

CASING FAILURE IN GEOTHERMAL WELLS

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ABSTRACT:

Although the well's prognosticated temperature differentials and chemistry are incorporated in the casing string design, the statistics gathered from the different wells drilled indicate an increase in number of casing failures as compared to earlier geothermal drilling, i.e. 1976 - 1983. Aside from the source of the casings and cement, the only difference are: current wells are drilled with higher build-up rates (BUR) and with tighter/smaller target radius (TR) from 1.5°/100 ft BUR x 300m TR to 2.5°/30m BUR x 2Sm TR; and, larger diameter casings are utilized in most of the wells for production casing, i.e. from 9-5/8" OD to 13-3/8" OD.

Based on the study, as the diameter of the casing increases, failure due to mechanical wear and tear and axial stress greatly increases due to increase in drilling sideload and casing bending load from high dogleg severity factor, respectively. The cumulative effect of casing wear and tear and the axial stress from bending loads correspondingly reduces the casing's strength to withstand stresses from external pressures, tensile stress and axial thermal stress.

From the numerous corrective and preventive measures adopted, the most effective to prevent casing failure as tested in the different wells are: the tie-back system; increase in wall thickness of the inner casing specially for casings to be set within the casing-to-casing section; and, the proper placement of drill pipe / casing rubber protectors.

1.0 INTRODUCTION

Casing design of 316 wells (93 vertical / 223 directional) drilled covering period from 1976 to July 12, 1996 and occurrences of casing failure were correlated to existing studies relating casing failure to different factors. Statistics based on Table 1.1 indicates an increase in occurrence of casing failure with the bigger casing size; and, with increase in BUR and decrease in TR. There was an increase of casing failure occurrence for the period covering 1989 to July 1996. Majority of the twenty four (24) cases of production casing failures during said period are inside the anchor casing. The failures were classified into four (4) modes of failure which are failure

due to formation problems such as acidic formation or discharge, or external flow; failure due to poor quality of cementing job such as green cement or fluid entrapment, thermal casing failure during well discharge and quenching; and, failure due to mechanical wear and tear. The most common factor always present in all of the modes of failure is the failure due to mechanical wear and tear. Other factors, which also contributed to the increase in occurrence of casing failures are: 1) Increase in production casing size. The increase in the casing size lead to the increase in tooljoint sideload which correspondingly hastened

TABLE 1.1 - Well Statics for period covering 1976 to July 1996.

YEAR	NO. OF WELLS		NO. OF FAILURE*		BIG HOLES (Failures)	BUR, O/30m (TR, m)
	VERT'L	DIRECT'L	VERT'L	DIRECT'L		
1976-80	50	1	1	0		1.5
1981	15	11	2	1		1.5-2
1982	12	21	2	4		2 (300)
1983	4	26	1	3		2 (180-300)
1984	1	5	0	1		2-2.5 (150)
1985-87	0	7	0	2		2 (150)
1988	1	3	0	0		2.5 (150)
Sub Total	83	74	6	11		
1989	3	10	0	2		2-2.5 (30-150)
1990	0	13	0	0		1.75-2 (30-100)
1991	0	12	0	2		2-2.5 (30-100)
1992	0	15	0	2		2-2.5 (25-100)
1993	2	16	0	1	2 (0)	2-2.5 (50-100)
1994	5	39	2	7	5 (3)	2.5 (30-100)
1995	0	36	0	6	12 (5)	2-2.5 (20-100)
1996	0	8	0	2	7 (2)	2-2.5 (30-100)
Sub Total	10	149	2	22	26 (10)	
TOTAL	93	223	8	33		

*Wells with production casing failure located inside the anchor casing string

higher for larger casing sizes assuming equal tooljoint lateral load. Lowering of the sload is possible by adding more drill pipe rubber protectors or lowering drill string weight. The first option being preferred over the other for economics reason. Other factors can be varied but drilling cost and safety of the well should be put into proper balance.

WEAR EFFECT ON API CASING STRENGTHS

Most of the casing strengths are dependent on the casing thickness such as:

MODE	FORMULA	APPLICABLE (D/t) range
Elastic	$P_E = \frac{(46.95 \times 10^6)}{[(D/t)\{(D/t)-1\}^2]}$ Equation 2.3	$(D/t) \geq \frac{2+B/A}{3 B/A}$
Transition	$PT = [Y_p * F/(D/t)] - G$ Equation 2.4	$E_{min} \geq (D/t) \geq \frac{Y_p * (A - E)}{C + Y_p * (B - G)}$
Plastic	$PP = [Y_p * \{A/(D/t) - B\}] - C$ Equation 2.5	$T_{min} \geq (D/t) \geq \frac{\{[(A-2)^2 + 8(B+C/Y_p)]^{1/2} + (A-2)\}}{2*(B+C/Y_p)}$
Yield	$PYP = 2*Y_p * \{[(D/t) - 1]/(D/t)^2\}$ Equation 2.6	$P_{min} \geq (D/t)$

AXIAL STRESS EFFECT ON CASING STRENGTHS

Another factor affecting the baseline published strength of the casing are the stresses on the casing frozen when the string is cemented such as stresses due to the casing weight itself, buoyancy and bending. Although theoretical analysis has shown that axial tension has no effect on the elastic collapse mode but within the plastic collapse range follows the API reduced collapse formula, Equation 2.7, which is based on the Henckey-von Mises strain energy distortion theory of yielding.

$$\text{API Reduced Collapse Pressure Rating} = P_{ca} = \{[1 - 0.75 * (\sigma_A / Y_p)^2]^{1/2} - 0.5 * (\sigma_A / Y_p)\} * P_c \quad \text{Equation 2.7}$$

TABLE 2.7 : REDUCED COLLAPSE PRESSURE RATING

CASING SIZE, OD (Inches)					CASING SIZE, OD (Inches)				
9-5/8					13-3/8				
CASING WEIGHT, (ppf)					CASING WEIGHT, (ppf)				
47					68				
CASING GRADE					CASING GRADE				
K55					K55				
CROSS SECTIONAL AREA, inches ²					CROSS SECTIONAL AREA, inches ²				
13.572					19.446				
YIELD STRENGTH, Y _p (PSI)					YIELD STRENGTH, Y _p (PSI)				
55000					55000				
COLLAPSE PRESSURE RATING, P _{ca} (psi)					COLLAPSE PRESSURE RATING, P _{ca} (psi)				
3884					1950				
PIPE BODY TENSILE STRENGTH (kips)					PIPE BODY TENSILE STRENGTH (kips)				
746.48					1089.53				
TENSILE LOAD (kips)	TENSILE STRESS (psi)	(σ _A /Y _p)	DERATE FACTOR	REDUCED COLLAPSE PRESSURE RATING (psi)	TENSILE LOAD (kips)	TENSILE STRESS (psi)	(σ _A /Y _p)	DERATE FACTOR	REDUCED COLLAPSE PRESSURE RATING (psi)
0.00	0.00	0.00	1.00	3,884.00	0.00	0.00	0.00	1.00	1,950.00
37.32	2,750.00	0.05	0.97	3,783.26	53.48	2,750.00	0.05	0.97	1,899.42
74.65	5,500.00	0.10	0.95	3,675.21	106.95	5,500.00	0.10	0.95	1,845.17
149.29	11,000.00	0.20	0.88	3,436.90	213.91	11,000.00	0.20	0.88	1,725.53
223.94	16,500.00	0.3	0.82	3,166.02	320.88	16,500.00	0.30	0.82	1,590.54
298.58	22,000.00	0.40	0.74	2,866.71	427.81	22,000.00	0.40	0.74	1,439.26
373.23	27,500.00	0.50	0.65	2,528.89	534.77	27,500.00	0.50	0.65	1,270.21
447.88	33,000.00	0.60	0.55	2,153.29	641.72	33,000.00	0.60	0.55	1,081.08
522.52	38,500.00	0.70	0.45	1,729.54	748.67	38,500.00	0.70	0.45	868.33
597.17	44,000.00	0.80	0.32	1,247.19	855.62	44,000.00	0.80	0.32	628.16
671.81	49,500.00	0.90	0.18	685.52	962.58	49,500.00	0.90	0.18	344.17
746.46	55,000.00	1.00	0.00	0.00	1,089.53	55,000.00	1.00	0.00	0.00

Based on initial rating the collapse resistance of the 9-5/8" OD x 47 ppf x K55 casing is almost twice as much as the 13-3/8" OD x 68 ppf x K55 casing and with reference to the same stress or depth. Table 2.7. The initial collapse pressure rating, i.e. at no load condition, of the 13-3/8" OD x 68 ppf casing is equal to the reduced collapse pressure rating of the 9-5/8" OD x 47 ppf stressed approximately by 65% of its tensile load.

The highest reduction in the original casing strength due to axial stresses are within section of highest tensile stresses such as section of highest weight (top most section of the casing string) and bending load (high DLS sections or Build up sections). The bending load is expressed as follows:

BENDING LOAD (BL), lbs = 63 x DLS²/100ft x OD (inches) x CASING WEIGHT (ppf) Equation 2.8.

Table 2.8 is a tabulation of bending loads for the different casing sizes used with respect to DLS. With the same DLS, the bigger size is stressed more than the smaller casing, i.e. at 2.5 BUR/DLS the bending load stressing the 13-3/8" OD x 68 ppf casing is 13.4% of its tensile strength while the 9-5/8" OD x 47 ppf is only 9.5%. In terms of stresses the 13-3/8" OD x 68 ppf is stressed by 7367 psi while the 9-5/8" OD x 47 ppf is stressed by only 5250 psi.

CASING SIZE (inches)	18 5/8	13 3/8	13 3/8	13 3/8	9 5/8	9 5/8
CASING WEIGHT (lbs/ft)	87.50	72.00	66.00	54.50	47.00	43.00
DOGLEG SEVERITY, deg/100ft	BENDING LOAD (kips)					
0.50	51.34	30.33	28.85	22.96	14.25	13.04
1.00	102.67	60.67	57.30	45.92	28.50	26.07
1.50	154.01	91.00	85.95	68.88	42.75	39.11
2.00	205.34	121.34	114.60	91.85	57.00	52.15
2.50	256.68	151.67	143.25	114.81	71.25	65.19
3.00	308.01	182.01	171.90	137.77	85.50	78.22
3.50	359.35	212.34	200.54	160.73	99.75	91.26
4.00	410.68	242.68	229.19	183.69	114.00	104.30
4.50	462.02	273.01	257.34	206.65	128.25	117.33
5.00	513.35	303.35	286.49	229.62	142.50	130.37
5.50	564.69	333.68	315.14	252.58	156.75	143.41
6.00	616.02	364.01	343.79	275.54	171.00	156.44

Eased on both the reduced collapse pressure rating and the bending load, it can be readily seen that bigger size casing is more prone to collapse failure than smaller size casing.

3.0 THERMAL CASING FAILURE

All the thermal casing failures are first noticed either after discharge or quench operations, are at the tooljoint and with a corresponding decrease in casing diameter as tagged by an impression block. On three wells, casing failure occurred from 22m to shallower depths from surface. On these three instances, the cement at the shallow section of the well was disturbed by actions taken to centralized the production casing to the casing head flange (CHF) thus providing a free length; failure occurred in section where a high temperature differential existed during discharge; and, elongation was restricted due to the uncentralized production casing w/ respect to expansion spool or due to compacted cement at the CHF during expansion. On another well a free length was seen from CBL results indicating poor cemented annular column between sections of good cement column which provided for the free length and the good cemented column providing for the restriction to the elongation during the discharge of the well; and, also within a high temperature differential section. All of the casing failure that occurred during discharge are within the cool section of the well, i.e. above the water table where cool gas accumulated. On two occasions, casing failure occurred during quench at the hotter section of the well where the casing parted within a poorly cemented section.

Thermal stress occur in a system, or part of a system, when thermal displacement (expansion or contraction) which would otherwise freely occur are partially or completely restrained. Any temperature change, increase or decrease, induces stresses and deforms the pipe. Any temperature change, whether a temperature increase or decrease induces stresses and deforms the pipe. The amount of linear deformation δ_L is expressed by:

Linear Deformation $\delta_L = \alpha L (AT)$

Equation 3.0

where α is the coefficient of linear thermal expansion, usually expressed in units of inch per inch per degree of temperature change, 1.2×10^{-5} in/in - °C (1.2×10^{-5} m/m - °C, 6.9×10^{-6} in/in - °F); L is the free uncemented/ unsupported length, inches; and AT is the change in temperature, °C (°F).

If a deformation, due to change in temperature, is permitted to occur freely by use of expansion joints or spool, no load or stress is induced in the structure. Table 3.1 are the corresponding free length a 13-3/8" OD and 9-5/8" OD production casing string can tolerate without stressing the pipe due to the allowable deformation provided by the expansion spool. But in some cases it may not be feasible to permit these temperature deformations, i.e. exceeding expansion allowance provided by the expansion joint or spool; the result is an induced stress resisting the expansion or compression. The stresses caused by these internal forces are known as axial stresses due to temperature. Equating thermal deformation to the allowable stresses the pipe can endure is expressed by:

TABLE 3.1 : ALLOWABLE FREELNGTHwithout stressing the pipe.

ΔT T2 - T1 °C	CASING SIZE	
	13-3/8	9-5/8"
	ALLOWABLE FREE LENGTH (FL) -meters (converted) -	
100	423.33	317.50
125	338.67	254.00
150	282.22	211.67
175	241.90	181.43
200	211.67	158.75
225	188.15	141.11
250	169.33	127.00
275	153.94	115.45
300	141.11	105.83
325	130.26	97.69
350	120.95	90.71
375	112.89	84.67
400	105.83	79.38

ASSUMPTION δ = 20 inches, for big hole expansion spool
15 inches for regular hole expansion spool

TABLE 32 : MAXIMUM DIFFERENTIAL TEMPERATURE

CASING OD, inches	13-3/8"			9-5/8"		
	N/L80	K55	K55	N/L80	K55	K55
CASING GRADE	N/L80	K55	K55	N/L80	K55	K55
CASING WEIGHT, ppf	68	68	54.5	47	47	43.5
JOINT STRENGTH, psi	62240	42790	42240	67200	46200	44000
FREE LENGTH, meters	MAXIMUM TOLERABLE TEMPERATURE INCREASE, °C					
Without Free Expansion	178.85	122.95	121.38	193.10	132.76	126.44
100	602.16	546.27	544.69	510.59	450.24	443.92
150	461.06	405.17	403.59	404.76	344.41	338.09
200	390.51	334.62	333.04	351.85	291.50	285.18
250	348.18	292.28	290.70	320.10	259.75	253.43
300	319.95	264.06	262.48	298.93	238.59	232.26
350	299.80	243.91	242.33	283.81	223.47	217.15
400	284.68	228.79	227.21	272.47	212.13	205.81
450	272.92	217.03	215.45	263.66	203.31	196.99
500	263.51	207.62	206.04	256.60	196.26	189.93
550	255.87	199.93	198.35	250.83	190.48	184.16
600	249.40	193.51	191.93	246.02	185.87	179.35
650	243.98	188.08	186.50	241.96	181.60	175.28
700	239.32	183.43	181.85	238.46	178.11	171.79
750	235.28	179.40	177.82	235.43	175.09	168.77
800	231.76	175.87	174.29	232.78	172.44	166.12
850	228.65	172.76	171.18	230.45	170.11	163.79
900	225.89	169.99	168.41	228.38	168.03	161.71
950	223.41	167.52	165.94	226.52	166.18	159.86
1000	221.18	165.29	163.71	224.85	164.51	158.19
1050	219.17	163.28	161.69	223.34	163.00	156.67

$$a L (AT) = PL / AE = SL / E \text{ Equation 3.1}$$

The maximum stress a pipe can withstand prior failure is equal to allowable stresses from 6, allowable deformation as provided by the pipe property and δ_{allowance}, the length of allowable expansion as provide by the expansion spool and is expresses by Equation 3.2

$$\delta_t = \delta + \delta_{allowance} \text{ Equation 3.2}$$

Utilizing the pipe property in the design for thermal stresses is just appropriate and effectively the tolerance of a given free length of pipe to temperature change is increased. Table 3.2 shows the effect of combining pipe property and allowable expansion to the tolerable temperature. Included in the table is the temperature, without allowing expansion, to which the joint will be stressed to its maximum limits regardless of free length as derived from Equation 3.1. Karlsson 7/78 have indicated that "If the formation surrounding the casing in the well allows axial expansion of the stress free expansion the resulting maximum temperature will be higher."

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EFFECT OF PRE-TENSION

Due to high temperature changes in which the casing is exposed to, the strength of the casing is effectively reduced and the development of thermal stresses is taken into account. The neutral temperature of the casing is the temperature at which the casing is axially unstressed. The casing's neutral temperature, T_n, depends on two factors: well temperature, T_w, during the hydration period of the cement as it solidifies; and, axial stress, σ, in the casing due to its weight plus any mechanical tension applied at the well head or any point of interest and bending forces due to dogleg severity. The temperature increase that will release the axial stresses due to pretension is expressed by:

$$\Delta T_{\sigma} = \sigma / \alpha E \text{ Equation 3.3}$$

where: a = axial stress, psi
= Casing Weight, lbs + bending load lbs
Cross-sectional area of casing, square inch

Neutral Temperature is the sum of the formation temperature, temperature of cement during hydration and the equivalent temperature of the total axial stress in the pipe frozen by the cement computed from Equation 3.3.

$$T_n = T_f + T_c + \Delta T_\sigma \quad \text{Equation 3.4}$$

where: T_f = Temperature of formation prior cementing,
 T_c = temperature change of cement during hydration,
 i.e., 38°C (100°F) (Shryrock 1982)

If the temperature of the cemented casing differs from T_n , by ΔT , i.e. ($T_{FINAL} - T_n$), a thermal stress, σ_t , induced is $\sigma_t = \alpha L (\Delta T)$. The thermal stress is compressive if the casing final temperature is higher than the neutral temperature and tension if the casing temperature is lower. Based on the above equations, it can be concluded that pre-tensioning the casing increases the neutral temperature, thereby, effectively reducing the possible severity of change in temperature for any final temperature above the neutral temperature but posing as a disadvantage if cooling or

quenching of the well will be required. Table 3.4 shows the effect of pre-tension on wells with casing failure due to thermal stress. The free length on the said wells were very minimal, but due to the uncentralized casing, the expansion spool became useless and the expansion of the casing was restricted. The pre-tension is effectively released while centralizing the casing.

TABLE 3.4 : Effect of Pre-tension on wells with thermal casing failure.

WELL W E	302		306D		307D	
Depth of failure, m	18		17		22	
Formation Temperature @ point of failure, °C	40		40		60	
Temperature increase due to cement hydration, °C	38		38		38	
PRE-TENSION @ POINT OF FAILURE (lbs) 1>	0	250,000	0	310,000	0	325,000
DOGLEG SEVERITY, °/30m	0	0	0	0	0	0
CASING WEIGHT, lbs/ft	54.5	54.5	54.5	54.5	54.5	54.5
CASING OD, (inches)	13 3/8	13 3/8	13 3/8	13 3/8	13 3/8	13 3/8
DOGLEG SEVERITY, °/100ft	0.00	0.00	0.00	0.00	0.00	0.00
BENDING LOAD (lbs)	0	0	0	0	0	0
Equivalent Temp @ initial load T_e , °C = $\sigma / \alpha E$	0.00	46.26	0.00	57.38	0.00	60.14
$T_{NEUTRAL}$, °C	78.00	124.26	78.00	135.35	88.00	148.14
T_{MAX} , °C (Actual recorded)	270	270	285	275	270	270
ΔT , °C	192.00	14574	207.00	145.64	182.00	121.86
Thermal Stress, $\sigma_t = \alpha E \Delta T$, - psi	66.816	50.718	72.036	52.075	63.336	42.409
JOINT COMPRESSM STRENGTH, psi	42,240	42,240	42,240	42,240	42230	42,240
FAILURE FACTOR	1.58	1.20	1.71	1.23	1.50	1.00

For casing failure due to thermal stress to occur, three (3) conditions should be present as follows. free length; there is a considerable change in temperature; and, restriction to expansion or contraction of the free length.

4.0 TRAP FLUID FROM PRIMARY AND REMEDIAL CEMENTING JOB

There are two obvious sources of trap fluids noticed causing casing failures, e.g. over retardation of the cement slurry “green cement” and remedial top jobs due to losses during primary cementing operations. The trap fluid contributes to the free length and restriction to the deformation of the casing which are pre-conditions for thermal casing failure to occur. In addition to the thermal stress, elevated pressures generated from the expansion of the trapped fluid between the anchor and production casing during heat-up of the well causes severe loads leading to the failure by way of collapse in the production casing. Collapse of the production casing located in the open hole section seldom occurs for the formation is bound to break prior the casing.

There are other factors contributing to the occurrence of trap fluid such as, free water content of the slurry which also comes from settling of heavier cementing materials, non-centralized casing “low stand-off”, inadequate/incomplete displacement of unwanted fluids during cementing, influx of formation fluid during cementing and premature/flash setting of cement.

OVER RETARDATION:

Over retardation “green cement” are observed in wells wherein high temperature retarders were utilized in sections expected to be within the high temperature region, i.e. 100°C and over. Although the cement slurries

are found to be acceptable as tested with the prognosticated formation temperature for thickening time, free water, and compressive strength prior use in the wells, the temperatures which actually exist in the well during the curing of the cement didn't reach the prognosticated temperature to which the slurry is tested. The critical period of the cement slurry for it to set is during its first **24-48** hours after being put in place. During the first **24-48** hours, the setting cement should not be disturbed otherwise the cement column **will** be of poor quality and **will** not be able to serve its purpose. The temperature to which the cement slurry is tested is reached only during discharge of the well, e.g., period not less **than** a month from time the cement is set in place.

REMEDIAL TOP JOBS:

Remedial top jobs are cementing jobs pumped and/or squeezed through two casings from the drilling spool. This job is conducted after encountering losses or drop in cement column during the last stage of the primary cementing jobs. The losses are induced by the hydrostatic pressures of the cement slurry, e.g. weights between 13.5ppg to 15 ppg which is way above mud weight ranging from 8.9 ppg to 11.0 ppg used during drilling of a geothermal well. The losses can also be a recurring loss of a previous plugged, cemented or LCM plugged, lost circulation zones.

The trap fluid in a remedial top job is aggravated by the washing of the casing annulus immediately after encountering a lost of circulation during the last stage of the primary cementing operation. Another situation that can aggravate presence of trap fluid is the multiple hesitation / squeeze top cementing jobs wherein pumping of a non homogenous slurry is very likely to occur and free water settles above each top job. The occurrence of casing failure coincides to the depth between computed column of the remedial top jobs.

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5.0 FAILURE DUE TO FORMATION CHARACTERISTICS.

There are two characteristics of the formation which contributed to the casing failure, i.e. acidic formation and discharge; **and, high** temperature - high pressure external **flow**.

ACIDIC FORMATION OR DISCHARGE

For both acidic formation **and** acidic fluid discharge, presence of acidic fluids are detected during drilling and discharge. For formations with acidic fluids which are to be cased, it is usually designed that the section be cased-off by two casing strings, i.e. anchor and production casing. Recent casing design incorporates the use of expensive corrosion resistant casing located **within** the acidic formation. The presence of acidic minerals are closely monitored during drilling to determine the proper placement of a double casing and/or corrosion resistant casing.

ACIDIC DISCHARGE

Majority of the wells with acidic discharged failure are plugged and abandoned due to severe corrosion of the production casing and sometimes even the wellhead assembly. Production of the acidic wells are not pursued due to its adverse detrimental effect to the production system.

EXTERNAL, FLOW

High temperature **high** pressure external flow causes the localized external erosion of the casing **within** the flow region. These high temperature **high** pressure flow region can and will erode the cement surrounding the casing and eventually the casing itself. Although these section are relined **with** a smaller casing to continue producing from the said well, production will **correspondingly** decrease to **as** much as **fifty** percent (50%) from a production casing of 13-3/8" OD and relined **with** a 9-5/8" casing

6.0 SOLUTIONS

1. Tie Back System. The tie back system is the most effective measure to address three (3) major factors leading to casing failures which are mechanical wear and tear, thermal stress **and** losses of circulation during primary casing cementing operations. Mechanical wear and tear **is** greatly reduced since the drill string and liner string/s did not rub the inner portion of the tie-in string since the tie-in string is only set after completely drilling the well to target depth and, **also**, after setting the last production liner string. Possible losses of circulation attributed to the formation while cementing the tie-in string is also eliminated since the liner hanger with tie-back receptacle to which the tie-in string will be connected is inside the anchor casing. Another protection is the curing of the leaks at the tie back receptacle prior **running in** the tie-in string, to be ensured that the cement column **will** not drop due to leaks at the receptacle. Failure due to thermal stress is thereby eliminated since the possibility of a free length/ uncemented production string section is greatly minimized.
2. Setting a thicker production casing string inside the anchor casing. Aside from a thicker **wall** to protect against wear and tear due to erosion or production testing/ monitoring tools during production of the wells, the casing with a thicker wall provides a higher pressure rating and tensile *strength* be it at the tool joint or at the pipe body itself.
3. Minimizing BUR and DLS to $2.0^{\circ}/100$ ft specially for wells requiring larger diameter casings. Bending stress for the casing is greatly reduced in addition to the reduction to the sideload forces of the drill string to the casing for wells with higher **BUR** and DLS. Aside from this, the difficulty in running-in 18-5/8" anchor casing strings observed in wells with BUR greater than $2.0^{\circ}/100$ ft is eliminated.
4. Proper placement of drill pipe / casing rubber protectors. CIC logs are conducted on some wells wherein casing wear is monitored against the placement of rubber protectors. Based on the results of the CIC logs the placement of rubber protectors with least wear to the casing is adopted **as** a standard drilling practice.
5. Utilizing soft banding materials and/or drill pipes with worn-off hard band inside the production casing string. Although measures 4. and 5. does not affect the tie-back system, wear and tear of the production casing below the tie-in string is greatly minimized.
6. Utilizing MWD for directional drilling. Although MWD is quite expensive for geothermal well **drilling**, wear and tear of the casing *string*, is greatly reduced since there is minimal pipe rotation inside the casing string; **and**, drilling time and DLS is likewise reduced by having no correction runs due to the regular monitoring of the well track and the immediate response to the **drilling** parameters to attain and/or maintain the required well track. The wear depth due to the direct influence of the contact time, e.g. dependent on the rotary speed and rate of penetration, is greatly reduced. For the casing failures discussed, the tie back system is a more appropriate and economical alternative.
7. Using light weight slurry on the second stage of the primary cementing job. Almost **all** of the geothermal wells are drilled with drilling mud weighing not more than 10.0 ppg. More often, circulation losses occur during primary cementing of the last stage due to hydrostatic pressure of the cement slurry used ranges from 13.0- 15.0 ppg. This is specially **true** for multiple stage cementing jobs where the second stage cementing collar is set in the open hole. Aside **from** using light weight cement slurry to prevent occurrence of lost of circulation due to annular fluid pressures exceeding overburden pressure causing the formation to **break/fracture**, the stage cementing collar is also set above the previous casing shoe. In spite of this, losses is not totally eliminated due to occurrence of lost of circulation on the first **stage** where an open hole section up to the stage cementing collar was **left** uncemented prior the second stage.
8. Open hole inflatable packers below the stage cementing **collar** are used in some wells but are not quite successful due to packer rubbers being damaged during **running-in**; and, the purpose of having a reduction in the hydrostatic pressure underneath the packer is voided by the presence of **an** over-size hole at which the packer **is** set. Cement baskets located above and below the stage cementing collar performed comparatively **similar** to the packers but is a **far** cheaper option.

9. Proper centralization of the casing string with respect to the openhole. Existing programs are utilized to determine the proper placement of casing centralizers to ensure attainment of adequate stand-off. Adequate stand-off eliminates the presence of unwanted fluid in the annular column by removing the resistance to flow due to tightness of a section for the cement slurry during cementing.

10. Evaluated the necessity and procedure for conducting remedial top jobs. Free lengths usually occurs at the top most section of the casing string and once this free length is cemented by remedial top jobs, more often fluid entrapment will exist and free lengths amid well cemented sections will be present, two requisites for the possible occurrence of thermal stress casing failure. The requirement of a remedial top job is currently being evaluated as against the allowable free length which the casing can tolerate so as not to have thermal stress during production discharge testing. If the free length is required to be cemented, cementing through perforations at the bottom most section of the free length is always preferred over the remedial top jobs.

11. Proper centralization of the production casing ensuring undisturbed expansion into the expansion spool. Casing centralizing bowls and casing head flanges provided with centralizing bolts are utilized to ensure proper centralization of the production casing

7.0 CONCLUSION

The primary and most common contributing factor to casing failure is mechanical wear and tear. As the casing size is increased, mechanical wear and tear increases due to higher side loads.

Higher build-up rates provided for the higher influence in the occurrence of casing failure due to bending loads and also higher wear and tear rate at sections with higher dogleg severity factors.

Mechanical wear and tear during drilling is prevented by utilizing the tie back system wherein the tie-in string is only set prior conducting completion test. The tie back system also provided a higher success rate for cementing the casing to casing section where most of the failures covered by the study are located.

Effect of mechanical wear and tear during production testing is further minimized by utilizing a thicker casing inside a casing to casing section.

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