GRC Transactions, Vol. 41, 2017

Geothermal well design using the new 2015 New Zealand Standard and 1991 Standard:

A case of MW-20A in Menengai, Nakuru County, Kenya

Anthony Ng'ang'a and Johnstone Maleche

Geothermal Development Company (K) Ltd. P .O Box 100746, 00101, Nairobi, Kenya.

Keywords

Well design, New Zealand design code, geothermal well, reservoir condition, boiling point for depth, fracture pressure, overburden, minimum casing depth, design premise, Calculated design factor, minimum design factor, corrosion.

ABSTRACT

The design of geothermal wells is an important task in well construction, as this allows the effective conveyance of geothermal fluids from deep depths to the surface for utilization. The New Zealand design code NZS 2403:1991 has been used for the last two decades to design geothermal wells, but in 2015 it was replaced by a new design code NZS 2403:2015. This report presents the design of a geothermal well using the two design codes for comparison purposes. The well was designed using exact reservoir conditions in Menengai geothermal field in Kenya, using MW-20A as a reference well. After determining the reservoir pressure, the minimum casing depth for the different casing strings was determined from the codes. In addition, the design premises were established and it was found that the worst case for design was when the well was considered to be filled with steam from bottom to surface. Design calculations were carried out given this condition using the two codes and the best casing strings were determined. The design computations showed that a 20" 94 lb/ft casing, 13⅜" 54.5 lb/ft casing and 9⅝" 47 lb/ft casing were adequate to be run in hole for surface, anchor and production strings respectively. Further calculations showed that the weight of the production casing could be reduced to 36 lb/ft and still be within the minimum design factors, but to account for corrosion during the life of the well, the 47 lb/ft production casing was selected. Due to high stresses when the production casing rises into the wellhead, the weight of the upper two joints of the anchor casing string was changed to 72 lb/ft from 54.5 lb/ft. Several design considerations have changed between the codes that include the following: The 2015 code gave deep minimum casing depths compared to the 1991 code. Temperature reduction factors for yield were reduced in the 2015 code when checked against the 1991 code. Minimum design factors for thermal expansion of anchor casing into wellhead and compressive stress in liners were reduced to 1.4 and 1.0 in the 2015 code from 1.5 and 1.2 in the 1991 code, respectively. The 2015 code considers fracture pressure for maximum pressure boundary while determining minimum casing depth while the 1991 code considers the overburden. The 1991 code does not allow the thermal expansion of the casing to exceed minimum yield, while the 2015 code acknowledges the use of

strain based design in such cases. It is recommended that to avoid the introduction of tensional stresses into the well, cold fluids should not be pumped into a hot well.

1. Introduction

Hole (2008a) describes the geothermal well design process as a think through process where the engineer has to consider; the purpose and objective of the well, conditions likely to be encountered downhole during drilling, identification of material and equipment required, and safe drilling procedures that will ensure successful well completion and thereafter a satisfactory design life of the well. A sound design is required to achieve a satisfactory well drilling process, and to obtain the integrity and desired life of the well. Part of the design is the selection of casing depths and specification of the material weights and connections.

The course taken in casing design and determining the right specification embraces the knowledge of the prerequisite services of the casings, proper setting depths and scrutinizing potential modes of failure. Typically, geothermal wells are constructed from several concentric steel casings, with cement in the annulus between the casing walls and the hole. It is essential to achieve structural integrity of the casings, especially for high temperature wells which are normally characterized by high temperature and pressure. Failure of casings in such wells may lead to reduced energy output from the well or making it difficult to operate the well and in worst cases cause unsafe conditions outside the well such as blow outs (Kaldal et al., 2013).

The New Zealand 1991 code of practice for deep geothermal wells (NZS 2403:1991) has been used as a guideline for designing geothermal wells since it was released. Since the inception of this design code, many deep geothermal wells have been drilled worldwide providing additional design information and challenges necessitating the revision of the code. Therefore, the NZS 2403:1991 code has been undergoing review and in 2015 it was replaced by NZS 2403:2015 code of practice for deep geothermal wells. The NZS 2403:2015 code has incorporated the knowledge and experiences gained by geothermal drilling experts from years of designing geothermal wells.

This study will use the new and old New Zealand code of practice (NZS 2403:2015) and (NZS 2403:1991) to design a 2000 m deep well for the reservoir conditions already identified at the Menengai geothermal area in Kenya. The reference high temperature geothermal well MW-20A, is a directional well already drilled in the Menengai geothermal field to a depth of 2219 m. The design will be limited to 2000 m since the codes are limited to that depth. The report will describe the well design process, list all equations, and then follow it with calculated examples.

First, the objectives and criteria are established for drilling the well, and then the expected loads are estimated on each casing string (surface, anchor and production casing) during well drilling, heating up (static) and flowing (dynamic). Based on the calculated loads the casing design will be made according to API, ISO and New Zealand norms. The results, based on the two New Zealand standards, will be compared to well MW-20A as it was drilled in Menengai, Kenya in 2014

2. Design Methodology

To establish the design premises with the exact reservoir conditions for well MW-20A, the temperature and pressure logs for different heating and shut-in periods were plotted and studied. The objective is to obtain the minimum casing depths based on the maximum temperature and pressure for the well in the static condition. In addition, valuable information on the well enthalpy, mass flow and well head pressure was obtained from the discharge tests, and thereby enabling the usage of the Hola program at Icelandic Geosurvey-ISOR to simulate the dynamic conditions for MW-20A.

After MW-20A was capped with Class 900 master valve the well was allowed to heat for 11 days before a temperature and pressure logging run was done (Figure 1).

After 11 days of heating, the well was discharged for 103 days and shut-in for six days. Logging was done and the results obtained are shown in Figure 2. Note that the pressure log was unsuccessful as the clock failed.

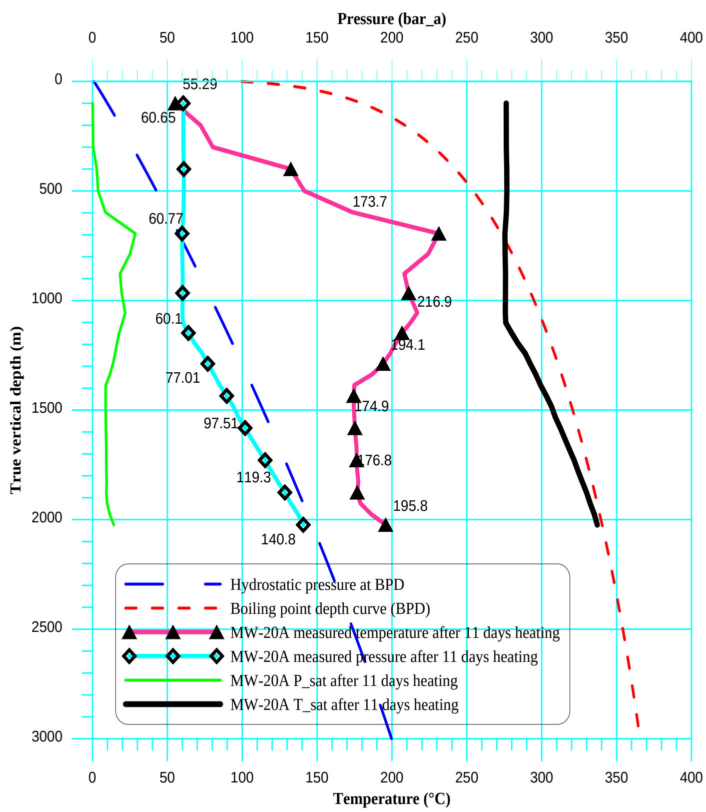

Figure 1: MW-20A temperature and pressure profiles 11 days after well capping

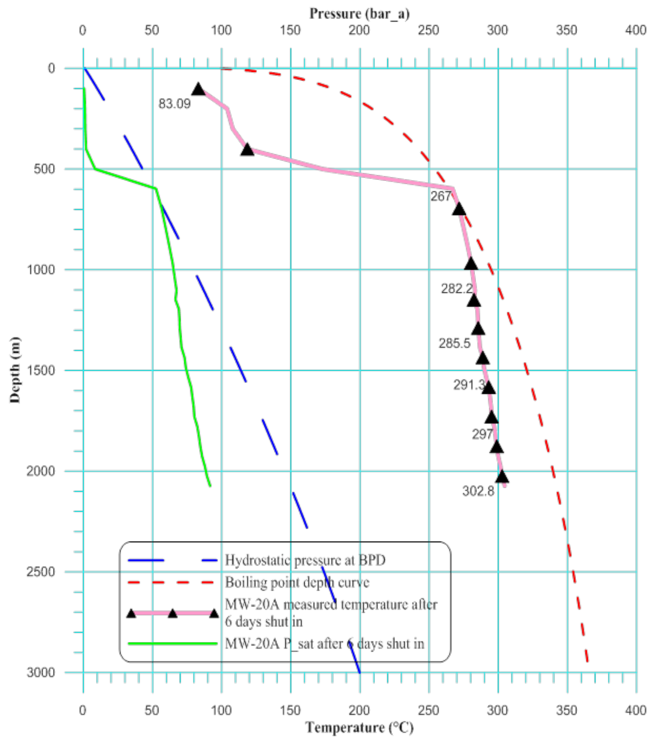

Figure 2: MW-20A temperature and pressure profiles after 103 days of flowing and six (6) days of shut-in

Further, two more logs were done after eight days and 21 days of shut in, as shown in Figure 3 and Figure 4 respectively.

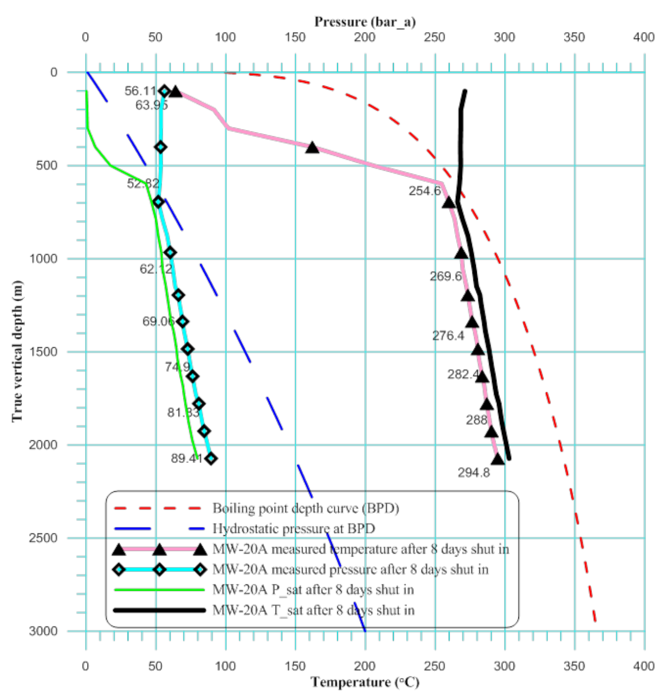

Figure 3: MW-20A temperature and pressure profiles after 103 days flowing and eight days of shut-in

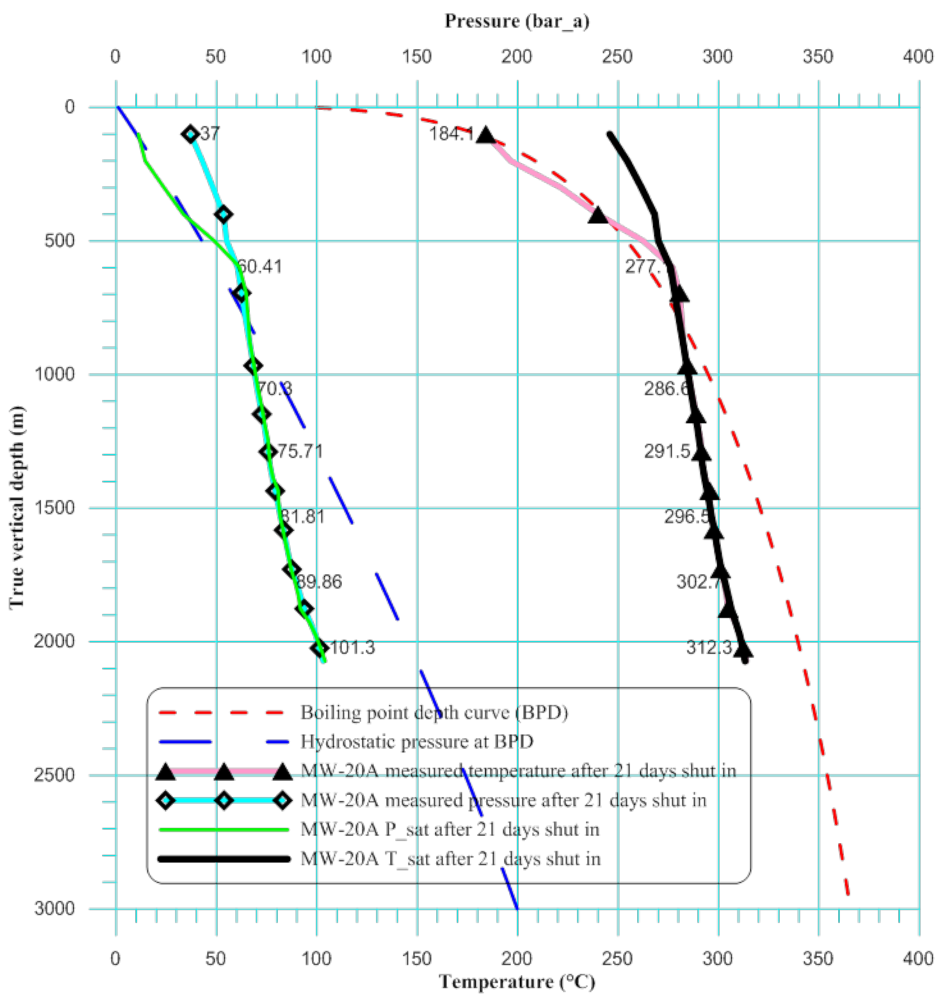

Figure 4: MW-20A temperature and pressure profiles after 103 days flowing and 21 days of shut-in

From the above logs, the pressure pivot point/depth was determined by plotting all the pressure logs. As shown in Figure 5 the pivot was at 95 bars at 1500 m. This is the point where the pressure in the well remained unchanged for the different logging periods, and is the basis for the design. After the pivot point was determined, the hydrostatic pressure curve at boiling was shifted to pass through this point, and similarly the BPD curve was shifted to show the corresponding temperatures for the hydrostatic pressure curve as shown in Figure 6.

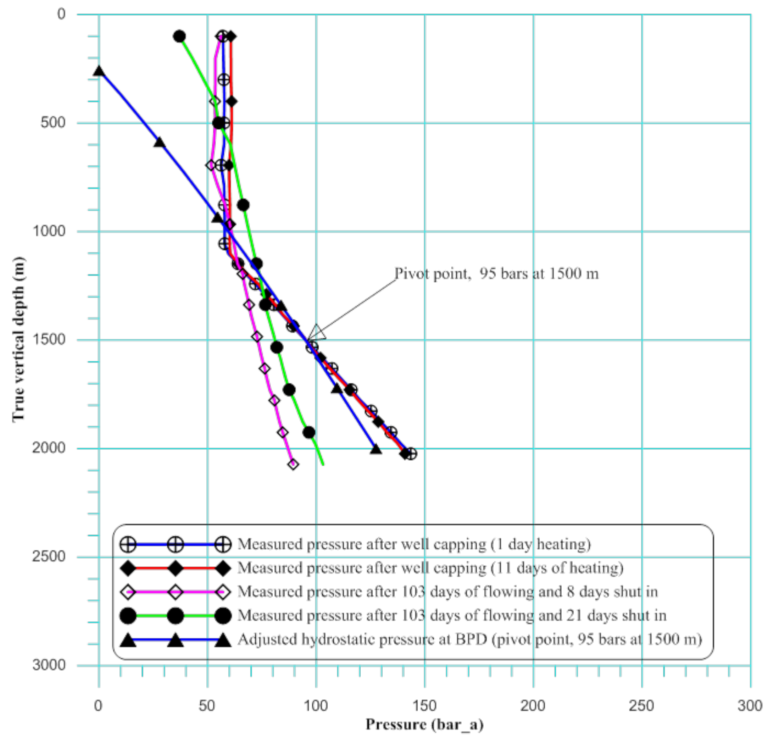

Figure 5: MW-20A pressure profiles

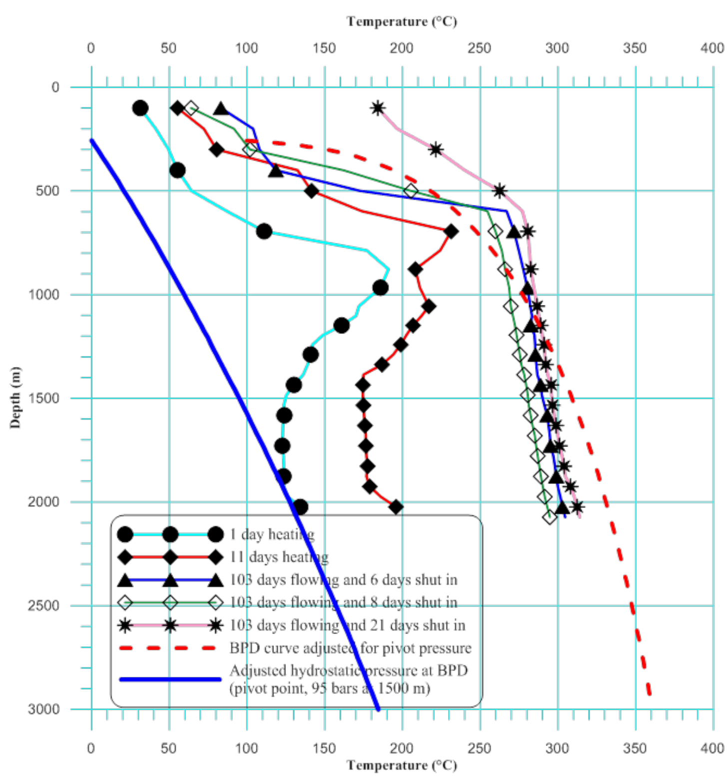

Figure 6: MW-20A temperature profiles, adjusted BPD curve and adjusted hydrostatic pressure at BPD

The adjusted hydrostatic pressure at the BPD curve represents the boiling pressures in the well. This pressure curve acts as the lower margin for the determination of minimum casing depth according to both NZS 2403:1991 and NZS 2403:2015. The upper boundary for NZS 2403:1991 is the pressure from the underlying bedrock known as the overburden and is calculated using Equation 1; in this case the overburden is composed of trachyte rocks with minor intrusions of tuff and syenite. The 2015 New Zealand code of practice (NZS 2403:2015) has replaced the use of overburden with the effective containment pressure (fracture pressure) for minimum casing depth determination and is computed using Equation 2, Eaton Formula.

$$S_v = \rho \; x \; g \; x \; h \tag{1}$$

Where ρ = Density of the underlying bedrock (kg/m3);
g = Gravitational acceleration (9.81 m/s2);
h = Depth below liquid level (m);
Sv = Overburden pressure (vertical pressure due to the weight of the overlying formations (MPa).

$$P_{frac} = P_f + \frac{v}{1 - v}(S_v - P_f) \tag{2}$$

Where P_f = Pore pressure (MPa);
v = Poisson's ratio;
Sv = Overburden pressure (vertical pressure due to the weight of the overlying formations (Mpa);
P_{frac} = in situ fracture pressure of a formation (MPa).

Figure 7 and Figure 8 show the minimum casing determination for Menengai using NZS 2403:1991 and NZS 2403:2015 respectively. It is evident from the two Figures that the new New Zealand code of practice NZS 2403:2015 gives deeper depths for the production casing and subsequent casings that follow compared to the earlier code NZS 2403:1991. The NZS 2403:2015 code gives minimum depth of the production casing as 740 m and NZS 2403:1991 gives the minimum depth as 450 m.

From the various wells drilled in Menengai geothermal field, many logs and measurements have been done to create the conceptual model of this field. It has been deduced in the process that in many wells there are cold flows beyond 1000 m depth, which was initially considered to be the best depth for the production casing. Due to this finding, a decision was made to place the production casing shoe between 1150 m and 1200 m to case off these cold inflows.

For this reason, the production casing will be set at 1200 m and the preceding casing string depths recalculated. Figures 9 and 10 show the adjusted production casing depth to 1200 m and the minimum depths for the preceding casing strings, anchor and surface casings, for NZS 2403:1991 and NZS 2403:2015 respectively.

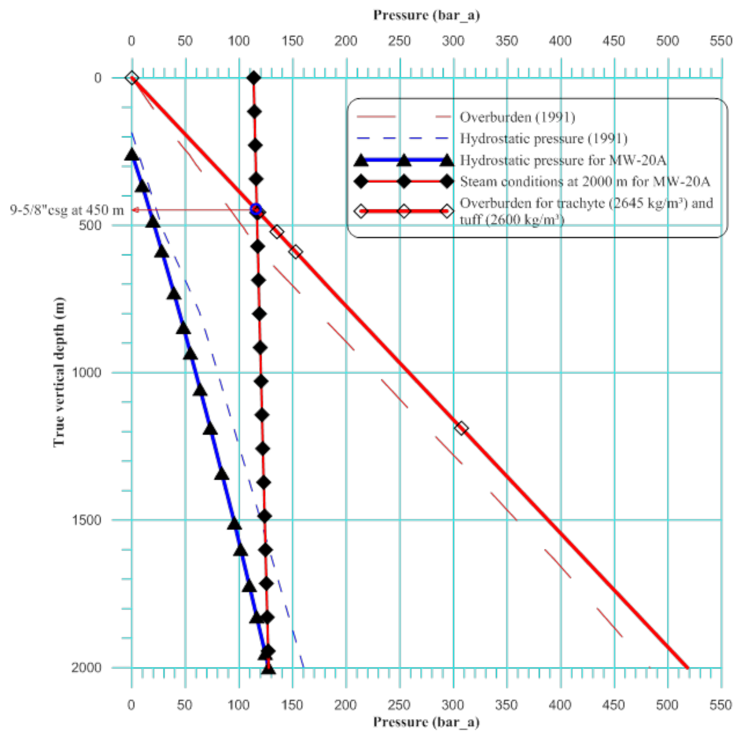

Figure 7: Minimum casing depth determination using NZS 2403:1991; the solid lines are for the conditions in Menengai and the dotted ones for the example shown in the standard

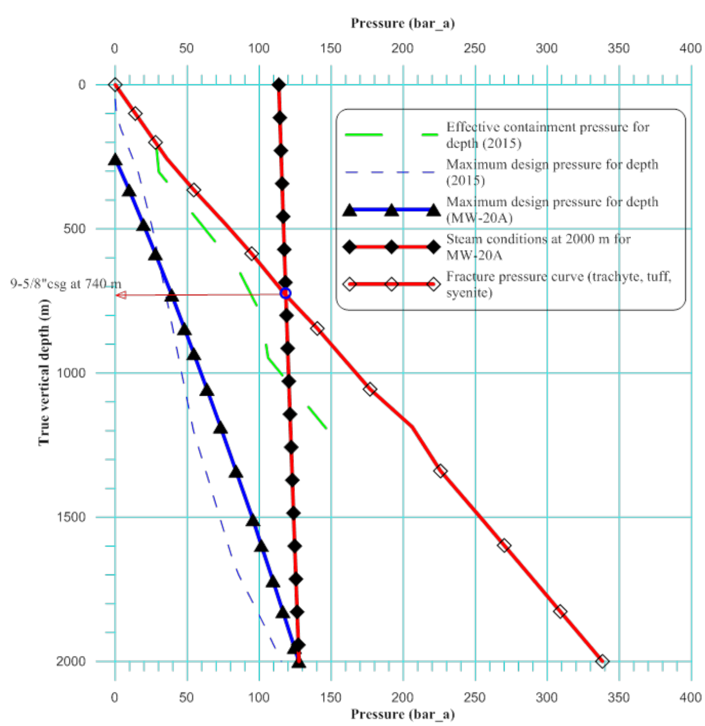

Figure 8: Minimum casing depth determination using NZS 2403:2015; the solid lines are for the conditions in Menengai and the dotted ones for theexample shown in the standard

The results from NZS 2403:1991, after adjusting the production casing shoe to 1200 m place the minimum anchor casing depth at 290 m and the surface casing minimum depth at 20 m. These depths are shallow, given that the water table in Menengai is expected to be at 300 m. Therefore, the depths for the anchor and surface casing are adjusted to 350 m and 80 m respectively.

Using NZS 2403:2015, after adjusting the production casing shoe depth to 1200 m, the minimum shoe depths for the surface and anchor casings are relatively deep at 140 m and 470 m respectively, and these depths have been used for the design.

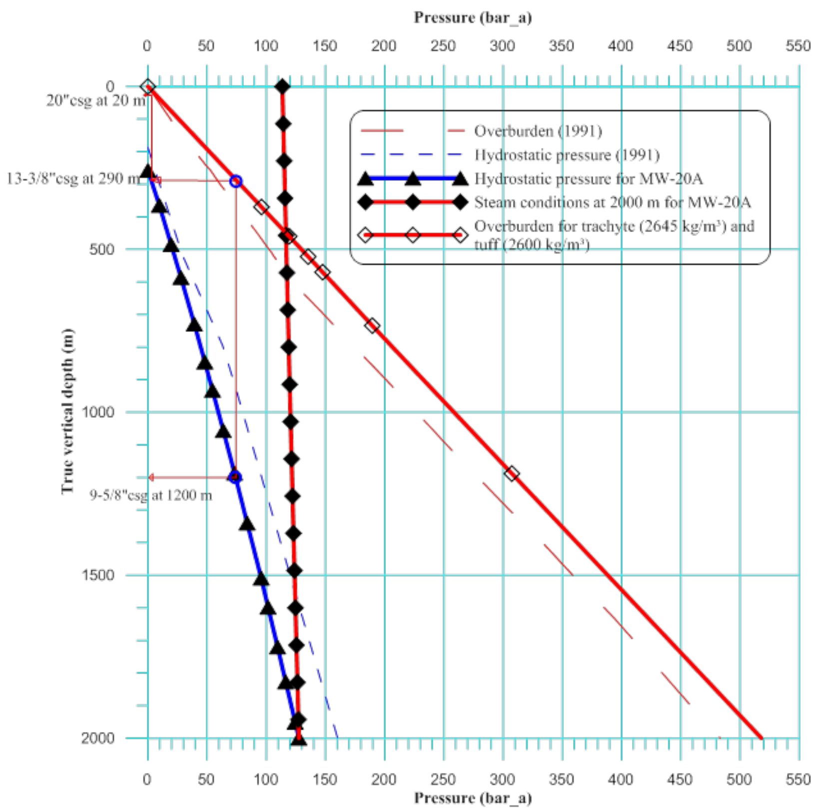

Figure 9: Adjusted production casing depth to 1200 m in NZS 2403:1991; the solid lines are for the conditions in Menengai and the dotted ones for the example shown in the standard

3. Design premises

Three design premises were considered to find the worst case scenario and the design for it. The three cases considered were: static (shut-in) condition, dynamic (flowing) condition and the third case is that the well is full of steam from bottom to surface. These conditions are displayed in Figures 11, 12, and 13.

For the shut-in condition, the temperatures are very low since this is when there is an accumulation of gases in the production casing, suppressing the fluid level in the well. The worst case scenario was found to be when the well was full of steam from bottom to surface, as is the design premise in the NZ standards.

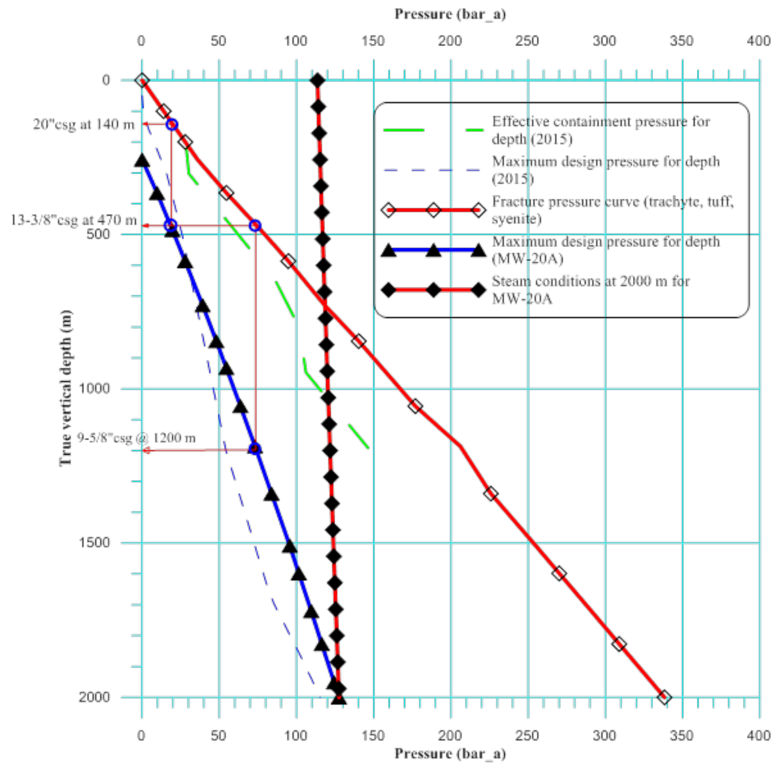

Figure 10: Adjusted production casing depth to 1200 m in NZS 2403:2015; the solid lines are for the conditions in Menengai and the dotted ones for the example shown in the standard

With this condition, the maximum pressure and temperature at the bottom of the well is 127.3 bars and 329.2°C respectively. For the shut in condition it is assumed that cold gases have accumulated at the top of the well depressing the water level to the depth of the casing shoe. For the gas filled well the temperatures are very low within the casing.

4. Design calculations

After establishing the minimum casing depths for the different casing strings from the NZS 2403:1991 and NZS 2403:2015 design codes, the best casing weights, diameter and grade were calculated. The diameter of the casing is known, since the well is a regular well.

A regular well casing string constitutes a 30” conductor casing, 20” surface casing, 13⅜” anchor casing, 9⅝” production casing and 7” slotted liners (Thorhallsson, 2015). The chosen grade for all the casing strings is K55, which has resistance to H2S and has been approved as it conforms to ANSI/NACE MR 0175/ISO 15156 (NZS 2403:2015).

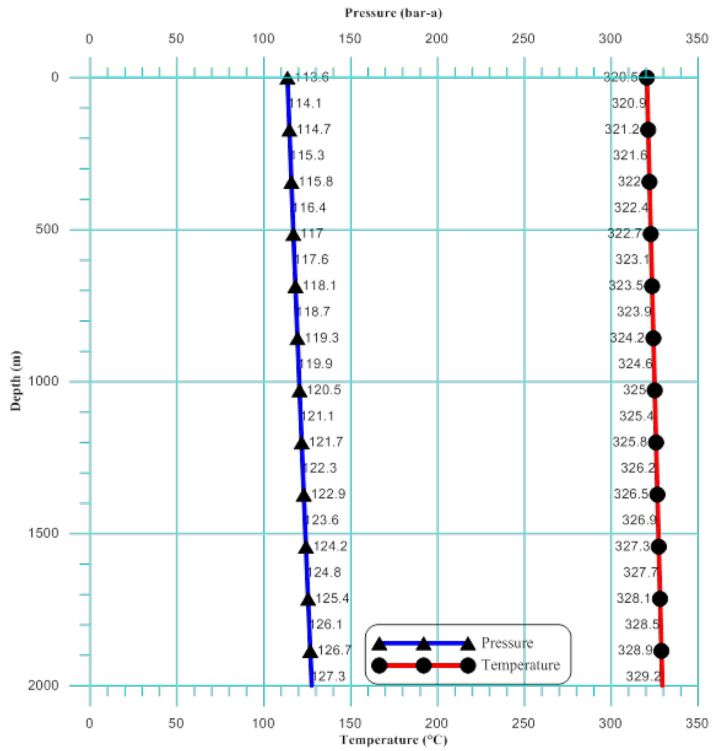

Figure 11: Steam conditions in MW-20A

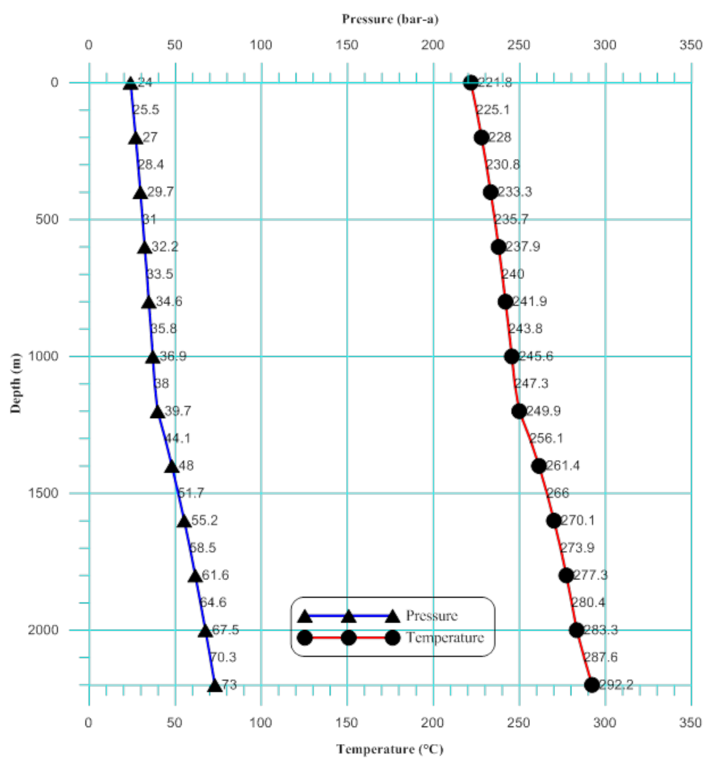

Figure 12: Flowing TP conditionsin MW-20A

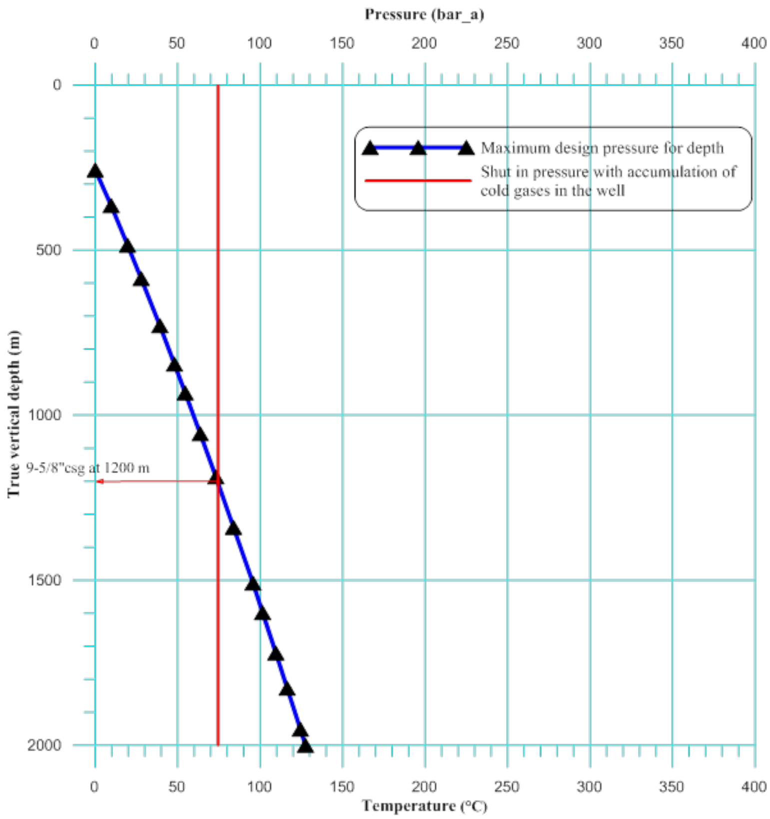

Figure 13: Shut in condition with accumulation of cold gases at the top of the well

The casing grade is essential as it determines the burst pressure and axial tensile strength, while the wall thickness (weight) of the casing defines collapse (Finger and Blankenship, 2010). Design for burst, axial stress and collapse was done for a steam filled well as this was the worst case scenario. Well design equations from the two codes i.e. NZS 2403:1991 and NZS 2403:2015 were used to calculate loads and stresses shown below in Figure 14.

5. ISO/TR 10400

The equations from the two design codes were used to calculate casing loads and stresses assuming a well full of steam from bottom to surface. To check the adequacy of the chosen casing strings in terms of the calculated burst, collapse and axial stresses, the ISO/TR 10400 technical report was used to calculate the allowable limits.

The computed design factors were then checked against the minimum design factors as provided in the two design codes. The formulas below from ISO/TR 10400 technical report were used to verify the appropriateness of the design or selected casing strings.

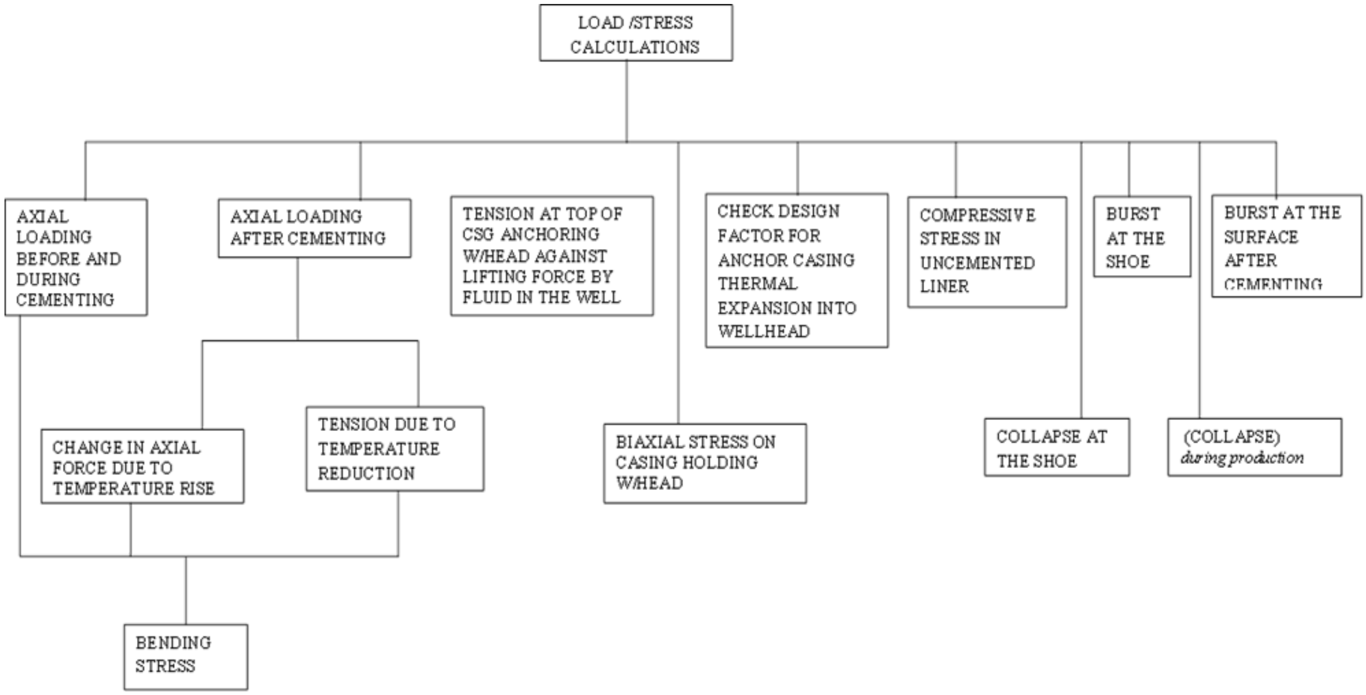

Figure 14: Loads and stresses considered in NZS 2403:1991 and NZS 2403:2015

5.1 External pressure resistance (collapse)

Collapse is dependent on the D/t ratio of the casing. For K55 casing grade, the ratio delineates the type of collapse that is going to occur, thereby giving the equation to be used to calculate the collapse limit for the casing. Table 1 below shows the various D/t ratio ranges for K55 and the type of collapse in that range.

TABLE 1: D/t ratio ranges for K55

D/t ratio	14.81	and less	Yield strength collapse
	14.81	25.01	Plastic collapse
	25.01	37.21	Transition collapse
	37.21	and greater	Elastic collapse

a. Yield strength collapse equation

$$PY_p = 2f_{ymn}\left[\frac{(D/t)-1}{(D/t)^2}\right] \tag{3}$$

Where f_{ymn} = Minimum yield strength;
D = Pipe outside diameter;
t = Pipe wall thickness;
PY_p = Pressure for yield strength collapse.

b. Plastic collapse equation

$$P_P = f_{ymn}\left[\frac{A_c}{D/t} - B_c\right] - C_c \tag{4}$$

Where f_{ymn} = Minimum yield strength;
A_c = Empirical constant in the historical API collapse equation;
B_c = Empirical constant in the historical API collapse equation;
C_c = Empirical constant in the historical API collapse equation;
D = Pipe outside diameter;
t = Pipe wall thickness;
P_p = Pressure for plastic collapse.

c. Transition collapse equation

$$P\,\mathrm{T} = f_{ymn}\left[\frac{F_c}{D/t} - G_c\right] \tag{5}$$

Where F_c = Empirical constant in the historical API collapse equation;
G_c = Empirical constant in the historical API collapse equation;
D = Pipe outside diameter;
t = Pipe wall thickness;
PT = Pressure for transition collapse.

d. Elastic collapse equation

$$P_E = \frac{46.95\ x\ 10^6}{[D/t\,(D/t-1)^2]} \tag{6}$$

Where D = Pipe outside diameter;
t = Pipe wall thickness;
P_E = Pressure for elastic collapse.

5.2 Triaxial yield of pipe body (Burst, yield)

a. Capped-end conditions - axial, radial and hoop stress: evaluated at the inner diameter

$$P_{iYLc} = \frac{f_{ymn}}{\left(\frac{(3D^4 + d_{wall}^4)}{(D^2 - d_{wall}^2)^2} + \frac{d^4}{(D^2 - d^2)^2} - \frac{2d^2 d_{wall}^2}{(D^2 - d^2)(D^2 - d_{wall}^2)}\right)^{1/2}} \quad (7)$$

Where D = Pipe outside diameter;
d_{wall} = Inside diameter based on Kwall t, dwall = D - 2Kwall t;
d = Pipe inside diameter;
f_{ymn} = Minimum yield strength;
t = Pipe wall thickness;
K_{wall} = Specified manufacturing tolerance of pipe wall e.g. tolerance of 12.5%, Kwall = 0.875;
P_{iYLc} = Internal pressure at yield for a capped-end thick tube.

b. Zero axial load - radial and hoop stress: evaluated at the inner diameter

$$P_{iYLo} = f_{ymn}(D^2 - d_{wall}^2)/(3D^4 + d_{wall}^4)^{½} \quad (8)$$

Where D = Pipe outside diameter;
d_{wall} = Inside diameter based on Kwall t, dwall = D - 2Kwall t ;
f_{ymn} = Minimum yield strength;
t = Pipe wall thickness;
K_{wall} = Specified manufacturing tolerance of pipe wall e.g. tolerance of 12.5%, Kwall = 0.875;
P_{iYLo} = Internal pressure at yield for an open-end thick tube.

c. Historical, one-dimensional yield pressure design equation (the Barlow Equation for pipe yield)

$$P_{iYAPI} = \left[2f_{ymn}(k_{wall}t)/D\right] \quad (9)$$

Where D = Pipe outside diameter;
f_{ymn} = Minimum yield strength;
t = Pipe wall thickness;
K_{wall} = Specified manufacturing tolerance of pipe wall e.g. tolerance of 12.5%, Kwall = 0.875;
P_{iYAPI}= Internal pressure at yield for a thin tube.

5.3 Bending stress

$$\sigma_b = \pm M_b r / I = \pm E \cdot c \cdot r \tag{10}$$

Where Mb = Bending moment;
r = Radial coordinate d/2 ≤ r ≤ D/2;
I = Moment of inertia of the pipe cross section, I = π/64(D4 - d4);
E = Young's modulus;
c = Tube curvature, the inverse of the radius of curvature to the centre line of the pipe;
σb = Bending stress.

6. Results

Design calculation results for the two codes (NZS 2403:1991 and NZS 2403:1991) are as tabulated below.

6.1 Collapse

Below in Table 2 and 3 collapse and burst pressures for the different casing sizes are shown and the calculated design factors. Collapse has been calculated considering the annulus is filled with 1.85 kg/l of cement slurry, and water of mean specific volume of 0.988 l/kg at 50°C.

Table 2: Collapse pressure using NZS 2403:1991

CASING GRADE K55		COLLAPSE					
		Depth	**1991 Code (MPa)**	**Collapse resistance (MPa)**	**Calculated design factor**	**Minimum design factor**	**lb/ft**
Production casing (9⅝")	Top	10	0.08	26.84	326.51	1.20	47
	Middle	600	4.93	26.84	5.44	1.20	
	Shoe	1200	9.86	26.84	2.72	1.20	
Anchor casing (13⅜")	Top	10	0.08	7.89	95.94	1.20	54.5
	Middle	170	1.40	7.89	5.64	1.20	
	Shoe	350	2.88	7.89	2.74	1.20	
Surface Casing (20")	Top	10	0.08	3.53	42.94	1.20	94
	Middle	40	0.33	3.53	10.74	1.20	
	Shoe	80	0.66	3.53	5.37	1.20	

Table 3: Collapse pressure using NZS 2403:2015

CSG GRADE K55		COLLAPSE					
		Depth	**2015 Code**	**ISO/TR 10400**	**Calculated design factor**	**Minimum design factor**	**lb/ft**
Production casing (9⅝")	Top	10	0.08	26.84	317.36	1.20	47
	Middle	600	5.07	26.84	5.29	1.20	
	Shoe	1200	10.15	26.84	2.64	1.20	
Anchor casing (13⅜")	Top	10	0.08	7.89	93.25	1.20	54.5
	Middle	240	2.03	7.89	3.88	1.20	
	Shoe	470	3.97	7.89	1.99	1.20	
Surface Casing (20")	Top	10	0.08	3.53	41.74	1.20	94
	Middle	70	0.59	3.53	5.98	1.20	
	Shoe	140	1.18	3.53	2.99	1.20	

6.2 Burst

Burst pressure calculations consider a cement slurry density of 1.85 kg/l inside the casing and hot water of mean specific volume of 0.988 l/kg at 50°C in the annulus as shown in Table 4 and 5.

Table 4: Burst pressure using NZS 2403:1991

CASING GRADE K55		BURST					
		Depth	**1991 Code (MPa)**	**ISO/TR 10400**	**Calculated design factor**	**Minimum design factor**	**lb/ft**
Production casing (9⅝")	Top	10	0.10	32.40	326.32	1.5	**47**
	Middle	600	5.96	32.40	5.44	1.5	
	Shoe	1200	11.91	32.40	2.72	1.5	
Anchor casing (13⅜")	Top	10	0.10	18.91	190.44	1.5	**54.5**
	Middle	170	1.69	18.91	11.20	1.5	
	Shoe	350	3.48	18.91	5.44	1.5	
Surface Casing (20")	Top	10	0.10	14.48	145.82	1.5	**94**
	Middle	40	0.40	14.48	36.46	1.5	
	Shoe	80	0.79	14.48	18.23	1.5	

Table 5: Burst pressure using NZS 2403:2015

CSG GRADE K55		BURST					
		Depth	**2015 Code**	**ISO/TR 10400**	**Calculated design factor**	**Minimum design factor**	**lb/ft**
Production casing (9⅝")	Top	10	0.08	32.40	383.15	1.5	
	Middle	600	5.07	32.40	6.39	1.5	47
	Shoe	1200	10.15	32.40	3.19	1.5	
Anchor casing (13⅜")	Top	10	0.08	18.91	223.61	1.5	
	Middle	240	2.03	18.91	9.32	1.5	54.5
	Shoe	470	3.97	18.91	4.76	1.5	
Surface Casing (20")	Top	10	0.08	14.48	171.22	1.5	
	Middle	70	0.59	14.48	24.46	1.5	94
	Shoe	140	1.18	14.48	12.23	1.5	

6.3 Axial loading before and during cementing

During running of casing strings and cementing, casing axial tensile forces develop and act on the casing string, the calculated forces and design factors are shown in Table 6 and 7. Where the well is deviated for directional wells, stress due to bending is added to the hook load (tensile load).

The bending stress in this case will be considered maximum at the kick off point (400 m) considering the 1991 code and KOP at 500 m for the 2015 design code, where highest bending of the casing is expected.

Bending stress will be added to the tensile load at the kick off depth. The casing string that is in the deviated section is the production casing (9⅝ casing). The maximum dog leg severity has been taken as 3° per 30 m.

6.4 Axial loading after cementing

Axial loading after cementing may arise due to a rise in temperature in the well or when cold fluids are pumped in to the well. This results in compressive and tensional forces which are calculated as shown below in Section (a) and (b) for the two (2) design codes.

In addition to these forces, bending stress from deviated sections of the well should be added to the calculated compressive and tensional forces. The bending stress is calculated at the kick off point where the stress is considered maximum, with a dog leg severity of 3° per 30 m. The deviated casing string is the production casing.

Table 6: Axial forces on casings before and during cementing (1991 Code)

CSG GRADE K55		Length (m)	Hook load, F_p (kN)	Minimum tensile strength(kN)	Calculated design factor	Minimum design factor	lb/ft
20" Csg	Surface	80	95.99	11374.73	**118.50**	1.8	**94**
13⅜ Csg	Surface	350	243.69	6555.90	**26.90**	1.8	**54.5**
9⅝ Csg	Surface	1200	719.05	5735.18	**7.98**	1.8	**47**
	Kick Off Point (KOP) at 400 m	400	239.68		**5.81**		
	Bending		747.58				
	Stress at KOP + Bending stress		**987.27**				

Table 7: Axial forces on casings before and during cementing (2015 Code)

CSG GRADE K55		$F_{csg\ air\ wt}$ (kN)	$F_{csg\ contents}$ (kN)	$F_{displaced\ fluids}$ (kN)	$F_{hookload}$ (F_p) (kN)	Minimum tensile strength (kN)	Calcul. design factor	Min. design factor	lb/ft
20" Csg	Surface (140 m)	192.12	251.44	275.06	**168.50**	**11374.73**	**67.51**	1.8	**94**
13⅜ Csg	Surface (470 m)	373.95	367.33	412.92	**328.36**	**6555.90**	**19.97**	1.8	**54.5**
9⅝ Csg	Surface (1200 m)	823.38	444.19	546.15	**721.42**	**5735.18**	**7.95**	1.8	**47**
	Kick Off Point (KOP) at 500 m	343.07	185.08	227.56	**300.59**		**8.28**		
	Bending				**392.48**				
	Stress at KOP + Bending stress				**693.07**				

a. Compressive force due to temperature rise where there is partial longitudinal and lateral constraint

When cementing has been done, temperatures in the well may rise introducing compressive forces as shown in Table 8 and 9. The bottom hole setting temperature for the production, anchor and surface casings was taken as 75°C, 50°C and 30°C respectively.

A temperature of 120°C has been selected to be the maximum expected temperature in the well after cementing. The change in temperature is 45°C, 70°C and 90°C for the production, anchor and surface casing respectively.

Table 8: Axial force due to temperature rise (1991 Code)

	Compressive force, F_c (kN)	**Minimum Compressive strength(kN)**	**Calculated design factor**	**Minimum design factor**
20" Csg	3751.06	11374.73	**3.03**	1.2
13⅜ Csg	1681.51	6555.90	**3.90**	1.2
9⅝ Csg	945.65		**3.39**	1.2
Bending at kick off (400 m)	747.58			
	1693.23	5735.18		

Table 9: Axial force due to temperature rise (2015 Code)

	Compressive force, F_c (kN)	**Resultant force, F_r (kN)**	**Minimum yield strength (kN)**	**lb/ft**
20" Csg	-4266.83	**-4317.88**	**6581.71**	**94**
13⅜ Csg	-1912.72	**-1939.86**	**3793.41**	**54.5**
9⅝ Csg	-1075.67	-1223.23	**3318.52**	**47**
	Bending at kick off (500 m)	-392.48		
		-1615.71		

b. Tension due to temperature reduction when cold fluid is circulated from surface during drilling, testing or reinjection

Table 10 and 11 shows tension as a result of cool fluid being circulated, during drilling, testing or reinjection. It was assumed that the temperature of the cold fluid introduced was at an ambient temperature of 25°C.

The bottom hole setting temperature after cementing for the production, anchor and surface casings was taken as 75°C, 50°C and 30°C respectively. The change in temperature was therefore 50°C, 25°C and 5°C for the production, anchor and surface casing strings respectively.

Table 10: Tension when cool fluid is circulated in the well (1991 Code)

Casing string	**Tension force, F_t (kN)**	**Minimum tensile strength(kN)**	**Calculated design factor**	**Minimum design factor**	**lb/ft**
20" Csg	177.13	**11374.73**	**64.22**	1.8	94
13⅜ Csg	510.46	**6555.90**	**12.84**	1.8	54.5
9⅝ Csg	893.11				
Bending at kick off (400 m)	747.58	**5735.18**	**3.50**	1.8	47
	1640.69				

Table 11: Tension when cool fluid is circulated in the well (2015 Code)

	F_t (kN)	**Resultant force F_r (kN)**	**Minimum yield strength (kN)**	**lb/ft**
20" Csg	237.05	**185.99**	**6581.71**	**94**
13⅜ Csg	683.11	**655.97**	**3793.41**	**54.5**
9⅝ Csg	1195.19			
Bending at kick off (500 m)	392.48	**1832.60**	**3318.52**	**47**
	1587.67			

6.5 Tension at the top of any string anchoring a wellhead against a lifting force by fluid in the well

The anchor casing holds the wellhead after the well has been completed. Lifting force by fluid in the well may introduce tension at the top of the anchor casing. The tension forces calculated from the two design codes is as shown in Table 12.

The maximum well head pressure is 11.36 MPa from the worst case scenario where the well is assumed to be filled with steam from bottom to surface. The weight of the selected master valve, Class 900 manufactured by Alfa Oil, is 2 tonnes.

Table 12: Tension on anchor casing due to lifting force by fluid in the well (1991 & 2015 Codes)

Casing string anchoring w/head	F_w (Tension at the top) (kN)	Minimum tensile strength (kN)	Calculated design factor	Minimum design factor	lb/ft
13⅜ Csg	896.42	87775.69	**97.92**	**1.80**	**72**

6.6 Design factor for anchor casing thermal expansion into wellhead

During the operation of the well the production casing may rise into the wellhead, introducing stresses onto the anchor casing. Table 13 shows the design factor for this case and how the best casing string is arrived at for both the 1991 code and 2015 code.

Table 13: Design factor for anchor casing thermal expansion into wellhead (1991 & 2015 Codes)

lb/ft	Anchor casing tensile strength (kN)	Rising casing (prod casing) Compressive strength (kN)	Calculated design factor	Minimum design factor	
54.5	6555.90	5735.18	**1.14**	**1.50**	
61	7389.71	5735.18	**1.29**	**1.50**	
68	8216.98	5735.18	**1.43**	**1.50**	
72	8775.69	5735.18	**1.53**	**1.50**	**Adequate**

6.7 Extreme fibre compressive stress in an uncemented liner due to axial self-weight and helical buckling

Slotted liners are run in hole after drilling to the determined depth. The slotted liners allow the steam into the well and up to the surface through the production casing. The liners may hang using a liner hanger or they may be rested at the bottom of the well. When rested at the bottom, as is the practice in Menengai, compressive forces due to axial self-weight and helical buckling need to be considered.

The slots in the liner are 20 mm in diameter and there are eight slots around the circumference of the liner. The distance in between the rows along the axial direction is 60 mm, resulting in 16 rows of slots for every 1 m of the liner. Due to the slotting, the liner cross section area and the moment of inertia is reduced and were calculated as 4520.91 mm2 and 16238393 mm4.

The joint strength for the liner was 2832.64 kN with a joint efficient of 0.96 required for this calculation. The compressive stress calculated is shown in Table 14 for both the 1991 code and 2015 code.

Table 14: Compressive stress in uncemented liner due to axial self-weight and helical buckling (1991 & 2015 Codes)

		Depth of liner	Compressive stress (MPa)	Calculated design factor	Minimum design factor
7" Csg 26 lb/ft	Top	10.00	1.63	**223.03**	**1.0**
	Middle	640.00	104.40	**3.48**	**1.0**
	Bottom	830.00	135.40	**2.69**	**1.0**

Table 15: Design factor for maximum differential burst pressure at surface after cementing (1991)

lb/ft	Well head Press (MPa)	Well head Temp. (°C)	Temp. reduction factor on yield strength	Internal yield strength (anchor) (MPa)	Calculated design factor	Minimum design factor	
54.5	11.36	320.5	0.95	18.91	**1.58**	**1.8**	
72	11.36	320.5	0.95	25.5	**2.13**	**1.8**	Adequate

6.8 Maximum differential burst pressure at the surface (after cementing)

The highest differential burst pressure is expected to occur at the surface after cementing. The calculated design factor for this case is compared with the calculated design factor in Table 15 and 16 for the 1991 code and 2015 code respectively. The anchor casing is considered here as it supports the well head.

Table 16: Design factor for maximum differential burst pressure at surface after cementing (2015)

lb/ft	**Well head Press (MPa)**	**Well head Temp. (°C)**	**Temp. reduction factor**	**Internal yield strength (anchor) (MPa)**	**Calculated design factor**	**Minimum design factor**	
54.5	11.36	320.5	0.8	18.91	**1.33**	**1.80**	
72	11.36	320.5	0.8	25.5	**1.80**	**1.80**	Adequate

6.9 Biaxial stress if the wellhead is fixed on the casing being considered (combined effects of axial and circumferential tension)

After drilling is completed a wellhead is placed on the anchor casing, introducing biaxial stress. The calculation of this stress is based on the upper casing joints interacting with the well head. The well head pressure used for this calculation is the maximum expected pressure of 11.36 MPa. Table 17 and 18 displays the calculation of biaxial stress and the design factor comparison for the 1991 code and 2015 code respectively.

Table 17: Biaxial stress on anchor casing (1991)

	Biaxial stress, f_t (MPa)	**Yield strength(MPa)**	**Calculated design factor**	**Minimum design factor**	**lb/ft**
13⅜ Csg	163.32	379	**2.32**	**1.5**	72

Table 18: Biaxial stress on anchor casing (2015)

	Biaxial stress, f_t (MPa)	**Yield strength (MPa)**	**Calculated design factor**	**Minimum design factor**	**lb/ft**
13⅜ Csg	210.85	379	**1.80**	**1.5**	72

6.10 Design for the thermal expansion of a trapped liquid (inner casing string collapse resistance should exceed burst strength of outer string) (1991 Code)

The 1991 design code instructs that a sacrificial casing is needed if there is trapped liquid within a cemented annulus. The design is such that if the trapped fluid expands, the outer casing should burst rather than the production casing collapse.

To allow this, then the collapse resistance for the production casing should be higher than the burst of the outer casing (anchor casing). The weight of the 13⅜" casing and 9⅝" casing is 54.5 lb/ft and 47 lb/ft respectively. In Table 19 the calculated design factor is compared with the desired design factor.

Table 19: Design factor for thermal expansion of a trapped liquid

<table>
<tr><th></th><th>Prod. csg collapse (MPa)</th><th>Anchor csg Burst (MPa)</th><th>Calculated design factor</th><th>Minimum design factor</th></tr>
<tr><td>13⅜ Csg</td><td></td><td>18.91</td><td rowspan="2">1.42</td><td rowspan="2">1.2</td></tr>
<tr><td>9⅝ Csg</td><td>26.84</td><td></td></tr>
</table>

6.11 Hoop stressing (collapse)-during production (2015 Code)

The worst case scenario for the design has been chosen to be when the well is filled with steam from bottom to surface during production. Considering this case, collapse is computed at the production shoe so as an appropriate casing string can be provided. The differential collapse pressure is shown in Table 20 and the design factor calculated. The fluid inside the casing is steam and therefore the density is assumed to be zero.

Table 20: Collapse during production

Differential external pressure $\Delta P_{external}$	**Production casing collapse pressure at 1200 m**	**Calculated design factor**	**Minimum design factor**
21.7782	26.83	**1.23**	**1.20**

7. Joint strength

The selected casing strings need to be checked for strength at the connections, or at the joints. The chosen type of connection is a buttress and Table 21 shows the strength of the joints for each casing string and the joint efficiency. According to the society of petroleum engineers it is imperative during casing design to appreciate that the API joint-strength values are a function of the ultimate tensile strength (SPE, 2015).

Table 21: Joint strength and efficiency

Casing	lb/ft	Joint strength (kN)	Pipe body strength (kN)	Joint efficiency
20	94	6576.49	11374.73	**0.58**
13⅜	54.5	4612.96	6555.90	**0.70**
9⅝	47	4444.00	5735.18	**0.77**
7"	26	2832.64	2961.20	**0.96**

8. Corrosion

NZS 2403:1991 and NZS 2403:2015 design codes recognize the effect of corrosion which reduces the cross section area of casings. The production casing is the main conveyor of geothermal fluid to the surface and into the wellhead. This casing will be prone to corrosion where conditions for corrosion are favourable.

From the design that has been carried out, the production casing string selected is 9⅝" 47 lb/ft. Closer examination shows that the weight of this casing can be reduced to 36 lb/ft and the design will still be adequate as the collapse design factor will be 1.23, compared to a minimum design factor of 1.2 required from the two (2) codes.

However, due to corrosion effects during the life time of the well, reducing the thickness would compromise the anticipated well life. Corrosion is regarded to be acceptable for material used at a rate of 0.1 mm per year from studies conducted in Iceland on wells across the country (Thorbjornson, I., personal communication, September 21, 2015); this translates to 2 mm in 20 years. If the weight of the production casing is reduced from 47 lb/ft to 36 lb/ft the thickness is reduced by 3.1 mm. Hence if corrosion is to be considered the chosen casing of 47 lb/ft is adequate during the life of the well estimated to be 20 to 30 years.

9. Well head selection

The design premise adopted for designing the considered well was the steam filled condition as this presented the worst case scenario. The expected pressure and temperature at the wellhead in this condition is 11.36MPa and 320.5°C as shown in Figure 15. The most suitable wellhead from Figure 15 is an ANSI 900 or Class 900 master valve.

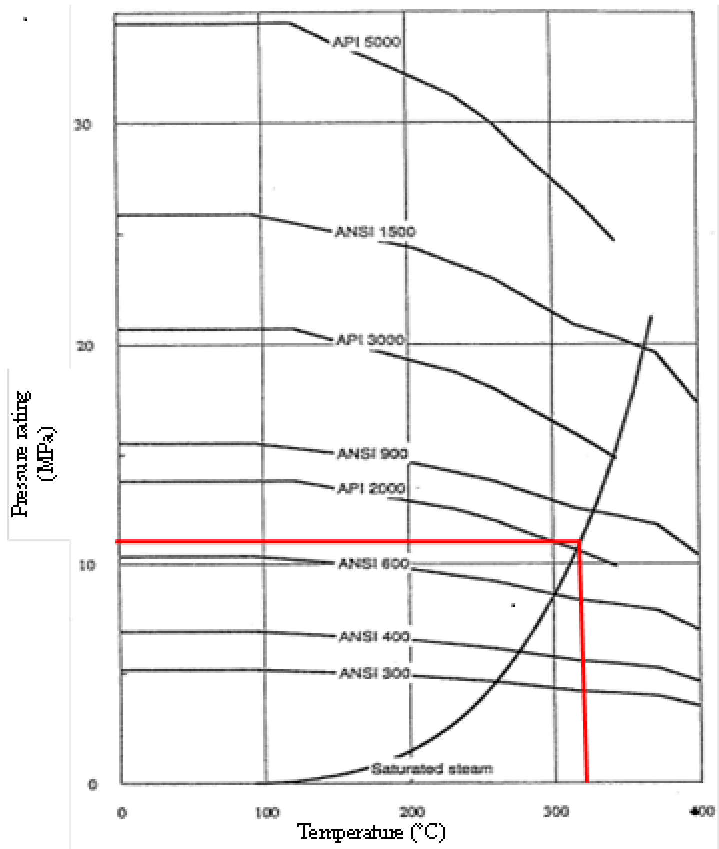

Figure 15: Wellhead working pressure de-rating for flanges and valves conforming to ANSI/ASME B16.5 and to API Spec 6A (New Zealand Standard, 2015)

10. Conclusion

The two New Zealand design codes have been used to design a 2000 m well, although in principle the two codes differ as will be detailed here. NZS 2403:1991 uses the overburden of the underlying formation as the maximum pressure boundary while determining the minimum casing depth, whereas the 2015 code, NZS 2403:2015 adopts the fracture pressure as the maximum boundary for minimum casing determination.

Increase in temperature reduces the yield strength, modulus of elasticity and tensile strength of steel and therefore reduction factors have been provided for various temperature ranges, quite notable is that the reduction factors in the 2015 design have been reduced compared to the ones previously found in the 1991 design code. For example, the temperature reduction factor for yield strength at a temperature of 300°C is 0.8 in the 2015 design code whereas in the 1991 code the reduction factor is 0.95.

Some of the minimum design factors have been reduced in the 2015 design code, for instance the minimum design factor for anchor casing expansion into the well head and compressive stress due to liner self-weight and helical buckling are 1.4 and 1.0 respectively, while in the 1991 code the minimum design factors are 1.5 and 1.2 respectively.

The 1991 code accounts for the thermal expansion of fluids trapped within the casing by providing an outer casing with a lower burst pressure resistance than the collapse resistance of the inner casing and provide a minimum design factor of 1.2. On the other hand the 2015 design code recognizes the effect of high pressures generated by expansion of trapped fluids and stipulates that an adequate safety margin against yield arising from this case is to be taken into account while designing for collapse.

Thermal expansion of the casing is not allowed to exceed the minimum yield in the 1991 design code, while in the 2015 design code this is allowed and it is advised that when this is anticipated, the strain based design should be considered.

While determining the minimum casing depth it was noted that the 2015 code gave deeper minimum casing depths compared to the 1991 code. The two design codes provide guidance of minimum casing determination up to 2000 m. More light needs to be shed for wells that are to be drilled deeper than 2000 m. Generally from the calculations obtained during the design process there was no significant variation between the two design codes that was noted.

The author recommends that after the casing cementing has been done and drilling has to continue, then if possible the drilling fluid temperature should be elevated close to the bottom hole setting temperature of the casing to avoid introduction of tensional forces in the well. Similarly during reinjection activities, cold fluid should not be pumped into the wells.

REFERENCES

Finger, J. and Blankenship, D., 2010: Handbook of best practices for geothermal drilling. Sandia National Laboratories, Albuquerque. Website: http://artikel-software.com/file/geothermal%20drilling%20handbook.pdf

Gabolde G. and Nguyen, J. P., 2014: Drilling Data Handbook (9th edition). Editions Technip, Paris,? pp.

Hole, H., 2008a: Geothermal Well Design–Casing and Wellhead. In Petroleum Engineering Summer School. Dubrovnik, Croatia. Workshop (Vol.26). http://www.geothermal-energy.org/pdf/IGAstandard/ISS/2008Croatia/Hole02.pdf

ISO/TR 10400, 2007: Petroleum and natural gas industries - Equations and calculations for the properties of casing, tubing, drill pipe and line pipe used as casing or tubing. Technical report, ISO/TR 10400, 229 pp.

New Zealand Standard, 2015: Code of practice for deep geothermal wells. Standards New Zealand, Wellington, NZ, 102 pp.

New Zealand Standard, 1991: Code of practice for deep geothermal wells. Standards Association of New Zealand, Wellington, NZ, 93 pp.

Thorhallsson, S., 2015: Well designs and geothermal drilling technology. UNU-GTP, Iceland, unpublished lectures, 379 pp.

SPE (Society of Petroleum Engineers), 2015: Casing and tubing, Petrowiki, Website: http://petrowiki.org/Casing_and_tubing#Connection_design_limits