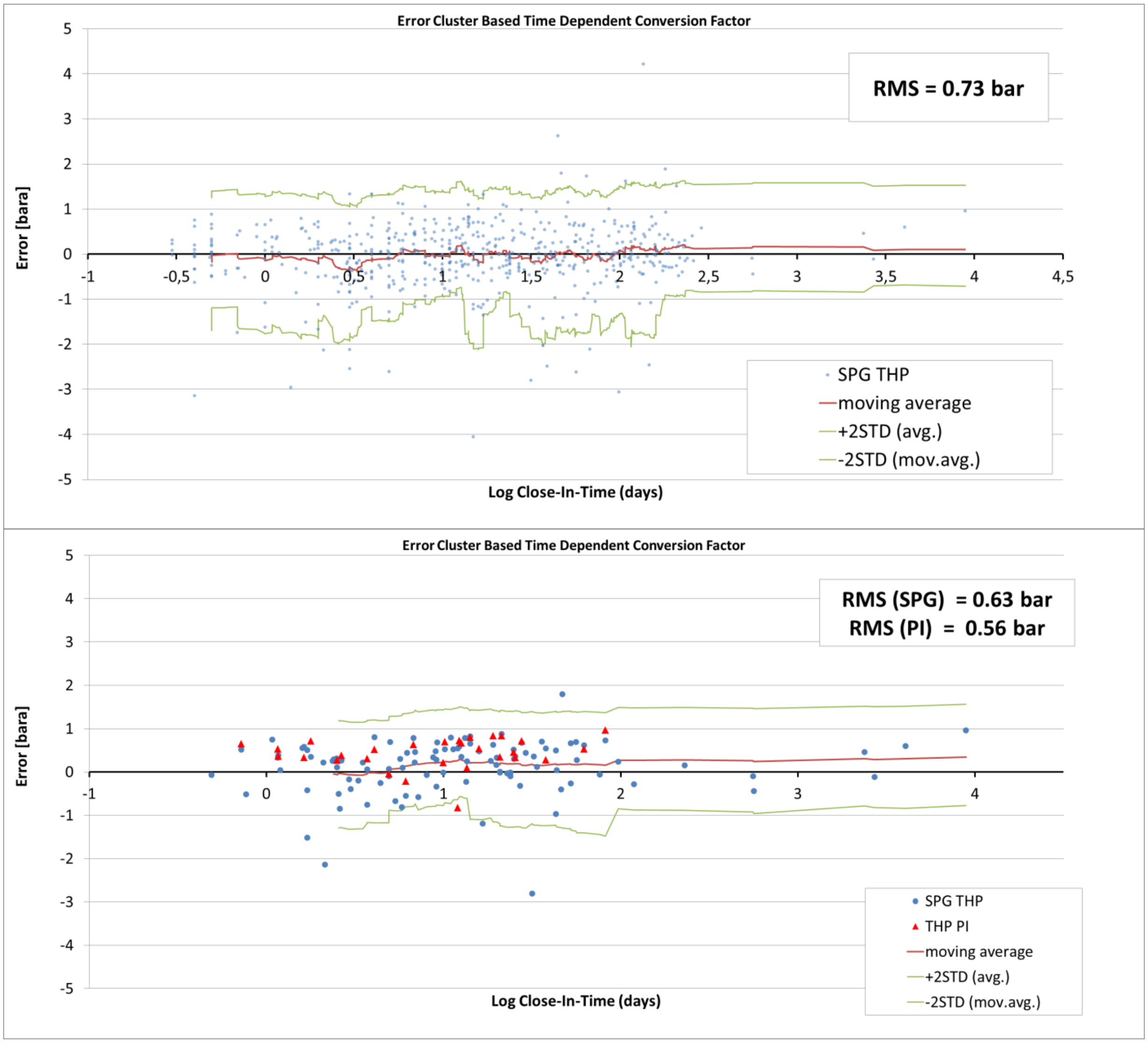


Figure 35: Error behavior of Cluster Based Time Dependent Conversion Factor versus log (days shut-in time).

9. Conclusions

- The CITHP to CIBHP conversion is strongly dependent on wellbore temperature. The average wellbore temperature changes significantly after shut-in of the well (up to some 25°C difference between a flowing well and the geothermal gradient for a long-term shut-in well). After 40+ days of shut-in the wellbore is still cooling down to the geothermal gradient.

- As there is no direct and continuous measurement of wellbore temperature available, well shut-in time can be used as a proxy for average wellbore temperature.

  The existing conversion methods do not take into account this temperature/time-dependent error (isothermal wellbore conditions were assumed).

- Two new time-dependent methods are developed in this study, both are more accurate than the existing methods and have an error independent of shut-in time of the well.:

Method	Dataset	RMS Error [bara]
Time dependent conversion factor (per cluster)	**All SPGs** **Post 2000 SPGs** **PI THP**	**0.73** **0.63** **0.56**
Time dependent Single-Step integral (per cluster)	**All SPGs** **Post 2000 SPGs** **PI THP**	**0.71** **0.52** **0.41**

- For quick use a field wide constant conversion factor of CIBHP = 1.2316 *CITHP can be used, yielding an RMS error of 1.39 bar (but increasing up to 3 or 4 bar for shut-in times < 10 days)

- The recommended conversion to use is the newly proposed time dependent conversion factor per cluster yielding an RMS error of 0.73 bar which is constant over time (cluster specific functions to be found in chapter 7.2.1 on page 35).

- A significant part of the conversion error is captured by the uncertainty in THP and BHP measured by the different gauges and by the dead-band used in EQ storage. The dead-banding can be refined to e.g. 0.01% in the future if necessary. The dead band time factor is probably not critical since pressure build up is relatively slowly. Also when generating CITHP from Wikker just when values are changed/captured, the CITHP values are most accurate and this can be easily implemented in the Wikker case.

Appendix 1 – Derivation of the single step integral

The downhole pressure conversion is based on gravitation:

$$\frac{dp}{dh} = \rho(p,T) \times g$$

where:

dp/dh	vertical pressure gradient
ρ	gas density
g	gravitational constant.

Combining the gas law ($p \times V = Z \times n \times R \times T$) and the gas density ($\rho = n \times M/V$), pressure can be described as:

$$p = \frac{\rho \times Z \times R \times T}{M}$$

Where:

R	gas constant
M	molecular mass
T	temperature, K.

Inserting the latter into the former gives:

$$\frac{dp}{p} = \frac{M \times g}{Z \times R \times T} dh$$

Assuming constant gas temperature and gas compressibility Z-factor in the well bore, the equation can be integrated to:

$$CIBHP = CITHP \times \exp\left(\frac{M \times g \times h}{Z \times R \times T}\right)$$

For ideal gases at constant pressure and temperature the molar volume is given by:

$$V_m = \frac{V}{n} = \frac{V}{m} \times M = \frac{M}{\rho}$$

Introducing the gas specific gravity:

$$SG_{gas} = \frac{M}{M_{air}}$$

In practice, a correction factor C = BHPmeas/BHPcalc, needs to be applied

$$CIBHP = C \times CITHP \times \exp\left(\frac{M_{air} \times \ SG_{gas} \times g \times h}{Z \times R \times T}\right)$$

Constants used:

M_{air} = 0.028966 kg/mol

Source: http://www.engineeringtoolbox.com/molecular-mass-air-d_679.html

R = 8.3144621 J/(mol K)

Source: Mohr, Peter J.; Taylor, Barry N.; Newell, David B. (2008). "CODATA Recommended Values of the Fundamental Physical Constants: 2006". Rev. Mod. Phys. 80: 633–730.

g = 9.81 m/s^2

Source: The international system of units (SI) – United States Department of Commerce, NIST Special Publication 330, 2008, p. 57

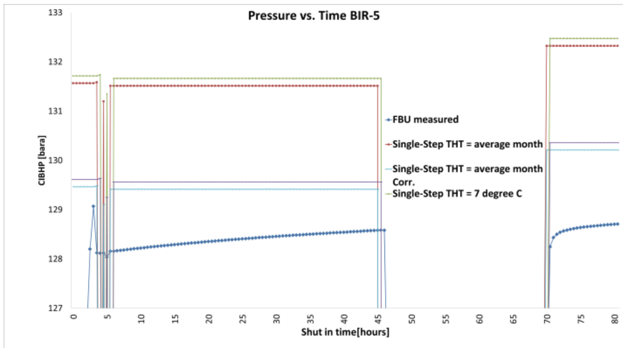
SG_{gas} = 0.64

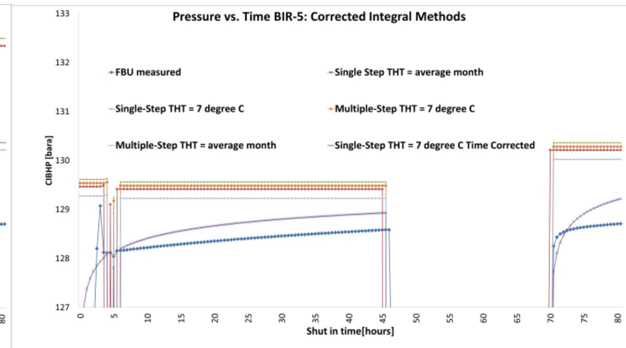
Assumption isothermal and constant Z factor.

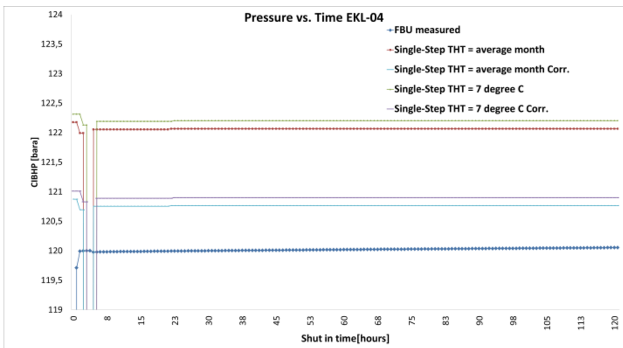
The average temperature can thus be determined as the average of reservoir and tubing head temperature. The THT in static conditions is approximately 7° C. Used by Production Technologists. The average pressure can be determined from CITHP and the PVT model density at that pressure to half the wellbore's length. With this average pressure the Z factor can be calculated.

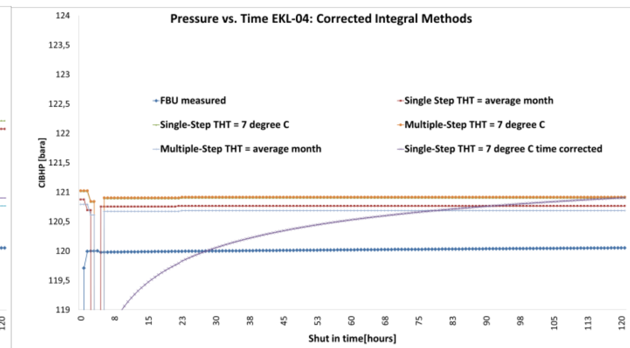
Appendix 2 –THP-BHP conversions compared to FBU

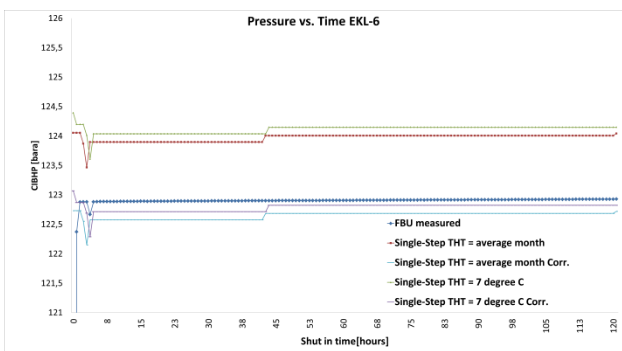
THP and BHP increasing

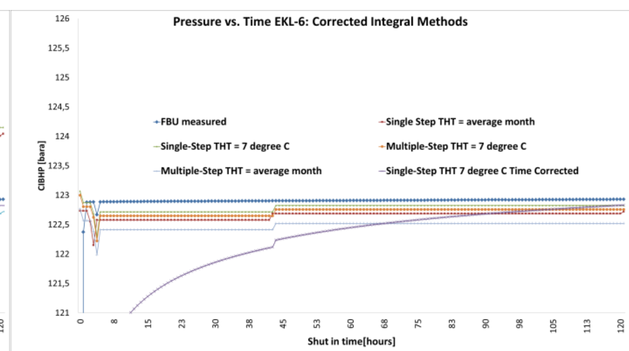


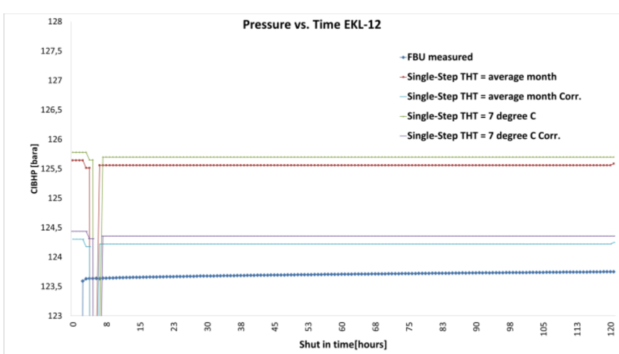


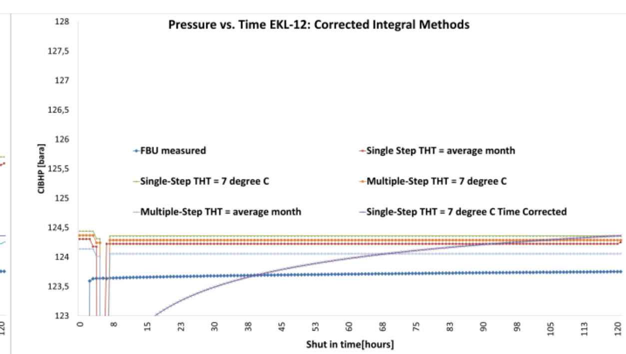


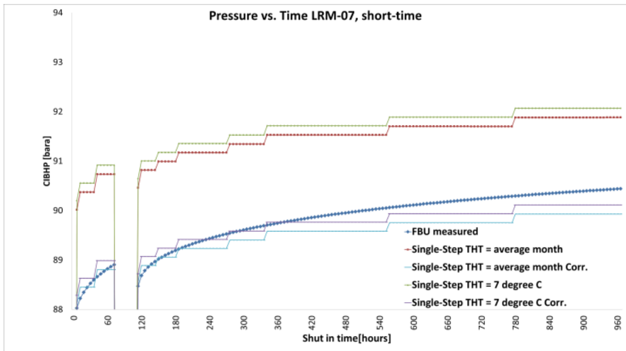


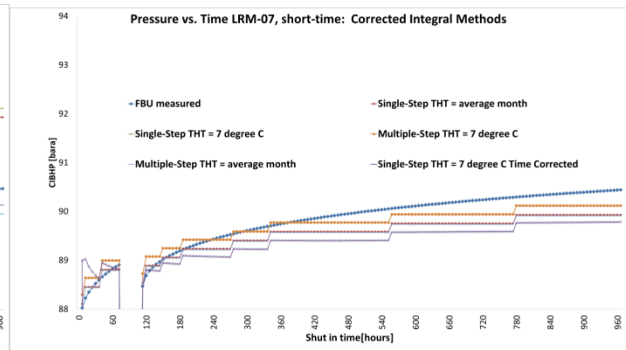


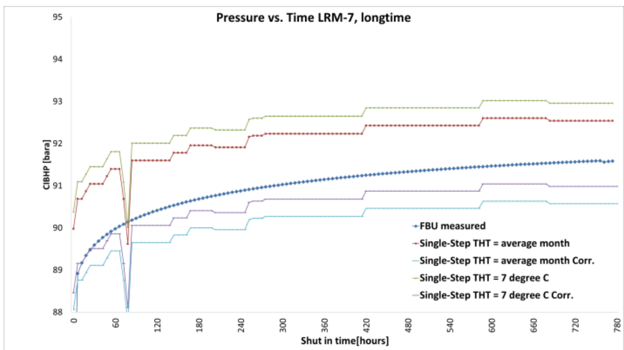


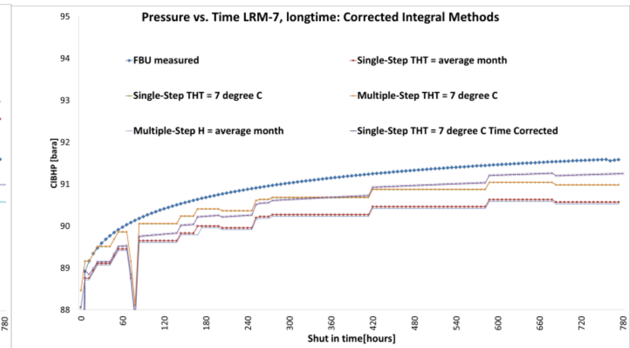


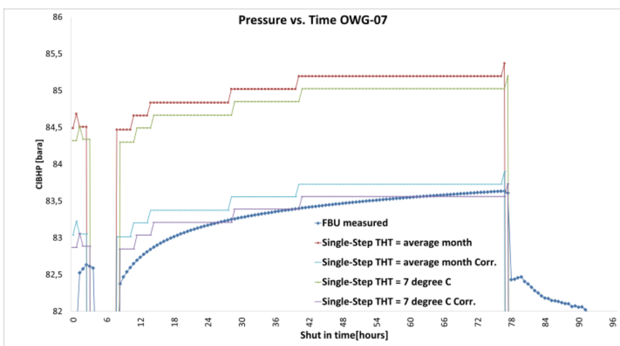


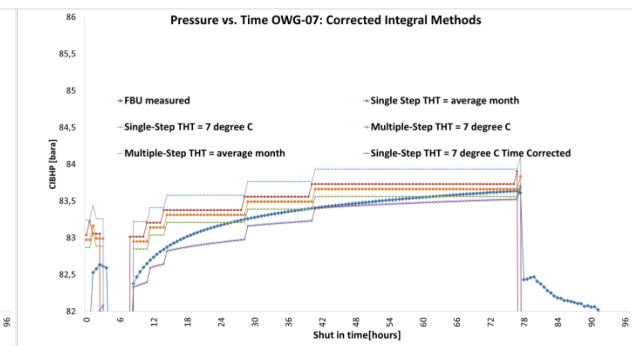

Pressure vs. Time LRM-07, short-time
CIBHP [bara]
Shut in time[hours]
FBU measured
Single-Step THT = average month
Single-Step THT = average month Corr.
Single-Step THT = 7 degree C
Single-Step THT = 7 degree C Corr.

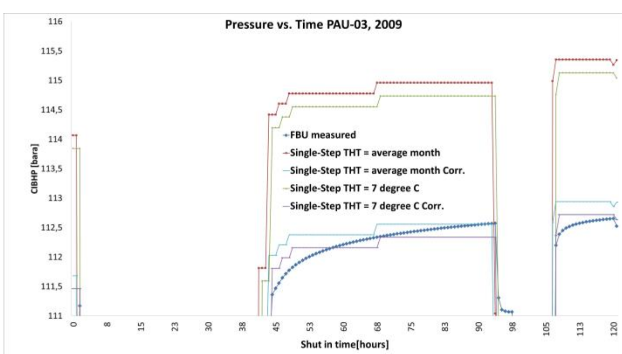

Pressure vs. Time LRM-07, short-time: Corrected Integral Methods
CIBHP [bara]
Shut in time[hours]
FBU measured
Single-Step THT = average month
Single-Step THT = 7 degree C
Multiple-Step THT = 7 degree C
Multiple-Step THT = average month
Single-Step THT = 7 degree C Time Corrected

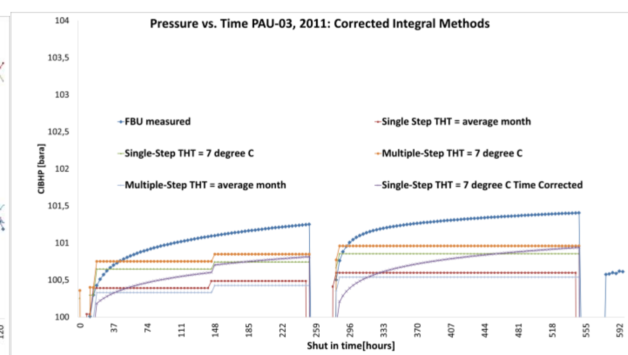

Pressure vs. Time LRM-7, longtime
CIBHP [bara]
Shut in time[hours]
FBU measured
Single-Step THT = average month
Single-Step THT = average month Corr.
Single-Step THT = 7 degree C
Single-Step THT = 7 degree C Corr.

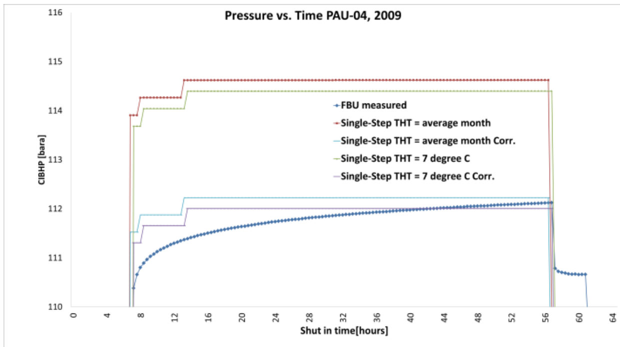

Pressure vs. Time LRM-7, longtime: Corrected Integral Methods
CIBHP [bara]
Shut in time[hours]
FBU measured
Single-Step THT = average month
Single-Step THT = 7 degree C
Multiple-Step THT = 7 degree C
Multiple-Step H = average month
Single-Step THT = 7 degree C Time Corrected

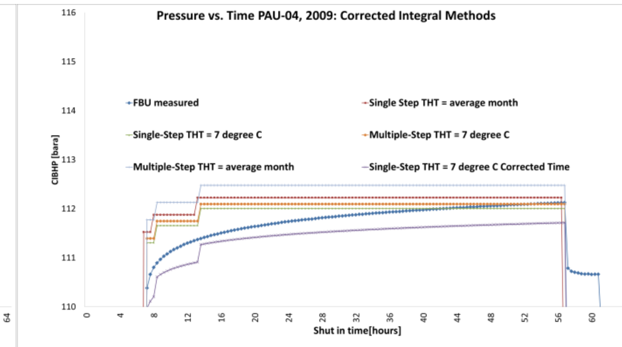

Pressure vs. Time OWG-07
CIBHP [bara]
Shut in time[hours]
FBU measured
Single-Step THT = average month
Single-Step THT = average month Corr.
Single-Step THT = 7 degree C
Single-Step THT = 7 degree C Corr.

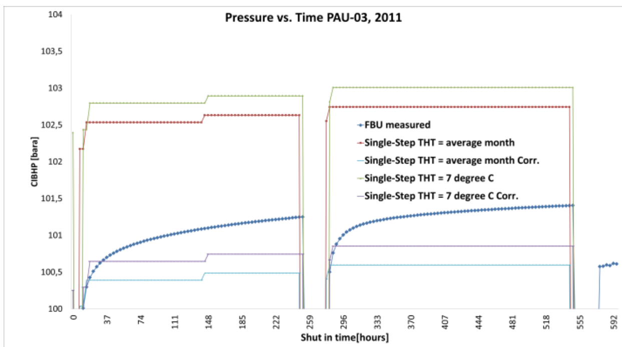

Pressure vs. Time OWG-07: Corrected Integral Methods
CIBHP [bara]
Shut in time[hours]
FBU measured
Single Step THT = average month
Single-Step THT = 7 degree C
Multiple-Step THT = 7 degree C
Multiple-Step THT = average month
Single-Step THT = 7 degree C Time Corrected

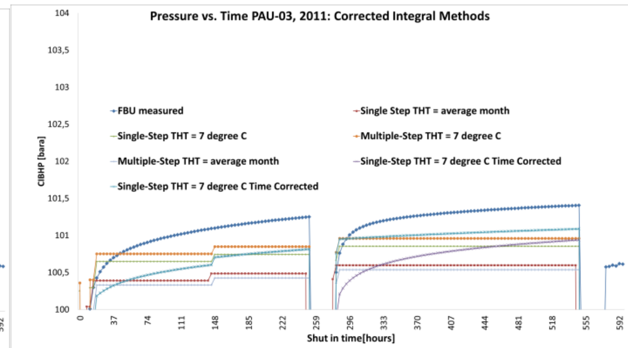

Pressure vs. Time PAU-03, 2009
CIBHP [bara]
Shut in time[hours]
FBU measured
Single-Step THT = average month
Single-Step THT = average month Corr.
Single-Step THT = 7 degree C
Single-Step THT = 7 degree C Corr.

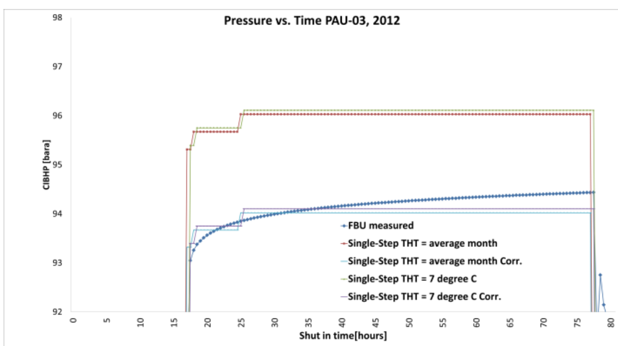

Pressure vs. Time PAU-03, 2011: Corrected Integral Methods
CIBHP [bara]
Shut in time[hours]
FBU measured
Single Step THT = average month
Single-Step THT = 7 degree C
Multiple-Step THT = 7 degree C
Multiple-Step THT = average month
Single-Step THT = 7 degree C Time Corrected

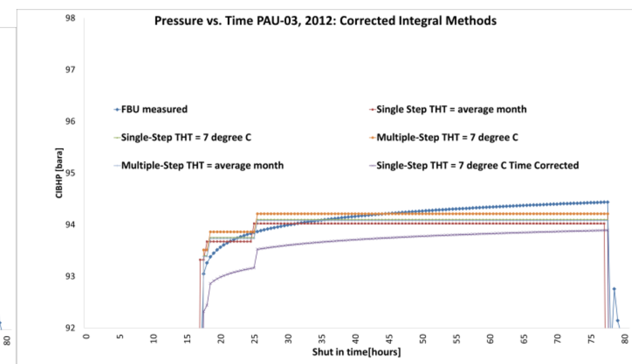

Pressure vs. Time PAU-04, 2009
FBU measured
Single-Step THT = average month
Single-Step THT = average month Corr.
Single-Step THT = 7 degree C
Single-Step THT = 7 degree C Corr.
Shut in time[hours]

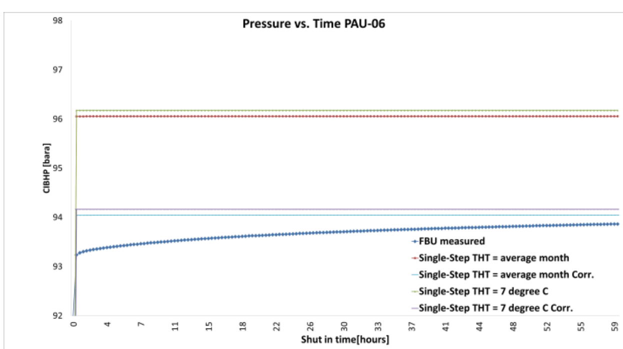

Pressure vs. Time PAU-04, 2009: Corrected Integral Methods
FBU measured
Single Step THT = average month
Single-Step THT = 7 degree C
Multiple-Step THT = 7 degree C
Multiple-Step THT = average month
Single-Step THT = 7 degree C Corrected Time
Shut in time[hours]

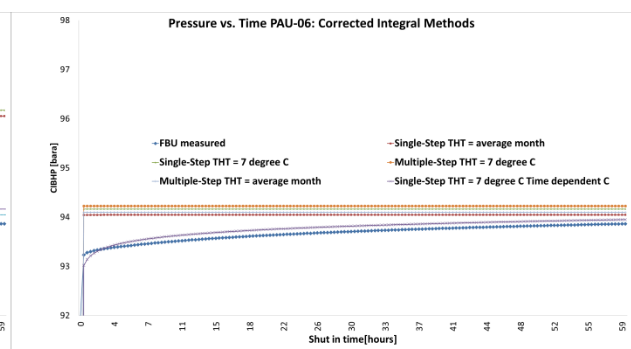

Pressure vs. Time PAU-03, 2011
FBU measured
Single-Step THT = average month
Single-Step THT = average month Corr.
Single-Step THT = 7 degree C
Single-Step THT = 7 degree C Corr.
Shut in time[hours]

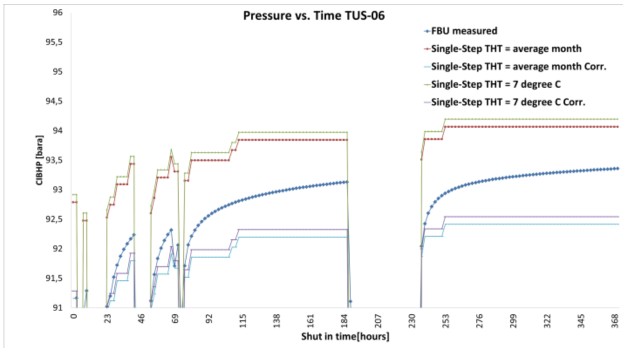

Pressure vs. Time PAU-03, 2011: Corrected Integral Methods
FBU measured
Single Step THT = average month
Single-Step THT = 7 degree C
Multiple-Step THT = 7 degree C
Multiple-Step THT = average month
Single-Step THT = 7 degree C Time Corrected
Single-Step THT = 7 degree C Time Corrected
Shut in time[hours]

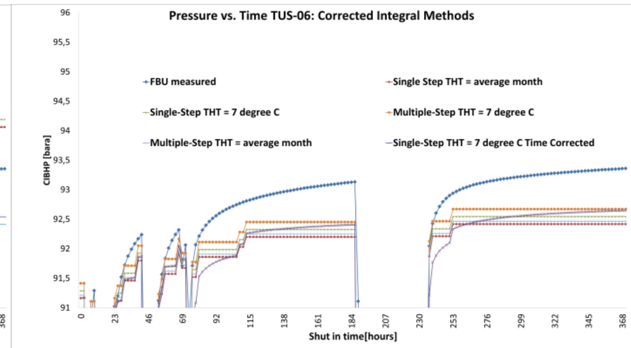

Pressure vs. Time PAU-03, 2012
FBU measured
Single-Step THT = average month
Single-Step THT = average month Corr.
Single-Step THT = 7 degree C
Single-Step THT = 7 degree C Corr.
Shut in time[hours]

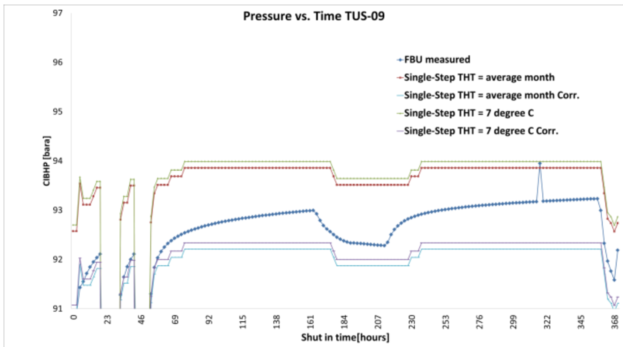

Pressure vs. Time PAU-03, 2012: Corrected Integral Methods
FBU measured
Single Step THT = average month
Single-Step THT = 7 degree C
Multiple-Step THT = 7 degree C
Multiple-Step THT = average month
Single-Step THT = 7 degree C Time Corrected
Shut in time[hours]

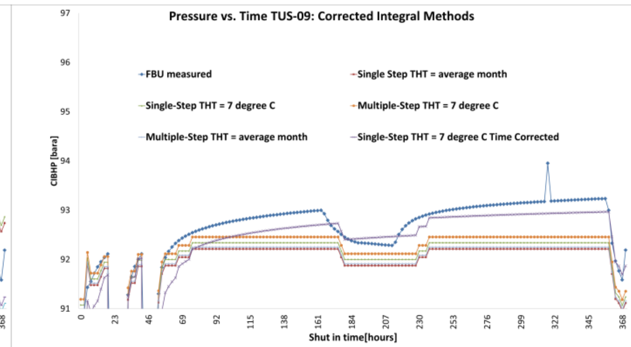

Pressure vs. Time PAU-06
FBU measured
Single-Step THT = average month
Single-Step THT = average month Corr.
Single-Step THT = 7 degree C
Single-Step THT = 7 degree C Corr.
Shut in time[hours]

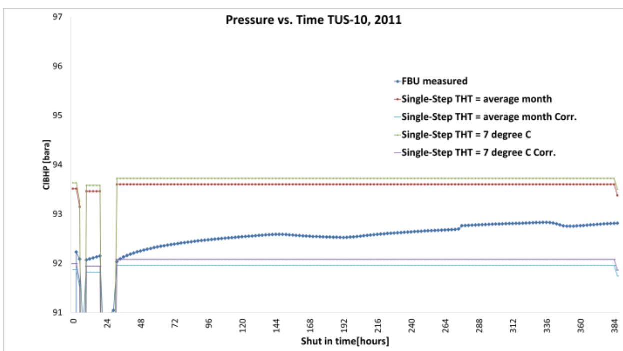

Pressure vs. Time PAU-06: Corrected Integral Methods
FBU measured
Single-Step THT = average month
Single-Step THT = 7 degree C
Multiple-Step THT = 7 degree C
Multiple-Step THT = average month
Single-Step THT = 7 degree C Time dependent C
Shut in time[hours]

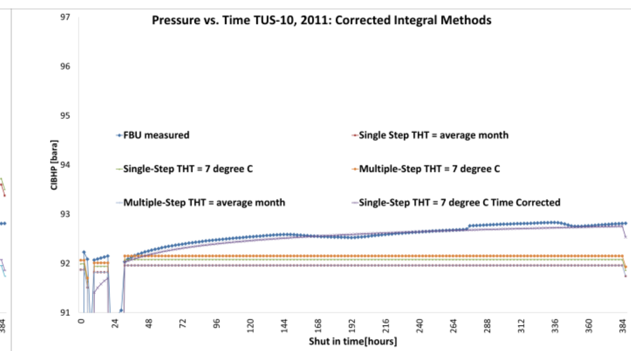

Pressure vs. Time TUS-06
FBU measured
Single-Step THT = average month
Single-Step THT = average month Corr.
Single-Step THT = 7 degree C
Single-Step THT = 7 degree C Corr.
CIBHP [bara]
Shut in time[hours]

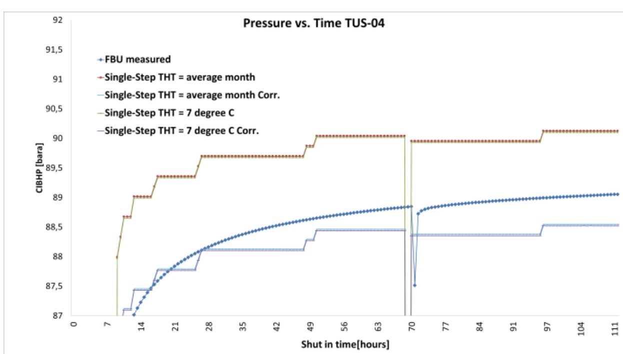

Pressure vs. Time TUS-06: Corrected Integral Methods
FBU measured
Single Step THT = average month
Single-Step THT = 7 degree C
Multiple-Step THT = 7 degree C
Multiple-Step THT = average month
Single-Step THT = 7 degree C Time Corrected
CIBHP [bara]
Shut in time[hours]

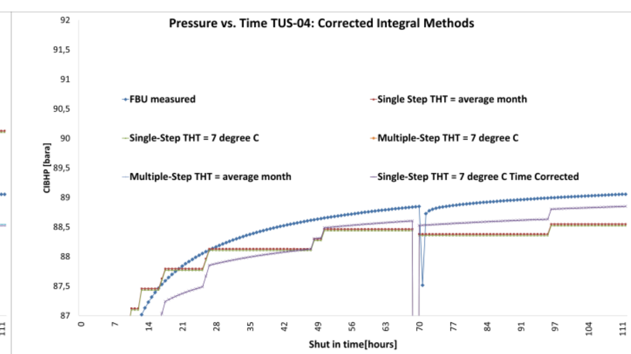

Pressure vs. Time TUS-09
FBU measured
Single-Step THT = average month
Single-Step THT = average month Corr.
Single-Step THT = 7 degree C
Single-Step THT = 7 degree C Corr.
CIBHP [bara]
Shut in time[hours]

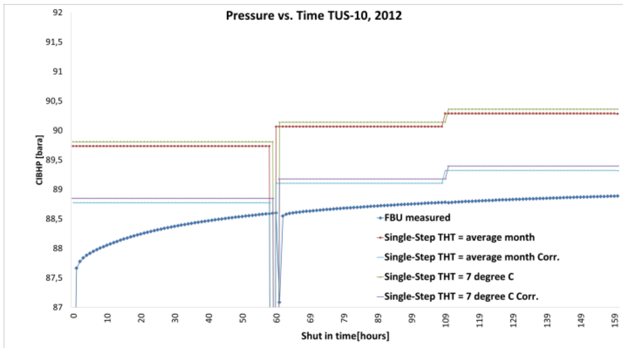

Pressure vs. Time TUS-09: Corrected Integral Methods
FBU measured
Single Step THT = average month
Single-Step THT = 7 degree C
Multiple-Step THT = 7 degree C
Multiple-Step THT = average month
Single-Step THT = 7 degree C Time Corrected
CIBHP [bara]
Shut in time[hours]

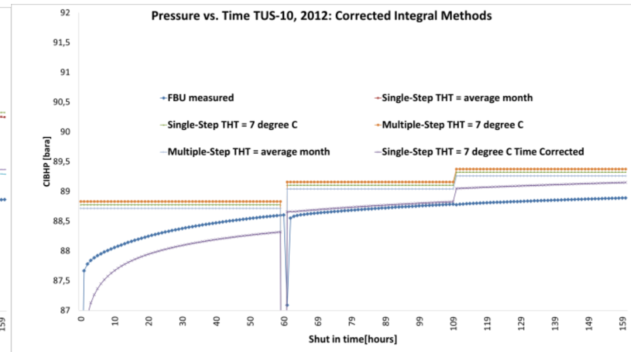

Pressure vs. Time TUS-10, 2011
FBU measured
Single-Step THT = average month
Single-Step THT = average month Corr.
Single-Step THT = 7 degree C
Single-Step THT = 7 degree C Corr.
CIBHP [bara]
Shut in time[hours]

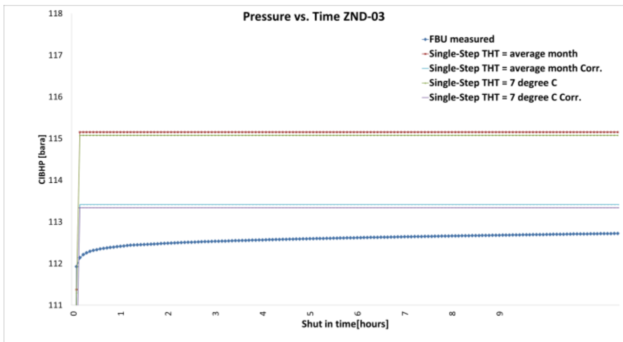

Pressure vs. Time TUS-10, 2011: Corrected Integral Methods
FBU measured
Single Step THT = average month
Single-Step THT = 7 degree C
Multiple-Step THT = 7 degree C
Multiple-Step THT = average month
Single-Step THT = 7 degree C Time Corrected
CIBHP [bara]
Shut in time[hours]

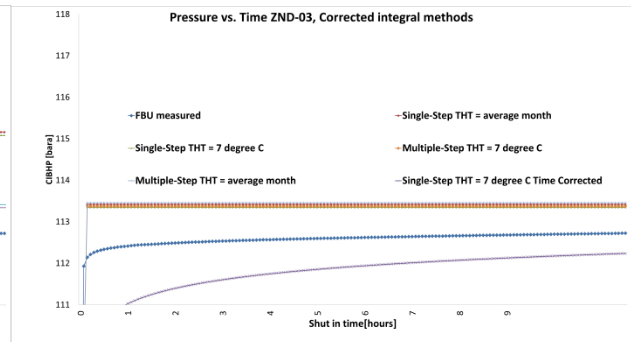

Pressure vs. Time TUS-04
FBU measured
Single-Step THT = average month
Single-Step THT = average month Corr.
Single-Step THT = 7 degree C
Single-Step THT = 7 degree C Corr.
CIBHP [bara]
Shut in time[hours]


Pressure vs. Time TUS-04: Corrected Integral Methods
FBU measured
Single Step THT = average month
Single-Step THT = 7 degree C
Multiple-Step THT = 7 degree C
Multiple-Step THT = average month
Single-Step THT = 7 degree C Time Corrected
CIBHP [bara]
Shut in time[hours]

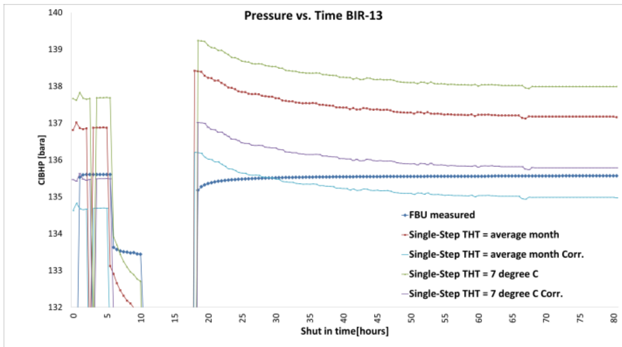

Pressure vs. Time TUS-10, 2012
CIBHP [bara]
Shut in time[hours]
FBU measured
Single-Step THT = average month
Single-Step THT = average month Corr.
Single-Step THT = 7 degree C
Single-Step THT = 7 degree C Corr.

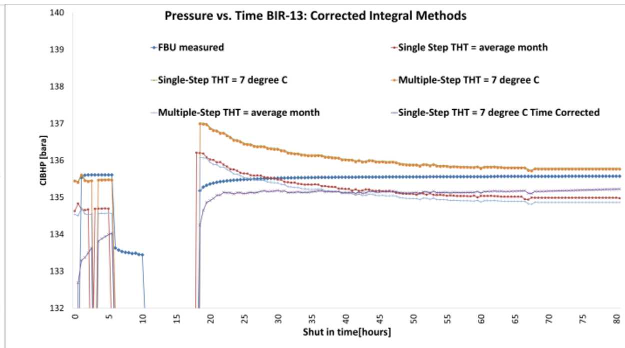

Pressure vs. Time TUS-10, 2012: Corrected Integral Methods
CIBHP [bara]
Shut in time[hours]
FBU measured
Single-Step THT = average month
Single-Step THT = 7 degree C
Multiple-Step THT = 7 degree C
Multiple-Step THT = average month
Single-Step THT = 7 degree C Time Corrected

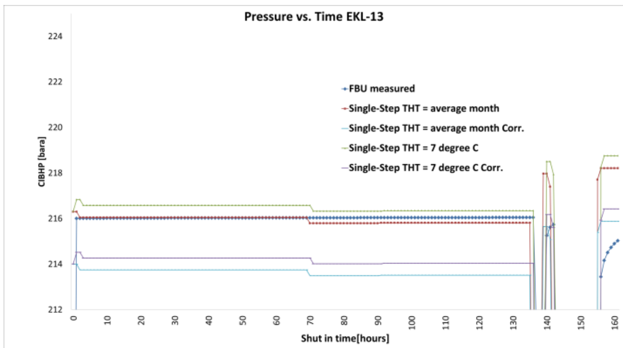

Pressure vs. Time ZND-03
CIBHP [bara]
Shut in time[hours]
FBU measured
Single-Step THT = average month
Single-Step THT = average month Corr.
Single-Step THT = 7 degree C
Single-Step THT = 7 degree C Corr.

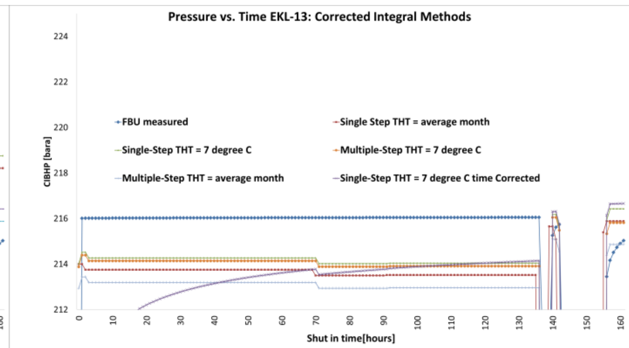

Pressure vs. Time ZND-03, Corrected integral methods
CIBHP [bara]
Shut in time[hours]
FBU measured
Single-Step THT = average month
Single-Step THT = 7 degree C
Multiple-Step THT = 7 degree C
Multiple-Step THT = average month
Single-Step THT = 7 degree C Time Corrected

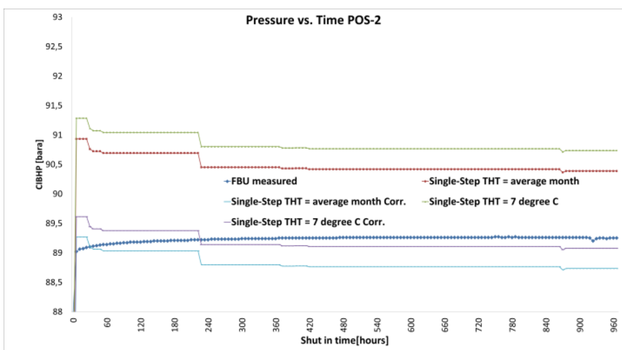
THP decreasing and BHP increasing

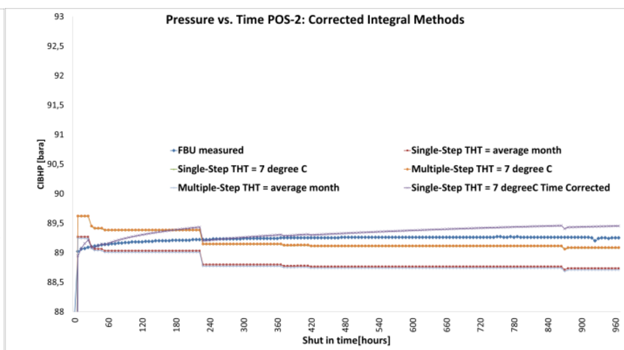


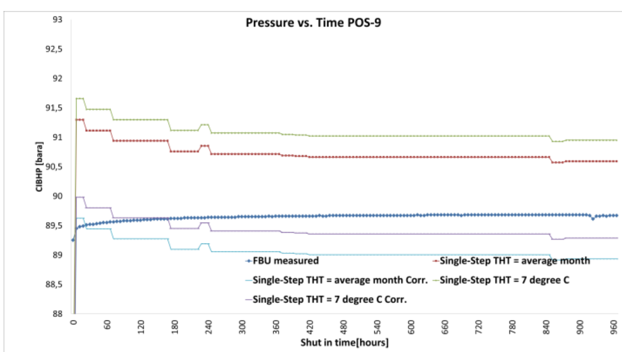


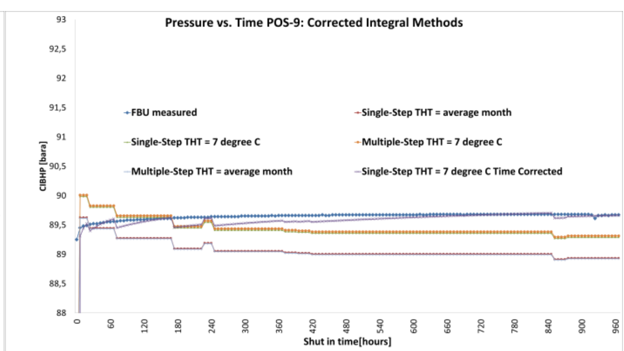


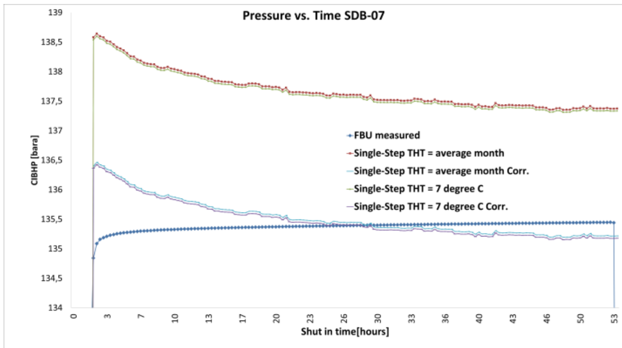


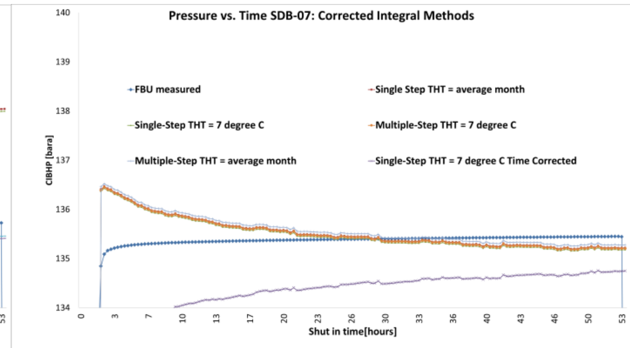


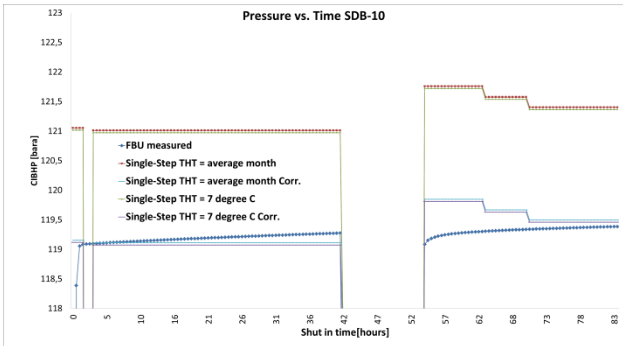


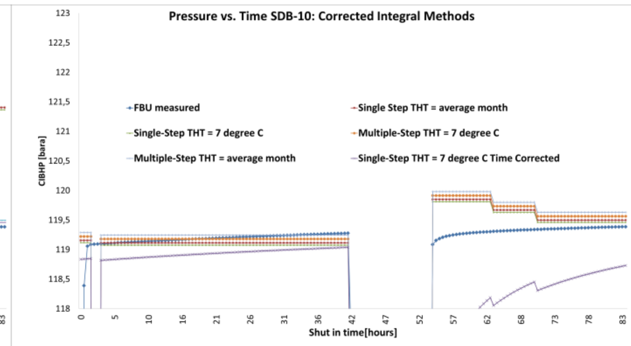





Pressure vs. Time SDB-07
ClBHP [bara]
Shut in time[hours]
FBU measured
Single-Step THT = average month
Single-Step THT = average month Corr.
Single-Step THT = 7 degree C
Single-Step THT = 7 degree C Corr.


Pressure vs. Time SDB-07: Corrected Integral Methods
ClBHP [bara]
Shut in time[hours]
FBU measured
Single Step THT = average month
Single-Step THT = 7 degree C
Multiple-Step THT = 7 degree C
Multiple-Step THT = average month
Single-Step THT = 7 degree C Time Corrected


Pressure vs. Time SDB-10
ClBHP [bara]
Shut in time[hours]
FBU measured
Single-Step THT = average month
Single-Step THT = average month Corr.
Single-Step THT = 7 degree C
Single-Step THT = 7 degree C Corr.


Pressure vs. Time SDB-10: Corrected Integral Methods
ClBHP [bara]
Shut in time[hours]
FBU measured
Single Step THT = average month
Single-Step THT = 7 degree C
Multiple-Step THT = 7 degree C
Multiple-Step THT = average month
Single-Step THT = 7 degree C Time Corrected

Appendix 3: Dead Weight Test

A dead weight tester utilizes an accurately calibrated piston and a weight that is set to balance the pressure at the face of the piston (Figure 36). The pressure at the piston face is equal to the weight of the mass on the piston divided by the area of the piston. To ensure that the piston is not affected by sticking or mechanical holdup within the surrounding cylinder, the weight and piston assembly is spun while the reading is made. A reference mark on the stem of the piston must be aligned with the reference point on the body of the dead weight tester to assure that the pressure indication is accurate.

A dead weight tester measures gauge pressure, and may be used as a calibration standard for other pressure gauges. Tests required by regulatory agencies often specify that a dead weight tester must be used to measure pressure. (As described on www.ipims.com)

The standard accuracy of a DWT apparatus is around 0.015% of full scale pressure of the apparatus (according to http://us.flukecal.com/literature/articles-and-education/pressure-calibration/papers-articles/deadweight-tester-selection-g)

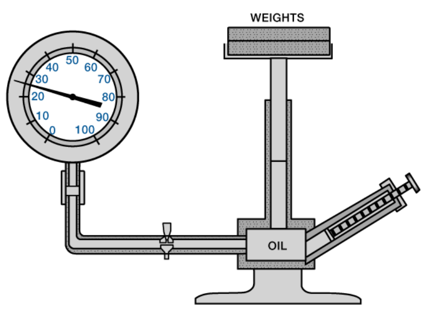
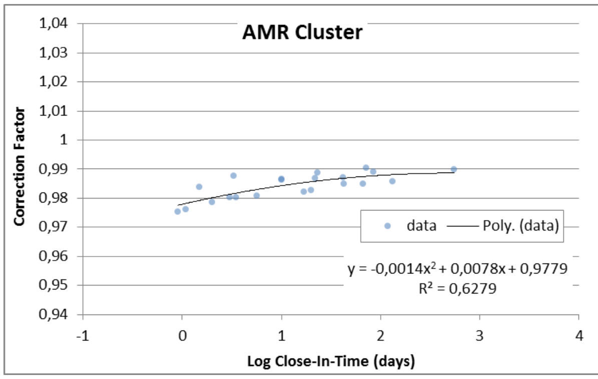
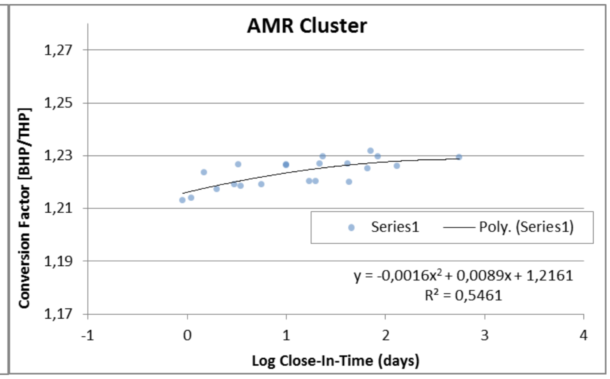
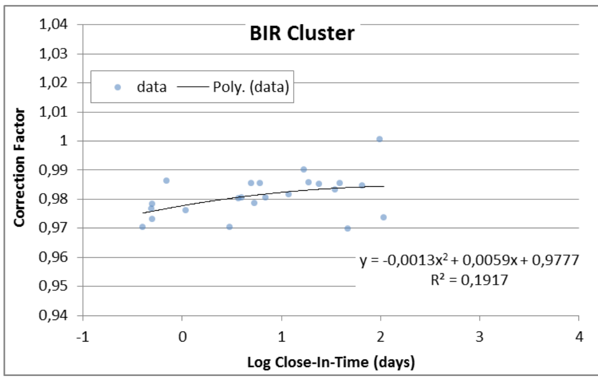


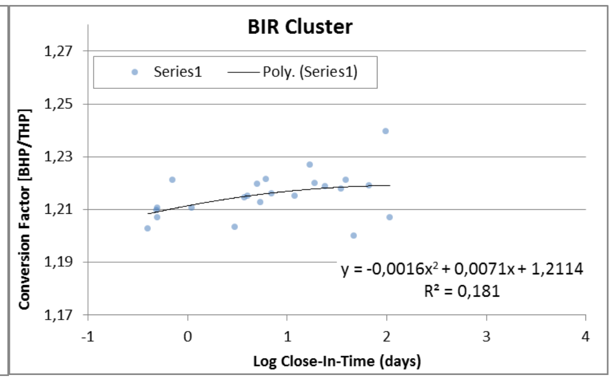
Figure 36: Dead Weight Tester

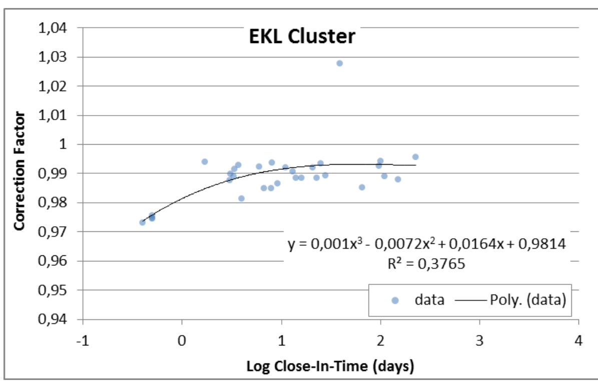
Appendix 4 – Cluster matched time dependent functions

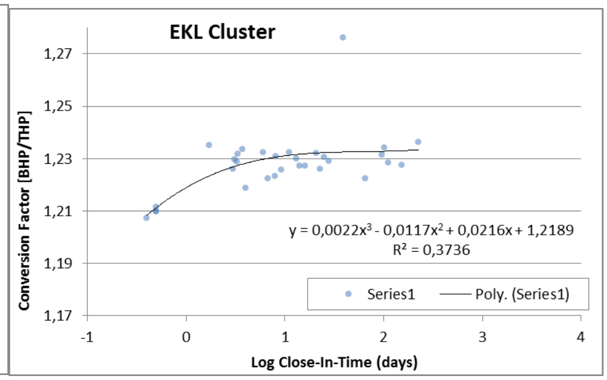


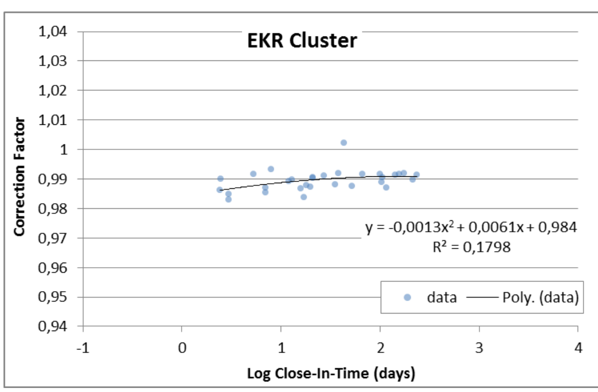


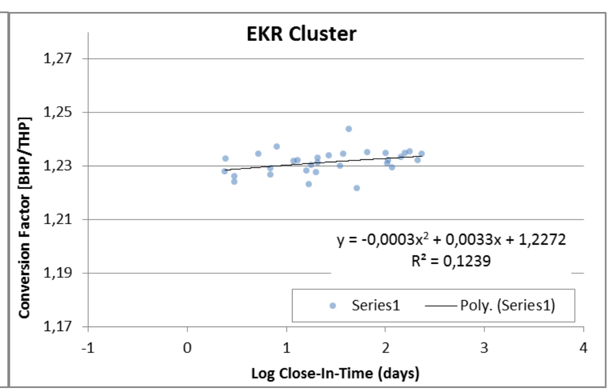


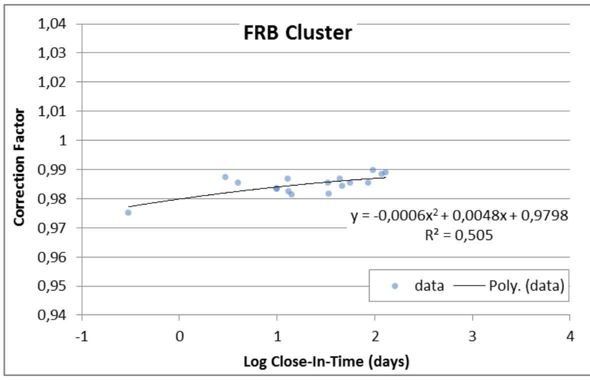


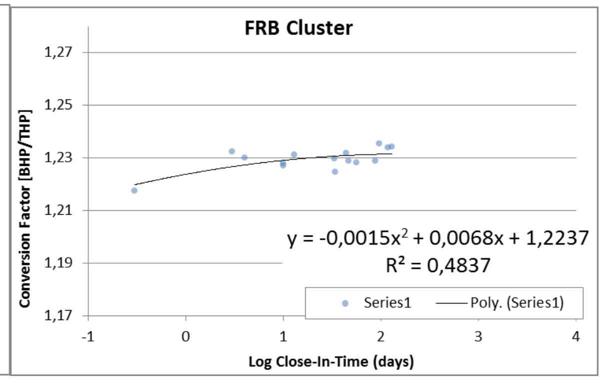


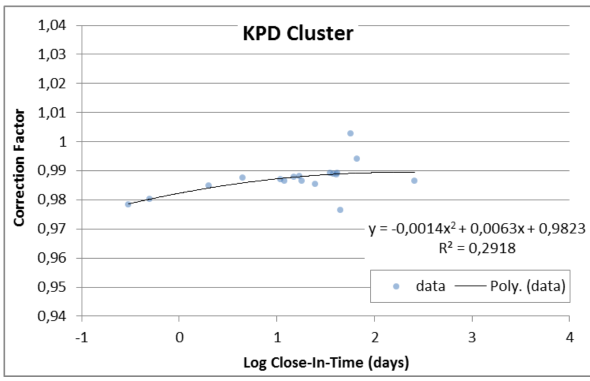


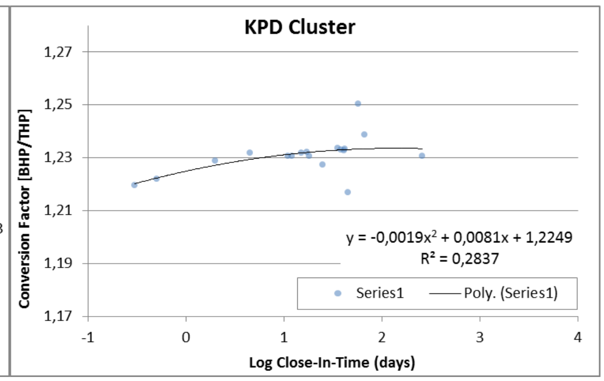


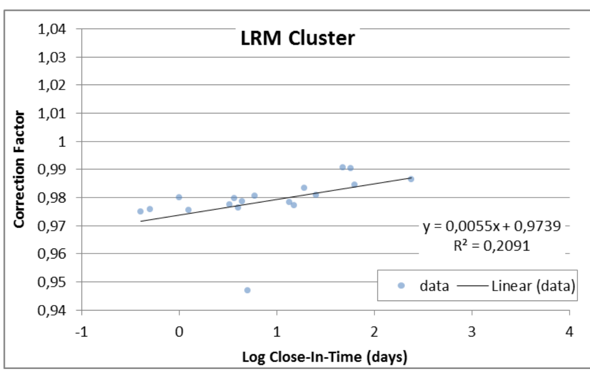


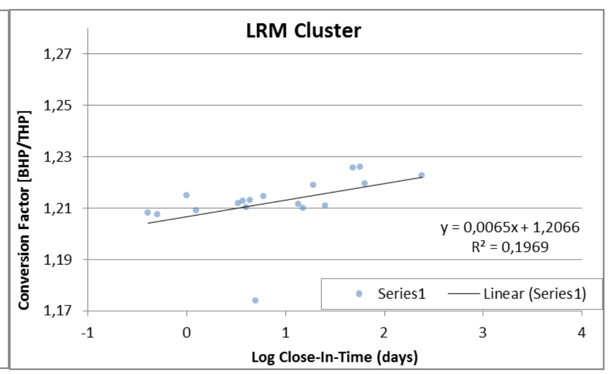

FRB Cluster
Correction Factor
Log Close-In-Time (days)
y = -0,0006x² + 0,0048x + 0,9798
R² = 0,505
data
Poly. (data)

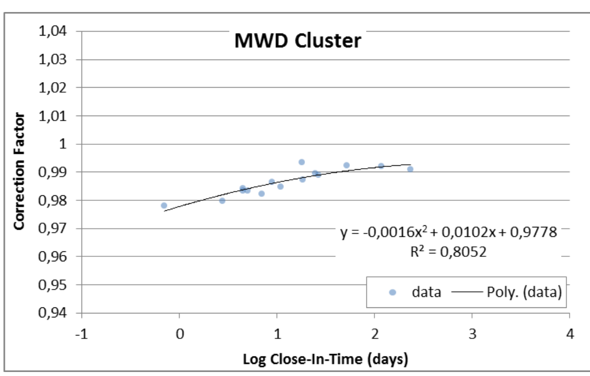

FRB Cluster
Conversion Factor [BHP/THP]
Log Close-In-Time (days)
y = -0,0015x² + 0,0068x + 1,2237
R² = 0,4837
Series1
Poly. (Series1)

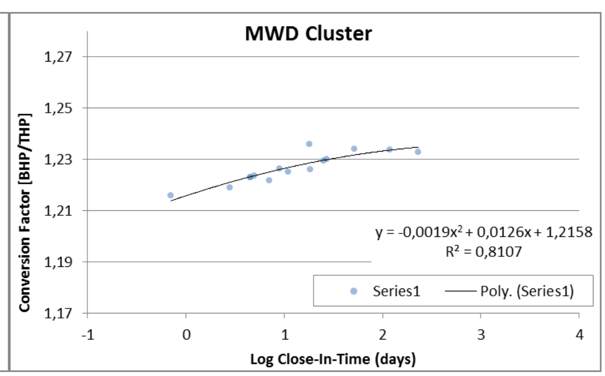

KPD Cluster
Correction Factor
Log Close-In-Time (days)
y = -0,0014x² + 0,0063x + 0,9823
R² = 0,2918
data
Poly. (data)

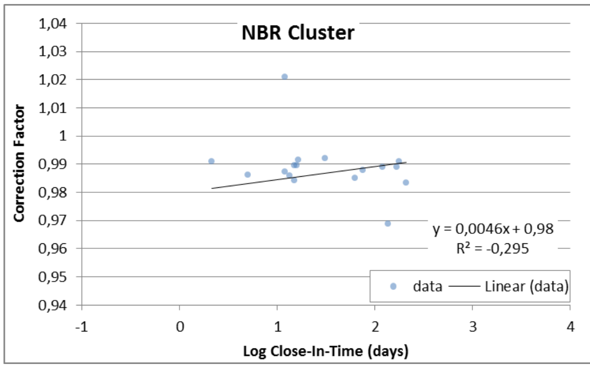

KPD Cluster
Conversion Factor [BHP/THP]
Log Close-In-Time (days)
y = -0,0019x² + 0,0081x + 1,2249
R² = 0,2837
Series1
Poly. (Series1)

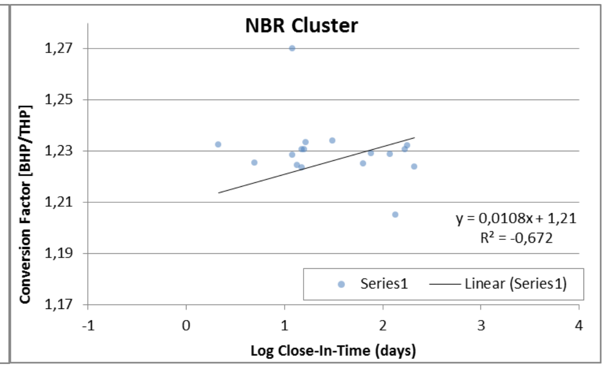

LRM Cluster
Correction Factor
Log Close-In-Time (days)
y = 0,0055x + 0,9739
R² = 0,2091
data
Linear (data)

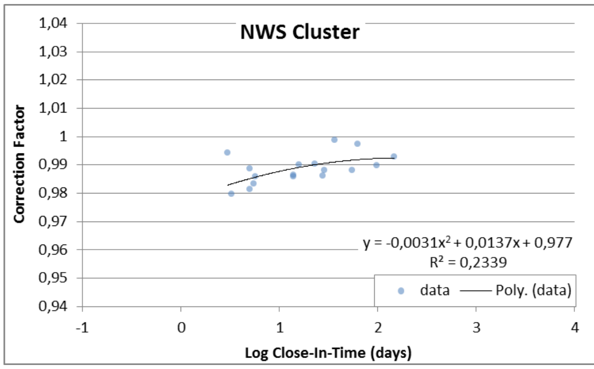

LRM Cluster
Conversion Factor [BHP/THP]
Log Close-In-Time (days)
y = 0,0065x + 1,2066
R² = 0,1969
Series1
Linear (Series1)

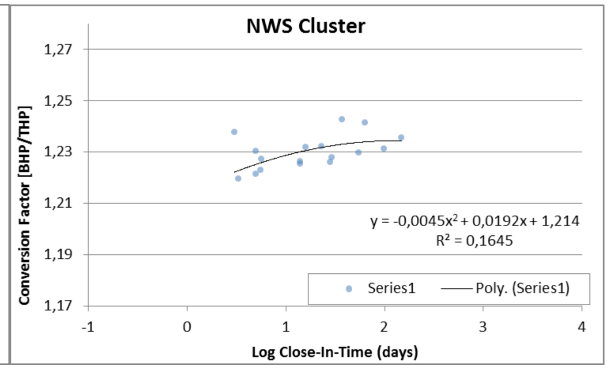

MWD Cluster
Correction Factor
Log Close-In-Time (days)
y = -0,0016x² + 0,0102x + 0,9778
R² = 0,8052
data
Poly. (data)

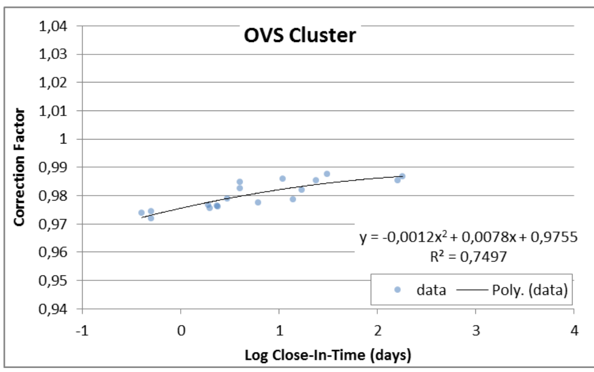

MWD Cluster
Conversion Factor [BHP/THP]
Log Close-In-Time (days)
y = -0,0019x² + 0,0126x + 1,2158
R² = 0,8107
Series1
Poly. (Series1)

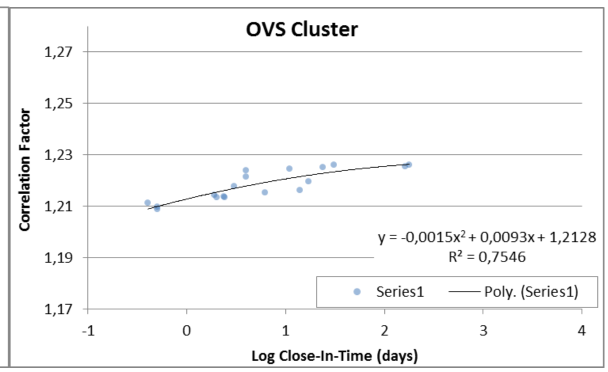

NBR Cluster
Correction Factor
Log Close-In-Time (days)
y = 0,0046x + 0,98
R² = -0,295
data
Linear (data)

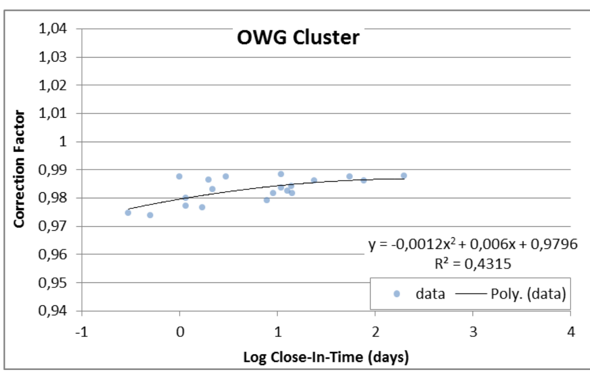

NBR Cluster
Conversion Factor [BHP/THP]
Log Close-In-Time (days)
y = 0,0108x + 1,21
R² = -0,672
Series1
Linear (Series1)

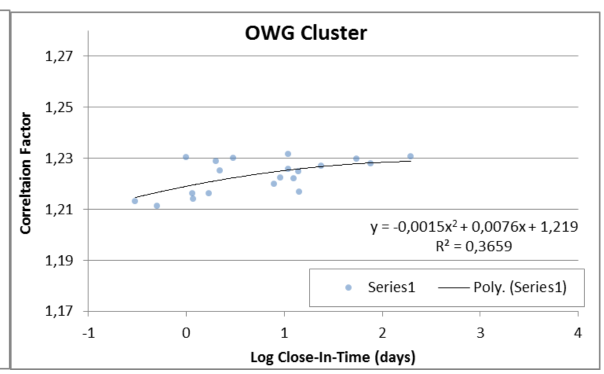

NWS Cluster
Correction Factor
Log Close-In-Time (days)
y = -0,0031x² + 0,0137x + 0,977
R² = 0,2339
data
Poly. (data)

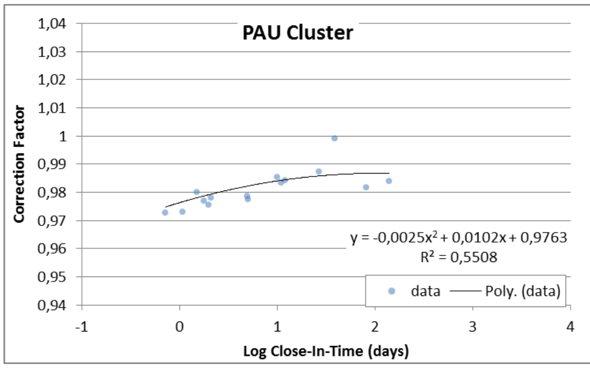

NWS Cluster
Conversion Factor [BHP/THP]
Log Close-In-Time (days)
y = -0,0045x² + 0,0192x + 1,214
R² = 0,1645
Series1
Poly. (Series1)

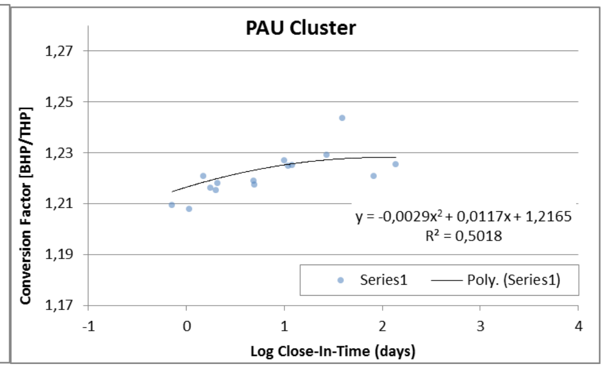

OVS Cluster
Correction Factor
Log Close-In-Time (days)
y = -0,0012x² + 0,0078x + 0,9755
R² = 0,7497
data
Poly. (data)

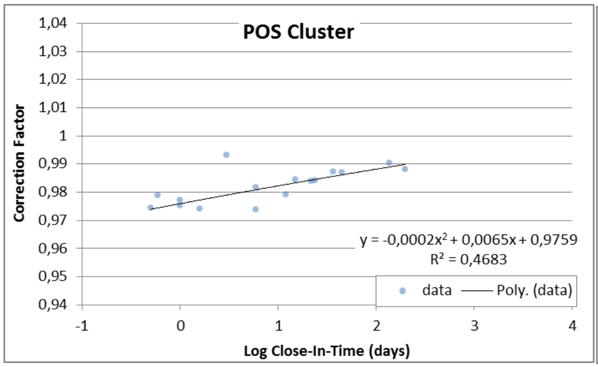

OVS Cluster
Correlation Factor
Log Close-In-Time (days)
y = -0,0015x² + 0,0093x + 1,2128
R² = 0,7546
Series1
Poly. (Series1)

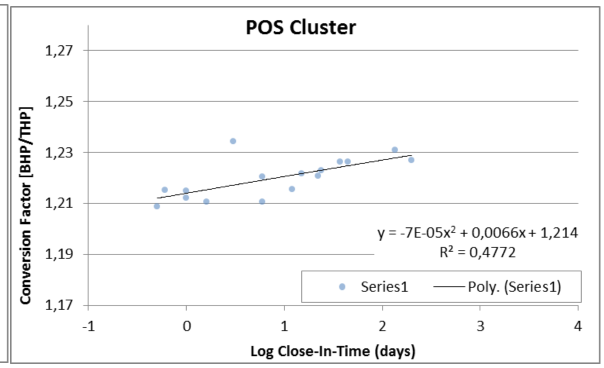

OWG Cluster
Correction Factor
Log Close-In-Time (days)
y = -0,0012x² + 0,006x + 0,9796
R² = 0,4315
data
Poly. (data)

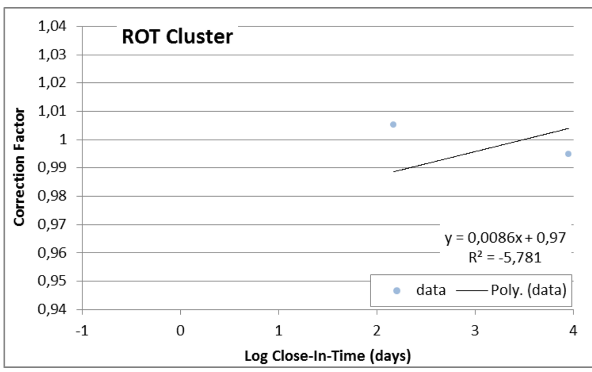

OWG Cluster
Correltaion Factor
Log Close-In-Time (days)
y = -0,0015x² + 0,0076x + 1,219
R² = 0,3659
Series1
Poly. (Series1)

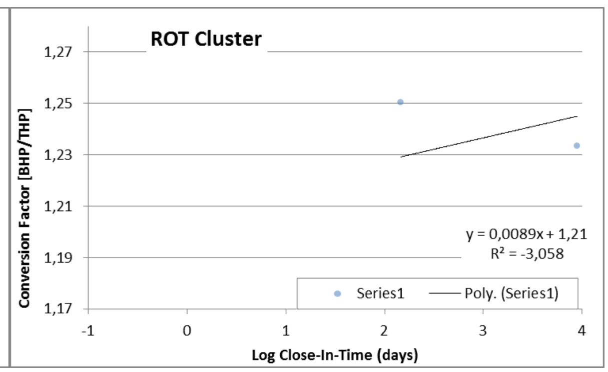

PAU Cluster
Correction Factor
1,04
1,03
1,02
1,01
1
0,99
0,98
0,97
0,96
0,95
0,94
-1
0
1
2
3
4
Log Close-In-Time (days)
y = -0,0025x² + 0,0102x + 0,9763
R² = 0,5508
data
Poly. (data)

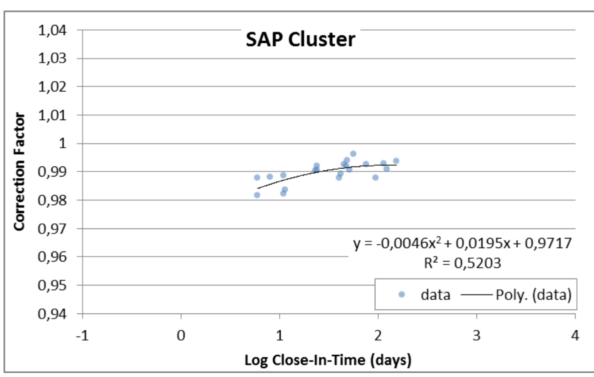

PAU Cluster
Conversion Factor [BHP/THP]
1,27
1,25
1,23
1,21
1,19
1,17
-1
0
1
2
3
4
Log Close-In-Time (days)
y = -0,0029x² + 0,0117x + 1,2165
R² = 0,5018
Series1
Poly. (Series1)

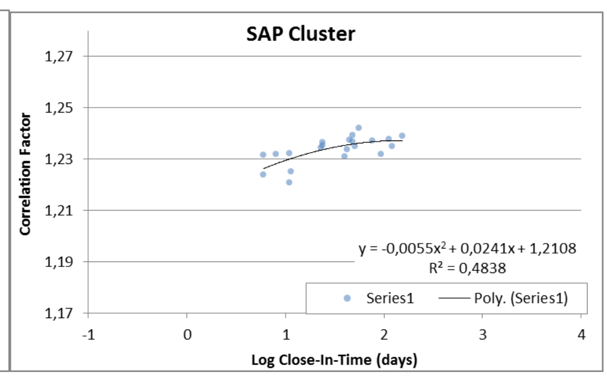

POS Cluster
Correction Factor
1,04
1,03
1,02
1,01
1
0,99
0,98
0,97
0,96
0,95
0,94
-1
0
1
2
3
4
Log Close-In-Time (days)
y = -0,0002x² + 0,0065x + 0,9759
R² = 0,4683
data
Poly. (data)

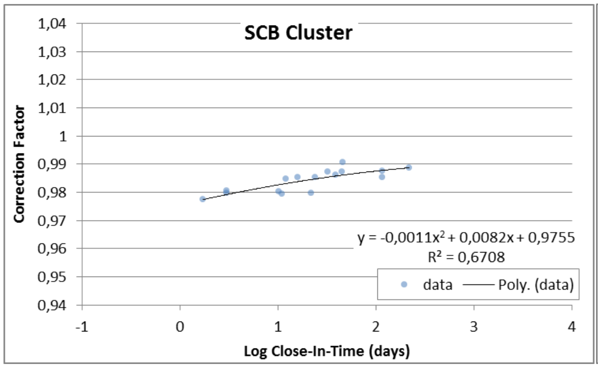

POS Cluster
Conversion Factor [BHP/THP]
1,27
1,25
1,23
1,21
1,19
1,17
-1
0
1
2
3
4
Log Close-In-Time (days)
y = -7E-05x² + 0,0066x + 1,214
R² = 0,4772
Series1
Poly. (Series1)

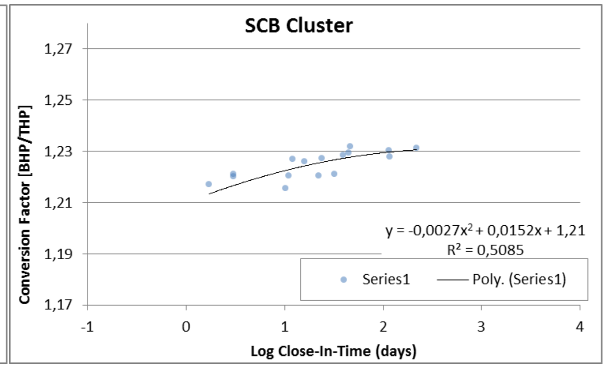

ROT Cluster
Correction Factor
1,04
1,03
1,02
1,01
1
0,99
0,98
0,97
0,96
0,95
0,94
-1
0
1
2
3
4
Log Close-In-Time (days)
y = 0,0086x + 0,97
R² = -5,781
data
Poly. (data)

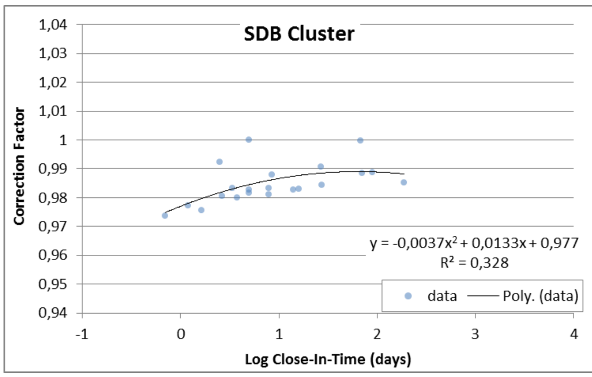

ROT Cluster
Conversion Factor [BHP/THP]
1,27
1,25
1,23
1,21
1,19
1,17
-1
0
1
2
3
4
Log Close-In-Time (days)
y = 0,0089x + 1,21
R² = -3,058
Series1
Poly. (Series1)

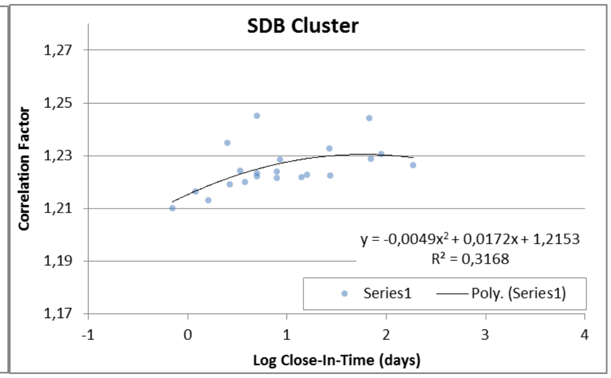

SAP Cluster
Correction Factor
1,04
1,03
1,02
1,01
1
0,99
0,98
0,97
0,96
0,95
0,94
-1
0
1
2
3
4
Log Close-In-Time (days)
y = -0,0046x² + 0,0195x + 0,9717
R² = 0,5203
data
Poly. (data)

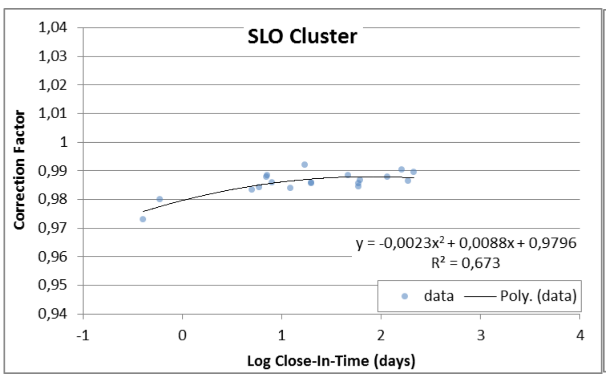

SAP Cluster
Correlation Factor
1,27
1,25
1,23
1,21
1,19
1,17
-1
0
1
2
3
4
Log Close-In-Time (days)
y = -0,0055x² + 0,0241x + 1,2108
R² = 0,4838
Series1
Poly. (Series1)

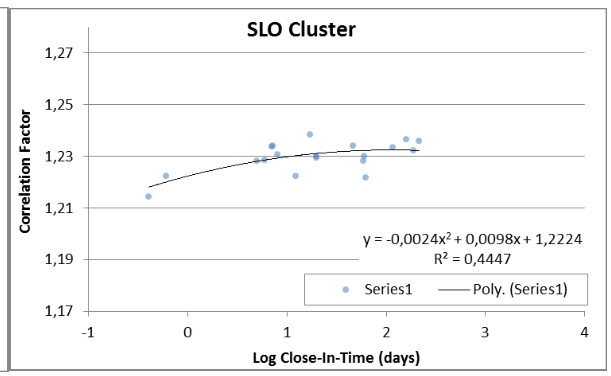

SCB Cluster
Correction Factor
Log Close-In-Time (days)
y = -0,0011x² + 0,0082x + 0,9755
R² = 0,6708
data
Poly. (data)

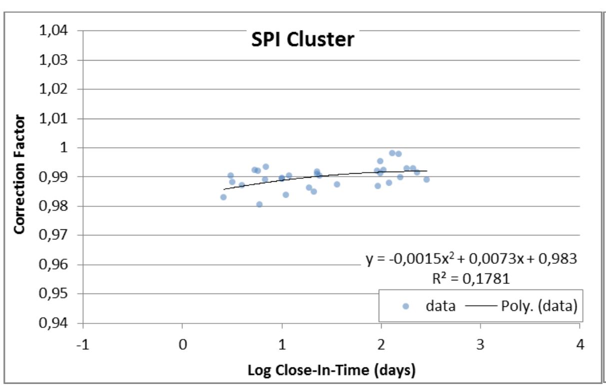

SCB Cluster
Conversion Factor [BHP/THP]
Log Close-In-Time (days)
y = -0,0027x² + 0,0152x + 1,21
R² = 0,5085
Series1
Poly. (Series1)

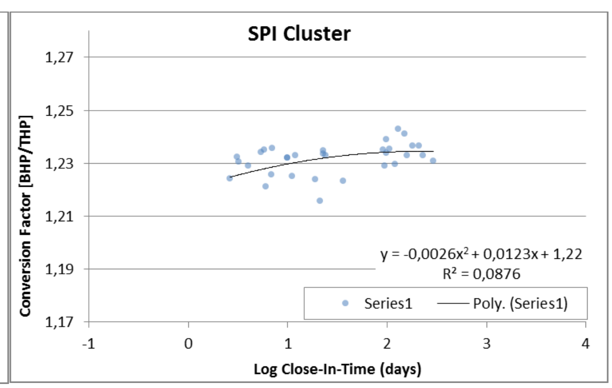

SDB Cluster
Correction Factor
Log Close-In-Time (days)
y = -0,0037x² + 0,0133x + 0,977
R² = 0,328
data
Poly. (data)

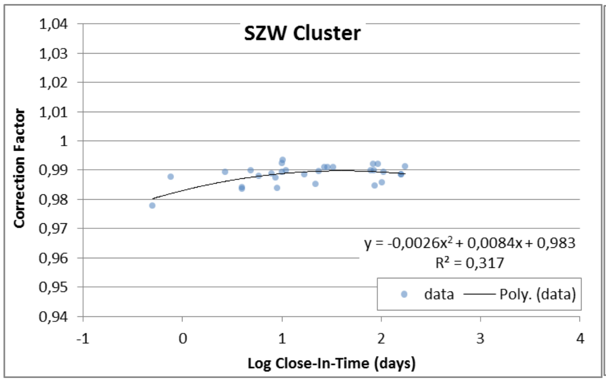

SDB Cluster
Correlation Factor
Log Close-In-Time (days)
y = -0,0049x² + 0,0172x + 1,2153
R² = 0,3168
Series1
Poly. (Series1)

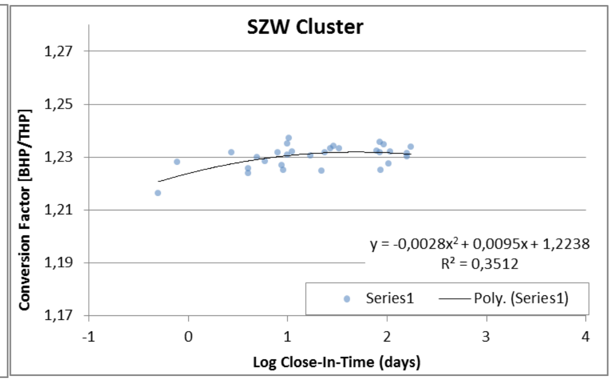

SLO Cluster
Correction Factor
Log Close-In-Time (days)
y = -0,0023x² + 0,0088x + 0,9796
R² = 0,673
data
Poly. (data)

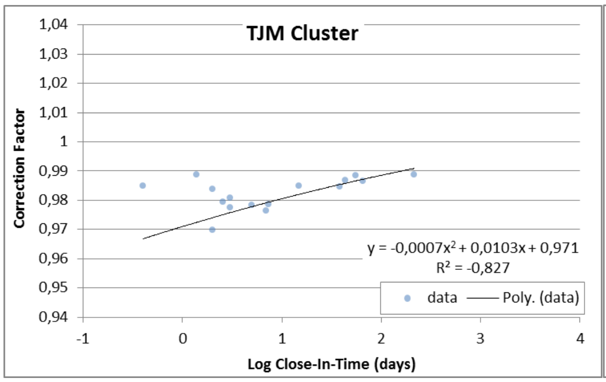

SLO Cluster
Correlation Factor
Log Close-In-Time (days)
y = -0,0024x² + 0,0098x + 1,2224
R² = 0,4447
Series1
Poly. (Series1)

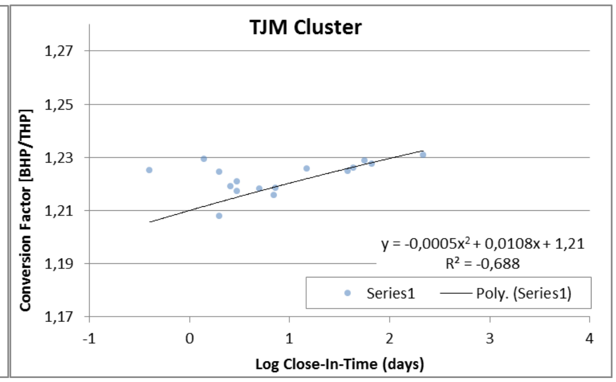

SPI Cluster
Correction Factor
Log Close-In-Time (days)
y = -0,0015x² + 0,0073x + 0,983
R² = 0,1781
data
Poly. (data)

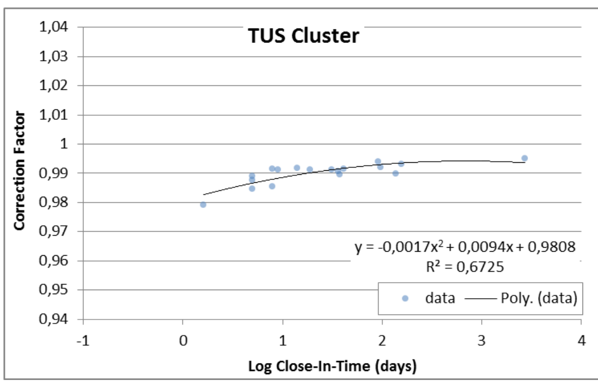

SPI Cluster
Conversion Factor [BHP/THP]
Log Close-In-Time (days)
y = -0,0026x² + 0,0123x + 1,22
R² = 0,0876
Series1
Poly. (Series1)

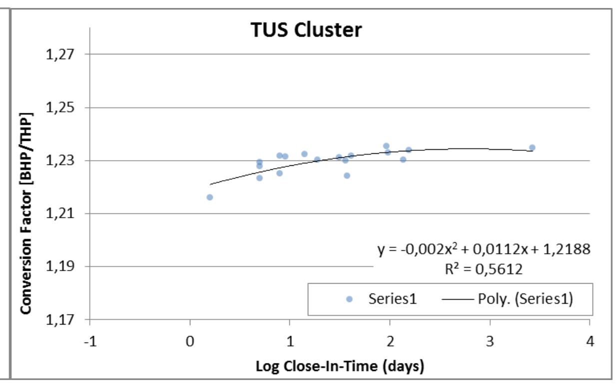

SZW Cluster
Correction Factor
Log Close-In-Time (days)
y = -0,0026x² + 0,0084x + 0,983
R² = 0,317
data
Poly. (data)

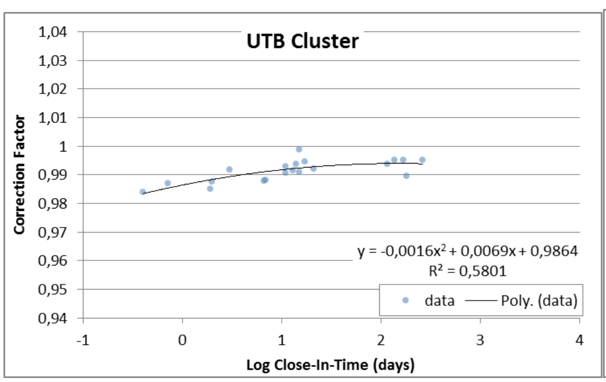

SZW Cluster
Conversion Factor [BHP/THP]
Log Close-In-Time (days)
y = -0,0028x² + 0,0095x + 1,2238
R² = 0,3512
Series1
Poly. (Series1)

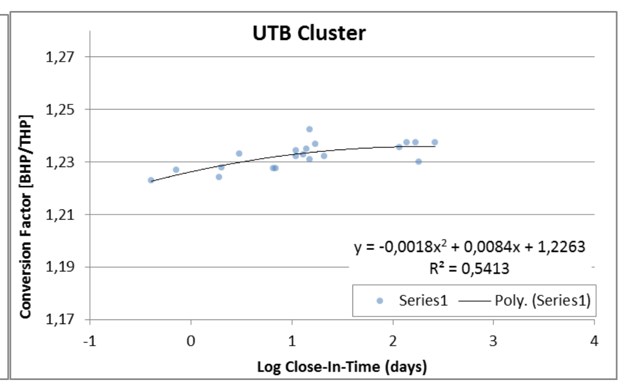

TJM Cluster
Correction Factor
Log Close-In-Time (days)
y = -0,0007x² + 0,0103x + 0,971
R² = -0,827
data
Poly. (data)

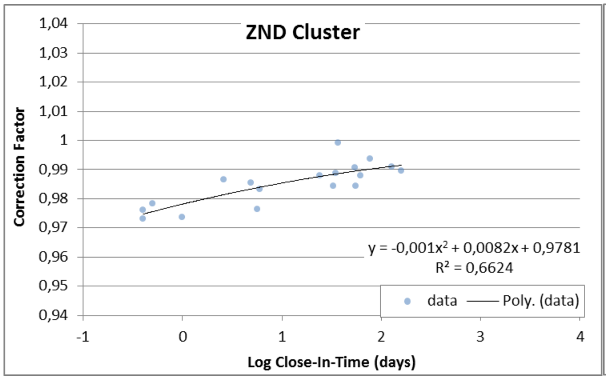

TJM Cluster
Conversion Factor [BHP/THP]
Log Close-In-Time (days)
y = -0,0005x² + 0,0108x + 1,21
R² = -0,688
Series1
Poly. (Series1)

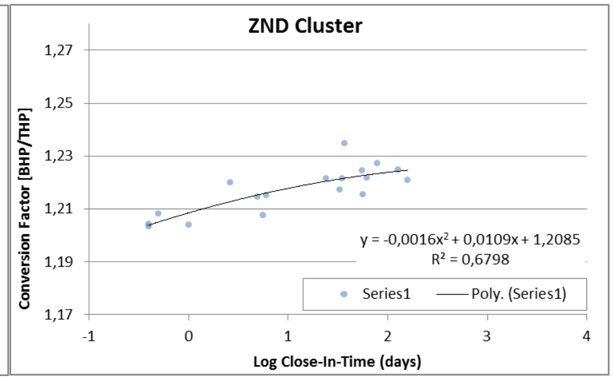

TUS Cluster
Correction Factor
Log Close-In-Time (days)
y = -0,0017x² + 0,0094x + 0,9808
R² = 0,6725
data
Poly. (data)

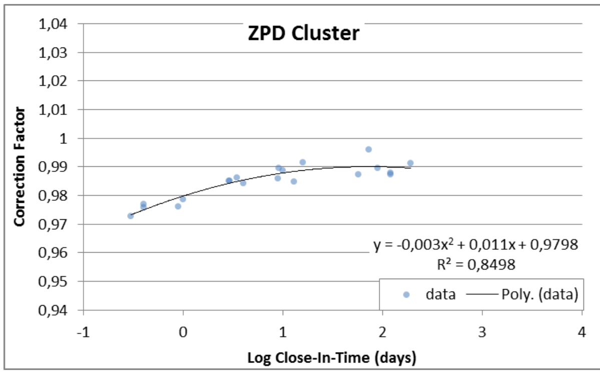

TUS Cluster
Conversion Factor [BHP/THP]
Log Close-In-Time (days)
y = -0,002x² + 0,0112x + 1,2188
R² = 0,5612
Series1
Poly. (Series1)

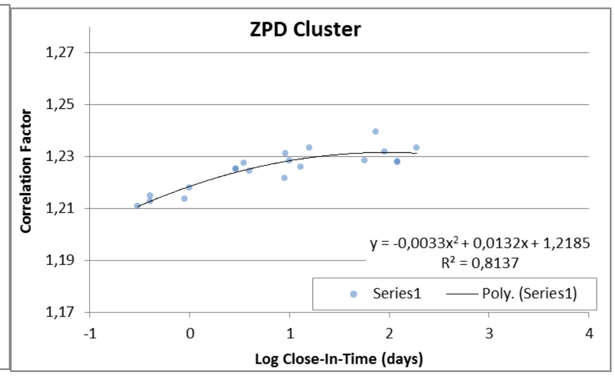

UTB Cluster
Correction Factor
Log Close-In-Time (days)
y = -0,0016x² + 0,0069x + 0,9864
R² = 0,5801
data
Poly. (data)

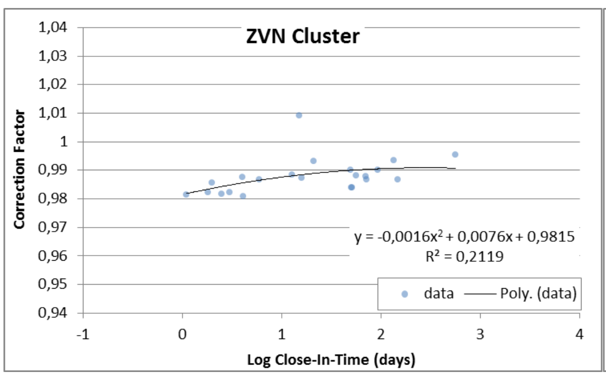

UTB Cluster
Conversion Factor [BHP/THP]
Log Close-In-Time (days)
y = -0,0018x² + 0,0084x + 1,2263
R² = 0,5413
Series1
Poly. (Series1)

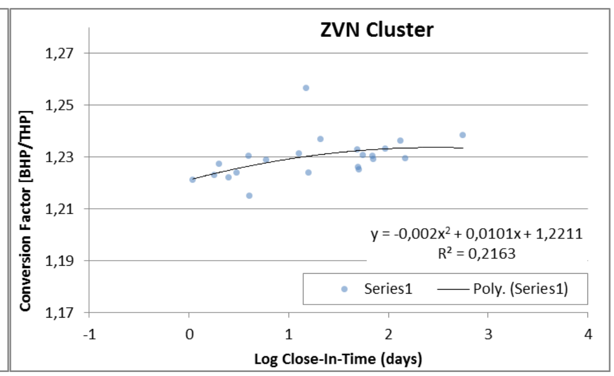

ZND Cluster
Correction Factor
Log Close-In-Time (days)
y = -0,001x² + 0,0082x + 0,9781
R² = 0,6624
data
Poly. (data)


ZND Cluster
Conversion Factor [BHP/THP]
Log Close-In-Time (days)
y = -0,0016x² + 0,0109x + 1,2085
R² = 0,6798
Series1
Poly. (Series1)


ZPD Cluster
Correction Factor
Log Close-In-Time (days)
y = -0,003x² + 0,011x + 0,9798
R² = 0,8498
data
Poly. (data)


ZPD Cluster
Correlation Factor
Log Close-In-Time (days)
y = -0,0033x² + 0,0132x + 1,2185
R² = 0,8137
Series1
Poly. (Series1)


ZVN Cluster
Correction Factor
Log Close-In-Time (days)
y = -0,0016x² + 0,0076x + 0,9815
R² = 0,2119
data
Poly. (data)


ZVN Cluster
Conversion Factor [BHP/THP]
Log Close-In-Time (days)
y = -0,002x² + 0,0101x + 1,2211
R² = 0,2163
Series1
Poly. (Series1)

Appendix 5 – Reservoir Pressure

When using the CITHP to CIBHP conversion methods for trying to establish reservoir pressure, it is important to clearly define reservoir pressure.

In the Mores model, the "reservoir pressure" is defined as the average pressure (at datum) within a range of gridblocks around the wellbore according to a 3 day radius of investigation.

- Consequently, when using the CITHP dataset to establish "reservoir pressure", should it be the CITHP after a minimum 3 days of shut-in?
- How much CITHP data is available ≥ 3 day shut-in?
- Possibly extent shorter build ups analytically?

CIBHP's from SPG data represent the reservoir pressure in the Groningen full field model indirectly. Consider an IPR range, which is a range of grid blocks which pressures are influenced by a shut-in of a well for a certain time. In the Groningen full field model the CIBHP as obtained from SPG's is assumed to be equal to the average pressure in the IPR range of a well which has been shut-in for 3 days. This average pressure in the IPR range is then the 'reservoir pressure' to which the full field model is matched. The 3 days shut-in time is selected as this accommodates for both shorter shut-in times and longer shut-in times as mentioned in the *GFR 2012*. The selected IPR range is thus fixed to 3 days and does not match the real shut-in period of the well during the SPG. One could therefore argue for the use of different IPR ranges corresponding to the actual shut-in times of the wells during their SPG's.

Appendix 6 – THP to BHP conversion from Genrem setup

In the Genrem set-up, the following is used for IPR and VLP:

Well inflow performance (P^2-method):

$$BHP^2 = P_{res}^2 - A \cdot Q_{sc} - F \cdot Q_{sc}^2$$

with:

BHP	Bottom hole pressure (bara)
P_{res}	Gridblock pressure (bara)
A	Darcy flow factor at pressure P ($bar^2/(10^3\ m^3/d)$)
Q_{sc}	Flowrate at standard conditions ($10^3\ m^3/d$)
F	Rate dependent flow factor at pressure P ($bar^2/(10^3\ m^3/d)^2$)

Vertical flow performance (modified Smith-Cullender equation):

$$BHP^2 = B \cdot THP^2 + C \cdot Qsc^2$$

with:

B	Static pressure correction factor at pressure P
THP	Tubing head pressure (bara)
C	wellbore friction factor at pressure P ($bar^2/(10^3\ m^3/d)^2$)

Combining both equations yields:

$$P_{res}^2 - A \cdot Q_{sc} - F \cdot Q_{sc}^2 = B \cdot THP^2 + C \cdot Qsc^2$$

Hence for shut-in conditions (Q_{sc}=0):

$$P_{res}^2 = B \cdot THP^2$$

or

$$\sqrt{B} = P_{res}/THP$$

Appendix 7 – Tubing Head Temperature

There are 2 constant THT's for which the accuracy of the conversions is investigated in this report.

The first is presented by Jort van Jaarsveld who used a standard THT for static conditions which is approximately 7 degree C.

The second THT is an average temperature per day/week/month or year can be used to account for warmer periods in summer time and colder periods in winter time. In this report an average monthly temperature in the month of the shut-in is tested[26].

One could also argue to use continuously monitored wellhead temperatures. However, well head temperature gauges are not installed in the wells in the Groningen field and will therefore not be used here. Also note that after shutting in a well, the tubing head temperature will decrease from flowing tubing head temperature (approx. 70- 80 ˚C) to well head temperature as a result from electrical tracing/insulation about 25 to 30 ˚C. The part in the shallow subsurface will be determined by (heated up) soil temperature near the well.

An alternative could be to use the temperature as measured by the temperature gauge at the manifold (TIA-001.PV in Figure 9). However the use of such a fluctuating (ambient) temperature results in non-physical behavior for CIBHP in the conversion. An example of the resulting unphysical fluctuation in calculated CIBHP is depicted in Figure 37.

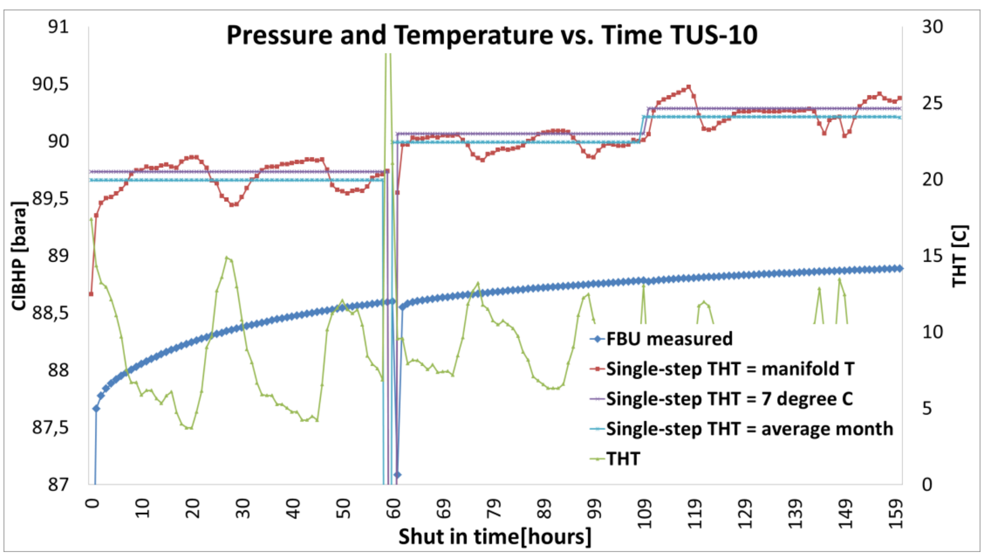


Figure 37: Unphysical fluctuation in calculated CIBHP resulting from the use of manifold temperature as THT, compared to results from using a fixed THT.

[26] Average monthly temperature obtained as temperature in Nieuw Beerta from https://weerstatistieken.nl/