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Estimating the Improvement of Tanawon Production Wells for Acid Treatment, Tanawon Sector, BacMan Geothermal Production Field, Philippines

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ABSTRACT

Production wells TW-1D and TW-2D in the Tanawon sector of the BacMan Geothermal Production Field were initially postulated to may have been damaged by mud after several problems were encountered during drilling. Analysis of the several pressure transient tests conducted in the wells and correlation of the drilling and geoscientific data confirmed the presence of formation damage caused by drilling mud and established the wells as good candidates for acid stimulation.

Flowing pressure, temperature, and spinner logs were also conducted in TW-1D during the medium term discharge tests to examine its wellbore dynamics and discharge characteristics. The availability of these downhole measurements coupled with the results of the pressure transient tests revealed that an effective quantification of the possible improvement of the well before the acid treatment could be undertaken. Modeling of the available welltest data through wellbore simulation further showed at least 50% improvement from the initial production capacity of the well could be realized.

1. BACKGROUND

The Tanawon sector is included in the BacMan Geothermal Production Field (BGPF), which is located in the Bicol volcanic region approximately 300 km southeast of Manila, Philippines (Figure 1). BGPF which is developed and operated by Philippine National Oil Company-Energy Development Corporation (PNOC-EDC) for electrical energy generation is divided into BacMan 1 (110 MWe) within Palayan Bayan and BacMan 2 (40MWe) within the Cawayan and Botong sectors. Part of BGPF's expansion program is to develop additional power in the Tanawon sector; south of the BacMan 2 Cawayan and Botong areas.

PNOC-EDC embarked on the initial development of the Tanawon sector in 2000 where two production wells (TW-1D and TW-2D) were successfully drilled through a joint venture with Kyushu Electric Power Company (Kyuden) of Japan. Because of severe drilling problems, i.e. persistent fills, tight spots, stuck-up drill pipes, TW-1D was sidetracked and was prematurely completed at 2050.5 meters Measured Depth (mMD). The programmed depth of the well is 2700 mMD. The second production well TW-2D was drilled as a big hole to ensure successful intersection of its structural targets because of drilling problems experienced in TW-1D. However, the same drilling problems were encountered which prompted another sidetracking and premature termination of drilling at 2611.8 mMD that is around 88 m shallower than targeted depth. Well TW-2D completion has a 9 5/8" Ø blank liner on top of its 7" Ø slotted liner.

Figure 1: BacMan Geothermal Production Field Map.

TW-1D and TW-2D were initially evaluated to have suffered significant formation damage during drilling. The two wells lost about 6,100 bbls and 4,000 bbls of high viscous drilling mud in the openhole respectively. A considerable amount of cement was likewise injected in the wells during cement plugging. Analysis of the pressure transient data of the wells also revealed positive skin values that confirmed the presence of formation damage.

Resource assessment conducted by Delfin, et. al., (2001) showed about 4.28 km^2 of resource area for Tanawon which includes blocks I1, I2, H1, and K as shown in Figure 2. Using Monte Carlo analysis, around 36.6 MWe or 915 MWe-years power potential is most likely seen, with 40% maximum probability of attaining more than 40 MWe.

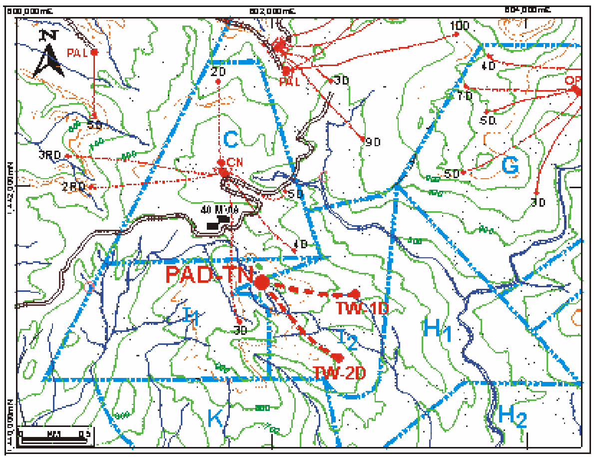

Figure 2: Cawayan and Tanawon Resource Blocks.

The development strategy for Tanawon would then call for the acid stimulation of TW-1D and TW-2D and drilling of the additional production wells in the same pad to complete the 40 MWe development. This paper focuses on the estimation of the possible improvement of the two production wells before the acid treatment with emphasis on refining the estimation method discussed by Aleman and Clothworthy (1996).

2. WELLTEST DATA

The main permeable zone in well TW-1D was initially identified at around 1920-2025 m MD based on results of Pressure, Temperature and Spinner (PATS) logs conducted during completion tests. The profiles also showed a gas column just below the 9 5/8" production casing shoe as described by the erratic spinner responses along this depth. The injectivity index of TW-1D was calculated at around 16 li/s-MPa, much less than indices of nearby Cawayan wells, which ranged from 56 to 125 li/s-MPa.

The waterloss survey during TW-2D completion test revealed that most of the injected fluids exited at 2500-2550 mMD. A low injectivity index of 12.3 li/s-MPa was also calculated during completion test.

3. DISCHARGE DATA

3.1 TW-1D

TW-1D was successfully discharged on 20 March 2001 by air compression at a compressed wellhead pressure (WHP) of740 Psig (5.1 MPag). Discharge test took about four months with the well initially flowed at fullbore discharge (FBD) for one month followed by the discharge at different throttled conditions. The WHP along with the weir flow, mass flow, and enthalpy steadily increased, indicating further well clearing.

The stable outputs are summarized in Table 1 and are plotted in Figure 3. The bore output curves showed linear trends in total mass flow, discharge enthalpy, and steam flow with decreasing values at higher WHPs. At large mass flows, the low permeability formation brings about a large pressure drawdown which causes fluids to flash in the formation, thus the "excess enthalpy". Pressure drawdown is reduced when the well is throttled; giving a much lower discharge enthalpy.

Date	Status	WHP (MPag)	Mass Flow (kg/s)	Enthalpy (kJ/kg)	Steam Flow (kg/s)	Water Flow (kg/s)	MWe*
22-Apr-01	FBD	0.66	52.6	1469.0	19.7	32.9	8.9
17-May-01	THR1	0.79	48.6	1308.0	14.4	34.2	6.5
5-Jun-01	THR2	1.17	48.0	1290.0	13.8	34.2	6.3
20-Jun-01	THR3	1.67	40.7	1260.0	11.1	29.6	5.0
25-Jun-01	THR4	1.41	45.5	1282.0	12.9	32.6	5.9
17-Jul-01	THR1	0.81	50.4	1297.0	14.6	35.8	6.7

* at 0.70 MPaa SP and 2.2 kg/s-MWe SR

Table 1: Well TW-1D Bore Output Summary.

3.2 TW-2D

Medium-term discharge (MTD) of TW-2D was carried out for two months from 21 April to 26 June 2001. Initial discharge attempt was made through air compression. However, the well did not sustain discharge and was then stimulated using the two-phase fluids from nearby TW-1D.

After one month of full bore clearing discharge, the wellhead pressure of TW-2D stabilized at 0.48 MPag which is still below the commercial wellhead separation pressure of 0.70 MPag (Table 2). The total mass flow recorded (37kg/s) was also lower than that of TW-1D (53.0 kg/s) while its discharge enthalpy was comparable.

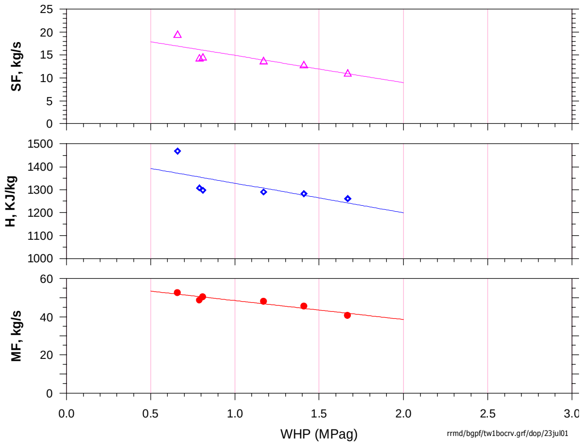

Figure 3: Well TW-1D Bore Output Curve.

Date	Status	WHP (MPag)	Mass Flow (kg/s)	Enthalpy (kJ/kg)	Steam Flow (kg/s)	Water Flow (kg/s)	MWe*
22-May-01	FBD	0.48	36.9	1317.0	-	-	-
6-Jun-01	THR1	0.56	35.6	1277.0	-	-	-
19-Jun-01	THR2	0.79	30.5	1210.0	7.6	22.9	3.4
26-Jun-01	THR3	0.63	37.0	1242.0	-	-	-

* at 0.70 MPaa SP and 2.2 kg/s-MWe SR

Table 2: Well TW-2D Bore Output Summary.

The bore output curve in Figure 4 shows declining trends in total mass flow, enthalpy, and steam flow with increasing WHP. It also shows the well's maximum discharge pressure of 0.80 MPag and that the well may collapse upon reaching a wellhead pressure of 1.0 MPag.

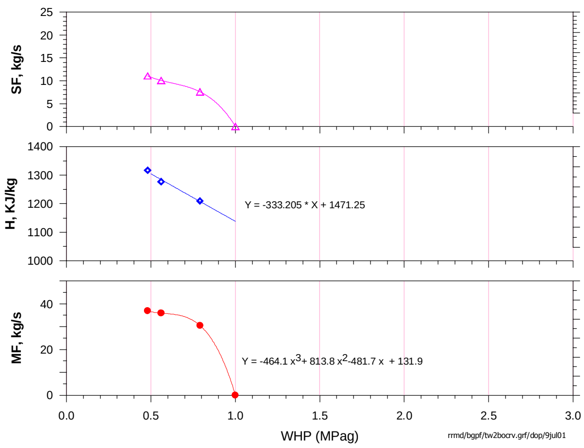

Figure 4: Well TW-2D Bore Output Curve.

As in TW-1D, two-phase fluids entering TW-2D likewise results from the significant pressure drop in the formation. At smaller flows, pressure drawdown is reduced; thus the lower enthalpy.

Analysis of the discharge chemistry of TW-1D and TW-2D showed that both wells have very low potential to develop scale deposits of calcite and anhydrite at reservoir conditions. Saturation indices of these minerals for TW-1D are at equilibrium values while TW-2D discharge fluid is slightly supersaturated.

TW-1D and TW-2D discharge tests yielded marginal output compared to the nearby Cawayan production wells that have an average output of around 12 MWe. Considering proximity and well targets, Tanawon wells have a bigger chance of improving; once formation damage is removed through acid treatment.

4. FLOWING PATS SURVEYS

Flowing surveys using the electronic Pressure and Temperature-Spinner (PATS) tool were also conducted in TW-1D to illustrate and quantify the individual feedzone contribution. Downhole logs were performed with the sidevalve throttled to 20 and 24 handwheel turns (HWT) with the maximum logged depth at 2025 mMD.

At 20 HWT throttled condition (wellhead pressure of 1.27 MPag), TW-1D was flowing with 45 kg/s massflow. Maximum recorded temperature was 270°C at 2000 mMD (Figure 5). This was slightly lower than the 260°C measured at the bottomhole (2025 mMD); where stationary readings showed no spinner response. The spinner profiles pointed to the major permeable zone at around 1925-1928 mMD; confirming the 1920-2025 mMD major feedzone identified during the completion test. Minor contributions were also identified as coming from around 1615-1620 mMD, 1650-1700 mMD, and 2005-2015 mMD. These zones were not easily visible in the completion test profiles because of the gas column detected in the wellbore which could have masked the feedzones. Temperature and pressure profiles show fluids at saturated condition.

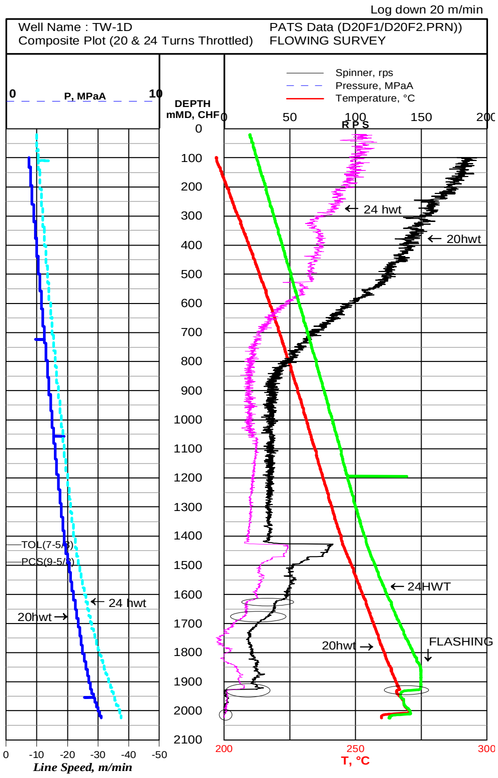

Figure 5: TW-1D Flowing PATS Profiles.

Correlation of the spinner responses at different logging speeds shows that the major feedzone contributes approximately 20 kg/s or 44% of the total mass flow and around 14 kg/s (31%) of the total mass flow is coming from the permeable zone at 1650-1700 mMD. The uppermost feedzone at 1615-1620 mMD contributes approximately 9 kg/s (20%) while the minor feedzone near the bottom (2005-2015 mMD) produces around 2 kg/s (5%) of mass flow.

At 24 HWTs throttled condition, the well produced around 35 kg/s total massflow at wellhead pressure of 1.76 MPag. The same permeable zones were obtained from the spinner profiles with the major zone at 1925-1928 m MD and a fluid (liquid) temperature entry of about 275°C. The bottomhole temperature (2025mMD) was 263°C; slightly higher compared to the earlier survey. No spinner response was also recorded at the bottom. The fluid inside the wellbore flashes at around 1850 m MD based on temperature and pressure profiles obtained.

Comparison of the flowing pressure profiles at 20 and 24 HWT throttled conditions also revealed a productivity index of around 15 kg/s-MPa similar to the injectivity index value earlier recorded during completion tests. This relationship is not uncommon to most of the production wells in BGPF.

5. WELLBORE SIMULATION

A steady-state, deepest feed/up wellbore simulation was performed on TW-1D to match and validate the results of the PATS surveys using the commercial wellbore simulator WELLSIM (GENZL, 1997), assuming that the conditions did not vary significantly with respect to time. This was also done to model the wellbore dynamics and discharge characteristics of the well. The WELLSIM two-phase flow correlation was found most appropriate based on results of the modeling process. Since WELLSIM doesn't handle multi-CO_2 feed, wellbore simulation was carried out in stages with calculations from the deepest feed up to the wellhead.

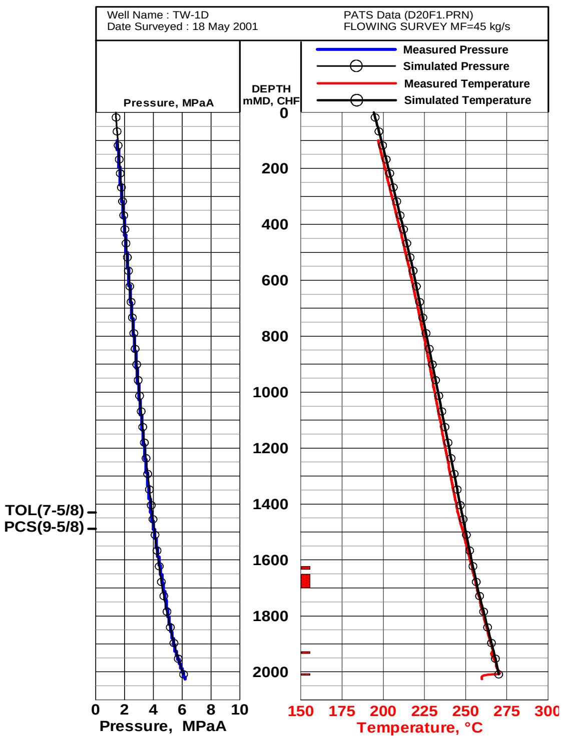

Figure 6: TW-1D Simulation Results at 20 HWT throttled condition.

The feedzone (massflow) contributions obtained from the spinner profile correlation at the 20 and 24 HWT throttled conditions were initially employed and were later varied to match the corresponding flowing pressure and temperature profiles. The model results revealed very little difference between the calculated massflow contributions and the feedzone contributions from spinner profile analysis.

Initial simulation results at the 20 HWT throttled condition suggest that a small amount of CO_2 is required to match the bottomhole condition of the fluid. Model results showed that the well is discharging fluid at two-phase condition at the bottom feedzone at 270°C with enthalpy of about 1186 kJ/kg and containing about 0.28%w of CO_2 (Figure 6). The fluid at the major feedzone (1925-1928 mMD) enters at two-phase condition with an enthalpy of about 1202 kJ/kg and a CO_2 content of approximately 0.39%w.

Two-phase fluid also enters at the two uppermost permeable zones with enthalpies of around 1450 kJ/kg and 1.32%w CO_2 at 1650-1700 mMD and 1470 kJ/kg and 1.1%w CO_2 at 1615-1620 mMD. The simulated discharge enthalpy at the wellhead (1.3MPag) was calculated at about 1310 kJ/kg with 1.3%w CO_2.

The two-phase fluid condition observed inside the wellbore at 20 HWT is possibly caused by the significant pressure drop near the sandface of the well. This pressure drop could be attributed to the considerable mud lost in the formation that has restricted the flow of reservoir fluid. Hence it is likely possible that much higher reservoir fluid temperature (> 270°C) is expected as seen from the flowing PATS data obtained at 24 HWT condition where a 275°C temperature fluid entry is observed.

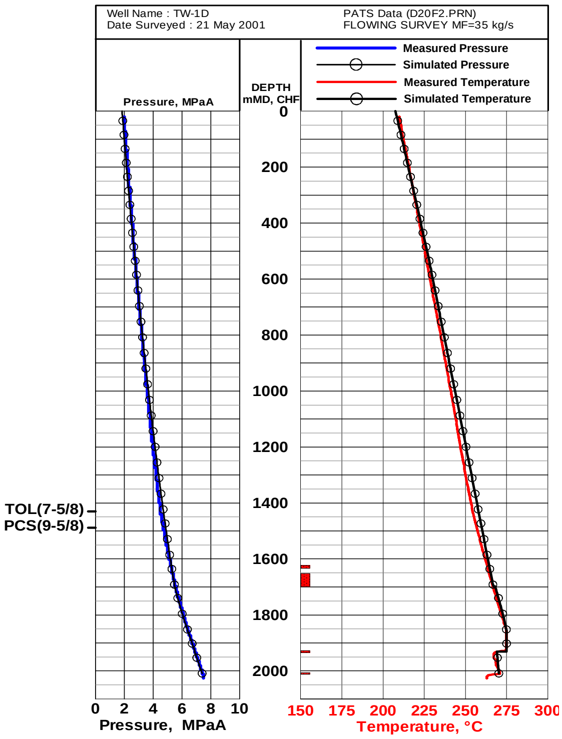

Figure 7: TW-1D Simulation Results at 24 HWT throttled condition.

Modeling results of the 24 HWT throttled condition confirmed the liquid feed contribution at the major permeable zone with enthalpy of around 1212 kJ/kg and a dissolved CO_2 concentration of about 0.14%w (Figure 7). The enthalpy of the uppermost permeable zones was found to be similar to the simulated two-phase enthalpy in the 20 HWT throttled condition with 1.2%w CO_2 at the top feedzone (1615-1620 mMD) and about 1.4%w CO_2 at 1650-1700 mMD. The simulated discharge enthalpy at the wellhead (1.76 MPag) was 1253 kJ/kg with 1.5%w CO_2.

6. SKIN CALCULATIONS

Drilling geothermal wells with mud usually creates formation damage that is generally termed skin (s). The skin effect has been seen as an area of lower permeability adjacent to the wellbore that gives an additional hydraulic resistance to the flow of reservoir fluids. The viscous drilling mud often exhibits non-Newtonian behavior inside the wellbore and usually produces a seal that retards fluid flow.

When the downhole pressure reaches critical level during the injectivity test, the injected freshwater forces a path through the mud cake and once this flowpath is open, the mud does not offer additional resistance to fluid flow as the injection pumprate increases. This means that the calculated injectivity index from the plot of injection flowrate versus downhole pressures (injectivity test plot) is determined solely by the permeability of the formation with negligible effect from the mud (Aleman and Clotworthy, 1996).

A fixed minimum pressure is then required to keep the flowpath open through the mud cake. This is determined by extrapolating the injectivity plot to zero flow and the calculated minimum pressure is then referred here as skin pressure (Aleman and Clotworthy, 1996). Acid treatment then removes the mud cake and the skin pressure and restores the original permeability of the nearby formation. Figures 8 and 9 below show the skin pressures calculated from TW-1D and TW-2D injectivity test data.

After plotting the measured zero flow (shut-in) pressure, an offset in downhole pressure can then be seen between the calculated skin pressure at zero flow and the measured zero flow pressure. This pressure differential is now termed ΔPskin that is also required to maintain fluid flow through the mud cake. The calculated ΔPskin for TW-1D is around +0.8 MPa while TW-2D produced a higher value of about +4.0 MPa. The positive ΔPskin values obtained suggests the presence of formation damage in the wells. The method of analysis presented above can also be extended to the calculated productivity index of a given well using the same analogy in establishing the ΔPskin.

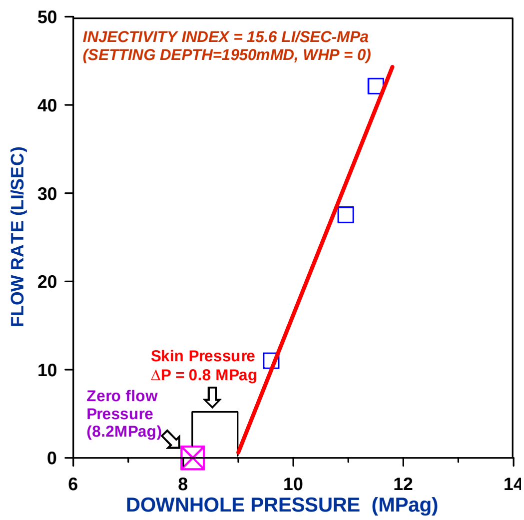

Figure 8: TW-1D Injectivity Test Plot with Calculated Skin Pressure.

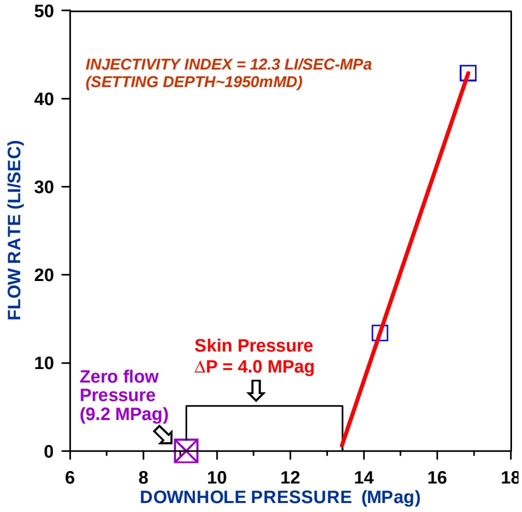

Figure 9: TW-2D Injectivity Test Plot with Calculated Skin Pressure.

The presence of skin is normally determined from the analysis of pressure transient data (pressure build-up/falloff data for example) using standard welltest interpretation techniques (Theis curve solution). In some cases, a computer-aided approach is applied to pressure transient analysis, automating such procedures as type curve matching and pressure derivative calculation. Furthermore, the data can then be easily tested under various combinations of well/reservoir models and boundary conditions so that the most appropriate conditions could be determined.

The available pressure transient data of production wells TW-1D and TW-2D were then analyzed to establish the presence of skin effect and to determine other reservoir parameters such as transmissivity (kh). Here, a welltest interpretation software Saphir (Kappa Engineering, 1995) was employed to derive these reservoir parameters. Reservoir temperatures of around 270-275°C and pressure of around 12.0 MPa and an average porosity of 10% were initially employed in the model. A homogenous reservoir model with wellbore storage and skin and an infinite boundary condition was initially applied in the analysis.

The pressure falloff and pressure buildup data for TW-1D together with their corresponding pressure derivative and the model results are plotted in Figures 10 and 11. Results of the pressure transient analysis are listed in Table 3.

Positive skin values (+20 to +39) were calculated from pressure transient analysis of TW-1D which indicates a damaged wellbore. A permeability-thickness product (kh) of around 4.5 to 5.4 darcy-meters was also obtained from analysis of pressure transient data. The simulated kh value was also lower than permeability values (8 to 20 darcy-meters) of neighboring Cawayan wells. TW-1D was likely damaged by significant amount of cement, mud, and loss circulation materials used to remedy extensive drilling problems. In the original hole, ~7800 barrels of drilling mud were used, while ~6100 barrels were lost in formation in the final hole.

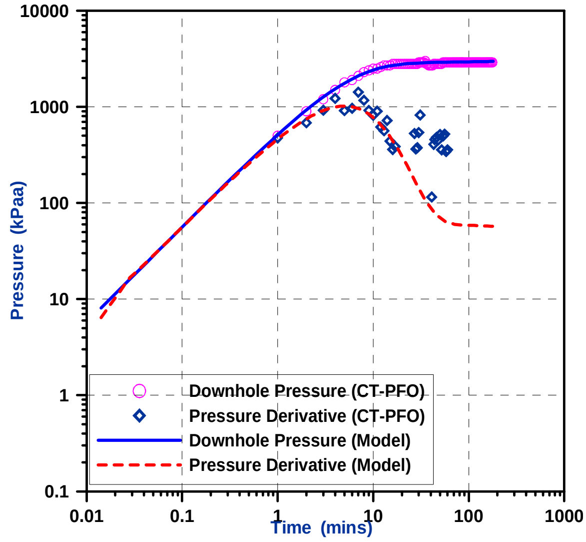

Figure 10: TW-1D Pressure Falloff Analysis.

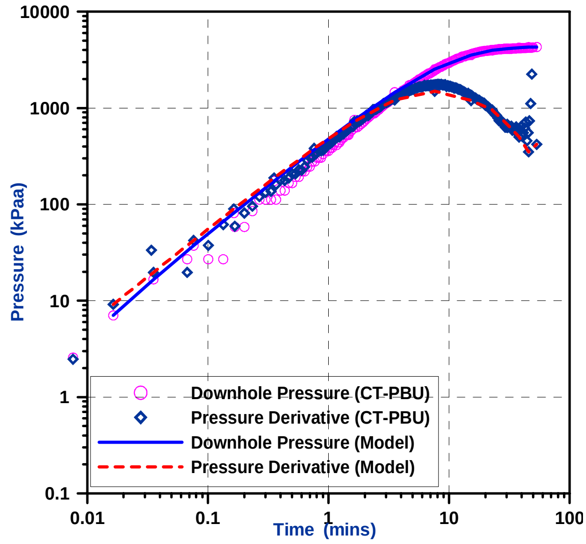

Figure 11: TW-1D Pressure Buildup Analysis.

Well Name	Skin (s)	ΔPskin (MPa)	Transmissivity kh (d-m)
TW-1D			
a. CT PFO (Nov 2000)	+20	2.1	~ 5.4
b. PBU (May 2001)	+39	3.5	~ 4.5
c. Injectivity/Zero Flow	-	0.8	-
TW-2D			
a. Injectivity/Zero Flow	-	4.0	

Table 3: Summary of Pressure Transient Results of TW-1D and TW-2D.

There was no pressure transient analysis made for TW-2D due to the unreliable PFO data obtained. Nevertheless, the well is likewise believed to have suffered formation (mud) damage due to the significant volume of drilling mud (~4,000 barrels) lost in the formation and the calculated ΔPskin value based on the injectivity test data calculation discussed earlier.

If not for the mud and cement damage, TW-1D and TW-2D are considered very permeable based on the massive circulation losses and blind drilling recorded. It is on this premise that these wells were considered for acid treatment; that is to remove the low-permeability area adjacent to the wellbore.

6. CAPACITY GAIN ESTIMATION

Aleman, et al., (1996) illustrated a conservative method of estimating the output gain from the ΔPskin values of candidate wells prior to acid treatment. Assuming the skin damage (ΔPskin) is completely removed after the acid treatment, the improvement is estimated by

Capacity Gain = (Injectivity Index) x (ΔPskin)

where the injectivity index is assumed to remain constant. Experience from previous acid stimulation jobs conducted by PNOC-EDC shows that the injectivity index, in most cases, increases after stimulation thereby producing a much bigger improvement in production capacity. A much bigger improvement is likewise expected once a negative skin value is obtained; that is, a stimulated well. The increase in total massflow is then converted to power output (MWe) assuming a steam dryness of 30% and a steam rate of about 2.2 kg/s-MWe. Table 4 below summarizes the capacity gain estimates for TW-1D and TW-2D using the method discussed above. A range of improvement from 1.7 to 7.4 MWe is calculated for TW-1D and around 6.7 MWe increase for TW-2D.

Well Name	Injectivity (kg/s-MPa)	ΔPskin (MPa)	Capacity Gain (MWe)
TW-1D a. Injectivity/Zero Flow b. PFO (Nov 2000) c. PBU (May 2001)	15.6	0.8 2.1 3.5	~ 1.7 ~ 4.5 ~ 7.4
TW-2D	12.3	4.0	~ 6.7

Table 4: Estimate of Capacity Gain for TW-1D and TW-2D.

The availability of the flowing pressure, temperature, and spinner (PATS) logs for TW-1D coupled with the results of the pressure transient tests suggested that an effective quantification of the possible improvement of the wells before the acid treatment can be undertaken. To achieve this, wellbore simulation at fullbore discharge (FBD) condition was initially conducted using the results of the modeling process of the PATS surveys at 20 and 24 HWT throttled condition. The modeling process was also conducted using WELLSIM and simulation was also carried out with the calculations from the deepest feedzone up to the wellhead. A linear pressure drawdown relationship was assumed in the model and a similar CO_2 concentration of 0.28%w at 20 HWT was also employed at the bottom feedzone. The results of the model at FBD condition is shown in Figure 11 and summarized in Table 5.

The model results at FBD condition was then used in simulating the possible improvement before the acid treatment by applying the estimated gain in productivity assuming that the calculated ΔPskin (s) will be reduced to zero. A total massflow gain of around 30 kg/s is calculated based on the productivity index (15.0 kg/s-MPa) and ΔPskin (2.1 MPa) of TW-1D. This increase in total massflow was proportionately distributed to the calculated massflow contribution of each feedzone assuming all the available feedzones are initially targeted for acid treatment. The reduction of ΔPskin to zero would also translate an equivalent 2.1 MPa increase in downhole pressures for the initial simulation run.

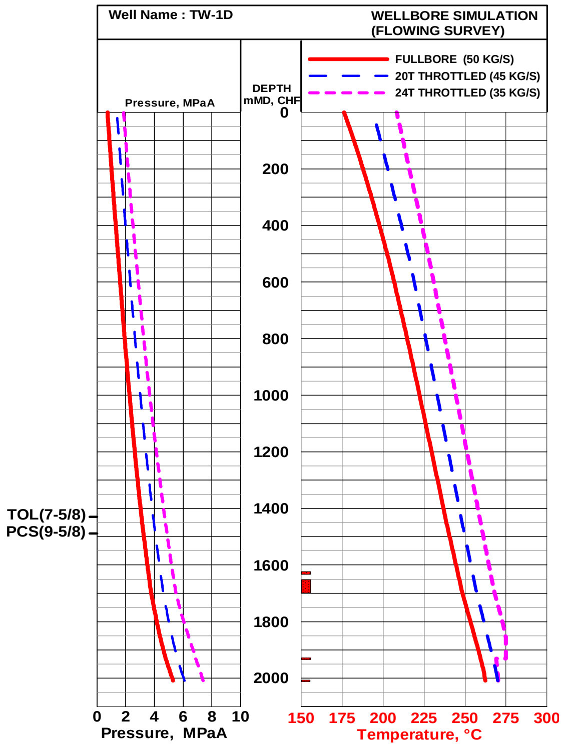

Figure 11: TW-1D Wellbore Simulation at FBD.

Output Parameters	Pre-Acid (FBD)	Post-acid (FBD)
Wellhead Pressure (Mpag)	0.73	1.28
Massflow (kg/s)	50.0	81.0
Discharge Enthalpy (kJ/kg)	1312	1324
Power	8.0	12.2

Table 5: Simulation Results of TW-1D Pre and Post Acid Treatment.

Simulation results show single-phase fluid condition at the bottom. Table 5 presents the results of the wellbore simulation before and after acid stimulation of TW-1D at FBD condition. The simulated discharge parameters after acid treatment produced an increase in power output of around 4.2 MWe which translates to about 50% improvement in power capacity. Additional simulation runs were also made to investigate the improvement of TW-1D by limiting the targeted payzone for acid treatment (e.g. major zone only) and simulation results showed improvement to a lesser degree.

6. SUMMARY

Pressure transient analysis in TW-1D and TW-2D confirmed that the wells suffered significant formation damage during drilling as caused by the considerable amount of mud lost in the formation. This is also reflected in the low values of injectivity index, permeability-thickness product as well as the marginal discharge parameters obtained. Eliminating the damage through acid treatment became an option which could restore their original permeability and improve the production capacities of the wells.

Knowledge in the estimated gain in output before doing an acid job can be a vital tool in assessing and formulating strategic development plans for the wells and the Tanawon sector as a whole. In view of the considerable cost involved in an acid treatment, the availability of a quantitative estimate of capacity gain can be a factor in proving the cost effectiveness of the operation.

The use of flowing pressure and temperature profiles gives a more accurate capacity gain estimation as they provide a clearer model of the wellbore dynamics, discharge characteristics, and feedzone contributions. These, coupled with the pressure transient test results give an effective measure of potential increase in well output prior to the acid treatment. Wellbore simulation further showed that at least 50% increase in output of TW-1D can be realized.

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