MATERIAL DAMAGES IN GEOTHERMAL POWER PLANTS

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SUMMARY A survey of material damages has been carried out in Japanese geothermal power plants. The most frequent damage has been clear from the evaluation of the answers to questionnaire distributed in the power plants. And it has been shown how to estimate easily material corrosion rates by means of Cr–equivalent contribution of each element of materials, which were introduced from experimental corrosion data.

1. INTRODUCTION

As DeBerry et al.(1978) and Ellis et al.(1981, 1983) reported on several corrosive species in a geothermal environment, geothermal fluids contain H_2S, CO, and other gases as well as H^+, Cl^- and other ions, then materials of geothermal facilities are often damaged in various forms by these corrosive substances. In addition, the materials are damaged due to collisions with solid particles formed by precipitation of the dissolved substances from the fluids, and are also damaged by high temperatures as well as high pressures of the fluid.

First this paper deals with the evaluation of the answers to a questionnaire. The questionnaire was set out on the material failures of the geothermal facilities to the seven electric power generating companies who are engaged in geothermal power generation, and the twenty companies who have a concern in geothermal development.
Next the paper deals with a conventional method for evaluating corrosion rates of materials, which was derived by means of Cr–equivalent contribution of each element of materials.

2. MATERIAL FAILURES

Table 1 shows the chemical composition of geothermal fluids in the main geothermal power plants in Japan. According to the questionnaire, the outline of materials used currently is shown in Table 2. In case of wells and pipelines, carbon steels, stainless steels, low alloy steels and others occupies 67.7%, 24.3%, 2.7% and 5.3%,

Table 2. Materials used in the geothermal facilities (%).

	carbon steel	low alloy steel	stainless steel	others
(a)	67.7	2.7	24.3	5.3
(b)	37.1	56.1	–	6.8
(c)	21.5	4.3	33.3	40.9

*(a)Well and pipelne, (b)Drilling facility, (c)Well logging facility

respectively. In case of drilling facilities, low alloy steels and carbon steels occupies 56.1%, 37.1%, respectively, and stainless steels are not used almost. In case of well logging facilities, stainless steels, carbon steels, low alloy steels and others occupies 33.3%, 21.5%, 4.3% and 40.9%, respectively.

According to the questionnair, the outline of the material failures at the respective facilities are shown in Table 3, and their details in Table 4.

2.1 Facilities for well–production and transportation

Materials used In the group of mostly used carbon steels, they use J–55, K–55, N–80, P–105 of API for standardized well casing pipes, and also use SS41, STPG38, SB42 and SCPH2, etc of JIS for surface facilities. In the group of stainless steels, three types of austenitic steels such as SUS304, SCS13 and SUS316 are mostly used, which occupies 70.0% of the total stainless steels. Others are martensitic stainless steels of SUS403, SUS420J2, precipitation hardening stainless steels of SUS630, duplex steels, and heat–resisting casted steels of SHC–11. In the group of low alloy steels, they use C–75 for API–Well casing pipe, and Cr–Mo steel (SCM440) and Ni–CR–Mo steel (SNCM220) for turbine rotors.

Other than steels, FRP is used at the transportation pipes for medium and low temperature geothermal water less than 100°C, and concrete and wood are used at well head silencers and cooling towers. Cu and Cu alloys are used at electronics equipment.

Material damages Tables 4(a) shows the damages happened to wells and pipelines. The general corrosion is commonly caused in casing pipes and transportation pipes by

Table 3. Material failures(%).

	general corrosion	erosion–corrosion	crack	pitting	scaling	others	unknown
(a)	28.0	25.4	10.2	3.4	23.7	6.8	2.5
(b)	12.4	19.1	20.3	3.4	1.1	24.6	19.1
(c)	24.2	11.6	6.4	5.2	–	52.6	–

*(a)Well and pipelne, @)Drilling facility, (c)Well logging facility

Table 1. Composition of geothermal fluids in main geothermal plants in Japan.

Area		Composition of condensed rater and hot water (ppm)														Vapor and noncondensable gas (vol%)				
																Concentration		Composition of gases		
		pH	H_2S	T-CO_2	Cl^-	SO_4^{2-}	Na^+	K	Ca^{2+}	Mg	Fe	Al	SiO_2	B	As	Vapor	gas	H_2S	CO_2	R
Matsukawa	C. Water	5.35~5.61	104		0.3~0.71	0.30~3.9	0~0.01	0.01	0.01~0.32	0.02	0.01~0.20	0.01	0.7~0.76			99.4~99.63	0.37~0.57	1.19~15.1	82.6~85.5	2.3~2.6
		Vapor dominated																		
Otake	C. later	5.0—5.3	trace		I —								0~0.6			99.7—99.9	0.1~0.3	1.3~4.3	91.9—95.2	2.2~4.7
	H. later	7.7—8.6			110~1.810	17.7—172	693—1.100	123—142	21.0—73.3	0.01—0.29	0.01~4.2		495—683		1.1—3.0					
Onuma	C. Water	5.9—7.7	trace		1.85—3.70	1.65—4.94	10.0—27.0	0—0	0.88—1.28	0.10—0.78	0.08~0.37		0~5.0	32.0—56.0	0.004 0.007	99.9—99.97	0.03—0.07	9.54—16.03	39.1~82.00	5.4~51.28
	H. Water	7.3—7.9			454~536.6	145.3 203.3	341.5 407.5	51.5—55.5	7.54—11.06	4.04—7.83	0.10~0.27		395.0 412.0	116.0 145.0	9.81~12.81					
Onikobe	C. Water	3.3—5.5	0—398		0.3~8.4	5~17	0.1—6.0	0.1	1~1.8	0.5	0.02~1.00		0.02~1.70			99.3—99.94	0.06—0.69	20.4—35.70	54.2—76.33	3.21~23.04
	H. Water	3.3—9.6			37.6—8.370	15.3—492	850—2.600	170—230	24—1.310	4.8—9.7	0.15~180		91.5~730							
Hatchobaru	C. Water	4.3—4.7			0.03~5.0						0.10~0.46		0.02~4.0			99.8—99.9	0.1~0.2	1.3—9.1	51.8~94.0	1.3—13.2
	H. later	4.3—8.4			297~3.860	43.0—582	181~2.310	42~349	9.9~94.0	0.01—3.62	0.15~5.5		544—1.380		0.05~3.97					
Kakkonda	C. Water	5.86—	140.0		0.9	1.6	0.15	0.02	0.13	0.03	0.03—1.3	0.02	1.6~446			99.943	0.057—0.06	24.7—26.2	63.0—63.9	10.8~11.4
	H. Water	8.86—9.1	0—6.0		142~619	33.0—98.0	375—499	58.0	7.64—10.5	0.08	—1.3	0.02	126—446							
Mori	C. Water	5.51—6.09	13.0—39.4	623—1.416	0.1—1.1	0.3—4.217	—0.6	~0.14	0.1—0.2	0.02~0.2	~0.1	—0.04	—28		0.04	94.6—97.6	2.4~5.4	0.5~2.2	97.4—98.1	0.4—1.3
	H. Water	7.7—9.28	—9.3	181—352	4.080 7.070	0—651	2.640 4.710	361—837	3.4—190	0.1—2.4	0.2~0.78	—7.6	326—809		4.0 7.9					
Kirishima	C. Water	5.1	142				406	60								99.94	0.06	17.0	76.4	
	H. later																			

C. Water: Condensed later, H. Water: Hot later

Table 4. Material failure frequency.

(a) in wells and pipelines.

		C	E	EC	SCC	P	O	U	S	Total
1	Casing	3	1	1	2			1	2	10
2	Master valve	3	4	1			1		3	12
3	Silencer	3	4						1	8
4	Two phase flow pipeline	5	6	1						12
5	Wellhead separator	2	2	2					1	7
6	Hot water pipeline	4	1		1		1	1	4	12
7	Steam pipeline	2	2		1	3	1			9
8	Separator		1		1				2	4
9	Turbine		2		3		2	1	5	13
10	Cooler	2			1		2		2	7
11	Pump	3	1		1	1			2	8
12	Reinjection well								5	5
13	Reagent tube						1			1
14	Electrical device	3								3
15	Others	3	1		2				1	7
	Total	33	25	5	12	4	8	3	28	118

C: Corrosion. E: Erosion. EC: Erosion-corrosion. SCC: Stress corrosion cracking.
P: Pitting. O: Others. U: Unknown. S: Scaling

(b) in drilling facilities.

		C	E	EC	SCC	P	F	O	U	S	Total
1	Bit		2				1	8	1		12
2	Drilling collar	1	2		1	1	2	2	3		12
3	Stabilizer	1	2	1	2		3	3	2		14
4	Drilling pipe	3	1	3	2	1	3			1	14
5	Tool joint	1	3	1	1	1	1	2	2		12
6	Casing	1		1	1			3	2		8
7	Master valve								1		1
8	Wellhead device								1		1
9	Rotary machine	1					1	2	1		5
10	Mud separator	2						1	1		4
11	Mud pump			1				1	1		3
12	Mud piping								1		1
13	Others	1							1		2
	Total	11	10	7	7	3	11	22	17	1	89

(c) in well logging facilities.

		C	E	SCC	P	O				U	Total
						D	(V)	(LT)	Other		
1	Wire	6	5	4	2				5	1	23
2	Armored cable: conductor wire	4			1				4		9
	insulator					8			6		14
	outer wire	10	6	2	2				5		25
3	Winch								3		3
4	Sheave								3		3
5	Logging probe	3				3	4	3	3		16
6	Others								3		3
	Total	23	11	6	5	11	4	3	32	1	96

D: Degradation. (V): Damage due to vibration. (LT): Damage due to low teapetature acidic hot water. It occupies 28.0 percent of the total number of damages in wells and pipelines. The erosion–corrosion (25.4%) happens at the pipes for two phase flow which runs in high velocity, and also at the elbows and well head silencers where the flow direction and velocity turn abruptly with change of the cross–sectional area in its path.

There comes stress–corrosion cracking (10.2%) which happens to a coupling section (C–75) of casing pipes when used under H_2S and CO, existing environment. Stress cracking also happens to a stud of turbine–rotor wheel (CrMo steel) as well as the moving blade (13CrMo) where stress concentrations are easily to take place, the expansion bellows (SUS316L) of steam transportation pipes where the working stress is easily to remain, and the condenser gas extraction pipes (extra low carbon austenitic stainless steel) where the steam and the air are mixed together. Pitting (3.4%) happens to bellows (SUS316L) of steam transporting pipelines.

Meanwhile, there have some troubles caused by the deposition of scale. It was a big problem that the first stage moving blade of a turbine was broken when it contacted with the Scale deposited at the turbine nozzle. There have also been serious problems such as lowing the turbine efficiency due to the Scale deposition on turbine blades, and decreasing the capacity of production well or reinfection well as well as plugging hot water transportation pipes due to the scale deposition.

2.2 Drilling equipment

Materials used Low alloy steels are used in a large quantity for drilling equipment such as well casing materials (C–75, E–75 etc) and Cr–Mo–steels (SCM440, SAE4100). Carbon steels for machine structure use (S45C etc), carbon steels for pipeline use (SGP, STPG38), steel castings for high temperature and high pressure service (SCPH–2) are used for almost all structural materials of surface equipment such as well head equipment, rotary table machines and mud water piping, etc.

Besides, tungsten carbide is used for bit–cutters, stabilizer blades and tool joints. In this application, stainless steels are not so much used.

Material damages Tables 3 and 4(b) show the damages happened to drilling equipments. In both cases of air drilling and aerated mud drilling, damages are caused in drill pipes due to general corrosion (12.4%) and erosion–corrosion (19.1%). There have also cutting–off in screw sections due to fatigue, and breaking–down in pipes or wires due to stress corrosion cracking (20.3%). Besides, in bits, drill collars, stabilizers, tool joints and casing pipes, damages are caused due to erosion under a severe environment of a hard geological formation at a high temperature. In particular, it is a big problem that bit cones fall off because of the failure of friction–bearing bodies and bearing–lubricant seals.

2 3 Well logging equipment

Materials used Carbon steels for general structure (SS41) are used for winches and sheaves. High carbon steels for wire rods (SWRH) and stainless steels (SUS 304, SUS 316, 18 Cr–8Ni–1.5 Mo Steel) are used for sheath wires of armored cables and ordinal wires. Monnel, Inconnel, SUS 303, SUS420J2 and SS 41 are used for the body of well logging sonde. In addition, copper, and teflon and ceramics are used for lead wires and insulators, respectively.

Material damages Tables 3 and 4(c) show the damages happened to well logging equipments. In the case of logging wires and armored cables, there happens cutting–off of *strings* of wires due to acidic corrosion, due to their contacts with bore hole rocks, due to a twist in them while winding operations, or due to stress corrosion cracking, etc. There also happens breaking–down of teflon insulators of an armored cable due to a high temperature and a high pressure, and breaking–down of ceramics insulators due to hot water coming into inside them.

In many cases, corrosion damages of logging sonde can be avoided by using stainless steels, but there exist other problems such as collapses of a sonde body made of SUS420J2, SUS304 at a high temperature and a high pressure, failures of O–rings or connectors of sonde, and deterioration of electronic parts, etc.

2.4 Counter–measures to the material failures

When the material damages happened, various counter–measures were taken, which depended on the degree of importance of the equipment or facilities, and also the degree of damages. The outline of the counter–measures is shown in Table 5 for wells and pipelines, drilling facilities, and well logging facilities. In the table, "replacing" means the replacement of the damaged part with the same material as before, "exchanging" means the replacement with a higher quality material than that before, and "patching" means the repair of the damaged portion by any methods such as welding, etc.

Table 5. Counter–measures to the material failures (%).

	replacing	exchanging	patching	others
(a)	30.7	25.3	14.3	29.7
(b)	37.3	5.1	–	57.6
(c)	59.7	9.7	–	30.6

(c)Well logging facility

In case of the geothermal production and transportation equipment as shown in the table, exchanging for wells and pipelines occupies 25.3% which is higher than those of other facilities, (5.1% in case of "Drilling facility" and 9.7% in case of "Well logging facility"). This is due to the reason that it is relatively easy to detect the cause of damages for the facilities except for borehole casings. And it is possible to adopt higher–grade materials which make them economical in a long run. Also, the reason of higher percentage of patching in case of "Well and pipeline" in comparison with "Drilling facility" and "Well logging facility" is related to the good working conditions in the case of on–ground–surface facilities.

Further, some distinguished examples of up–grading of borehole casings can be seen in the up–grading of materials by the adoption of duplex stainless steels or the up–grading of structures modified from API round screw or API buttress screw to premium joint.

In case of drilling facilities, the percentages of exchanging and patching are very low. When rotating parts such as drill bits, drill pipes and stabilizers are damaged, it is coped not only with replacing by a new article, but also reducing working hours and other counter–measures belonging to "others" in the table such as attaching of rubber protectors in case of drill pipes. Thus, it is quite natural that the percentage of "other" has been increased.

In case of well logging facilities, the percentage of "replacing" is the most. This is due to the reason that logging wires or logging cables are to be inspected and replaced at every specific time of usage, not only when damages take place, but also even when damages have not taken place.

3. EVALUATION OF CORROSION DAMAGES

Laboratory tests and field tests were done to evaluate material resistances against a geothermal environment. At the tests, various materials are examined. They were carbon steels, low alloy steels, martensitic stainless steels, precipitation hardening stainless steels, ferritic stainless steels, duplex stainless steels, austenitic stainless steels, high Ni austenitic stainless steels, Ni–based alloys, Ti–based alloy and cast alloys.

Laboratory test Table 6 shows a representing result of autoclave corrosion tests at Cl^- concentrations of 10^3 ppm – 1.2×10^4 ppm. Table 7 shows an another result of the tests done in hydrochloric acidic solutions with saturated H_2S gas. From these results, it was found that as the temperature becomes higher and the volume of H_2S gas increases, the corrosion progresses increasingly and carbon steels and low alloy steels would become unavailable under such environments.

Field test Ikeuchi et al. (1982) reported that a high temperature–high velocity two phase flow testing installation was set up at Onikobe geothermal area as shown in Fig.1.

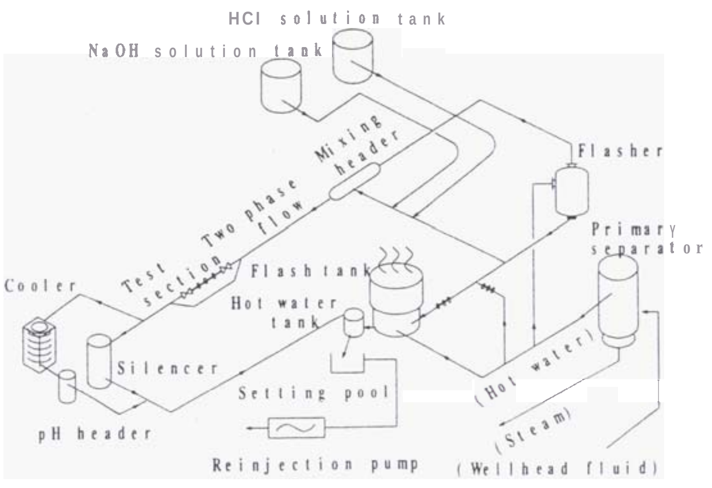

Figure 1. Schematic of GIRI–Tohoku testing installation at Onikobe geothermal area.

Using wellhead hot fluids, systematic experimental tests were carried out to evaluate material resistances against erosion–corrosion environments. Table 8 shows representing results of the test at temperatures 110°C – 137°C, flow velocities 80 – 100 m/s, pH = 2, 2.6, 3.2, 4.5.

It is found from Table 8 that conventional materials such as SS41 and STBA23 have a worry in use when the flow velocity is large, even at pH 4.5. When pH becomes down to 3.2 SUS430 and 630 system materials have a problem in use, too. And when pH becomes 2, higher grade materials fail to be available. According to the experiments conducted so far, it can be said that stainless steels equivalent to SUS 32951 are possible to be used with relatively low prices at pH 3–4.

Corrosion assessment diagram From these experimental results relationships between the corrosion rates of materials and the respective environmental factors have been obtained. By means of Cr–equivalent contribution of each element of materials introduced from the relationships, material corrosion rates can be easily described. The method of analysis is outlined briefly as follows.

As Kurata(1987) showed, it was assumed that a corrosion rate model satisfies the following equation.

$$CR = K \cdot EXP\{-(E_a / R \cdot T)\} \cdot (H^+)^n.$$

It is expressed in the form

$$\log(CR) = \log(K) - (0.434\ E_a) / (R \cdot T) + n \cdot \log(H^+) \quad (1)$$

where CR : corrosion rate (mm/y), E_a:activated energy, $\log(H^+)$:–pH, n:reaction degree of hydrogen ion, R:gas constant, T:temperature.

E, and n can be derived from regression analysis of the data of experiments. T and H^+ can be measured. On the other hand, K which is dependant on the material is proportional to the Cr–equivalent Cr_{eq} defied by equation (2), where the alloy elements of a material are formulated after being converted to Cr_{eq} and the contributions of other elements to corrosion resistant properties are expressed on a basis of Cr.

$$Cr_{eq} = (\%Cr) + b_1(\%Ni) + b_2(\%Mo) + b_3(\%Cu) \quad (2)$$

Therefore eq.(1) is conventionally expressed in the form

$$\log(CR) = A_0 + A_1(Cr_{eq}) + A_2(pH) + A_3(1/T) \quad (3)$$

where A, can be obtained by means of static treatments.

Based on this relation equation, a diagram can be drawn to evaluate the corrosion rate of a material under some geothermal environments which has never been experimented.

Figure 2 is a diagram showing the evaluation result of material damages drawn by eq.(3). By trying to forecast usable materials for the case of temperature 150°C and pH 2.0 which has never been experimented up to now based on this diagram, it was found that the usable material without any anxieties under such environments needs more than 45 wt% of Cr equivalent and just corresponds to Hastelloy

Table 6. Corrosion rates of materials in HCl solutions.

(mm/y)

Temp	150°C		200℃		2501'		300℃	
pH	2	4	2	4	2	4	2	4
Cl⁻ppm	30000	30000	30000	30000	30000	30000	30000	30000
J 55								
SM80S	4.022	2.494	4.258	0.476	10.729	2.272	3.489	5.579
STBA24	2.815	I. 231	1.611	0.406	6.379	2.082	3.149	3.592
STBA25	2.303	1.749	1.218	0.194	7.845	3.174	5.351	3.125
STBA26	I. 067	0.137	I. 030	0.458	3.409	0.774	5.646	0.632
MS13	0.820	0.607	0.809	0.319	2.743	1.054	I. 794	0.545
SUS630	0.136	0	I. 33	0.25	0.204	0.321	I. 59	0.20
SUS430			5.46	0.36		0.79	7.115	0.65
SUS329J1	0.675		0.636		0.041		0.3	
SUS329J2L		0.021	0.065	0.043		0.065	0.114	0.083
SUS304	0.882		0.8		0.269		3.65	
SUS316			0.043	0.040			0.213	0.568
SUS316L	0.103		0.430		0.072		3.20	
SUS310S								
Hastelloy-C276			0.007				0.072	
Inconel-600	0.165		0.542		0.357		0.654	
Ti-6AI-4V			0.314				0	

Table 7. Corrosion rates of materials in H_2SO_4 solutions saturated with H_2S.

(mm/y)

Temp	100℃		150℃		200°C		250℃		300℃					
pH	2		2		2		2		2		3		4	
Cl⁻ppm	1000	30000	1000	30000	1000	30000	1000	30000	1000	30000	1000	30000	1000	30000
J 55	3.14		20.39		38.69	16 21	48.19		41.05		6.50		5.49	
N 80	4.10		19.78		36.51	16.57	41.06		45.79		12.23		5.09	
SM80S	0.95		20.30		10 17	5.093	30.60		15.26	3.48	6.009		4.063	
STBA24	1.39		10 36		9.69	5.207	23.41		9.61	3.14	4.748		3.207	
STBA25	3.64	.	13.01		9.70	5.470	25.40		12.87	5.35	5.278		3.963	
STBA26	I. 22		17.12		6.16	2.439	22.35		8.88	5.64	4.680		0.800	
SUS444	-	1.488	-	2 18	2.26	5.486		8.16		5.67		4.906		4.580
SUS329J2L	0.005		0.483		0.717	0 134	0.526		0.151	0.114	0.081		0.023	
SUS304	0.455		1.38		0.755	I 575	2.75		4.25		3.01		1.83	
SUS316		0.499		2.14	1.055	2.458		2.74	0.243	2.96		1.447		0.348
MA800H		0.116		0.148	0.095	0.017		0.196		0.042		0.760		0.264
Hastelloy-C276		0.001		0.006	0.050	0.011		0.052		0.001		0.017		0.037

Table 8. Erosion–corrosion rates of materials experimented at Onikobe field test.

(mm/y)

Temp	110℃							
Flow rate	100m s				80m/s	80m/s	80m/s	80m/s
pH	2.0	2.6	3.2	4.5	2.0	2.6	3.2	4.5
SS-41	I32	72 I	4 6	0.28	706	I67	49.I	0.56
J-55	226	61.0	0 84	0.18	430	128	29.3	0.48
N-80	192	48 8	0 87	0.21	403	98.4	24.7	0.49
STBA23	I13	42.6	1.3	0.12	384	I20	40.4	0.39
STBA24	81.9	25 3	1.7	0.26	322	I34	31.0	0.34
STBA26	72.0	7 86	0 81	0.21	148	20.5	3.03	0 045
SUS630	42.8	51 I	0 054	0.004	30.4	0.055	0.034	0.013
MS13-2	0.039	0.01	0 0103	0.006	32.5	0.17	0.031	0.038
SUS430	204		0.537	0.017	118	53.8	0.305	0.019
SUS329J2L	I. 7		0.002			0.085	0.011	0.005
SUS304	36.1		0.003	0	142	0.686	0.010	0.004
SUS316	5.01		0.005		110	0 006	0.008	0.004
MA20Nb	0.709	0 002			35.0	0.007	0.007	0.004
Hastelloy-C276	0.0053				0.009	0.002	0.004	0.002

C276 or equivalent which is a high–grade Ni–base alloy, after being selected out of 86 kinds of steels used for the experiment.

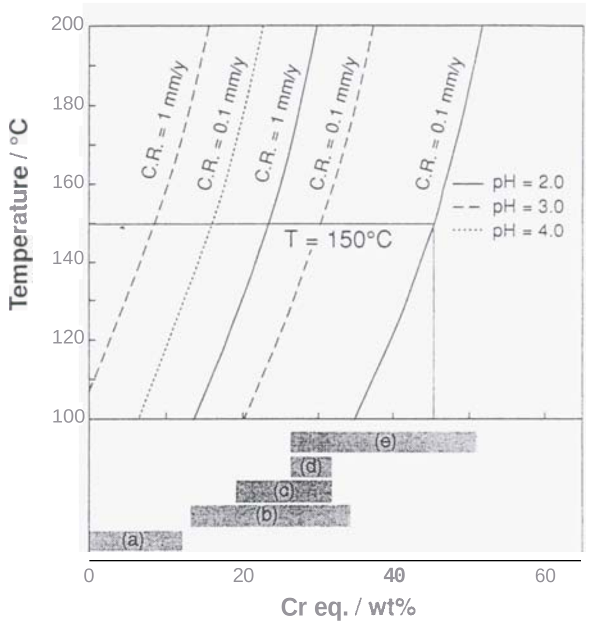

Figure 2. Corrosion assessment diagram of materials.
(a) carbon and low alloy steel,
(b) ferritic steel, (c) austenitic steel,
(d) duplex steel, (e) Ni–base alloy

4. CONCLUSIONS

(1) According to the answers to questionnaire set out on the material failures of the geothermal facilities, the most frequent damages are as follows: (a) In facilities for well productions and transportation pipelines, 53.4% of the total number of damages were due to general corrosion and erosion–corrosion. (b) In drilling equipment, 31.5% of the damages were due to general corrosion and erosion–corrosion. There were cutting–off in screw sections of drilling pipes due to fatigue, and breaking–down in pipes due to SCC(20.3%). (c) In well logging equipment, there were cutting–off of strings of wires due to acidic corrosion, friction with borehole rocks, SCC, etc.

(2) Cr–equivalent contribution of each element of materials was derived from experimental relationships between the corrosion rates of materials and the respective environmental factors. Then material corrosion rates can be easily described as $\log(CR) = A_o + A_1(Cr_{eq}) + A_2(pH) + A_3(1/T)$.

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