

VMSS3 – Technical Description

Online Capable Production Engineering and Multiphase Virtual Metering Software Package

Sections to this technical paper include an Overview, Detailed Description and Application examples.

I. Overview

The Virtual Metering Simulation Software Package(VMSS3) simultaneously calculates the multiphase/single phase engineering fluid dynamics, heat transfer, and thermodynamic relationships for oil and gas/condensate wells and their downstream production facilities gathering systems. Thus, the VMSS3 provides the Client with accurate flow rate measurements for the three phase flows of gas, oil/condensate, water, and provides the pressure/ temperature/ flow rate information for simulation and optimum operation and design of the production systems. The VMSS3 package can now tie in with the Field Data Acquisition System (DAS) for instant online real time calculations. A detailed description of VSSM3 is contained in the [download document]

The VMSS3 technology has been under development during the last thirty years and has undergone rigorous field production testing in 413 wells and production facilities that produce from reservoirs with varying reservoir fluid properties. Applications have been made in 60 oil and gas/condensate field projects to provide optimal designs. Applications can be made in well/producing systems with limited experience or scarce data by simulating against the extensive virtual memory data banks that have been built up in 60 fields and several hundred applications.

The VMSS3 package should be applied to wells and their production systems to improve the accuracy of multiphase flow rate measurements and to reduce field investments and operating costs. Please refer to the categories below:

- to provide accurate well multiphase flow rate measurements without the need to install expensive wellhead or downhole multiphase meters or wellhead separators.
- to provide improved production testing for multiphase meters located at a distance downstream from wells-at the end of flowlines, production manifolds, or trunkline junctions. The VMSS3 package operates in parallel with the multiphase meters, thus

enabling accurate multiphase measurements to continue when the multiphase meter is out of service (10 –30% of the time), and provides meter proving and calibration capability for the multiphase meters.

- provides pressure/temperature/flow rates for future field conditions, as example, declining reservoir pressures, increasing water cuts, and increasing gas/oil ratios.
- calculates the flow rate increases generated from adding facilities modifications to the well and production systems. VMSS3 can be used to evaluate the most economical cost/benefit production system additions.

II. Detailed Description & Applications

A. Background

Virtual metering is a relatively new term describing the measurement of well flow rates without the use of multiphase orifice, venturi, or various commercial three phase meters. It entails the application of a complex set of algorithms and computational methods that originated in the late 1950's and have been progressively improved and extended since then. In our applications, we have developed extensive data banks from applications in 60 oil and gas/condensate fields. Accurate simulations of several hundred wells and surface producing systems operating in these fields have resulted from closely matching well and producing tests employing virtual metering simulation software calculations. The developments improving the speed and scope of smaller more economical computers has enabled virtual metering since the simulators are now capable of continuously updating well calculations on a real time on line basis.

Virtual metering is grounded in a comprehensive set of physically sound and theoretically correct algorithms that are combined with field test data, physical properties data and computer based methodologies:

- The multiphase/single phase fluid mechanical equations and correlations contained in our simulation models are applied to wells and surface producing systems. Extensive field research has been carried out to provide more accurate and comprehensive multiphase flow algorithms and correlations. In addition, contributions from research papers published in the literature are included in the basic relationships and technologies.

- Temperature description includes the temperature and heat transfer equations and correlations that are applicable to wells, surface systems and other in-line producing elements, operating primarily in multiphase flow.
- Our models contain accurate mathematical descriptions and coefficients developed by regression techniques to provide accurate correlations of the thermodynamic PVT properties and other physical properties of the reservoir fluids, flowing primarily in multiphase flashing flow, but also in single phase pressure crude above the bubble point. We have correlated physical properties for black oil, variation of properties with reservoir depth, wet gas and retrograde condensate. The fluid samples are obtained from downhole and surface fluid sampling which are then analyzed in the PVT lab or by chromatographic analysis. The regression calculation procedures accurately determine the equation coefficients for the set of equations describing the PVT properties and the complete array of physical properties is calculated within each flow increment.
- Concurrent developments of computer-based numerical analysis methods are employed in order to solve the large number of relationships and coefficients efficiently and accurately. The calculations proceed incrementally starting at the reservoir and calculating stepwise through the reservoir pay and then up the well and through the surface producing system and any devices, elements, or equipment facilities contained in the flow system.

The resulting comprehensive physically detailed field production simulation models are referred to as PTQ simulation models (pressure – temperature – flow rate). When applied to wells they provide the technical basis of the virtual metering simulation software. The PTQ simulation models have been applied to design, planning, optimization, and field operational analyses in 60 oil and gas/condensate fields.

Tables 1 and 2 contain the results of well and surface system validation for the North Sea and Middle East.

Our PTQ Simulators and the initial virtual metering applications were first developed for the Middle East fields and were later extended to oil and gas provinces worldwide. In the beginning, empirically based multiphase correlations were developed for standard petroleum industry measurement devices; including orifice plates, venturi meters, chokes and flow beans used to directly measure multiphase well flow rates and end-of -flowline

flow rates at the production manifold. These direct flow rate measurement devices were inaccurate with error ranges of ± 15 to 35% . However, well flow rate measurements required much better accuracy. Therefore, oil company managements funded large programs to carry out extensive engineering research and development studies which were combined with comprehensive engineered field production testing. The resulting virtual metering technology was applied to 195 wells. The well flow rate calculation accuracy obtained from the virtual meter simulations and software were in the range of ± 1 to 2% , as confirmed by 195 engineered well production tests carried out on 12 different fields with varying reservoir fluids.

Extensive testing was also carried out on a wide variety of surface systems, hilly and level terrain, on and offshore, with wellhead separators and without, including the effects of bends, valves, sand trap devices, as well as measurement devices. The multiphase surface systems are more complex than wells and in 172 surface system engineered production tests, about 90% fell in an accuracy range of $\pm 4.5 - 7.9\%$, while those with slugging low velocity flow in part or all of the system the accuracy declined to $\pm 10 - 13\%$.

Because of the high cost of installing separators in difficult remote and offshore areas, the long lead times between ordering and installation, and shortages of separator capacity that limited daily production, test separators were not installed in many of the difficult and inaccessible fields, or in offshore fields. The virtual metering computer programs were applied to all the wells in the fields because the wellhead flow rates calculated were more accurate than test separator results would have been on the basis of daily operations. The application of the virtual metering computer program simulations had the additional benefit of making large CAPEX and OPEX savings since test separators were not needed.

The test separator flow rate estimates were questionable because few meter provers were readily available to prove the gas and liquid phase outlet meter flow rates. Also, there were errors in flow rate measurements caused by LCO (liquid carryover) and GCU (gas carryunder) effects, as well as slugging, surging and foaming effects. These required corrections in the tests and improved testing procedures, but these were beyond the capability and time available to the plant operators. Well flow rate measurements under these conditions showed ± 15 to 25% accuracy and many tests had to be discarded. Later on, tests conducted in the North Sea demonstrated similar problems.

When production engineers were assigned to carry out the 367 tests that serve as a basis for both the virtual metering simulation programs and the PTQ simulation programs, better accuracy was obtained, primarily due to meter proving of the single phase streams.

Careful operation of the separators and monitoring of the material and energy balances also assisted in accurate flow rate measurement.

Well flow rate estimates are critical in providing accurate production accounting allocations, in making reliable estimates of producible reserves, and in providing accurate performance (PTQ) estimates for the wells and production systems, both in the short and longer term.

B Example Application: BH well 1 Virtual Metering, Wellhead Pressure - Flow Rate Simulation

Figure 1 shows the Wellhead Pressure versus Flow Rate (B/D liquid basis at standard conditions) performance relationship that is generated by the virtual metering well simulation program (the graph is referred to as a well PQ chart).

Two production tests were carried out on this well and their P_w 's and Q 's are plotted on the PQ chart. There is good correspondence between the flow rates calculated by the virtual metering well Simulation Program and the field production tests. Thus the virtual metering simulation of the PQ performance for this well demonstrates accuracy of $\pm 1-2\%$ compared with engineered production tests. This accuracy compares very favorably to multiphase meters measuring well flow rates.

Note also that the virtual metering program calculates the well $P_w - Q$ relationship over the range of well flow rates from zero to maximum and includes the portion of the $P_w - Q$ curve where slugging flow in the well is predicted and at very low flow rates where well cease flow is predicted. Again, it should be noted that current multiphase meters cannot accurately predict flow rates for unfavorable multiphase flow conditions occurring over the full range of well performance. Thus, the virtual metering well simulation program provides operators, engineers and management with well flow rates of good accuracy over the well flow capacity ranges and also can identify potentially infeasible or difficult regions of the $P_w - Q$ charts.

Not printed out is the corresponding $T_w - Q$ chart which also is obtained from the well simulation. The wellhead temperature values are important in estimating temperature related effects like hydrate formations, scaling, wax deposition, Joules Thompson temperature drops, and others. Temperature also relates directly to the well elevation pressure drop through GOR and fluid density.

The second (lower) $P_w - Q$ curve on the Figure 1 BH1 PQ Chart results from the lower input reservoir pressure. Reservoir studies for this case showed that reservoir pressures will decline with time at a predicted rate in BH1. The estimated lower reservoir pressures reduce wellhead pressures and flow rates, so planning also requires the $P_w - Q$ functions at lower reservoir pressures.

Figure 2 shows the PQ chart for increases in Gas/Oil Ratios in the well.

Figure 3 shows the BH1 PQ chart where the incoming reservoir pay has begun water encroachment with the well producing increasing water cuts over time. The physical properties subroutine is adjusted to incorporate the addition of the water cuts.

C. BH1 Input Values to the Virtual Metering Simulation Program

Static Reservoir Pressure, P_s

This basic input is usually measured by wireline operations with the downhole pressure gauge located at the bottom hole conditions, with the well shut in. In some operations the gauge is run monthly on the wireline. In more difficult and expensive operations it may be measured less frequently.

In some recent wells, especially offshore, and in horizontal wells, downhole gauges both for reservoir pressure and temperature have been installed for continuous reading. The downhole gauges are calibrated to $\pm 1/4$ to $1/2$ % accuracy before being run downhole. The P_s is a key input to the virtual metering program. The depth at which the static reservoir pressures are measured over time, Z_s , is also an input to the virtual metering program.

Reservoir Temperature

The bottom hole temperature T_s (degrees F) is measured at the same depth as the static reservoir pressure Z_s and is an input to the virtual metering program

Flowing Bottom Hole Pressure, P_f

While the well is flowing, a pressure gauge is lowered by wireline and the flowing bottom hole pressure is measured at the same depth as the static (shut-in) reservoir pressure. If this is not possible because of flow velocity, the P_f is measured at an alternative depth

Zf. A delta P correction must be made to adjust Ps and Pf to the same depth. Pf and Zf are inputs to the virtual metering program.

Productivity Index or Inflow Performance Function

The pressure drop across the reservoir pay is measured by the productivity index in BH1 which is the flow rate divided by the pressure drop across the reservoir pay,

$$PI = Q (b/d) / (Ps - Pf). \text{ Psi.}$$

In wells where the delta P = (Pr – Pf) varies with Q, the inflow performance equation that relates Pr – Pf to Q with two or three coefficients is derived. These relationships are determined usually by two or three flow rate tests carried out by the wireline or production logging testing crews under engineering supervision. The two or three coefficients are input to the program subroutine that generates the IFP function which then enters the virtual metering program.

A computer program that works in conjunction with the well virtual metering program can calculate the resulting inflow performance from a reservoir pay divided into ten sections with varying PIs, water cuts, and gas/oil ratios in each zone. The resulting blend flowing into the well is then calculated as input.

Well Depth, Lengths and Diameters of Casings, Tubing and Downhole Chokes

This information is available from the driller's records and is also required for the wireline production testing, and is accurate to + - 1 % for most wells. The inputs must define whether the flow is in the casing, in the annulus between casing and tubing, or in the tubing.

The well configuration is input to the virtual metering program

There is also an input for calculating the pressure drop – flow rate relationship for a downhole choke in line for the incremental calculation, stepwise up the well.

The configuration input includes horizontal and inclined wells, as well as vertical and inclined wells.

Thermodynamic PVT properties and other Physical Properties Correlations

For BH 1, downhole reservoir fluid samples were taken with an Amerada Bomb sampler operating under full reservoir pressure. More than one sample would be taken when the

fluid properties varied with depth. The reservoir samples were analyzed in the PVT lab to measure the fluid thermodynamic properties both above and below the bubble points as a function of pressure and temperature from initial reservoir pressures and temperatures to standard conditions (14.73 psia and 60 degrees F)

The properties measured as a function of P & T are:

- liquid phase density, pcf
- gas phase density, pcf
- saline water density and salt content, pcf and ppm
- gas/oil ratio at P and T, acf/bbl
- liquid viscosity, centipoise
- gas viscosity, centipoise (optional if determined from correlations)
- bubble point pressure as a function of T, psi.

These PVT lab analyses are presently available to us for 60 reservoir fluids world wide. Therefore, from limited data on a specific well, the entire physical properties PVT relationships can be estimated. These can be improved later when and if more complete reservoir fluid data becomes available. The reservoir fluid PVT data is processed through our PVT regression package which develops the best-fit coefficients for the twelve equations describing the laboratory PVT data. There are 55 coefficients in the normal PVT program application. The accuracy of the physical properties calculations is + - 1 to 2 %, with some properties +- ½ %

The virtual metering program has been adapted to information available in many fields which are not as complete as the BH1 properties data. These include methods for adapting equations of state to the more accurate program formulation. The properties functions are often obtained with only limited data available for a well. Techniques have been worked out to use the data banks on 60 reservoir fluids to simulate the entire function from limited data. These functions are used until more complete reservoir fluid samples become available. The properties data can also be reconstructed from separator and flowline samples which provide guidance for interpreting available well physical properties data. Surface line samples are often taken if there have been increases in gas/oil ratios or water cuts. This information is then integrated into the available physical property data relationships and correlations.

The other physical properties that enter into the well virtual metering program are entered directly as correlations, such as specific heat ratios, surface tensions, Joule Thompson

temperature effects, hydrate and wax deposition correlations which are expressed as functions of P and T.

Thus, the input values for the well virtual metering program can be defined very accurately, often within 1 to 2 %. Therefore the complex flow rate calculations will also show an accuracy of + - 1 to 2 %. To the extent that there are problems in defining the input accurately, this will reflect in the accuracy of the resulting flow rate calculations.

The virtual metering program integrates with any multiphase metering device at the wellhead or located downstream at a production manifold. The control equations are modified and the PVT relationships in the meter calculation system are adjusted to match the P_w/T_w versus Q results obtained from the virtual metering program. Thus the virtual metering program can serve as a meter prover to bring a multiphase meter to the same level of accuracy and allow it to adjust to operating at flow rates and flow regimes where it is too inaccurate when operating alone. Multiphase meters often are out of service due to mechanical or electronic problems. The virtual metering program continues to operate, providing the operator with accurate flow rate information.

D. Well Virtual Metering Program Procedures

The technical procedures are listed below:

- Monthly (later sometimes quarterly) downhole wireline testing and data collection. In some wells downhole gauges for continuous reading of pressures and temperatures at specified depths have been provided:
- measure the P_f (s), flowing bottom hole pressure (s) at a flowing rate (or rates) at a specified Z_f 's, the bottom hole depth consistent with the initial zero point of the well flowing configuration for the stabilized flowing well.
- Measure the P_s (static bottom hole pressure) at Z_s , the specified total depth, the same as for P_f measurements in most wells although the well is shut in when P_s is measured (flow rate equals zero). In wells with multiple zones, more than one P_s/ Z_s measurement may be specified in order to provide additional measured data for reservoir pay inflow performance analysis and calculations.

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- Measure the temperature at Z_s . If other depths are required for measurements measure temperatures at other depths so that the temperature gradient can be calculated for the bottom hole conditions
 - The downhole wireline or production logging assembly can be equipped with a spinner survey tool or a recording liquid phase orifice or venturi meter. In most wells there is a high pressure liquid leg in the bottom of the well. Measure the liquid phase flow rate(s) at the specified depth Z_f , or at other nearby depths where liquid phase elevation differences enable P & T corrections to be made. If some gas is out of solution but bubble homogeneous multiphase flow is maintained, the measurements are still taken and adjusted to reflect gas out of solution at the specified P & T.
 - the Amerada bomb or similar high pressure sampler is run to Z_o or specified depth (at known P & T) to collect reservoir fluid adequate for PVT Analysis in the laboratory, preferably by the full Corelab's method or as specified to determine physical properties as a function of P & T (above and below the bubble points. Bubble point pressure is established as a function of temperature. Note that the bottom hole reservoir fluid samples are not taken on a monthly basis. It may be taken initially and later if there have been changes in fluid properties. Sometimes reservoir fluid samples are only taken to run simple GOR or water cut tests if the well is affected by gas coning or increasing solution gas, or by water encroachment usually flowing from the lower casing or tubing perforations of the pay.
 - In many wells as example BH1, the productivity index is adequate to characterize the performance of the reservoir pay over the operating range of the well. In this case one flow rate test is sufficient. If the inflow performance of the reservoir pay is more complex and requires an equation with two or three coefficients as a function of flow rate, testing at two or three flow rates will provide the data to compute the IFP coefficients.
 - The other inputs as specified in previous paragraphs.
 - Conduct the matching of the wellhead pressures and temperatures with the virtual metering program using the specified data inputs and generate the resulting well flow rates. Plot, inspect and compare the performance curves ($P_w/T_w/Q$ Charts) with similar wells.

E. Interaction between Well Virtual Metering Program and the Downstream Flowlines and 2/3 phase Separators Simulation Models

Of the original 195 wells tested many were equipped with wellhead separators. Well flow rate accuracy of 1-2 % were achieved because the wellhead separator outlet streams were measured with meter proven PD and orifice meters. Care was taken to operate the separators at optimal flow rates and liquid levels so that liquid carryover (LCO) and GCU (gas carryunder) were negligible.

Pressure - Temperature – Flow Rate (PTQ) Simulations were carried out on 172 surface flowing systems. The simulations were later extended to other fields. Pressure and temperature data was recorded at the head and end of the lines and sometimes at intermediate points. The flow rates were measured in test separators located in the Gas/Oil Separating Plants (GOSPs). The test flow rates were compared with the calculated flow rates based on matching upstream and downstream P & T measurements. Depending on the degree of hilly terrain and the flow regimes, calculation accuracy compared with matched production data were in the 5 – 10 % range in most systems with a few in uphill slugging flow in the 10 – 13 % range. 175 production tests were also carried out on Gas/Oil separators to develop accurate simulation capabilities. Later on additional tests were carried out in other fields with roughly comparable accuracy.

The PTQ simulation models that were developed have been effectively employed in several hundred surface systems in order to conduct operational analyses and to design, plan and optimize the surface systems and facilities.

The well flow rates can be estimated by back calculating from the GOSP separator flow rates through the flowlines back to the wells using the simulators and available field data. However, using the surface flowline simulation for well allocations causes an inherent inaccuracy of 5 – 10 % or more in the estimated well flow rate. We do not recommend this procedure for determining accurate well flow rates. The application of the well virtual metering program described above is recommended since it has shown the capability of measuring well flow rates to +/- 1 to 2 %, which is better than any other methods or procedures.

F. Implementation of the Virtual Metering Program for Wells

The implementation steps are outlined below:

- (1) In order to apply the virtual metering simulation program to the five candidate fields, the field operators and engineers would gather all the data available as described in the above paragraph C :Input the values to the virtual metering simulation program.
- (2) We will evaluate the available data for completeness. It is often found that sufficiently complete information is not available. In most cases the data banks on 60 reservoir fluids and the several hundred simulated wells and surface systems will provide ways to complete the data inputs.
- (3) The first runs are then made on the wells in the field. These are compared with flow rate data. The $P_w - Q$ and $T_w - Q$ curves are calculated. These are compared with similar well performances around the world for reasonableness and potential accuracy
- (4) A program of testing is developed to perfect the data inputs until the 1 –2 % accuracy standard is achieved The improved performance curves are generated

Key data inputs as previously discussed are:

- (a) PVT analysis data obtained from bottom hole samples, or flowline and wellhead samples and downstream separator samples if the bottom hole samples are not available.
- (b) measurements of bottom hole and well head pressures and temperatures and available productivity index and bottom hole flow rate data.
- (c) a detailed description of the well configuration including depth, casing and tubing diameters, well chokes submersible pumps and gas injection facilities (if any) and well inclinations
- (d) we have developed our well simulation model to the point where we can simulate horizontal flow and lateral tie-ins and this configuration data is required for horizontal well applications.

The virtual metering simulation program will converge to match wellhead pressure and temperature at a flow rate. The verification of flow rates predicted by the virtual metering simulation program can be compared against the downhole liquid leg flow rate measured by spinner surveys; orifice or venturi liquid meters from the wireline or production logging rig; reservoir pay PI and IFP downhole tests; metered well head separator tests;

and surface line facilities tests based on metering oil and gas rates at separators located at or near the production manifolds. The last will also require PTQ simulation of the surface line and separation facilities.

The calibrated virtual metering simulation programs applied to the wells in a field are free of the electro-mechanical faults and operating range limitations that apply to multiphase meters. Once set, the virtual meter simulation well models will perform accurately over a wide range of well flow conditions if the physical properties, gas coning and water cut are known and changes are tracked across time. Acknowledging the expense of obtaining additional bottom hole samples and the PVT analysis costs, we have developed advanced software that enables a base PVT analysis to be modified based on flowline and separator samples measuring GOR, water cuts, and liquid and gas phase densities. Chromatographic analysis of reservoir fluids can also be integrated and regressed into the physical property PVT relationships and become input into the virtual metering Program.

- (5) Once the virtual metering simulation program has been adapted to the wells in a given field, the next step would be to install and customize the software. The considerations involved here are:
 - (a) location of the computing facilities, central and/or local PCs.
 - (b) definition and installation of pressure, temperature and flow sensors to interface with the virtual meter software on either an off-line or real-time basis.
 - (c) providing user friendly interfaces tailored to user needs. This is a critical task.
 - (d) providing useful well performance reports at specified time intervals.
 - (e) shake down tests of the software and supporting system elements.

- (6) Training is identified as a separate step, but actually it is preferable to have a person assigned from the beginning for each separate field application. Training would involve imparting knowledge of the underlying mathematical and engineering basis of the software along with its application. In this regard, the virtual meter software as a simulation model can be applied for a variety of purposes in addition to flow prediction. These include:
 - (a) developing well performance data
 - (b) well modification studies including submersible pumping and gas lift, for example
 - (c) longer range prediction of the effects of gas coning, water encroachment and reservoir pressure decline

(d) well performance effects on surface line operation

Table 1

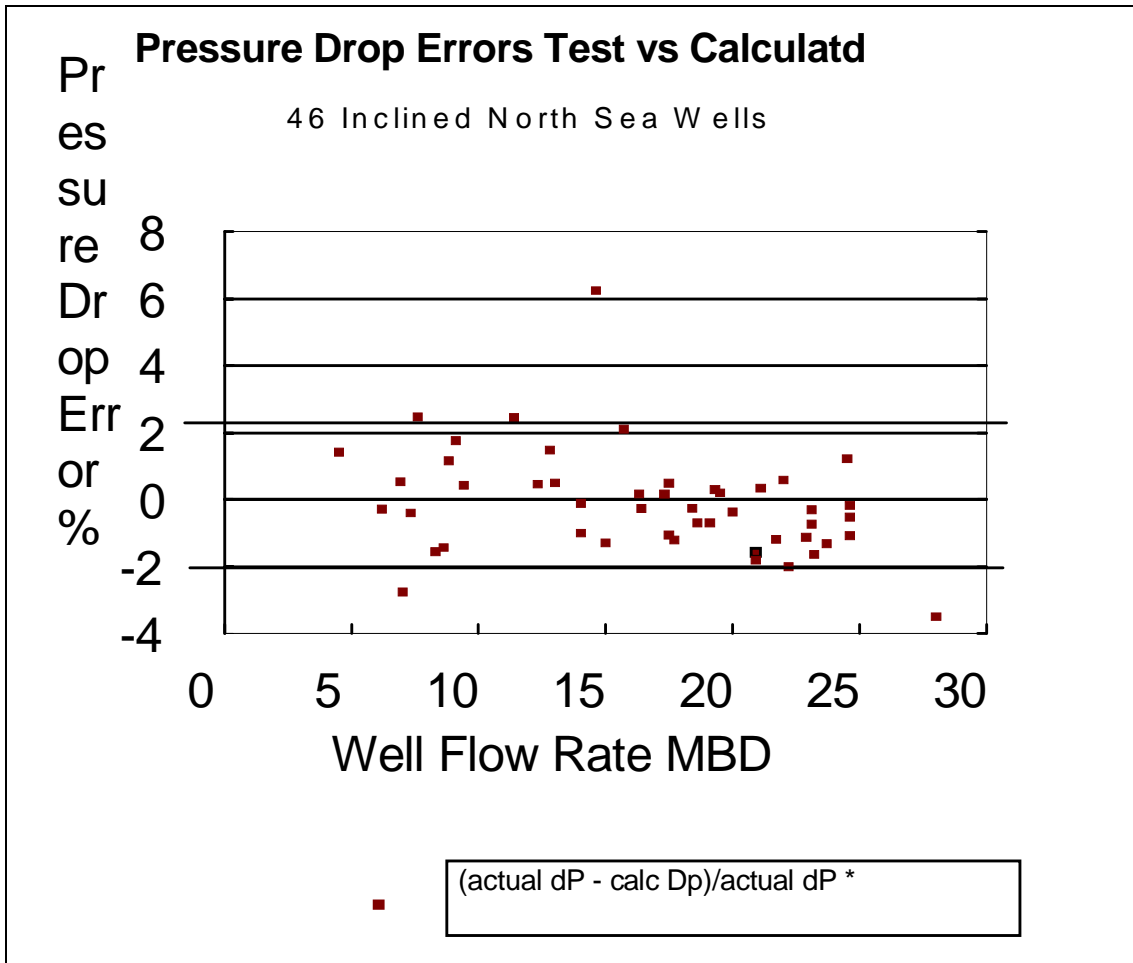


Table 2

Validation against 367 Wells & Surface Facilities						
OIL FIELD	OIL WELLS			SURFACE SYSTEMS		
	No.	Average Deviation (%)	Maximum Deviation (%)	No.	Average Deviation (%)	Maximum Deviation (%)
AGHA JARI	44	0.05	0.50	39	0.67	5.2
AHWAZ	31	0.28	0.77	30	0.16	5.1
GACH SARAN	29	0.08	0.57	25	0.78	2.6
RAG E SAFID	13	0.17	0.79	9	1.4	7.2
MARUN	31	0.08	0.95	29	0.60	4.0
PARIS	18	0.33	0.80	14	2.0	6.9
KARANJ	6	0.27	0.75	3	0.51	4.7
BIBI HAKE-IMEH	11	0.05	0.55	11	0.45	4.2
NAFT E SAFID	9	0.04	0.96	9	INSUFFICIENT DATA	
PAZAN	3	INSUFFICIENT DATA		3	3.8	5.7
TOTAL	195	0.13	0.70	172	0.73	4.5
DATA ACCURACY	+ 1-2 %			+ 3.7-10 %		

Over five thousand simulation cases have been carried out on existing production systems. Thus the model has been thoroughly tested and validated against a large quantity of test data, configurations and fluid properties from real systems composed of complex flow and process elements.

Figure 1

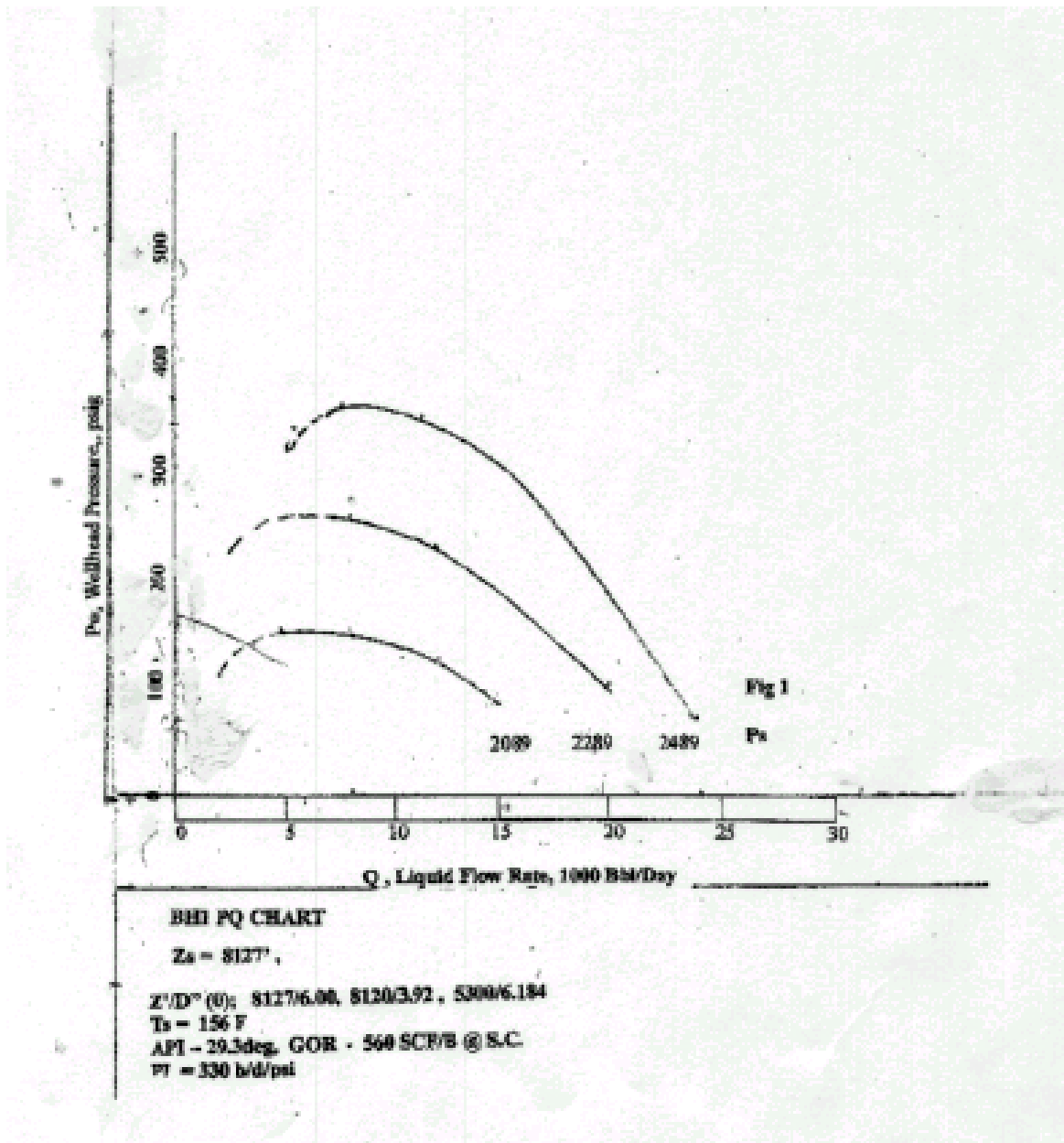


Figure 2

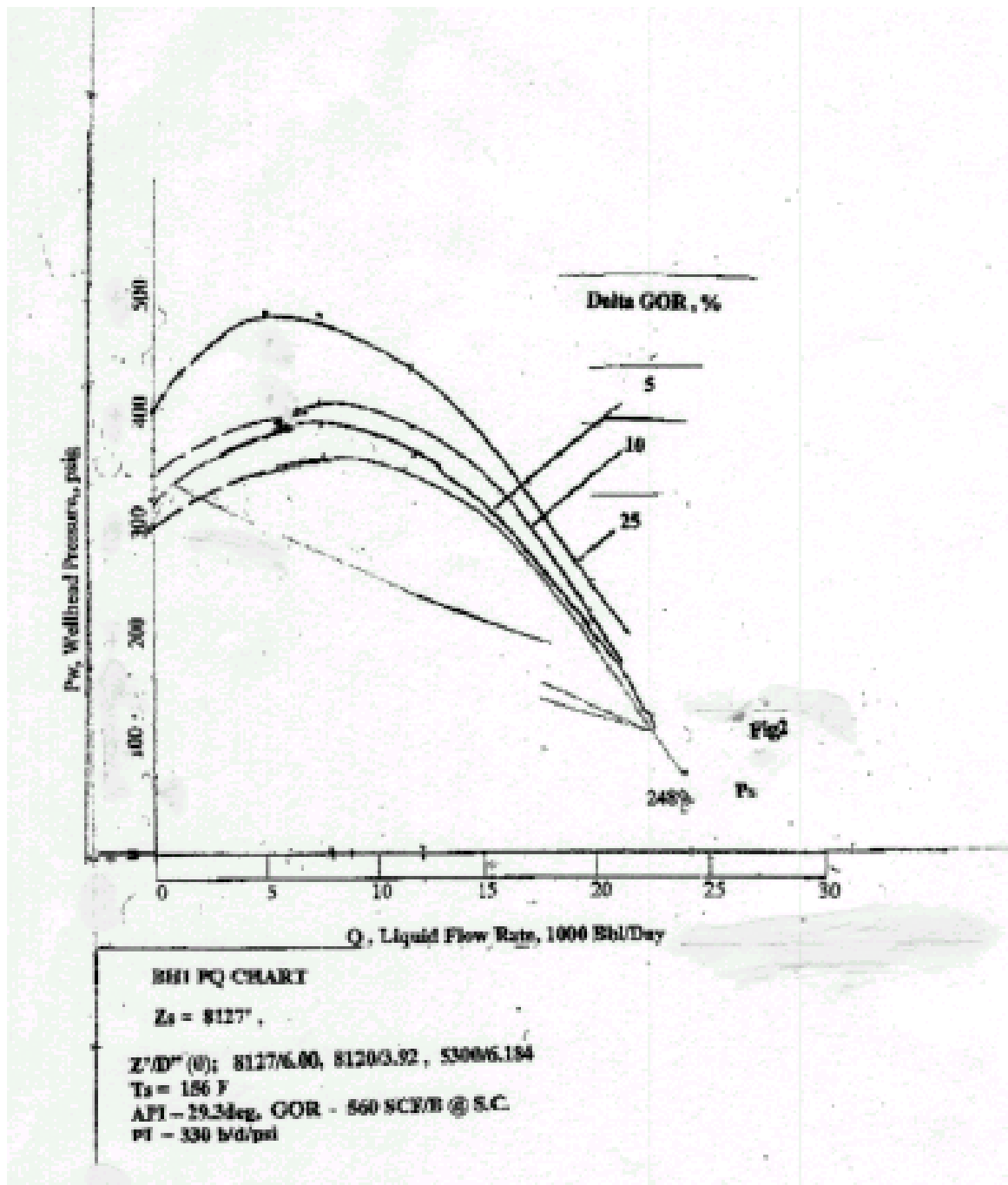
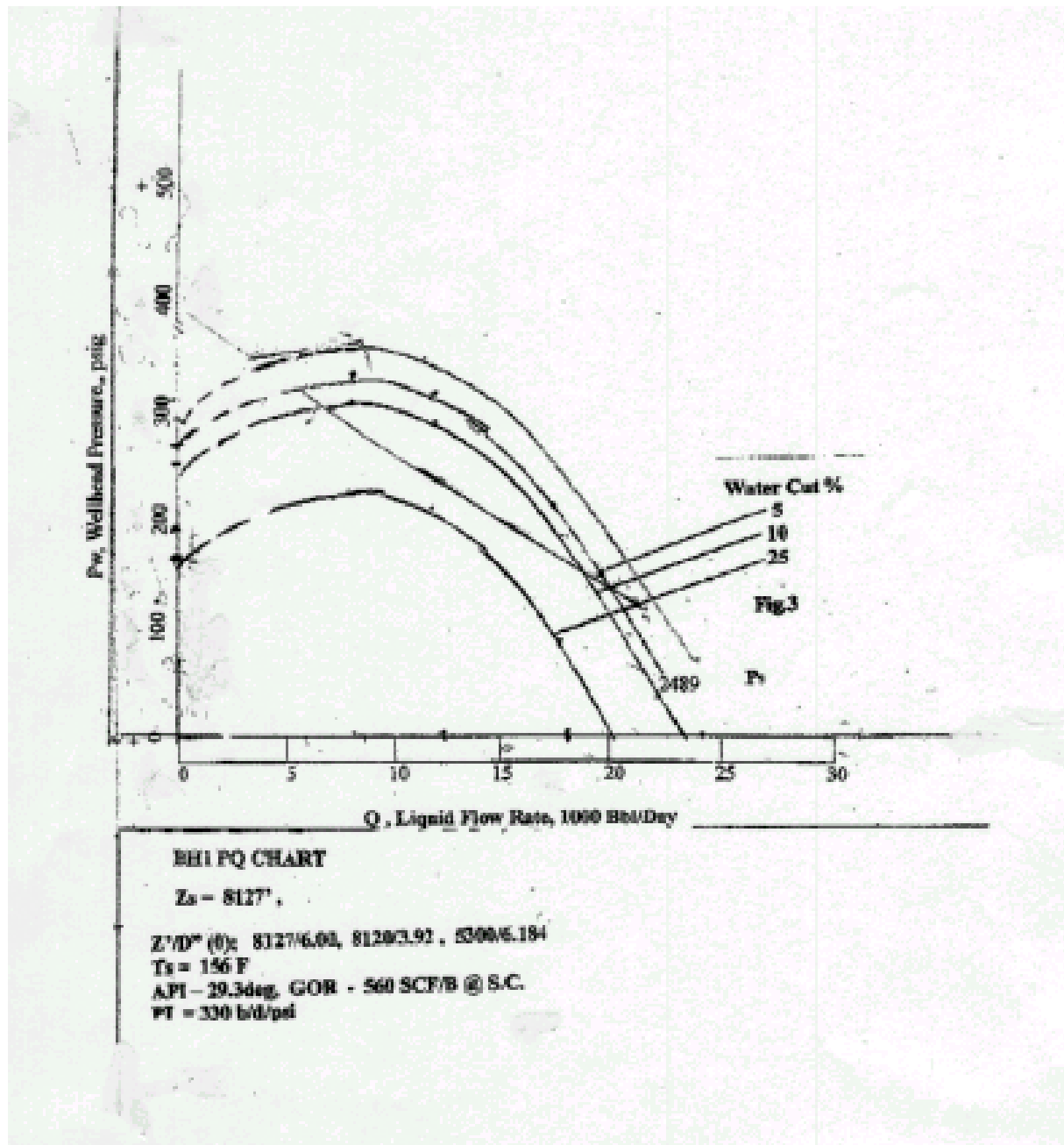


Figure 3



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