FAILURE ANALYSIS AND MITIGATION OF CORROSION ON CONDENSATE REINJECTION PIPELINE IN WAYANG WINDU GEOTHERMAL POWER PLANT

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ABSTRACT

Corrosion on reinjection pipelines has been renowned as one of the most challenging problem in geothermal plants as also found in Wayang Windu plant. A systematic failure analysis, design appraisal, and corrosion mitigation program have been carried out to investigate and alleviate thinning and leak failures on the condensate pipeline. Failure analysis by carrying out chemical characterization of corrosion products using X-ray diffractography, chemical analysis of condensate fluid, and field observation revealed that the failures had been likely caused by oxygen corrosion. The counteractions toward this corrosion issue have been conducted by both partial pipe spool repairs and total replacement with a non-metallic material as short and long term mitigation program, respectively. The latter program has been successfully accomplished by consecutively performing feasibility study, material selection, engineering design, installation, and testing. As a result, a new 4-km pipeline has been installed properly from a newly-established material of high density polyethylene (HDPE) to replace the failed existing steel pipeline. The HDPE was deliberately selected as the optimum material in comparison with Polyvinylidene Fluoride (PVDF), Chlorinated Polyvinyl Chloride (CPVC), and Polypropylene (PP). A pilot and comparative pipeline design were applied especially for the pipe stress analysis which became a hallmark of the thorough projects to conceive a proper supported above-ground HDPE pipeline. Moreover, the HDPE pipeline was installed by butt fusion joint which had been qualified by destructive tests comprising tensile tests and macroscopic observation as well as by field hydrotest. In addition to effectively mitigate the corrosion problem, this replacement has enriched the above ground facility with the application of corrosion-free and low life-cycle cost HDPE pipes as an alternative material in geothermal power plants.

1. INTRODUCTION

Wayang Windu Power Plant is located in Pangalengan, West Java – Indonesia. Currently, it has 2 units of power station which are dispatching a total of 227 MW electricity into West Java transmission grid operated by Perusahaan Listrik Negara (PLN). Unit 1 was put into commercial operation in June 2000 which at that time possessed the largest geothermal turbine in the world with generation capacity of 110 MW. (Murakami, 2000). In March 2009, Unit 2 was commenced with generation capacity of 117 MW.

Wayang Windu plant consists of Power Station and Steam Above Ground System (SAGS). Drawing layout for geothermal operation system is shown on Figure 1. The latter is designed to hand on two-phase geothermal fluid, separate it into clean steam and waste brine streams, convey the steam to the power station for power generation and convey separated brines and power station condensates to reinjection wells. The power station condensate in excess of the requirement of the closed circuit cooling water system is disposed of through a condensate reinjection system, separated from the brine reinjection system. This facility has encountered several failures of thinning and leaks on several locations along its first 4 km.

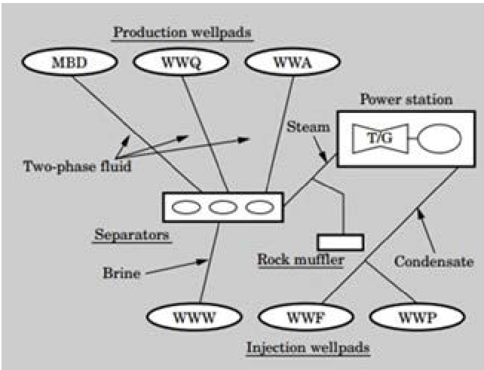


Figure 1: Drawing layout of power station and SAGS (Murakami, 2000)

For that case, mitigation program comprising failure analysis, design review, inspection-monitoring activities, and pipe replacement have been successfully accomplished. This work is intended to sum up the essential scheme of all technical matters in mitigation performed in order to provide field references to avoid similar occurrences in the future development of geothermal power plants.

2. CONDENSATE PIPELINE SYSTEM AND FAILURE OCCURENCES

2.1 Condensate Pipeline System

The condensate reinjection pipeline is a 16” carbon steel pipeline which runs by gravity (no pump) from the power station to dedicated reinjection wells for about 8 km long. Carbon steel was used based on the design assumption that the condensate would be substantially deoxygenated by the main condenser in the Power Station.

This 16” pipeline runs downhill from Power Station at 1712 AMSL to a low point at 1569 AMSL before rising pass the local high point at 1591 AMSL. It then runs downhill towards the reinjection well pads. This elevation configuration, as shown on Figure 2, causes the pipeline generally operates under open-channel flow regime, where the pipeline will be at the saturation vapour pressure of approximately 0.1 bar abs (i.e. vacuum), except the lowest point sections that is pressurized and operates under full-pipe flow regime.

The reinjection pipeline has such important roles that makes geothermal power plant becomes the most sustainable and renewable energy resource by conveying and returning geothermal fluid back into hydrothermal system after the energy extraction. Moreover, it also provides pressure support and additional recharge which could maintain production capacity in addition to reduce environment impacts (Diaz, 2015).

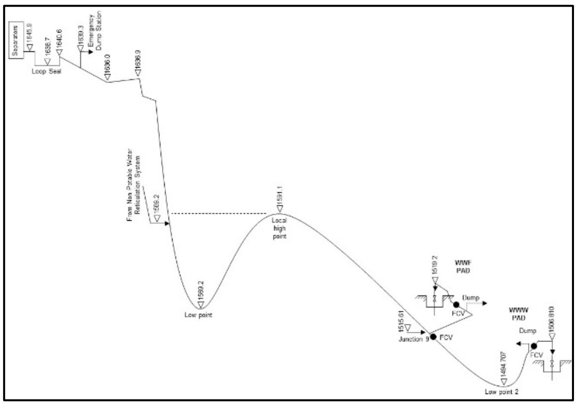


Figure 2: Elevation profile of reinjection pipeline (after separator only; not to scale)

2.2 Failure Occurrences

The condensate reinjection pipeline conveys condensate fluid which is presumably corrosive due to its gas and mineral contents. Wayang Windu condensate pipeline has encountered several thinning and leaks caused by internal corrosion which interrupt operation and emerge environmental issues. This failure predominantly occurred internally at the bottom of the pipe, while the top remains good or is less corroded. It also took place at the base metal of straight pipe as well as at the elbows, but it is not related to either the girth or seam weld of the pipes.

Interestingly, related to the elevation profile of the pipeline as shown on Figure 2, this thinning and leaks mostly occurred at the downhill area rather than level or uphill area. In addition, it occurred more likely at the sections which operate under open-channel flow regime rather than full-pipe one. The corrosion had occurred since Unit 1 operation, then has been heavier after increasing of Unit-2 operation load in the middle of 2009 although the additional operating load still complied with pipeline design capacities.

2.3 Corrosion Inspection and Monitoring of Condensate Reinjection Pipeline

Condensate pipeline thickness is regularly inspected for corrosion damage by spot external ultrasonic thickness gauging. The latest full inspection was conducted before pipe replacement in 2011 as presented in this work.

2.3.1 Pipe thickness distribution

The leaks of condensate pipeline took place in the first downhill area along the pipeline and has not occurred in its downstream area. Therefore, thickness data and mapping were mainly investigated in this upstream area. Pipe thickness distribution mapping of this area is shown on Figure 3.

Figure 3 shows that there was a thickness difference between Top (uppermost of pipe wall) and Bottom (lowermost of pipe wall) position of the pipeline. Thickness at the Top was slightly below the pipe nominal thickness, so the thinning can be neglected. Whilst, thickness at the Bottom indicates more substantial thinning. In regard with the Bottom position, Figure 3 also shows that thickness in the upstream area was lower than thickness in the downstream area. It can be seen that the average thickness for this area reached 4.8 mm. As was confirmed by field observation, that area was the most possible locations for the leak occurrence.

This 16” API 5L Grade B pipeline possesses design pressure of 28.1 bar, so it would have minimum allowable thickness about 6 mm (ASME, 2009). Therefore, the thickness mapping result shows that numerous pipe sections have thickness below MAT. In spite of that, the inspection was conducted by spot measurement so that the monitoring result did not provide the best estimation for leak occurrences. As a consequence, the leak still might be occurred at pipe section with higher thickness data, particularly if localized corrosion took place.

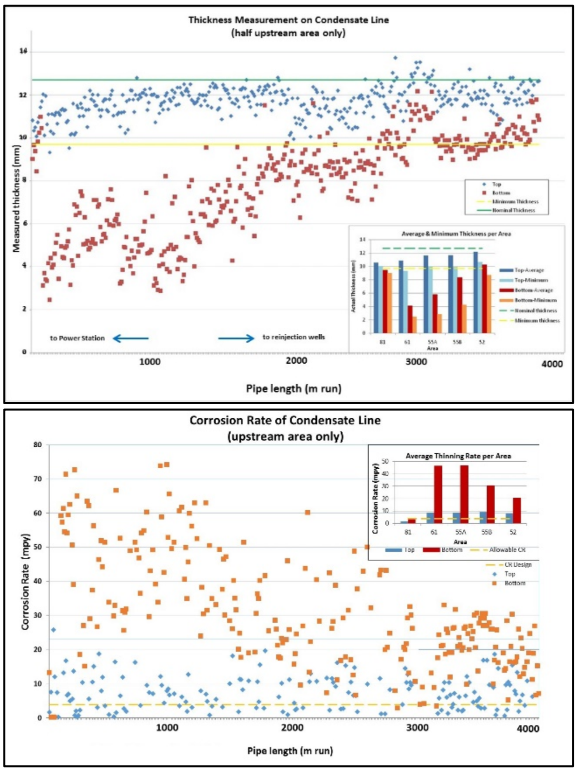


Figure 3: Pipe thickness distribution and corrosion rate (in mils per year, mpy) along condensate reinjection pipeline

2.3.2 Corrosion rate calculation

Thickness measurement data of condensate pipeline from 2008 to 2011 are utilized for calculating average corrosion rate in order to estimate and identify corrosion mechanism on the pipeline. The calculation result is presented on Figure 3.

Corrosion rate along the pipeline was 0.13-74.1 mpy (mils per year) with almost all the bottom position had higher corrosion rate than the top. Two highest corrosion rate were at the first downhill area with average value of 52.0 mpy and 46.7 mpy. These rates were considerably far above the allowable corrosion rate. It means that the corrosion allowance design was not appropriate for the recent condition. In addition, it was also suspected that the corrosion rate has increased in the downstream area. This lead to prediction that the corrosion may shift more to the downstream of the pipeline.

3. FAILURE ANALYSIS OF CORROSION ON CONDENSATE REINJECTION PIPELINE

3.1 Pipeline Design and Operation

Material and design specification as well as operation condition of the pipeline are shown below. In addition, material heat analysis as shown on Table 1was also evaluated.

Pipe material	:	API 5L Grade B
Delivery condition	:	as-rolled
Pipe dimension:	:	16 in x 12.7 mm
Corrosion allowance	:	3 mm
Lifetime design	:	30 years
Corrosion protection	:	NaOH injection
Design pressure	:	28. 1 barg
Design temperature	:	100 °C
Max. allowable flow rate	:	177 kg/s
Operating pressure	:	-0.002 to 10. 62 barg
Max. operating temperature	:	51 °C
Actual mass flow rate	:	100-150 kg/s

Table 1 Heat analysis of pipe material

Element	%w	Element	%w
C	0.14	Cu	0.02
Mn	1.15	Cr	0.05
P	0.023	Ni	0.03
S	0.006	Mo	0.01
Si	0.27	Fe	balance

Condensate reinjection pipeline was constructed from a manganese carbon steel which typically has low resistance towards oxygen corrosion. This corrosion property is indicated by as-rolled condition and its composition with no weathering element (Cu, Cr, Ni, or P) for enhancement of oxygen corrosion resistance (Jones, 1996). This characteristic was proven by field inspection result indicating high corrosion rate on the pipes. Indeed, the pipeline was actually not designed for oxygenated water due to assumption that the condensate would be deoxygenated in the main condenser in the Power Station.

On the other hand, it is noticeably shown that all actual operation parameters were controlled far below each design value. These are related to pipeline overdesign purpose in order to accommodate mechanical protection design against well back-flow, overpressure, and maximum hydrostatic conditions although it was historically infrequent.

In general, the condensate pipeline had been safely operated for mechanical protection. Thus, the failure was not directly related to the operational parameters. Unfortunately, it has not been adequately designed to withstand the corrosion damage.

3.2. Water Chemistry Monitoring

Condensate chemistry data monitoring for last 3 years including oxygen contents were evaluated.

Table 2 Chemical analysis of condensate fluid

Parameter	Unit	Actual	Monitoring limit
pH	-	7.3	5.5-9.0
EC	µS	391	-
TDS	ppm	209	5000
SO_4^-	ppm	18	1200
B	ppm	22	-
NH_3	ppm	8	-
$CaCO_3$	ppm	12	800
HCO_3^-	ppm	29	-
Bacteria	cfu	1650	10000
Dissolved oxygen:	ppm		0.03
- before Turbine condenser		6.42	
- after Turbine condenser		0.55	

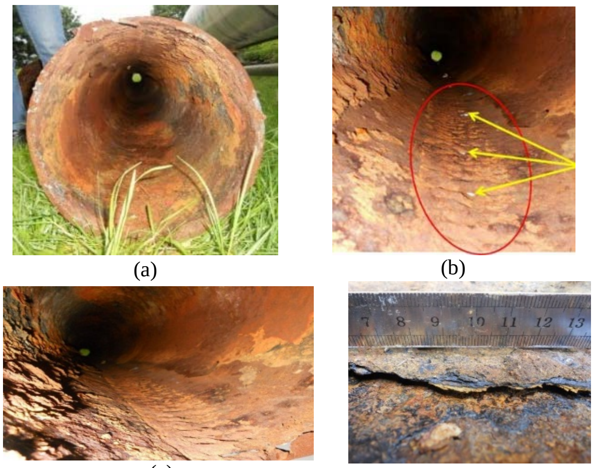
Studying the chemical composition of the fluid, it is well understood that the pH of minimum 5.6 is acceptable and indicates near-neutral fluid (due to NaOH injection) which usually has low corrosivity. Whilst, the elevated temperature condition up to 50°C could potentially accelerate the corrosion reaction, but not (or less) increase the tendency of the corrosion. Likewise, electrical conductivity in range of 143-391 µS with TDS range of 71-209 ppm assigns the condensate as non-saline water category indicating low corrosivity.

In this condition, the corrosion on the pipeline might only be occurred due to high reduction potential thanks to dissolved oxygen content in the fluid. Condensate chemistry analysis on Table 2 shows that condensate fluid contains considerable dissolved oxygen which is far higher than oxygen corrosion limit, 30 ppb (Jones, 1996). De-oxygenation in the turbine condenser can only reach about 1 ppm which is not adequate to avoid the oxygen corrosion on the pipeline. This condition can be more severe due to existence of SO_4^{2-}, CO_3^{2}, and HCO_3^- ions which can also contribute for corrosion rate acceleration and passive layer destruction (Fontana, 1987).

3.3. Field Observation and Chemical Characterization

3.3.1. Field observation

Visual inspection during field observation were conducted on the failed pipes in the upstream area where the most severe corrosion taken place. Several field picture are shown on Figure 4 and its observation results are presented on Table 3.



(a) (b) (c) (d)

Figure 4 Visual observation on pipe internal corrosion

Table 3 Summary of visual inspection finding

Fig.	Finding / Features	Indication / Cause
4a	Uniform corrosion on all internal surface	General corrosion due to oxygen corrosion
4b	Directional metal loss pattern	Erosion
4b	Wavy corroded surface	Flow-induced corrosion
4b	Localized leaking point	Oxygen corrosion
4c	Elongated tubercle	Oxygen corrosion
4d	Tubercle layers	Oxygen corrosion (tuberculation)

Observation on some corroded pipes along the pipelines delivered several typical finding. There were a number of similar features on the pipes such as uniform corrosion, tubercle or stratified corrosion product, and directional metal loss pattern. Uniform corrosion on pipe draining water is one of typical features of oxygen corrosion. Simultaneously, corrosion product characterization by XRD also confirmed this. This evidence was strengthened by tubercle finding (Fig. 4c and 4d) which is typical for oxygen corrosion products.

On the other hand, directional metal loss found indicates that thinning was also assisted by erosion mechanism instead of corrosion only. Numerous dents due to erosion were clearly shown. Another evidence of corrosion erosion process is shown by a tubercle which is induced by flow direction namely elongated tubercle (Nalco, 1993).

In addition, there was a wavy corroded surface that indicates typical process of oxygen corrosion: form a cathodic-anodic pattern where localized corrosion is rapidly occurred in anodic area that could eventually become a leaking point. Briefly, all these finding strengthen the presumption that root cause was flow induced oxygen corrosion.

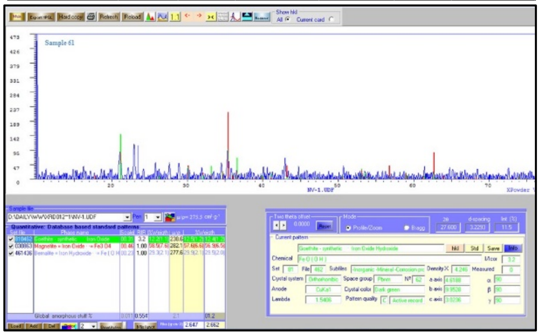
3.3.2. X-ray Diffraction for Corrosion Products

Chemical characterization of corrosion product of the pipes were conducted by X-Ray Diffraction (XRD) method. The results were then processed qualitatively by Automatic Powder Diffraction (APD) and quantitatively using XPowder^{TM} analysis. Diffractogram of XRD test result for all samples are presented on Figure 5. Those XRD analysis results are summarized on Table 4.

Despite minor difference associated with software database, both results revealed that all specimens consist of various iron oxide (magnetite and maghemite) and hydroxide (iron (III) hydroxide, goethite, lepidocrocite, and akaganeite). Moreover, all diffractograms of test specimens did not present diffraction pattern of other possibility compound such as iron carbonate (siderite) or iron sulfide (pyrite) although condensate fluid also contains CO_3^{2-} and SO_4^{2-} ion. Those verified that the pipeline encountered oxygen corrosion due to contact with oxygenated condensate fluid. Indeed, any other corrosion mechanism such as CO_2 or H_2S corrosion was not evidently found.

Table 4 Summary of XRD analysis

Sample	A			B		
Automatic Powder Diffraction	Goethite	Magnetite	Iron Hydroxide	Lepidocrocite	Magnetite	Iron Hydroxide
	FeO(OH)	Fe3O4	Fe(OH)3	FeO(OH)	Fe3O4	Fe(OH)3
X-Powder Analysis	Goethite	Magnetite	Bernalite	Lepidocrocite	Bernalite	Maghemite
	FeO(OH)	Fe3O4	Fe(OH)3	FeO(OH)	Fe(OH)3	Fe2O3
	12.5	57.6	29.9	12.7	42.8	44.5



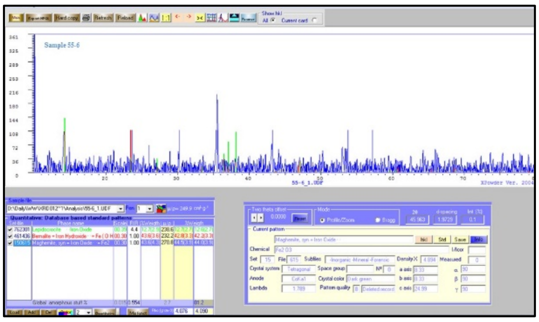


Figure 5 XRD test results

3.4. The Root Cause of Failures

Field observation and laboratory analysis delivered conclusion that the failures were caused by flow-induced oxygen corrosion. The oxygen corrosion were proved by: (1) corrosion product of iron oxides and iron hydroxides; (2) extremely high dissolved oxygen in the fluid up to 1.18 ppm; and (3) oxygen corrosion features such as tubercle growth, and localized leak pattern. Moreover, erosion thanks to high flow rate and pipe geometry has been proved by field observation of flow regime and typical erosion features such as dent, wavy corroded surface, and directional metal loss pattern on corroded pipe surfaces.

4. MITIGATION ACTION

Two types of mitigation were carried out, particularly pipe spool repair and pipe replacement with non-metallic material.

4.1. Pipe Spool Repair

Partial pipe spool repair was taken as short term mitigation program. Repair processes were conducted by patching, pipe lamination with fiber reinforced plastic (FRP) coating, pipe replacement with newly pipes, and pipe rotation such that the thicker part of the pipe is positioned on the top. These processes were decided based on the latest thickness inspection data and resources availability. The thickness data were utilized for corrosion rate and remaining life assessment to determine priority of pipe spool replacement and the suitable repair method.

Several operation manoeuvres had to be set during the repair, so the power generation was not interfered. This included conveying the condensate fluid by temporary line, draining it into SAGS ponds, or pumping it into temporary reinjection wells. Even though the repair process spent considerable budget and resources, it was the most effective solution in the field to mitigate the corrosion damage.

4.2. Replacement with Non-metallic Material

4.2.1. Pipeline replacement as long term mitigation

Partial pipe spool repair had effectively prevented the subsequent leak of the pipeline. However, it had been realized that the corrosion would still potentially take place. The repair however was applied to avoid the leak until more proper mitigation could be performed. Several options could be taken as long term mitigation such as inhibitor reinjection or de-aerator installation to eliminate dissolved oxygen. Considering technical and cost optimization, replacement with non-metallic material was deliberated as the most effective solution to be implemented. In addition to effectively eliminate corrosion on the pipeline, the construction process was expected to take less cost and time.

4.2.2. Material alternatives and selection criteria

The tenet of the material selection study is that the selection is not to find the best properties nor the least price material, but more importantly it has to be appropriate with condensate chemistry and reinjection operation in the existing plant.

All material alternatives were polymer pipe materials which have been widely used in energy industries, including High Density Polyethylene (HDPE), Polyvinylidene Fluoride (PVDF), Chlorinated Polyvinyl Chloride (CPVC), and Polypropylene (PP).

All nominated materials were compared each other to find the most appropriate one. The selection was based on the several criteria including mechanical properties, internal/external pressure capacity, water and chemical resistance at elevated temperature, abrasion/ erosion resistance, degradation factor, joinability and maintainability.

In regard with mechanical properties, a thin wall linear elastic model was examined to find the capability of each materials to withstand the operating condition. Moreover, resistance toward water and chemical for each material was anticipated especially for aggressive substances contained in condensate fluid such as boric acid, calcium bicarbonate, ammonia, and sulphate.

For abrasion resistance, the absolute and relative roughness of each material were evaluated. It was included in the selection criteria due to its effect either on abrasion by any slurry that is possibly contained in the fluid or on pipeline hydraulic property (PPI, 2008). Degradation factor was also considered since the pipeline was designated for outdoor application, while most of polymer materials have common problem with degradation, especially by ultraviolet radiation.

Table 5 presents the brief result of material study. In general, all alternative materials can be applied for given operational condition. PVDF and HDPE are the most two superior materials in term of chemical resistance and UV degradation than other non-metallic materials. However, In terms of cost – performance ratio, HDPE was more superior and considered as the most suitable replacement material (Wedgner, 2015). Accordingly, HDPE pipe was selected for replacement to alleviate corrosion problem of the condensate pipeline.

Table 5 Summary of material selection study result

Material	Mechanical Strength	Water resistance	Chemical resistance	Erosion resistance	Degradation	Joinability	Maintainability	Cost
HDPE	E	E	E	E	E	E	E	E
PVDF	E	E	E	E	E	E	E	G
CPVC	E	E	P	G	P	E	E	E
PP	E	E	E	E	P	E	E	E
Carbon steel (as comparison)	E	P	P	P	P	P	E	E
E = Excellent; G = Good; F = Fair, P = Poor								

5. DESIGN AND INSTALLATION OF HDPE PIPELINE FOR CONDENSATE PIPELINE REPLACEMENT

5.1. HDPE Pipe Material for Reinjection Pipeline

There were several additional reasons to utilize HDPE pipe material. Firstly, HDPE is a flexible, though, and corrosion-free material. It also provide low life cycle cost due to elimination of cost-related inspection and maintenance activity. It has been widely used as water or gas distribution networks and it has been used as drainage and sewerage of condensate fluid in Wayang Windu plant. Moreover, it has adequate hydraulic and stress performance, see 5.3.

Despite those advantages, HDPE resistance against geothermal condensate was concerned the most since it has been no record of HDPE pipe used for condensate. The project was fairly challenging as it was the first time applied for geothermal condensate pipeline. In addition, another challenge is to design the HDPE pipes, which have high thermal expansion, to be compatible with the existing field where was limited by tight space adjacent to the existing pipe.

5.2. HDPE Properties

HDPE material is recently well developed and effectively used for low temperature – low pressure piping (PPI, 2008). The pipe replacement was PE 100 – 400 mm MOD SDR 11 PN 16 manufactured by polymer extrusion. Laboratory test including tensile test, carbon dispersion, heat reversion test, and hydrotest were conducted following the extrusion process. Properties of HDPE material that is used in Wayang Windu are shown on Table 6.

In regard with HDPE pipe application in Wayang Windu, carbon black content becomes important properties because it would assure pipe resistance against degradation by UV radiation. Additive of 2% carbon black roles as sacrificial UV stabilizers that would be depleted by UV energy absorbed, so it could shield the base material (Gilroy, 1985).

Furthermore, thermal stability is also essential provided that condensate pipeline is operated at elevated temperature about 50ºC. It is slightly below the HDPE design capacity. However, thermal stability and stress rupture test provide guarantee that the HDPE pipeline would have lifetime up to 23 years in given operating condition (PPI, 2008)

Table 6 Typical properties of HDPE materials (PE 100)

Properties	Unit	Typical Value
Material Specification	-	PE 100
Density	kg/m^3	> 949
Melt flow rate	g/10min	0.25 (190ºC/5.0 kg)
Tensile stress at yield	MPa	25
Elongation at break	%	> 600
CVN impact test	kJ/m^2	16
Hardness	Shore D	60
Minimum required strength	MPa	10
Hydrostatic Strength	MPa	8
Design life	year	50 at 20ºC
Brittleness temperature	ºC	≤ - 70
Carbon black content	%	≥ 2
Thermal stability	Min	> 5 min at 210ºC
Operational temperature	ºC	-40 to 60

5.3. Pipeline design

5.3.1. Hydraulic analysis and pipe sizing

This section presents hydraulic simulation and pipe sizing results of HDPE for condensate pipeline. Simulation is performed using HYSYS® at steady state condition. The design criteria are based on API RP 14E requirement and flow velocity limitation of 3-7 ft/s given by Crane Co. (1976). Data input on this simulation are shown on Table 7.

Condensate pipeline consists of series of pipe segment declining along mountainous area as elevation profile shown on Figure 6. Pipeline pressure and temperature simulation for condensate fluid for each case of HDPE pipe sizes of 18”, 16”, 14”, and 12” are presented on Figure 7.

Table 7 Material and operation data input for modelling

Material Properties		
Absolute roughness	:	9 x 10-3 mm
Relative roughness	:	2.3 x 10-5
Thermal conductivity	:	0.465 W/m.K
Outside diameter	:	12.75; 14; 16; 18 in
Wall thickness	:	0.375 in
Operation & environment condition		
Flow rate	:	180 kg/s
Inlet temperature	:	50 ºC
Inlet pressure	:	0.8 bar
Ambient temperature	:	21-33 ºC
Humidity	:	60-94%
Seismic load	:	0.4-0.5G

Figure 7 indicates internal pressure increase in direction to reinjection wells. The configuration of the condensate pipeline, which drives by gravity, creates such hydrostatic pressure that would cause the maximum pressure takes place at the lowest point. On the other hand, pipeline temperature would slightly decline in a minor rate for pipeline performance and reinjection system requirement.

The pipe sizing would be relied on the velocity criteria since both simulated pressure and temperature profile complied with API RP 14E requirement. The 16” pipe was then selected due to providing higher flow rate than 14” pipe and lower manufacturing cost than 18” pipe. Whilst, the 12” pipe size would likely cause the fluid initiates erosion process due to excessive velocity (Nalco, 1993). Moreover, the application of 16” HDPE pipe would not reduce the initial flow capacity thanks to lower absolute roughness surface although it possesses smaller internal diameter than other typical steel pipe size.

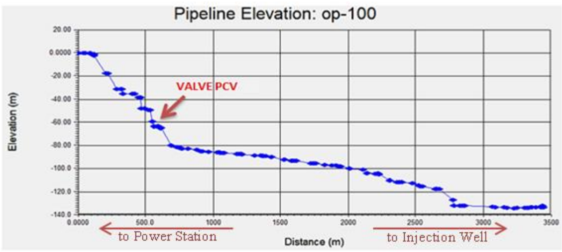


Figure 6 Pipe elevation profile along pipe distance

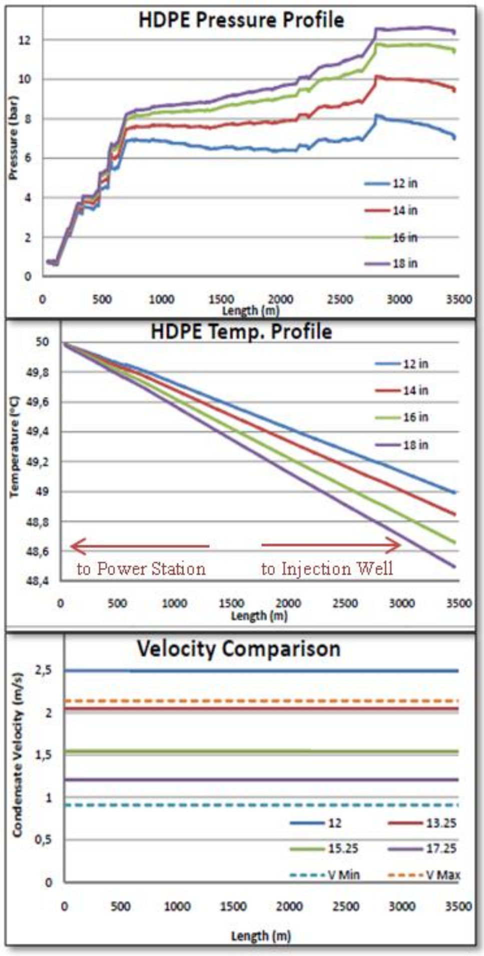


Figure 7 Process parameter simulation results

Table 8 Tabulation of process simulation results

	Unit	12”	14”	16”	18”
End-point pressure	bar	7.1	9.5	11.5	12.4
Maximum pressure	bar	8.2	10.2	11.8	12.6
Outlet temperature	ºC	49.0	48.9	48.7	48.5
Minimum velocity	ft/s	8.189	6.716	5.069	3.960
Maximum velocity	ft/s	8.192	6.719	5.072	3.967
Maximum flow rate	kg/s	156	190	252	323

5.3.2. Pipe stress analysis

Stress modelling was simulated using Bentley Autopipe® based on ASME B31.1 Code (2009). Data on Table 7 as well as other HDPE data shown on Table 9 were applied. In regard with the simulation process, supported pipeline on-grade (above ground) installation was employed. This configuration was carried out by application of four modelling of support as shown on Table 10. The simulation results are presented on Figure 8, Table 11, and Table 12. It consists of maximum pipe stress occurrence, its allowable value, and stress ratio as well as displacement analysis on several combination of loading case.

The maximum allowable stress ratio on sustained, expansion, and hydrostatic load were under requirement of the ASME code. Regardless of that, a number of technical issues have to be concerned during HDPE pipeline design. First of all, HDPE pipeline system generates high displacement due to expansion. It has to be accommodated with the application of pipe guide and line stop supports particularly as in this case where less space is available due to the existing pipe.

Secondly, the applicable supports have to be arranged with short span up to 4 meter each other. HDPE pipeline cannot support contained fluid weight by itself, but it is directly transferred to the supports. Thus, shorter span and more support number were required. Lastly, the application of apparent modulus instead of tensile modulus in this simulation gave important design consideration. This modulus was valid to be used in the calculation due to the viscoelastic properties of HDPE which have evidently accommodated pipe flexibility (PPI, 2008).

Table 9 HDPE properties and operating data for PSA simulation

Properties / design	Unit	Value
Minimum yield strength	MPa	25.5
Ultimate yield strength	MPa	33.3
Long modulus	MPa	784.5
Hoop modulus	MPa	784.5
Shear modulus	MPa	117.7
Density	kg/cm3	958
Poisson's ratio	-	0.4
Operating pressure	bar	12
Design pressure	bar	15
Hydrotest pressure	bar	22.5

Table 10 Four support models used in simulation

No.	Support Head	Shoe	Description
1	G type	L type	Guide support
2	T type	L type	V-stop support
3	G type	S type	Guide + Line stop
4	Anchor	Anchor	Fixed anchor

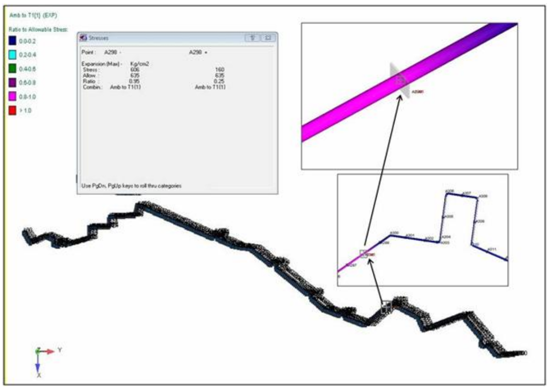


Figure 8 Illustration of simulation result showing location of maximum applied stress ratio

Table 11 Tabulation of simulation results

Description	Maximum sustained stress	Maximum expansion stress	Maximum occasional stress	Maximum hoop stress ratio
OPERATING PRESSURE LOAD				
Point	A380	A298	A00	A400
Stress (Kg/cm^2)	54	606	11306	5
Allowable (Kg/cm^2)	227	635	272	227
Ratio	0.24	0.95	41.56	0.02
Load combination	GR + Max P{1}	Max Range	Sus. + E1{1}	Max P{1}
DESIGN PRESSURE LOAD				
Point	A380	A298	A00	A400
Stress (Kg/cm^2)	54	606	11306	6
Allowable (Kg/cm^2)	227	635	272	227
Ratio	0.24	0.95	41.56	0.03
Load combination	GR + Max P{1}	Max Range	Sus. + E1{1}	Max P{1}
HYDROTEST LOAD				
Point	A 380	A298	A00	A400
Stress (Kg/cm^2)	54	606	11306	9
Allowable (Kg/cm^2)	227	635	272	227
Ratio	0.24	0.95	41.56	0.04
Load combination	GR + Max P{1}	Max Range	Sus. + E1{1}	Max P{1}

Table 12 Tabulation of displacement analysis results

Description	Disp. (mm)	Point	Load comb.
OPERATING PRESSURE LOAD			
Maximum X	-44.402	A528	GT1P1{1}
Maximum Y	-30.167	A328	Static seismic 4{1}
Maximum Z	5.739	A05 F	GT1P1{1}
Max. Total	48.607	A21 F	Thermal 1{1}
DESIGN PRESSURE LOAD			
Maximum X	-44.438	A528	GT1P1{1}
Maximum Y	-30.166	A328	Static seismic 4{1}
Maximum Z	5.758	A05 F	GT1P1{1}
Max. Total	48.607	A21 F	Thermal 1{1}
OPERATING PRESSURE LOAD			
Maximum X	-44.402	A528	GT1P1{1}
Maximum Y	-30.167	A328	Static seismic
Maximum Z	5.739	A05 F	GT1P1{1}
Max. Total	48.607	A21 F	Thermal 1{1}
HYDROTEST LOAD			
Maximum X	-44.529	A528	GT1P1{1}
Maximum Y	-30.165	A328	Static seismic
Maximum Z	5.807	A05 F	GT1P1{1}
Max. Total	48.607	A21 F	Thermal 1{1}

Regardless of the aforementioned results, it has to be recognized that the HDPE material database were not all available in the latest version of software used. Therefore, to validate manual data input and software limitation, additional calculation at several critical points was also conducted, particularly for expansion and occasional load. The reference used was EPRI Technical Report which had established proposed design of above ground HDPE piping. This also considered other viscoelastic failure mechanism, which are uncovered by the conventional method, such as creep, slow crack growth, and fatigue (EPRI, 2010).

The comparison result are shown on Table 13. Both calculation apparently did not give significant difference and can ensure that the pipe would be safe to operate against load case of sustained, hydrostatic, and occasional, as well as for fatigue and creep damage in given design limitation.

Table 13 Verification of stress analysis simulation results (expansion load only)

	Unit	EPRI Design	Autopipe® (B31.1)
Stress	MPa	7.72	6.28
Allowable	MPa	25.5	33.3
Ratio	-	0.3	0.19

5.4. HDPE Pipeline Installation and Testing

5.4.1. Pipeline Installation by Butt Fusion

In the field, HDPE pipes were joined by butt fusion method. The join process was remarkably fast up to 10 join per day (~60 meter). There was no non-destructive examination applied for quality control of butt fusion process, so the quality was merely based on tight controlling of butt fusion process parameters as shown on Table 14. The installed pipeline is exemplified on Figure 9.

Table 14 Butt fusion parameters applied

Parameter	Unit	Value
Heating Temperature	ºC	205-235
Bead Up Pressure	kPa	3586
Bead Up (Heating) Time	s	218
Approx. Bead Width after Bead Up	mm	4.14
Cooling Time	s	555
Welding & Cooling Pressure	kPa	3586
Welding & Cooling Time	min	55
Minimum Bead Width after Cooling	mm	21.18
Maximum Bead Width after Cooling	mm	32.27

Figure 9 Installed HDPE line (black pipe) next to existing steel condensate line and insulated brine reinjection line

5.4.2. Bonding Qualification Test

In addition to visual inspection for quality control of joining, qualification test of butt fusion for HDPE pipeline was also performed by destructive tests. Test assembly was fabricated by butt fusion parameters specified on Table 14 and tensile tested refer to EN 12814-2 standard. Figure 10 shows the specimen after test and the result is summarized on Table 15.

Macroscopic examination reveals difference solidification orientation between fusion area and base material. It indicates melt flow orientation during bead up pressure step in butt welding process. This solidification process leaves tiny gap in welding area which is not melted during heating and pressurizing. These features, however, may not influence the pipe strength. The HDPE tensile test specimen experienced large plastic deformation during tensile tests until the ductile fracture occurred. The weld join area remained solid as the failure occurred at base material. Butt fusion parameters used were then qualified for pipe installation.

Figure 10 Fractography of butt fusion joint

Table 15 Tensile test result of applied butt fusion method

Test parameter	Result
Tensile Strength at Yield	28 MPa
Elongation	139%
Failure location	Base Material
Failure mode	Ductile

5.4.3. Hydrostatic Leak Test

Field hydrostatic tests performed after installation following ASTM F 2164 – 02 standard with slight customization. It was performed partially to accommodate pressure limit on high range elevation. The test diagram is shown on Figure 11.

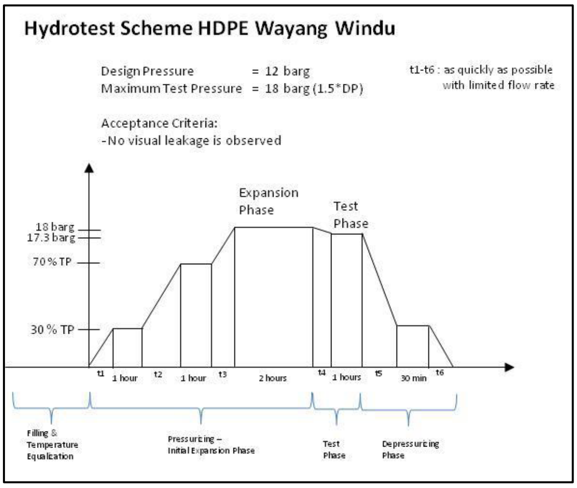


Figure 11 Hydrostatic test diagram

Fresh water was filled up with controlled rate to avoid transient pressure surge. Temperature equalization was not required since both fluid and section test temperature are below 27ºC (PPI, 2008). During the initial expansion, the test section was pressurized gradually to test pressure 18 bar and make-up water was added to maintain the pressure above 12 bar. Afterwards, the pressure was slightly reduced during test phase hence visual check and pressure monitoring could be carried out with minimum expansion effect. No visual leakage was observed in all test phases and the pipeline integrity was not altered.

6. SUMMARY OF MITIGATION EXPERIENCES

Internal corrosion resulting in excessive thinning and leaks has taken place on a 16” condensate reinjection pipeline in Wayang Windu geothermal power plant. Adjustment of operational parameters has been attempted as well as replacement with new pipes in addition to patching or pipe laminating. What beneficial is repair by rotating pipes such that the thicker part of the pipes were positioned on the bottom. It was carried out based on the fact that the most severe thinning most likely to occur on the pipe bottom area. This attempt has been successfully solved the leak problem and give time to work on long term and more proper solution.

Failure analysis, design review, and other inspection activities revealed that the failures were most likely caused by flow-assisted oxygen corrosion. Replacement with non-metallic material was deliberately decided to solve the corrosion. The replacement with HDPE materials apparently was not trouble-free works. It was actually more demanding in each of project phases basically due to the unawareness in a non-metallic pipe construction. Adaptation of the non-metallic standards such as ISO standards for design, installation, and testing of HDPE pipes has to be well understood for the next projects.

In spite of different standards and consideration taken during design and installation phases, a new 4-km HDPE pipeline was carefully constructed and has effectively eliminated the corrosion problem. At present, the pipeline has been operated for almost 2 years without any considerable problems. Furthermore, the construction process of HDPE pipeline appeared to be cost-efficient which merely accounted for 60-70% of typical pipe size steel construction cost (Wedgner, 2015). In addition, the HDPE also offers low operational cost since there were almost no cost-related operational activities needed to date.

Regardless of this effective countermeasures, we are aware that the corrosion is still continuing on the steel section of the condensate pipeline. The corrosion problem on the downstream area and possible similar occurrence on the well casing are being studied to be solved. The corrosion experience in the upstream section of condensate pipeline has broadly opened the course of the problem. At the moment, several endeavours are being conducted as a new challenge to seek better solution for preventing the corrosion damage.

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