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Real Time Production Monitoring with Prediction and Validation

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WellFlo	+ vedlegg/annet: …………
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Content

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Abstract

This Master of Science studies Optimum Online's real time estimated production at the Ekofisk Field. Information from offshore process sensors are used to validate the individual well estimates and to detect any deviation in a wells performance.

In order to ensure the quality of the estimated production, a temperature verification is used by monitoring the differences between the calculated temperature in the simulations and the measured temperature at the wellhead. An accepted limit in deviations determines if the production is verified or not. Solutions for improvement of estimates during an unverified period are suggested, depending on what cause the change in well behaviour.

Upstream and downstream choke pressures, and choke size are used to predict a flowrate through choke. The flowrate is compared to Optimum Online real-time estimates and to welltests. The aim is to find an expression of a predicted flow rate that is a function of the pressure drop and may detect a decline in production. The flowrate will be thoroughly examined before implemented and tested in Optimum off line version and checked for verification.

1. Introduction

1.1 Background

The Ekofisk and Eldfisk fields are one of the largest and most important fields in the North Sea. Both fields are producing from chalk reservoirs located within the PLO018 license area. As of January 2009 a daily production of 213,000 bbl/d are produced from 104 wells and furthermore 34 wells are water injectors. 41 of the producers are on gas lift.

1.2 Optimization Potential

Integrated operations (IO) and production optimisation are highly focused in the petroleum industry worldwide. One of the key elements in production optimisation is teamwork based on real time data, monitoring, allocating, implementation and development. Extended use of real time data is essential for the future production optimisation and the industry is focused on integrating real time data into the work processes, turning the high frequency data into real value to be able of early detection of unwanted well performance, better and more frequently decision making in order to optimize production, simpler workflows and rationalised planning.

One important advance in the oil industry operations is monitoring the process by using real time data. This allows doing faster diagnostic, and faster and more effective decisions.

Determining the individual well rates is an important task in the measurements of total produced oil and gas. The basis of determination of a wells contribution is well testing, and is still the leading principle in determining the individual well flow rates today. Integrated operations enables allocation in real-time and contributes to continuous well monitoring and individual wells performance.

1.2.1 Transmitters

Huge amounts of data are generated from sensors in a production system of wells. The sensors are placed at wellhead, upstream choke, downstream choke, downhole gauges, separators and at the flow lines. Downhole gauge is placed at the fluid column in the well, and the pressure and temperature are used for trend analysis, and simulation correlations which can be implemented in well analysis.

A field model which is continuously updated can help the engineers optimise, forecast and track developing trends in production. As with all models, high quality input data is needed to get quality output.

2 Theory

2.1 Inflow and Outflow Theory

The operating conditions in a well can change during the traditional allocation period of one month before updating, as the reservoir parameters (P_{res},WC, GOR) changes during depletion. This may lead to incorrectly allocated values for the well production.

2.1.1 IPR and TPR curves

The well head pressure is proportional to the bottomhole pressure at a constant rate. A decrease in the downhole pressure could be a consequence of natural depletion in the reservoir, skin or a scale bridge. This will imply a reduced wellhead pressure. The behaviour of the temperature is more complex such as change in heat transfer along the pipe due to change in flow rate. However there are methods in simulation programs with correlations and analyses with their respectively calculations.

IPR curves are made from two parameters, drawdown also called productivity index (PI), and the reservoir pressure. PI is the slope of the IPR curve, while P_{res} is the point where the curve crosses the y-axis and the flowrate equals zero. [4] The TPR curve is affected by tubing parameters as pipe size, wall roughness, wellhead pressure and gas lift rate.

2.1.2 Vogel Inflow Performance

The Vogel relation [7] is used for calculating the Inflow performance in wells. The inflow performance curve model is used in this study. The inflow is given by:

$$\frac{q_o}{q_{o\,max}} = 1 - 0.2\left(\frac{P_{wf}}{P_r}\right) - 0.8\left(\frac{P_{wf}}{P_r}\right)^2 \qquad (2.1)$$

where

q_o - is the oil rate,

$q_{o\,max}$ -is the max oil rate when P_{wf}=0,

P_{wf} -is the wellbore flowing pressure, and

P_r - is the reservoir pressure

A vertical lift performance curve indicates what a well is expected to produce at a given wellhead pressure and is traditionally updated using well test results. The sum of these theoretical well rates should ideally match the measured total production. Deviations are determined from the allocation factor, hence giving an idea of the uncertainty in the estimated production.

The inflow performance (IPR) and vertical lift performance (VLP) is combined to provide the well deliverability. The intersection of the plots of flow rate versus the bottomhole pressure of these two components gives the expected deliverability. The intersection also describes a specific instant of the well and depends strongly on the type of flow regime controlling the well performance.

2.2 Scale

After water breakthrough the produced flow rate will contain water. This can be confirmed by increasing watercut. An analysis of the produced water will determine if it is the formation water or injected water that is present in the reservoir.

Formation of scale is mainly due to the mixing of the formation water and the sea water injected into the reservoir. The formation water contains ions of Barium and Strontium, while the seawater contributes with ions of sulphate. When the combination of right temperature and pressure are present the ions may react with the chalk and form scale.

Scale can be present in the perforations, in the tubing or at the surface facilities, such as the choke or in the flow line. A scale problem may lead to production loss and is an increasingly problem at the Ekofisk field due to the increase in produced water.

2.2.1 Scale deposition in the choke valve.

The most common location of scale deposition in the flow line is where a pressure drop may occur or the flow passes through a restriction. Therefore, a choke valve is sensitive to scale deposition since part of the valve consists of several smaller holes exposed to the flow, depending on the choke setting. These holes may slowly plug up from scale and will also over time affect the actual choke size.

2.3 Allocation

"the mathematical process of assigning portions of a commingled production stream to the sources, typically wells, leases, units, or production facilities, which contributed to the total flow through a custody transfer or allocation measurement point." [1]

Total produced volume in a field is the sum of individual production from all contributing wells. The total production is measured as total oil, water and gas phase at separator and measured as single phases afterwards and is hence regarded to be of sufficient accuracy. Describing the multiphase individual well stream is more complex as the constituents vary in their physical properties as density, viscosity and chemical composition. The common way to find the single well rates is by well testing with a test separator. In order tp redistribute the total measured production rate back to the individual wells, good allocation routines are required.

2.3.1 Well tests

The most common form of well testing are the single rate drawdown test, the pressure build up test, and the multi-rate drawdown test. The production is routed to a test separator to perform analysis and measurements. Each well is tested approximately once a month, depending on well stability and performance.

Well testing is mainly required to allocate the production of hydrocarbons to each well and to update the reservoir parameters in the models. It is also used to monitor well performance.

2.3.2 Well test practice:

Well flow lines are routed to the test separator and the output flows of oil, gas and water are measured after some hours when the flow is believed to be reasonably stable. A welltest usually takes four hours and the flowrate is averaged during the test periode.

2.4 Real Time Data

2.4.1 Optimum Online

Optimum Online retrieve and treats data from different sources and represents the results in a web interface. The Online system provides production simulation by process real-time values from offshore platforms to an onshore network system. The network system is a field model witch takes into account all the limitations in a production process. A well model for each single well in the field is implemented in the network system. The well model will be updated and tuned by new welltests. Each single well and is thereby monitoring any deviation from the production forecast. Different equipment or operation parameters can be changed in the models to analyze a production optimization or to prevent undesirable influence on the production system. Figure 2.1 is showing the information process.

The main data source in Optimum Online is the PI System data base. Welltest results are retrieved from NPAS .

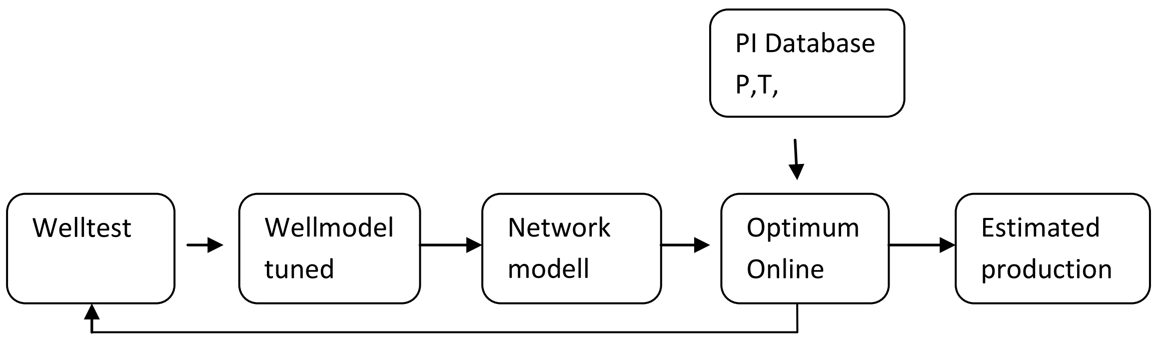


Figure 2.1. is showing how the information is collected in a simulation.

2.4.2 PI Systems

PI systems receive all types of data from the control systems, transmitters and simulation results and represents data in a web interface. Measurements from transmitters are automatic transferred via fiber optic cable to PI database. The information can be loaded and visualized graphically with current and historic data. Another option is to load datasets direct to excel and do further analysis. In this work, excel is primarily used for loading data from transmitters, but also to do statistic analysis, such as calculating the average and mean values for a certain period. Optimum Online load real-time data from PI database.

2.5 Models

Two types of software modelling programs are used in the context of this work, WellFlo which is a well model program, and ReO which is a field model program. The well model incorporates multiphase flow from near well bore via the point it enters a well bore and until it reaches the wellhead. There is one well model for each well, with the PVT parameters, equipment geometry, artificial lift, geothermal gradient and heat capacity controlling the output. The field model consists of all well models in a field connected to the topside facilities to model the comingled flows.

2.5.1 WellFlo

WellFlo is an application for a single well performance analysis where well test data are being analysed. The software includes building the well with relevant completion, depth, inclination and dimensions in the tube. Fluid parameters are PVT data, viscosity, densities, API and flow type. Input parameters are GOR, water cut, flow rates, temperatures and pressure during the well test. Based on reservoir parameters the IPR and VLP curves will be constructed and used to calculate an operating point. Several tube correlations are available matching the profile in the tube and well tests.(see section 2.3.2 for more details on the IPR)

2.5.2 ReO

ReO is a field model application connecting each well and top side facilities. The model is used for field performance analysis and production optimisation. The software can also be used to run future scenarios and visualise results. Optimum Online runs this model in real time by importing wellhead temperature and pressure. For gas lifted wells, the casing head pressure and gas injection rate are also loaded in thecalculationsl. All these parameters are imported from the PI process book to the online system.

2.5.3 The Network Model

WellFlo solves the flow in the well from bottom hole to the outlet node at the surface. The modeled wells are connected in the field (ReO) which is the network solver of the surface facilities, such as pipes, separators, pumps, compressors, valves, compressors and choke. The simulations are a continuous process based on real-time data from sensors mounted on the different facilities. The simulations start every 12 minutes of every hour day and night. The calculated rates are compared to a fiscal metering and the difference will be distributed back to each well, based on an individual weighting of the wells.

An Off-line simulation version can be run to do further analysis in order to detect any deviation in the production or by changing some parameters to analyze performance on gas lift optimization or capacities in the surface facilities.

2.5.4 The Chokes at Ekofisk

The chokes at 2/4 Mike platform are standard Mokveld valves. The wells are connected to a common production line after the choke.

2.6 Multiphase flow

Two-phase flow behaviour depends strongly on the distribution of the phases in the well, which in turn depends on the direction of the flow relative to the gravitation. Iin upwards two-phase flow, the lighter phase will be moving faster than the denser phase. This term is often called the *holdup phenomenon*-that is, the denser phase is "held up" in the pipe relative to the lighter phase [1].

Correlation models are different methods for calculating the pressure gradient, dp/dx, which can be applied at any location in the well. The objective is often to calculate the overall pressure drop, Δp, over a considerable distance. Over this distance the pressure gradient in gas-liquid flow can vary significantly as the downhole flow properties change with pressure and temperature as it moves upwards. At some point, gas comes out of solution, causing a gas-liquid flow. As the pressure continuous to drop, new flow regimes may occur farther up in the tubing.

2.6.1 Pressure drop.

In order to determine the overall pressure drop over a finite length of pipe, the variation of the pressure gradient as the fluid properties change in response to the changing pressure must be considered. Equation 2.4 is the general expression for pressure drop inside the tubing. The total pressure drop is the sum of three part;: hydrostatic, frictional and acceleration:

$$\left(\frac{dP}{dx}\right)_{tot} = \left(\frac{dP}{dx}\right)_{hyd} + \left(\frac{dP}{dx}\right)_{fric} + \left(\frac{dP}{dx}\right)_{accel} \qquad (2.2)$$

The hydrostatic gradient is the product of the density from the multiphase column of fluid flowing within the well. It is proportional to the cosine of deviation of the well from the vertical. Most correlations use flow regime maps to determine the type of flow, and then calculating the liquid-gas holdup depending on the estimated flow regime.

Equation 2.4 is a general equation of the hydrostatic pressure gradient, where β is the angle of deviation from vertical.

$$\left(\frac{dP}{dx}\right)_{hyd} = \rho_m g sin\beta \qquad (2.3)$$

where

ρ_m - is the mixture density, and

g - is the gravity

The friction gradient contributes by the friction between the pipe wall and the fluid, which is a function of the wall roughness and Reynold's number. Also there is a friction between the phases in multiphase flow. The correlations use different estimates of the friction factor.

In general the friction pressure gradient is given by:

$$\left(\frac{dP}{dx}\right)_{fric} = \frac{f\rho_m v_m^2}{2d} \qquad (2.4)$$

where

v_m - is the mixed velocity

The acceleration gradient is a relative small contribution to the total pressure drop and is caused by the increase in kinetic energy of the fluid as it expand and accelerates with decreasing pressure. The equation is:

$$\left(\frac{dP}{dx}\right)_{accel} = -\rho_m v_m \left(\frac{dv_m}{dx}\right) \qquad (2.5)$$

2.6.2 Pressure Gradient Correlations drop between the bottomhole and the wellhead.

Since the pressure drop in the tubular can be large, an accurate calculation is of importance.

Over the years, numerous correlations have been developed to calculate the pressure gradient in vertical and horizontal gas-liquid flow. Two-phase flow in horizontal pipes differs markedly from that in vertical pipes, except for the Beggs and Brill correlation which can be applied for any flow directions. Completely different correlations have to be used depending on if the well is horizontal or vertical.

2.6.3 Flow regimes.

The flow regime does not affect the pressure drop as significantly in horizontal flow as it does in vertical flow. This is because there is no potential energy contribution to the pressure drop in horizontal flow. However, the flow regime is considered in some pressure drop correlations and can affect production operations in some other way. Most importantly, the occurrence of slug flow often needs designing or other equipment specialty to handle the large volume of liquid contained in a slug.

2.6.4 Multiphase Flow through Chokes

The flow rate is controlled with a wellhead choke, a device that places a restriction in the flow line. Several factors makes it desirable to restrict the production rate in the well, and surface equipment , including prevention of formation damage, stabilization of the flow or prevention of coning and sand production. Accordingly, accurate prediction of the relationship between the pressure drop and the flow rate through the choke is of importance.

A number of publications have presented different methods for the prediction of choke performance. In the absence of comparison study, an objective selection of a method for calculation of choke performance becomes very difficult [2]. The similarity of the presented methods is the need for an estimation of the mixture density and the assumption of keeping the density constant.

Not many publications has reported sufficient data on multiphase flow through chokes, some even discarded in the lack of sufficient information [2]. An application of the choke performance in the lack of either upstream or downstream pressures, use of a prediction of the upstream or downstream pressures may be used., The models for prediction require caution in the sense of uncertainties and average error.

Models predicting the mixture flow rate through a choke for a given geometry and flow conditions have a different approach, especially for critical-subcritical flow, slip or no-slip conditions and assumptions [2,3].

Ashford and Pierce (1974), Sachdeva et al. (1986) and Perkins (1990) presented quite similar mechanistic models for predicting flow rate through chokes, using upstream and downstream pressures, upstream temperature, gas-liquid ratio, water cut and oil, gas and water gravities. Although they used the same approach, they arrived with three different equations to calculate the mixture flow rate. Ashford and Pierce presented the simplest derivations with the least number of assumptions.

2.6.5 Critical and Subcritical Flow

There are two types of flow behaviour across chokes, namely, critical and sub-critical.

When gas-liquid mixtures flow through a choke, the fluid may be accelerated sufficiently to reach sonic velocity in the throat of the choke. When this occurs, the flow is critical and changes in the pressure downstream of the choke do not affect the flow rate. The advantage is that the downstream pressure may vary without influencing the volume flow rate. Therefore, it has to be determined if the flow is critical or not. To determine the flow rate of two phase flow through a choke, empirical correlations for critical flow are generally used. Estimating critical two-phase flow through the choke is by comparing the velocity in the choke with the two-phase sonic velocity, given by Wallis, for homogeneous mixtures as [1]:

$$v_c = \left\{\left[\varepsilon_g\rho_g + \varepsilon_l\rho_l\right]\left[\frac{\varepsilon_g}{\rho_g v_{gc}^2} + \frac{\varepsilon_l}{\rho_l v_{lc}^2}\right]\right\}^{-0.5} \qquad (2.6)$$

Where

v_c - is the sonic velocity of the mixture and

v_{gc} - is the sonic velocities of the gas

v_{lc} - is the sonic velocities of the liquid.

ε_l - is the liquid fraction

ε_{lg} - is the gas fraction

A rule of thumb is to expect a sonic velocity for the gas when the upstream choke pressure has a factor of 1.8 higher than the absolute downstream choke pressure [6]. For subcritical flow, the actual pressure ratio for the flowing conditions is less than the critical pressure ratio. The flow rate is related to the pressure drop across the restriction.

When a well is being produced with critical flow through a choke, the relationship between the wellhead pressure and the flow rate is controlled by the choke, since downhole pressure disturbance do not affect the flow performance through the choke. However, the attainable flow rate from a well at a given choke size, can be determined by matching the choke performance with the well performance, as determined by the intersection of the well IPR and VLP curve. The choke performance curve is a plot of the liquid flow rate versus the flowing tubing pressure and can be obtained from the two-phase choke correlations, assuming that the flow is critical [1].

2.7 Flow velocities

Before assing the flowrate through chokes, the dynamics in two-phase flow has to be considered.

2.7.1 Superficial Velocities

The superficial velocities are defined by:

$$U_{lS} = \frac{q_l}{A} \tag{2.7}$$

where

q_l – is the liquid volume flowrate.

A – is the cross sectional area

$$U_{gS} = \frac{q_g}{A} \tag{2.8}$$

where

q_g - is the gas volume flowrate.

The sum of the superficial velocities equals the real average velocity in the flow:

$$U_{mix} = U_{gS} + U_{ls} \tag{2.9}$$

2.7.2 Phase Velocities

The phase velocities are the real velocities of the flowing phases in a pipe. They may be defined locally or as a cross sectional average in the pipe and are defined as:

$$u_l = \frac{q_l}{A_l} \tag{2.10}$$

$$u_g = \frac{q_g}{A_g} \tag{2.11}$$

where

A_l and A_g- is the cross sectional area occupied with liquid or gas.

In order to quantify u_l and u_g, it is necessary to determine the real flowing cross sections A_l and A_g for liquid and gas. This is equivalent to knowing the amount of liquid and gas in the flow, i.e. the fractions. It is important to distinguish between the superficial and phase velocities.

2.7.3 Relative phase velocities and slip

Gas and liquid may flow with different phase velocities in pipe flow. This difference is referred as the relative velocity or the slip ratio and is defined by:

$$S = \frac{u_g}{u_l} \tag{2.12}$$

The slip ratio is dimensionless.

2.7.4 Fluid Fractions

In some cases it may be difficult to calculate or measure the fraction of gas and liquid exactly, especially when the dynamics in the flow are unknown. In these cases it may be necessary to make an estimation of the fluid fractions:

$$\alpha_l = \frac{q_l}{q_l + q_g} \tag{2.13}$$

$$\alpha_g = \frac{q_g}{q_g + q_l} \tag{2.14}$$

Note that the difference in the calculated estimations (superficial) does not take into account any difference in phase velocities (slip) and is therefore called the no-slip fractions.

2.7.5 Fractions at slip

It is possible to determine the true fractions when there is a slippage between the liquid and gas phases. This is a theoretical basis since a slippage will vary in a producing well and the slip ratio can be difficult to predict without having an installed multiphase flow metering. If slip is present and the slip ratio is known, the fluid fractions can be calculated as:

$$\varepsilon_l = \frac{q_l}{q_l + \frac{1}{S} \cdot q_g} = \frac{U_{lS}}{U_{lS} + \frac{1}{S} \cdot U_{gS}} \qquad (2.15)$$

$$\varepsilon_g = \frac{q_g}{S \cdot q_l + q_g} = \frac{U_{gS}}{S \cdot U_{lS} + U_{gS}} \qquad (2.16)$$

2.7.6 Density

Determination of effective density for a two-phase flow provides knowing the fluid fractions and the single phase fluid properties

$$\rho_m = \rho_l \varepsilon_l + \rho_g \varepsilon_g \qquad (2.17)$$

Where

ρ_m -is the mixture density.

2.8 In-situ conditions

The fluid properties at in-situ conditions has to be considered when predicting a flow rate through choke.

2.8.1 Compressibility factor

The compressibility factor is defined as the gas-deviation factor. It is a multiplying factor introduced into the ideal-gas law to account for the departure of true gases from ideal behaviour: PV=ZnRT, where the Z is the compressibility factor.

2.8.2 Critical state

Is the term used to identify the unique condition of pressure, temperature and composition where in coexisting all properties of vapour and liquid becomes identical.

2.8.3 Critical Temperature and Pressure

Critical temperature, t_c and critical pressure, p_c is the temperature or pressure at critical state.

2.8.4 Pseudocritical and pseudoreduced Properties

Properties of pure hydrocarbons are often the same when expressed in terms of their reduced properties. The same reduced-state relationship often applies to multi component systems if pseudo critical temperatures and pressures are used, rather than the true critical properties of the systems. A calculation of the pseudo critical values from the composition of the system varies depending on the correlation being used. The ratio of the property is called the pseudo reduced property as pseudo educed pressure $p_{pr}=p/p_{pc}$.

2.9 Bernoulli – One phase

Bernoulli's principle combined with pressure drop across choke is widely used in the petroleum industry to predict flowrates. Although having Bernoulli's Principle as a basis, the approach to a theoretical model is different, depending on the implementation of the conditions in the flow regime, fluid properties and geometry in the choke.

Derivation of the Bernoulli's principle starts with mass- and impulse conversation:

Mass

$$\frac{\partial}{\partial t}(\rho A) + \frac{\partial}{\partial x}(\rho A v) = 0 \tag{2.18}$$

Impuls

$$\frac{\partial}{\partial t}(\rho A v) + \frac{\partial}{\partial x}(\rho A v^2) + A\frac{\partial p}{\partial x} = 0 \tag{2.19}$$

Where

$\rho - is\ the\ density$

$v - is\ the\ velocity$

$A - is\ the\ cross\ sectional\ area\ of\ the\ pipe$

$p - is\ the\ pressure$

Some assumptions has to be made:

Assumption 1. **I**mpulse Equation: Neglect the hydrostatic pressure in a horizontal pipe.

Assumption 2. Impulse Equation: Preliminary neglect the friction

Also notice the expression of $A\frac{\partial p}{\partial x}$ in two dimensions:

$$A\frac{\partial p}{\partial x} = \frac{\partial}{\partial x}(Ap) - p\frac{\partial A}{\partial x} \tag{2.20}$$

Assumption 3. The stream is now in a "steady state" condition, i.e. no changes in time:

Mass

$$\frac{\partial}{\partial x}(\rho A v) = 0 \tag{2.21}$$

Impulse

$$\frac{\partial}{\partial x}(\rho A v^2) + A\frac{\partial p}{\partial x} = 0 \tag{2.22}$$

The expression $\partial_x(\rho A v^2)$ can be written:

$$\partial_x(\rho A v^2) = v\partial_x(\rho A v) + \rho A v \partial_x v, \tag{2.23}$$

From eq. (2.21), simplifications can be made:

$$\rho v \frac{\partial v}{\partial x} + \frac{\partial p}{\partial x} = 0 \tag{2.24}$$

$$\partial_x\left(\frac{1}{2}\rho v^2\right) = \frac{1}{2}v\partial_x v + \frac{1}{2}v\partial_x v = v\partial_x v \tag{2.25}$$

Now (2.24) can be written:

$$\rho\frac{\partial}{\partial x}\left(\frac{1}{2}v^2\right) + \frac{\partial p}{\partial x} = 0 \tag{2.26}$$

Assumption 4. The density is constant (by assuming incompressible fluid or small pressure drops).

Now the expression is:

$$\frac{\partial}{\partial x}\left(\frac{1}{2}\rho v^2 + p\right) = 0 \tag{2.27}$$

And further:

$$\frac{1}{2}\rho v^2 + p = constant \tag{2.28}$$

- along the pipe. This is the standard principle of Bernoulli.

2.9.1 Volume rates and pressure drops.

By assuming that the Pressure Drop $\Delta p = p_1 - p_2$ is known, the volume flow rate can be found by:

$$Q = A_1 v_1 = A_2 v_2 \tag{2.29}$$

Based on A_1, A_2, and ρ are known, from eq. (2.28) it now follows:

$$\Delta p = \frac{1}{2}\rho Q^2 \left(\frac{1}{A_2^2} - \frac{1}{A_1^2}\right) \tag{2.30}$$

Now Q can be solved by:

$$Q = \frac{A_1 A_2}{\sqrt{\rho}} \sqrt{\frac{2\Delta p}{A_1^2 - A_2^2}} = K_V \sqrt{\frac{\Delta p}{\rho}} \tag{2.31}$$

2.9.2 Two-phase and no-slip.

In consideration of a simplified two-phase model:

Assumption 5. By using no-slip between the phase velocities (see section 2.8.2 for more details), the phase velocities are equal:

$$v_g = v_l = v \tag{2.41}$$

Now the mixture density ρ can be defined:

$$\rho = \rho_g \alpha_g + \rho_l \alpha_{l,} \tag{2.42}$$

where α is the volume fraction.

The equations now are:

Mass:

$$\frac{\partial}{\partial t}\left(\rho_g \alpha_g A\right) + \frac{\partial}{\partial x}\left(\rho_g \alpha_g A v\right) \tag{2.43}$$

$$\frac{\partial}{\partial t}\left(\rho_l \alpha_l A\right) + \frac{\partial}{\partial x}\left(\rho_l \alpha_l A v\right) \tag{2.44}$$

Impuls:

$$\frac{\partial}{\partial t}(\rho A v) + \frac{\partial}{\partial x}(\rho A v^2) + A\frac{\partial p}{\partial x} = 0 \tag{2.45}$$

By again include assumption 1-3, and modify assumption 4 by applying this equation to two-phase flow:

Assumption 6. We now assume ρ_g *and* ρ_l to be constant and re- writing eq. (2.30) and (2.31) to:

$$\partial_x(\alpha_g Av) = 0 \tag{2.46}$$

$$\partial_x(\alpha_l Av) = 0 \tag{2.47}$$

Since $\alpha_g + \alpha_l = 1$ the sum of these equations is:

$$\partial_x(Av) = 0 \tag{2.48}$$

Now we also have:

$$\partial_x(\alpha_g Av) = \alpha_g \partial_x(Av) + Av\partial_x\alpha_g = Av\partial_x\alpha_g = 0 \tag{2.49}$$

And then it follows:

$$\frac{\partial \alpha_g}{\partial x} = 0 \tag{2.50}$$

It follows that the volume fraction is constant along the pipe and thereby the mixture density ρ remains constant, considering the assumption 1-3 and 5-6.

Bernoulli. Note that by adding eq. (2.30) and (2.31) will lead to eq. (2.18) where ρ is the mixture density. The same derivation from section 2.10 will give an equivalent Bernoulli principle for two-phase:

$$\frac{1}{2}\rho v^2 + p = const \tag{2.51}$$

2.9.3 Bernoulli expressed by Pressure Drop.

At a given mixture density ρ, pressure drop Δp and area A_1 and A_2, the volume can be expressed by:

$$Q = \frac{A_1 A_2}{\sqrt{\rho}} \sqrt{\frac{2\Delta p}{A_1^2 - A_2^2}} \tag{2.52}$$

This will follow the same derivation as for section 1.1. Also notice the lack of information to be able to determine the individual rates Q_g and Q_l.

2.9.4 Free slip

In the previous chapter the phase velocities at any time were strongly connected by practicing:

$$v_g = v_l = v \tag{2.53}$$

Based on this theory the phases are completely mixed. Next step is to separate the different phase velocities in a flow rate.

Assumption 7. Interaction between the phases at a common pressure. In addition with assumption 1-2 the equations now are:

Mass:

$$\frac{\partial}{\partial t}(\rho_g \varepsilon_g A) + \frac{\partial}{\partial x}(\rho_g \varepsilon_g A v_g) = 0 \tag{2.54}$$

$$\frac{\partial}{\partial t}(\rho_l \varepsilon_l A) + \frac{\partial}{\partial x}(\rho_l \varepsilon_l A v_l) = 0 \tag{2.55}$$

Impuls:

$$\frac{\partial}{\partial t}(\rho_g \varepsilon_g A v_g) + \frac{\partial}{\partial x}(\rho_g \varepsilon_g A v_g^2) + A\varepsilon_g \frac{\partial p}{\partial x} = 0 \tag{2.56}$$

$$\frac{\partial}{\partial t}(\rho_l \varepsilon_l A v_l) + \frac{\partial}{\partial x}(\rho_l \varepsilon_l A v_l^2) + A\varepsilon_l \frac{\partial p}{\partial x} = 0 \tag{2.57}$$

Applying assumption 3 and 6 as for section 2.10:

$$\frac{1}{2}\rho_g v_g^2 + p = const \tag{2.58}$$

$$\frac{1}{2}\rho_l v_l^2 + p = const \tag{2.59}$$

Resulting a Bernoulli for two “free” phases and different velocities.

2.9.5 Volume rates expressed by the Pressure Drop.

By introducing the variables:

$$A_g = \varepsilon_g A, \qquad A_l = \varepsilon_l A \tag{2.60}$$

We get an analogous derivation [5] as for section 2.10.1:

$$Q_g = \frac{A_{g,1}A_{g,2}}{\sqrt{\rho_g}}\sqrt{\frac{2\Delta p}{A_{g,1}^2 - A_{g,2}^2}} \tag{2.61}$$

$$Q_l = \frac{A_{l,1}A_{l,2}}{\sqrt{\rho_l}}\sqrt{\frac{2\Delta p}{A_{l,1}^2 - A_{l,2}^2}} \tag{2.62}$$

3 Calculations and Analysis in WellFlo

WellFlo is a Nodal analysis program. It is designed to analyze the behavior of petroleum fluids in wells. The behavior is modeled in terms of the pressure and temperature of the fluid as a function of flow rate and fluid properties.

The software uses description of the reservoir, and the well completion, and the surface hardware combined with the fluid properties data. Calculations will determine the pressure and temperature of the fluids.A typically function in WellFlo is calculation and determination of the deliverability. Another option is solving for pressure drops given measured flow rates.

WellFlo uses a technique to calculate the operating point where the pressure at a point (mode) in the system is calculated for a range of flow rates, by calculating downwards from the top of the system, and upwards from the bottom. Only one flow rate will provide the same pressure at the solution node calculated in both directions. This is graphically obtained from an intersection of curves.

The outflow part of the calculation will run from the top of the component selected as the top node, down to the solution node. The inflow part of the calculation will run from the bottom of the component selected as Bottom Node, up to the solution node. The bottom of the component selected as the Solution Node, is used as the End Point of both calculations.The calculation sequences are [9]:

- First, a temperature profile is calculated from the bottom and up for the current rate.
- If gas lift is being performed, the casing head pressure profile is calculating using the temperature from stage 1 and the specified CHP and injection gas gravity.
- Pressure Drop run is made between the end- and solution node for the current flow rate. Each node traverse is sub-divided into computation segments.
- Pressure drop are calculated sequentially.

Also in the program, the bottom of the casing component is the mid-perforation depth. This flow rate and the corresponding pressure, determine the operating point [9].

3.1 Tuning Procedure in Wellflo

There are a number of parameters to tune in order to match the model to observations. The objective must be a consistent technique of matching that depends on what causes the deviation.

3.1.1 Well parameters

In this category there are especially three important factors. These are the inner diameter of the tube, wall roughness and well path. It is appropriate to tune these parameters since the uncertainty could be relatively significant. Wall roughness affects the frictional pressure drop gradient while the well path (horizontal/vertical well) mainly affects the hydrostatic and the acceleration friction drop gradient. For horizontal well a pressure drop calculation procedure may use the term “liquid holdup” which also compensate for the lack of potential energy.

Besides well parameters, fluid parameters from PVT and reservoir parameters are build in the model.

3.1.2 Input parameters

A wellmodel is tuned for each new test results and the be imported in Optimum Online.

Data input from the well test are:

Q liq - Liquid volumetric flow rate (water + oil)

GOR - produced gas oil ratio

WC - Produced water cut

WHP - Wellhead pressure

WHT - Wellhead temperature

Addition for gas lift wells:

GIR - Gas injection rate

CHP - Casing head pressure

Based on these input data the bottom hole flowing pressure (IPR) is calculated with the best fit pressure drop correlation (TPR). The operating point is given by the intersection between the inflow and outflow curve and will estimate the deliverability for the well. The test reliability for each well will depend on the quality of the inputs. The well test data should be use critically before approved, especially for unstable wells (slug).

The Vogel equation is used for calculating the inflow performance curves for all the wells in the Analysis (read section 2.1.2 for more details).

3.2 Pressure drop correlations

The pressure drop correlations are used to calculate the pressure drop from the bottom hole to the wellhead. The accuracy of the estimations varies with rate, GOR, WC, well inclination, tubing size, gas lift etc.

A general expression for the pressure drop is given by the hydrostatic (eq. 2.3), frictional (eq. 2.4) and acceleration pressure (eq. 2.5) loss.

There are several different correlations to choose between in WellFlo. Correlations used in this study are:

- Duns and Ros standard
- Duns and Ros modified
- Beggs and Brill standard
- Beggs and Brill modified
- Beggs and Brill no slip

- Hagedorn and Brown modified
- Gray

None of the correlations consider oil-water slip. Duns and Ros, Beggs and Brill have flow pattern consideration and gas-liquid slip included in the calculations. Hagedorn and Brown only consider gas-liquid slippage, but do not consider flow pattern.

The category of correlation used in this analysis is *Well and Riser Flow Correlation* which is used in well components below the Wellhead and cover vertical, slanted or horizontal wells.

3.2.1 Tuning with L-factor

The L-factors can be used to calibrate or adjust the pressure drop computation in the well, the pipeline or the sub-critical choke setting. During the Nodal Analysis, the total pressure gradient in each computation increment (normally 250 ft), will be multiplied by the value which is specified for the appropriate L-factor. This means that a L-factor less than 1 will reduce the calculated pressure drop and for an L-factor more than 1 it will be increased.

By apply all the pressure drop correlations computed in the Well and Riser Components, the values can be used as a sensitivity analysis for fine- tuning a correlation to match measured data. This will automatically find the best match for a set of measured data points.

3.2.2 Temperature gradient Correlations in WellFlo

Variations in thickness of the pipe wall along the wellbore, and different fluid properties in annulus will influence the heat transfer between the well and the fluid on its way up to the surface. This will lead to different thermal gradients along the path. The model takes this into consideration.

There are three temperature models available in WellFlo[9]:

1. Manual. This is the simplest temperature model. It uses the temperature specified at component nodes and interpolates between them. This is a static temperature description and the same profile is used at any flow rates.
2. Calculated. This is a model that calculates the temperature profile at each flow rate from a component-by- component simplistic heat loss model. It is based on Ramey's and Willhite's Heatloss correlations and does not account for any pressure effect. The model works on a component by component basis and takes the deviation (well path) into account which affects the external temperature gradient.

The reservoir fluid is assumed to enter the well bore at layer temperature, T_{res} and heat transfer is modelled between the flowing wellbore fluid column and the external geothermal temperature and is accounting for the heat loss coefficients of the intervening media.

A constant A_r for a given flow rate is calculated between the components from its heat transfer coefficient, U_{wb}, the specific heat of the wellbore fluid mixture, C_{pf}, and the thermal conductivity, K_e of the surroundings. The surroundings could be air, sea water or earth depending on the displacement and elevation.

Relaxation Distance, A_r, is given by:

$$A_r = \frac{Q_m C_{pf}}{2\pi \cdot r_{ci} U_{tf}} \tag{3.1}$$

Where

Q_m -is the mass flow rate

U_{tf} -is the total heat transfer.

U_{tf} is given by:

$$U_t = \frac{K_e U_{wb}}{K_e + U_{wb} r_{ci} f_D(t)} \tag{3.2}$$

Where

r_{ci} -is the inner pipe diameter

U_{wb} is the Heat Transfer Coefficient that appears in the component and includes tube, annulus fluid, casing and cement, i.e. well components and for surface components.

$f_D(t)$ is a dimensionless transient heat conduction time function for the earth derived from the Hasan and Kabir [9].

The relaxation distances A, are calibrated so that the computed wellhead temperatures and separator temperatures match the values at the specified flow rates. Downhole, the relaxation distance is calibrated against the upstream wellhead temperature. For the surface facilities, A_r is calibrated against the heat loss from wellhead to the separator. This model is taking into account the different flow rates and is therefore the most accurate.

The well components lose heat by conduction from the well stream temperature to the surrounding formation at a geothermal Temperature which is interpolated between the layer and the surface. The heat transfer will therefore depend on:

- The Flow Rate
- Fluid in the annulus
- The calculated or an input heat loss coefficient of each component.

Downstream of the wellhead, the heat transfer is modeled between the moving flow line fluid and external ambient temperature.

The model changes at the wellhead/Xmas Tree node. Instead of varying the external (earth) temperature, T_e, there is assumed to be a constant ambient surface temperature for each component. For surface the model is now simplified by no longer being dependent on depth, deviation or elevation.

The surface components lose heat by convection to the surroundings medium at the specified atmospheric temperature (or seawater), depending on elevation. The heat transfer coefficient is depending on:

- The flow rate
- The calculated or the manually entered heat loss coefficient of each component
- The heat transfer coefficient of the fluid entered in the wellhead/xMas Tree dialog.
- Ambient surface temperature is assumed to be applied with inputs:
- Sea Water Temperature
- Ambient surface temperature

3. Calibrated. This is an option to tune the calculated model to a temperature measured at a known flow rate at the well head or gauge and the outlet temperature, e.g. separator. The calibration applies one tuning factor from the reservoir to the wellhead or gauge, and another tuning factor from the wellhead or gauge to the outlet node such that the calculated temperatures at the specified flow rate match the specified wellhead-or gauge temperature and the outlet temperature. These tuning factors are then applied in the program.

The following inputs are required:

- The ambient surface – and sea water temperature.
- Measured wellhead temperature.
- Temperature of the fluid entering the separator or at the outlet node.
- The flow rate (oil and water) at which these temperature were measured.

A subsurface model will automatically assume liquid in the tubing-casing annulus unless only gas in annulus is selected. The option then is “Gas to MD” in the annulus, an option that is partly filled with gas and partly filled with liquid. WellFlo then calculates with gas in overlying measured depth (MD) whereas below MD is assumed to be filled with liquid. Otherwise (when gas in annulus is selected) the program assumes that annulus below the MD also is filled with gas. This is something that has to be considered for gas lifted wells.

WellFlo will use different heat loss models for well components above and below the specified measured depth (MD). The default Thermal conductivity for gas in annulus is 0.504 BTU/ft.D.°F and for water 9.192 BTU/ft.D.°F. These values can be modified.

Figure 3.1 and 3.2 shows sensitivity analysis on gas lifted well M-18. The first figure is calculated with gas only in annulus, while the next is calculated with gas to middle side pocket mandrel, resulting in different flow rates.

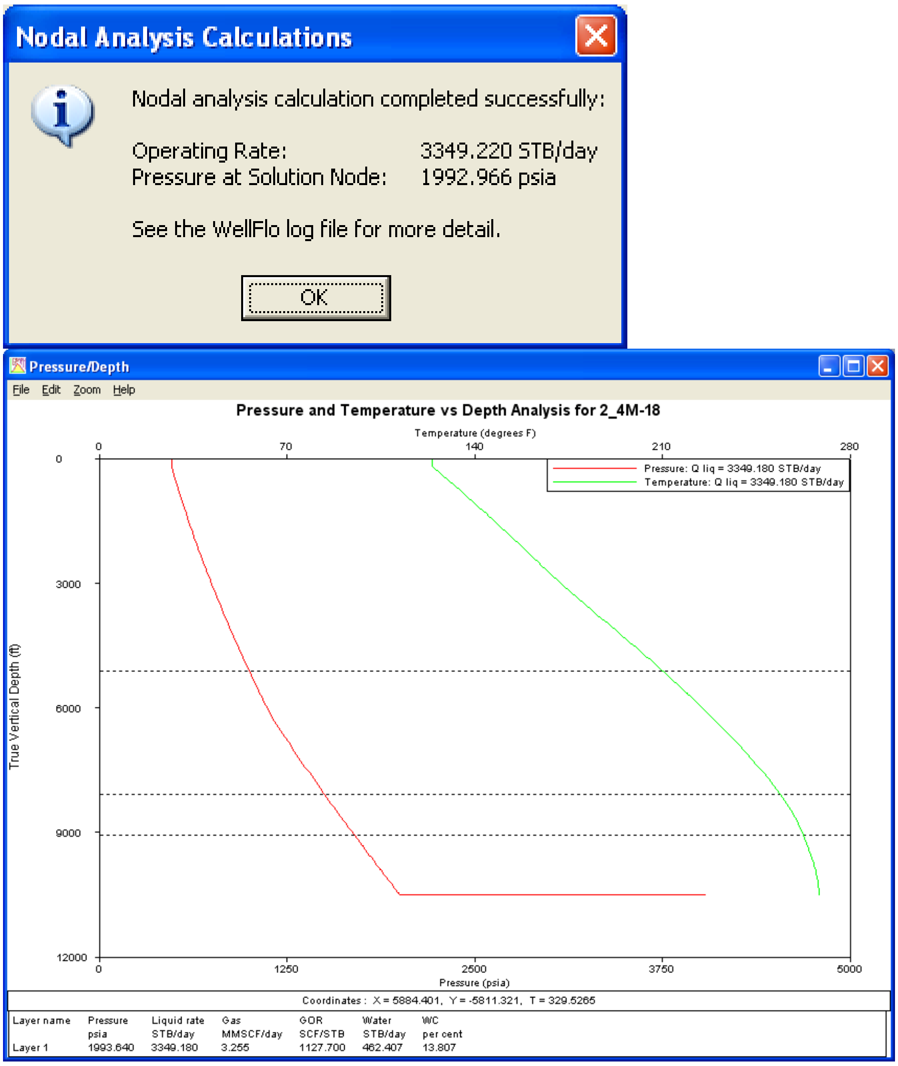
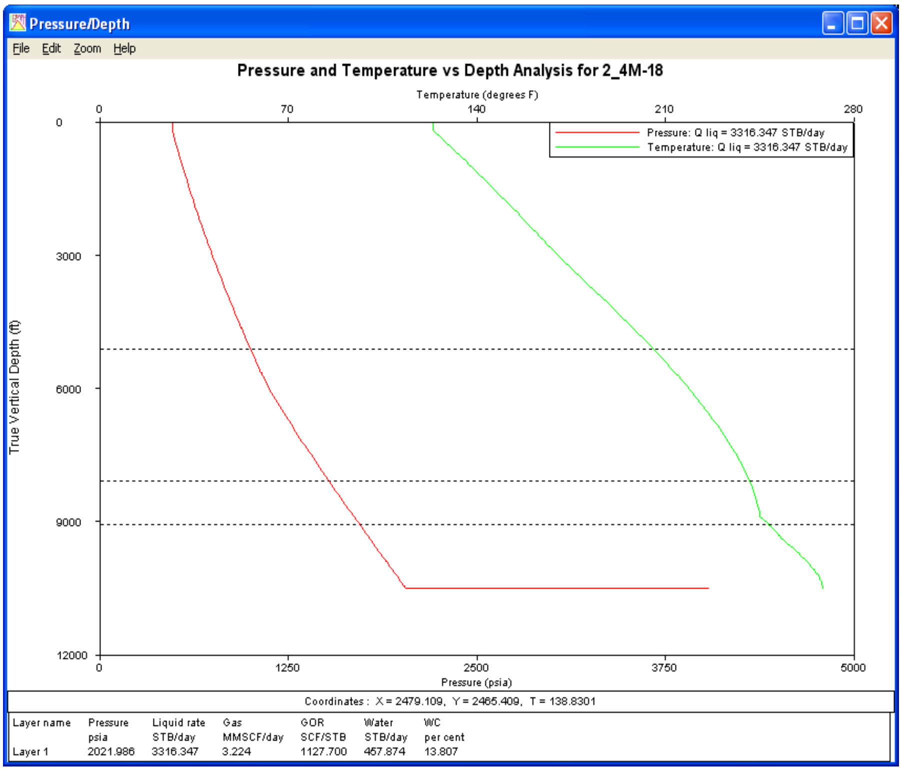


Figure 3.1. Shows a temperature profile for a gas lifted well with only gas in annulus.



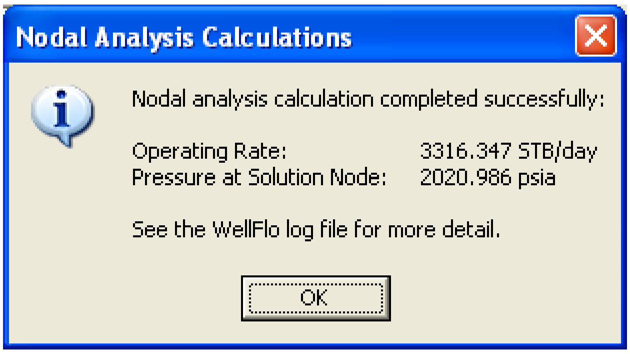


Fig.3.2 .Shows a temperature profile for a gas lifted well with gas only to measured depth.

Temperature gradient calculation for each well is based on Ramsey and Willhite's heat loss correlation. A constant true vertical geothermal gradient is calculated from the surface down to the reservoir.

The overall heat transfer coefficient depends on resistance to heat transfer from the flowing fluid to the surrounding medium, soil for the casing and seawater for the riser [11]

$$\frac{1}{U_{tot}} = \frac{r_{to}}{r_{ti}h_t} + \frac{r_{to}ln\left(^{r_{to}}/_{r_{ti}}\right)}{k_t} + \frac{r_{to}ln\left(^{r_{ins}}/_{r_{to}}\right)}{k_{ins}} + \frac{r_{to}}{r_{ins}(h_c-h_r)} + \frac{r_{to}ln\left(^{r_{co}}/_{r_{ci}}\right)}{k_{cas}} + \frac{r_{to}ln\left(^{r_{wb}}/_{r_{co}}\right)}{k_{cem}} \quad (3.3)$$

Where

U_{tot} - is the overall heat transfer coefficient

r_{to} - is the outside radius of the tubing [ft]

r_{ci} - is the inside radius of the casing [ft]

r_{ti} - is the inside radius of the tubing [ft]

r_{ins} - is the radius outside the insulation material [ft]

r_{wb} - is the wellbore radius [ft]

r_{co} - is the outside radius of the casing [ft]

k_{cas} - is the conductivity of the casing material [BTU/hr-ft^2-°F]

k_{cem} - is the cement conductivity [BTU/hr-ft^2-°F]

h_t - is the forced heat transfer coefficient for the annulus fluid [BTU/hr-ft-^{2}°F]

k_{ins} - is the conductivity of the insulating material [BTU/hr-ft^2-°F]

k_t - is the conductivity of the tubing material [BTU/hr-ft^2-°F]

h_c - is the convective heat transfer coefficient for annulus fluid [BTU/hr-ft^2-°F]

Deduction is not included. The temperature is a function of the pressure drop gradient and is calculated simultaneously. In WellFlo nodal analysis the pressure and temperature gradients are solved explicitly, [9).

3.2.3 Oil-Water slippage in WellFlo

The pressure drop correlations in WellFlo are treating oil-water-gas flow as a type of gas-liquid flow. All the correlations in WellFlo are treating oil and water as one phase and the density is averaged. The error caused by such an assumption is depending on the flow pattern. For non-segrated flow, water in oil or oil in water, the phases are expected to be mixed. The degree of a homogeny mixture will then be high and water and oil flowing as a single phase. A very viscous oil flow rate it will lead to a dispersed bubble flow with little water hold-up resulting in no-slip.

For segregated flow, oil and water will not flow with the same phase velocity. The slip will then depend on the flow rates and inclination of the well. Oil can move both faster and slower than water and this is a source of error and may give both overestimated and underestimated pressure drops.

3.2.4 Surface Choke

For the mixture flow, the pressure drop is computed using a critical or sub-critical flow equation. The critical flow equation is handled by a correlation selected in the Nodal Analysis. Downstream pressure cannot be determined in the case of critical flow. If critical flow occurs in an upstream to downstream through a choke, the computation stream will stop at the choke.

3.2.5 WellFlo reports

For more specific relevant details, reports may be generated by a View Analysis Log which gives a view of detailed information about fluid properties during the Nodal Analysis Calculation.

The parameters listed are:

- Pressures and temperatures
- In-situ flow rates, densities and viscosities of each phase
- In-situ phase and superficial velocities
- Hydrostatic, frictional, acceleration and total pressure gradients
- No slip and in-situ liquid holdups
- Flow regime identifiers
- Erosional velocity

Each Correlation has flow regime numbers. The numbers can be reported versus measured- or true vertical depth, or versus length from wellhead for surface Components.

4 The Analysis

4.1 Objective of the study

The objective of this study is to gather and analyse relevant available information from existing data sources in order to improve the production profile in real-time production estimates. Data from permanent temperature and pressure sensors can be interpreted in order to ensure the quality of the estimates. New solutions are required when there is an indication of deviations between estimated flow rates and welltest.

The software simulation programs used is fully described in section3.

Bernoullis equation will be used in calculations of predicted flow rate through choke and be analyzed before compared with estimated flowrates from Optimum On-line.

4.2 The procedure

This is a practical analysis of finding the flowrate as a function of pressure drop. Upstream choke pressure and downstream choke pressure will determine the pressure drop across a choke. By making some simplifications and using Bernoulli principle associated with increase of flow speed, a calculated flowrate through choke is conducted.

In this work there will be performed analysis on the wells M-01 to M-15 on the Ekofisk 2/4 Mike platform, except for M-08 and M-13 which was sidetracked during the period of research. M-07 has a continuous slug flow.

Analyzing the behavior of real time estimated production will be performed in the following way:

1. Use temperature as a verification of real-time estimated production
2. Calculate flow rates from Bernoulli's equation, and use pressure drop across chokes.
3. If thereal-time estimated production becomes unverified, the well model will be tuned against Bernoulli flowrates and implemented in the network model for new simulations and checked for temperature verification.

4.2.1 The Pressure Ratio

The pressure ratio is a ratio of the downstream pressure relative to the upstream pressure.

4.2.2 A Temperature Verification

Results of the WellFlo's calculated flow rate provide a corresponding calculated wellhead temperature and pressure. The calculated temperature will be used as a *production verification status*, by compare the calculated temperature with the measured wellhead temperature. Accepted deviation in measured temperature is set by a upper and lower limit of the calculated temperature.

An alarm will be trigged when the measured temperature is crossing the limit. This deviation will be an indication of that there has been a change in the wells performance. The estimated production is no longer representing the welltest due to changes in flowrate, watercut, GOR, etc.

It is of importance to be aware of that the estimated flowrates is controlled by the vertical lift performance curve (VLP) and not the inflow performance cure (IPR). The shape of the IPR curve, calculated in WellFlo, will only be changed by variations in water cut or GOR, while a change in the liquid rate (or reservoir pressure) will translate the VLP. This means that the estimated flowrates is only controlled by the pressure drop in the tube. This is shown by the step wise estimates following the welltests, see fig [4.1]

In this analysis the temperature verification primarily is used as a helping tool to find a more meticulous way of measuring the "natural" decline in production rate between well tests. The aim is to bring a smoother curve in the production rate versus time, instead of the step wise production estimates.

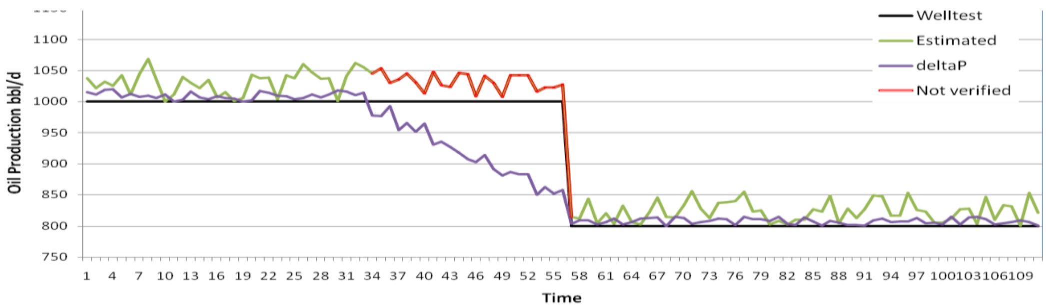


Figure 4.1. The figure is showing the RT-estimated production become unverified. The blue line represents how the Bernoulli equitation can be used and implemented in the well model in order to verify the estimates.

The upper and lower temperature limit was at first fixed to 20 degrees Fahrenheit. This seemed to be to large accepted deviation for some wells, resulting in a too high number of verified normal producing wells. Some temperature limits were reduced to 5 degrees Fahrenheit, which seems to be a good tolerance in accepted deviation for temperature. For gas lifted, slugging or unstable wells the tolerance has to be greater due to more various temperatures. For these wells the limit is 10 degrees Fahrenheit.

The Temperature Verification is directly connected to Optimum Online's real-time estimations. The system will trig an alarm when a well is unverified, (see appendix A).

4.2.3 Pressure Drop Measurements Across Choke

For unverified production, the next step is to use the surface data and make new references in the network model to improve estimated production in Optimum Online, and also by using the new data sources in determining changes that may have occurred in the well performance. This can be achieved by using Bernoulli's principle and pressure drop across the choke. Bernoulli's principle is described in section (2.10).

Measurements of upstream choke pressure and downstream choke pressure are retrieved from PI.

Before calculations, some theoretical assumptions have to be made:

- Incompressible liquid rate
- Constant mixture density (between the well tests or until change in choke size).
- Constant error from transmitter data.

Flow characteristics through the choke can be difficult to predict as one may have to assume slip in the flow regime, the moment a flow is passing through the choke. Simultaneously changes in densities varying with the pressure upwards the tube makes it difficult to predict a representative value of the mixture density. Variations in the velocities also will influence the value of the discharge coefficient and must be considered when using Bernoulli's principle. Another important consideration is to allow changes in choke size that will immediately change all these parameters. It can be difficult to maintain a sufficient complete overview of the uncertainties in the modeling process.

First, considering the available information:

- Individual flowrates from well tests
- Duration of well tests
- Pressure drop across the choke
- Monitoring the choke size.

4.2.4 Discharge Coefficient

When using the Bernoulli's principle to calculate a flowrate through choke, there is some extra pressure losses which must be compensated. These may be put into a discharge coefficient C_d which account for additional flow effects.

The discharge coefficient is a function of the Reynolds number and varies a lot in multiphase flow. Well tests measurements at test separator on the 2/4 Mike platform has showed a variation of the discharge coefficient from 0.91 to 0.96. Other measurements showed uncertainties of the C_D up to 20%., [10].

Different methods for calculations of the discharge coefficient are published with varying results, refer to [2] for further information. Determination of a good discharge estimator depends on finding a dependency of C_D in combination of many variables in terms of physical geometry and mixture properties.

Now considering eq. (2.31) Bernoulli and introduce a discharge coefficient C_D, to compensate for the friction loss:

$$Q_v = C_D \cdot \sqrt{\frac{\Delta p}{\rho_m}} \cdot K_V \qquad (4.1)$$

The dimensionless constant K_V is calculated from the cross sectional areas before and at the restriction (choke). Variations in the choke size will result in a calculation of a new constant (Kv) Also, it has to be considered the risk of scale formation in the choke, and thereby incorrect choke size. A change in the choke size will also influence the fluid properties as density and flow regime.

By averaging the pressure drop during the welltest, it will be representative to the flowrate at welltest. (read section 2.4.1 for more details on performing the welltest). Equation (3.4) may now be reversed with respect to K_V:

$$K_V = \frac{Q_{WT}}{\sqrt{\frac{\Delta \mathrm{p_{kv}}}{\rho_m}}} \cdot \frac{1}{C_D} \qquad (4.2)$$

Where

Q_{WT} - is the average of the mixed flowrate during the welltest

Δp_{kv} - is the averaged pressure drop during welltest

P_m - is the mixture density

C_d - is the discharge coefficient

The K_V value is calculated by not using the cross sectional areas due to choke variables settings and the risk of scale that also may influence the diameter. Instead it is determined during welltest. Now the flowrate can be calculated by equation (3.4):

$$Q_V = C_D \sqrt{\frac{\Delta p_{current}}{\rho_m}} \cdot K_V \qquad (4.3)$$

Where

$\Delta p_{current}$ - is the current pressure drop

And by replacing K_V:

$$Q_V = C_D \sqrt{\frac{\Delta p_{current}}{\rho}} \cdot \frac{1}{C_D} \frac{Q_{WT}}{\sqrt{\frac{2\Delta p_{KV}}{\rho}}} \qquad (4.5)$$

As can be seen by eq.(3.5), the calculated rate depends mainly on correct estimation of the density and discharge coefficient. As mentioned previous, these parameters varies a lot and involves uncertainties. The model has to be simplified, due to the lack of simultaneous gas-liquid-ratio measurements:

- The mixture density is kept constant between the welltests or until a change in the choke size.
- The discharge coefficient is kept constant until a new welltest or change in the choke size.

Now the calculated flowrate can be expressed as a function of pressure drop:

$$Q_V = Q_{WT}\sqrt{\frac{\Delta p_{current}}{\Delta p_{KV}}} \qquad (4.6)$$

During the welltest, the $\Delta p_{current}$ also should be averaged so that Q_V is equal to Q_{WT} in order do get a fully representative estimate of the rate as a function of the pressure drop. From the moment a welltest is over, the current pressure drop ($\Delta p_{current}$) will vary and Δp_{KV} remains constant until new calculations when a new welltest is performed or there has been a change in the choke size.

The calculated flowrate does not split the phases and is preliminary a measurements of total flow rate. An alternative is to use the single flowrates from welltest. This method does not account for changes in watercut and GOR. The calculated flowrate will be compared with the total estimated production from Optimum Online.

4.2.5 Building the flow rate model

To qualify the K_V, new calculations have to be done while monitoring:

- New welltests
- Change in choke size
- dP the moment K_v is calculated.

These parameters are the most important for calibratinging K_V in certain intervals. Also, the calculation account s for the uncertainties in densities and discharge coefficients. Figure 4.2 is showing an influence diagram of the dependencies in the process.

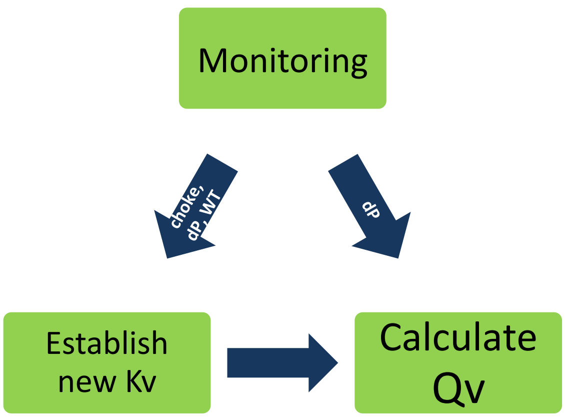


Figure 4.2. Influence diagram showing the dependencies in calculations. *Q_v is the Bernoulli flowrate.*

Calculations of the new flowrate, Q_V may be done continuously, varying with the pressuredrop measurements. The resolution in time are optional from PI. A high time resolution will be able to detect slugging in the wells, which can be a problem in some wells on the Ekofisk Field.

4.2.6 The mixture density

The mixture density must be converted to upstream condition:

The mixture density, ρ_m are calculated from the individual flowrates taken from welltests and PVT reports.. The liquid phase is assumed incompressible and gas is converted to upstream conditions by determining the compressibility factor.

4.3 Dummy tests

The Bernoulli rate is calculated at a given time period and will have a representative temperature and pressure for the same period. This is enough information to make a so called dummy test and tune the wellmodel with these parameters. Making a dummy test is only valid for unverified production. The test will be made in WellFlo (see appendix A for details) and imported in ReO for new simulations. The new calculated temperature will be tested for verification.

The inputs in a dummy test are:

- new calculated liquid rate
- Wellhead pressure
- Wellhead temperature
- Gaslift parameters, gaslift rate and casing head pressure
- DHGP (Down Hole Gauge Pressure)

The watercut and GOR will be maintained constant. Normally, the down hole gauge pressure is used for sensitivity analysis, in order to find the best fit correlation. In a dummy test, the correlation is the same as the original tuned wellmodel in order to compare the temperatures when check for verification. The only change is the L-factor which has to be determined when calculating the pressure drop in the tube.

The liquid rate is calculated as follows:

$$\frac{Q_V}{Q_{WT}} \cdot q_{l-}$$

Where

q_l - is the liquid rate from welltest (oil+water)

Several simulations with both dummy test and the unverified estimates are needed in order to make a good comparison. The simulations are performed manually, by using historical data representing the unverified period.

5 Results and discussion

In the beginning of this examination, a lot of effort was used to find a representative expression of the mixture density when using the Bernoulli equation at in-situ conditions. Converting flowrates from standard condition to in-situ, by using PVT data gave a sense of the uncertainties in the estimation and the risk of not calculate the flowrate by success. Ending up with an expression which is not involving the densities or the discharge coefficient simplified the procedure and eliminated some of the uncertainties.

A sensitivity analysis was performed on different densities to see the influence on the calculations. The purpose was to calculate fluid fractions based on upstream pressure conditions, by estimating a range of slip and at standard conditions. Using the Bernoulli equation, one has to assume that the density remains constant. It was of interest to analyze the differences in results. However, this work was early discharged due another procedure.

The upper and lower temperature limit was at first sat to be 20 degrees Fahrenheit. This seemed to be to high acceptance for deviation in temperature, resulting in a too large number of verified normal producing wells. The limits were reduced to only 5 degrees Fahrenheit, which seems to be a good tolerance in accepted deviation for temperature. For gas lifted, slugging or unstable wells the tolerance has to be greater due to more various temperatures. For these wells the limit is 10 degrees Fahrenheit.

The Temperature Verification is connected to Optimum Online's real-time estimations. The system will flag an alarm when a well is unverified, see fig [5.1]

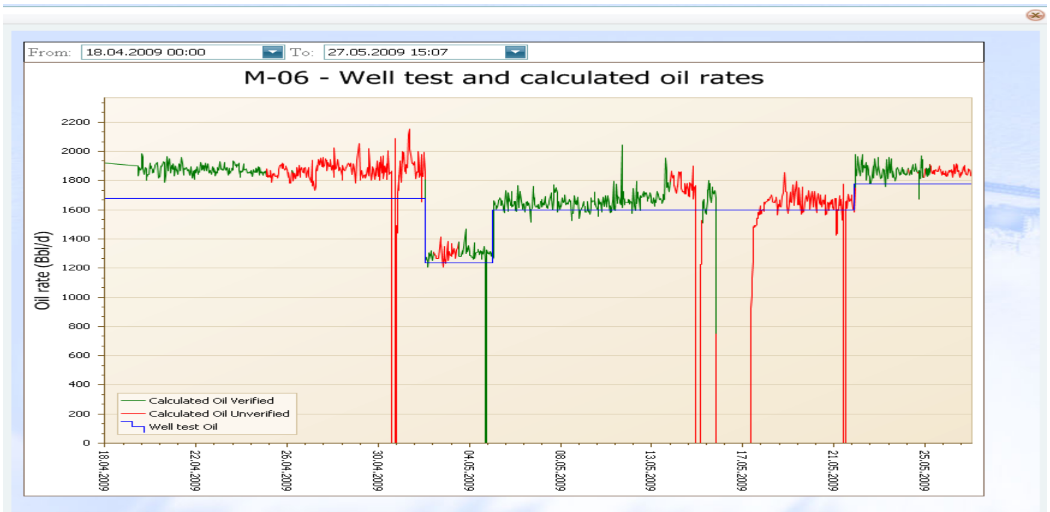


Figure 5.1 . Verification of oil Rates for the well M-06. The green line shows a verified estimation, while the red is unverified.

The flowrate calculated with the Bernoulli equation can be used as a single estimator of total flow or split the phases by using the water cut and GOR from welltest. This is not an optimal solution considering that this solution will not detect any change in the individual flowrates between the welltests.

The Bernoulli calculated flowrate was examined in several ways, in order to ensure the quality of the predicted flowrate. One option was to use 30 minutes average on the upstream pressure. This was examined on the M-07 which is a gaslifted well and is continuous producing with slug. The pink line in figure 5.2 represents 30 minutes averaged upstream pressure, while the blue represents 5 seconds time resolution. The slug is clearly represented in the graph.

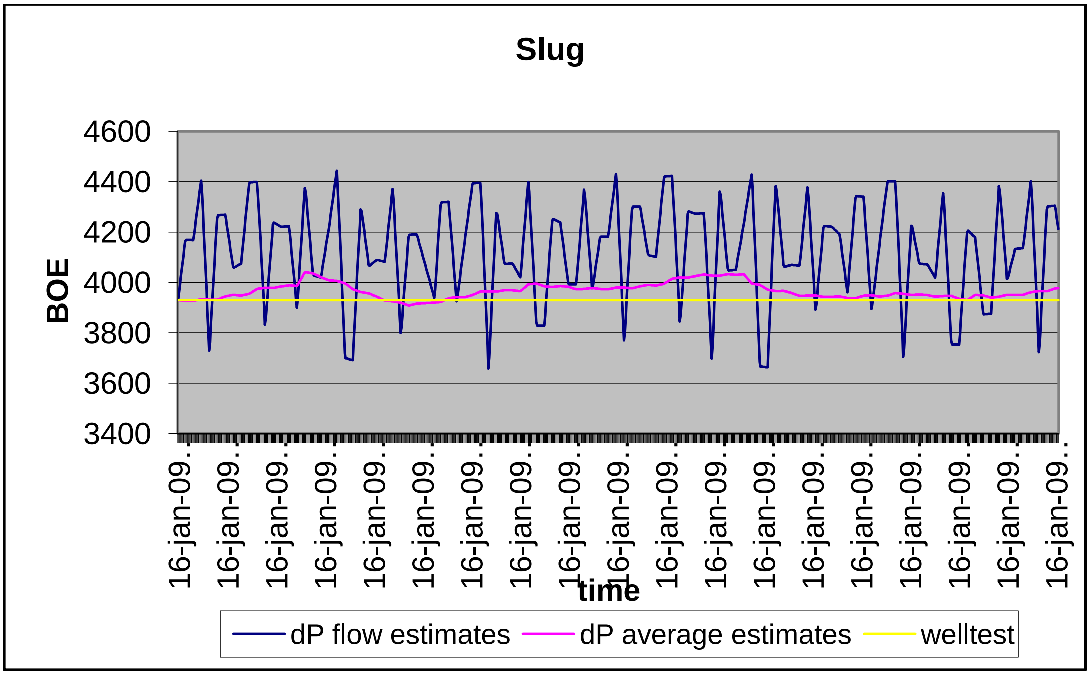


Figure 5.2. Showing slug at M-07.

Another examination performed was by using the Bernoulli pressure drop estimates on critical flow, even though the flowrate is not dependent on the downstream pressure. This was done to check the response to the measured pressure drops, (see appendix A)

The calculated Bernoulli flowrate was also checked for the dependencies of monitoring the choke and welltest. By using this method, it will always be necessary with a welltest to make the calculation. It was however, interesting to investigate how the flowrate was predicting a coming welltest. Figure 5.3 is showing the calculated flowrate, by monitoring the choke only.

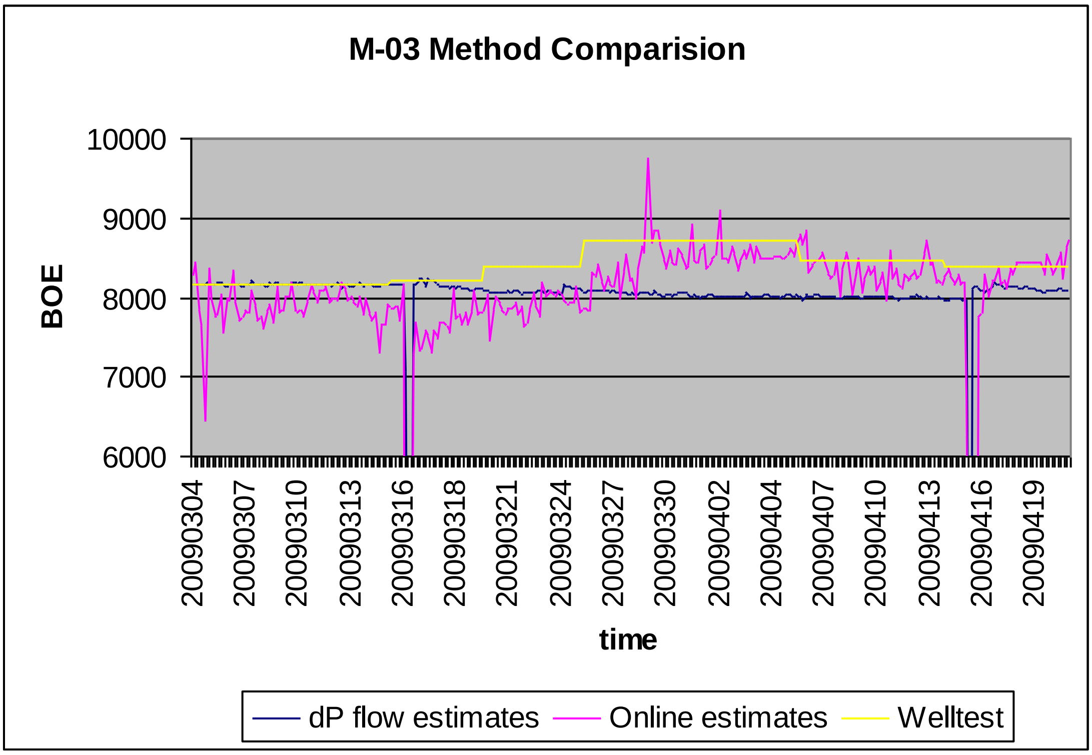


Figure 5.3. Calculated flowrate by monitoring the choke and not update with the welltests.

The Bernoulli calculated flowrate seems to detect a change in the well performance for sub critical flow. 14th of May, the well M-06 was about to die. The real-time estimated production was showing unverified before shut in (see figure 5.5). The predicted Bernoulli flow rate was also showing a decrease in production, but suddenly a large increase in production (see figure 5.3). Information from the off shore log was telling that the well was put on gaslift the15th of May, and back as a normal producer the 18th of May. The reason for a shut in status in Online estimates is the high wellhead pressure when the well was on gaslift.

At 11th of June, the method of using Bernoulli in predicting flow rate, was programmed in a local database at Optimum. Results can be seen in appendix A.

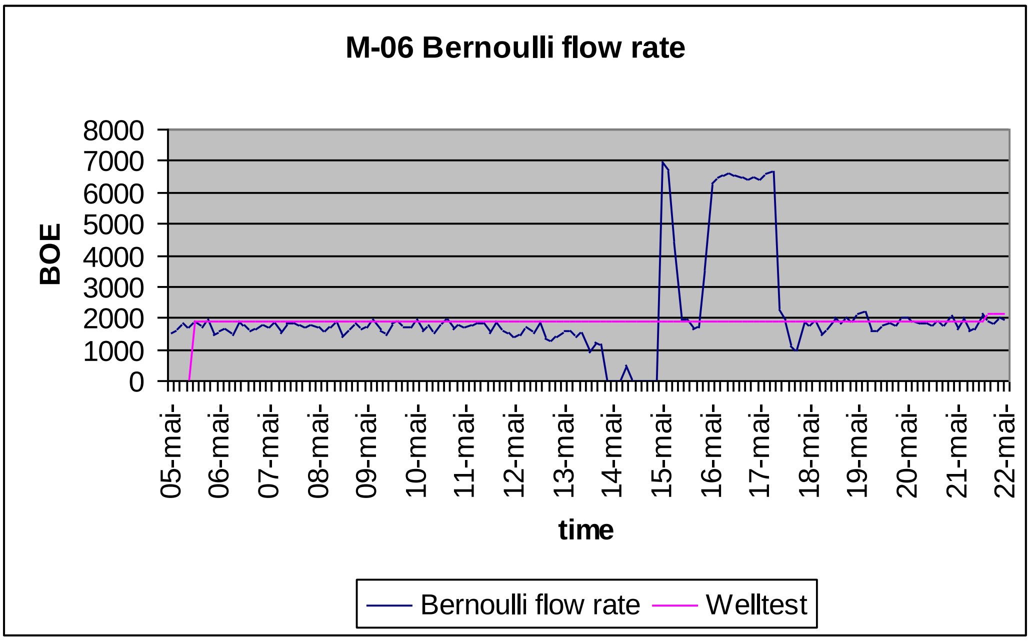


Figure 5.4 . The Bernoulli rate at first showing a decrease in flowrate, and then a suddenly increase.

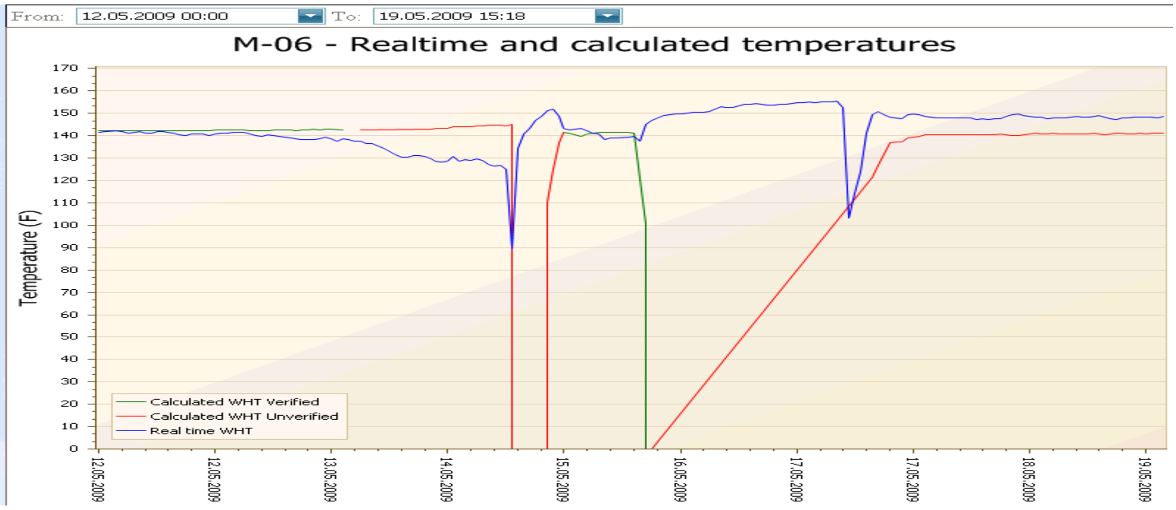


Figure 5.5. The measured temperature (blue line) is falling due to a decrease in production. The red line is sowing unverified estimates and the well is shut in.

6 Conclusion and Recommendations

1. The use of temperatures to verify real-time estimated production seems to predict a reasonably change in well performance. Advantage of this method is the ability to improve the allocation for each single well and detect any deviations in the well behavior. Variations in temperature may also indicate changes in water cut and GOR. It is important to be aware of that this method does not capture these changes. However, the deviations in temperature could be basis for further work in predicting the flux in water cut and GOR.
2. An expression for predicting the flow rate through chokes by using Bernoulli's equation was successfully found and seems to have a potential for further development. The flow rate can be used as a single BOE estimate, or for use in Wellflo as dummy tests. The benefit of only using the calculated Bernoulli flowrate is the opportunity to use historical data from PI and analyze special events at any time resolutions. This may be a powerful tool in diagnostics and planning process. In this analysis, a high time resolution of 5 seconds did detected slug flow. . A subcritical flow will predict the natural decline in production, slug flow or other unexpected behavior in the well. It is also possible to split the flow into single phases by assuming constant GOR and water cut from the well tests.

   It is worth mentioning that programming the calculations of the predicted flowrates into a software and bringing it in real time, could with contribute with the status of the well, when it is shut in. An interesting survey would then be to compare it to fiscal measurement.

   Small variations in flowrates are shown for critical flow. An unverified production could indicate a change in watercut or GOR. Therefore a pressure drop method is not an alternative for both calculating the flowrate or in dummy tests. A method that could be worth investigated, is graphing the wellhead pressure at different choke settings. The flow rate is found by the intersection of the WPR curve and the choke line.

3. Use of dummy tests in simulations during unverified periods gave a match in temperature. New dummy tests were imported in the simulation model if the a new unverified temperature.
4. Monitoring chokes to predict the relationship between the pressure drop and the flow rate through the choke seems to be a proper application to the temperature verification in detecting the change in well performance for sub critical flow. Performance of the model was found to be in good agreement with Optimum Online estimates and in matching new well tests. Over time, a reduced flow rate was observed as a consequence of decrease in pressure drop. This was also reflected periodical in the temperature verification, showing real time estimations starting to deviate from the Bernoulli estimates. Making a dummy test in Wellflo and import it to the real time model, gave a match within the temperature verification. Unstable wells, slugging or gaslifted wells needed a better tolerance in temperature acceptance and may give a reinforced well performance. Especially when putting a normal well at gas lift, or change the injection rate. By such unforeseen situations, there is need for e new reference before a new well test and could be worth further investigations.

References

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Nomenclature

A =cross sectional area [ft^2]

A_l = cross sectional area occupied with liquid [ft^2]

A_r =relaxation distance[ft]

A_g =cross sectional area occupied with gas [ft^2]

CHP =casing head pressure [psia]

dP =pressure drop

$F_D(t)$ = dimensionless transient heat conduction

g =gravity [ft/s^2]

GOR =gas oil ratio [scf/d]

GIR =gas injection rate [scf/d]

h_t = forced heat transfer coefficient for the annulus fluid [BTU/hr-ft^2°F]

h_c = convective heat transfer coefficient for annulus fluid [BTU/hr-ft^2-°F]

IPR =inflow performance relation

k_{cem} - is the cement conductivity [BTU/hr-ft^2-°F]

K_e =thermal conductivity [BTU/ft D.°F]

k_{ins} - is the conductivity of the insulating material [BTU/hr-ft^2-°F]

k_t = conductivity of the tubing material [BTU/hr-ft^2-°F]

PI =productivity index [STB/d-Psia]

P_{wf} =wellbore flowing pressure [Psia]

P_r =average reservoir pressure [Psia]

P_{pr} =pseudo reduced pressure[psia]

p_{pc} =pseudo critical pressure [psia]

q_l = liquid rate [STB/d]

q_o =oil rate [STB/d]

$q_{o\ max}$ =max oil rate when P_{wf}=0 [STB/d]

r_{ci} = inside radius of the casing [ft]

r_{co} = outside radius of the casing [ft]

Q_m =mass flow rate [lb/ft^3]

Q_V = Volume flow rate calculated by Bernoulli's equation [bbl/d] (v:venturi)

r_{ins} = radius outside the insulation material [ft]

r_{to} = outside radius of the tubing [ft]

r_{ti} = inside radius of the tubing [ft]

r_{ci} =inner pipe diameter [ft]

RT =real-time

S =dimensionless slip ratio

T_{pc} =pseudo critical temperature [degF]

T_{pr} =pseudo reduced temperature [degF]

TPR =tubing performance relation

U_{gS} =superficial gas velocity [ft/s]

U_{lS} = superficial liquid velocity [ft/s]

U_{tf} =total heat transfer

U_{tot} =overall heat transfer coefficient [BTU/hr-ft^2-°F]

u_l =liquid phase velocity [ft/s]

u_g =gas phase velocity [ft/s]

WC =water cut, dimensionless

WHP = wellhead pressure [psia]

WHT =wellhead temperature [degF]

ρ_m = mixture density [lbm/ft^3]

α_l =dimensionless estimated liquid fraction/no slip fraction

α_g =dimensionless estimated gas fraction/no slip fraction

ε_l =dimensionless true liquid fraction at slip

ε_g =dimensionless true gas fraction at slip

v_c =sonic velocity [ft/s]

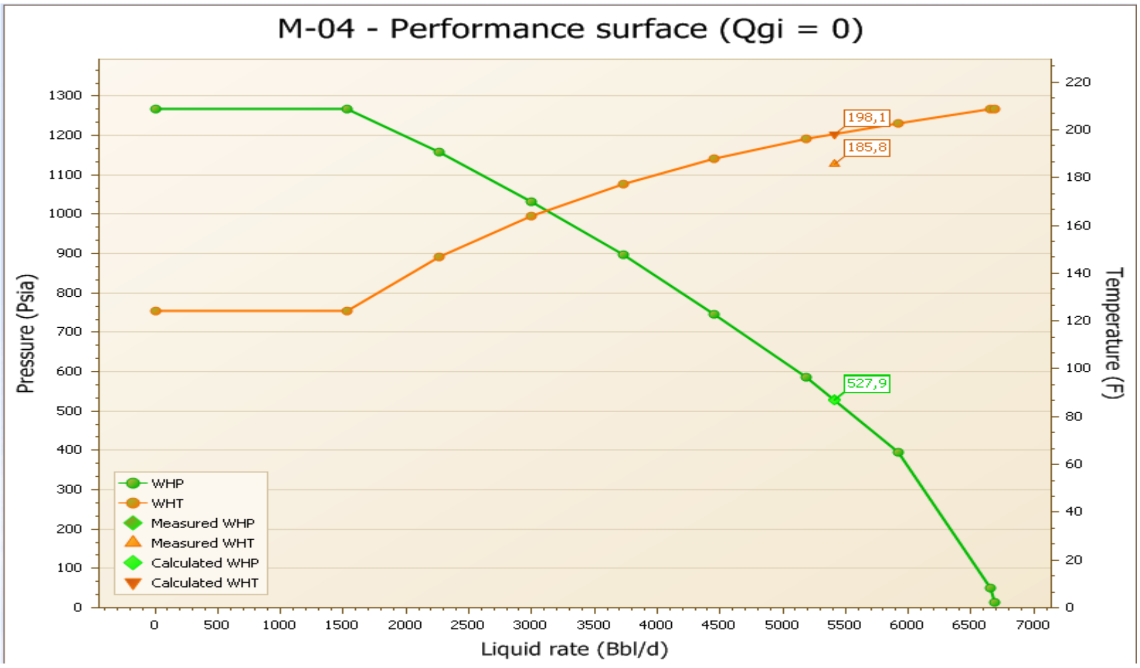
v_{gc} =sonic velocity for gas [ft/s]

v_{lc} =sonic velocity for liquid [ft/s]

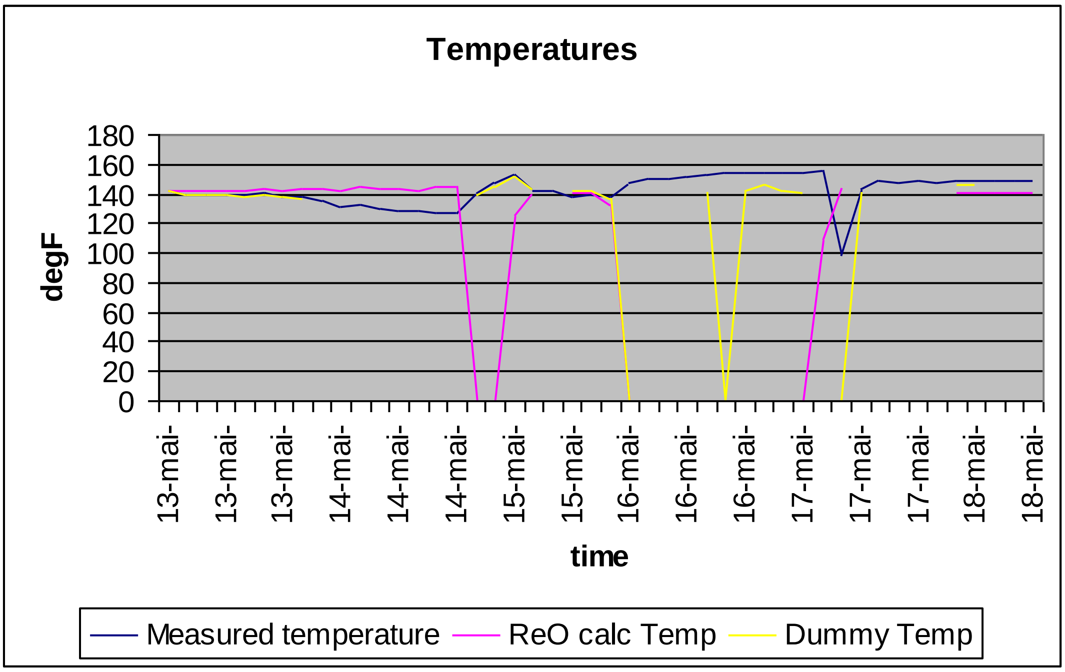
v_m = mixed velocity [ft/s]

Appendix A

The graph is showing the difference between measured temperature (outside the curve) and calculated temperature (red line) for unverified production estimates. The green line is the differences in pressure.



Simulation results at unverified temperature compared with simulation results from dummy tests for M-06. The discontinuity is a result of no results from the simulations due to high WHP



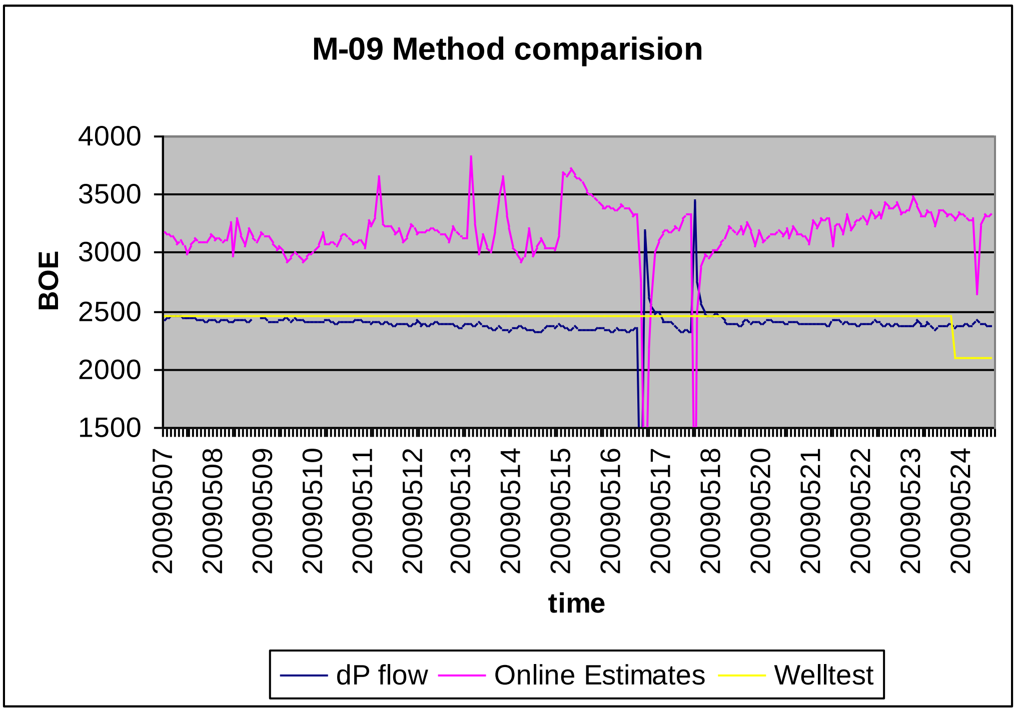
Some information about the wells:

Well	Flow	Average* GOR [scf/d]	Average* WC %	accep. dev. ΔT upper&lower lim [degF]	Comment
M-01	sub-critical	3208	9.94	10	
M-02	sub-critical	1988.4	74.96	5	
M-03	critical	1117.6	37.92	5	
M-04	sub-critical	1083.3	21.34	10	
M-05	critical	792	24.17	5	
M-06	sub-critical	1227.8	3.9	10	
M-07	critical	517.4	33.9	10	slug
M-08					sidetracked
M-09	critical	5181.2	4.98	5	
M-10	sub-critical	2601	42.6	5	variations in WT
M-11	critical	1144.7	70.1	5	
M-12	critical	1212.6	11.4	5	
M-13					sidetracked
M-14	critical	1143.9	29.2	5	
M-15	critical	1611.2	34.08	5	

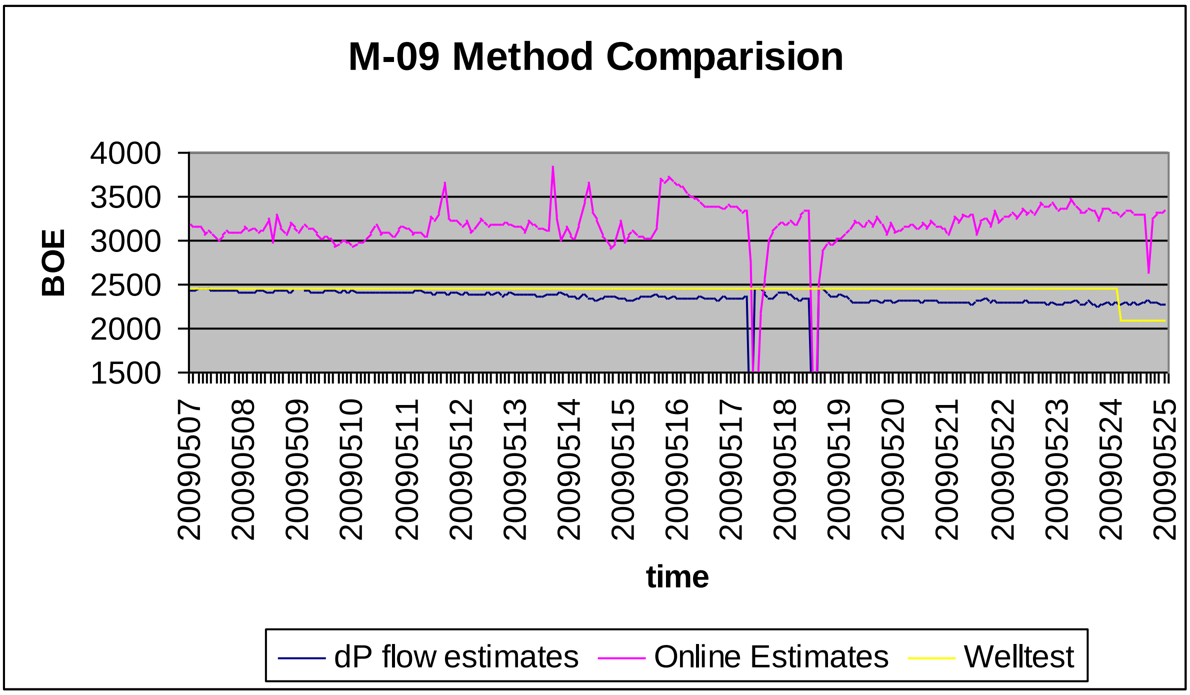
*Average from several welltests

Method Comparision

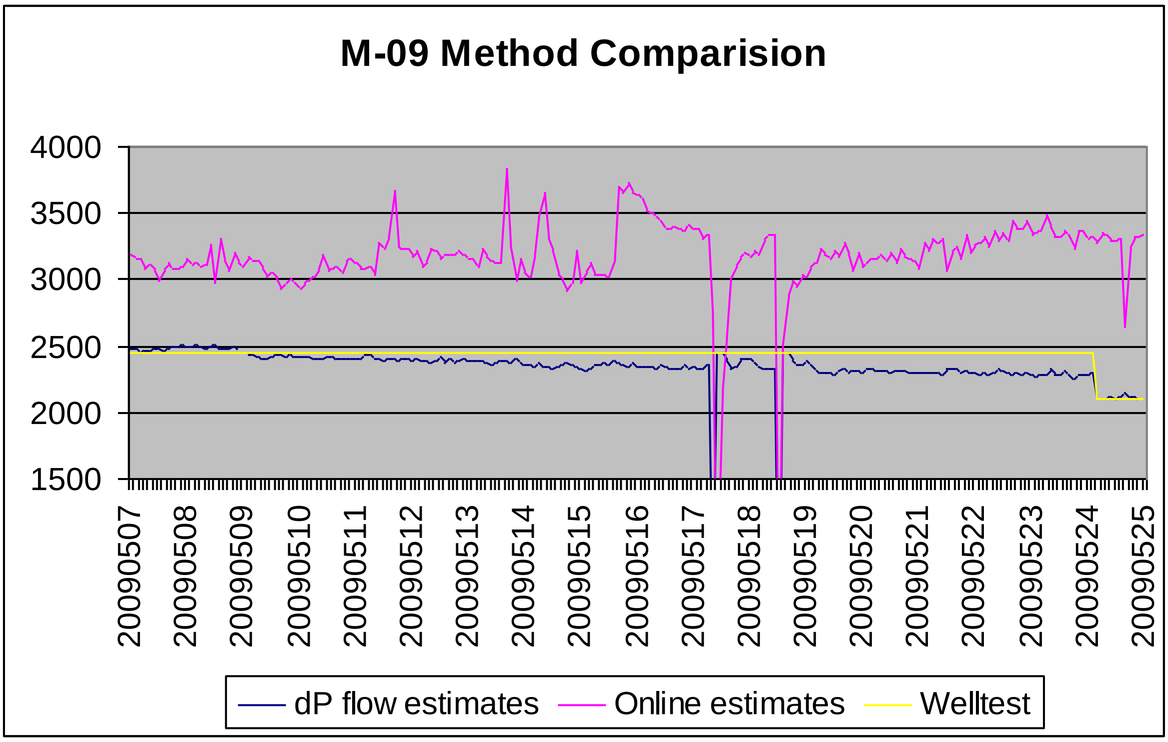
1. The graph is showing Bernoulli flow rate, without monitoring the choke size and not included with coming welltest:



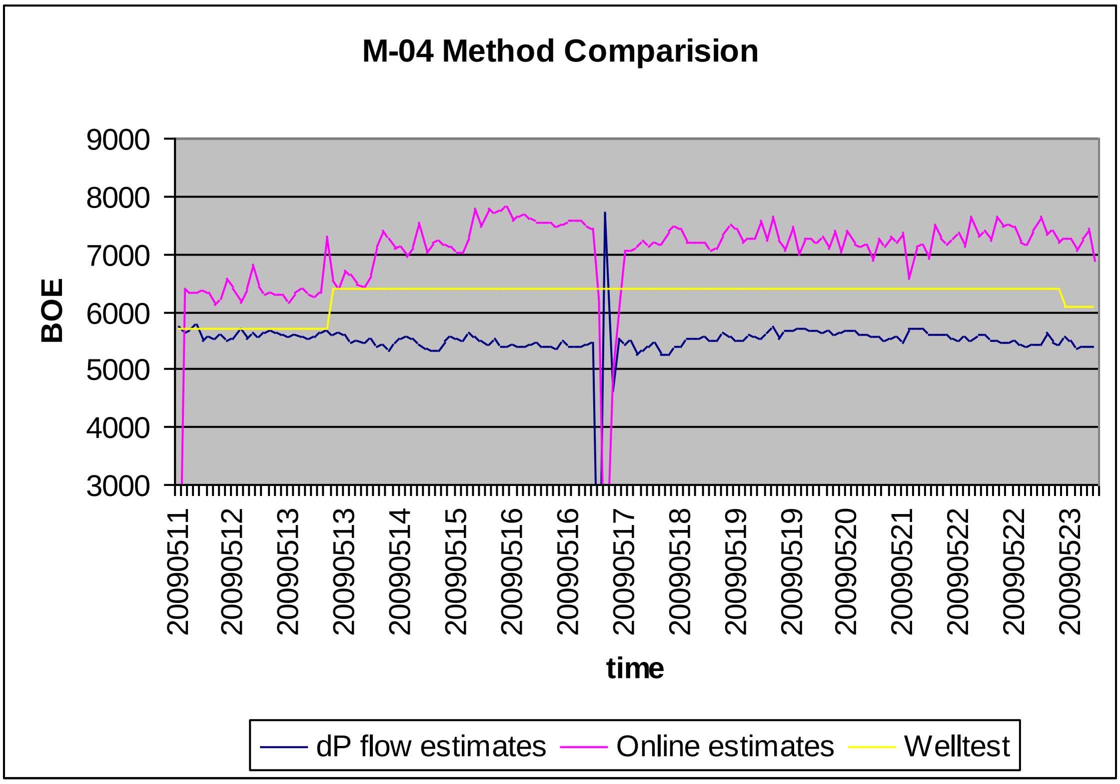
2. The next graph is showing the same well in the same time period, but is monitoring the choke:



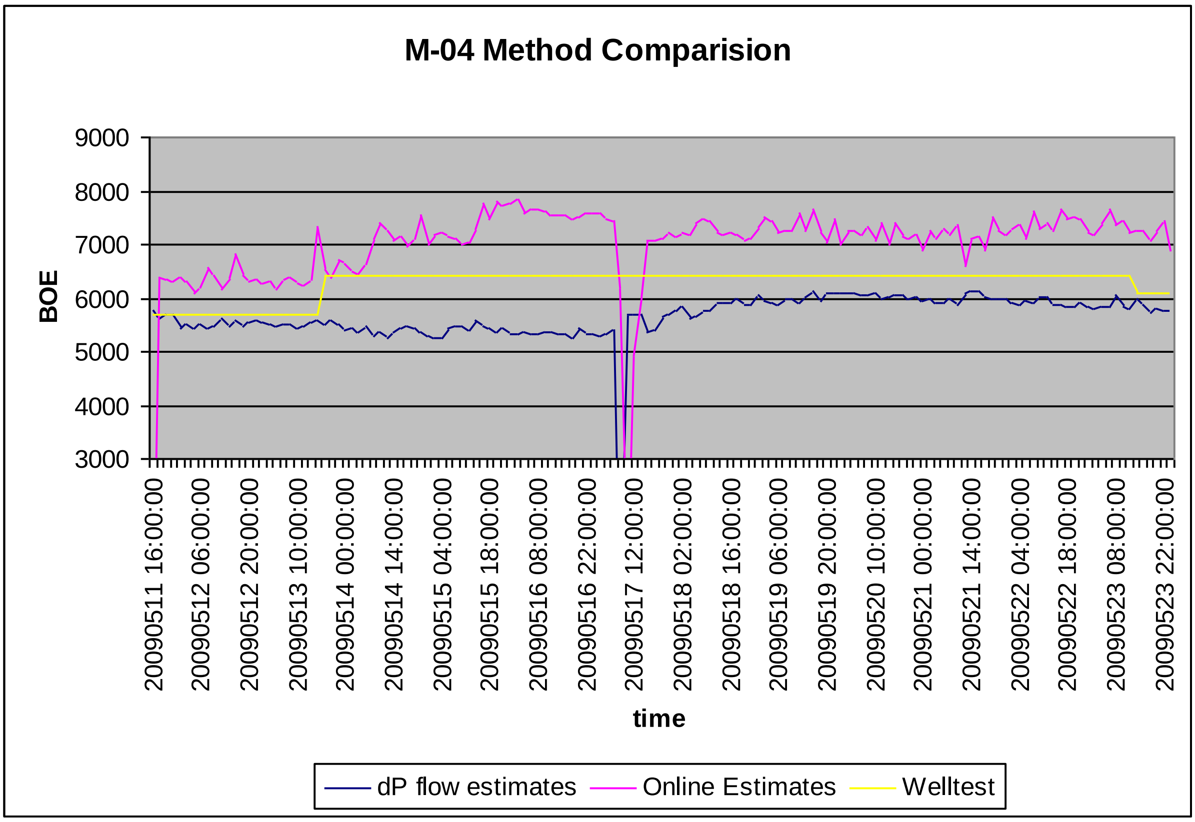
3. This graph includes both monitoring the choke and is updated with coming welltests:



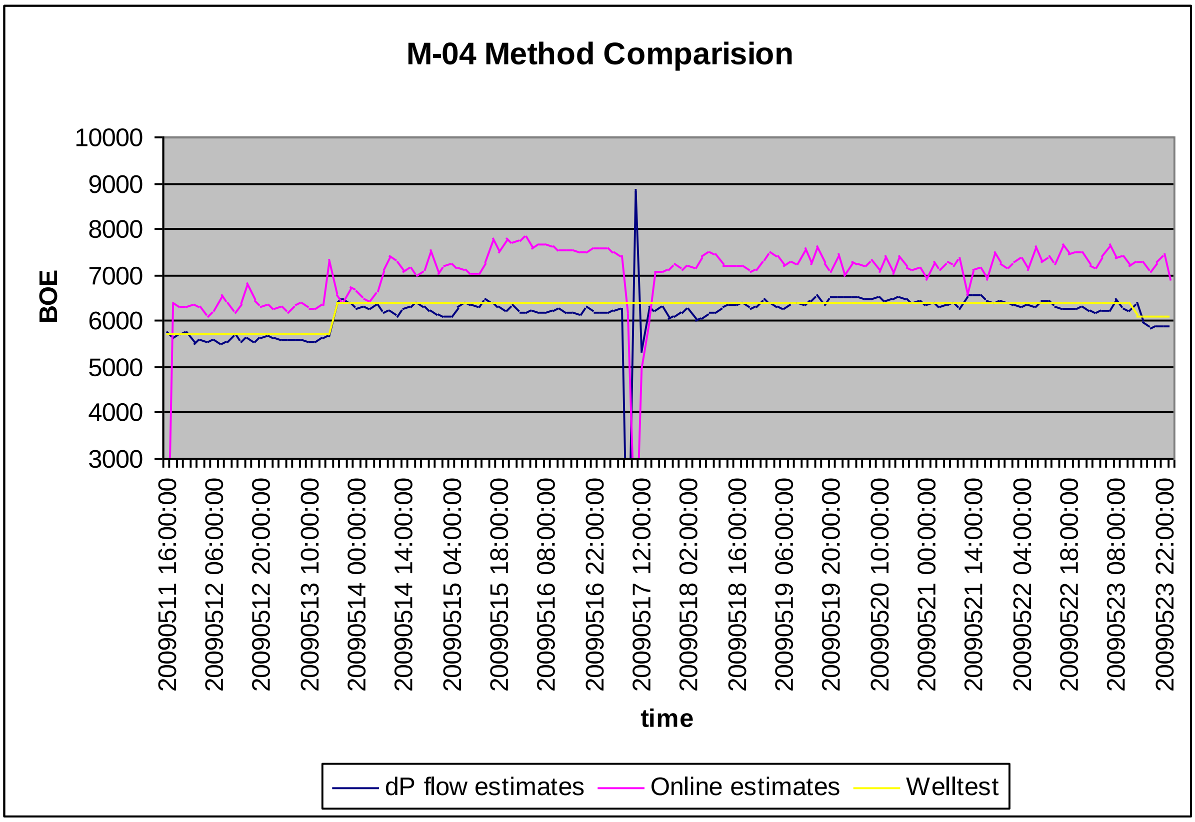
1. Calculated Bernoulli flowrate, without monitoring the choke or new welltests:



2. Calculated Bernoulli flow rate with choke monitoring, and not updated with welltests:



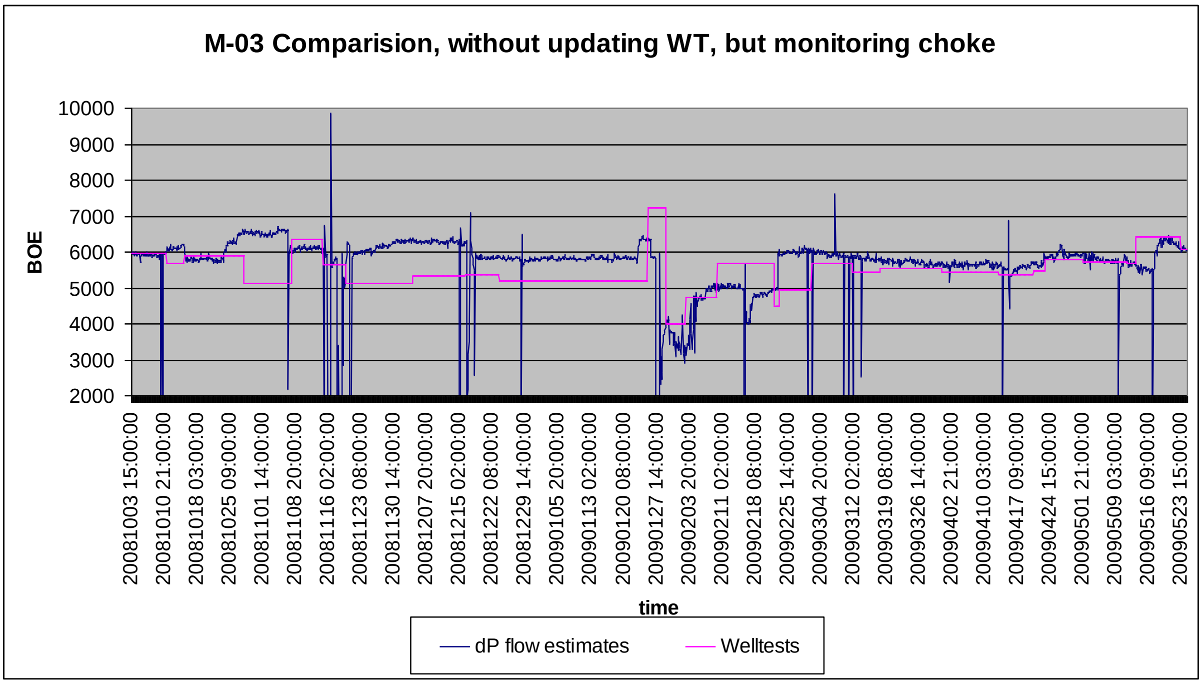
3. Calculated Bernoulli flow rate included choke monitoring and welltests:



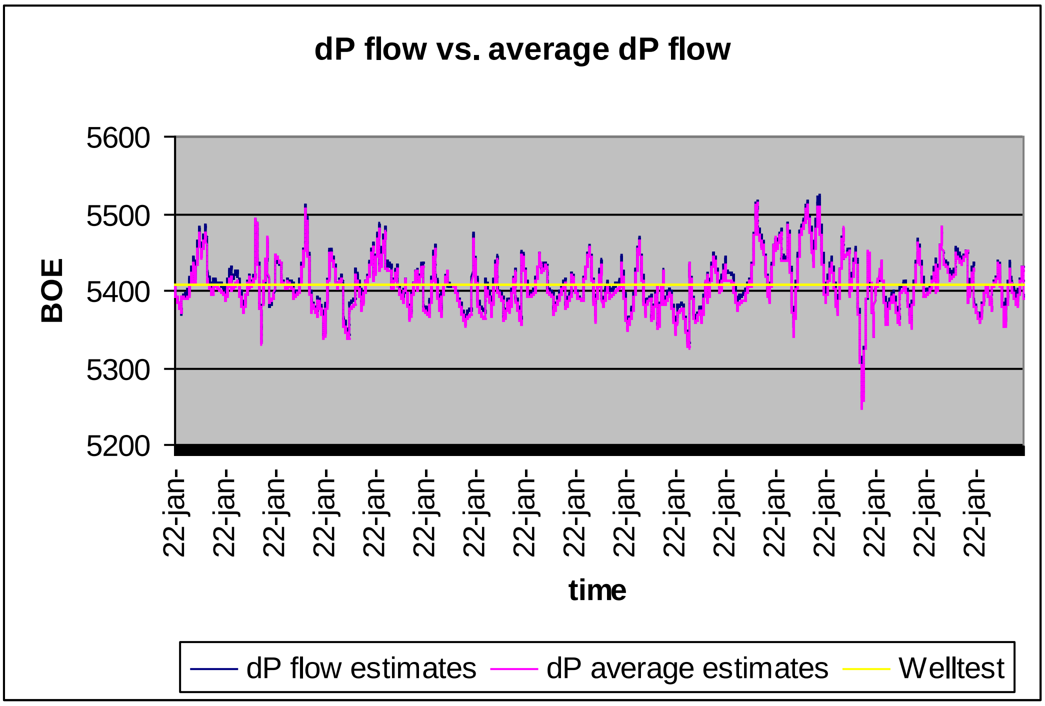
M-04 Welltests

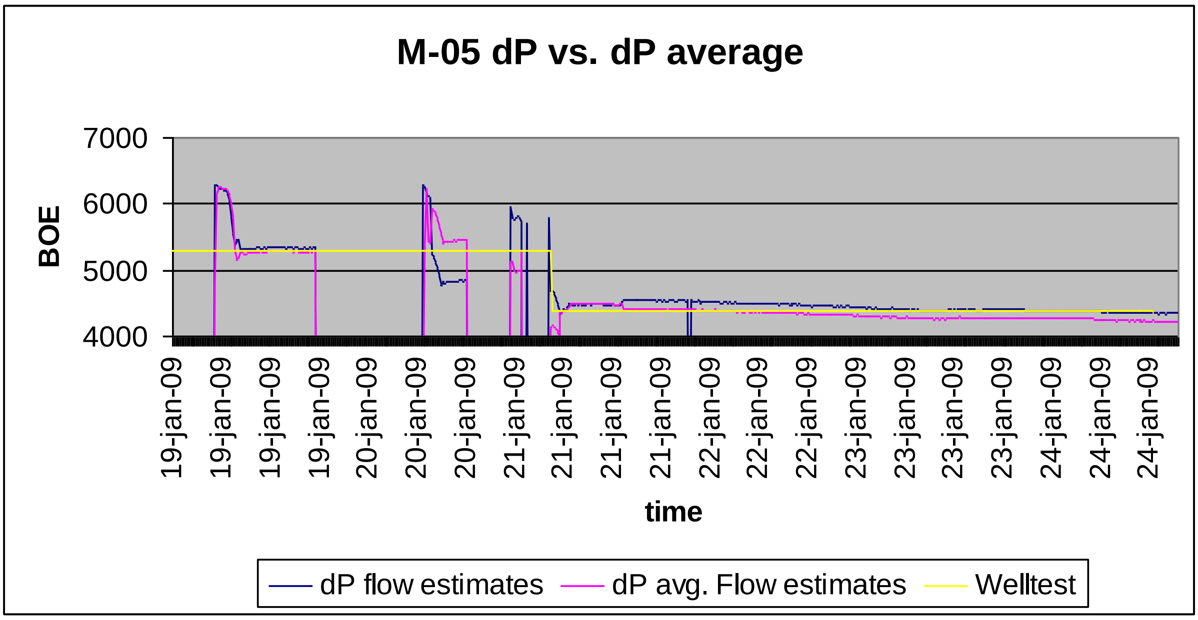
Date	WHP	WHT	GOR	WC	Duration	Q liq	BOE
39944	559	193.7	1041	21.99	17:00-21:00	5011.4	5694.73333
39946	558.4	200.9	1193	21.41	17:00-21:00	5540.6	6407.26667
39956	546.2	197.8	1028	22.08	15:00-19:00	5364.4	6081.06667

M-03 was examined for a longer period:



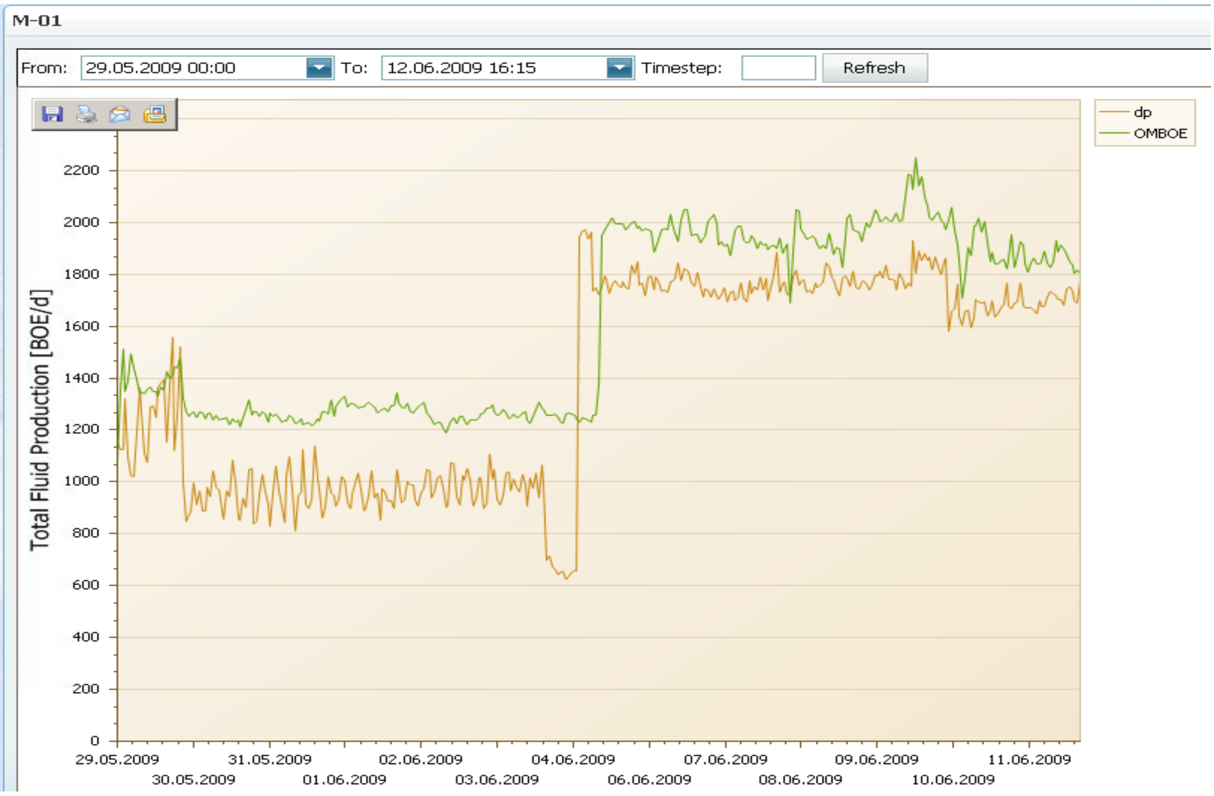
Comparing averaged upstream pressure (30 min) with 30 minutes time resolution:

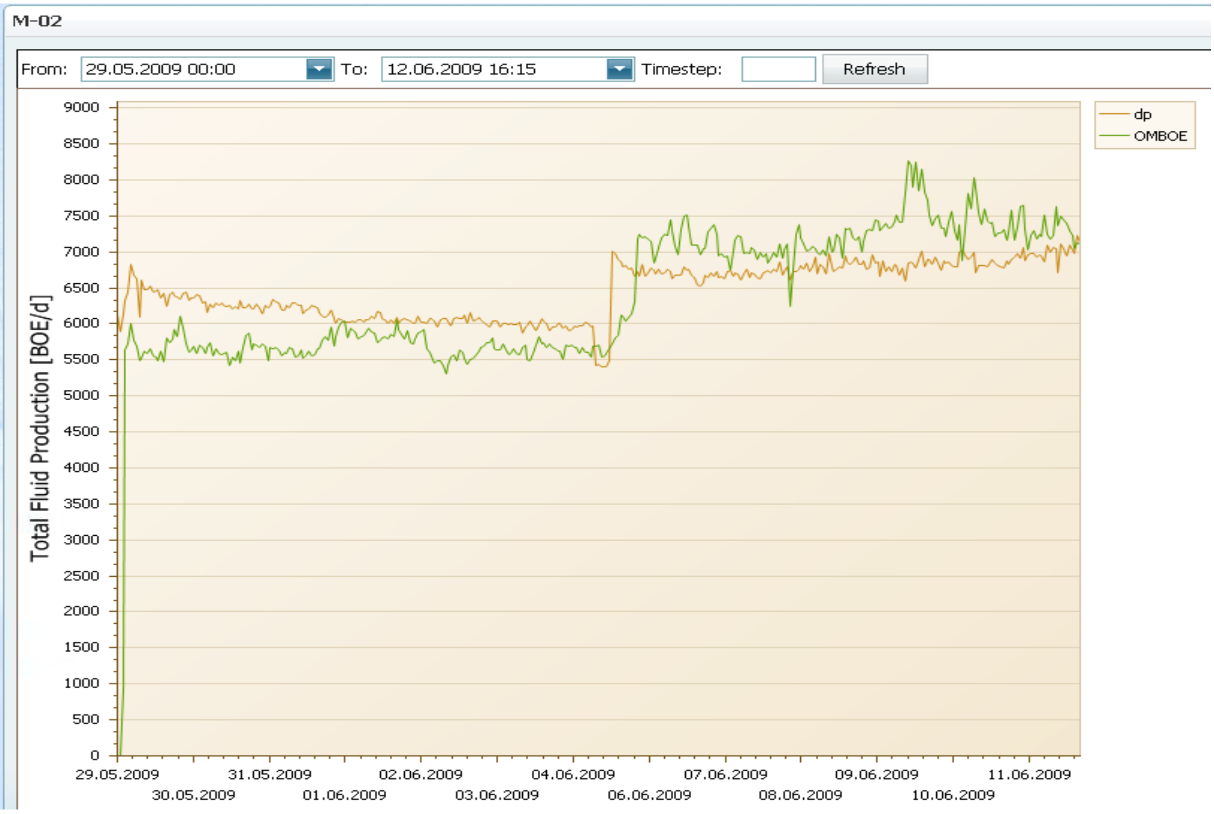


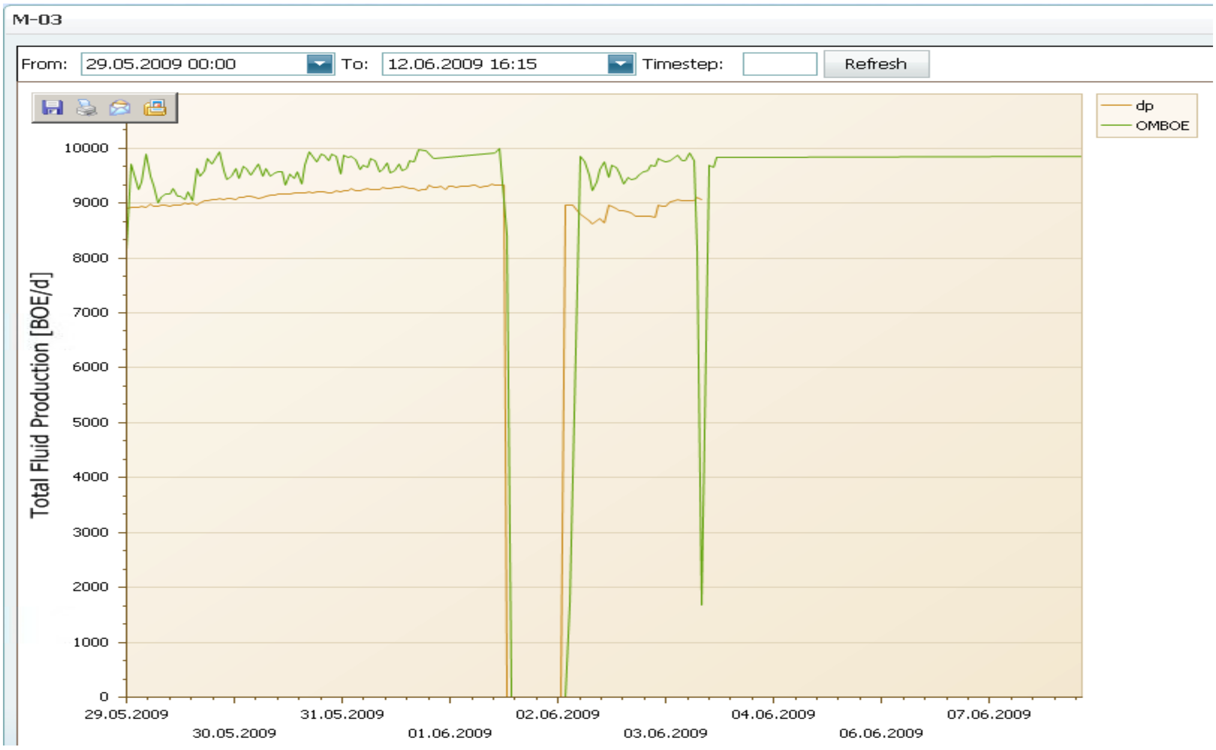


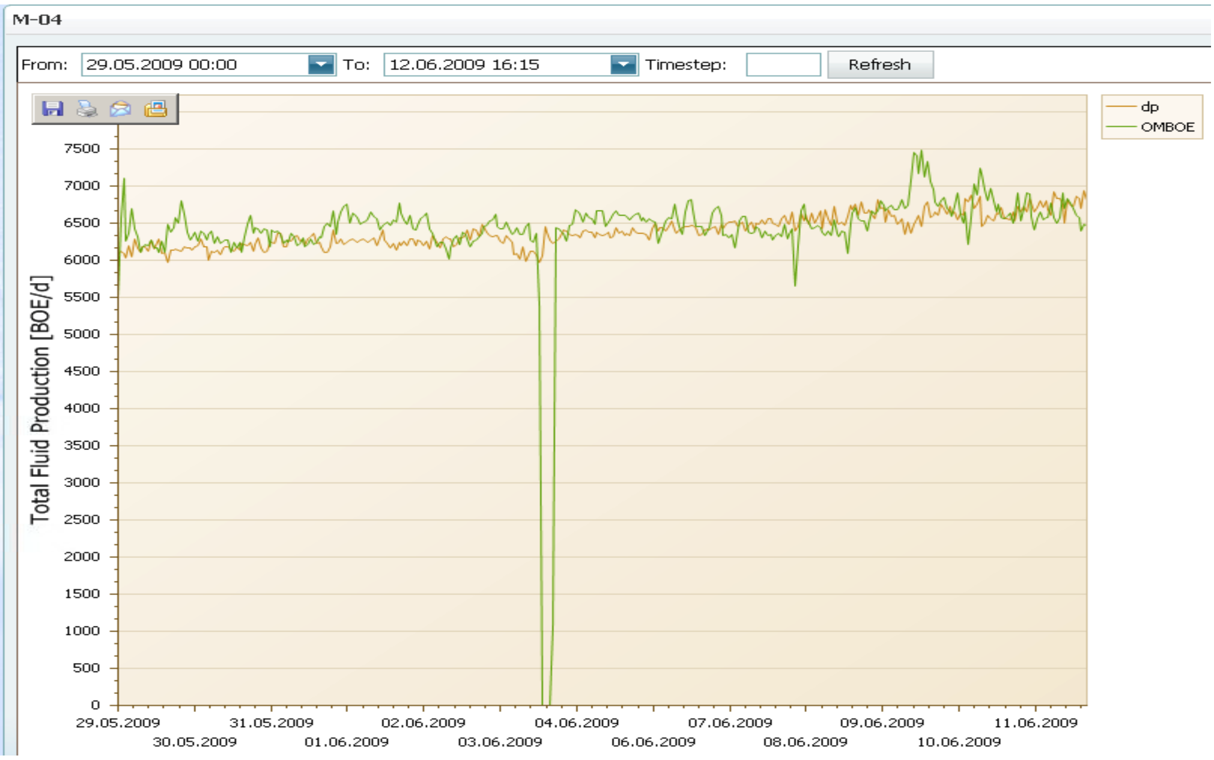
M-05 dP vs. dP average
BOE
7000
6000
5000
4000
19-jan-09
19-jan-09
19-jan-09
19-jan-09
20-jan-09
20-jan-09
20-jan-09
21-jan-09
21-jan-09
21-jan-09
21-jan-09
22-jan-09
22-jan-09
22-jan-09
23-jan-09
23-jan-09
23-jan-09
23-jan-09
24-jan-09
24-jan-09
24-jan-09
time
dP flow estimates
dP avg. Flow estimates
Welltest

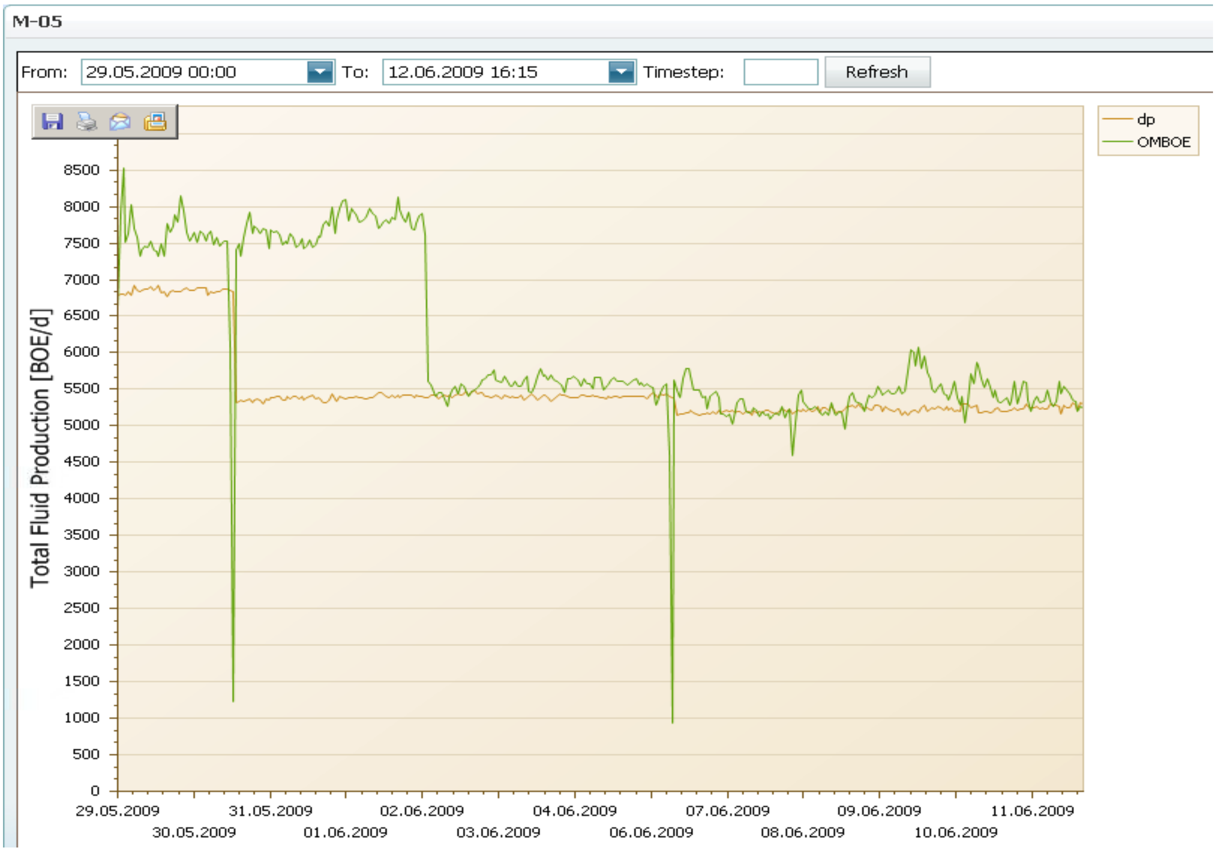
Predicted flowrates from Bernoulli equation.



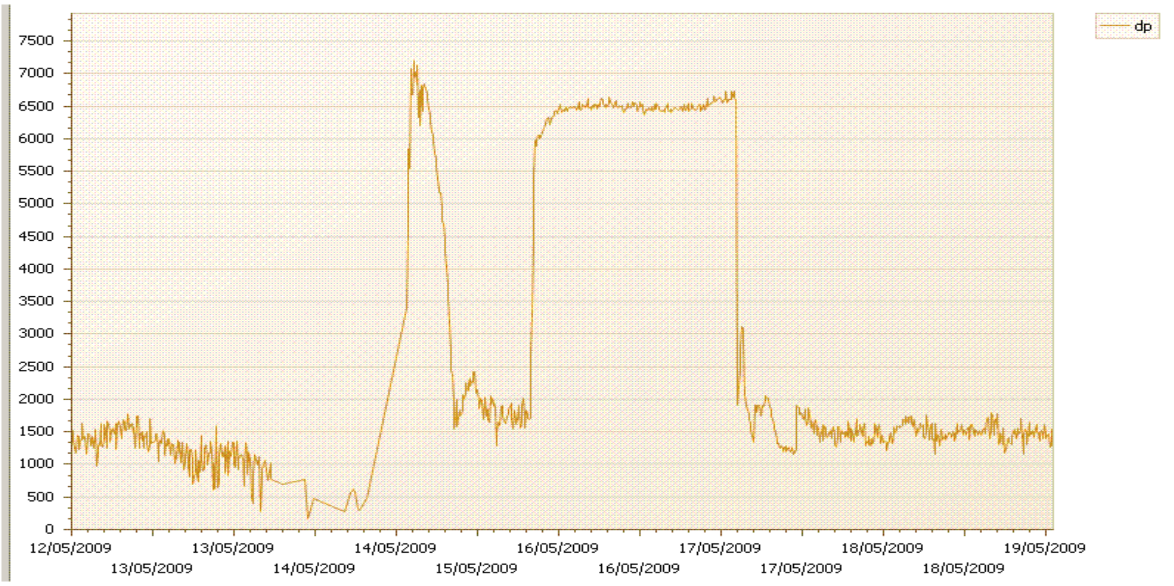



M-03
From: 29.05.2009 00:00
To: 12.06.2009 16:15
Timestep:
Refresh
dp
OMBOE
Total Fluid Production [BOE/d]
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
29.05.2009
30.05.2009
31.05.2009
01.06.2009
02.06.2009
03.06.2009
04.06.2009
06.06.2009
07.06.2009


M-04
From: 29.05.2009 00:00
To: 12.06.2009 16:15
Timestep:
Refresh
dp
OMBOE
Total Fluid Production [BOE/d]
7500
7000
6500
6000
5500
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
29.05.2009
30.05.2009
31.05.2009
01.06.2009
02.06.2009
03.06.2009
04.06.2009
06.06.2009
07.06.2009
08.06.2009
09.06.2009
10.06.2009
11.06.2009


M-05
From:
29.05.2009 00:00
To:
12.06.2009 16:15
Timestep:
Refresh
dp
OMBOE
Total Fluid Production [BOE/d]
8500
8000
7500
7000
6500
6000
5500
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
29.05.2009
30.05.2009
31.05.2009
01.06.2009
02.06.2009
03.06.2009
04.06.2009
06.06.2009
07.06.2009
08.06.2009
09.06.2009
10.06.2009
11.06.2009

M-06


dp
7500
7000
6500
6000
5500
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
12/05/2009
13/05/2009
13/05/2009
14/05/2009
14/05/2009
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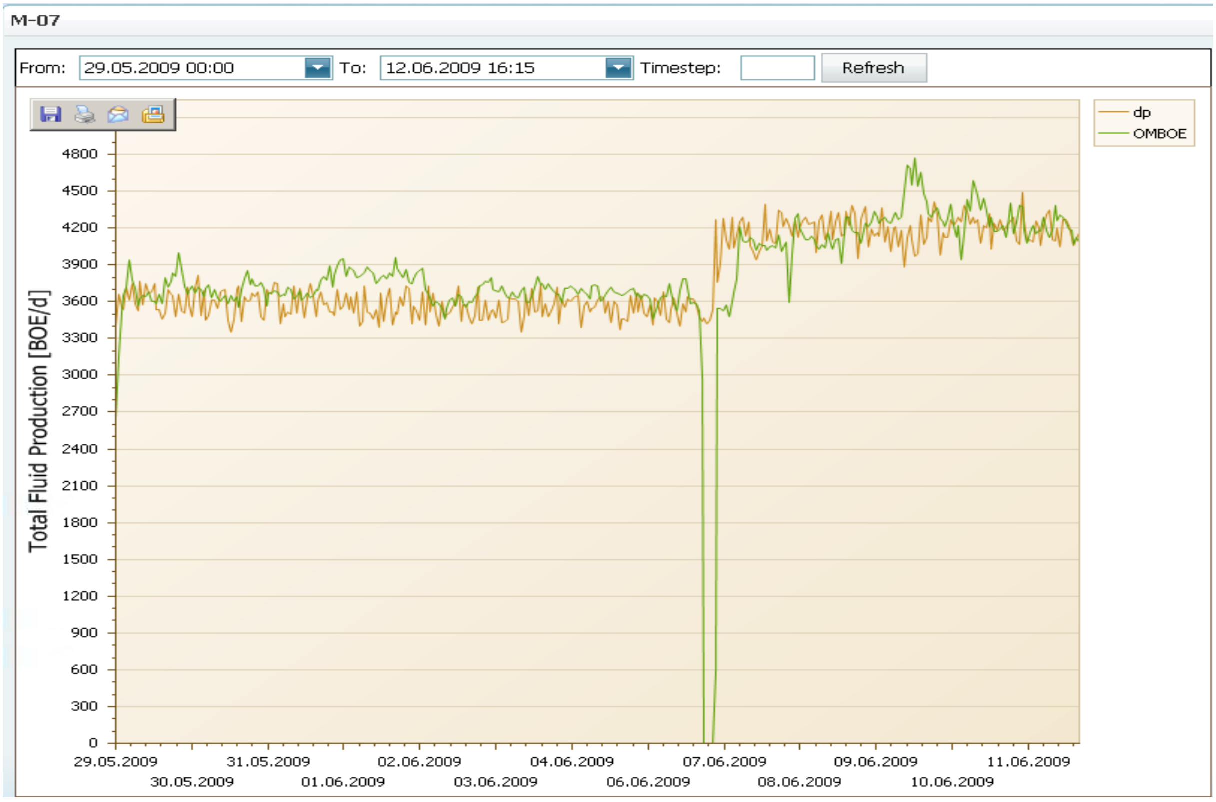
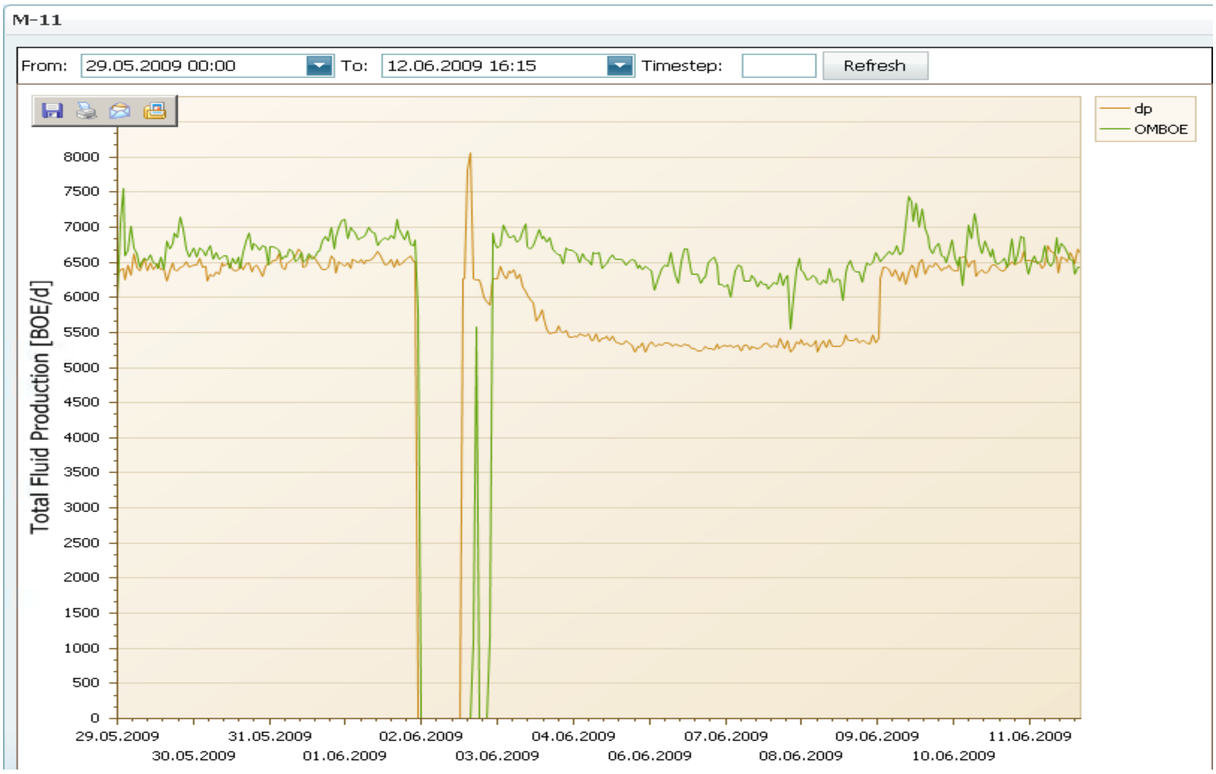
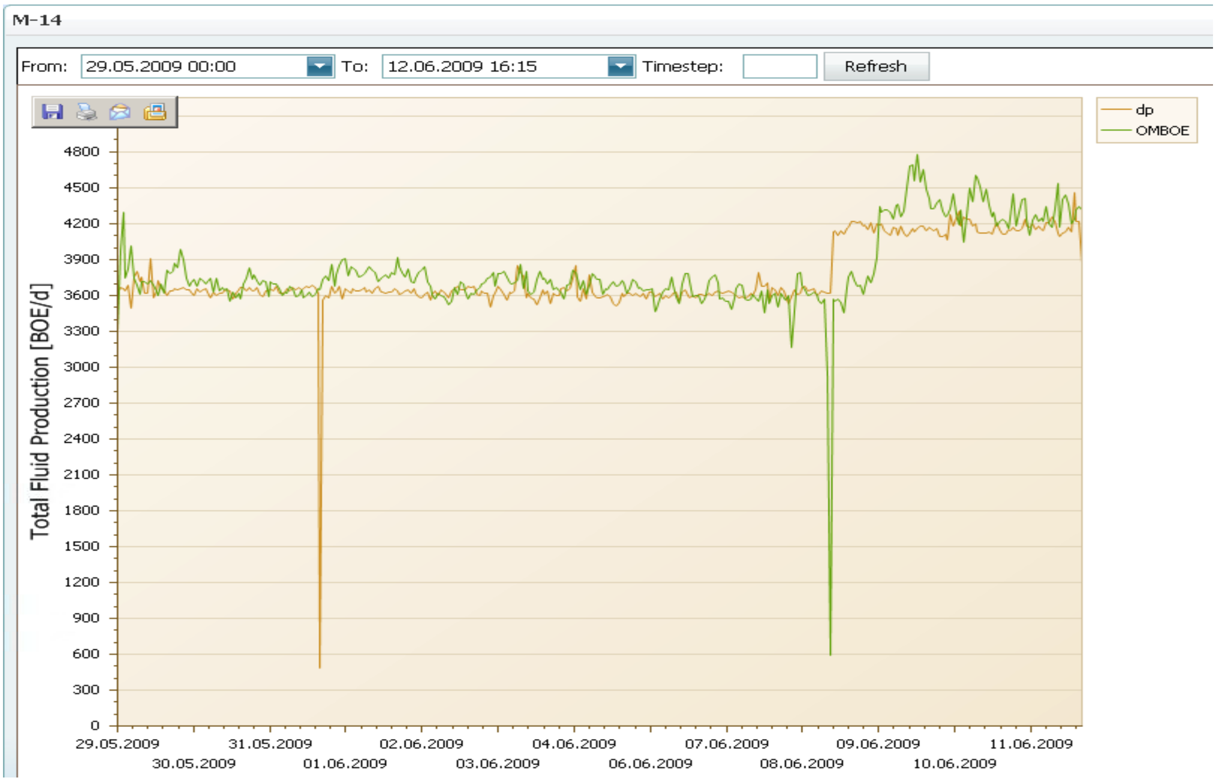
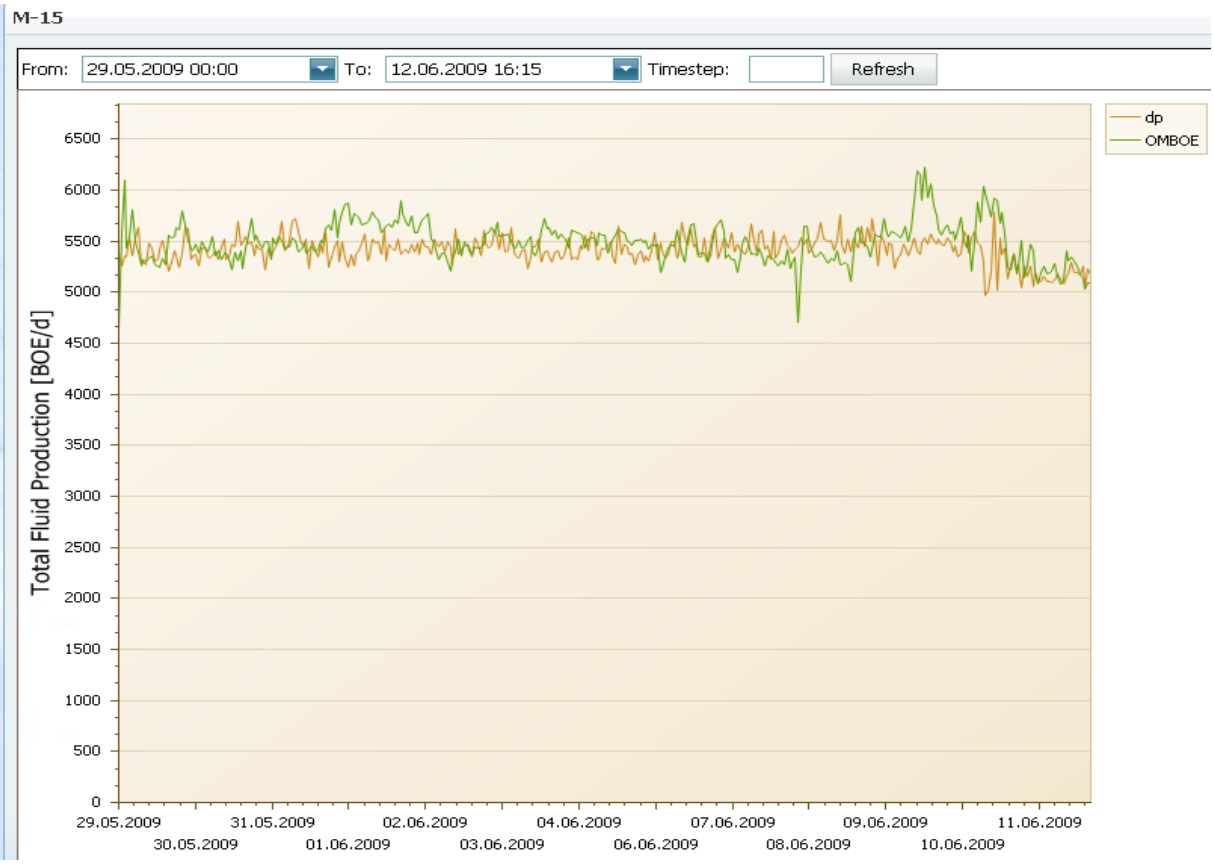
16/05/2009
17/05/2009
17/05/2009
18/05/2009
18/05/2009
19/05/2009


M-07
From: 29.05.2009 00:00
To: 12.06.2009 16:15
Timestep:
Refresh
dp
OMBOE
Total Fluid Production [BOE/d]
4800
4500
4200
3900
3600
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
29.05.2009
30.05.2009
31.05.2009
01.06.2009
02.06.2009
03.06.2009
04.06.2009
06.06.2009
07.06.2009
08.06.2009
09.06.2009
10.06.2009
11.06.2009


M-11
From: 29.05.2009 00:00
To: 12.06.2009 16:15
Timestep:
Refresh
dp
OMBOE
Total Fluid Production [BOE/d]
8000
7500
7000
6500
6000
5500
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
29.05.2009
30.05.2009
31.05.2009
01.06.2009
02.06.2009
03.06.2009
04.06.2009
06.06.2009
07.06.2009
08.06.2009
09.06.2009
10.06.2009
11.06.2009


M-14
From: 29.05.2009 00:00
To: 12.06.2009 16:15
Timestep:
Refresh
dp
OMBOE
Total Fluid Production [BOE/d]
4800
4500
4200
3900
3600
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
29.05.2009
30.05.2009
31.05.2009
01.06.2009
02.06.2009
03.06.2009
04.06.2009
06.06.2009
07.06.2009
08.06.2009
09.06.2009
10.06.2009
11.06.2009


M-15
From: 29.05.2009 00:00
To: 12.06.2009 16:15
Timestep:
Refresh
dp
OMBOE
Total Fluid Production [BOE/d]
6500
6000
5500
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
29.05.2009
30.05.2009
31.05.2009
01.06.2009
02.06.2009
03.06.2009
04.06.2009
06.06.2009
07.06.2009
08.06.2009
09.06.2009
10.06.2009
11.06.2009

Dummy Tests

Dates of performing simulations with on-line values and dummy tests implemented in the network model.

Simulations performed with dummy tests for unverified periods				
Well	**Date**			
M-01	06.feb	10.mar	01.apr	
M-02	21.mar			
M-03	03.jun			
M-04	05.mar	10.mar	20.mar	21.mai
M-05	29.mar			
M-06	29.mai	01.jun	14.jun	
M-07	24.mar	27.apr		
M-09	01.jan	05.mar	28.mai	
M-10	01.mar	03.apr	05.mai	
M-11	28.12.2008			
M-12	29.12.2008			
M-14	30.12.2008			
M-15	31.12.2008	12.jan	10.apr	

Example of results from simulations:

Accepted deviation: 10 degF **M-07** **Date**	**Time**	**Measured T [degF]**	**RT calc T* [degF]**	**Dummy T [degF]**
30.04.2009	06:00	186.67	171.5288	186.67
30.04.2009	08:00	185.97	172.1696	185.97
30.04.2009	10:00	186.15	172.4612	186.15
30.04.2009	12:00	186.33	171.0698	186.33
30.04.2009	14:00	186.03	172.1246	186.03
30.04.2009	16:00	187.12	170.9762	187.12
30.04.2009	18:00	186.59	172.436	186.59
30.04.2009	20:00	186.32	172.1732	186.32
30.04.2009	22:00	186.29	172.166	186.22
01.05.2009	00:00	186.25	172.1498	186.14
01.05.2009	02:00	186.28	172.175	186.17
01.05.2009	04:00	186.49	171.6026	186.17
01.05.2009	06:00	186.26	171.986	186.01
01.05.2009	08:00	186.42	172.256	186.3
01.05.2009	10:00	186.45	171.5612	186.33
01.05.2009	12:00	186.59	172.571	186.52

T*= unverified temperature.

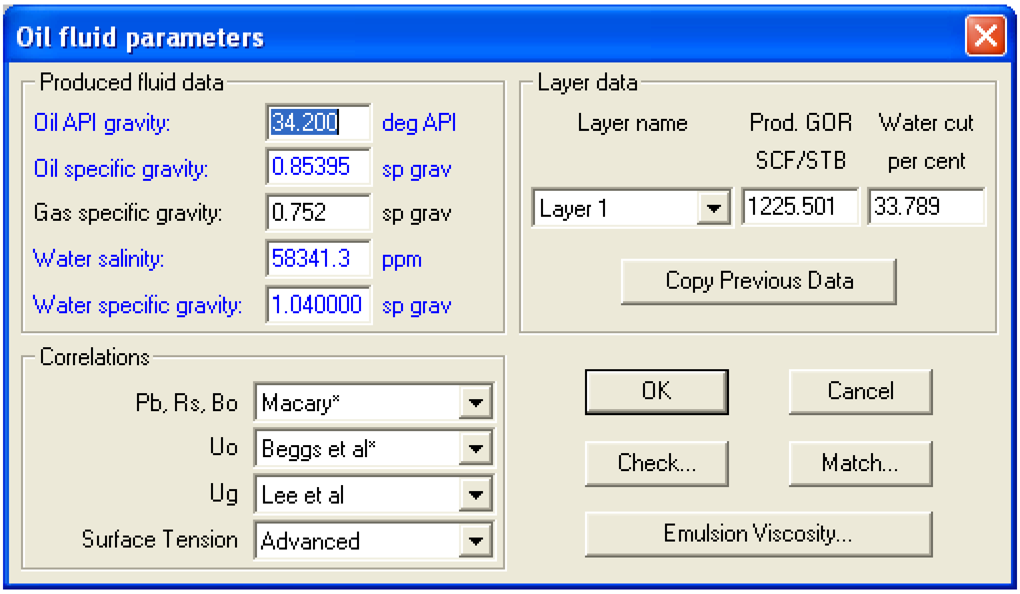
In addition, it will be given results of oil rate, water rate and gas rate for each well.

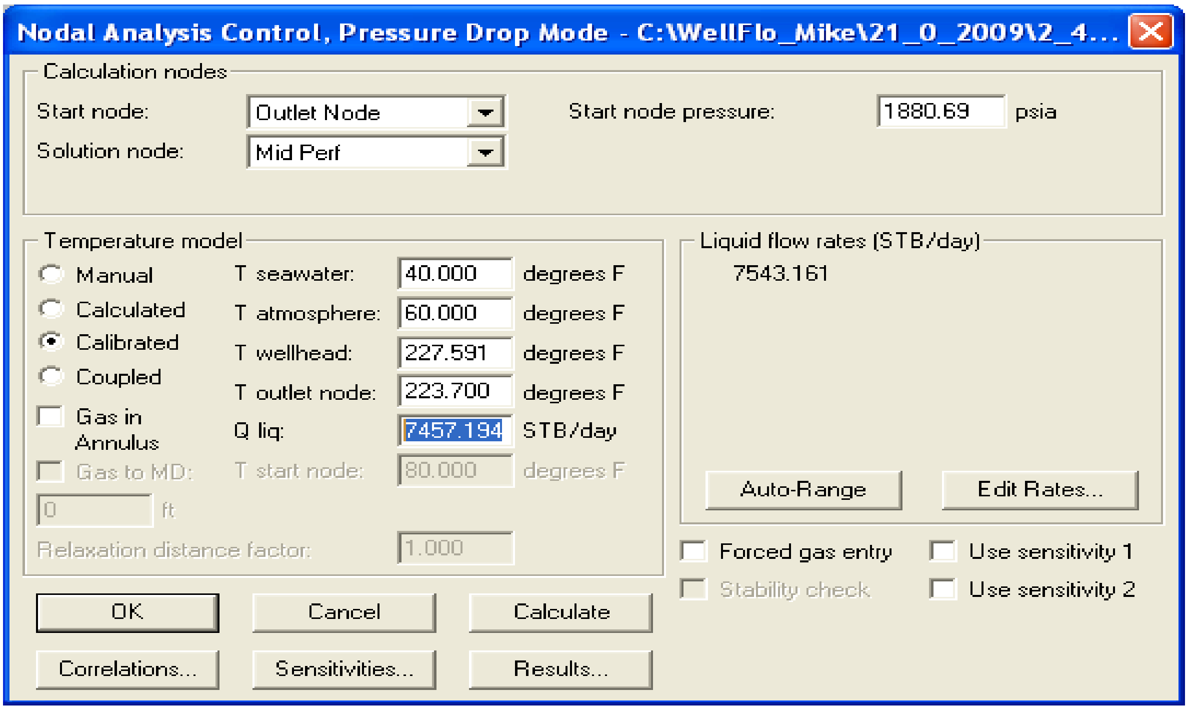
Tuning Procedure

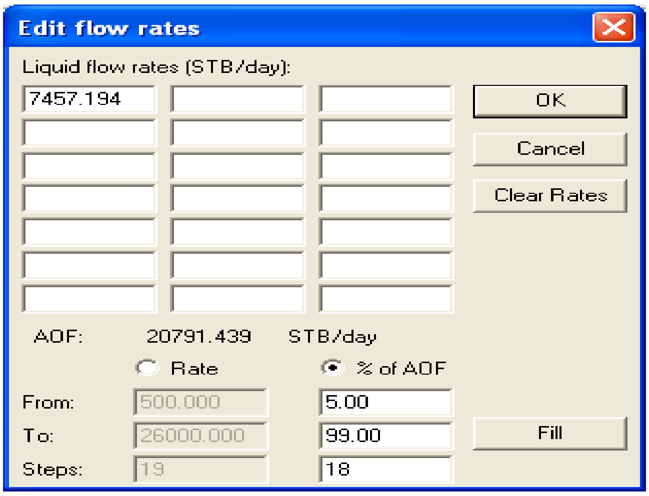
The diagram shows the tuning procedure in WellFlo. The procedure does not include building the well with equipments, well inclination and PVT data (gravity, API etc.).

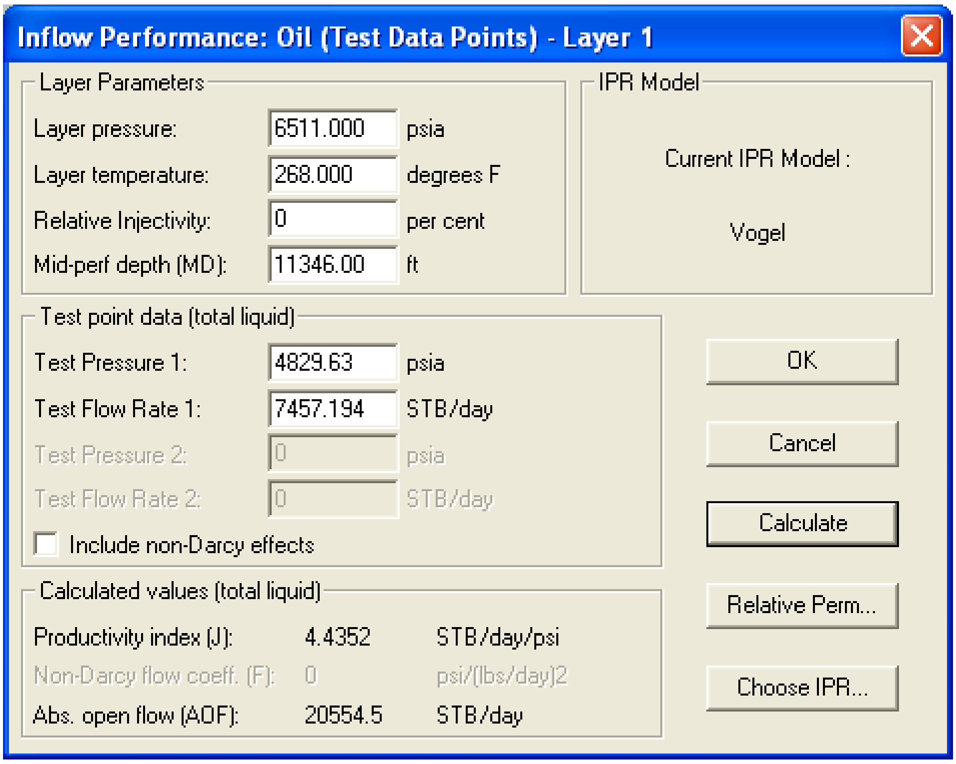
Step 1: Input parameters

The first input in the tuning procedure is the fluid parameters from well test results; *GOR, Water Cut* and *Liquid Rate*. This is done in three different windows:



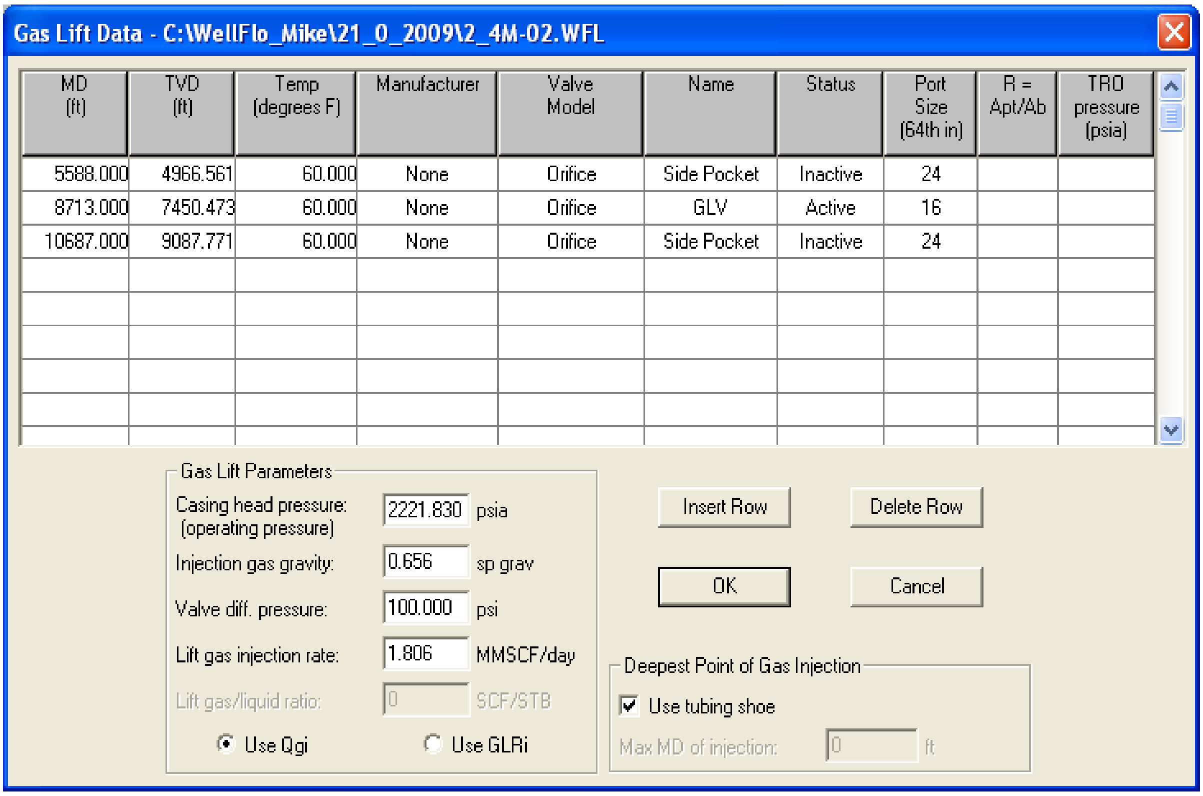




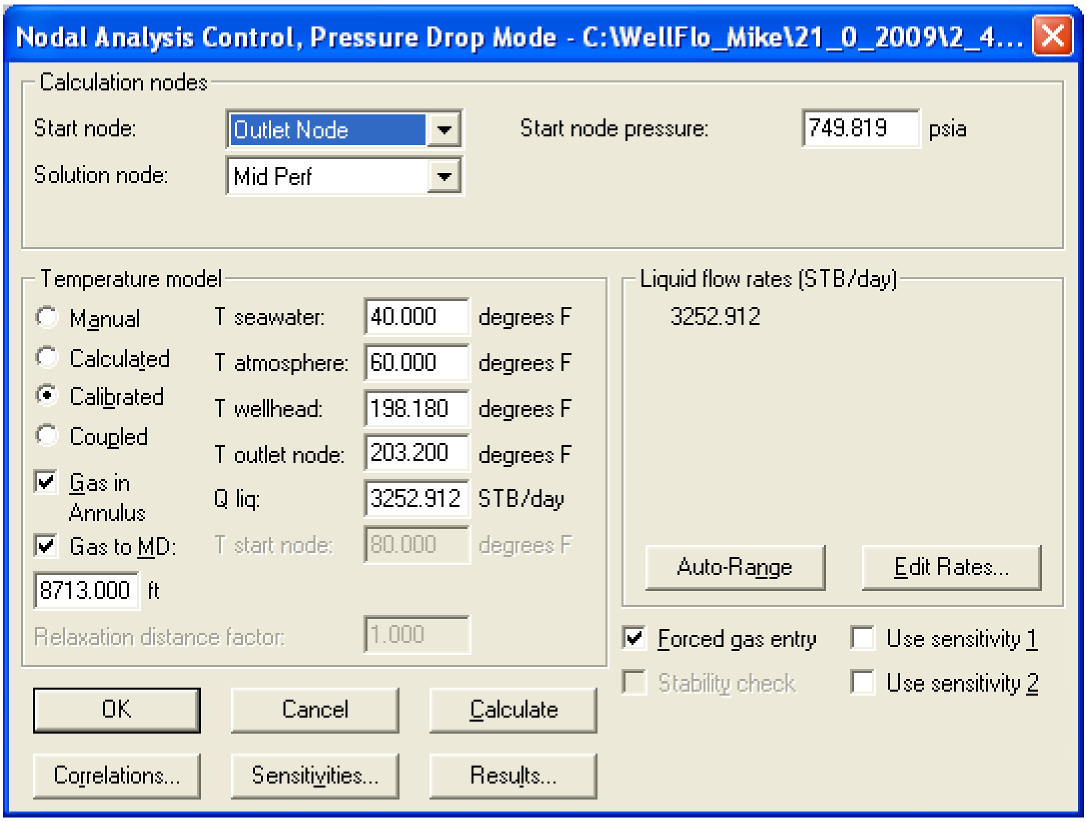


Gas Lift Data: If the well is on gas lift, the gas injection rate and the CHP has to be updated.

If not the gas lift valve is set to be *not active.*



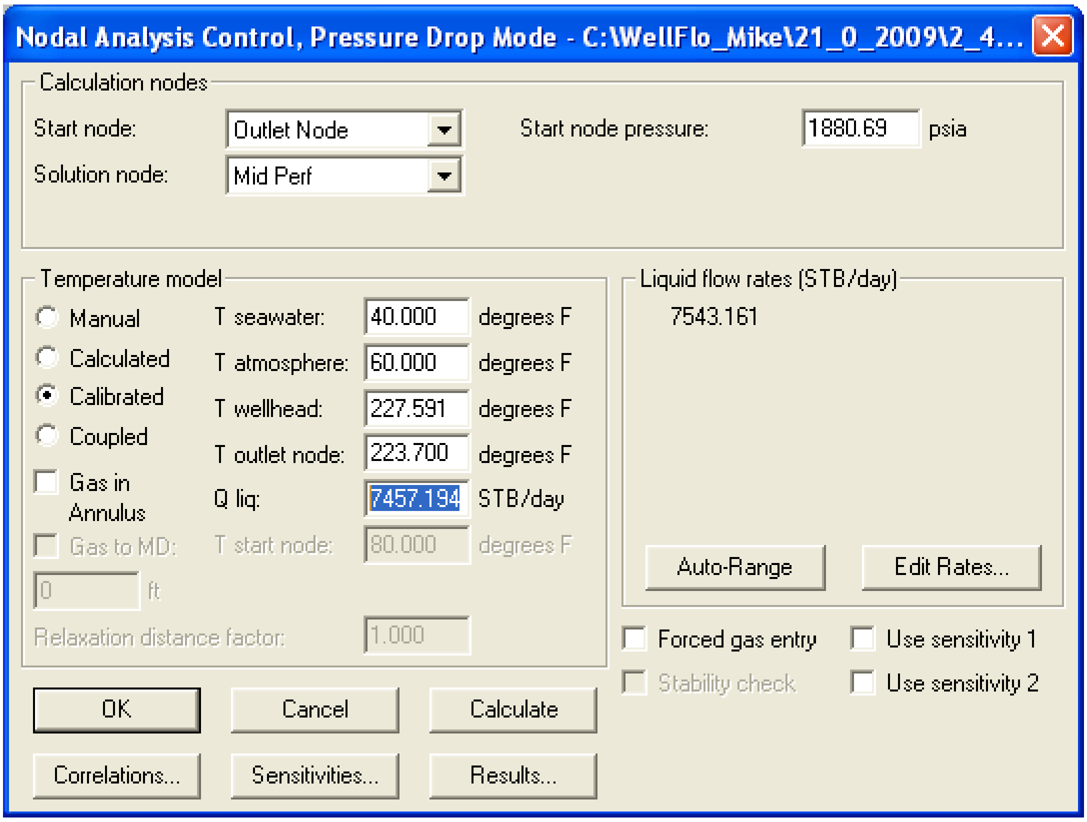
Nodal Analysis Control- Pressure Drop Mode: Update *WHP, WHT* and Q_L.



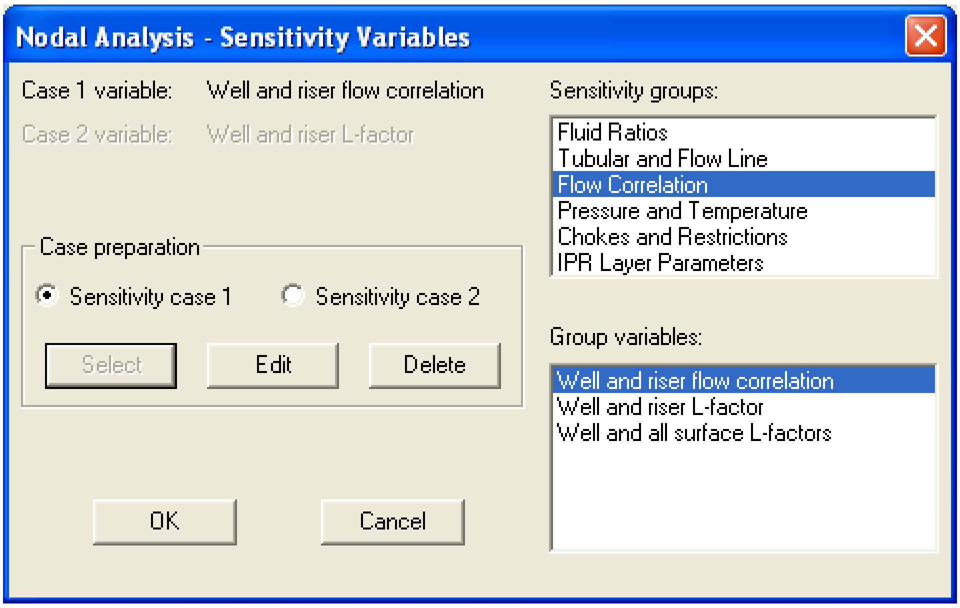
Step 2: CALCULATION AND TUNING

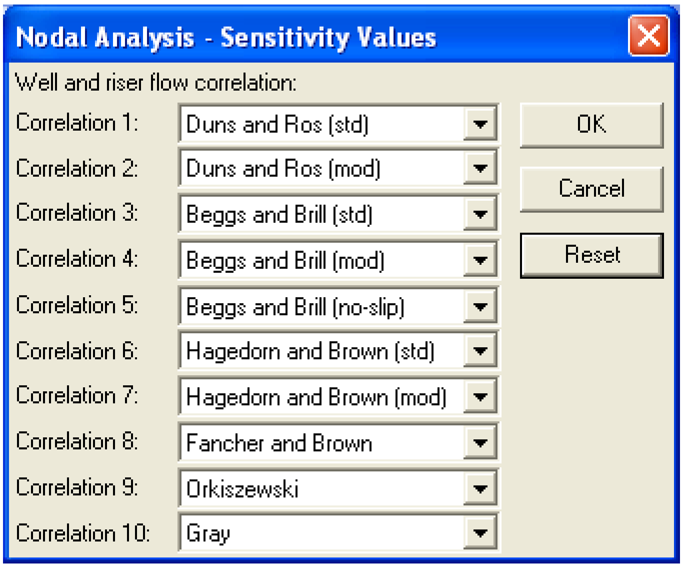
The tuning procedure depends on if down hole gauge pressure is available.

If not: The pressure is calculated at the Mid. Perforation node and then inserted to the **Reservoir control** under Test Pressure 1 in order to find the operating point.



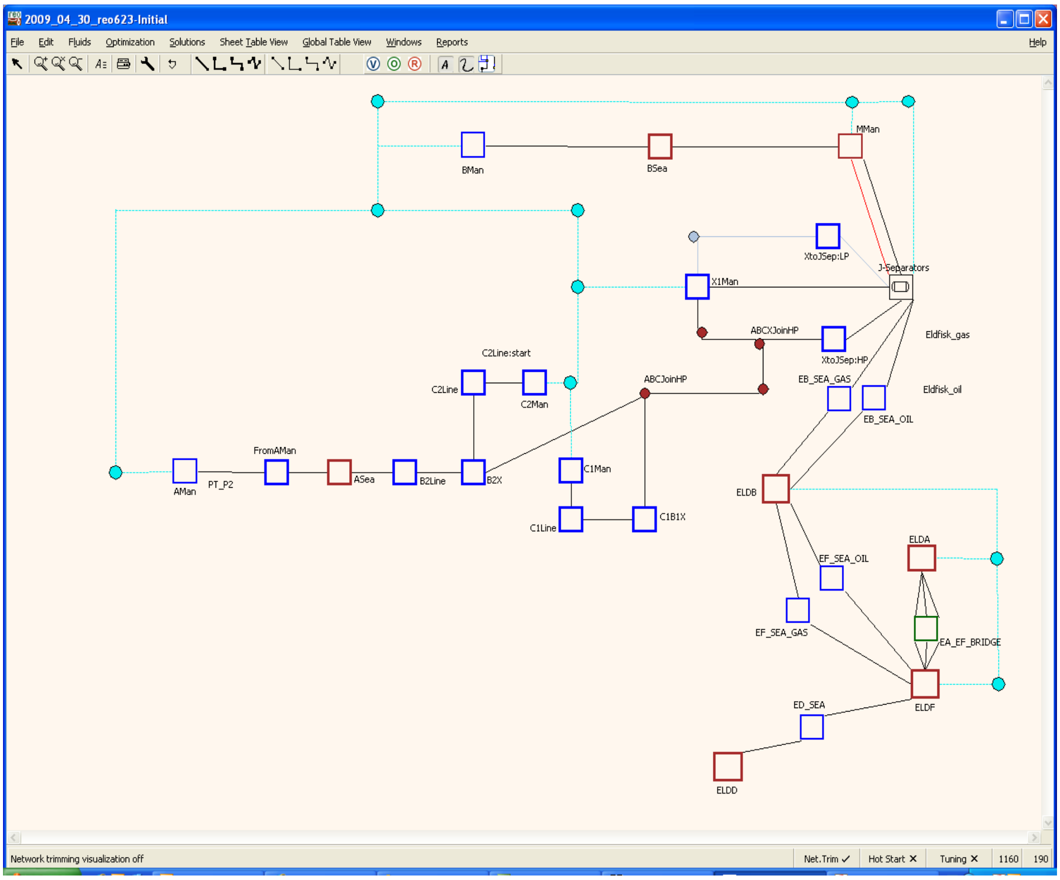
If the data is to be tuned against measured gauge pressure, the pressure is tuned with L-factor until it matches using the *Gauge Carrier* as the *Solution node.* This is done by loading a dvp-file (depth versus pressure) to run sensitivities and find the best fit L-factor in the correlations. New pressure is calculated at the mid perforation, with the additional L-factor before added into Reservoir Control. Finely the Operating point, giving the deliverability, is calculated.


Nodal Analysis - Sensitivity Variables
Case 1 variable: Well and riser flow correlation
Case 2 variable: Well and riser L-factor
Case preparation
Sensitivity case 1
Sensitivity case 2
Select
Edit
Delete
OK
Cancel
Sensitivity groups:
Fluid Ratios
Tubular and Flow Line
Flow Correlation
Pressure and Temperature
Chokes and Restrictions
IPR Layer Parameters
Group variables:
Well and riser flow correlation
Well and riser L-factor
Well and all surface L-factors

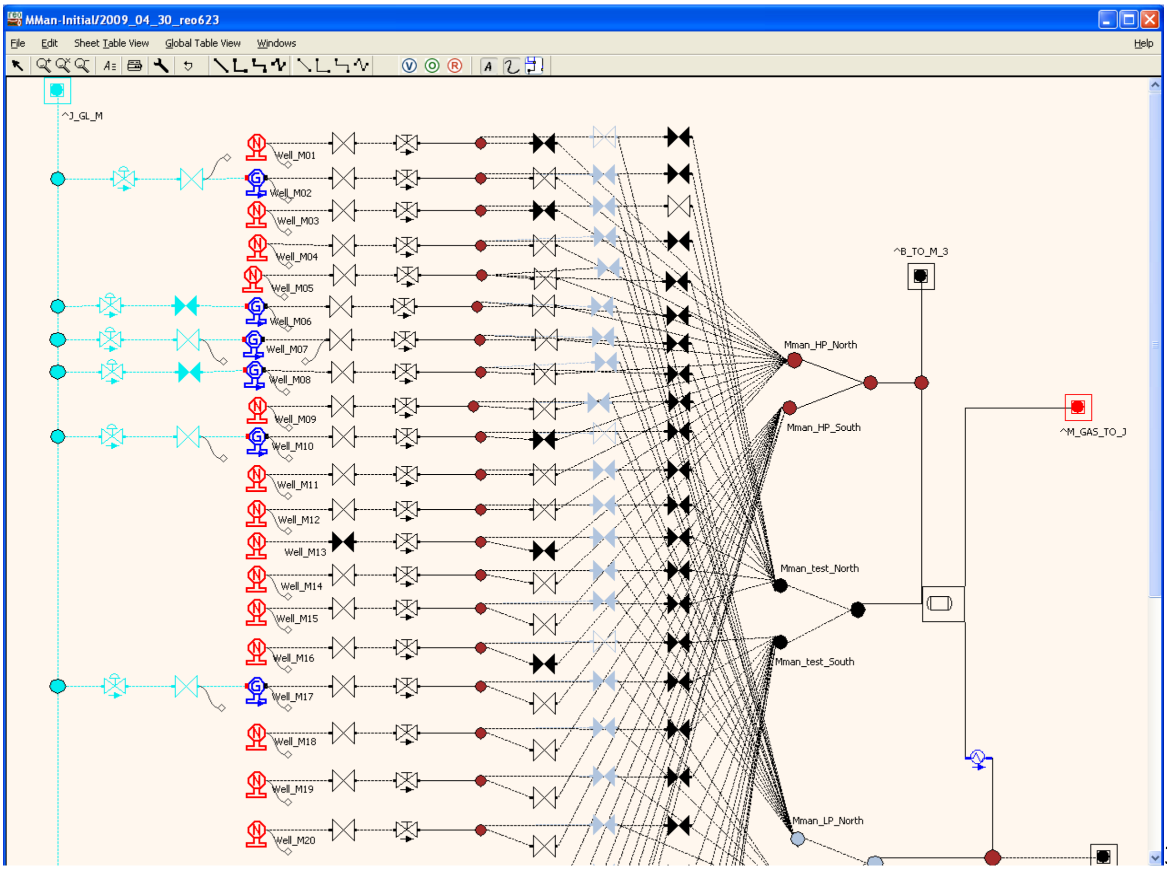

Nodal Analysis - Sensitivity Values
Well and riser flow correlation:
Correlation 1: Duns and Ros (std)
Correlation 2: Duns and Ros (mod)
Correlation 3: Beggs and Brill (std)
Correlation 4: Beggs and Brill (mod)
Correlation 5: Beggs and Brill (no-slip)
Correlation 6: Hagedorn and Brown (std)
Correlation 7: Hagedorn and Brown (mod)
Correlation 8: Fancher and Brown
Correlation 9: Orkiszewski
Correlation 10: Gray
OK
Cancel
Reset

Optimizing procedure in ReO

1. Chooce platform. Here, MMan represents the Mike platform.

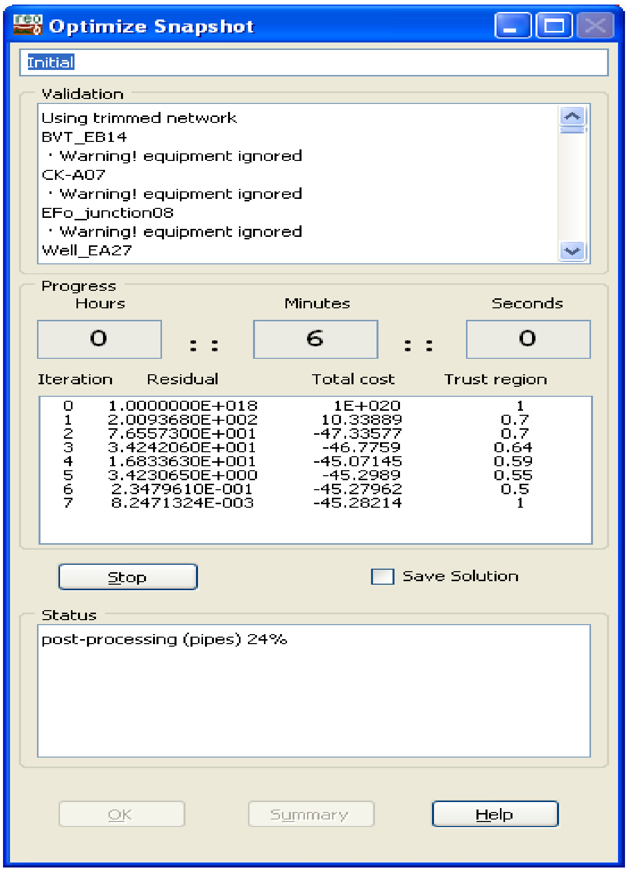


2. Select the well and chose *import WellFlo file*.

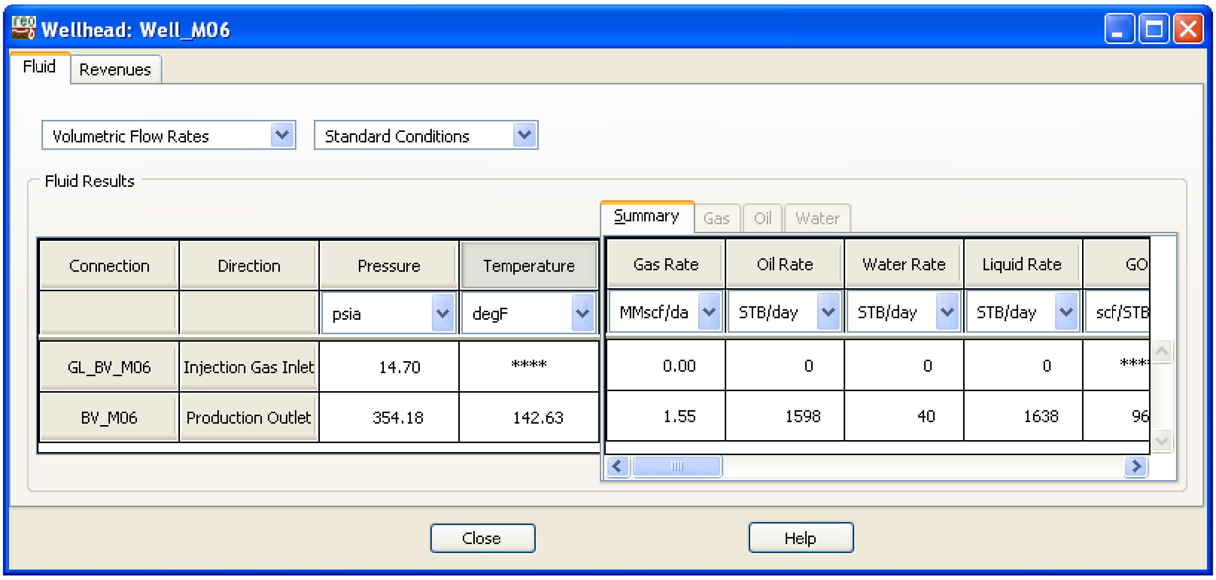


3.

Click on the optimization tab, and select *optimize*

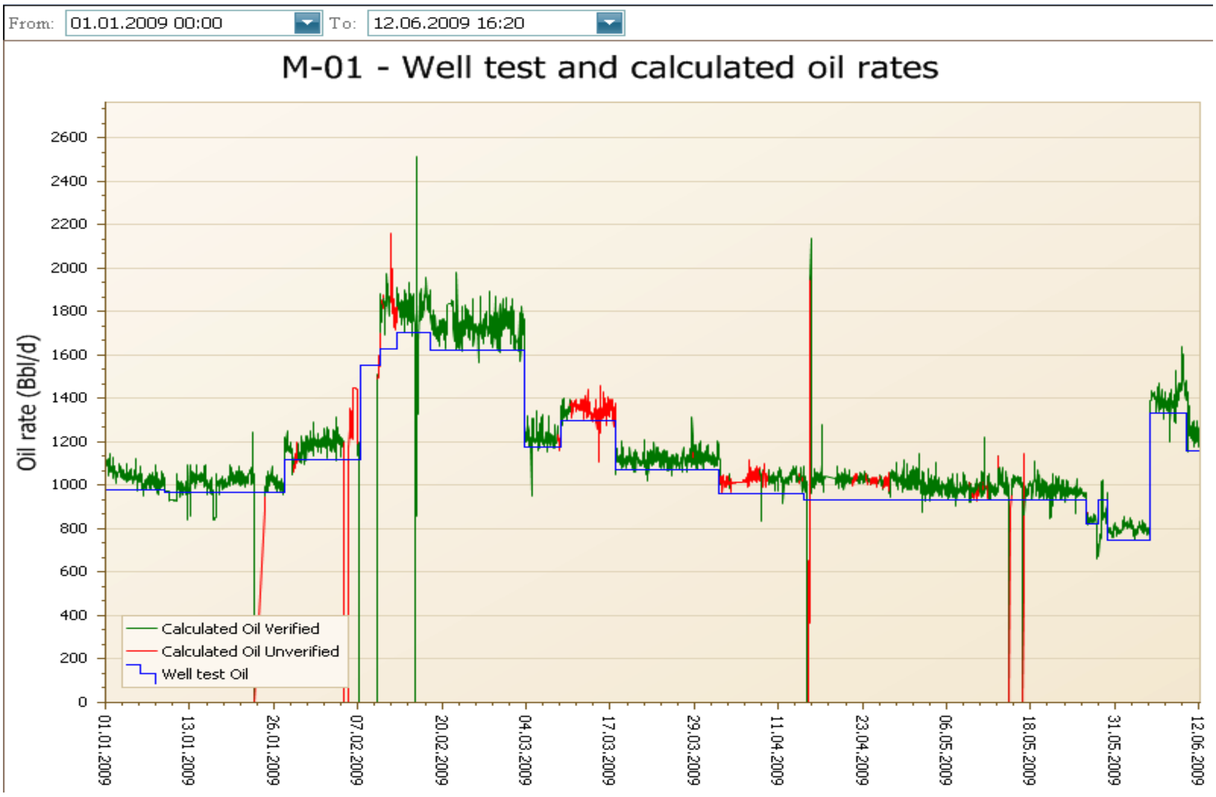


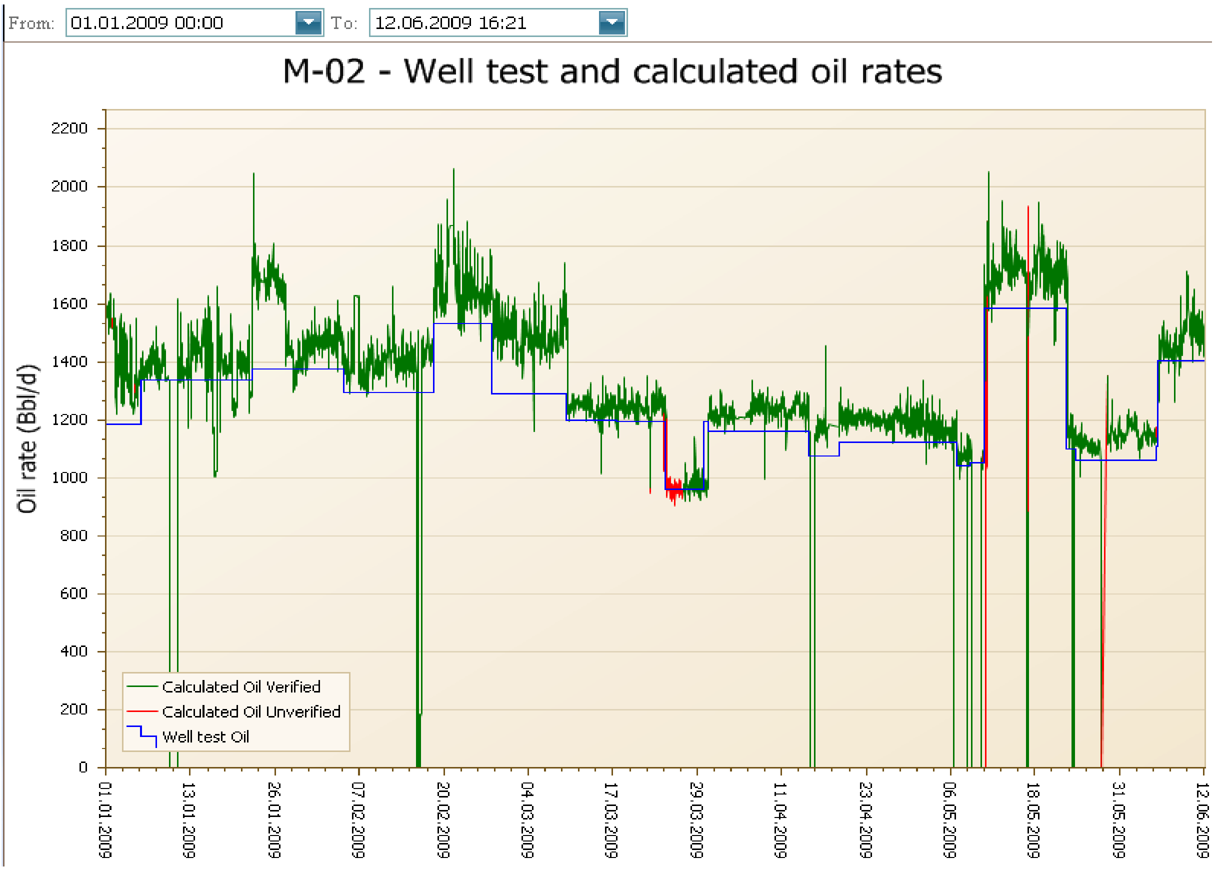
4. When simulation is successes, there is an option to click on the well and read results:

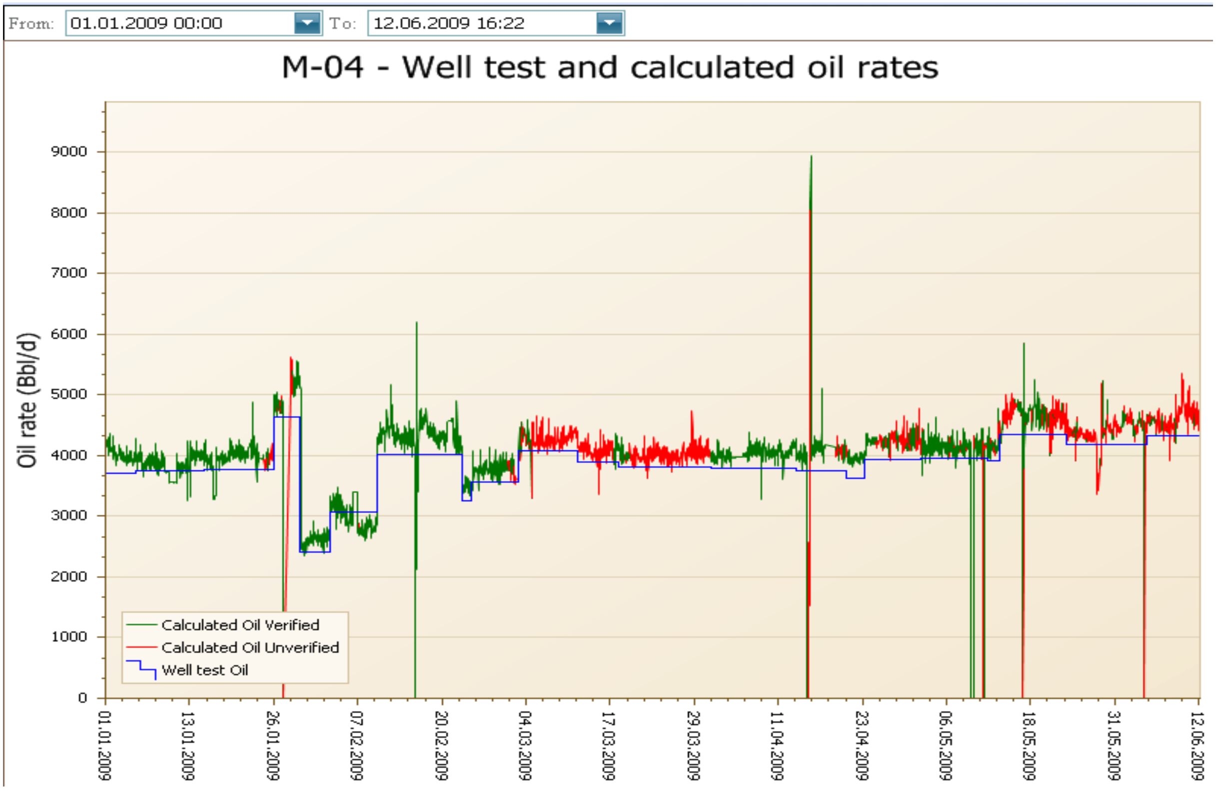


Connection	Direction	Pressure	Temperature	Gas Rate	Oil Rate	Water Rate	Liquid Rate	GO
		psia	degF	MMscf/da	STB/day	STB/day	STB/day	scf/STB
GL_BV_M06	Injection Gas Inlet	14.70	****	0.00	0	0	0	***
BV_M06	Production Outlet	354.18	142.63	1.55	1598	40	1638	96

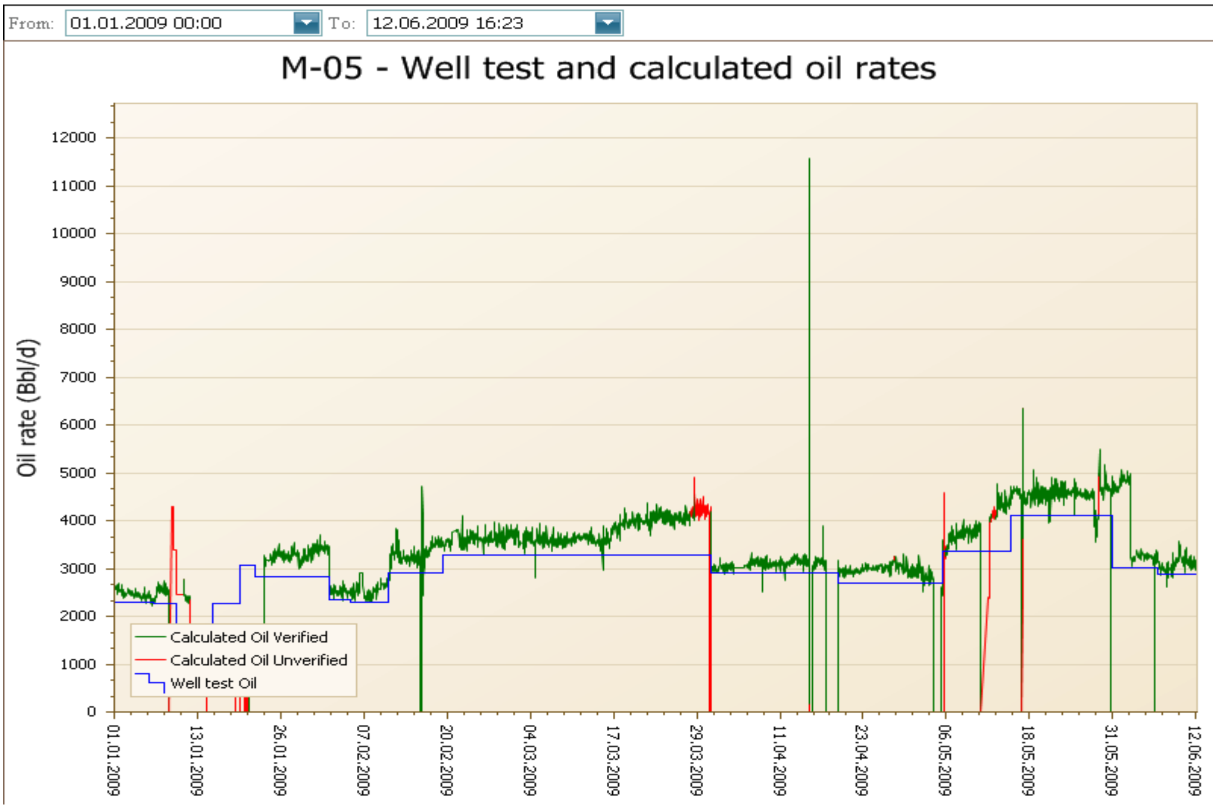
Simulation results and Temperature Verification



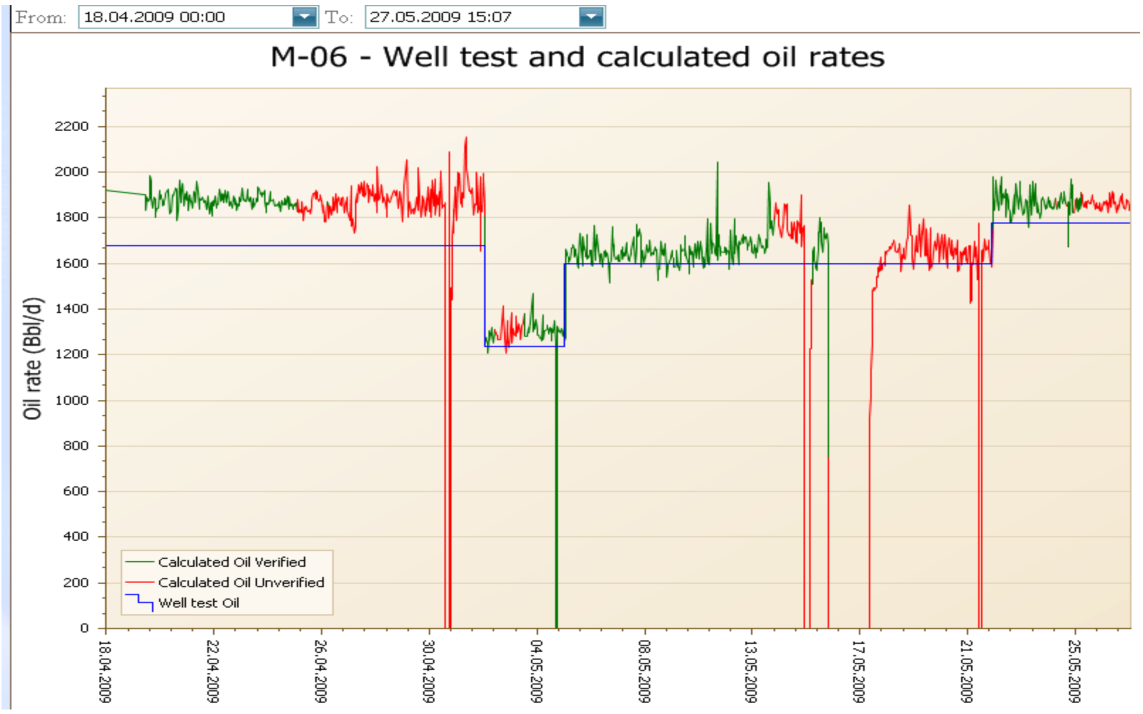




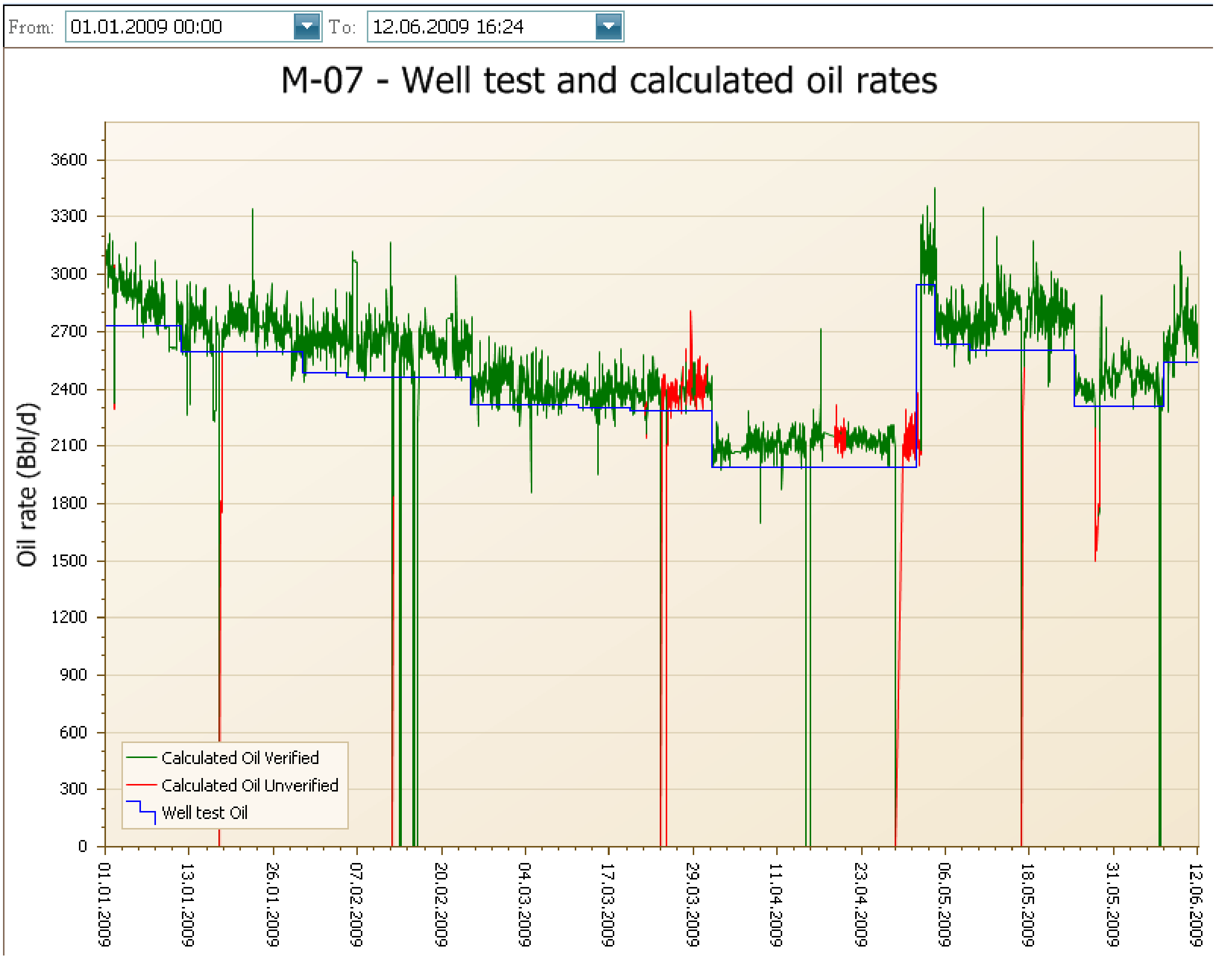
From: 01.01.2009 00:00
To: 12.06.2009 16:22
M-04 - Well test and calculated oil rates
Oil rate (Bbl/d)
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
Calculated Oil Verified
Calculated Oil Unverified
Well test Oil
01.01.2009
13.01.2009
26.01.2009
07.02.2009
20.02.2009
04.03.2009
17.03.2009
29.03.2009
11.04.2009
23.04.2009
06.05.2009
18.05.2009
31.05.2009
12.06.2009



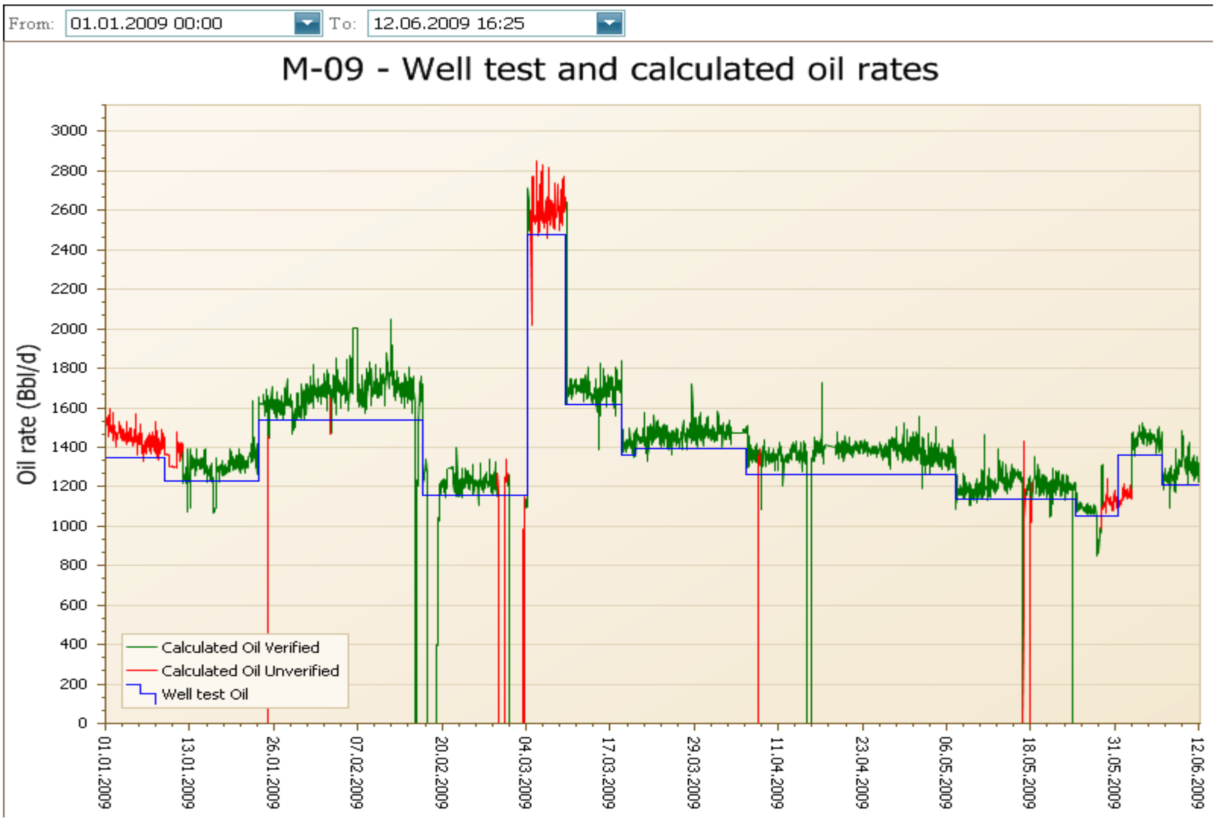
From: 01.01.2009 00:00
To: 12.06.2009 16:23
M-05 - Well test and calculated oil rates
Oil rate (Bbl/d)
12000
11000
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
Calculated Oil Verified
Calculated Oil Unverified
Well test Oil
01.01.2009
13.01.2009
26.01.2009
07.02.2009
20.02.2009
04.03.2009
17.03.2009
29.03.2009
11.04.2009
23.04.2009
06.05.2009
18.05.2009
31.05.2009
12.06.2009

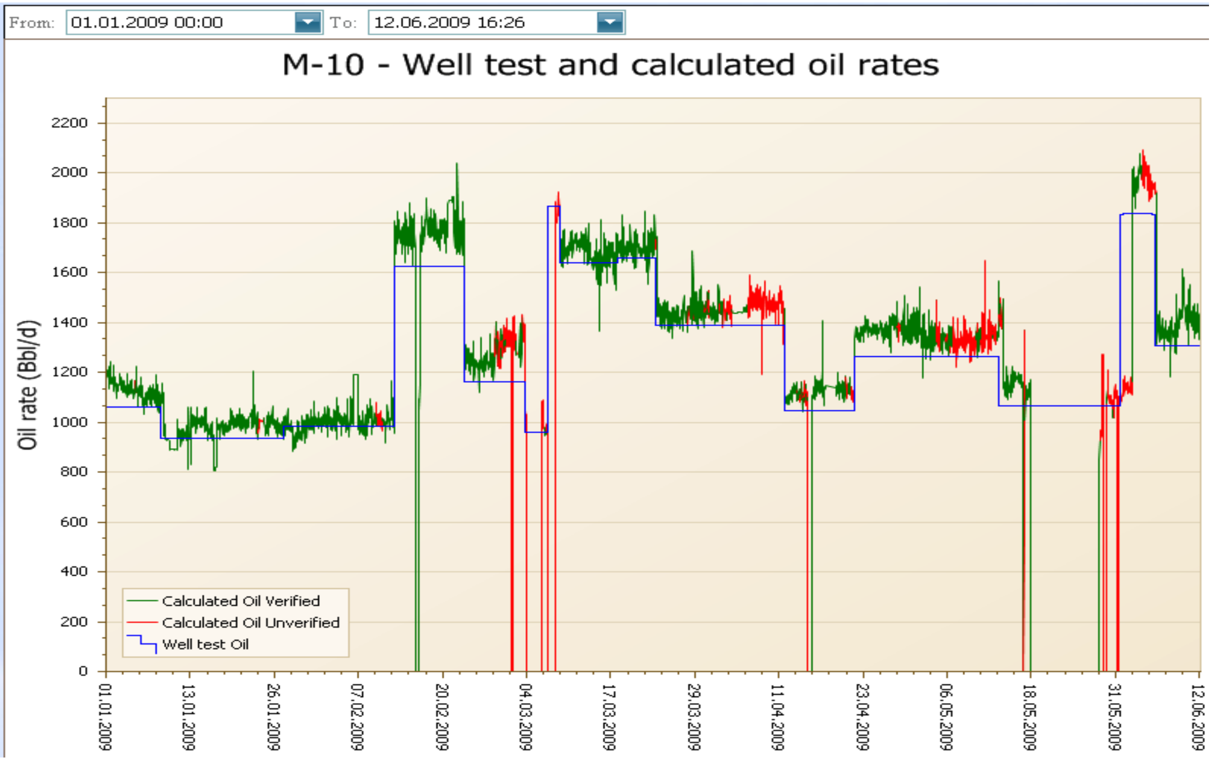


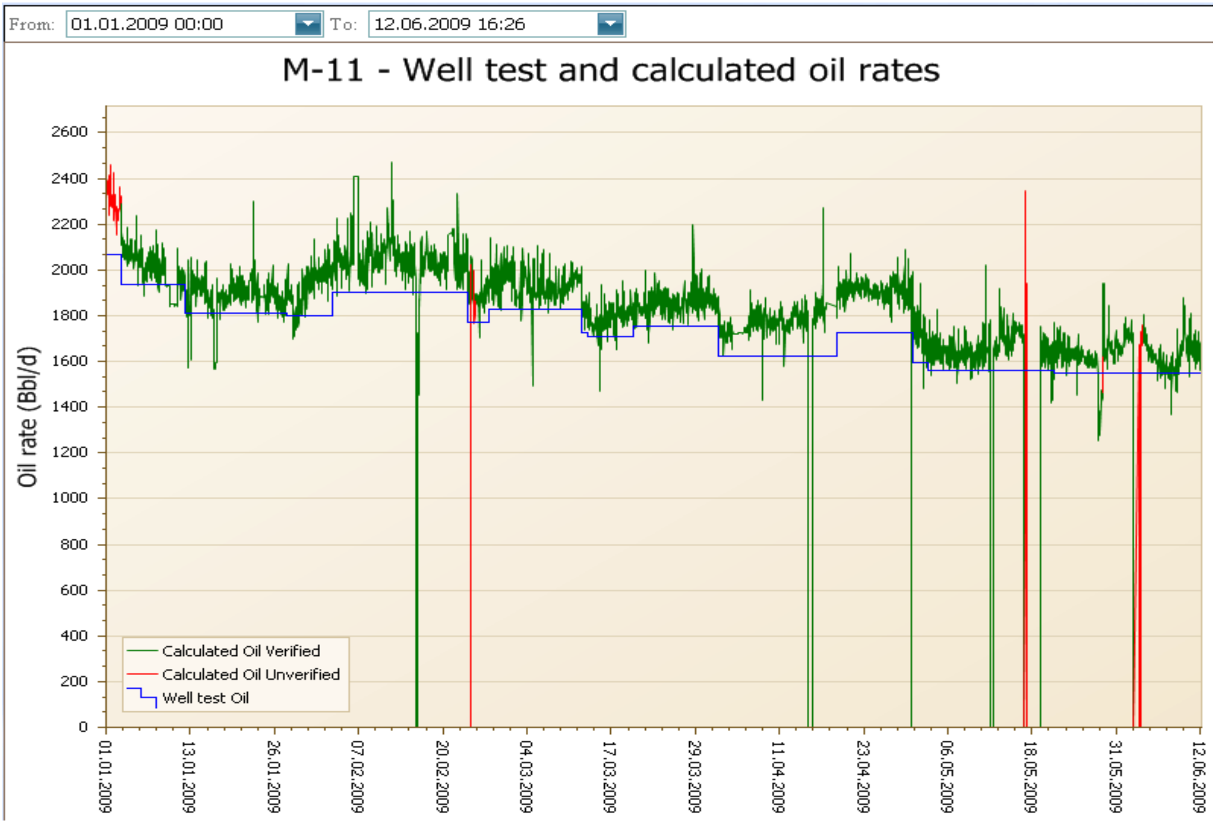
From: 18.04.2009 00:00
To: 27.05.2009 15:07
M-06 - Well test and calculated oil rates
Oil rate (Bbl/d)
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Calculated Oil Verified
Calculated Oil Unverified
Well test Oil
18.04.2009
22.04.2009
26.04.2009
30.04.2009
04.05.2009
08.05.2009
13.05.2009
17.05.2009
21.05.2009
25.05.2009



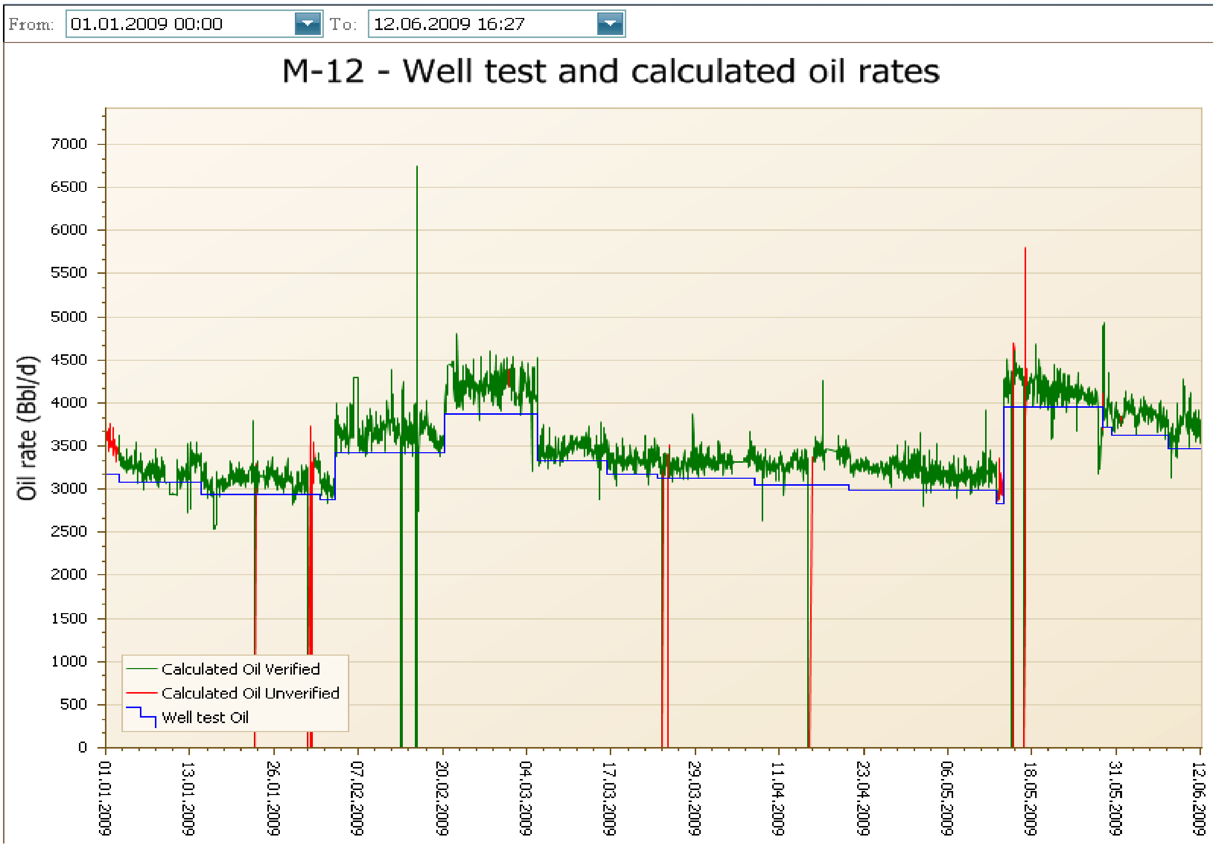
From: 01.01.2009 00:00
To: 12.06.2009 16:24
M-07 - Well test and calculated oil rates
Oil rate (Bbl/d)
3600
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Calculated Oil Verified
Calculated Oil Unverified
Well test Oil
01.01.2009
13.01.2009
26.01.2009
07.02.2009
20.02.2009
04.03.2009
17.03.2009
29.03.2009
11.04.2009
23.04.2009
06.05.2009
18.05.2009
31.05.2009
12.06.2009


From: 01.01.2009 00:00
To: 12.06.2009 16:25
M-09 - Well test and calculated oil rates
Oil rate (Bbl/d)
3000
2800
2600
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Calculated Oil Verified
Calculated Oil Unverified
Well test Oil
01.01.2009
13.01.2009
26.01.2009
07.02.2009
20.02.2009
04.03.2009
17.03.2009
29.03.2009
11.04.2009
23.04.2009
06.05.2009
18.05.2009
31.05.2009
12.06.2009

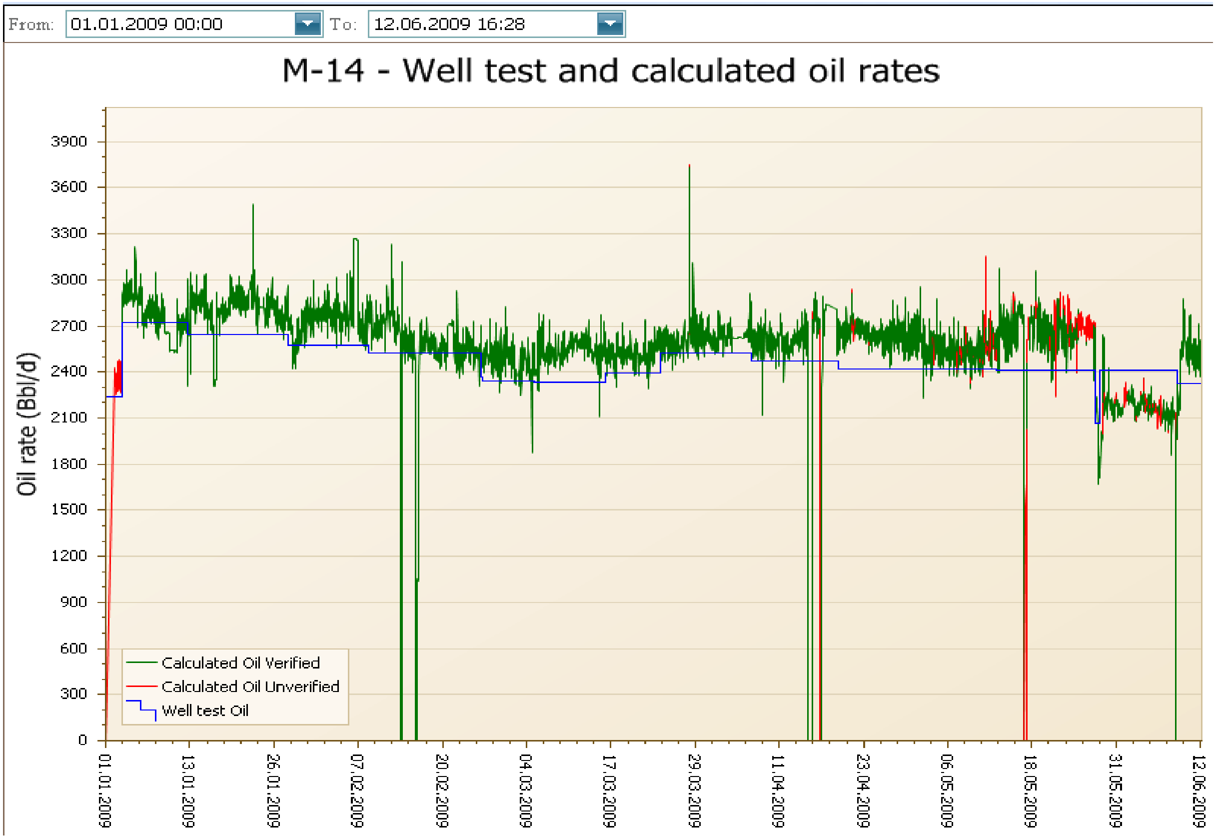

From: 01.01.2009 00:00
To: 12.06.2009 16:26
M-10 - Well test and calculated oil rates
Oil rate (Bbl/d)
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Calculated Oil Verified
Calculated Oil Unverified
Well test Oil
01.01.2009
13.01.2009
26.01.2009
07.02.2009
20.02.2009
04.03.2009
17.03.2009
29.03.2009
11.04.2009
23.04.2009
06.05.2009
18.05.2009
31.05.2009
12.06.2009

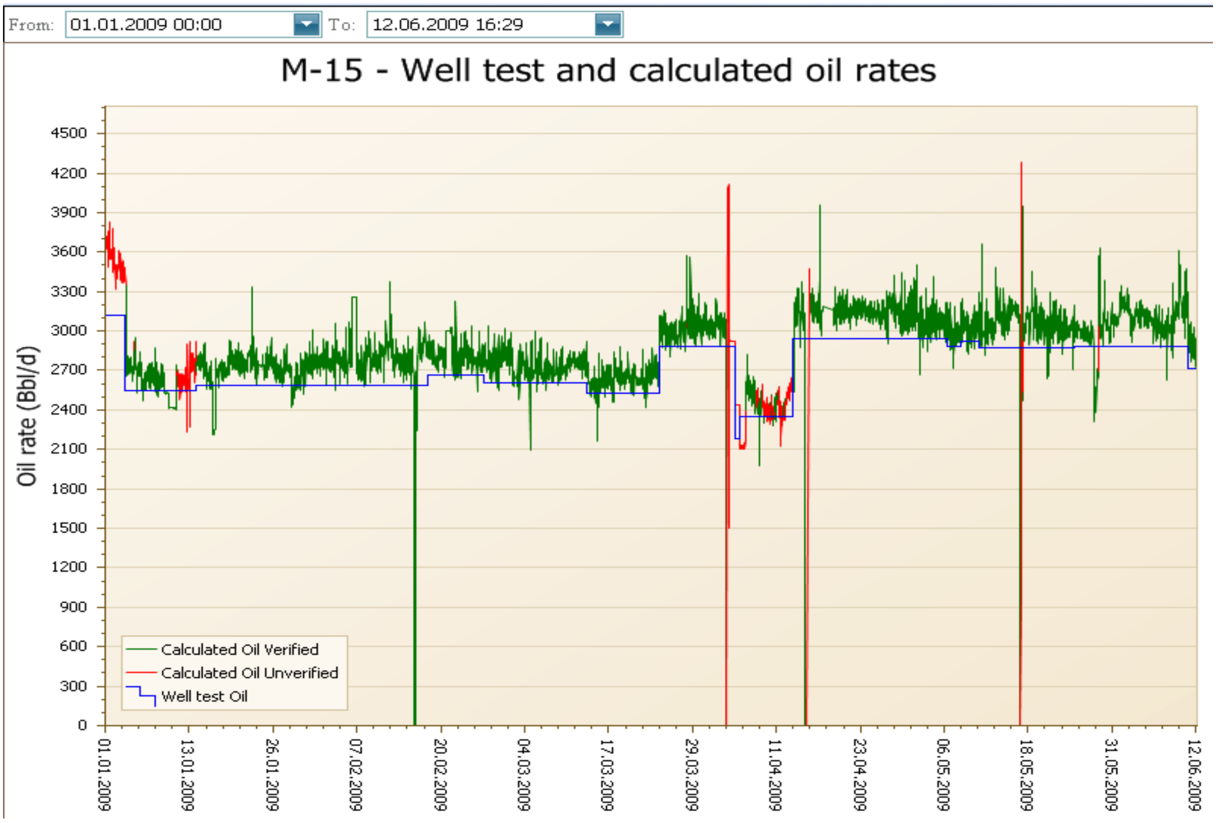


From: 01.01.2009 00:00
To: 12.06.2009 16:26
M-11 - Well test and calculated oil rates
Oil rate (Bbl/d)
2600
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Calculated Oil Verified
Calculated Oil Unverified
Well test Oil
01.01.2009
13.01.2009
26.01.2009
07.02.2009
20.02.2009
04.03.2009
17.03.2009
29.03.2009
11.04.2009
23.04.2009
06.05.2009
18.05.2009
31.05.2009
12.06.2009



From: 01.01.2009 00:00
To: 12.06.2009 16:27
M-12 - Well test and calculated oil rates
Oil rate (Bbl/d)
7000
6500
6000
5500
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
Calculated Oil Verified
Calculated Oil Unverified
Well test Oil
01.01.2009
13.01.2009
26.01.2009
07.02.2009
20.02.2009
04.03.2009
17.03.2009
29.03.2009
11.04.2009
23.04.2009
06.05.2009
18.05.2009
31.05.2009
12.06.2009


From: 01.01.2009 00:00 To: 12.06.2009 16:28
M-14 - Well test and calculated oil rates
Oil rate (Bbl/d)
3900
3600
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Calculated Oil Verified
Calculated Oil Unverified
Well test Oil
01.01.2009
13.01.2009
26.01.2009
07.02.2009
20.02.2009
04.03.2009
17.03.2009
29.03.2009
11.04.2009
23.04.2009
06.05.2009
18.05.2009
31.05.2009
12.06.2009


From: 01.01.2009 00:00 To: 12.06.2009 16:29
M-15 - Well test and calculated oil rates
Oil rate (Bbl/d)
4500
4200
3900
3600
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Calculated Oil Verified
Calculated Oil Unverified
Well test Oil
01.01.2009
13.01.2009
26.01.2009
07.02.2009
20.02.2009
04.03.2009
17.03.2009
29.03.2009
11.04.2009
23.04.2009
06.05.2009
18.05.2009
31.05.2009
12.06.2009

Simulated real-time values was compared with results from simulations with dummy tests. Calculated temperature deviation accepted from measured temperature, is for M-06 is 10 degrees Fahrenheit:

Well:	**Temperatures [degF]**		
M-06	**R-T calc Temp.**	**Measured Temp.**	**Dummy Temp.**
13-mai-09 00:00:00	142,28	142,260018	142,2
13-mai-09 03:00:00	142,35	139,905023	139,75
13-mai-09 06:00:00	142,41	139,689629	139,48
13-mai-09 09:00:00	142,52	139,546965	139,19
13-mai-09 12:00:00	142,62	138,798597	138,28
13-mai-09 15:00:00	143,02	140,18262	139,72
13-mai-09 18:00:00	142,45	137,96435	137,49
13-mai-09 21:00:00	142,94	137,531207	136,15
14-mai-09 00:00:00	143,15	134,875448	*
14-mai-09 03:00:00	142,77	131,358923	*
14-mai-09 06:00:00	144,57	132,388892	131,75
14-mai-09 09:00:00	143,16	130,336625	*
14-mai-09 12:00:00	143,48	128,288574	*
14-mai-09 15:00:00	142,58	128,77498	*
14-mai-09 18:00:00	144,57	127,638795	*
14-mai-09 21:00:00	144,89	127,16757	*
15-mai-09 00:00:00	101	140,82885	140,02
15-mai-09 03:00:00	100.985	147,302873	144,68
15-mai-09 06:00:00	125,77	152,299799	151,95
15-mai-09 09:00:00	140,9	142,496423	142,13
15-mai-09 12:00:00	*	141,45678	*
15-mai-09 15:00:00	141,12	138,265993	142,34

Appendix B

Data sources from PI:

Upstr P [barg] _M-43-PT-10511	Downstr. P [barg] _M-43-PT-10514	Choke size [%] _M-43-ZT-10512	Temp [degC] _M-43-TT-10513
80.50926971	22.2599678	11.60000038	87.84079742
80.45629883	22.47626305	11.60000038	87.72499847
80.32499695	22.30355453	11.60000038	87.61294556
80.27204895	22.18118858	11.60000038	87.5687027
80.22485352	22.76850319	11.60000038	87.50791168
80.16261292	22.56083488	11.60000038	87.43520355
80.04060364	22.22386169	11.60000038	87.39897156
80.12809753	22.32917595	11.60000038	87.57767487
80.09363556	22.82262802	11.60000038	87.6475296
80.0591507	22.54389954	11.60000038	87.69826508
80.04060364	22.58600044	11.60000038	87.71418762
79.97499847	22.22868538	11.60000038	87.7908783
79.89678192	22.53261566	11.60000038	87.76143646
79.87823486	22.14545059	11.60000038	87.79772186
79.82189941	22.21612549	11.60000038	87.80644989
79.7687912	22.76906013	11.60000038	87.80750275
79.71250153	22.57664299	11.60000038	87.85559845
79.73439789	22.9138813	11.60000038	87.80278778
79.69059753	22.92790604	11.60000038	87.79667664
79.63762665	22.50828934	11.60000038	87.79772186
79.55010223	22.80681038	11.60000038	87.73587036
79.48455048	22.00694466	11.60000038	87.70547485
79.46261597	23.04554176	11.60000038	87.7329483
79.36250305	22.65449333	11.60000038	87.68953705
79.36250305	22.60722923	11.60000038	87.69726563
79.2842865	22.68940926	11.60000038	87.68662262
79.26571655	22.65851021	11.60000038	87.69059753
79.07810211	22.38804245	11.60000038	87.74958038
79.09075165	22.62930679	11.60000038	87.79088593
79.00279236	22.79326057	11.60000038	87.78462982

Arrangement of data sources:

P up/Pdownst	P(ups)-P(downs)[barg]	Q (Bernou)[BOE]	Welltest [BOE]
3.616773862	58.24930191	4769.788657	
3.579611907	57.98003578	4758.751355	
3.601443744	58.02144241	4760.450291	4760.833333
3.618924597	58.09086037	4763.297186	4760.833333
3.523501429	57.45635033	4737.211685	4760.833333
3.553175817	57.60177803	4743.203072	4760.833333
3.601561454	57.81674194	4752.045403	4760.833333
3.588493266	57.79892159	4751.313006	4760.833333
3.509395828	57.27100754	4729.564861	4760.833333
3.551255654	57.51525116	4739.639217	4760.833333
3.543814844	57.4546032	4737.13966	4760.833333
3.597828531	57.7463131	4749.150195	4760.833333
3.545828106	57.36416626	4733.409923	4760.833333
3.606981693	57.73278427	4748.593846	4760.833333
3.592971216	57.60577393	4743.36759	4760.833333
3.503385328	56.99973106	4718.350263	4760.833333
3.530750854	57.13585854	4723.981115	4760.833333
3.47974212	56.82051659	4710.926874	4760.833333
3.47570325	56.7626915	4708.529157	4760.833333
3.538146567	57.12933731	4723.711521	4760.833333
3.487997704	56.74329185	4707.724477	4760.833333
3.611793991	57.47760582	4738.08785	4760.833333
3.448068906	56.4170742	4694.172598	4760.833333
3.503168307	56.70800972	4706.260653	4760.833333
3.510492252	56.75527382	4708.221494	4760.833333
3.494330135	56.59487724	4701.563814	4760.833333
3.498275739	56.60720634	4702.0759	4760.833333
3.532157949	56.69005966	4705.515746	4760.833333
3.495058526	56.46144485	4696.018161	4760.833333
3.466059281	56.20953178	4685.530377	4760.833333
3.509804036	56.46931267	4696.345341	4760.833333
3.468874468	56.15707588	4683.34355	4760.833333
3.558443434	56.71386909	4706.503784	4760.833333
3.456279665	55.96538544	4675.343493	4760.833333
3.495928346	56.23942757	4686.776242	4760.833333
3.503460579	56.24968719	4687.203722	4760.833333
3.572520337	56.66828728	4704.612059	4760.833333
3.573531348	56.60271835	4701.889499	4760.833333
3.539003067	56.37241745	4692.314401	4760.833333
3.53637969	56.34024239	4690.97512	4760.833333
3.379432135	55.2845459	4646.817833	4760.833333
3.414177512	55.48331451	4655.163862	4760.833333
3.454777536	55.72921562	4665.468261	4760.833333
3.341003206	54.95610046	4632.9939	4760.833333