Proceedings World Geothermal Congress 2005
Antalya, Turkey, 24-29 April 2005

Methods of Removing Solids from the Discharge of Steam Dominated Wells in Leyte Geothermal Production Field, Philippines

R.R. Villa, Jr., H.L. Isip, J.R.S. Peñaranda, N.D. Salonga, D.B. Rubin, U.R.P. Bontia and V.S. Saw

PNOC Energy Development Corporation, PNPC Complex, Merritt Road, Fort Bonifacio, Taguig City, Philippines

lgpf_geoservices@energy.com.ph, pherj@yahoo.com

Keywords: Solids in dry steam, steam washing, wellhead solids removal, erosion, corrosion

ABSTRACT

The transition of the Upper Mahiao and Tongonan-1 sectors of the Leyte Geothermal Production Field from being water dominated to a steam dominated system has brought along changes in the discharge characteristics of wells in these sectors. These sectors became steam dominated due to the expansion of the reservoir steam zone with a corresponding lowering of the well water levels. The discharge fluids from the wells in these sectors contained solids carried-over from the well bore. The discharge ejecta, determined by petroanalysis, were composed of cement, amorphous silica and corrosion products. The presence of solids in the high velocity steam discharge has thinned out the branchlines, main two-phase lines, compensator bellows and liners, and separator vessels due to the erosive nature of the solids as they are carried by the steam discharge to the separator vessels. The measurement of the thinning rate of surface pipelines using ultrasonic thickness (UT) gauging and analysis of total suspended solids in steam (TSS) are used to monitor the effects of the solids in the steam discharge.

Three methods were applied to remove these solids from the steam discharge. Two methods involved “steam washing”, conducted by injecting either hot brine or cold water into the pipeline to wash the steam and flush the solids to the injection lines. The last method was by installing a wellhead solids removal system (WSRS) consisting of a piping configuration designed to dislodge the solids by taking advantage of the steam discharge velocity and centrifugal force. These methods were able to remove significantly the solids from the steam discharge (from TSS monitoring) by around 80 to 100%. The thinning rates in the pipelines were also significantly reduced by 60 to 99%, depending on the section of the line.

1. INTRODUCTION

The Tongonan Geothermal Field reservoir used to be a water-dominated system (Fig. 1) hence, in the Fluid Collection and Recycling System (FCRS), separators were designed to handle two-phase fluids dominated mainly by water. Solid particles carried over from the wellbore to the two-phase lines were thoroughly wetted and were scrubbed by the water phase, thus, the solids were easily flushed to the brine line down to the injection wells. The separated steam from the vortex separation process is absolutely free of solid debris. The velocity of the solid was so low to cause erosion. This system has been operating efficiently since the commissioning of the field on July 1983.

This observation was supported by the fact that from 1983 to 1996, very minimal erosion was observed from both the two-phase and steam lines. Similarly, the inspection of the turbine blades during this period showed that the deposits observed were mainly silica and halites suggesting that the impurities were minerals dissolved in liquid carried over to the steam phase.

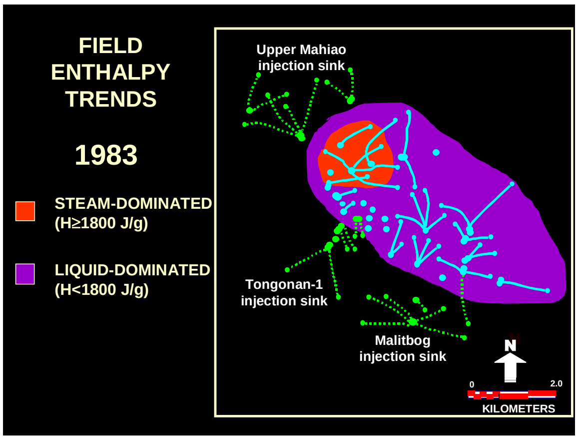

Figure 1: 1983 baseline condition of Tongonan reservoir

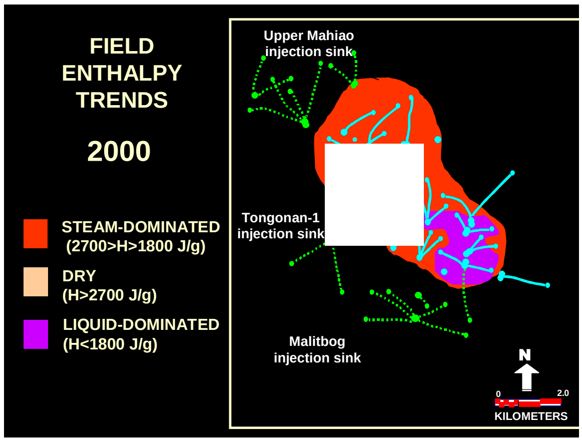

Figure 2: Reservoir condition of Tongonan on 2000

On 2000, the reservoir began to experience a massive pressure and water level drawdown. This was the result of the massive fluid extraction of the reservoir that started in late 1996 when the field was expanded and new power plants were commissioned for the Leyte-Cebu/Luzon interconnection projects. Within the span of four years from 1996 to 2000, the reservoir experienced an unprecedented change from being water-dominated into a steam-dominated reservoir (Fig. 2). Erosion-corrosion of both the two-phase and steam lines became widespread. Pinhole leaks were widely manifested. Some of the well branchlines and separator steamline elbows and drain pots were replaced due to the massive erosion observed. Whereas the deposits before were silica, what were observed in the recent inspections of both the FCRS lines and vessels are corrosion products.

The sand-sized corrosion products are mostly made up of flakes of passive films of corrosion products supposedly coating the pipe and protecting it from further corrosion (Fig. 3). Generally, the wellheads have design pressures of up to 6.1 MPa with a corrosion allowance of 1.6 mm for a 25-year plant life. The two-phase branchlines (25 to 35 cm diameter) have design pressures of 2.1 MPa, thicknesses of 7.1 to 12.7 mm, and corrosion allowance of 2.1 to 3.8 mm for 25 years (0.08 to 0.15 mm/year). From 1983 to 2001, no significant abrupt thinning observed at the 2-phase branchlines and separator vessels.

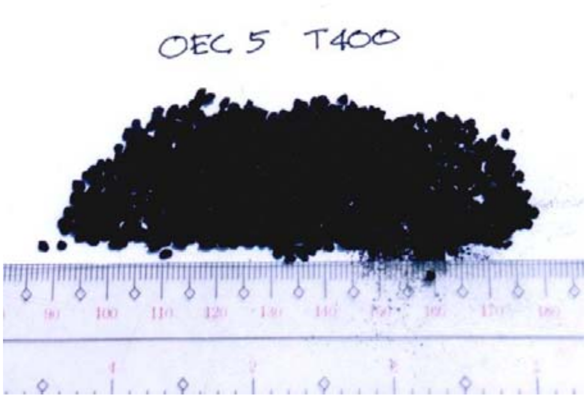

Figure 3: Solids collected from the steam strainers

Starting May 2001, solids were noted to go along with the steam discharge causing severe erosion along the branchline resulting to the rapid thinning of the compensator liners and separator vessels. In wells where water is present, erosion was not as severe compared with those producing steam only but having solids discharge as demonstrated in several wells in Tongonan-1 and Upper Mahiao. Among the major effects observed during the course of the utilization of these dry wells with solids discharge are rapid thinning of the branchlines, bursting of the compensator liners and thinning-out and development of pinhole leakages in the upper shell of the separator vessels. Costly repairs were conducted so as to allow continuance of the operation of the power plants. This is aside from the potential and actual revenue losses that may be incurred due to steam shortfall to the power plants as a consequence of the outage of the separator vessels. Temporary and permanent mitigating measures were applied to deal with this problem of solids in steam. This paper summarizes the concepts and the methods undertaken in determining the source of the debris in steam. The relative advantages and disadvantages of each method are also discussed and evaluated in this paper.

2. TONGONAN EROSION-CORROSION MODEL

The physical and chemical characteristics of the debris collected all suggests that the debris are products of the corrosion/erosion process. Normally, the carbon steel pipe used in the steam and two-phase lines forms a high temperature corrosion film (magnetite and hematite) as a product of the reaction of high temperature steam and the steel pipe wall. These corrosion products will coat the bare pipe wall thereby preventing further corrosion. This process is called passivation. This film is tight and adherent to the pipewall and cannot be easily removed. There are two ways that these passive film will peel off, (1) when the pipe undergoes heavy condensation and temperature will drop causing flashing (i.e. during shutdown in the absence of backheating, opening and start-up) forcing the passive film to form a secondary reaction and (2) erosion caused by the high velocity solids flowing along the line (i.e. sandblasting effect).

2.1 Corrosion Model

Geothermal fluids with low H_2S levels will stabilize magnetite formation inside the pipe surface, while moderate to high levels of H_2S in the fluids favor pyrite overlying a thin layer of magnetite. The thin magnetite layer makes a significant contribution to the corrosion protection and, as a result, most geothermal fluids have a similar on-line corrosion rate. In addition, the existence of scales in the form of monomeric silica can independently block the surface from the corrosive solution and give low corrosion rates. In simplistic terms, the formed scales and corrosion products blocks the metal surface from the corrosive solution.

Theoretical redox potential-pH (Pourbaix) type diagrams are used to predict the stability of the formed corrosion products as a function of temperature. In the case of Tongonan-1, separate corrosion models are constructed for each of the two-phase lines and separators, steam lines, and brine lines to account for the different types of fluids and temperatures. Moreover, to account for the changes in fluid types with time, two corrosion models are constructed for the two-phase lines, one for the 1983 to 1999 period and one for 1999 to present (Villa and Salonga, 2001).

We use well 102 to represent the corrosion models in the two-phase lines. The generated Pourbaix diagram (Fig. 4) for 1990 conditions shows that the fluids will be stable with magnetite and pyrite. Moreover, in cases of lower wellhead pressure operations, silica scales (possibly monomeric) may form along the line. The scales and magnetite film will protect the pipe material from the possible corrosion attack of the flowing fluids as long as the same conditions are maintained throughout the lifetime of the FCRS.

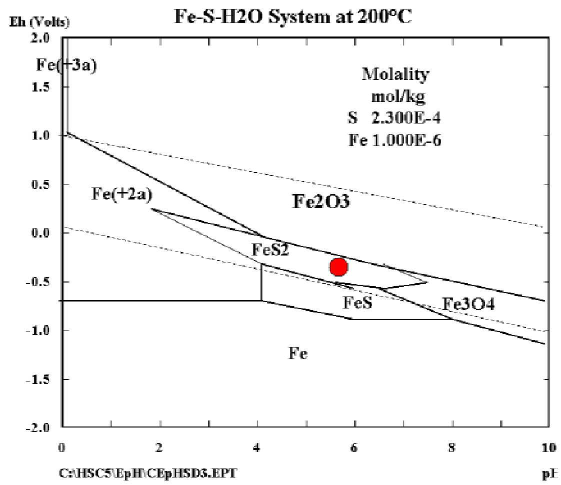

Figure 4: Well 102 Eh-pH diagram at 200°C in 1990

During 2000 (Fig. 5), conditions showed that pyrite would be more favored over magnetite. However, this may not mean a shift to critical condition because at high temperature, thin magnetite layers can form beneath the pyrite layer.

The corrosion model in well 102 branchline can also be the same model in the separator vessels. From 1983 to 1997, when there was still a liquid fraction in the discharge, silica scales, magnetite and pyrite formed below the water level inside the separator. These films protected the material from the corrosive action of the flowing fluids. However, above the water level, no scales were formed. Instead, the materials were exposed to the H_2S in the steam-phase, and therefore pyrite with associated underlying thin magnetite layer was formed. At the operating conditions of 0.7 MPa, the corrosion products of pyrite + magnetite may have protected the materials from further corrosion. However, pyrite usually becomes unstable and brittle when exposed to atmosphere, particularly during shutdowns wherein atmospheric gases are introduced during inspections.

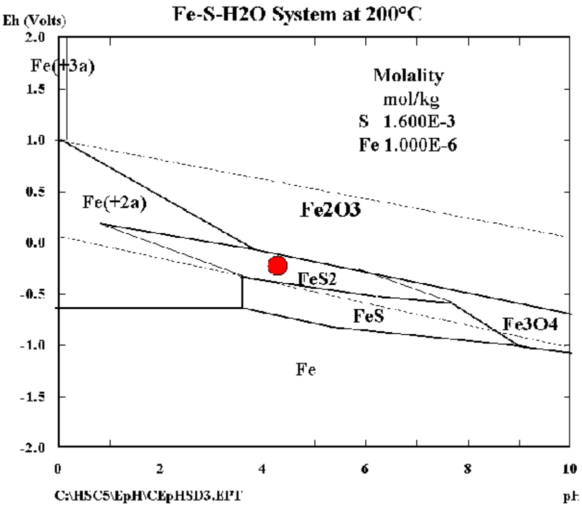

Figure 5: Well 102 Eh-pH diagram at 200°C in 2000

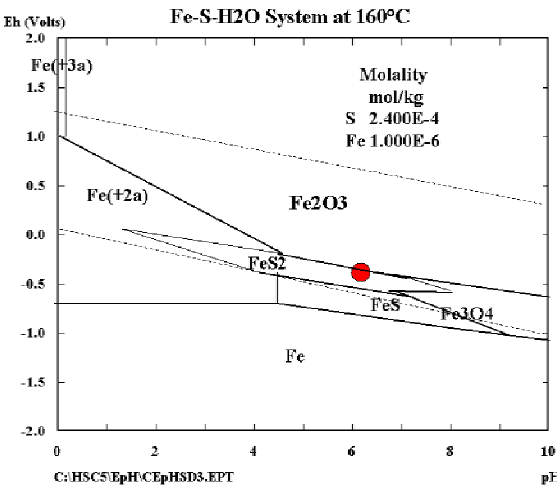

Figure 6: Separator steamline Eh-pH diagram at 160°C

The changes from 1999 to present may have exposed the whole vessel to an H_2S-rich steam-phase. At present, instead of the combined protective layers of silica-magnetite-pyrite layers, the vessel is more stable with pyrite corrosion product. However, petrographic analysis of silica and the corrosion product layers in the separator vessels (Zaide-Delfin et al., 2001) revealed that the silica layers are presently deteriorating. Without these layers, the vessel will be exposed to the corrosive attack of the flowing H_2S-rich steam.

In the steam lines, protective scales formed based on the Pourbaix model (Fig. 6), is pyrite. During "wet shutdowns" or if the pipes are exposed to the atmosphere, the pyrite layers tend to be unstable and fractured. Along these fractures, acid attack can occur which could ultimately lead to pitting corrosion. The occurrence of "pinholes" in the steam lines in 1997 to 1999 can be associated with this process.

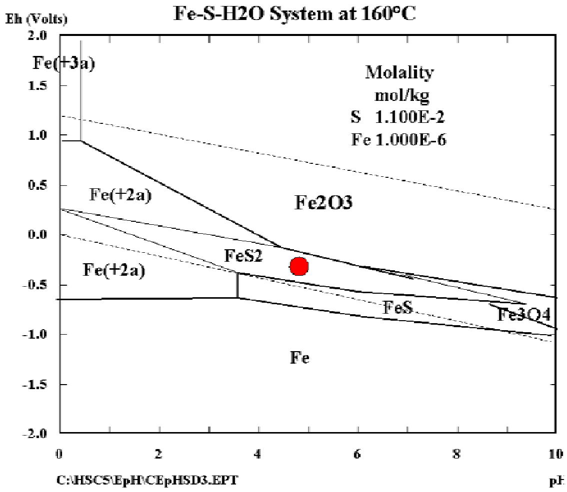

Figure 7: Separator brineline Eh-pH diagram at 160°C

In brinelines, silica is the most protective film against corrosion. Moreover, the separated alkaline brine will favor the formation of magnetite + pyrite (Fig. 7). From 1983 to present there has been no report of leakages in brinelines caused by corrosion or pitting.

2.2 Erosion Model

Erosion can also occur in the pipelines as a result of the impingement of the entrained solids or water droplets on the pipe surfaces. This process is demonstrated in the elbows and sweep-bends along the two-phase lines, where erosive actions of the solids and flowing fluids accelerate the thinning rate of the materials. Usually, the potential of erosion to take place depends upon the velocity of the flowing fluids and the volumetric ratio of solids to fluids. Salama, et al. (2000) estimated the erosional velocity in the pipelines using the following formulas:

For solid-free fluids:

$$V = 400/\rho_m^{0.5} \tag{1}$$

For sand-laden fluids:

$$V = (D\rho_m^{0.5})/(20W^{0.5}) \tag{2}$$

where V is the erosional velocity (m/s), ρ_m is the fluid mixture density (kg/m3), D is pipe inside diameter (mm), and W is sand flow rate (kg/d). In theory, if the velocity of the flowing fluids inside the pipes exceeded the calculated erosional velocity, erosion of the materials as well as the passive films of silica + magnetite + pyrite may take place. Liquid and two-phase fluids with solids may have lesser eroding action because of their lower velocity compared to purely steam with solids.

Villena and Isip (2001) calculated the erosional velocities in the different streams of the Tongonan-1 FCRS and the results are presented in Table 1. During the period when the production wells of Tongonan-1 were producing mainly liquid and two-phase fluids, the erosional velocities were rarely exceeded. With the change to a steam-dominated discharge, the erosion potential increased in almost all of the stream points of Tongonan-1 FCRS.

Table 1: FCRS lines that exceed the erosion velocity

SERVICE	FLUID	MASS FLOW (kg/s)		VELOCITY (m/s)		EROSION VELOCITY	
		before SLI	after SLI	before SLI	after SLI	with sand	without sand
W202 BL	2-Phase	33.7	32.1	18	62.3	54.4	120
W212 BL	2-Phase	59.3	35.4	50.8	88.8	45.6	138.4
W215 BL	2-Phase	43.8	39.4	59.4	107.8	41.3	142.5
W213 BL	2-Phase	47.5	26.9	45	82	47.4	150.4
W209 BL	2-Phase	30.2	33.9	49.5	93.5	44.4	149.8
W214 BL	2-Phase	36.5	18.9	50.4	51.9	59.6	142.7
W105 BL	2-Phase	63	33.2	44.8	105	41.7	153.8
W101 BL	2-Phase	44	28.7	63	91.9	44.8	154.1
W109 BL	2-Phase	15.2	15.3	46.6	50.7	60.3	156.6
W106 BL	2-Phase	36.7	18.9	72	57.9	56.4	150.7
W110D BL	2-Phase	35.4	29.8	70.5	86.8	46.1	146.9
W102 BL	2-Phase	62.8	29.2	39.4	91.3	44.9	152.2
W103 BL	2-Phase	35.6	31.3	49.9	83.7	46.9	140.8
W108 BL	2-Phase	25.3	31.3	47.2	79.8	48.1	137.5
W111D BL	2-Phase	40.9	44	69.5	133.7	37.1	150.1
W2R2 BL	2-Phase	47.7	29.1	30.5	72.1	50.5	135.6
SS#1 HP STL	Steam	174.5	260.3	46.9	73	50.2	164.5
TCP Inlet	Steam	284.9	284.9	57.7	57.7	56.5	167.1
SLI	Steam	0	174.1	NA	65.2	52.2	161.2

In well 102, its velocity of 39.4 m/s at a mass flow before of 62.8 kg/s is below the calculated erosional velocity of 44.9 m/s for sand laden fluids (assuming 0.00002% sand volume) and way below 152.2 m/s for solid-free fluids. The present 29.2 kg/s steam flow would have a velocity of 91.3 m/s. If there would be entrained solids with the discharges, the erosional velocity of 44.9 m/s can be easily surpassed and erosion may take place.

As the process of erosion destroys the protective films, the initial solids from the wells may generate increased volume of solids upon destruction of the corrosion films, as well as the silica scales, in the two-phase lines until it reaches the separator vessels.

3. TEMPORARY MITIGATING MEASURES

While no permanent solution is yet being implemented to deal with the problem of solids in steam, some "stop-gap" measures were undertaken to minimize the impact of the problem. Among them are the replacement of the upper shell of most separator vessels in Tongonan-1 that had thinned-out, installation of sacrificial plates inside the separator vessels, replacement of the existing schedule 40 branchlines that have thinned out with schedule 80 pipes, and frequent servicing of the compensators. All these have minimized the FCRS downtime but did not stop nor minimize the erosion rate that has been taking place in the pipes. Moreover, these are very expensive measures.

4. SOLIDS IN STEAM REMOVAL METHODS

Among the major considerations in the choice and design of the solids removal system is the cost of implementation and ease of operation of the system. Thus, the first considered was washing the steam with either hot brine or cold spring water so as to scrub the solids from the steam. The other was solids removal at the wellhead (wellhead solids removal system , WSRS) using a simple piping system that will deflect the solids away from the steam being channeled to the separator vessels. The main purpose of each method is to remove the solids from the steam before it could do more damage at the downstream two-phase lines, separator vessels and even steam lines. Moreover, the other major consideration is to minimize the loss of steam during the conduct of the solids removal process. Each method has relative advantages and disadvantages with application.

4.1 Steam Washing Using Hot Brine

The first method applied in Tongonan-1 was steam washing of the main two-phase lines with hot brine, of similar chemistry with Tongonan-1 fluids, coming from another sector and introduced just before separator station 1 (SS#1) by gravity (Fig. 8). These separator vessels already had a history of having high erosion rates at its upper shell, having already been replaced once.

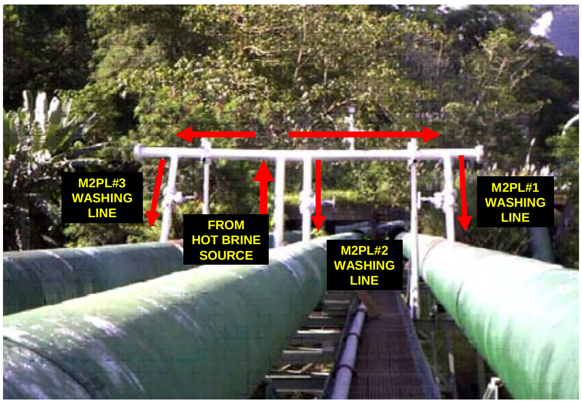

Figure 8: Steam washing (using hot brine @160°C) at SS#1 Main 2-Phase Line

4.2 Steam Washing Using Cold Spring Water

The second method applied in Upper Mahiao was steam washing using cold spring water. The washing was conducted by channeling cold river water and injecting it at the wing valve of the well's expansion spool using a high-pressure pump (Fig. 9) and at a calculated rate that will not cause appreciable condensation that can lead to the collapse of the steam discharge. This was done at several wells having very high erosion rates at its branchlines and isolation valves.

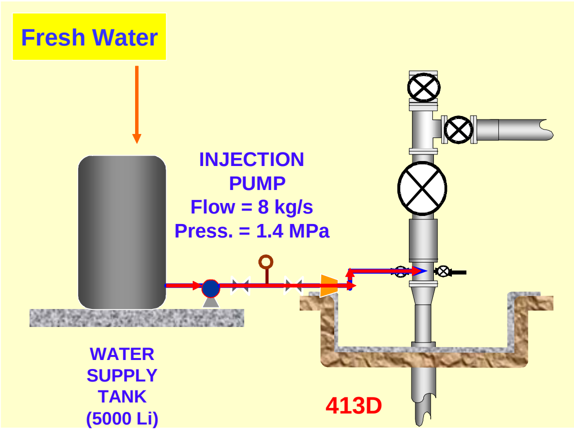

Figure 9: W401 steam washing (using cold spring water)

4.3 Wellhead Solids Removal System (WSRS)

The WSRS is designed to separate the solids from steam through the use of a larger-sized inverted u-shaped piping installed above the wellhead assembly. As the steam and solids traverse through the inverted u-shaped piping, the velocity and centrifugal force deflects the heavier solids and concentrates these at the outermost side of the piping. The solids are then deposited into a larger-diameter catchpot at the horizontal end of the system (Fig. 10). An exhaust valve in the catchpot maintains a pressure lower than the inverted u-shaped piping to allow steam with the concentrated solids to flow through. A horizontal pipe installed perpendicularly after the u-shaped section and opposite to where the solids are concentrated conveys the relatively clean steam to the main two-phase line.

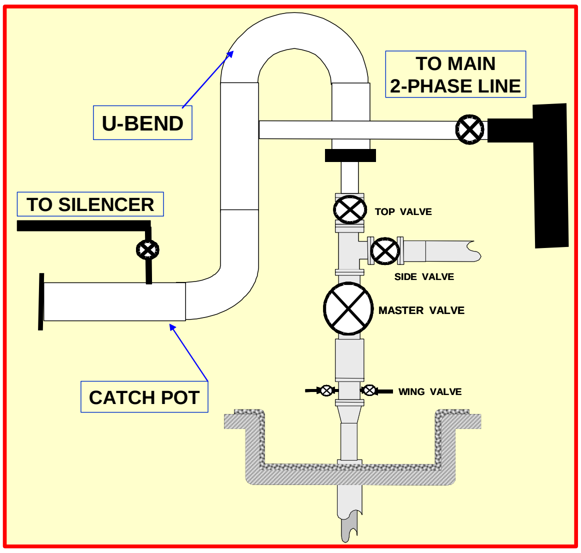

Figure 10: W111D Wellhead Solids Removal System

The erosion at the inverted u-shaped piping is minimized because the velocity is decreased with the u-pipe having a larger diameter (4,064 mm) than the production casing and master valve outlet (2,540 mm). It is also expected that with this design, the solids will have less chance of entering the line intended for the clean steam because it would preferentially flow to the lower pressure catchpot downstream. After the solids are collected, the catchpot needs to be opened and cleaned periodically. The washed steam will be less erosive downstream because the solids are scrubbed-off. This then makes the erosion controllable.

5. EFFICIENCY EVALUATION

The designed thinning rate for most FCRS facilities is only 0.12 mm/yr. For the FCRS to last at its expected operating life (25 years), the thinning rate in any section of the FCRS should not exceed this level. However, the solids in steam phenomena altered the previous condition of having an acceptable thinning rate measured from 1983 to 1997. Thus, the criteria for evaluating the efficiency of each method will be on how much it lowered the thinning rate and how much solids were removed from the steam. The thinning rate using UT while each method is in-service and TSS monitoring are used in the evaluation. Opening the line and weighing how much solids were collected during the period is also used.

5.1 Steam Washing Using Hot Brine Efficiency

To effectively capture the suspended solids in steam, the set-up must have enough water to scrub off the solids. Over washing will induce unnecessary condensation that can lead to the collapse in steam phase. Considering that the brine also contains silica, the brine to steam injection ratio was simulated in order to attain the maximum injection rate while minimizing steam loss due to condensation and controlling the silica saturation index levels. The simulation found the optimum washing ratio to be 80% steam and 20% wash fluid. Translating this to actual values based on the normal loading of SS#1, the amount of brine to be diverted and injected should be from 50 to 57 kg/s.

During the actual test, however, the optimum washing rate was sometimes not attained or maintained due to numerous constraints and field problems. Nevertheless, monitoring of both TSS and UT at different washing rates showed the efficiency of this method. At the start of the steam washing the washing rate was very low because of the limited capacity of the injection well used. The TSS at the steam header initially was at a minimum. With the opening of the rest of the throttled steam wells to increase steam supply, the TSS fluctuated. The TSS dropped to a minimum when the washing rate was increased to 36 kg/s. With the further decline in injection capacity, the washing rate dropped again resulting to TSS fluctuations (Fig. 11).

At the washing rate between 11 to 26 kg/s, the TSS was not effectively controlled, but at a rate of 36 kg/s and above, the TSS dropped below 20 ppm. This suggests that in order for the steam washing to be effective, a sufficient amount of brine should be used to scrub off the suspended solids in steam. When a different injection well in use enabled the washing rate to be raised to 52 kg/s the TSS was dropped to zero as can be seen in the latter part of Figure 11.

UT measurements were conducted in the three separator vessels in SS#1 (Table 2). The upper shell of SP 120 near the ellipsoidal head encountered the highest thinning rate of up to 15.82 to 18.25 mm/yr while the thinning rates of the other separator vessels was 3 mm/yr. This occurred when the vessels were fully loaded without steam washing. When steam washing was applied, the thinning rate at SP-120 was reduced to 1.97 to 3.78 mm/yr at the same location and load. This is an 80 to 88% reduction in thinning rates at SP-120 while the thinning rates of the other vessels also dropped to around 1 mm/yr. At this time, however, the washing rate was only 26 to 30 kg/s, still below the recommended rate of 50 to 57 kg/s. At the same washing rate of 26 kg/s and with the separator vessel load reduced, the thinning rate dropped to 0.67 mm/yr while the other vessels were below 0.1 mm/yr.

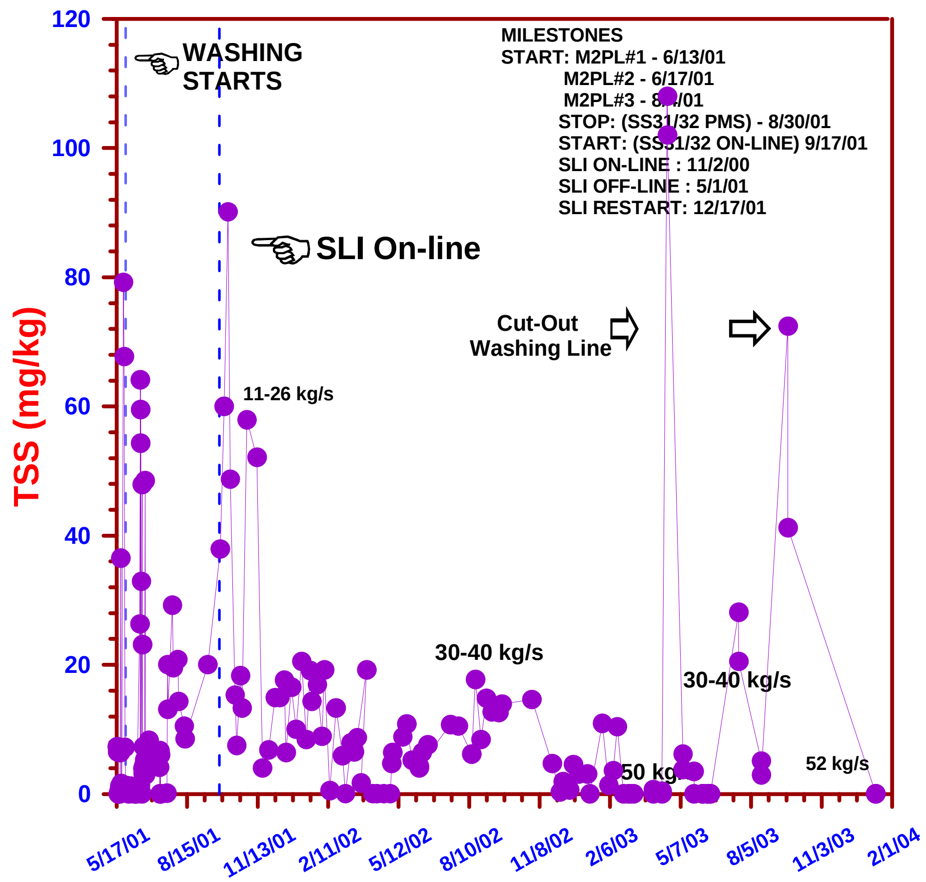

Figure 11: TSS Trend at SS#1 Steam Header

Table 2: UT Measurement at SS#1 separators

SEPARATOR VESSEL SP 120

TEST	DESIGN	AS	THICKNESS		RATE	THICKNESS		RATE	THICKNESS		RATE
POINT	THICK	BUILT	10/2/01	12/6/01	mm/yr	2/4/02	9/11/02	mm/yr	9/14/02	9/20/02	mm/yr
A-3	17.00	24.00	24.00	23.88	0.67	23.88	21.61	3.78	21.61	21.35	15.82
B-3	17.00	20.00	18.95	18.95		18.72	18.49	0.38	18.49	18.49	
A-4	17.00	24.00	22.37	22.37		22.35	21.17	1.97	21.17	20.87	18.25
B-4	17.00	24.00	18.87	18.87		18.57	18.25	0.53	18.25	18.25	
BIFUR	17.00	12.70	12.39	12.39		12.37	12.28	0.15	12.28	12.28	
			NO SLI & W/ WASHING			W/ SLI & WASHING			W/ SLI & NO WASHING		

SEPARATOR VESSEL SP 130

TEST	DESIGN	AS	THICKNESS		RATE	THICKNESS		RATE	THICKNESS		RATE
POINT	THICK	BUILT	10/2/01	12/6/01	mm/yr	2/4/02	9/11/02	mm/yr	9/14/02	9/20/02	mm/yr
A-3	17.00	24.00	23.32	23.32		23.32	22.18	1.90	22.18	22.12	3.65
B-3	17.00	20.00	18.65	18.63	0.11	18.49	17.87	1.03	17.87	17.87	
A-4	17.00	24.00	22.45	22.44	0.06	22.44	21.99	0.75	21.99	21.99	
B-4	17.00	24.00	18.97	18.97		18.43	17.81	1.03	17.81	17.81	
BIFUR	17.00	12.70	8.82	8.82		8.68	7.86	1.37	7.86	7.84	1.22
			NO SLI & W/ WASHING			W/ SLI & WASHING			W/ SLI & NO WASHING		

SEPARATOR VESSEL SP 140

TEST	DESIGN	AS	THICKNESS		RATE	THICKNESS		RATE	THICKNESS		RATE
POINT	THICK	BUILT	10/2/01	12/6/01	mm/yr	6/24/02	9/11/02	mm/yr	9/14/02	9/20/02	mm/yr
A-3	17.00	24.00				23.00	22.73	1.25	22.73	22.64	5.47
B-3	17.00	20.00				23.70	23.58	0.55	23.58	23.51	4.26
A-4	17.00	24.00				23.50	23.24	1.20	23.24	23.15	5.47
B-4	17.00	24.00				23.53	23.29	1.11	23.29	23.22	4.26
BIFUR	17.00	12.70				8.60	8.54	0.28	8.54	8.53	0.61
			NO SLI & W/ WASHING			W/ SLI & WASHING			W/ SLI & NO WASHING		

Test point A is located at the ellipsoidal head while B is at the top of upper shell

Table 3: UT monitoring results at W401 branchline.

UT Monitoring Prior to Wellhead Washing

TEST POINT	DES. THK EXCL. C.A.	DES. THK INCL. C.A.	CRITICAL THICKNESS	ACTUAL THICKNESS			THINNING RATE, mm/yr
				10/19/02	11/7/02	11/12/02	
A4	14.47	17.47	7.99	16.80	16.71	16.29	7.76
A1.3	12.09	15.09	6.74		17.72	17.50	16.06
A3.3	12.09	15.09	6.74		17.58	17.35	16.79
B3	14.47	17.47	7.99	15.54	15.25	14.84	10.65
C1	14.47	17.47	7.99	17.04	16.74	16.48	8.52
C'4	14.47	17.47	7.99		16.44	16.12	23.36
C1-3	14.47	17.47	7.99		17.52	-	
D1	14.47	17.47	7.99	17.92	17.73	17.15	11.71

UT Monitoring During Wellhead Washing @ 3.4 kg/s

TEST POINT	DES. THK EXCL. C.A.	DES. THK INCL. C.A.	CRITICAL THICKNESS	ACTUAL THICKNESS			THINNING RATE, mm/yr
				11/11/02	11/16/02	11/23/02	
A4	14.47	17.47	7.99	16.57	16.55	16.50	2.13
A1.3	12.09	15.09	6.74	17.61	17.60	17.57	1.22
A2.3	12.09	15.09	6.74	17.40	17.40	17.38	0.61
B2	14.47	17.47	7.99	15.19	15.18	15.13	1.82
C1	14.47	17.47	7.99	16.67	16.66	16.65	0.61
C'4	14.47	17.47	7.99	16.40	16.35	16.27	3.95
D1	14.47	17.47	7.99	17.43	17.40	17.39	1.22
D1.1	14.47	17.47	7.99	17.32	17.30	17.27	1.52
D2.4	12.87	15.87	9.01	18.20	18.18	18.13	2.13
E	12.09	15.09	6.74	9.82	9.81	9.78	1.22

This illustrates the effectiveness of steam washing using hot brine in the main two-phase lines. The succeeding UT measurements, with the washing rate increased to 52 kg/s, the UT results indicated that the thinning rates dropped further to 0.1 to 0.2 mm/yr (up to 99% reduction), coupled with the total reduction of TSS in steam.

A drawback to this method, however, is that it cannot protect the section upstream of the injection point, in this case, the wellhead and branchlines as the injection point was at the main two-phase line. Moreover, after the wash fluid scrubs the solids, it will be flushed with the brine into the brineline and eventually into the wellbore. This may lead to the lowering of the capacity of the injection well. This was addressed by installing a modified solid trap, which effectively removed the solids from the brine prior to injection into the wellbore (Fig. 12).

Figure 12: Modified Solid Trap installed at W1R8D

5.2 Steam Washing Using Cold Spring Water Efficiency

The principle applied to this method is similar to that of using hot brine in washing. In terms of efficiency, the results are almost similar to using hot brine as can be seen from the UT monitoring, the thinning rate dropped significantly as long as enough wash fluid (20% of total steam) was injected. This is shown in Table 3 where the thinning rate of the branchline without steam washing ranges from 8.52 to 23.36 mm/yr. The solids flowing along this line were so erosive that when a sacrificial valve was installed in-between the branchline and was throttled to test for erosiveness, it took only 40 hours for the valve to develop a pinhole leak. When steam washing was conducted at 3.4 kg/s into the wing valve, the thinning rate dropped to 0.61 to 3.95 mm/yr. This is an 83 to 96% reduction in thinning rate. The recommended washing rate of this well was 6 kg/s and it is estimated that if this will be maintained, the thinning rate will be reduced up to 99%.

The method is expensive because of dedicated pump and fuel or electricity costs. Aside from having a higher operating cost, the other drawback to this method is that it has a high tendency to collapse the steam because of the very low temperature of the spring water (~20-25°C) when injected. Moreover, based on experience, this method induced another problem. This was the localized corrosion at the injection point caused by the reaction of oxygenated water with the metal after the water boiled upon injection into the expansion spool causing a leak at the wing port (Fig. 13). The use of a stainless steel injection nozzle and the installation of a stainless steel doubler plate inside the injection point prevented a similar recurrence (Fig 14).

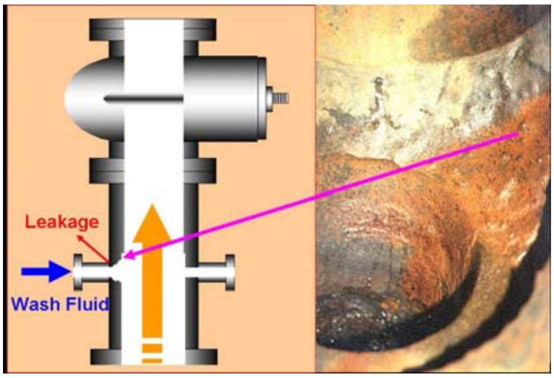

Figure 13: Wing Valve leak due to localized corrosion

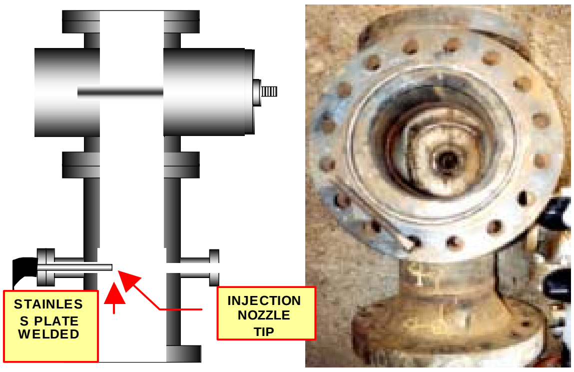

Figure 14: Steam washing injection point modification

5.3 WSRS Efficiency

Without the WSRS, the thinning rate of the branchline was 4.38-4.43 mm/yr at a load of 17 MW. It dropped to 0.87 to 1.30 mm/yr but at lower load of 2.6 MW. With the WSRS, the thinning rate dropped to 0.33 to 0.53 mm/yr at the same low load (2.6 MW), or a 59% to 62% reduction in the thinning rate. With an increase in load to 10 MW, the measured thinning rate declined further to 0.10 to 0.33 mm/yr or a 75% to 89% further reduction of the measured thinning rate. Comparing the thinning rate with the system on-line at higher load of 10 MW to the thinning rate when the well was at 17 MW without the WSRS, the WSRS can further reduce the thinning rate by as much as 93% to 98% (Table 4). The system was also more effective if operated at a higher load when steam flow velocity is high enough to deflect the solids (Table 5).

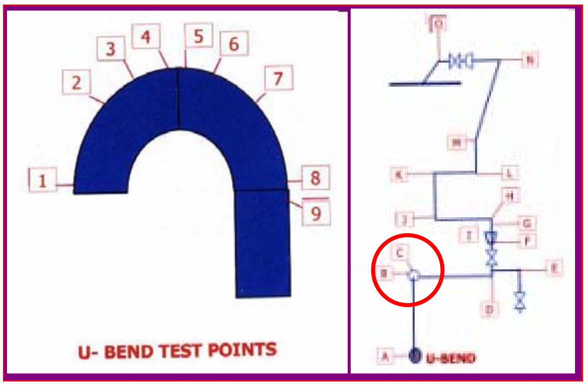

Figure 15: WSRS UT monitoring points

While this is a significant reduction in thinning rate, this is still not enough to comply with maximum thinning rate of only 0.12 mm/yr. Therefore, the installed branchline replacement will not last at its designed operating life of 25 years. This method may prove inferior compared to other methods. However, in areas where washing is not possible and expensive to operate, this system could prove it's worth enough to at least minimize the thinning rate. With the expect erosion in the branchline and to prolong its utilization, the branchline needs to be replaced with thicker pipes so that maintenance could be minimized. Instead of schedule 40 pipe, schedule 80 can be used so that there will have ample time to replace the piping if the UT measurements would indicate so.

Table 4: UT monitoring at the W111D branchline.

WITHOUT SOLIDS REMOVAL SYSTEM (at High Load = ~17 MW)								
SIZE	DESC.	PRESS.	TEST	DESGN THK		ACTUAL THK		EROSION
			POINT	EX. CA	IN. CA	10/9/01	3/7/02	RATE
INCHES		MPa		mm	mm	mm	mm	mm/yr.
10	ELBOW	6.1	A4*	12.10	15.10	11.86	10.07	4.38
10	ELBOW	6.1	B3*	12.10	15.10	12.55	10.74	4.43

WITHOUT SOLIDS REMOVAL SYSTEM (at Low Load = ~2.6 MW)								
SIZE	DESC.	PRESS.	TEST	DESIGN THK		ACTUAL THK		EROSION
			POINT	EX. CA	IN. CA	10/18/02	11/29/02	RATE
INCHES		MPa		mm	mm	mm	mm	mm/yr.
10	ELBOW	6.1	B4	12.10	15.10	8.50	8.35	1.30
10	ELBOW	6.1	C2	12.10	15.10	9.10	9.00	0.87

WITH SOLIDS REMOVAL SYSTEM (at Low Load = ~2.6 MW)								
SIZE	DESC.	PRESS.	TEST	DESGN THK		ACTUAL THK		EROSION
			POINT	EX. CA	IN. CA	1/18/03	3/14/03	RATE
INCHES		MPa		mm	mm	mm	mm	mm/yr.
10	ELBOW	6.1	B3	12.10	15.10	13.18	13.10	0.53
10	ELBOW	6.1	C1	12.10	15.10	11.84	11.79	0.33

WITH SOLIDS REMOVAL SYSTEM (at High Load = ~10 MW)								
SIZE	DESC.	PRESS.	TEST	DESGN THK		ACTUAL THK		EROSION
			POINT	EX. CA	IN. CA	9/20/03	1/10/04	RATE
INCHES		MPa		mm	mm	mm	mm	mm/yr.
10	ELBOW	6.1	B1	12.10	15.10	12.96	12.86	0.33
10	ELBOW	6.1	C3	12.10	15.10	11.75	11.72	0.10

* - Different Test Location

Table 5: UT monitoring results at the WSRS U-bend.

With Solids Removal System (at low load = ~2.6 MWe)								
Size	Desc.	Press	Test Point	Design Thickness		Actual Thickness		Erosion Rate
Inches		MPag		mm	mm	mm	mm	mm/yr
				Ex. CA	Inc. CA	1/18/03	3/14/03	ER
16	U-Bend	6.1	1	18.44	21.44	22.19	21.98	1.39
			2	18.44	21.44	22.61	22.51	0.66
			3	18.44	21.44	22.96	22.88	0.53
			4	18.44	21.44	22.94	22.79	1.00
			5	18.44	21.44	22.05	21.99	0.40
			6	18.44	21.44	21.99	21.85	0.93
			7	18.44	21.44	22.12	22.02	0.66
			8	18.44	21.44	21.85	21.76	0.60
			9	18.44	21.44	20.91	20.81	0.66
Average Erosion Rate								0.68
With Solids Removal System (at higher load = ~10 MWe)								
Size	Desc.	Press	Test Point	Design Thickness		Actual Thickness		Erosion Rate
Inches		MPag		mm	mm	mm	mm	mm/yr
				Ex. CA	Inc. CA	9/20/03	1/10/04	ER
16	U-Bend	6.1	1	18.44	21.44	21.79	21.61	0.59
			2	18.44	21.44	22.4	22.25	0.49
			3	18.44	21.44	22.73	22.63	0.33
			4	18.44	21.44	22.65	22.22	1.40
			5	18.44	21.44	21.85	21.67	0.59
			6	18.44	21.44	21.78	21.61	0.55
			7	18.44	21.44	21.85	21.72	0.42
			8	18.44	21.44	21.48	21.34	0.46
			9	18.44	21.44	20.76	20.51	0.81
Average Erosion Rate								0.53

5.4 Steam Loss Due to Solids Removal

All of the above methods incurred an energy loss while undergoing solids removal. Based on the summary of steam losses tabulated in Table 6, we can see that steam washing using cooler spring water incurred the highest steam loss. It condensed 27 to 36% of steam per kilogram of cooler water injected. With hot brine, it will condense only around 6% of steam per kilogram of hot brine. These are based on actual flow measurements while the system is on-line. The WSRS will have a fixed steam loss of 1 to 2.5 kg/s from the exhaust valve needed to maintain lower pressures in the catchpot.

Table 6: Energy Loss due to condensation during washing.

Location Washing	Wash Flow (kg/s)	Discharge Flow (kg/s)	Steam Condensation (kg/s)	Energy Loss (MWe)
Cold Water				
W401	6.81	9.3	2.49	1.12
W412D	7.26	9.2	1.94	0.87
W413D	13.82	18.3	4.48	2.01
Hot Brine				
W301	9.02	9.6	0.58	0.29
WSRS*				0.5-1.0

* - estimated amount of steam bleed off to silencer

The method with the least energy loss is the steam washing using hot brine because of the relatively narrow difference between the temperature of the hot brine injected and that of the two-phase fluid. This was followed by WSRS with a fixed energy loss of around 0.5 to 1.0 MWe. The most energy-guzzler method is steam washing using cold water because of the big difference between the temperature of the cold wash fluid and the two-phase fluid leading to a significant steam condensation during the washing process.

6. CONCLUSION

From all these observations, we can conclude that all the methods were able to effectively reduce the thinning rate and were effective in removing the bulk of the solids carried by the steam. Their efficiencies are determined by the amount of solids removed, the reduction in thinning rates and the amount of energy lost on the process of solids removal. Their applicability is dependent on the need and nature of the field or area. For example, in areas where brine is abundant, steam washing using hot brine is applicable. In areas where there is no brine, or pumping of wash fluid is expensive, the wellheads solids removal system is applicable. If steam loss due to condensation is not an issue and in areas where there is abundant cold water supply with or without the need of pumping, then steam washing using cold water is applicable.

Based on the experience of Tongonan and the operating needs of the field, we classified the methods accordingly: (1) Steam washing using hot brine in solids removal. This is because aside from being the most effective in reducing the thinning rate and in removing the TSS in steam, it is the method with the least energy loss; (2) Steam washing using cold water follows as long as energy loss due to condensation and operating costs is not an issue, in which case this becomes the last option. Also, corrosion due to the reaction of oxygenated water with the metal should be dealt with; and (3) WSRS. Although this method is applicable in some areas in Tongonan where there are no hot brine and cold water supplies, this method still has a relatively higher thinning rate than the other method.

REFERENCES

Artiaga, G.A. W111D Incident Report. PNOC-EDC Internal Report. Tongonan, Philippines (2003).

Roine, A. HSC Chemistry for Windows ver. 2.03. Outokumpu Research Oy, Pori, Finland (1998).

Salama, M.M. An Alternative to API 14E Erosional Velocity Limits for Sand Laden Fluids. Journal of Energy Resources Technology (2000).

Villa, R. R.. Evaluation of the Performance of 1R8D Modified Solid Trap. PNOC-EDC Internal Report. Tongonan, Philippines (2003).

Villa, R. R. (2002). 1R3 Capacity Decline and Its Impact on Tongonan-1 Injection System. PNOC-EDC Internal Report

Villa, R.R., and Salonga, N.D. The Occurrence of Solids in Steam of Tongonan-1. PNOC-EDC Internal Report. Tongonan, Philippines (2001).

Villena, J.P. and H.L. Isip. Calculated Velocity and Erosional Velocity of the different sections of LGPF. Technical Meeting Presentation Material. PNOC-EDC Internal Reports (2001).

Zaide-Delfin, M.C. and Rosell, J.D.: Petroanalysis of Scales and Corrosion Samples from LGPF. PNOC-EDC Internal Report. Tongonan Philippines (2001)