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Gunung Salak Geothermal Power Plant Experience of Scaling/Deposit: Analysis, Root Cause and Prevention

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ABSTRACT

The INDONESIA POWER Gunung Salak Geothermal Power Plant had successfully upgraded their plant in 2005. This upgraded activity was expected to produce an extra 15 MWe of electricity power according to enhancement design calculations. However, problems occurred that resulted in de-rating after the enhancement project.

Based on the root cause analysis, one of the causes of the below optimal behavior was the conveyance of solid particles in the additional geothermal steam. Some of the solid particles were of types commonly observed in geothermal systems, such as silica. In addition to silica, results of laboratory tests showed that there was also a large amount of ferrous iron particles.

Further material testing by SEM and EDS showed that deposition of this material was not caused by turbine blade corrosion. Deposits were found in the shape of layers, and each layer had a different morphology and composition. This finding clearly shows that the turbine was not corroded. Instead, this condition happened as the result of steam-carried particles. The result of an XRD test indicated low scrubber efficiency, which is also indicated by the location of the deposit downstream of the scrubber.

Some preventative measures have been carried out in order to handle the effect of these ferrous iron particles. Monitoring the chloride content, modification of the steam strainer and future installation of a non-oxygenated turbine wash system hopefully will solve the problem of ferrous iron particles.

1. INTRODUCTION

Geothermal power plays an important role in the Java-Bali grid because it provides base load energy. Geothermal power plants contribute 5% of the power in the overall grid system, which has a demand of around 15,000 MWe. The Gunung Salak Power Plant is one of multiple geothermal features in the Java-Bali grid that supplies not less than 180 MWe. Since its first commercial operation in 1994, the Gunung Salak Power Plant provides reliable electricity (average of 98% EAF) at cheap energy prices and also with environmental friendly emissions.

The Gunung Salak geothermal area can be classified as a water-dominated steam field with a high content of Non Condensable Gas (NCG) and relatively low steam purity. In order to minimize problems, the Gunung Salak geothermal area is divided into two major locations, a west area and an east area. The difference between those areas is primarily the steam content. The west area has not only a small amount of NCG but also wet steam conditions. In contrast, the east area has a large NCG percentage and dry steam conditions.

These reservoir characteristics result in differences in the design of and operation conditions for the two areas. The west area was developed by PT. Indonesia Power and has a design based on 6.2 bars gauge pressure of steam (slightly superheated) and 0.83% NCG. These design requirements are fulfilled with 6-stages double flow and a double admission Ansaldo‘s turbine. A conventional gas removal system with 3-ejectors is used to improve the vacuum system. Based on the current steam supply, three units were built to supply 165 MWe.

In 2004, the electricity demand increased incrementally in the Java-Bali grid and created a need for additional electrical power. In order to solve the problem, the Gunung Salak Power Plant planned to increase the power generation capacity with some modifications. The idea was to improve the installed capacity by 5 MWe each without any major changes in overall systems. This was done by changing the first 2-stages to get more steam flow into the turbine and also enlarging the 3-ejectors capacities. The modification of turbine stages only involved a static blade (diaphragm) without any changes on a moving blade (rotor). The result was satisfying, as electrical output reached 60.4 MWe and 4.8 bar of gauge chest pressure.

After almost a year of operation within excellent performance, the plant had a problem of de-rating, especially for Unit 3. Power generation capacity decreased from 60 MWe to 58.5 MWe at the lowest.

2. MODIFICATION

Ansaldo proposed some modifications for the additional 5 MWe of generator output power. These modifications were:

2.1 Diaphragm Replacement

Diaphragm replacement had been done in the 1st and 2nd stages of the turbine; however, the rotor blade still used a 55 MWe design. The main goal of this replacement was to extend steam flow entering into the turbine. According to the formula

$$W = \dot{m} \cdot \Delta h \quad (1)$$

Where $\dot{m}$ is steam flow and Δh is differential enthalpy because of the turbine expansion process. Since no thermodynamic parameters such as pressure and temperature were changing, enthalpy of turbine inlet would have not change. However, more steam flow would result to more overall turbine work.

Physically, the turbine modification was performed by enlarging the diaphragm blade angle of attack from 5 deg into 7 deg. As a result, steam flow was raised to 30 T/h.

This diaphragm modification did not require any material change. The new turbine diaphragm used the same material type as the old one. Generally, turbine materials are as shown in Table 1.

Table 1: Gunung Salak turbine blade materials.

Rotary and stationary blade	DIN-X15Cr13 /ASTM A276-TP403	martensite stainless steel	Medium corrosion resistance
			Good wear resistance
			Scaling resistance up to 649°C
Rotary disk	DIN 28NiCrMo95 / ASTM A471 Cl 4	forged low alloy steel	Forged steel
			Intended use for rotor disk and wheel
Diaphragm disk	ASTM A668 CL B	-	Forged steel
			For general use

2.2 Gas Removing System

The gas removal system consisted of 3-ejectors with inter and after condenser. The gas removal system basically had two strings of ejectors that operated 1 x 100%. The difference between those strings of ejectors is the percentage of NCG that can be extracted, 0.53% and 0.3%.

Since its first commissioning in 1997, the operation of a single 0.53% NCG string could only reach 0.14 bar of condenser vacuum absolute pressure but not 0.09 bar. This problem was practically solved when the other string was being operated. Condenser vacuum absolute pressure could then reach the value of 0.11 bar.

During the up rating period, another 0.53% NCG string was installed to replace the 0.3% NCG string. This modification was believed expected to improve the gas removal system performance. However, the expected result was not achieved. The gas removal system had to operate with both of its strings to get 0.11 bar of absolute pressure.

2.3 Steam Supply Consideration

On the steam upstream side, as the consequence of additional generator power output, more steam supply will be needed. Therefore, some new wells were added: AWI 7.3 (5th June 2004), AWI 8.6 (23rd July 2004) and AWI 8.7 (15th March 2005). It was hoped that these additional wells could increase steam supply by as much as 30 T/h. In 2000, chemical composition analyses were conducted based on Standing Operation Procedure (SOP) and steam guidelines.

This additional steam supply would affect the capacity of main steam lines and equipment. To evaluate this issue, the separator and scrubber were studied. The result showed that steam flowed through the separator with 540 kph rate, which was under the separator's maximum rate capacity of 550 kph. The steam flowing through the scrubber would also increase to 990 kph and still be below its maximum rate capacity of 1300 kph. Based on these data, both capacities were suitable for 60 MWe.

3. FACT FINDING

3.1 Operation Data

The problem of de-rating did not happen immediately; it took about six months before the power generation capacity started to fall. In these six months of operation, some other parameters were changing as performance declined. These parameters were turbine chest pressure, steam mass flow, and condenser vacuum pressure.

Table 2 shows parameter conditions within operation period. The gray column is the period of turbine washing.

Steam inlet pressure flowed through the system with a gauge pressure 6.2 bar. This pressure dropped until it reached about 4.8 bar because of steam cleaning system and the effect of control valve. In the first month of operation, the gauge pressure condition shown was 4.8 bar. At this pressure level, it was assumed that there was no material blocking the steam flow.

The turbine chest gauge pressure then slowly increased to 5.3 bar and became 5.6 bar when the power generation output decreased to 58.5 MWe. This condition affected the turbine control valve opening to get more steam mass flow. During initial operation, the turbine control valve opened around 48% and 34%, which corresponds to 450 T/h of steam flow. Along with the pressure change, the control valve position increased to almost a fully open state (90%). Even so, steam mass flow fell down into 402 T/h. Such conditions surely affected turbine performance since it was affected by differential enthalpy and steam mass flow through the turbine.

A worsening condenser vacuum then accelerated this condition. The gas removal system operation was quite satisfactory until the problem of de-rating occurred. When the turbine condition was getting worse, the condenser vacuum absolute pressure also declined to 0.14 bar.

Table 2: Operation data expresses the condition of derating including turbine washing period.

Parameters	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Mar-05	Mar-05	Mar-05	Mar-05	Apr-05	May-05
Load (MW)	60.6	60.8	60.1	59.8	59.7	59.4	59.4	59.4	59.5	59.4	59.6	59.0	58.5
Chest Press. (barg)	4.50	5.30	5.30	5.35	5.40	5.40	5.65	5.60	5.50	5.50	5.50	5.70	5.60
CV 1 Pos. (%)	44.3	46.0	57.0	69.8	70.3	70.3	96.0	94.8	79.2	79.2	79.2	94.8	93.1
CV 2 Pos. (%)	36.3	38.8	48.2	58.2	58.9	58.9	95.0	94.0	71.7	71.7	71.7	94.0	91.3
Load Limit (%)	83.0	84.5	90.1	93.0	93.1	93.1	98.5	97.5	95.0	95.0	95.0	98.3	98.0
Cond. Press. (bara)	0.10	0.11	0.12	0.12	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.14	0.14
Steam Flow (T/h)	462	424	412	402	402	402	401	402	402	402	402	402	402
Steam Press. (barg)	6.07	6.04	5.97	5.92	6.00	6.00	6.19	6.19	6.21	6.20	6.20	6.20	6.15

This combination of problems raised the possibility that the steam was of bad quality. Based on experiences in the Kamojang Geothermal Power Plant, a change in turbine chest pressure that was followed by steam mass flow and condenser vacuum pressure decline indicated material deposition in the turbine. Deposition in the Kamojang's turbine was found to be in form of silica (Si) and could be easily washed away with a turbine washing system.

To solve this deposit issue, Ansaldo recommended turbine washing which employed condensate water from the condenser outlet. Turbine washing cleaned the deposit from the turbine by means of water injection into the steam line. It took 5 days to perform turbine washing, but the result was not satisfying. Turbine chest gauge pressure, control valve opening, and steam mass flow showed a slight change to 5.5 bar, 70% and 402 T/h, respectively. Unfortunately, power generation output did not change significantly. It only reached maximum 59.0 MWe before decreasing further to 58.5 MWe.

This condition lasted a while before the plant was downgraded again in May 2005. Power generation output reached 58 MWe before it was finally decided that an inspection needed to be conducted.

3.2 Root Cause Analysis (RCA)

The investigation team performed root cause analysis in order to find the main cause of de-rating. Figure 1 shows root cause analyses of unit de-rating. There were four possibilities that could make the unit decrease performance. The first factor was steam chest pressure change. This symptom could be caused by scale deposition and/or the fluctuation of steam pressure. Since the steam gauge pressure maintained in normal level over the operation period was (6.05 bar), the factor of fluctuation could be negligible. The other factor, scale deposition, could occur in the separator, scrubber and demister. However, to find if there was any relationship between the scale deposition issue and the steam chest pressure change, verification of laboratory material analysis was required.

The second factor was main steam flow decline. Operation data showed that the main steam flow declined from 460 to 402 T/h. Broken elements of the demister and a plugged strainer could cause such a decline. Doing visual inspection would detect this cause.

Condenser vacuum pressure decline could be another factor. The gas removal system and condenser performance affect the condenser vacuum pressure. The primary cause of decline in the gas removal system's performance could be the performance of the ejector, inter-condenser and after-condenser. Since its first operation, the capabilities of the gas removal system had never been tested. Therefore, the gas removal systems should be tested to see if the vacuum system is responsible for de-rating.

Generator performance could be one cause of de-rating, but operation data proved that generator was able to reach 60 MWe.

3.3 Inspection Period

On May 2005, de-rating problems were brought to an end by means of inspection. Overall inspection of the turbine and main steam line, including the demister and scrubber, was considered the best approach. The gas removal system and condenser were checked to ensure that they were clean of fouling and blocking materials.

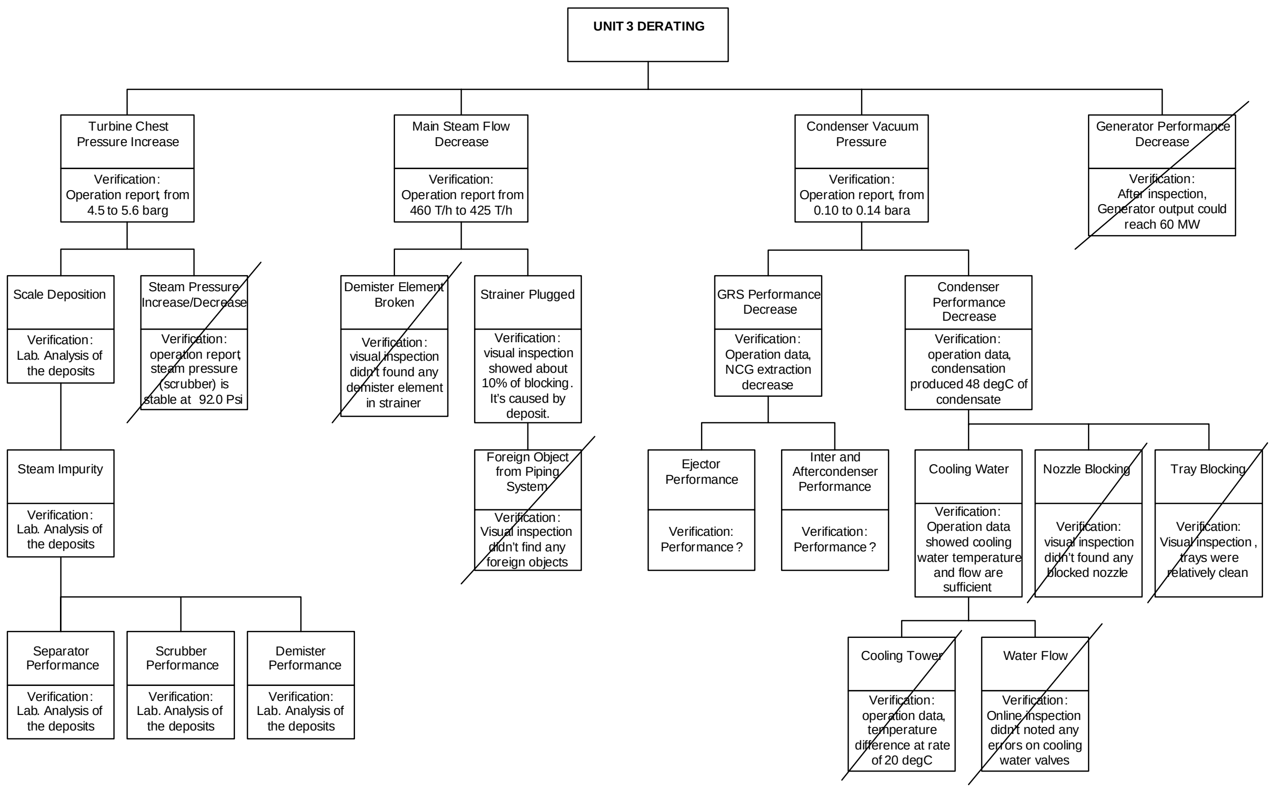

Figure 1: Root cause analyses of de-rating.

The result of inspection was quite shocking: the some thick deposit was found on the 1^{st} and 2^{nd} stages of the turbine leading and trailing edges. On the 2^{nd} and 3^{rd} stages of the turbine diaphragm (Figure 2 and 3), the thickness of the deposit reached 0.2 to 0.6 mm. The deposit also accumulated on the leading and trailing edges, but this accumulation was more uniform than in the 1^{st} stage. Different from those three stages, the 4^{th} stage of the turbine diaphragm had only a thin layer of material with 0.05 mm thickness. A clean turbine diaphragm surface was seen in the 5^{th} and 6^{th} stages. This was not unpredicted because the steam had a quite high water content in these stages and could trigger blade corrosion.

The cleaning methods of chisel chipping and fine grinding were used to remove the deposit from turbine blades. This technique caused a rough surface on the diaphragm blade, a condition that could disturb the steam flow dynamic. Careful visual inspection showed that there were no signs of corrosion on blade surfaces. This observation meant that there were no corrosion effects on the turbine material because of the turbine's interaction with steam.

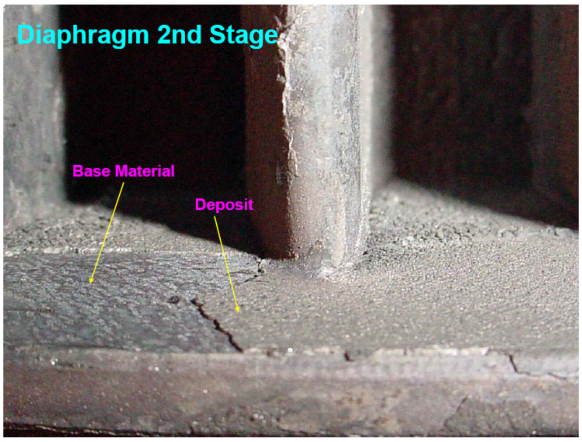

Figure 2: Deposit on 2^{nd} stage diaphragm.

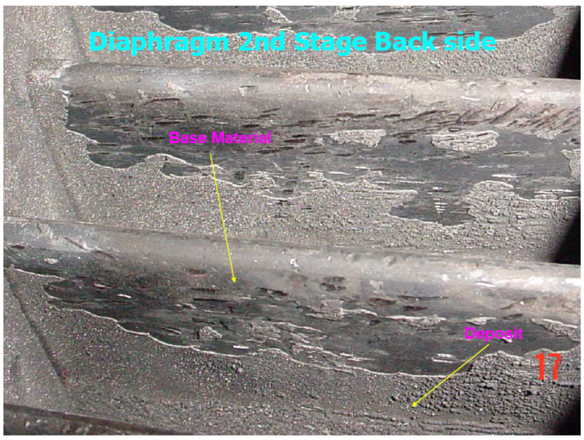

Figure 3: Deposit on the back side of 2^{nd} stage diaphragm.

Similar to the turbine diaphragm, the rotor blade experienced deposition problems in its first two stages. The deposit developed until it reached 1.1 – 1.8 mm thick. Figure 4 shows the condition of the 1^{st} stage rotor blade before cleaning. The deposit thickness was reduced to 0.5 – 0.7 mm on the 2^{nd} stage of rotor blade. The 1^{st} stage rotor diaphragm. The thickest deposit was on the 1^{st} stage with a thickness around 1.2 mm. The deposit was accumulated on blade had a thicker deposit than the 2^{nd} stage. This is normal because the 1^{st} stage interacts with steam flow with larger kinetic energy. On the 3^{rd} and 4^{th} stage rotor blades, a thin layer of deposit about 0.5 mm covered the blade uniformly. The clean shape of the 5^{th} and 6^{th} stage blades made the cleaning job easier. The cleaning job was done with chisel chipping and fine grinding as with the turbine diaphragm. Figure 5 shows the overall condition of 1^{st}, 2^{nd}, and 3^{rd} stage blades before cleaning. It is important to note that there were no signs of steam corrosion on turbine surfaces.

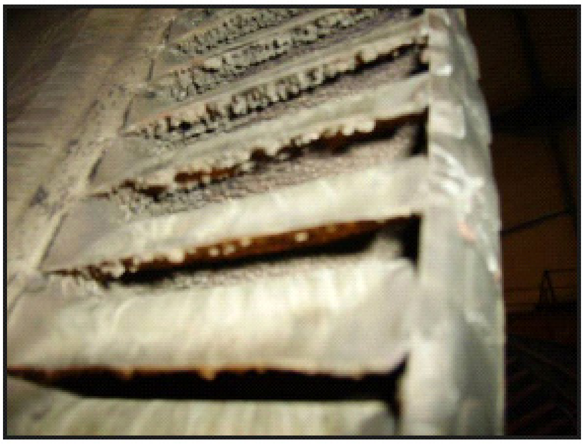

Figure 4: 1^{st} stage rotor blade before cleaning.

Figure 5: 1^{st}, 2^{nd} and 3^{rd} stage rotor blades before cleaning.

This deposit became the number one suspect for the cause of the de-rating problem. Further investigation was carried out to figured out the origin of the deposit. The first deposit origin suspected was the steam strainer. Figure 6 shows blocking deposits on the steam strainer. The steam strainer's main function is to filter out solid particles that are carried in the steam. The steam strainer has a cylindrical shape with mesh all over its surface. In the inspection period, a relatively thin deposit with size of 1 mm was found on the interior side of the strainer. This deposit caused around 10% blockage of the entire strainer surface. This blockage could affect the main steam flow's gradual decrease. Quite different from the interior side, the exterior side did not have such deposition and was considered clean.

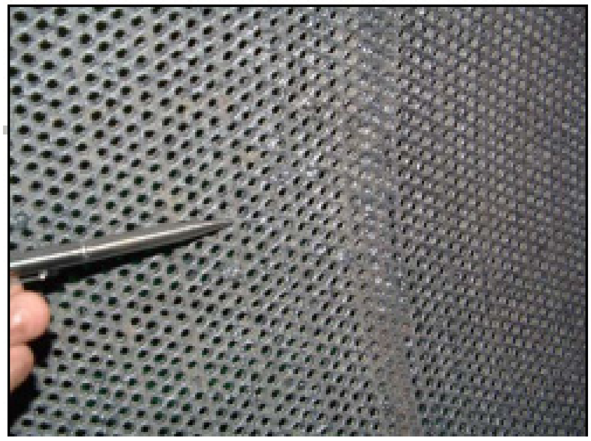

Figure 6: Steam strainer mesh with some blocking deposits on its interior side.

In addition to the steam strainer, the demister is a main piece of equipment in the steam line and so needed to be checked. The demister's purpose is to capture water that is in the steam. Steam flows through the demister's elements, and the resulting wet steam is depressed and water removed. Inspection found a large amount of material deposited in the areas of inlet, outlet, inner shell, bottom side and demister elements.

Figure 7: Demister top (steam outlet) deposit.

Figure 7 shows the deposit found in the top of the demister. The steam inlet side and inner shell had excessive deposit formation resulting in deposits that were around 4 mm thick. This part of the demister has an important role because it supports the centrifugal force of the steam. Centrifugal force is used to move heavy water particles in the steam to the outside. This water accelerates deposit formation. Beside the deposit, severe surface corrosion was found on the demister elements holder (Figure 8). However, there were no broken or plugged demister elements.

The upstream steam treatment equipment, the scrubber and separator, were also checked. The deposit found here was quite similar to that found in the demister. There was a large amount of deposited material on the inlet, outlet, inner shell, bottom side and internal element in both of these pieces of equipment. Figure 9 and 10 show the deposit on the scrubber and separator. The thickest deposit was on the bottom side and was about 3 – 4 mm.

Figure 8: Corrosion on demister elements holder damaged some demister elements.

Figure 9: Deposit on scrubber bottom.

Figure 10: Deposit on separator bottom.

4. MATERIAL TESTING

The material deposited in the steam line needed to be tested to figure out its source and to solve the problem. The material testing used samples of deposits from most of the equipment. Figure 11 shows a flow diagram of where samples were located.

The aim of material testing was to find out the morphology and composition of deposits, as this information could help determine if the problem was the result of corrosion or steam-carried material. The laboratory proposed three kinds of material testing:

- Scanning Electron Microscopy (SEM) was used to evaluate the morphology or structure of the deposit. This test also imaged layering in deposits.
- Energy Dispersive Spectroscopy (EDS) was used to analyze the composition of deposited material.
- X-Ray Diffractometry (XRD) was employed to quantitatively analyze the compounds in the deposited material.

Table 3 shows the compounds found in deposits. The laboratory compiled and analyzed the material testing results from all equipment.

Table 3: Deposit compounds from all equipment.

	1st Stage			2nd Stage			3rd Stage		
	Bot	Mid	Top	Bot	Mid	Top	Bot	Mid	Top
C	1.4	-	3.1	9.6	2.7	7.5	4.8	3.5	15.2
O	5.6	6.2	6.5	6.7	3.1	5.6	3.1	4.2	8.3
S	23.1	25.4	26.0	26.9	27.9	26.1	29.7	30.5	26.8
Fe	68.9	68.5	64.0	50.8	66.3	55.0	56.0	61.8	49.6

4.1 1st and 2nd Stage Rotor Blade

SEM and EDS showed that the deposit consisted of layers. There were three layers: bottom, middle and top, as ordered from the base of the material. The morphology of the deposits that stuck directly to the turbine blade surface was different from the above layers. The deposit stuck on the blade surface was thick (width 400 microns) and contained soft particles. On the middle layer, the deposit had cavities and a more angular form (width 500 microns). The result indicated that deposit deposition on the blade surface would degrade during times of operation.

The EDS results (Table 4) also showed differences in deposit type and composition between deposits stuck on the blade and the outer layers. It was quite remarkable that the element with highest content in the deposit was iron (Fe). The iron (Fe) content in the 1st stage changed from 58.14% in the bottom to 1.28% in the middle and 54.80% in the top. On the 2nd stage rotor blade, the deposit contained 47.64% iron in the bottom to 59.07% in the middle and 64.43% in the top. In deposits at all of these stages, there was no elemental carbon (C) in the middle layer. These layer transformations were caused by different particle chemical composition and morphology.

The XRD results showed that Fe_7S_8, $CaSO_4$ and $Fe_{0.957}O$ were the three dominant chemical materials in the 1st and 2nd stages.

Table 4: EDS results of 1st and 2nd stage rotor blade.

	1st Stage			2nd Stage		
	Bot	Mid	Top	Bot	Mid	Top
C	3.71	-	10.52	20.89	-	2.97
O	6.91	4.98	10.00	7.69	6.09	13.43
S	31.24	33.74	22.51	23.77	34.84	8.39
Fe	58.14	61.28	54.80	47.65	59.07	62.43

4.2 1st, 2nd, and 3rd Stage Diaphragm Blade

With respect to grain size, there was no difference between deposits stuck directly on the turbine blade and later deposits. However, deposit morphology showed that the bottom layer was thicker than the middle layer. The middle layer consisted of cavities rather than a solid. These cavities are an indication of the deposition phenomenon on the blade.

The EDS results (Table 5) showed differences between type and element percentage in all deposit layers. Carbon (C), oxygen (O), sulfur (S) and iron (Fe) were considered as the dominant elements in the deposit. In each stage, more than half of the deposit was iron (Fe), based on elemental composition, especially in the middle layer. The highest iron (Fe) element was in the 1st stage in the bottom (68.93%) and the lowest was in 3rd stage on the top (49.64%). There is a slight difference between the 1st, 2nd and 3rd stages in that there was no carbon (C) on 1st stage.

According to the XRD test, Fe_7S_8, FeS and SiO_2 were the dominant chemical compounds occurring in the 1st, 2nd and 3rd stages.

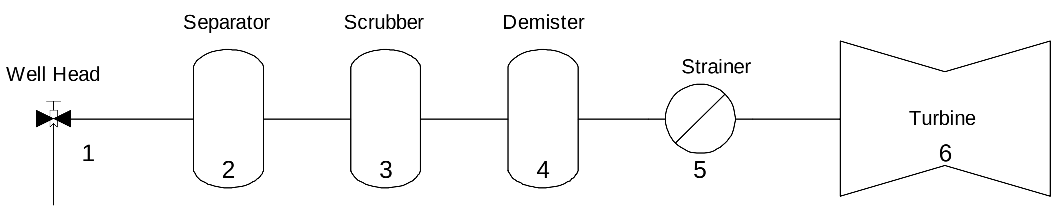

Figure 11: Main steam flow system for material testing samples.

Table 5: EDS results of 1st, 2nd, and 3rd Stage Diaphragm Blade.

	NaCl	SiO_2	Fe_3O_4	FeO	$FeCO_3$	FeS	FeS_2	Fe_7S_8	$CaSO_4$	$Fe_3(PO_4).H_2O$
Separator	√	√			√					
Bottom Scrubber		√	√							
Down Stream Scrubber			√				√			
Demister			√							√
Steam Strainer									√	
1st Stage Dia. Blade		√				√		√		
1st Stage Rotor Blade		√		√				√	√	

4.3 Steam Strainer

From its morphology, the deposit in the steam strainer could be classified into:

- Smooth particles on the strainer surfaces.
- Deposits in the form of plaques and particle unification.
- Combination of smooth particle and plaque deposit.

This shows that many different forms and parameters controlled the deposition phenomenon that occurred on the blade.

The EDS (Table 6) results indicated that the oxygen (O) in the deposits dominantly occurred in the steam strainer deposit (41.19%). The most important thing was that only a small amount of iron (Fe) element was stuck on the strainer. This meant that the Fe was not strained in the steam strainer and potentially brought into the turbine, where it in the end formed deposits. An XRD test reflected $CaSO_4$ in the steam strainer deposit.

Table 6: EDS result of steam strainer deposit.

C	O	S	Ca	Fe
4.35	41.19	21.42	28.10	3.98

Table 7: EDS result of demister deposit.

O	S	V	Fe
16.61	2.52	0.13	80.74

4.4 Demister

Observation of deposit morphology showed that the deposit contained many grain forms, such as rough particles and strait and long ligaments. Similar to the steam strainer deposit, the deposition phenomenon occurring in the demister was controlled by many kinds of factors.

EDS (Table 7) analyses showed that iron (Fe) is the most common element in the deposit (80.74%). XRD showed that Fe_3O_4, $Fe_3(PO_4).H_2O$ and SiO_2 were present in the demister deposit.

4.5 Scrubber

The deposit in the scrubber consisted of layers with different morphology and elemental compositions. The deposit on the bottom layer (with a width of 150 micron) consisted of smooth particles and a thick and brittle sub layer that had visible fracture cleavage surfaces. On the top, the deposit was 600 microns thick and was thicker and had more hollow space than the other two layers. It showed that the deposit deposition phenomenon would degrade the scrubber within time of normal operation.

EDS (Table 8) found that iron (Fe) was the most common element in the deposit (78.29%). XRD indicated Fe_3O_4 and FeS_2 compounds in the deposit.

Table 8: EDS result of scrubber deposit.

	Bot	Mid	Top
C	7.52	2.28	4.04
O	2.54	19.11	12.17
S	37.16	-	18.55
Fe	52.44	78.29	54.56

4.6 Separator

The deposit morphology in the separator showed that through the thick part solid layers and hollow space occurred by turns. This condition also indicated that deposit deposition was controlled by some parameter that varied temporally. There was always the possibility of particles with different type and morphology being carried out by steam and deposited in the separator downstream.

Results from EDS (Table 9) showed that the separator deposit contained carbon (C), oxygen (O), and aluminum (Al). Iron (Fe) occurred if carbon (C) was not present. The XRD result showed that SiO_2, NaCl and $FeCO_3$ were the dominant compounds in the deposits in the separator.

Table 9: EDS result of separator deposit.

	Bot	Mid	Top
C	9.72	-	8.58
O	43.31	43.84	35.05
Al	6.17	6.98	8.39
Si	35.22	38.72	37.50
Fe	-	2.77	-

5. MATERIAL ANALYSIS

5.1 Well Head

Steam composition was tested using condensed steam. For testing, the laboratory used Atomic Absorption Spectroscopy (AAS) and methods found in the Standard Methods for the Examination of Waste and Wastewater (SMEWW), 20th edition, and the Indonesian National Standard (SNI). The results indicated that steam from AWI 10.3 had the highest sulfide content (15.89 ppm) but that it lacked iron (Fe). A generator output of 60 MWe needs a steam supply of around 450 T/h. To fulfill this demand, steam supply from some additional wells joined the system in the separator. The test from AWI 10.3 is not representative of overall steam conditions. Therefore, the downstream system would be valid and accurate.

Table 10: Steam composition in major equipment

Samples	pH	TS	Chloride, Cl	Sulfide	Iron, Fe	Sodium, Na
		ppm	ppm	Ppm	ppm	Ppm
Well AWI 10-3	4.74	0	3.47	15.89	0	0.09
Separator	4.54	4	4.95	11.51	0	0.16
Down Stream Scrubber	4.46	18	14.85	0.16	0.047	33.58
Down Stream Demister	4.60	26	14.85	0.25	0.047	18.89

Table 10 shows steam compositions in the steam line. From these results, the two major elements carried by steam were chloride (14.85 ppm) and sodium (33.58 ppm). The steam condition indicated there was almost no iron (Fe) content in the steam. Therefore, wells could not be assumed as the source of iron (Fe) content in the deposit.

5.2 Turbine Blade

5.2.1 Visual inspection

The focus of visual inspection was the turbine rotor blade and diaphragm. Compared with conditions observed during the first year inspection, there were no features indicative of corrosion on the rotor blade and diaphragm. Marks observed on the blade surface were caused by mechanical cleaning, namely chisel chipping and fine grinding. However, these marks did not show signs of pitting corrosion or even general corrosion.

5.2.2 SEM and EDS

SEM showed that the deposit was in the form of layers. Figure 12 and 13 show SEM images from the 1st and 2nd stage rotor blades. These layers had quite different morphology and composition. It proved that the deposit is not a corrosion product. If it was a corrosion product, it would have the same morphology and composition. The most important information from EDS was that there was no indication of chrome element in the deposit.

Chrome is the main component of martensite stainless steel, the material of which the turbine blade was made. If the turbine blade had experienced corrosion, EDS would detect elemental chromium. The absence of chromium indicates that the deposit was not a corrosion product, but rather the result of deposition of steam-carried particles. Figures 14 through 16 give the SEM results on 1st, 2nd, and 3rd stage diaphragms.

5.2.3 Material to Corrosion

The turbine blade material could be classified as martensite stainless steel. In geothermal environments, the possible corrosion phenomena acting on this steel are Stress Corrosion Cracking (SCC), pitting corrosion, fatigue corrosion and corrosion erosion. The occurrence of general corrosion had little chance to act. The deposit on the turbine blade, if it was caused by corrosion, should come from general corrosion. The turbine blade material has very high resistance to general corrosion. Its corrosion rate is less than 30µm/year. This resistance is because of the formation of a chrome oxide passive film over the entire turbine blade surface and is the result of the chrome high content in the martensite steel.

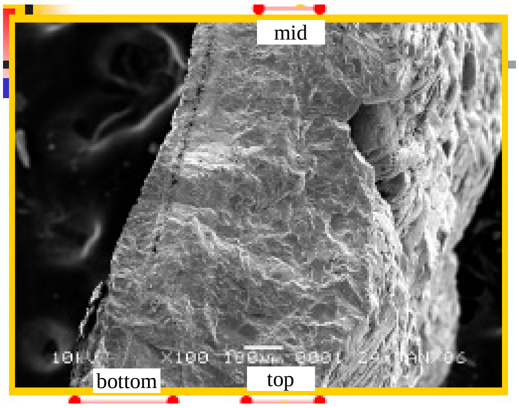

Figure 12: SEM result on 1st stage rotor blade.

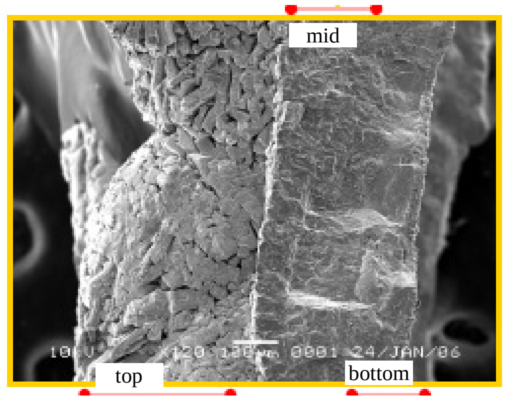

Figure 13: SEM result on 2nd stage rotor blade.

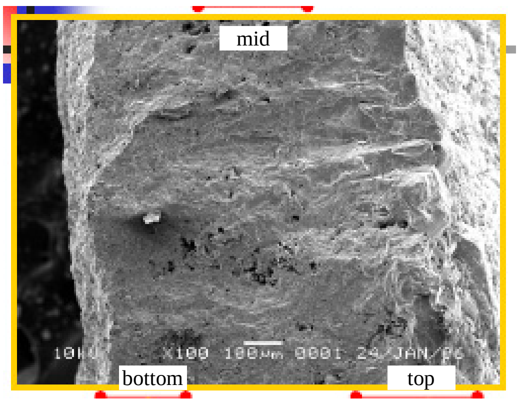

Figure 14: SEM result on 1st stage diaphragm.

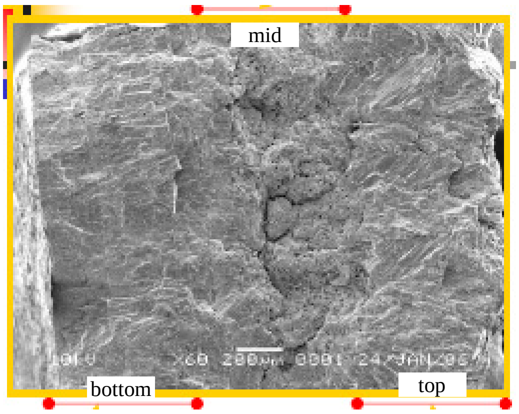

Figure 15: SEM result on 2nd stage diaphragm.

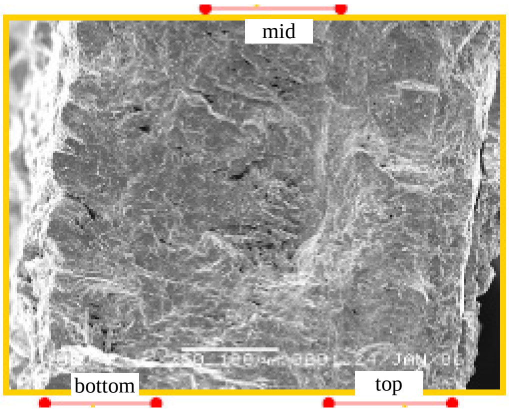

Figure 16: SEM result on 3rd stage diaphragm.

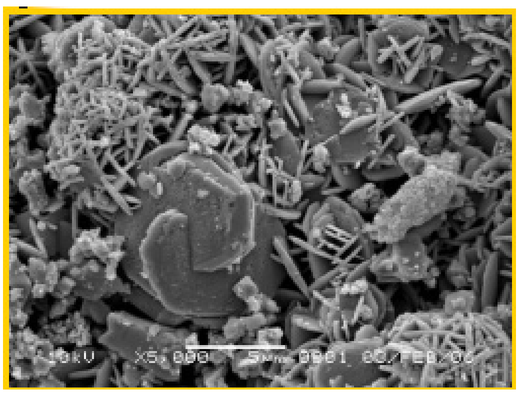

Figure 17: SEM result on demister deposit.

5.2.4 XRD

Particles with SiO_2 and $CaSO_4$ were deposited on the turbine blade. The deposit on the turbine blade also contained iron sulfide compounds (FeS, FeS_2 and Fe_7S_8). Iron sulfide compounds were the product of reaction between iron cations, which are abundant in all equipment and piping, and steam-carried O^- and S^- anions. Iron sulfide potentially forms a deposit on the turbine blade and ought to be filtered in the scrubber.

5.3 Demister

The analysis of downstream condensate composition showed a similar result with samples taken from downstream of the scrubber. Figure 17 is a SEM image of the demister deposit. This result indicates the main function of the demister. The demister did not extract any steam particles as the separator and scrubber did. EDS showed the same quantity of deposit types and elemental composition as deposits in the scrubber. XRD indicated no iron sulfide deposition since the demister deposit had only a little sulfur.

Demister performance was also analyzed. Demister performance should be analyzed based on the thermodynamic state of the steam. It should ensure that the steam is in a superheated conditioned. The Gunung Salak geothermal area, which is classified as wet steam reservoir, has thermodynamic conditions slightly above saturation. If the steam condition was less superheated or even saturated, it would affect the steam phase after the first stage expansion. Wetness of steam could be a trigger of material deposition.

5.4 Scrubber

5.4.1 Steam analysis

Condensate from steam taken downstream of the scrubber contained 33.58 ppm sodium, 14.85 ppm chloride, 18 ppm total solids, 0.16 ppm sulfide and 0.047 ppm iron. That the downstream condensate carried particles was proof of poor scrubber performance. These particles could form deposits in the plant downstream of the scrubber, including on the turbine blade. Based upon condensate composition in both units, Unit 3 had many more steam-carried particles that could cause deposit deposition than Unit 1.

5.4.2 SEM and EDS

In the scrubber deposit (Figure 18), morphology and chemical composition varied greatly between layers. The bottom layer and the next overlying later had different deposit types and elemental composition based upon EDS analyses. The result of this test indicated that the blade surface deposition constantly charged over operation time. This data corroborated the idea that low scrubber performance is responsible for deposit formation.

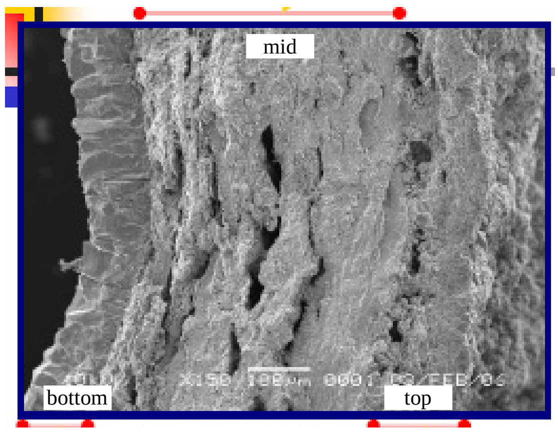

Figure 18: SEM result on scrubber deposit.

5.4.3 XRD

Particles with NaCl and $FeCO_3$ from the separator should be filtered very well in a scrubber. If the scrubber were effective, these compounds should not exist downstream of the scrubber. However, XRD detected deposits with an iron carbonate compound (Fe_3CO_4) downstream of the scrubber. As occurred on the turbine blade, the iron oxide compound was the product of reaction between iron, which is abundant in all equipment and piping, and steam-carried O^- and C^- anions. Iron oxide, which was supposed to be filtered in the scrubber, potentially formed a deposit on the turbine blade.

5.5 Separator

5.5.1 Steam Data

The data on condensate composition from the separator showed that the condensate had quite large sulfide and chloride contents, around 11.5 ppm and 4.59 ppm, respectively. The total solid and iron (Fe) levels were low, about 4 ppm and 0 ppm, respectively. However, this data does not represent the overall steam condition from production wells. The steam supply to the separator is from a complex combination of wells. Therefore, analyses of the steam composition upstream of the separator should not be used as representative of downstream steam conditions.

5.5.2 SEM and EDS

Deposit layering showed clearly that particles and deposit morphology changed over operation time. Figure 19 shows an SEM image of the separator deposit. If particles and chemical composition changed, separator deposition would be affected. An EDS test indicated that separator could work effectively to remove particles containing magnesium (Mg), potassium (K) and chloride (Cl). However, the separator was not effective at filtering out silica (Si), sodium (Na), calcium (Ca), and sulfur (S).

5.5.3 XRD

XRD showed the composition of deposits in the separator. Some of them were SiO2, NaCl and $FeCO_3$. It supported the results of EDS that indicated the separator was unable to effectively remove Si and Na.

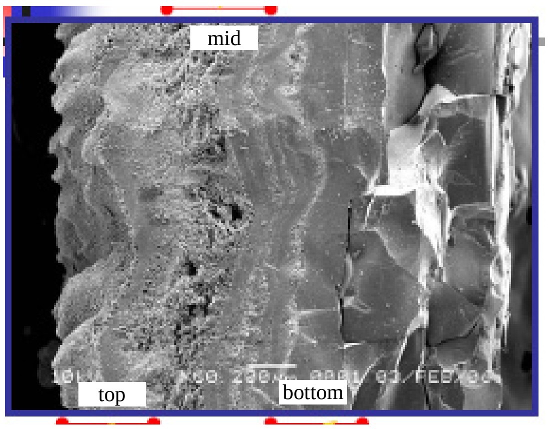

Figure 19: SEM result on separator deposit.

6. IMPROVEMENT

The problems of de-rating and deposit deposition have occurred for almost three years. Over these years, some improvement and alternative solutions have been tried.

6.1 Turbine Washing

After turbine washing failure in 2005, there were some changes in order to get a better result.

First considered condensate water purity. There is large difference between condensate water and pure treated water, as shown in Table 11. Condensate water has a high oxygen content. Oxygen will accelerate the process of deposit deposition on the turbine blade. Therefore, it would be better if the water had a low oxygen content. Nowadays, Chevron Geothermal Indonesia tries to improve their steam wash system by means of non-oxygenated water. This method has been used for almost a year. If examination shows that after this steam wash is effective and does not make the deposit upstream worse, it can be applied as a turbine washing fluid.

Table 11: Comparison of treated water with condensate water.

	condensate water	treated water
pH	5.66	8.05
DO	7.5	0.001
Cl_2	-	1.58

The second concern is about the water flow rate used in turbine washing. The condensate water flows through the main steam system with the capacity of 5 – 15%. Further analysis of water flow has to be done to determine the correct flow. If there is too much water, it will result in erosion of the turbine material.

6.2 Demister Improvement

The main improvement applied to the demister was the change of the holder material, which was corroded by steam. The original holder material was SS420 and 6 mm thick. Modification consisted of adjustment of holder thickness. It was changed to 8 mm thick without any material changes.

The result was quite satisfying. The demister element holder that experiences corrosion has decreased. Therefore, it assures that downstream of the demister is in a clean condition.

6.3 Steam Monitoring

In order to control the condition of the steam that enters the turbine, online monitoring of the steam is done for three main parameters.

First is NCG percentage. If it is at a high level, it will affect condenser performance. If the gas removal system cannot handle a NCG increase, the unit will de-rate. The second concern is the iron (Fe) level. Most deposits in the equipment contained detectable iron. Even though the steam from well AWI 10-3 has already been checked and is in good condition, it still has to be monitored. The last monitored parameter, is chloride (Cl^-) content. In addition to oxygen, increased chloride content in the steam will accelerate the problem of corrosion.

7. CONCLUSIONS

1. Unit 3 of the Gunung Salak Power Plant had experience de-rating of almost 2 MWe due to deposition of material in the equipment.

2. The deposit, consisting of mainly iron (Fe), was found in the main steam equipment, including the separator, scrubber, demister and on the turbine blades.

3. Material analysis (SEM, EDS and XRD) showed that the problem of deposit did not originate from corrosion. Instead, steam-carried particles were the main source of the deposited material.

4. Iron (Fe) particles came from all of the equipment and piping. Iron sulfide and iron oxide compounds were the product of reactions between iron cations and steam-carried O^- and S^- anions. Iron sulfide and iron oxide, potentially from a deposit on turbine blade, were suppose to be filtered in the scrubber.

5. Scrubber efficiency is very important for capturing solid particles. The result of bad scrubber performance can be deposit deposition on surfaces downstream of the scrubber.

6. Some major actions have been taken to improve performance, including the application of a non-oxygenated steam wash system, material improvement for the demister element holder and online steam monitoring.

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