

## RESERVOIR SIMULATION AND PREDICTION: A CASE STUDY OF AN OIL-RIM RESERVOIR IN A NIGER DELTA OILFIELD

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### **Abstract**

The water-injection-only option was started when simultaneous water and gas injection were stopped in an oil-rim reservoir. With geologic and pressure-volume-temperature dataset and production history of the oil-rim reservoir, an estimate of the oil-in-place, a forecast of production performance and other important parameters such as aquifer size and drive mechanisms were determined. The Material balance and Monte Carlo tools of MBAL reservoir engineering toolkit were employed, and the workflow was followed. An estimate of the original oil in place from material balance simulation of 93.4839 MMSTB, higher than the Monte Carlo simulation, with the P50 estimate of the Oil in Place as 82.9607 MMSTB were determined. Water Injection and Gas Cap Expansion were shown to be the major drive mechanisms in the years ahead till 2025, with increasing contribution from Fluid Expansion. A large aquifer exists, and reservoir pressure is expected to be high in the year 2025. The water-injection-only option has been shown to be capable of maintaining production efficiency in the oil-rim reservoir, based on the study of the oil reservoir in the Niger Delta.

**Keywords:** *History matching; Material balance equation; Production forecast; Reservoir simulation.*

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## **1. Introduction**

Beneath the earth's surface where hydrocarbon is found, reservoir engineers use parameters such as rock and fluid properties to estimate hydrocarbon in place and make predictions. The behavior of gas and liquid phases of hydrocarbon is affected by factors that assist in the estimation of hydrocarbon in places such as basic physics, chemistry, mathematics, and subsurface geology [1]. Production forecast is important because, in addition to inputs to the economics models and well timing requirements and design of facilities, they are used to schedule workover frequencies and optimize production.

In this work, simultaneous water and gas injection was started after about eleven months of production in the field. Due to the available market for the gas produced, the gas injection was stopped in 2017, and water injection alone was continued for pressure maintenance, improved recovery, and efficiency. The decision to use a single technique of water injection instead of combining two techniques of simultaneous water and gas injection was also justifiably expected to maintain production efficiency in accordance with research findings [2]. As a result of the strategy, material balance (MBAL) reservoir simulation software, used in reservoir engineering studies was used to estimate the hydrocarbon in place, determine aquifer size, reservoir drive mechanism, to make forecast of expected production and reservoir pressure up to 2025 for water-injection-only option since gas injection was stopped earlier in the life of the well. An estimate was made with the Monte Carlo simulation as a validator to compare with the MBAL simulation output of the oil in place.

## **2. Literature review**

Oil reservoirs sandwiched between bottom water and gas cap have been termed oil rim reservoirs [3]. In the work, it was pointed out that most oil reservoirs in the Niger Delta basin

are less than 80ft of thickness, and water/gas coning are common problems. Reservoir porosity and permeability values of 6-28% and 1-6208md are common [4].

However, a lot has been presented on oil rim reservoirs. Work on the assessment of oil rim reservoirs to highlight the strengths and weaknesses of existing models have been presented [5]. It was pointed out that inconsistency, the limited scope of application, and non-robustness are due to their inability to capture the physics of oil rim reservoirs.

Other recent works that have presented strategies for production in oil rim reservoirs exist. Simultaneous water and gas injection (with the maintenance of voidage replacement) has been shown as a technique to improve recovery in oil rim reservoirs [6]. In the work, reservoir simulation with sensitivity analyses of well placement, aquifer strength, permeability anisotropy, oil column thickness, and gas oil ratio relaxation policy on oil rim development was carried out. They suggested that simultaneous water and gas injection could increase the recovery factor of recovery by up to 15% of the stock tank oil initially in place. This is in contrast with another finding that simultaneous water and gas injection does not appreciably increase production efficiency [2]. In the work, they revealed that combining two techniques do not significantly increase recovery efficiency over a single technique to justify the cost of implementation. However, integrated approach and innovation in the form of state of the art engineering, technical initiatives, and application of new technologies have been suggested as tools to make significant changes in oil rim reservoir development [7]. The data used in their simulations may differ. In other words, no two reservoirs are expected to have exactly the same features.

Similarly, estimation of stock tank oil initially in place, and aquifer properties have been key reservoir engineering challenges, and reservoir material balance analyses provide solutions. From its initial development to advances in the material balance equation for both single and multi-tank models, lots of works have been presented for reserves estimation and other purposes [8- 12]. They highlighted that early stage use of production data is inapplicable, and that self-adaptive nonlinear regression could be adopted to advance material balance analysis. Also, analysis of distinct reservoir geologic units and features were shown to be possible by the use of MBAL multi tank option, and a tool for reservoir performance analysis that saves time and cost was presented. In summary, reserves estimation remained an essential task, and currently, there is no standardized reserves estimation procedure.

In particular, the generalized material balance equation (MBE) is given as [13],

$$N = (N_p[B_o + (R_p - R_s)B_g] - (W_e - W_p B_w) - G_{inj}B_{ginj} - W_{inj}B_{wi}) \div ((B_o - B_{oi}) + (R_{si} - R_s)B_g + mB_{oi} \left[ \left( \frac{B_g}{B_{gi}} \right) - 1 \right] + B_{oi}(1 + m)x \left[ \frac{S_{wi}C_w + C_f}{1 - S_{wi}} \right] \Delta p) \tag{1}$$

This is expressed for an oil reservoir as;

$$F = NE_t + W_e \tag{2}$$

The underground withdrawal, F, equals the surface production of oil, gas, and water with under reservoir conditions:

$$F = N_p * (B_o - B_g * R_s) + B_g * (G_p - G_i) + (W_p - W_i) * B_w \tag{3}$$

$$E_t = (B_o - B_{oi}) + (R_{si} - R_s)B_g + mB_{oi} \left( \frac{B_g}{B_{gi}} - 1 \right) + (1 + m)B_{oi} \left[ \frac{S_{wc}c_w + c_f}{1 - S_{wc}} \right] (P_i - P) \tag{4}$$

When there is no aquifer influx,  $W_e = 0$ , hence;

$$F = NE_t \tag{5}$$

$$F/E_t = N \tag{6}$$

A plot of F/E<sub>t</sub> will yield a horizontal straight line, and the intercept is N. Similarly, from equation (2);

$$F - W_e = NE_t \tag{7}$$

A plot of F - W<sub>e</sub> against E<sub>t</sub> will give a straight line with slope N, and;

$$F/E_t = N + W_e/E_t \tag{8}$$

Also, if the aquifer model is accurate, a plot of F/E<sub>t</sub> against W<sub>e</sub>/E<sub>t</sub> will give a straight line with an intercept at N and a unit slope.

Reservoir simulation using MBAL software is fundamental based on Equation (1) to Equation (8). Reservoir simulation has been in use by reservoir engineers [14] and has been used for single and multi-tank analyses [10], due to demonstrable repeatability and consistency criteria that usually lack in computational methods [15]. Decline curve analysis [16] and Monte Carlo simulation [17] are also used for estimation of recoverable oil in the reservoir. Though numerous questions have been asked on the reliability of Monte Carlo, lack of enough data will remain a problem [17].

Reservoir performance predictions are also carried out when history data are available, basically by the use of relative permeability. Nonetheless, errors and uncertainties occur in predictions. It could be due to the generalization of data gathered from only a small portion of the reservoir. It has been shown that additional data can and always reduce uncertainty [18].

Work has also been presented on a field in the Niger Delta basin [16]. In addition to presentations of the material balance workflow for the estimation of the oil initially, in place and decline curve analysis, it compared the estimate of the original oil in place derived by the use of material balance method and decline curve analysis. They reported that the value derived from material balance simulation was higher compared with the decline curve method. Though the results compared quite fine, they recommended the use of Monte Carlo analysis as another validator.

### 3. Materials and method

The geologic, pressure-volume-temperature, production and pressure history data used are associated with previous work in an oil-rim reservoir [3]. The material balance equation outlined earlier was applied for reserves estimation and production forecast. Also, the aquifer size and drive mechanisms were determined when the MBAL workflow was followed [16].

Table 1. Geologic data

Thickness	88.9865ft
Porosity	0.28
Saturation	0.25

Table 2. PVT Data

Formation GOR	998 scf/stb	Water Salinity	120000ppm
Oil Gravity	38 API	Oil Viscosity	0.27cP
Gas Gravity	0.75 sp.g	Oil Formation Volume Factor	1.69 rb/stb

Table 3. Relative permeability data

	Residual saturation	End point (fraction)	Exponent
K <sub>rw</sub>	0.25	0.75	2
K <sub>ro</sub>	0.20	0.8	2
K <sub>rg</sub>	0.20	0.85	2

### 4. Results and discussion

From the possible sources of energy in the reservoir and aquifer systems, the energy plot (Figure 1) is used to show the relative contributions of the main sources of energy. Whereas at the beginning of the production history, gas injection and water injection did not contribute to the drive mechanisms, the parameters contributed towards the end of the history. Particularly, water injection became the dominant drive mechanism in the year 2025, since gas injection was stopped some years earlier. Therefore, when determining the OOIP, initial production points were considered.

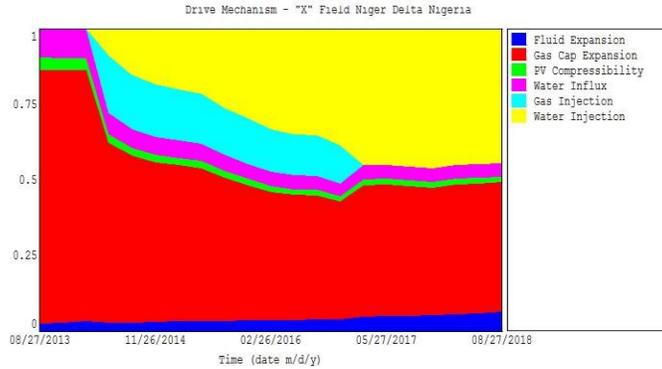


Figure 1. Energy plot showing the drive mechanisms

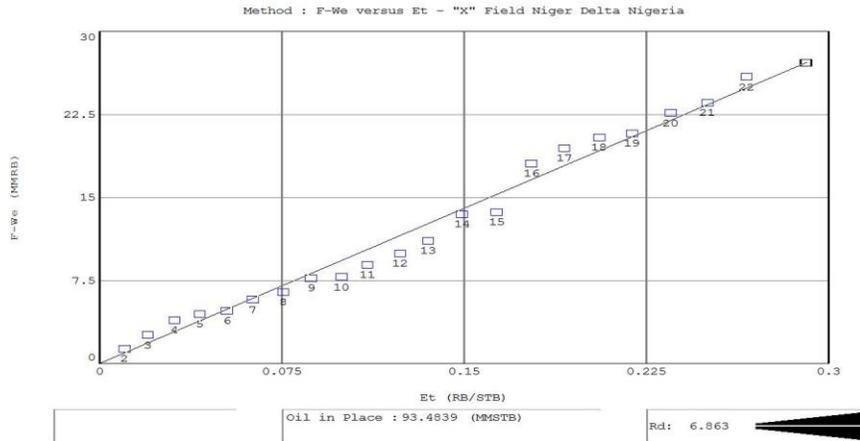


Figure 2. The graphical plot used to determine the Oil in Place (N)

The graphical plot (Figure 2) was derived from the material balance equations. The model was adjusted until the best line fit was obtained. The oil-in-place (N) was determined by the slope of the straight line.

Also, the analytical plot (Figure 3) provided non-linear regression to determine unknown aquifer and reservoir parameters. The outputs include oil production and water influx. The red line (without aquifer influx) underestimates the production compared with the blue line (with aquifer influx) since it serves as a check. At a reservoir pressure of 3560 psi, the oil production with aquifer influx is 21 MMSTB compared to 19.5 MMSTB without aquifer influx.

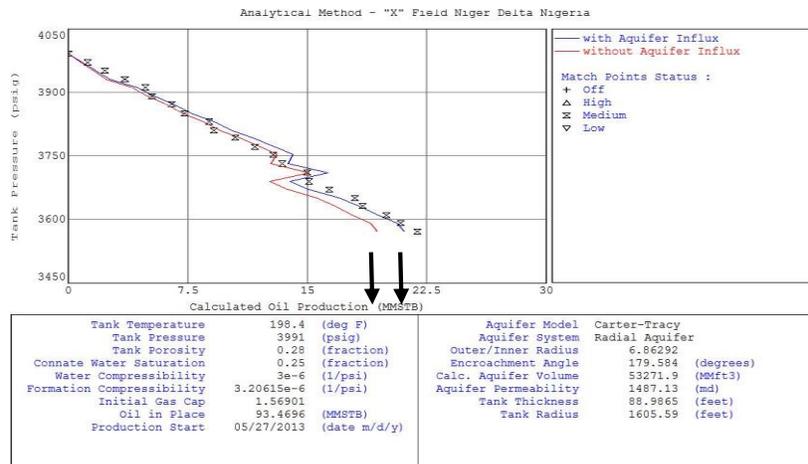


Figure 3. Regression output depicted by the analytical plot

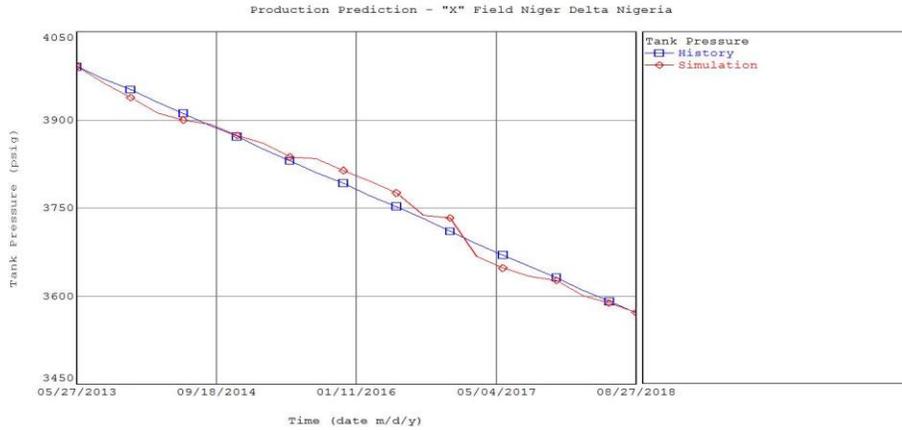


Figure 4. Historical production data compared with production simulation

To perform predictive analyses, a production simulation plot was generated and shown with the historical data (Figure 4). Similarly, Figure 5 and Figure 6 are the production predictions of reservoir pressure and oil production from start to end of production, respectively. The prediction makes use of well performance definitions and production constraints.

Moreso, reservoir pressure prediction (Figure 7) and oil production prediction (Figure 8) from start to the year 2025 were made with the water injection the only option of fluid injection. The reservoir pressure will be about 2960 psi by 2015, while the prediction for oil production is in the range 50- 51 MMSTB.

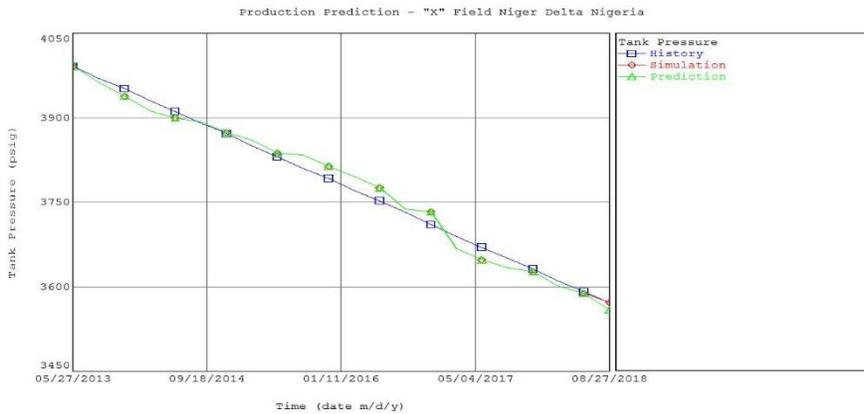


Figure 5. Production prediction of reservoir pressure from start to end of production

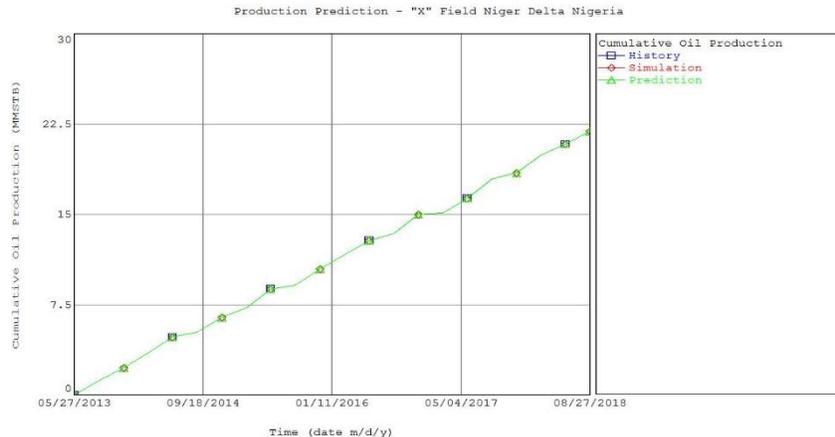


Figure 6. Production prediction of oil production from start to end of production

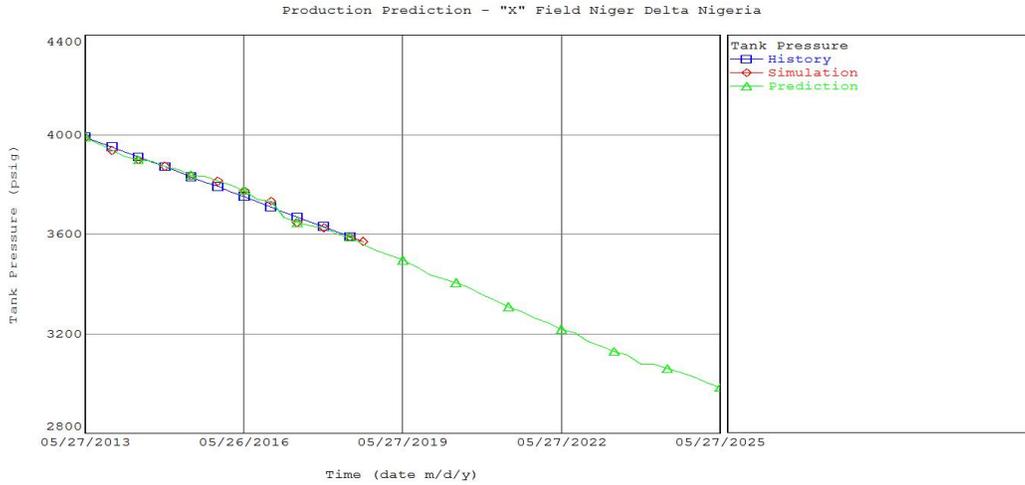


Figure 7. Production prediction of oil reservoir pressure from start to the year 2025

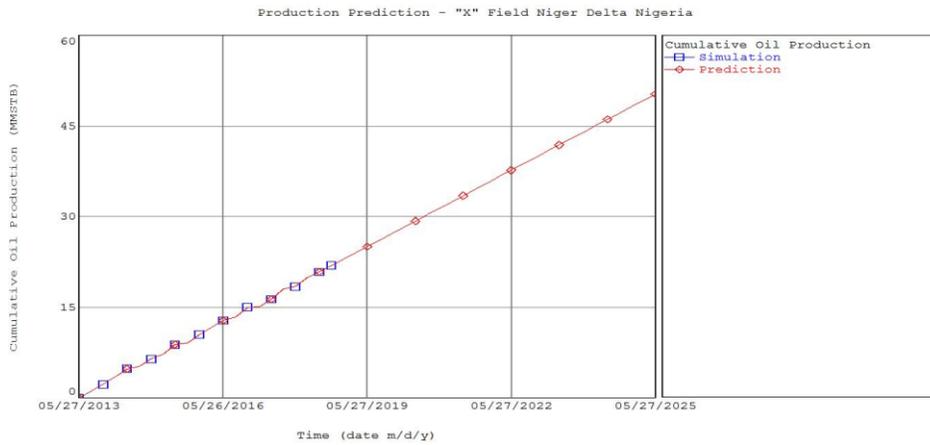


Figure 8. Production prediction of oil production from start to the year 2025

Table 4. Summary of results as output from the analytical plot

S/N	Parameter	MBAL Estimate
1	STOIIP (MMSTB)	93.4696
2	Initial Gas Cap (MMSCF)	1.56901
3	Outer/Inner Radius Ratio	6.86292
4	Reservoir Radius (ft)	1605.59
5	Encroachment Angle (degree)	179.584
6	Porosity	0.28
7	Aquifer Volume (MMft <sup>3</sup> )	53271.9

The result of the Monte Carlo simulation (Figure 9) at 50 percent probability is 82.9607 MMSTB with a standard deviation of 30.7929 MMSTB and mean reward of 80.6793 MMSTB. Also, the STOIIP from MBAL estimate is 93.4696 MMSTB (Table 4).

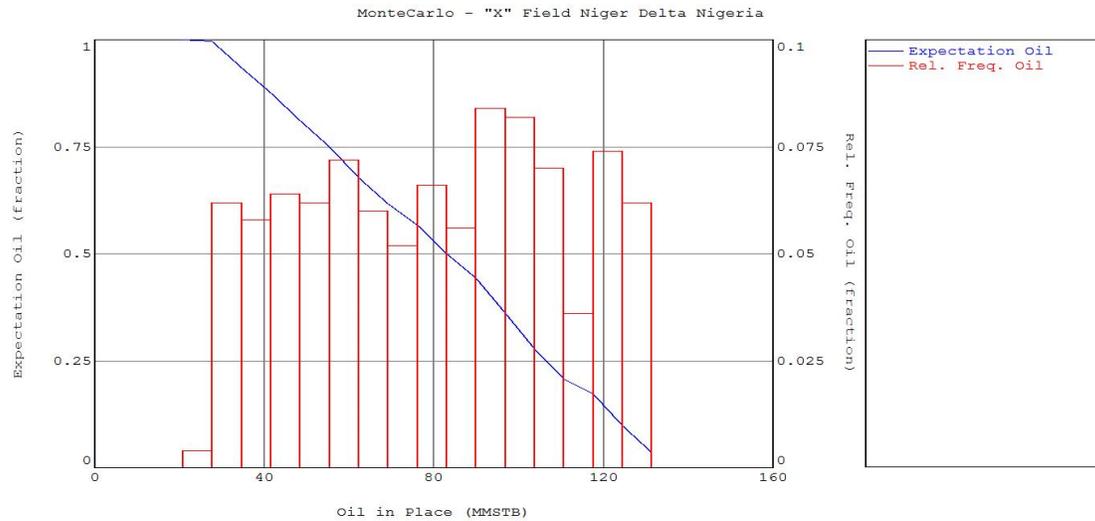


Figure 9. Plot of Monte Carlo simulation

## 5. Conclusion

The Original Oil in Place estimate from material balance simulation of 93.4839 MMSTB is higher than the Monte Carlo simulation, with the P50 estimate of the Oil in Place as 82.9607 MMSTB. Accuracy of the Monte Carlo simulation would be improved with more data. Water Injection and Gas Cap Expansion are the major drive mechanisms, with increasing contribution from Fluid Expansion. The reservoir has strong aquifer support that may have contributed to the performance at the end of the prediction period in addition to the high permeability.

## Nomenclature

$B_g$	gas formation volume factor, bbl/scf
$B_{gi}$	gas formation volume factor at $p_i$ , bbl/scf
$B_{ginj}$	gas formation volume factor of the injected gas, bbl/scf
$B_o$	oil formation volume factor at reservoir pressure $p$ , bbl/STB
$B_{oi}$	oil formation volume factor at initial reservoir pressure $p_i$ , bbl/STB
$B_w$	water formation volume factor, bbl/STB
$B_{wi}$	water formation volume factor at initial pressure, bbl/STB
$C_f$	formation (rock) compressibility, $\text{psi}^{-1}$
$C_w$	water compressibility coefficient, $\text{psi}^{-1}$
$G_{inj}$	cumulative gas injected, scf
$G_p$	cumulative gas produced, scf
$M$	ratio of gas cap gas volume to oil volume, bbl/bbl
$N$	initial oil-in-place, STB
$N_p$	cumulative oil produced, STB
$R_p$	cumulative produced gas-oil ratio, scf/STB
$R_s$	current gas solubility factor, scf/STB
$R_{si}$	gas solubility at initial pressure, scf/STB
$S_{wi}$	initial water saturation
$\Delta p$	change in the volumetric average reservoir pressure, psi
$W_e$	cumulative water influx, bbl
$W_{inj}$	cumulative water injected, STB
$W_p$	cumulative water produced, STB
MBAL software	Material balance software

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