SPE-178353-MS

Overcoming Limitations of Empirical Steady State Models using Multi Rate Testing, MRT

Michaels Ifechukwu, Igbinedion University Okada; Oladepo David Adebowale, Convenant University Ota

This paper was prepared for presentation at the Nigeria Annual International Conference and Exhibition held in Lagos, Nigeria, 4–6 August 2015.

Abstract

Gaslifted wells in mature fields have their peculiar characteristics that make them unique, like high water-cut, high GLR, and multiphase flow through the system. Such wells exist and it has being the tradition to model those using empirical steady state models. The objective of this work has been to determine if these empirical models are modeling the wells efficiently or not. Measured data, Multi-Rate Testing, MRT in form of gaslift injection rates and their corresponding liquid rates has been obtained and used as a basis for this research. If they do not model these wells satisfactorily, the project proceeds to determine the reasons and then recommend ways of overcoming these limitations.

The flow through the tubing is part of a system that starts with inflow from the reservoir. Empirical models developed under unique experimental conditions model multiphase flow from the bottom hole to the surface. These models, which include Beggs and Brill, Hagedorn and Brown, take into consideration several flow variables, which include liquid holdup, gas void, and flow regime to determine contributions of hydrostatic head, friction, and acceleration to pressure loss in the tubing. It was discovered that appreciable differences can exist in liquid rates calculated from these models and the measured liquid rates. This means the models are not efficient and the wells are not optimized.

Significant findings of this project are: the reasons for these deviations are centered on inherent flaws in these models. These models cannot capture the dynamic conditions of a gaslift well which produces liquid in slugs and some do not capture the effect of deviation on pressure gradient. Other reasons for deviation include the L-factor, productivity index, tubing inner diameter changes due to scale, roughness or oversized tubing, correlation model in use, and a combination of these factors. It is recommended that MRT be carried out more frequently.

Introduction

ABC Petroleum, AP has been producing oil since 1969. The company operates four offshore fields; A, B, C, D. As at the time of this research, about 256 active producer wells and 169 injector wells were existing in the fields. These wells comprise of mostly deviated, horizontal, sidetracked, and multilateral wells, which produce from a single reservoir or comingled. The fields drain three main reservoirs.

All AP fields are very mature fields that have being in production in excess of 30 years.

- A was discovered in 1966 and came on stream in 1969,
- B was discovered in 1970 and came on in 1972,
- C was discovered 1972 and came on in 1978,
- D was discovered in 1973 and came on in 1979.

AP fields exhibit the characteristics of mature fields which include;

- Declining production.
- High water cut due to water breakthough and water injection, A has an average BS &W of 92%, B a range of 30 to 99%, C an average BS &W of 65%, and D with a range of 3 to 30%.
- Ageing facilities.
- High recovery factor.
- Virtually all producers are on artificial lift; gas lift and Electric submersible pumps.

Well gaslift modelling and optimization are done using models developed with a commericial software. That has being the tradition. Recently, multi-rate test, MRT were carried out on some pilot wells and it was discovered that the measured liquid rate response from the well differ significantly from the model calculated liquid rates. This means the models are not representative of the well capability and therefore production from most wells are not optimized.

This difference in MRT and models' response is a major limitation of the empirical steady state correlations used for pressure drop calculations in the well models.

This project seeks to investigate the reasons for this differences in liquid rate response curves from measured MRT and calculated response from the models. The project goes further to suggest ways to overcome these limitations.

Empirical Steady State Flow Correlations

Transport of fluid up the tubing requires energy to overcome friction in the system and to lift the fluid to the surface. Pressure drops occur accross the components of the system and this loss varies with production rate. The amount of fluid flowing into the well from the reservoir depends on the pressure drop in the piping system and this depends on the amount of fluid flowing through it. To determine the performance of any well, it is necessary to calculate the pressure losses in all components. A relationship between flow rate and pressure must be avaliable for each component. According to Beggs, H.D (2006), about 80% of the total pressure drop in the system takes place in the tubing and therefore its an important component.

The Flow Correlation models the pressure and temperature changes that occur in the tubing and other piping components with respect to depth and inclination. The models determine liquid holdup and friction factor experimentally (empirically) for known liquid and gas flow rates. These are then used to calculate pressure drop at various depth points along the tubing for known design variables which include pipe diameter, fluid properties, and pipe angle.

The general applicable pressure equation is;

$$\left(\frac{dp}{dl}\right)total = \left(\frac{dp}{dl}\right)el + \left(\frac{dp}{dl}\right)f + \left(\frac{dp}{dl}\right)acc \tag{1}$$

$$\frac{dp}{dl} = \frac{\rho g\ sin\theta}{g} + \frac{f\rho v^2}{2gd} + \frac{\rho v dv}{gdL} \tag{1a}$$

A number of fluid correlation models, derived experimentally account for these pressure losses in a wellbore under a variety and unique flow conditions of water cut. Appendix 2 presents a summary of conditions under which some Multiphase correlations were developed. Models available on Wellflo include Duns and Ros, Begg and Brill, and Hagedorn and Brown.

Flowing gradient survey, FGS where Downhole memory gauges are sent down as deep as possible on wireline to measure pressure and temperature changes along the length of the tubing are used to calibrate these models and also check the efficiency of the gaslift valves.

Multirate Testing, MRT

Multirate testing, MRT is a technique used to capture the dynamic states of a well. MRT is used to determine the maximum well deliverability, MWD. MRT involves varying the gaslift injection rate and capturing the changing parameters of the well, which include the bottomhole flowing pressure, water cut, and the liquid production rates. The data can be captured using the following

- Well testing using test separator
- Multiphase flow meter
- Downhole guages

For the moment, liquid rates changes in MRT is captured using the test separators. At each injection rate, 2 days is allowed for flow stabilization before the reading is taken. After separation, liquid rate is measured using a turbine meter, gas is metered using an orifice meter, while the water cut is determined using manual settling procedures. Water cut measurement is important so that well's water cut sensitvity to drawdown changes can be monitored. Gaslift response curves of gaslift injection rate vs liquid rate can then be obtained **(Appendix 1)**.

With the present well injection rate noted, over injecting and under injecting are carried out to obtain the full curve response.

This is also practised in other companies, according to Gerrard, C *et al* (2007), in Shell E&P in Europe, models are updated by routing a well back to the test separator and performing a new well test. Less frequently, multi-rate tests, also called deliberately disturbed well testing are used to update the models.

Qualitative and Quantitative Analysis

The pressure profile from the FGS is matched against many correlations and the closest match is chosen. From this comparison, average error percentage and the standard deviation is calculated.

Appendix 3 presents the criteria for well candidate selection. Appendix 4 presents the 25 pilot wells selected. The models used in these wells are also compared with industry recommendations (Appendix 2).

Well models not using industry recommendations:

Some of the models used in some wells do not agree with industry recommendations for such wells based on well type, water cut, or GLR. The remark column indicates the model in use and the industry recommended models for such wells. Five horizontal wells fall under this category **(Table 1)**

Table 1—Wells not matching industry Recommendation

Well	Model	Ave Error % /Standard Deviation	Remarks
MM- 12ABC	**Duns**	**1.08/ 58.44**	**In Use**
	B and B (std)	-12.51/41.37	Recommended
	B and B (mod)	10.31/70.97	Recommended
G-15	**Gray**	**-4.89/125.05**	**In Use**
	B and B (std)	-21.65/66.53	Recommended
	B and B (mod)	5.70/ 132.14	"
	H and B (mod)	-22.70/ 129.79	"
Q-06A	**Gray**	**-25.57/359.61**	**In Use**
	B and B (std)	-37.58/323.50	Recommended
	B and B (mod)	-20.49/ 363.39	"
	H and B (mod)	-41.17/ 359.11	"
ZA-16A	**Gray**	**17.11/ 94.71**	**In Use**
	B and B (std)	-9.63/42.91	Recommended
	Band B (mod)	25.59/ 99.50	"
	H and B (mod)	0.01/ 103.34	"
RA-12ABC	**Gray**	**-2.26 /13.46**	**In Use**
	B and B (std)	-40.87/ 27.10	Recommended
	Band B(mod)	5.10/ 14.60	"
	Hand B(mod)	-43.69/ 15.69	"

From the above, with some of the industry recommended models having higher average errors and devaitions, it is seen that the industry recommendations are just guides, which may not apply to specific fields like AP wells/fields. It also points to the limitations of these models.

Well models matching industry recommendation

The well models used in the other 20 wells agree in one way or the other (well type, water cut, GLR) with the industry recommendations.

For the analysis, the entire wells were grouped using different criteria, which are Well type (horizontal or deviated), reservoir pool, tubing size, water-cut and GLR (See appendix 4). The error between the MRT and the models was calculated for each gaslift rate, model and well. The percentage error, average percent error, and standard deviation for the wells and the groups were subsequently calculated. **Table 2** presents the summary results from the analysis. The best three models are presented for each grouping.

Table 2—Data Analysis Results

Well Group	No of Wells	Model	Standard Deviation
Well Type			
Horizontal Wells (Figure 1)	10	B and B (std)	12.27
		EPS Mechanistic	14.47
		Gray	16.25
Deviated Wells	15	EPS Mechanistic	12.69
		H and B (mod)	13.48
		B and B (std)	13.92
Reservoir Pool			
A	5	B and B (std)	7.65
		EPS Mechanistic	7.72
		H and B (mod)	11.68
B	8	B and B (std)	22.03
		EPS Mechanistic	22.71
		H and B (mod)	23.87
C	11	B and B (std)	10.65
		Gray	10.67
		EPS Mechanistic	7.86
Comingled	1		
Tubing Size (inches)			
5 ½ and 4 ½	4	EPS Mechanistic	3.53
		Gray	4.41
		B and B (mod)	5.07
4 ½	12	EPS Mechanistic	15.77
		B and B (std)	18.60
		H and B (mod)	19.86
4 ½ and 3 ½	4	D and R (std)	9.81
		B and B (std)	12.19
		EPS Mechanistic	13.17
3 ½	5	H and B (mod)	10.23
		B and B (std)	10.32
		Gray	13.41
Water Cut (%)			
90 – 97	6	EPS Mechanistic	4.48
		B and B (std)	6.96
		Gray	8.10
80 – 89	11	B and B (std)	10.64
		EPS Mechanistic	11.20
		D and R (std)	13.26
40 – 79	7	EPS Mechanistic	20.28
		H and B (mod)	20.55
		B and B (std)	21.27
0 – 40	1		
GLR (SCF/STB)			
< 1000	4	EPS Mechanistic	3.28
		B and B (std)	6.84
		Gray	9.16
1000 – 3000	16	EPS Mechanistic	11.67
		D and R (std)	16.37
		B and B (std)	14.75
3000 – 6000	5	B and B (std)	16.99
		H and B (mod)	18.92
		Gray	20.86

Standard deviations for all the models under all the groupings are quite high further confirming the inadequacies of empirical steady state models. Furthermore, no trends were noticed in the plots. Notwithstanding, EPS mechanistic and Beggs and Brill (standard) are the most repeating models for the groups. Therefore, they should be considered in all cases.

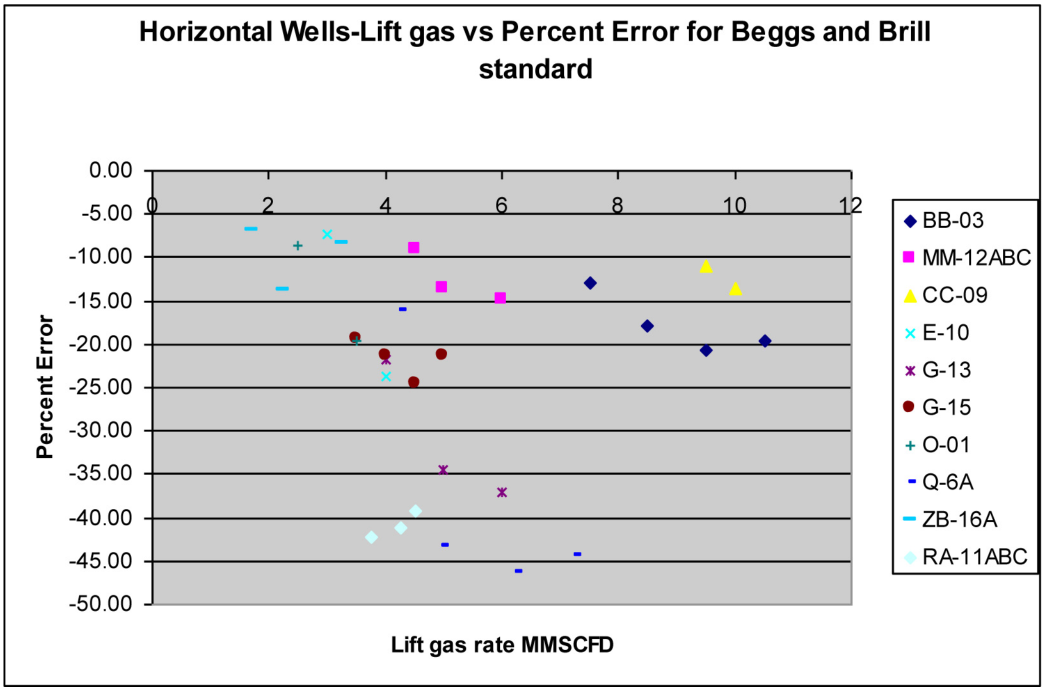


Figure 1—

Well where model liquid rate matchs MRT

One well, JJ-03A is worth mentioning. The MRT and model matchs perfectly (**Figure 2**).

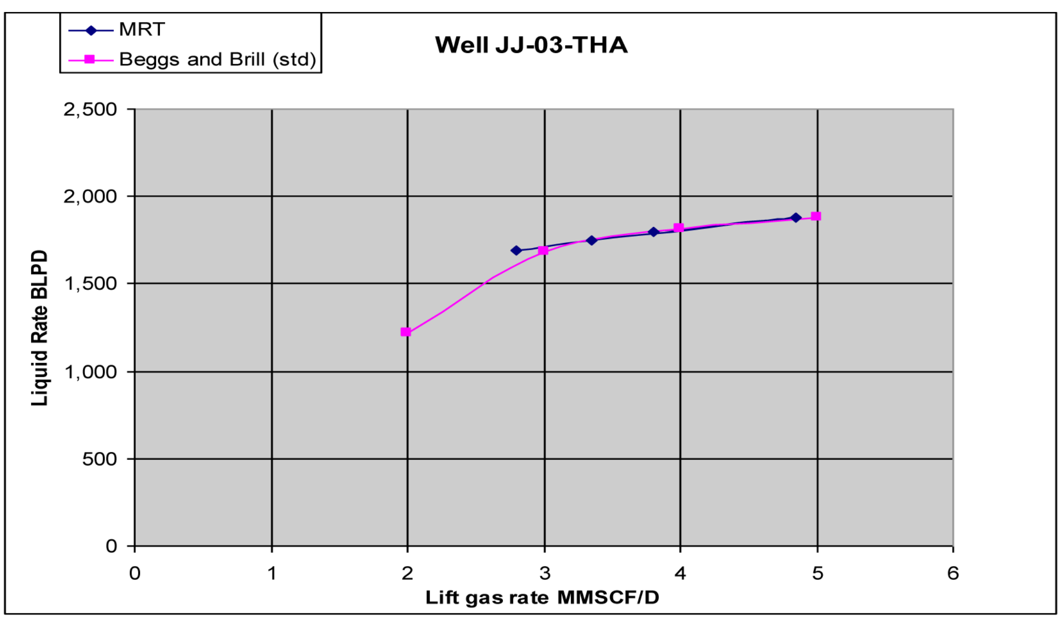


Figure 2—

On further investigation, (**Figure 3**), the plot of (gas injection rate, produced GLR, and Liquid rate) vs Date shows these parameters responds proportionately to the changes in P_{wf} caused by changes in gas injection rate.

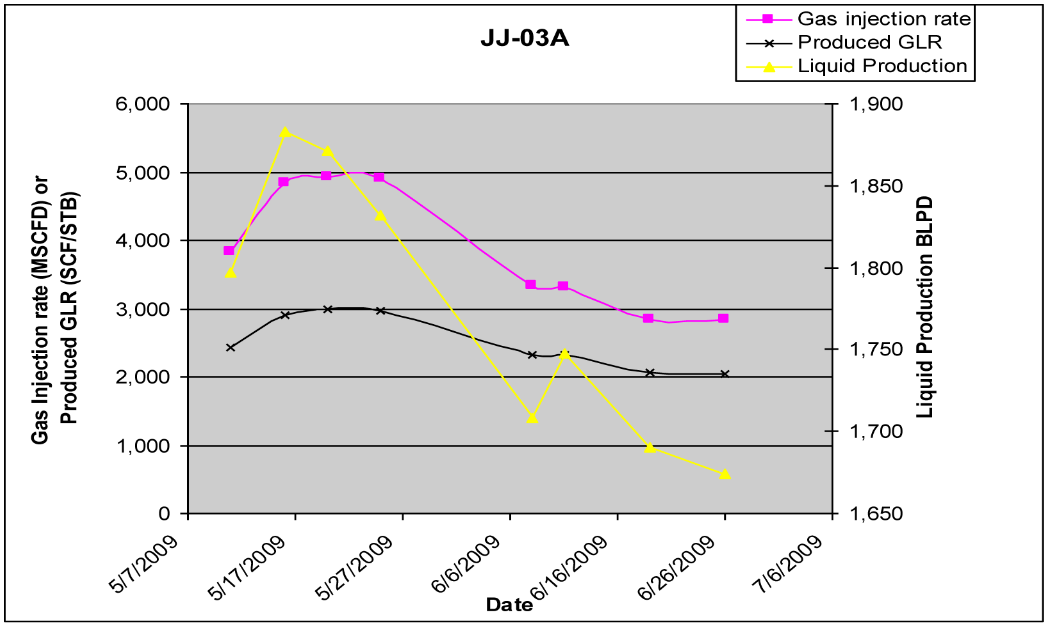


Figure 3—

This can only point to the fact that the reservoir pressure being used in the model (3000psia) is correct and also fairly constant. The following parameters of the well match the design specifications of Beggs and Brill (model in use);

- The Well is a deviated well and Beggs and Brill was designed for all flow directions
- The well has a maximum GLR of 3000 SCF/STB and the model is good for GLR $<$ 5000 SCF/STB.

It was also noticed that the well showed no water cut sensitivity to drawdown changes. The water cut has remained constant at 88% since 2006 and through out the MRT. This is also a reason for the perfect match since water cut is not a contributor to changes in P_{wf}. The reservoir pressure and water cut being constant means the changes in P_{wf} are only as a result of changes in gas injection rate.

Reasons for deviation between model liquid rates and MRT

Inherent flaws in empirical model construction

A huge source of error comes from inherent flaws in the models itself. These models are steady state and therefore cannot capture the dynamic nature of the well. The model uses a time averaged liquid holdup and gas void fraction to calculate the pressure gradient at different point along the tubing. This cannot capture the dynamic nature of gaslifted wells where slug flow is prominent. The models also assume other important parameters to be constant, which include water-cut, bottomhole pressure and GOR. These parameters vary appreciable and are difficult to keep constant.

Also, according to H. D Beggs (2006), most of the models, except Beggs and Brill neglect the effect of inclination angle on the liquid holdup. Inclusion of the pipe angle in the pressure gradient equation accounts for the fact that the hydrostatic head acts only over the true vertical depth while the friction loss occurs over the measured depth. High errors are usually obtained when vertical methods are used on directional wells, except small increments were angles are fairly constant are used.

Almost all the empirical models were developed using tubing sizes less than 2 inches, the smallest tubing used in AP is 3.5 inchs. This is also be a source of error.

AP wells are also peculiar; they produce at high water cuts up to 97%. Most of the models are only good for water cuts up to 10%.

Wellflo sensitivities

Several sensitivities were carried out on Wellflo including correlation models, L-factor, tubing inner diameter, roughness, and PI. Lift gas injection rate sensitivity was kept constant in all the sensitivities in other to obtain a gaslift response curve **Figure 4**.

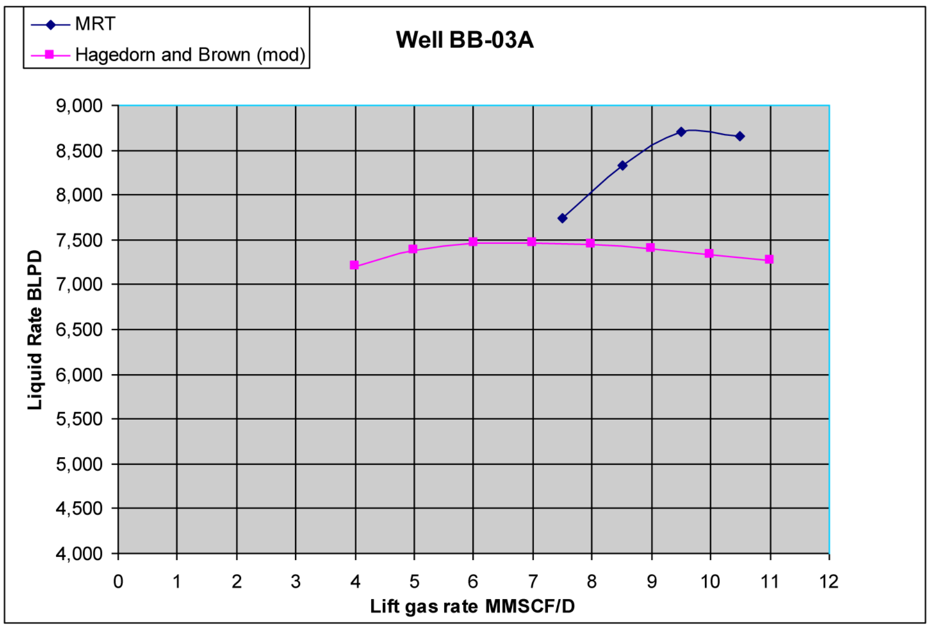


Figure 4—

After the analysis (See appendix), the MRT and Model curves for some wells matched after sensistivity was carried out on the following factors or a combination of them;

L-factor; This is an outflow friction correction factor to adjust pressure drop calculation to match measured data. The pressure drop in each increment gets multiplied by the value of L. High value of L (above 1) translates to higher pressure gradients and a higher bottomhole pressure.

Productivity Index; PI is the rate and pressure drawdown relationship of the reservoir. PI is affected most by pressure drawdown. It is also affected by perforation density (completion efficiency), phase changes when $P_{wf} < P_b$, viscosity, skin/formation damage, and turbulence around the well.

Reduced inner tubing diameter; this is mostly due to scale buildup in the tubing.

Roughness; this is the distance between the hill and valley of the microscopic bumps inside the tubing. As the tubing continues being in service, the roughness normally increases. However, from sensitivity carried out, roughness has a little effect on the liquid rate.

Correlation model; empirical model in use also causes deviation between the models and the MRT. In some wells, other models give a closer match to the measured data more than the model in use.

Oversized tubing; this leads to the well loading up liquid at lower gaslift injection rates. However, during MRT when the gaslift injection rate is increased, the liquid rate increased appreciably more than the model calculated rates.

Conclusion of results

Identifying trends was a top priority in this research. Unfortunately, there was no consistency in the data to confirm a trend. Deviation in liquid rate of model and MRT occur in all except one well. These variations are not consistent under any grouping. Consequently, it has being proved beyond all reasonable doubts that steady state empirical models cannot model the dynamic and complex nature of multiphase flow in tubing of gaslifted wells.

Recommendations

All things being equal, the MRT gives the true production capability of the well. It is therefore recommended that it be carried out frequently on all the wells and used to update/calibrate the models. The following are recommended;

1. **Table 2** can be used as a guide in selecting correlations that will give the best match to the measured data. MRT data should be used to fix the optimum liquid rate and gaslift injection rate.
2. Carry out MRT quarterly on high producers (2000 BLPD and above). Low producers below 2000 BLPD should be tested every six months.
3. Pre-MRT surveys using acoustic ultrasonic logging should be done prior to MRT to identify leaks in the tubing and gaslift valves. These leaks should be repaired before MRT. Gas leaks into the tubing from points other than the operating valves gives rise to a different localized flow regimes in tubing. This will change the pressure gradient in all other components thereby leading to error in model calculations.
4. Downhole pressure gauges should be incorporated into MRT. The gauges will monitor changes in P_{wf} and therefore drawdown changes with respect to production rates. From the plot of P_{wf} against gaslift injection rate, a better estimate of the PI can be calculated. With known P_{wf} and PI, appropiate reservior pressure can be forced on the model. This reduces uncertainity in the PI and pressure drawdown.
5. A core issue on MRT is the reliability of the measured liquid rates. This pilot was carried out using test separator orifice and turbine meters. Multiphase flow meters, MPFM should be incoporated into the MRT procedures. MPFM readings are realtime and captures the continous variations in liquid holdup and gas void fraction. MPFM readings can be used to validate test separator meter readings.
6. Sufficient time should be allowed in order to determine the full well response to P_{wf} change due to altered gaslift injection rate. In horizontal wells, change in drawdown can cause a section to start contributing or stop contributing to inflow. This means a change in PI. The well should be flown long enough for the full response to be felt at the surface. This is another area where MPFM will be very useful. Rates should be continously monitored and readings taken only when stabilized readings have being observed for a long time (at least 1 day).

Economic justification for MRT

MRT is an improved and extended form of the routine welltest carried out on the wells. The only additional costs are the increased man hours needed to multi test the well and the cost for acoustic logging. The operator needs to change the gaslift injection rate, monitor it for a while (at most 1 hour) and move on to other things while the testing continues. On the average to conduct multirate test, six additional man hours are needed in excess of the time for conventional welltesting. This can be covered convinently by the increased oil production that is expected. Though oil production will be lost in some wells, the gain gotten from other wells on the platform can compensate the loss.

Existing AP facilities have enough capacity to handle the anticipated increase in liquid rate. Therefore no additional facility cost is incured in conducting MRT.

Limitations of MRT

1. Appreciably production is lost when under-injecting during MRT and can take time to reverse after the test.
2. Distortion to the bottomhole pressure during MRT saw a drastic increase in watercut in some wells leading to loss of oil production even with increased liquid production. This data points are however not completely useless, since watercut sensitivity to drawdown in such wells could help optimize workover opportunities, like tubing change out, etc.
3. Availability of gaslift gas. This is more of an issue in summer when the compressor capacities are reduced. This is a major limitation as MRT may not be possible on all wells due for testing. It is therefore recommended that the MRT should be scheduled for periods when gas availability is not an issue.
4. Sufficient gaslift manifold/ casing head pressure. This is also dependent on the compressor capacity and present efficiency. Increased gaslift injection rates require higher gaslift manifold and casing head pressure.

Suggestions for further work

It is suggested that the accuracy of the test separator meters used should be studied further. Multiphase flow meters can also be studied and used in conjunction with test separator meters for validation. This will increase the accuracy/reliability of the measured liquid rates, which can make the causes of deviation better known and isolated.

Nomenclature

B and B	Beggs and Brill
H and B	Hagedorn and Brown
D and R	Duns and Ros
(std)	Standard
(mod)	modified
MRT	Multirate Test
g	acceleration due to gravity
p	mixture density
L	length of pipe section
Θ	angle of inclination
f	friction factor
g_c	conversion factor
P_{wf}	Bottom Hole Pressure

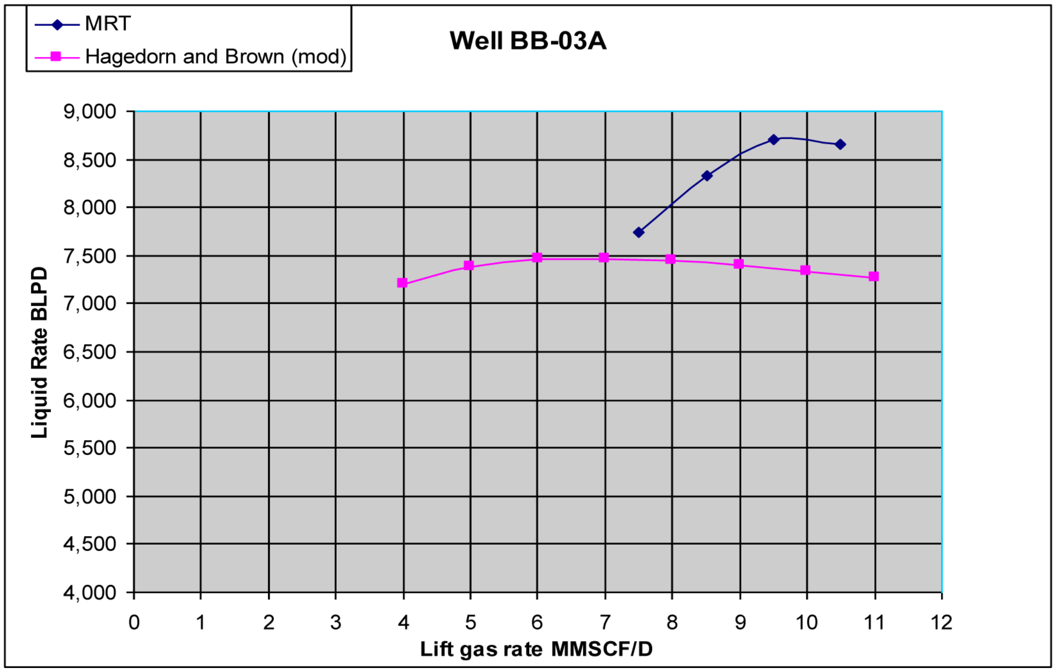
References

1 Beggs, H.D.: “Production Optimization Using Nodal Analysis,” Tulsa Oklahoma,2003
2 Takacs, G.: “Gaslift Manual“. PennWell
3 Brown, K.E. et alet al: “The Technology of Artificial Lift Methods, Volume 2b“. Petroleum Publishing Co., Tulsa, 1980
4 Cox, S.A., Sutton, R.P., and Blasingame, T.A.: “Errors Introduced by Multiphase Flow Correlations on Production Analysis,” paper SPE 102488 presented at the 2006 SPE Annual Technical Confrence and Exhibtion, San Antonio, Texas, 24-27 September
5 Gliere, L., Brun, B., Bure, E., Ryan, M., Al Jasmi, A.: “Maturing Field: A Case History Offshore Abu Dhabi,” paper SPE 88769 presented at the 11th Abu Dhabi International Petroleum Exhibtion and Conference, Abu Dhabi, U.A.E, 10-13 October 2004

6 Wiggins, M.L., Wang, H.S.: “A Two-Phase IPR for Horizontal Oil Wells,” paper SPE 94302 presented at the 2005 SPE Production and Operations Symposium, Oklahoma City, OK, 17-19 April
7 Gerrard, C., Taylor, I.C., Goh, K., de Boer, F.: “Implementing Real-Time Optimization in Shell E&P in Europe- Changing the Way We Work and Run Our Business,” paper SPE 108515 presented at Offshore Europe 2007, Aberdeen, Scotland, 4-7 September
8 Heriot Watt University,: “Production Technology Manual,” 2005. CTES, L.C, Technical Notes, www.ctes.com,: “Multiphase Flow Models Range of Applicability,” Conroe, Texas, 18th May 1998
9 Maurer Engineering Inc.,: “Multiphase Flow Production Model (PROMOD1)- Theory and User’s Manual, Houston, Texas, January 1994
10 Dubai Petroleum Facilities Overview Manual, April 2008Appendix

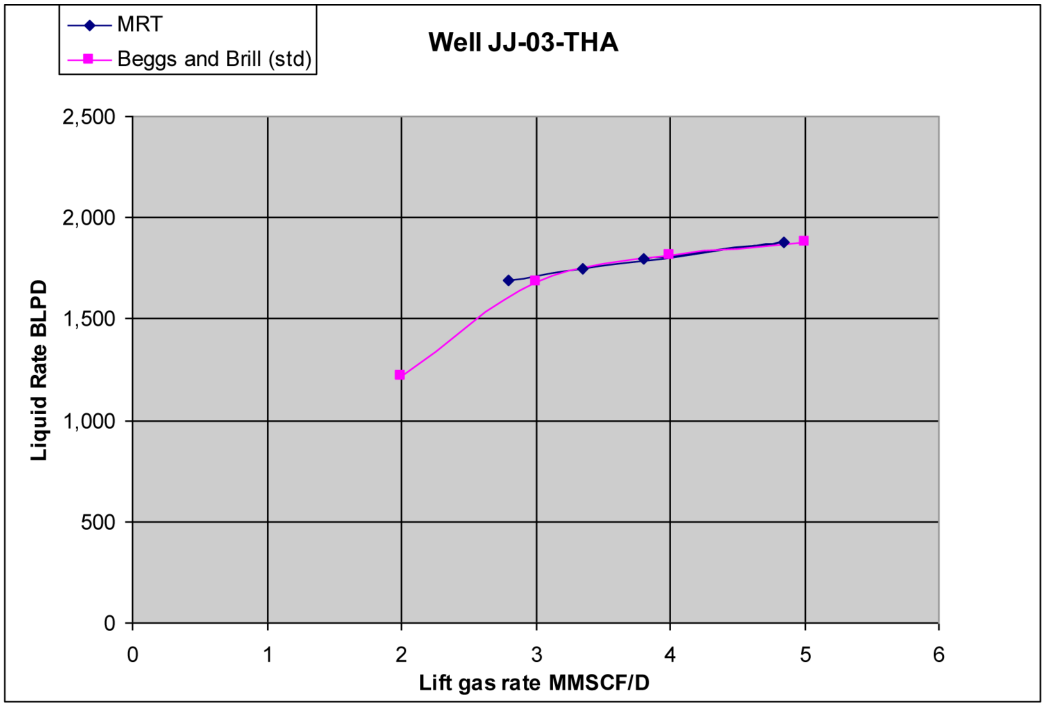
Appendix 1a

Gaslift Response Curve Generated from MRT and Empirical models for a well candidate



Appendix 1b

Gaslift Response Curve Generated from MRT and Empirical models for a well candidate



Appendix 2

Summary of Empirical Steady State Models

Correlation Model	Applicability and Limitations				
	Developed for	Tubing size diameter	Oil gravity	GLR	Water Cut
Duns and Rons (D and R)	Vertical flow of gas and liquid intended for use with dry oil/gas mixtures in wells	Over predicts pressure drop for tubing diameters between 1 and 3 inches	Good predictions of pressure profile for gravities (13-56 API).	Over predicts for a wide range of GLR. The errors becomes (< 20%) for GLR greater than 5000.	Not applicable for multiphase flow of oil, gas and water. Correlation can only be used with a suitable correction factor
Beggs and Brill (B and B)	All the flow directions. It was developed using sections of pipelines that could be inclined at any angle	Accurately predicts for tubing sizes between 1 and 1.5 in. Over predicts for larger sizes.	Reasonably good performance for a large range of oil gravities	Over predicts pressure drop with increasing GLR. The errors become large for GLR above 5000.	Good up to about 10% water-cut
Hagedorn and Brown (standard) (H and B std)	Vertical flow in oil wells. It is independent of flow patterns	Accurately predicts for tubing sizes between 1 and 1.5 in. Over predicts for larger sizes.	Over predicts pressure loss for heavier oils (13-25 API) and under predicts for lighter oils (40-56 API)	Over predicts for GLR greater than 5000	Good for a wide range of water-cut
Hagedorn and Brown Modified (H and B mod)	Bubble flow regime	”	“	“	“
Orkiskewski	Limited to two-phase pressure drops in a vertical pipe. Composite of several previous models with modifications	Good prediction for 1 and 2 in. tubing sizes. Over predicts for tubing sizes greater than 2 in.	Over predicts for low oil gravities (13-30 API). Predictions improve as oil API increases.	Very good accuracy for GLR up to 5000. The errors become large (< 20%) for GLR above 5000.	Good accuracy for a wide range of water-cuts.
Gray	Vertical flow in wet gas wells	Good prediction for tubing sizes below 3 in and flow velocities below 50ft/sec	Not applicable. But good for condensate production up to 50 bbl/MMscf	Good prediction up to 20000	Good prediction for water production up to 5 bbl/MMscf

Appendix 3

Well Selection Criteria

Well candidate selection criteria

Well candidates for this research was basically based on history. Wells picked had a track record of minimal problems and work overs. The prioritization criteria also include;

- Select wells that have no tubing leak potentials,
- Select wells with no history of gaslift malfunctioning
- Select wells located in areas where voidage changes have occurred in the recent past.
- Select wells with infrequent flowing gradient surveys or other relevant inflow /outflow information.
- Select wells with oversized tubing strings, with liquid fall back potential.
- Select wells that have a history of increased liquid/oil production at increased gas injection rates.
- Select wells that have proven difficult to history match on Wellflo.
- Select wells in which recent well intervention activities such as stimulations and perforations have been performed.
- Select wells with lower than normal GLR (Liquid to injection gas ratio).

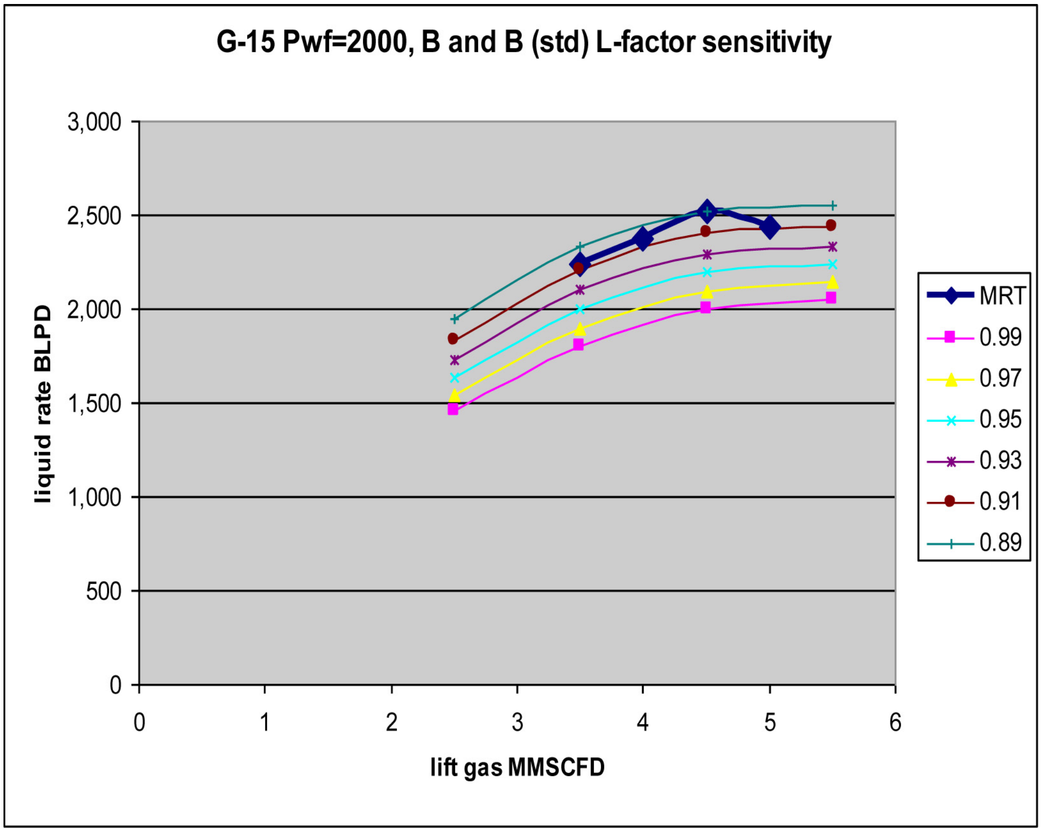
For high water cut wells that meet either of the above criteria, check to ensure low sea water content, to eliminate the possibility of mobilizing injection water through increased drawdown

Appendix 4
Well Candidates

Well	Well Type	Water Cut	GLR	Correlation in Use	Remarks
BB-03A	horizontal	90	990.5313	H and B (mod)	Good for:28-30 API, GLR<5000, wide range of water cut.
JJ-03	deviated	87	2440.718	B and B (std)	Good for:all flow directions, wide range of API,
JJ-08A	deviated	86	2668.497	H and B (mod)	Good for:28-30 API, GLR<5000, wide range of water cut
MM-11	deviated	80	1869.907	B and B (std)	Good for:all flow directions, wide range of API,
MM-12ABC	horizontal	28	1910.285	D-E-F	(not suitable for down flow)
NN-17	deviated	82	2252.402	H and B (mod)	Good for:28-30 API, GLR<5000, wide range of water cut
NN-03	deviated	69	2977.221	Gray	High GLR (<20000), water production< 5bbl/mmscf
BB-06	deviated	76	2506.909	B and B (std)	Good for: all flow directions, wide range of API
CC-09	horizontal	84	1114.374	H and B (mod)	Good for:28-30 API, GLR<5000, wide range of water cut.
D-04	deviated	86	2403.252	H and B (mod)	Good for:28-30 API, GLR<5000, wide range of water cut.
E-10	horizontal	84	3346.187	H and B (mod)	Good for:28-30 API, GLR<5000, wide range of water cut.
G-13	horizontal	87	3319.241	B and B (mod)	Good for: all horizontal wells, wide range of API
G-15	horizontal	93	1822.274	Gray	
I-08 (COM)	deviated	88	1415.207	H and B (mod)	Good for:28-30 API, GLR< 5000, wide range of water cut.
O-01	horizontal	97	411.9865	H and B (mod)	Good for: 28-30 API, GLR<5000, wide range of water cut.
P-02	deviated	93	501.3394	H and B (mod)	Good for: 28-30 API, GLR<5000, wide range of water cut.
Q-06A	horizontal	74	3046.811	Gray	
ZA-01	deviated	96	752.6768	B and B (std)	Good for: all flow directions, wide range of API
ZA-02	deviated	88	1544.108	H and B (mod)	Good for:28-30 API, GLR<5000, wide water cut
ZA-16A	horizontal	86	1565.312	Gray	
ZB-11	deviated	74	1943.233	EPS mechanistic	Applicable to all Fluid Types, Pipe Sizes and Inclinations.
ZB-12	deviated	64	5158.011	H and B (mod)	Good for: 28-30 API, wide range of water cut.
ZC-02	deviated	60	3604.838	H and B (mod)	Good for: 28-30 API, wide range of water cut.
ZC-03	deviated	95	1415.228	H and B (mod)	Good for: 28-30 API, wide range of water cut.
RA-11ABC	horizontal	5	2471.463	Gray	

Appendix 5a

Sensitivity Plots



Appendix 5b

Sensitivity Plots