Lifetime Prediction of a Recirculating Geothermal Cooling Water Pipeline

Keith A. Lichti[1], Rolan P. Vera Cruz[2] and Melchor A. Ballestero[3]

[1]MPT Solutions, PO Box 31-310, Lower Hutt, New Zealand

[2]IMAT Professionals, 2/F Topy's Building, Industria corner Economia Streets, Bagumbayan, Libis, Quezon City 1110, Philippines

[3]National Power Corporation, MakBan Geothermal Power Plant Facilities, Sto. Tomas, Batangas, Philippines

k.lichti@matperf.com rolanvc@edsamail.com.ph

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ABSTRACT

A carbon steel recirculating cooling water pipeline in a geothermal power station experienced an increasing number of leaks after 17 years of operation. A risk based inspection internal and external survey of surface corrosion and remaining wall thickness measurements by Non-Destructive Ultrasonic Testing (UT) identified specific areas of continuing high risk of perforation while other areas exhibited low and acceptable rates of damage accumulation. A Life Cycle Analysis (LCA) approach was used to identify options for repair / replacement, comparing new coated steel vs. new stainless steel or relining of existing pipeline. Replacement with Type 316L stainless steel was the most economic option with a pay back period of 7 to 10 years for the additional capital investment.

1. INTRODUCTION

A Risk Based Inspection (RBI) of critical components at MakBan Geothermal Power Plant C Unit 6 was completed after 17 years of operation in 2001. The work was completed in three phases: Phase 1, paper based assessment that identified critical locations for inspection; Phase 2, condition inspection performed using prepared inspection test plans; and, Phase 3, review of options for optimal maintenance, inspection and operations activities in the future.

This paper describes the RBI work done on Hot-Side and Cold-Side recirculating cooling water (CW) pipelines and uses the RBI results to conduct a Life Cycle Analysis (LCA) of rehabilitation and replacement options for economic operation over the next 23 years.

The work was part of a New Zealand Ministry of Foreign Affairs and Trade Overseas Development Assistance, ASEAN-New Zealand Corrosion Project involving 10 ASEAN countries. In the Philippines a number of agencies banded together to develop skills in Life Cycle Analysis (LCA) and RBI with a focus on geothermal energy production facilities, Vera Cruz, et al, 2001.

National Power Corporation (NPC) and Philippine Council for Industry & Energy Research & Development (PCIERD) participated in the project, which used the MakBan Geothermal Power Station for the technology transfer demonstration project.

Materials Performance Technologies (MPT) of New Zealand provided technical assistance for the work programme.

MakBan Plant C, Units 5 or 6, being 17 years old, were identified as being suitable for life extension and the experience was expected to be applicable to both younger and older plant. The work was expected to provide local capability to undertake similar projects in the future.

Expected Outcomes
At the end of the project the demonstration plant was expected to have:

- Extended life before rehabilitation was required.
- Reduced risk of unexpected failure and therefore improved safety.
- Reduced number of failures as the end of life was approached.
- Opportunities for reduced maintenance.

1.1 RBI and LCA Methodology

AS/NZS 3788:2001 outlines procedures for Risk Management (RM) and Risk Based Inspection (RBI) of pressure equipment. The standard uses a phased approach to RBI that is equally applicable to steam plant (Lichti, 2001, and Lichti et al., 2003) and to ambient pressure plant subject to corrosion damage. The methods described were used for this work:

Phase 1: Plant Risk Assessment and Life Estimation
This phase is a computational activity based on available information and reports on the design, maintenance, failure history and operational envelope. The process includes review of physical and chemical processes, historical and present operational envelopes, maintenance, inspection and test results and an external inspection of the nominated plant. The aim is to identify material-environment combinations and damage mechanisms that allow a life prediction for critical, at-risk plant so as to prepare Inspection Test Plans (ITPs) for the Phase 2 Condition inspection.

Phase 2: Condition Inspection of At-Risk Components
Condition inspections are scheduled for normal periods of off-line access. In some instances, where the risk is high and access is critical, special shutdowns may need to be scheduled. The work includes vessel and pipeline inspections according to the prepared ITPs and survey for additional damage, using the new condition assessment data to revise predictions of remaining life. The end result is a plan for life extension activities and for on-going monitoring and future inspections.

Phase 3 Monitoring and Metallurgical Analysis
This phase of work is required to provide assurance that the established design, process and operation conditions on which the initial predictions, condition assessments and final predictions were based do not change outside the set limits for safe operation. The work provides specification and selection of monitoring activities and equipment, metallurgical assessments, revised damage models, testing

of materials and cost benefit analysis for life extension or refurbishment activities.

The LCA work was done using AS/NZS 4536:1999, which provides a methodology for Life Cycle Costing (LCC). The standard gives a process for LCC, identifies cost considerations and has worked examples in spreadsheet formats that can be readily adapted for new LCC applications.

2. RBI OF CW PIPELINES

MakBan Plant C Unit 6 was 17 years old and the Unit was said to have had a specified design life of 25 years. However the MakBan geothermal steam field is expected to have a life in excess of 40 years and there are economic advantages in extension of the operating life of the power plant equipment beyond the design life. The results of the RBI were used to help predict the remaining life of the critical plant components and to revise those predictions at each phase.

A key element in any RBI is the estimation of damage mechanisms and the likely locations for these. Braithwaite and Lichti, 1980, Lichti and Wilson, 1983, Lichti et al, 1993, have outlined damage mechanisms related to aging geothermal plants.

This paper focuses on Hot-Side CW and Cold-Side CW pipelines in the power station. Figure 1 shows a plant flow diagram for the CW pipelines. The Hot-Side CW distribution pipeline and risers are shown in Figure 2.
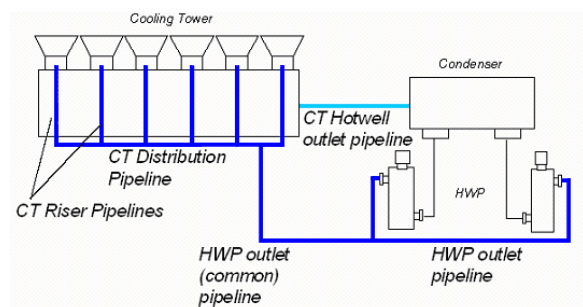

Figure 1: Hot-Side and Cold-Side CW circuit at MakBan Geothermal Power Station including Cooling Tower (CT) and Hot Well Pump (HWP).

Figure 2: MakBan Plant C Unit 6 cooling tower and Hot Side CW distribution and riser pipelines.

2.1 Phase 1 Historical Data Collection, Review and Analysis

Plant criticality assessment:
- The Hot Side CW and Cold Side CW pipelines (Figures 1 and 2) were identified as critical components for energy production as unexpected leaks contribute to loss of production and maintenance costs.

Material and environment
- The cooling water pipelines on this 17-year-old facility were made from plain carbon steel with internal polyethylene (PE) coating.
- The untreated Cooling Water had a pH of 3.5 to 4.0.
- The pH of the Cooling Water is adjusted to 6.5 to 7.5 by addition of NaOH.
- The temperature of the Hot-Side CW was 52°C.
- The temperature of the Cold-Side CW was 32°C.
- A proprietary zinc-based inhibitor was added on a batch basis.
- Two types of biocides were used alternately to control slime and bacteria build-up. Each was used once per week
- An anti-foaming agent was used as required in conjunction with the biocides.
- The treatment programme was monitored by measurement of pH (daily), by month long exposures of coupons for weight loss based corrosion rate determination, and bacterial counts (done 2 to 3 times per month).
- A potential-pH (Pourbaix) diagram was prepared to describe the corrosion chemistry, Iron sulfides and iron oxides were predicted to form. Typically, films found on carbon steels exposed to aerated condensates at low temperatures consist of non-protective sulfide and oxide phases as well as hydrated ferrous sulfates.

Damage mechanisms and life prediction
The damage mechanisms and corrosion rates for carbon steels exposed to recirculating geothermal cooling water at MakBan were predicted as follows:
- The principal damage mechanisms were expected to be erosion-corrosion of carbon steel in the aerated hydrogen sulfide containing condensate at locations where the PE coating had deteriorated, and accelerated atmospheric corrosion of the pipe surfaces in the vicinity of the fluid level of static fluids at shutdown when air was present.
- The corrosion rate of carbon steel exposed to untreated pH 3.5 to 4.0 MakBan Cooling Water was said to be on the order of 1 mm/year. In New Zealand, carbon steel corrosion rates in cold oxidizing (aerated) geothermal cooling waters are typically on the order of 1 mm/year even in low temperature (20°C) environments (Braithwaite and Lichti, 1980).
- The corrosion rate with inhibitor added to the CW, determined using corrosion coupons of bare carbon steel, was on the order of 0.38 mm/year.
- Perforations were known to have occurred. The pipelines being at low pressure and temperatures do not pose a major safety risk. The remaining life was thus expected to be determined by the frequency of leaks and the cost of these in lost production. .

Consequently, inspection was performed by visual examination of accessible areas of the pipeline internal and external surfaces and by UT measurement of remaining wall thickness. Areas having potential for erosion-corrosion and direct aeration on shutdown were specifically targeted.

2.2 Phase 2 Condition Inspection Results

Hot-Side CW – manhole access was provided on drained sections of the pipeline (refer to Figure 3). The CT Distribution Pipeline was accessible through a cutout section on the pipe wall (Figure 3, left photo). Preparations were also made for external UT measurements on the pipe.

Cold-Side CW - This pipeline was not accessible for internal inspection (see right photo in Figure 3) but wall thickness measurements were made from the outside by UT.

Visual Inspection of Hot-Side CW Pipeline

Visual inspection of the pipe internals of the Hot-Side CW pipeline showed that the original PE lining was no longer present in some portions of the pipe, most noticeably at the T-section of the pipe (junction between HWP Outlet Pipeline and CT Distribution Pipeline), shown in Figures 3 and 4. In these areas, only small patches of loosely adherent linings that could easily be removed by hand or by using a metal spatula remained. The steel substrate under these loose adherent linings showed less thickness loss than where it was exposed. Differences of up to 4 mm in thickness between the exposed and unexposed portions were observed. Erosion-corrosion was the main corrosion damage mechanism suggesting the inhibitor was unable to protect the exposed steel under turbulent conditions.

In those areas where the PE lining was still evident although no longer adherent to the substrate metal (e.g. Figure 4), significant protection from the corrosive cooling water was still provided to the underlying metal.

Figure 3: Locations for access to Hot-Side CW pipelines, at vertical T (at left photo), manhole to subsurface straight pipe section (at right photo). Cold-Side CW pipeline is seen at right of right photo.

Figure 4: Hot-Side CW loss of PE and erosion at T and retained PE in straight pipe.

The remnant PE linings could be easily dislodged by hand and underneath the lining, the substrate steel showed a smooth surface with uniform grey/black corrosion products over the metal surface. X-Ray diffraction of removed and dried corrosion product revealed these products included magnetite, hematite, and goethite as well as hydrated ferrous sulfate as expected for aerated geothermal condensates (see Table 1). These films appeared to have some protective ability, presumably with the benefit of the added inhibitor and shielding provided by the PE.

Table 1: X-Ray Diffraction analysis results for samples of corrosion product retrieved from Plant C Unit 6 Cooling Water Pipeline, DOST-ITDI, 2001.

Location	Plant C, Unit 6, Cooling Water, Hot-Side
Description As Collected	Thick Flakes of Grey / Black Corrosion Products
Description As Stored	Chunks, Brown on the Bottom, Broken for Analysis
Description At XRD	Flakes, Largest Piece Measuring 25x20x1mm, Yellow-Brown
XRD Results:	
Major	Magnetite, Hematite, Goethite
Trace	Iron II Sulfate Hydrate, Calcium Sulfate, Unknown

Magnetite (Fe_3O_4), Hematite (alpha Fe_2O_3), Goethite (alpha $FeO(OH)$ or $Fe_2O_3 \bullet H_2O$),. Iron II Sulfate Hydrate ($FeSO_4 \bullet 4H_2O$), Calcium Sulfate (alpha $CaSO_4$).

UT Thickness and Pitting Survey results

The results for the thickness survey for the Hot-Side and Cold-Side CW pipelines at the locations identified in Figure 5 are presented in Figures 6, 7 and 8 for the Hot-Side HWP Outlet Common Pipeline, the Hot-Side CW CT Distribution Pipeline and the Cold-Side CW Cooling Tower Cold Well Outlet Pipeline, respectively.
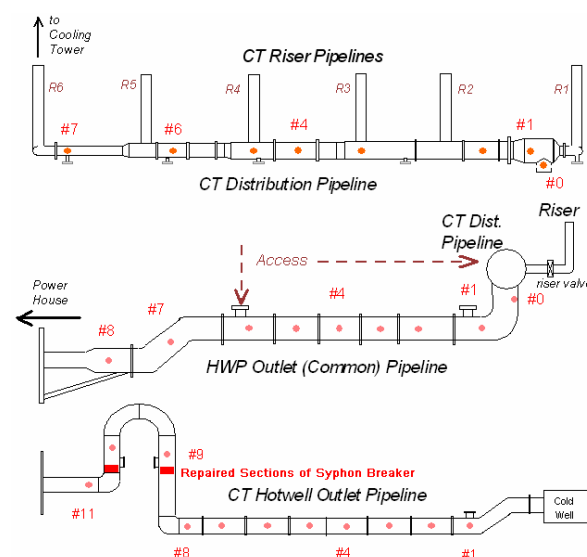

Figure 5: Locations for Hot-Side and Cold-Side CW wall thickness measurements.

The wall thickness data presented in Figures 6, 7 and 8, indicate:

- Hot-Side pipes are subjected to a more aggressive environment than the Cold-Side pipes.
- Accelerated thinning occurs preferentially at localized areas of the CW pipelines where the turbulence is high, such as pipe Ts, Ys and elbows.
- On the Hot-Side CW pipeline, the greatest loss of material due to erosion-corrosion was at the Hot-Side T-pipe section at the transition between the HWP Outlet Common Pipeline and the CT Distribution Pipeline - perforations have already occurred in the past and thickness values as low as 3mm were measured.
- The siphon breaker section of Unit 6 had been repaired by welding an outer shell over an area where perforation had occurred. Other regions of Cold-Side CW pipeline of Unit 6 that were measured show low risk of perforation from corrosion.

The data for the repaired siphon breaker area was complemented by the results obtained previously for Unit 5, Figure 9. That survey showed a high level of risk in the siphon breaker section of the CT Cold Well Outlet Pipeline around the standby water level where perforation and repairs had occurred in Unit 6.
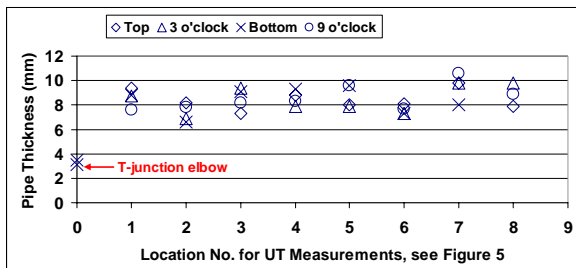

Figure 6: UT measurement results from HWP (Location 9) to T (Location 0) as given in Figure 5, July/01.
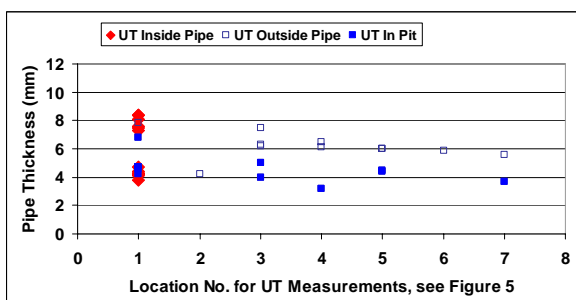

Figure 7: UT measurement results for Distribution Pipeline, taken from outside of smaller diameter pipe (Locations 2 to 7) and from outside and inside of section next to T (Location 1) as given in Figure 5, July/01. The inside measurements are at and beside areas of erosion-corrosion.
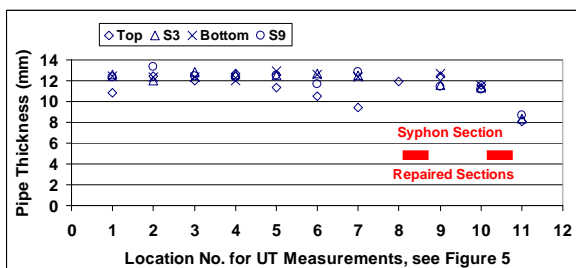

Figure 8: UT measurement results for Unit 6 Cold-Side CW, taken from outside for areas not repaired as given in Figure 5.
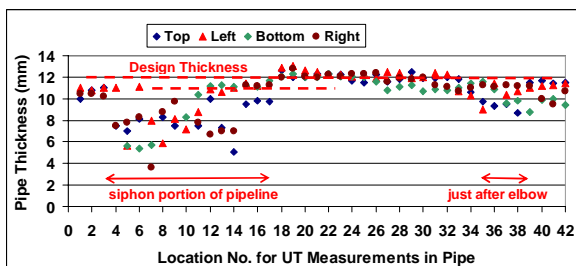

Figure 9: Results of a previous UT survey of Unit 5 Cold-Side CW pipeline completed in 1999. Note the order of locations is reversed from Figure 8.

Remaining Life Predictions

Table 2 gives a summary of the worst-case UT measurements in a number of areas in the Hot-Side CW pipeline that provide the basis for corrosion rate estimates for approximate determination of lifetime of the PE coating. The original pipe thickness values required for the rate estimations varied from 12 to 9 mm, Table 2. Original Thickness at UT points 0 and 1 on Figure 5 where perforation had been experienced was 12 mm.

End of life was taken as being when wall thickness reached 5 mm - a value that would allow repair before perforation.

Table 2: Corrosion rate (CR) calculations from UT measurements of wall thickness (Wall Th) performed on Cooling Tower (CT) distribution pipeline.

UT Location Figure 5	Original Wall Th	Measured Wall Th	Wall Loss	Actual CR	Target CR	Exposure Time	Time to End of Life (eg 4mm)	Years of PE Lining	Pit Wall Th	Ext Pit Depth
#	mm	mm	mm	mm/y	mm/y	years	years	years	mm	mm
2	11	4.2	6.8	0.40	0.38	17.8	0.5	0.0	none	none
3	11	6.3	4.7	0.28	0.38	12.3	6.0	4.7	5.0	1.3
3	11	6.2	4.8	0.28	0.38	12.6	5.8	4.4	4.0	2.2
4	11	6.5	4.5	0.26	0.38	11.8	6.6	5.2	3.2	3.3
5	11	6.0	5.0	0.29	0.38	13.1	5.2	3.9	4.4	1.6
6	10	6.0	4.0	0.24	0.38	10.5	5.2	6.5	none	none
7	9	5.6	3.4	0.20	0.38	8.9	4.2	8.1	3.7	1.9
The coupons have a target inhibitor Corrosion Rate of less than 0.38 mm/year.										
The PE lining retards the onset of corrosion depending on the pipe diameter and possibly flow rate.										

The calculations suggest that the PE lining provides up to 8 years of corrosion protection in some straight pipe sections and that section #2 is experiencing significant erosion corrosion, being beyond end of life (for the target remaining wall thickness). The number of perforations expected per year is also predicted to increase over previous years, making this pipeline a critical component in determining operating costs (through unplanned outages).

Table 2 also shows the extent of external corrosion due to under-film corrosion induced by acid rain. The amount of corrosion was not considered life limiting so long as perforation is not experienced, as repairing external corrosion pits presents a relatively simple maintenance job involving removal of corrosion product deposits and repainting. However, repair by welding would damage the PE lining and lead to accelerated internal corrosion.

Long sections of straight pipe were not considered to be at risk of failure over the next 5 to 10 years and retesting in 5 years was recommended. However, increasing perforations expected in the more turbulent areas prompted a programme of work for Life Cycle Analysis to consider repair and replacement options.

The LCA was constrained to identifying replacement options for the large diameter pipelines that were near end of life as it was considered uneconomic to replace all of the auxiliary CW carbon steel pipes to avoid the need for inhibitor. The adjustment of pH would still be required to avoid corrosion of auxiliary CW carbon steel pipelines and stainless steel pipelines. The latter from pitting corrosion in acidic thiosulfate containing solutions, Lichti et al, 1995, and accelerated deterioration of the wooden structural members of the cooling tower.

A similar argument can be applied to the Cold-Side CW pipeline with the main focus for targeted LCA of

replacement options being the siphon breaker area. The non-turbulent areas may have lifetimes in excess of 10 years.

2.3 Phase 3 Life Cycle Analysis

A simplified LCA comparison, was performed for available refurbishment options to determine the most economic repair / replace maintenance strategy for life extension of the pipeline to the minimum expected life of the steam field, a total life of 40 years, ie for another 23 years. The refurbishment options considered were:

Option 1- Total replacement in PE-lined Carbon Steel.
Option 2- Total replacement to Type 316L stainless steel.
Option 3- Paint coating after repair of damaged portions.

Methodology

Life cycle costs take into account all the relevant costs of a system over its entire lifetime, which includes both the direct and indirect costs. The following cost components were analyzed in the life cycle cost comparison of options for life extension of the Hot-Side CW pipeline:

- Initial Capital and Installation Costs.
- Operation.
- Maintenance (regular and otherwise).
- Lost production (due to unscheduled and scheduled shutdowns).
- Disposal Costs (such as Removal and Salvage).

Initial Capital and Installation Costs

The initial costs considered included design, delivery, purchase, installation, inspection, commissioning, and others (in the case of Options 1 & 3, the application of external coating). The breakdown of costs for each option is presented in Table 3.

Table 3: Initial Capital Costs breakdown for the life extension options considered (costs in PHP).

	Option 1	Option 2	Option 3
	PE-lined Carbon Steel	316L Stainless Steel	Repair & Recoat Existing
Design	6,000	6,000	76,500
Delivery	25,000	25,000	75,000
Purchase	1,000,000	3,000,000	200,000
Installation	28,000	58,000	220,000
Inspection	110,000	110,000	7,000
Commissioning	3,000	3,000	0
Others	375,000	0	375,000
TOTAL	**1,547,000**	**3,202,000**	**953,500**

Table 3 shows that Option 2 has the highest initial cost due mainly to the material cost for the Type 316L stainless steel, being more than twice that for Option 1. The lowest initial cost is that of Option 3.

Operation Costs

The operation costs included were mainly due to costs of corrosion control such as pH adjustment, use of inhibitor, biocides, anti-foaming agent, and staff monitoring costs for an assumed 52 man-days per year. It was assumed that the operations costs for the three options were all the same.

The replacement of Hot-Side CW pipes would not save on inhibitors and pH adjustment chemicals since carbon steel is still present in the auxiliary CW pipeline, and the Cold-Side CW pipeline if this was not refurbished. pH adjustment is necessary in order to prevent acid damage on the wooden structures of the Cooling Tower and pitting corrosion of the stainless steels used elsewhere in the plant, Lichti et al,

1995. The operation costs were still included in the calculations, although these do not influence the LCA result.

Maintenance Costs

For Option 1, maintenance costs were assumed to become significant from Year 11 and increase yearly by 30% in manpower and 10% in materials costs. The Year 11 manpower cost was equivalent to 6 man-days per year and 5% of the initial material cost. For Option 3, it was assumed that maintenance costs become significant from 5 years after application of coating and increase yearly by 30% in manpower and 10% in materials costs. The 5th year manpower cost was also equivalent to 6 man-days per year and 20% of the initial material (paint) cost. Option 2 was assumed to require no, or negligible, maintenance.

Lost Production Costs

The end of life of the PE-lined carbon steel pipe was taken to be after 17 years of operation. Just before the end of life an increase in the number of leaks experienced would be expected. In the LCA study, for Option 1, it was proposed that from Year 14 to Year 17 the scheduled shutdown to repair leaks and do maintenance would increase gradually from 24 hours to 40 hours. However, the unscheduled shutdown to repair leaks was assumed to increase exponentially from 3 days after Year 15. The lost production costs were derived by using the rated capacity of the plant and a kWh-rate of PHP1.70.

Option 2 was expected not to incur any lost production cost since stainless steel is assumed to be maintenance-free. Option 3, did not require a lost production cost as it was assumed that the maintenance would be done during scheduled shutdowns.

Disposal Costs

Disposal Costs, such as costs of removal and salvage value, were not given values in the calculations, since they are assumed negligible for the LCA duration of 40 years. Only Option 2 would have a significant salvage value.

Comparisons of Life Cycle Costs

The result of the life cycle cost analysis of the repair or life extension options for the Hot-Side CW pipeline is presented graphically in Figure 10. The inflation rate was assumed to be 6% per annum, and the interest rate on loans was assumed to be 12% per annum. Real costs based on the initial year, i.e. Year 0, were derived to calculate the life cycle costs presented in Figure 10.
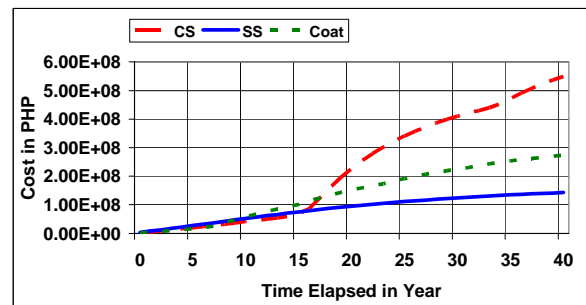

Figure 10. Life Cycle Cost analysis of life extension options for the Hot-Side CW pipeline.

The LCA study completed indicates that:
- Option 1, replacement using PE lined carbon steel offers initial advantages in the short term (less than 16 years). After that time replacement will again be required, or Option 3 will need to be initiated.

Lichti, Vera Cruz and Ballestero

- Option 1, loss of production costs rise sharply after 15 years and this scenario demonstrates the cost of not replacing the current pipe as leaks become more frequent.
- The cost of lost production with Option 1 greatly exceeds the cost of replacement, initial capital and installation costs, even using stainless steel.
- Option 2, replacement in 316L stainless steel, is the best option for life extension beyond 16 additional years of operation from the current year.
- Option 3, repair and recoating of the existing pipeline is the lowest initial cost but the highest ongoing cost and becomes uneconomic after only 7 years, when extensive repairs are again required.
- The payback period for recovery of additional capital cost for replacing with stainless steel rather than relining the existing pipe is 10 years. The payback period for recovery of additional capital cost for replacing with stainless steel rather than new PE lined carbon steel is 16 years.

3. CONCLUSIONS

A RBI was completed for MakBan Geothermal Power Station, Plant C Unit 6 Hot-Side and Cold-Side CW recirculating pipelines. The visual observations and UT results were used as input data for LCA of options for replacement and repair of at-risk sections of the pipelines.

Risk Based Inspection

The site-based RBI results are summarized as follows:

- The internal inspections of Hot-side and Cold-side carbon steel PE lined CW piping revealed that performance of the PE coatings was sensitive to local turbulence and temperature effects.
- The Hot Side CW, turbulent areas where the PE rapidly degraded subsequently experienced carbon steel erosion-corrosion and in some instances perforation occurred. These turbulent areas included T's, Y's and other areas where change in flow direction occurs.
- The PE coating on Cold Side CW carbon steel pipes provided better corrosion protection particularly in the straight pipe sections. The corrosion in the siphon breaker appeared to have been aggravated by the presence of a solution/air interface during shutdown promoting rapid local corrosion of the carbon steel surface.
- Externally, the coated Hot-Side CW pipe exposed to acid rain from the gas yard, experienced local under film corrosion in alternating wet/dry conditions, leading to formation of pits between 9 and 3 o'clock up to 3.5 mm deep.
- The CW piping in the critical areas of Ts and Ys as well as areas of direct aeration at shutdown were already experiencing perforation and leaks. A remaining life of 5 years to unacceptable leak rates and risk of pipe collapse was suggested.
- Straight pipe sections were assigned a longer lifetime of up to 10 years with recommended retest for confirmation in 5 years.

Life Cycle Analysis

A Life Cycle Costing was completed to identify the best repair / replacement strategy of the available options for a minimum additional 23 years of steam production:

- LCA suggested that replacement in Type 316L stainless steel was the best option for life extension beyond 16 additional years of operation from the current year.

- The payback period is on the order of 10 to 16 years for the initial increase in capital budget required for stainless steel over relining the existing pipe or replacement with coated carbon steel.
- Replacement in PE coated carbon steel was expected to experience repeated outages as seen with the original material selection within 16 years.
- Repair of the PE lining on the corroded pipe was the most costly option between 7 to 10 years, with repeated loss of production outages being again experienced before additional repairs and recoating activities are required.

4. ACKNOWLEDGEMENTS

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