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SLIMHOLE WELL CASING DESIGN FOR HIGH-TEMPERATURE GEOTHERMAL EXPLORATION AND RESERVOIR ASSESSMENT*****

1. INTRODUCTION

Slimhole drilling technology, as low cost alternative for exploration wells, can play an important role when addressing issues related to reservoir assessment for geothermal energy exploration in new areas. Beside the advantage of lower cost, slimhole technology reduces the environmental impact of field exploration and resource assessment. Wells with diameter less than 6 inches (152.4 mm) are defined as slimholes and they are less costly than normal production-size holes due to reduced cost of crew, rigs, cementing, drilling fluids, casing and tubing. This technology can be easily applied in remote areas, where helicopter-portable rigs can be used. Most of the technologies used in geothermal industry are adopted form Oil and Gas industry with some modifications. However, geothermal reservoir conditions are much different from oil and gas reservoirs, where steam/water at high temperature has to be produced in large quantities and thus large casing diameters and open hole sections are required for large scale utilization [1]. Wells with smaller in diameter can, however, be used for exploration drilling to

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confirm the resource. Slimhole technology is adopted from already established techniques from deep-water wells, mineral exploration and geotechnical investigations [2]. Slim wells can be utilized not only in high-temperature reservoirs. In Poland, three exploratory slim wells of 4 inch (101.6 mm) diameter are being investigated for geothermal reservoir assessment in Podkarpackie Voivodeship in southeastern Poland. These wells are planned to exploit geothermal waters of temperature from 70 to 80°C from depths of around 2000 m.

2. RESERVOIR CONDITIONS IN HIGH-TEMPERATURE WELLS

High-temperature drilling in Iceland has shown that bottom hole pressures and temperatures often follow the Boiling Point Depth (BPD) curve, assuming that water is boiling at any depth in the water filled well [3], as shown in Figure 1. Saturation conditions are compared to the measured temperature and pressure (TP) values in a well that is heating-up after drilling. The figure indicates that the measured pressure and temperature follow saturation pressure and temperature for most of the well depths, approximately from 600 to 1700 m. Cooling near the bottom of the well is caused by cold water pumping from the time of stimulating after drilling, as the well is still heating-up. Boiling point values were calculated using "steam tables" from the X-steam program, Excel add-in. Temperature profiles during drilling operations or while shut-in are quite different from temperatures while heating-up after drilling [4]. Also, as shown in Figure 2, temperatures of various Icelandic geothermal wells are in agreement with the BPD curve, with some even exceeding boiling point (supercritical conditions – scope of Iceland Deep Drilling Project) [1].

a) b)

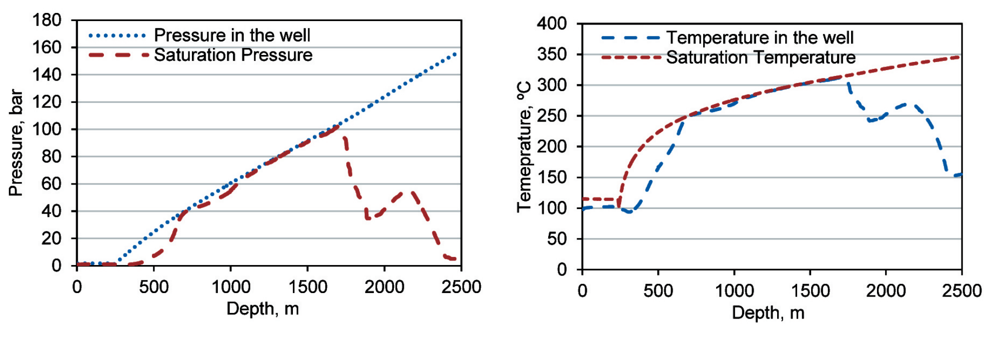

Fig. 1. Measured temperatures (a) and pressures (b) with saturation conditions in Icelandic high-temperature well (data provided by Sverrir Thorhallsson)

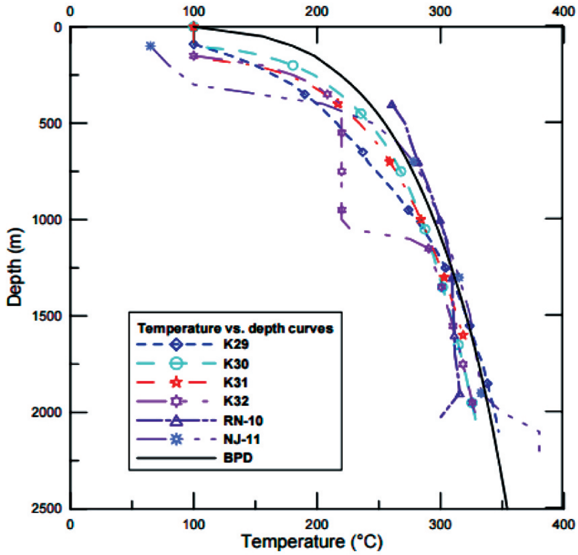

Fig. 2. Temperature profiles in high-temperature geothermal wells in Iceland K-Krafla, RN-Reykjanes, NJ-Nesjavellir [4]

The methodology used and the results obtained in this study are presented in the following sections: Section 3 presents the methodology used for the case study, i.e. casing design for a 2000 m deep vertical well with water level at 200 m, where the New Zealand Code of Practice has been applied. In section 4 results of calculations are presented and discussed for the casing design (section 4.1), casing loads (section 4.2), casing joints (section 4.3), API casing selection (section 4.4), wellhead selection (section 4.5) and finally conclusions in section 5.

3. METHODOLOGY

The most common geothermal exploration and assessment process involves drilling large diameter hole with production-size well and exercising lengthy flow tests right after drilling operations [1]. This method is very expensive and puts severe impact on surrounding environment. Drilling production-size holes can also put a large expense during first stages of the project and if well turns out to be non-productive or low in temperature, it can lead to long periods of debt for an investor [2]. In other words, very expensive geothermal wells are drilled with no reservoir knowledge and very high financial risk. Figure 3 represents three geothermal wells different in diameter: 12 ¼ inch in blue, 8 ½ inch in red and 6 inch in green. It can be noted that slimhole (green) wells have overwhelmingly lower demand on casing tonnage (60% lower than large-size holes) and cement amount (69% lower than large-size holes) and are much smaller in volume (74% lower than large-size holes) which equals to lower amounts of drilling fluid. These criteria amount to much lower costs of drilling wells with 6-inch diameter or less. As for Sandia National Laboratories report on slimhole drilling, intermediate cost of drilling slim wells is around 60% of the large well's overall costs to equivalent depth [2], where some other sources assume even 25 to 35% [5]. On this account, investor can drill three to four slim wells for the cost of one large-size well for better geothermal reservoir evaluation.

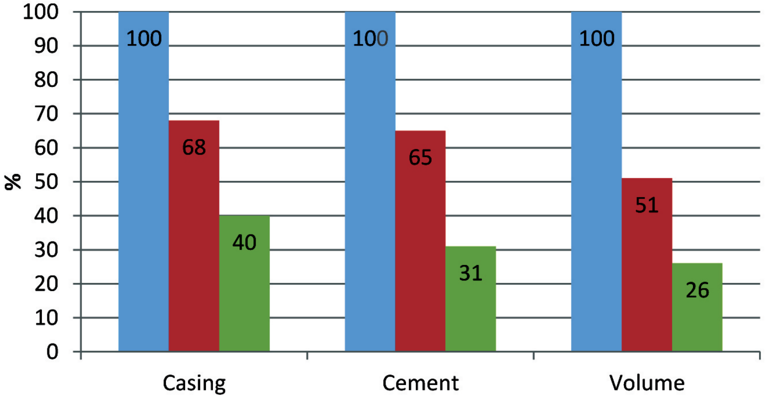

Fig. 3. Comparison of material usage for large size (12 ¼ inch) holes (blue columns), regular size (8 ½ inch) holes (red columns) and wells with 6 inch diameter (green columns) (data provided by Sverrir Thorhallsson)

Slim wells can be utilized to measure geothermal gradient and pursue flow testing in not yet assessed area. In reservoirs with low-permeability, size of the hole has no significant impact on total flow. However in high-permeability reservoirs, there might be some restrictions and higher friction losses, limiting total flow. A large number of researches made in Japan and USA confirm that flow testing in slim wells turned out to be equally informative as these in large size wells. Thus, data produced from slimholes can provide good prediction of reservoir productivity [2].

Two different methods of drilling slim wells are described in following paper, coring and rotary drilling (conventional) method. Wireline coring is a common method, sourced from the mineral exploration industry, designed for wells deeper than 300 m. It provides high quality core samples that can be used further for evaluation of reservoir conditions. Because of smaller hole diameter (from 2 to 6 inches) with corresponding core diameter (from 1 to 4 inches) and significantly smaller rigs, it can be easily applied for slim wells. Following method is performed by drilling an interval of 1 to 6 meters (depending on the length of core barrel) and retrieving the drill string each time with breaking the core just behind the bit. Next, wireline is run down to the core sample and it is retrieved with its inner tube. Top drive with hydraulic motor or chuck is used to turn the drill string. Due to very fine cutting production during coring and smaller hole volume, wireline coring can be carried out without drilling fluid returns ("blind" drilling) [2, 6, 7]. The core barrel used for drilling can be then left as a casing string, lowering the cost of casing. Conventional rotary drilling method comprises of drill string with tri-cone bit, drill pipes and Bottom Hole Assembly (BHA) with drill collars, crossovers, subs, jars and stabilizers. The drill string is rotated by either rotary table or top drive which applies torque to the string and allows it to travel downward [2]. This method uses low rotary speed and high weight on bit to crush rock formations and produce cuttings, which are only rock samples available to evaluate geothermal reservoir. As for Sandia report on slimholes, it is more favorable to use coring method, which involves less crew, smaller drill sites, less mud pumps and produces straighter hole. The ability of drilling "blind" can be also beneficial, as there is no need for mud logging and drilling mud recycling and thus lower environmental impact. "Blind" drilling can be also exercised through loss circulation zones. Main disadvantages of coring method is longer drilling time, especially in sedimentary formations and low availability of rigs able to drill below 1500 m of depth. The most favorable method in not yet assessed reservoirs, advised by authors is combination of coring and rotary method. It is very attractive for areas with softer formations at the beginning of drilling and relatively harder formation onwards. In summary, geological characteristic of chosen area should be thoroughly evaluated to select the best drilling method for slim wells. Following case study has general approach on slimhole drilling, thus both drilling methods were investigated.

4. RESULTS AND DISCUSSION

4.1. Casing design

Proper casing design is vital for safety and success of the drilling process as well as future integrity of the well. Casing design includes selecting casing diameter, weight of casing (thickness), steel grade and the casing joints which are analyzed for the case study and presented in the subsequent sections.

The well design includes deciding on the number of casing strings and the corresponding selection of the bit and the casing diameters and also the determination of the setting casing shoe depths. Typical casing programs for high-temperature wells include conductor casing, surface casing, anchor casing (intermediate casing), production casing and optional slotted or perforated liner in the open hole section. All casing strings should be cemented up to the surface, with the exception of liner which can be left uncemented in open hole. For this case study, casing strings were designed starting from the bottom of the well, proceeding to the top of the well. The boiling curves presented on Figure 4 were used as design criteria for the reservoir conditions [8–10].

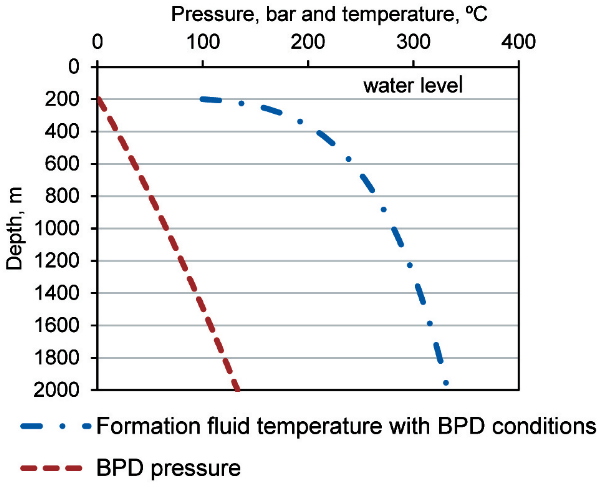

Fig. 4. Saturated temperature and pressure versus depth of the well

The design criteria and guidelines for high-temperature geothermal wells have been described in New Zealand Code of Practice from 1991 and the recent update from 2015. The main purposes of casing and liners in high-temperature wells are as follows [8, 9]:

– preventing a hole collapse caused by loose formation material,
– anchorage security and support of drilling operations,
– containing well fluids and withstand pressures imposed on casing,
– preventing contamination of fresh underground water,
– countering circulation losses during drilling,
– protecting the well from corrosion, erosion and fracturing.

Setting casing depths

When drilling a high-temperature geothermal well in a new area, without any adjacent wells or geological data, providing TP information as function of depth, a responsible assumption needs to be made. To cover the requirements of the "worst case scenario", the BPD conditions should be assumed. To determine the BPD curve for the case study and make borehole simulations for static (shut-in) and dynamic conditions (flowing), the X-steam program has been used [8].

The new NZS 2015 code determines the minimum depth of the casing strings based on the pore pressure and fracture gradient, which may be difficult to assess for a new area. Therefore, for flowing conditions the well is assumed to be steam filled using the pressure of the bottom of each section of the well as steam presure.

The NZS 1991 code approach is used for the case study as the criteria for pressure vs. depth for the water and overburden pressure are straight forward. As described in the NZS 1991, wellhead pressure in high-temperature wells is the saturation pressure of steam at the bottom hole (point with the highest temperature), subtracted by the weight of saturated steam, up to the surface. While the formation conditions for fracture pressure are not known, the overburden pressure is used as the limit for the steam column pressure to which casing might be exposed. The overburden pressure is determined by assuming an average specific gravity of formation (with density varied from 2300 to 2600 kg/m^3) [6, 9]. Relation between saturation pressure and temperature, as well as the NZS 1991 technique of setting casing depth is presented in Figure 5. The NZS 1991 method resulted with two casing strings with a minimum depth of the production casing of 560 m and the anchor casing of 150 m.

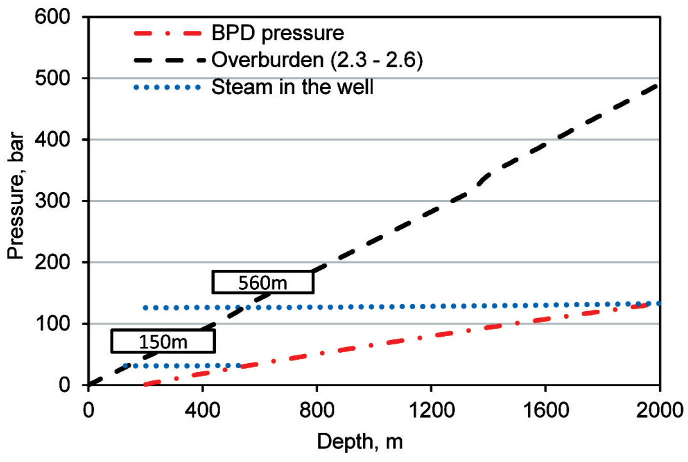

Fig. 5. New Zealand (NZS 1991) method of setting minimum casing depth for high-temperature wells (density in g/cm^3)

According to the information presented in reference [6] and [11], an alternative method is used in Iceland to determine the minimum casing depth to assess whether the well can be killed by heavy mud (with density of 1400 kg/m^3). The pressure profile for flowing well was applied assuming that inflow at the bottom hole is immediately converted to two-phase flow. The casing shoe depth is determined by intersecting the two-phase flowing well pressure with heavy drilling mud pressure as presented in Figure 6. Following the Icelandic method presented above two casing strings were selected: production at depth of 610 m and anchor at 170 m.

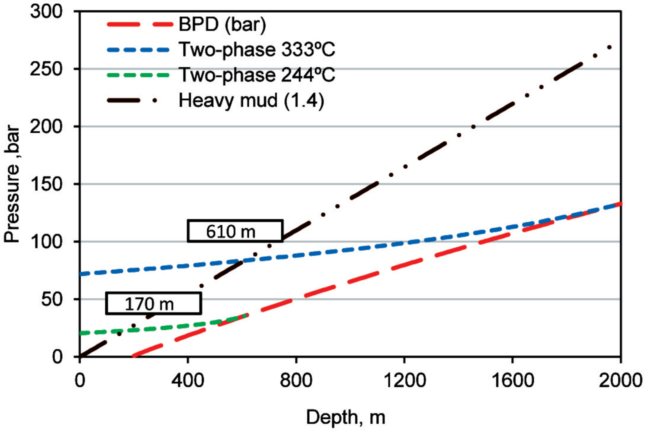

Fig. 6. Icelandic method for determining the minimum casing depth for high-temperature wells, using heavy mud and assuming two-phase flow from the bottom (density in g/cm^3)

Second Icelandic method of setting minimum casing depth (Fig. 7) is assuming the actual case for bottom hole temperature and pressure. To find casing shoe depth, two-phase density profile should not overcome the pressure of a cold water column. It is highly desirable that the well casing depth will allow the well to be killed by cold water only, even if there is an on-going "underground blow-out" in progress. Such a situation can occur, when there is a permeable zone just below the casing shoe. The well flows from bottom into this zone and simultaneously the cold water, which is provided to quench the well, flows down the casing to the same zone [6, 11]. Three casing strings were selected using second Icelandic method, namely production casing at depth of 940 m, anchor at 430 m and surface at 150 m.

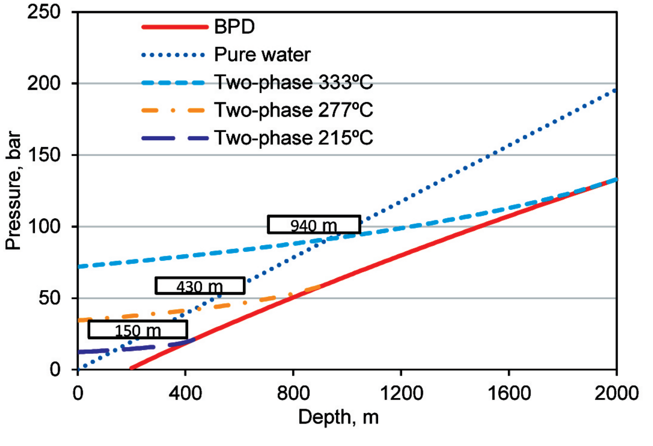

Fig. 7. Icelandic method for determining the minimum casing depth by assuming a likely temperature at the bottom of the well and quenching with cold water

As it is rather unlikely that the bottom hole temperature at 2000 m depth reaches 333°C, a more probable case was also considered using a bottom hole temperature of 280°C. As presented on Figure 8 the fluid turns into two-phase about half way up inside the flowing well. Following this method for 280°C as a bottom hole temperature, the results for production casing should have a minimum depth of 420 m and anchor casing at minimum depth of 140 m [6].

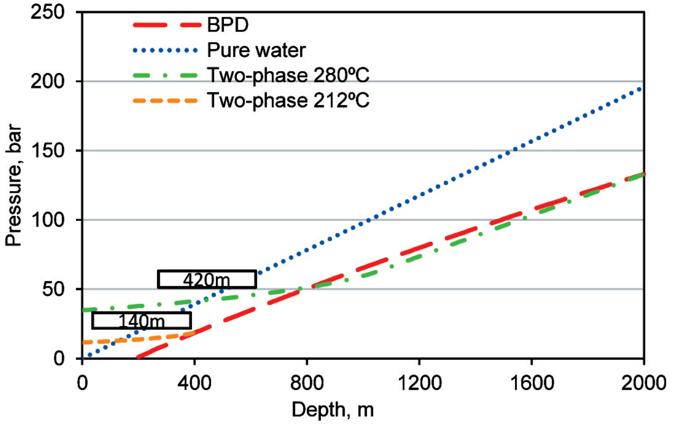

Fig. 8. Icelandic method for determining the minimum casing depth for high-temperature wells by assuming a BPD temperature at the bottom of the well and quenching with cold water

Comparing results of setting minimum casing depth with the first two methods, it can be assumed that they lead to roughly similar results. Using the second Icelandic method with BPD temperature as bottom hole temperature and cold water as killing fluid, casing program is supposed to be set around 300 m deeper with additional casing string implemented. The same Icelandic method with assumption of likely temperature of 280°C (Enthalpy of 1237 kJ/kg) at bottom hole, results in casing depth similar to the NZS 1991.

After comparison of all methods and results presented above, the final casing setting depth for this case study was set as follows: mandatory conductor casing at 30 m (pre-installed before the rig assembly), anchor casing at 200 m, production casing at 650 m and slotted liner to the depth of 2000 m hanged on liner hanger with 20 m overlapping. Actual casing setting depths are, however, usually based on minimum temperature (e.g. 210°C for high-temperature wells) at the production casing shoe and may be considerably deeper than the minimum criteria, which would require reassessing of the minimum casing depths for the anchor and surface casing.

Casing diameter

The inside diameter of production casing should ensure that down hole equipment such as liner or logging tools can easily run through the well [2]. Most of available measuring tools with diameter of either 35 or 42–44 mm would fit all reasonable sized holes, except some more advanced tools, such as micro-scanner or borehole televiewer with diameter above 70 mm. In this study, the selection of casing pipe diameters and bit sizes for each string is based on *API Specification 5CT, 5th edition* (Fig. 9). To fulfill the safety requirements of cementing, casing inside diameter should not be less than 2 inches (50.8 mm) larger than the outside diameter of joint attached to the next casing string. Drift diameter (used for determining the outside diameter of Bottom Hole Assembly tools) should not be larger than the outside diameter of any tools or equipment run through the casing [6, 8].

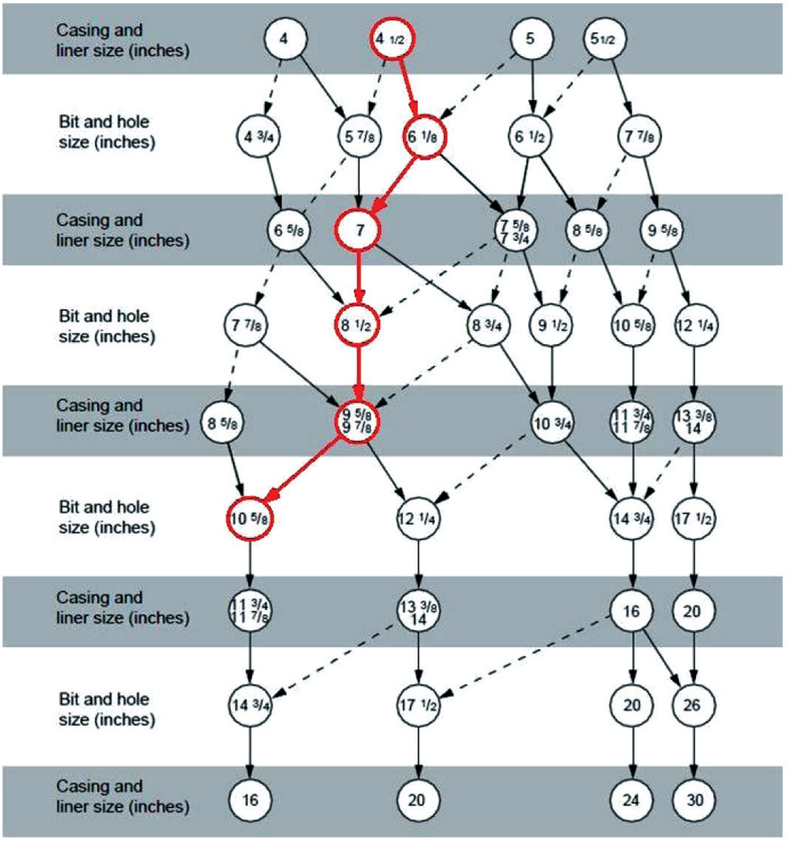

Fig. 9. Casing and bit program in accordance to API with selection for the case study (evaluated casing and bit program in following paper is marked in red) [12]

Steel grade and corrosion protection

Low alloy API K-55 (weldable) or L-80 (not weldable) steel type are the most preferable choice for high-temperature wells, as they minimize the possibility of failure caused by hydrogen embrittlement or sulphide stress corrosion [6, 8]. Tensile requirements for steel grade K-55 are presented in Table 1 [12, 13].

Table 1

Tensile requirements for K-55 casing [14]

Minimum yield strength	bar	3 790
	psi	55 000
Maximum yield strength	bar	5 520
	psi	80 000
Minimum ultimate tensile strength	bar	6 550
	psi	100 000

Looking at previous research [12] corrosion of the liner is expected to be more critical than the rest of the casing. To prevent corrosion of liner, which might originate from shallower casing, different methods can be applied [8]:

- adding inhibitors to circulating fluid,
- implementing larger casing diameter,
- application of corrosive resistance coverage onto the casing surface,
- different liner material choice, for instance glass fiber.

4.2. Casing loads

Various types of loads occur in the well during running, testing, cementing and production. These loads occur in axial (compressive and tensile) or radial direction (burst and collapse). For high-temperature wells, the most crucial loads are those caused by internal pressure and thermal expansion. Corrosion allowance needs to be taken into consideration while designing casing. Calculations presented in following sections are based on New Zealand Standard 1991 and recent update from 2015, as well as API standards. Cement density of 1900 kg/m^3 was applied for high-temperature geothermal wells [3]. Calculations for burst and collapse for the slotted liner were not included, as it is exposed only to axial self-weight compression (if standing on the bottom) or tension (if hanging with liner hanger) and helical buckling [3, 8].

Collapse pressure

The casing design must ensure that differential pressure between outside and inside the casing, during running or cementing operations, will not exceed the casing collapse resistance. For running the casing, the inside pressure is set to zero, as the casing is assumed to be empty for the design purposes. However, in practice, casing is periodically filled up with water while being run in the hole and then the collapse differential pressure becomes smaller [8, 9, 13].

Collapse pressure during cementing occurs when the annulus is filled with cement slurry and the casing is filled with water. Pressure at surface is assumed to be zero and the maximum collapse pressure at casing shoe is calculated. In this case study, additional 10 bars were added to the resulting collapse pressure for potential pressure loss due to friction while pumping the cement through the annulus. Safety factor of 1.2 was applied [8, 9].

$$P_{C\,cem} = (\rho_c - \rho_w) \cdot g \cdot h + P_p \tag{1}$$

$$P_{C\,run} = \rho_m \cdot g \cdot h \tag{2}$$

$$Design\ factor = \frac{casing\ external\ collapse\ pressure}{net\ external\ pressure} \tag{3}$$

where:

- $P_{C\,cem}$ – collapse pressure during cementing, bar,
- $P_{C\,run}$ – collapse pressure during running-in with casing, bar,
- P_p – pumping pressure, bar,
- ρ_w – density of pure (20°C) water, kg/m^3,
- ρ_c – density of cement, kg/m^3,
- ρ_m – density of drilling mud, kg/m^3,
- g – acceleration due to gravity, 9.81 m/s^2,
- h – increment of depth, m.

Burst pressure

Burst pressure, or internal yield is the difference between internal and external well pressure. Designing for burst must ensure that pressure inside the well will not exceed internal yield strength limit of casing. While designing for burst during production, pressure inside the well is assumed to be column of steam pressure, whereas annulus pressure is the formation pressure (BPD). Calculations were made for surface and casing shoe of each casing. External burst at surface is assumed to be zero. Safety factor of 1.8 and temperature reduction factor of 0.86 (Tab. 2) was applied.

Table 2

Results for burst and collapse calculations applied on anchor and production casing selected from section Setting casing depths, p. 470, using Excel worksheet

	Anchor casing [bar]	Production casing [bar]
Burst		
Burst pressure during production		
Burst at surface	126.2	126.6
Burst at surface by safety factor of 1.8	227.2	227.9
Pe at surface	0.0	0.0
Pi at surface	126.2	126.6
Burst at shoe	125.2	87.8
Burst at shoe by safety factor of 1.8	225.4	158.0
Pi at shoe	126.2	126.6
Pe at shoe	1.0	38.8
Collapse		
Collapse pressure during running of the casing		
Collapse at surface	0.0	0.0
Collapse at shoe	20.6	67.0
Collapse at shoe by safety factor 1.2	24.7	80.3
Pe at shoe	20.6	67.0
Pi at shoe	0.0	0.0
Collapse pressure after running of the casing		
Collapse at surface	0.0	0.0
Collapse at shoe	27.7	67.4
Collapse at shoe by safety factor 1.2	33.2	80.9
Pe at shoe	37.3	121.2
Pi at shoe	19.6	63.8

Together with collapse pressure, burst pressure dictates the choice of primary casing wall thickness [8]. Results for collapse and burst pressure are presented in Table 2.

$$P_{B\ prod} = (\rho_s - \rho_f) \cdot g \cdot h \tag{4}$$

$$Design\ factor = \frac{internal\ yield\ strength}{differential\ burst\ pressure} \tag{5}$$

where:

- $P_{B\,prod}$ – burst pressure during production, bar,
- ρ_s – density of steam column, kg/m^3,
- ρ_f – density of rock formation, kg/m^3.

Combination effects of axial and circumferential tension, while wellhead is fixed to the production casing are calculated using the equation below. Safety factor of 1.5 was applied [8].

$$f_t = \frac{\sqrt{5}}{2} \cdot \frac{P_w \cdot d}{(D-d)} \tag{6}$$

$$Design\ factor = \frac{steel\ yield\ strength}{maximum\ tensile\ strength} \tag{7}$$

where:

- P_w – maximum wellhead pressure, bar,
- d – pipe inside diameter, m,
- D – pipe outside diameter, m.

Axial Loading before and during cementing

Total tensile load (hookload), while running in and during cementing, applied on the casing (except conductor casing) are weight of casing in the air plus the weight of the casing content, less the buoyant effect resulting from fluids displaced by the casing [8].

The following different cases were investigated: drilling mud inside the casing and in annulus (m/m), cement inside the casing and drilling mud in annulus (c/m), cement inside the casing and in annulus (c/c) and water inside the casing and cement in annulus (w/c). Typical cementing method was considered, i.e. pumping slurry cement down through the casing and up to the annulus. This method is better suited for smaller in diameter casing programs. For large in diameter high-temperature wells, inner-string method is more commonly used [1]. Safety factor of 1.8 was applied for the calculated w/c hookload. Calculations were made using equations from the NZS 2015 and results are presented in Figures 10 and 11.

$$F_{csg} = F_{csg\ air\ wt} + F_{csg\ con} - F_{fluid} \tag{8}$$

$$F_{csg\ air\ wt} = L_z \cdot W_p \cdot g \tag{9}$$

$$F_{csg\ con} = L_z \cdot \rho_x \cdot \frac{\pi \cdot d^2}{4} \cdot g \tag{10}$$

$$F_{fluid} = L_z \cdot \rho_y \cdot \frac{\pi \cdot D^2}{4} \cdot g \tag{11}$$

where:

$F_{csg\ air\ wt}$ – weight of casing in the air, N,
$F_{csg\ con}$ – weight of internal content of casing, N,
F_{fluid} – weight of fluids displaced by casing, N,
F_{csg} – surface force suspending casing subjected to gravitational and static, hydraulic loads, N,
L_z – length of liner or depth of casing below any level, m,
ρ_x – density of section of fluids within the casing, kg/m^3,
ρ_y – density of section of fluids within the annulus, kg/m^3.

Minimum total tensile loading before and during cementing should be lower than pipe body yield strength of K-55 steel grade. For production and anchor casing, maximum hookload applied before and during cementing with safety factor will not exceed the pipe body yield strength [8].

$$Design\ factor = \frac{minimum\ tensile\ strength}{maximum\ tensile\ load} \tag{12}$$

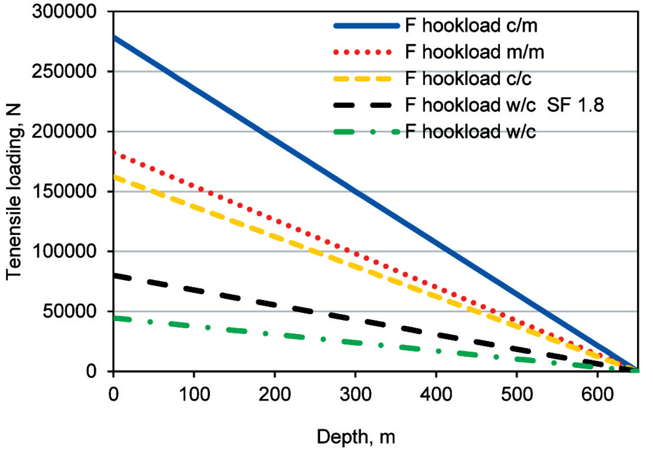

Fig. 10. Production casing tension loading before and during cementing operations

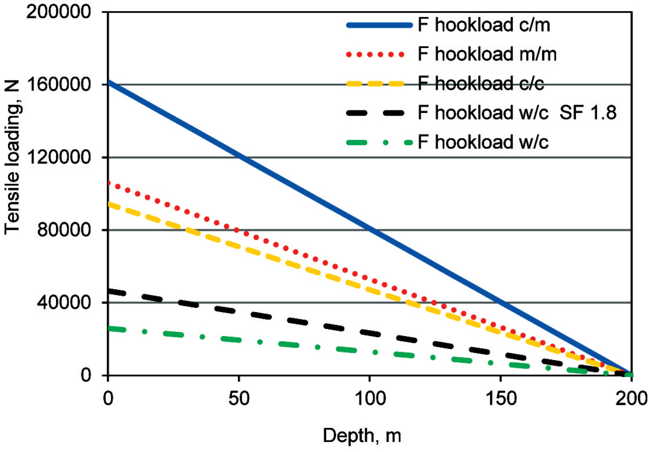

Fig. 11. Anchor casing tension loading before and during cementing operations

As presented in Figures 10 and 11, the highest tension loads are applied on casing during cementing, when cement is inside the casing and drilling mud is in the annulus. The minimum tensile force applied on the casing is when entire volume of cement is displaced into the annulus (w/c). Such conditions were selected for calculation of the collapse resistance.

Axial loading after cementing

When designing casing for geothermal well with boiling conditions, it is crucial to consider the temperature effects to allow for the changes in casing steel properties. Thus safety factors from Table 3 should be applied [3]. For design purposes temperature through the pipe is assumed to be constant. Results from calculations are presented in Table 4.

Table 3

Safety factors concerning temperature effects for casing K-55 [8]

K-55 casing properties – temperature effects							
Temperature (°C)	20	100	150	200	250	300	350
API Yield Strength (unitless)	1.00	0.94	0.90	0.90	0.85	0.80	0.70
Tensile Strength (unitless)	1.00	0.96	0.92	0.90	0.88	0.86	0.84
Modulus of Elasticity (10^3 MPa)	210	205	201	197	194	190	185

Table 4

Axial loading after cementing operations with tensile loads derated for temperature effects

Load case		Value	Resultant value	Calculated SF	Unit
Wellhead internal pressure where wellhead is fixed to the casing		142	212.5 (SF 1.5)	4.6	MPa
Fluid lifting force on production casing		258 930	388 390 (SF 1.5)	5.4	N
Fluid lifting force on anchor casing		489 810	734 710 (SF 1.5)	5.4	N
Thermal stress (tension stress due to cooling)	Anchor casing	697 760	723 600	5.7	N
	Production casing	249 850	294 320	7.9	N
Thermal stress (compressive stress due to heating up)	Anchor casing	797 450	823 280	5.0	N
	Production casing	1 684 990	1 729 460	1.3	N

After that cement sets, casing is exposed to axial loads due to temperature rise. The compressive force after cementing operations, when casing is constrained longitudinal and lateral is calculated using the coefficient of thermal expansion and temperature difference, as presented below. It is difficult to assume one specific temperature, as the temperature varies throughout the casing sting. For design purposes the temperature of 60°C was applied for anchor casing and 80°C for production casing. Modulus of elasticity was selected from Table 3 for boiling conditions, coefficient of linear thermal expansion was assumed to be $12 \cdot 10^{-6}$/°C. Design factor of 1.2 was applied [8].

$$F_c = E \cdot a \cdot (T_1 - T_2) \cdot A_p \tag{13}$$

$$F_r = F_c + F_p \tag{14}$$

where:

- F_c – change in axial force within casing body due to heating, N,
- F_p – axial force within casing body at cement set, N,
- F_r – resultant axial force within casing body, combining the force at cement set and subsequent thermal forces, N,
- a – coefficient of thermal expansion, °C^{-1},

E – modulus of elastic, MPa,
A_p – cross-sectional area of pipe, m^2,
T_1 – neutral temperature (i.e. temperature of casing at time of grout set), °C,
T_2 – maximum expected temperature, °C.

Tension loads due to circulation of cooled fluid from the surface during drilling or testing operations is calculated using following equations. Minimum temperature of 25°C was chosen for anchor casing and 55°C for production casing after cooling of the well [8].

$$F_t = E \cdot a \cdot (T_1 - T_3) \cdot A_p \tag{15}$$

$$F_r = F_t + F_p \tag{16}$$

$$Design\ Factor = \frac{minimum\ tensile\ strength\ of\ joint}{resultant\ compressive\ force} \tag{17}$$

where:
F_t – change in axial force within casing body due to cooling, N,
T_3 – minimum temperature after cooling, °C.

The axial loading (Tab. 4), enforced on top section of casing anchoring and the wellhead (in this case production casing) against the fluid (steam) inside the well is calculated using the follows equation. Safety factor of 1.5 was applied [8].

$$F_w = P_w \cdot \frac{\pi \cdot d^2}{4} \tag{18}$$

$$Design\ Factor = \frac{anchor\ casing\ tensile\ strength}{rising\ casing\ compressive\ strength} \tag{19}$$

Initial temperature rise in the well results in increase of the compressive loads in the cemented casings, which might decrease with time. On the other hand, tensile loads due to cooling might increase after installation of the casing strings [8].

Critical collapse strength for Oilfield Tubular Goods

Critical collapse resistance of K-55 steel grade casing was calculated using API equations from *API Bulletin 5C3, 1989*. Following formulas conclude minimum acceptable collapse values, which are determinated by geometrical deviations of casing and yield strength of the casing material. Theoretical calculation formals are presented in Table 5, whereas results in Table 6.

$$A = 2.8762 + 0.10679 \cdot 10^{-5} \cdot Y_p + 0.21302 \cdot 10^{-10} \cdot {Y_p}^2 - 0.53132 \cdot 10^{-16} \cdot Y_p^3 \tag{20}$$

$$B = 0.026233 + 0.50609 \cdot 10^{-6} \cdot Y_p^3 \tag{21}$$

$$C = -465.93 + 0.030867 \cdot Y_p - 0.10483 \cdot 10^{-7} \cdot {Y_p}^2 + 0.36989 \cdot 10^{-13} \cdot Y_p^3 \tag{22}$$

$$F = \frac{46.95 \cdot 10^6 \cdot \left(\dfrac{\dfrac{3B}{A}}{2 + \dfrac{B}{A}} \right)^3}{Y_p \cdot \left(\dfrac{\dfrac{3B}{A}}{2 + \dfrac{B}{A}} - \dfrac{B}{A} \right) \cdot \left(1 - \dfrac{\dfrac{3B}{A}}{2 + \dfrac{B}{A}} \right)^2} \tag{23}$$

$$G = (F \cdot B) / A \tag{24}$$

Previous equations are based on zero axial stress, however in normal working conditions that is never the case. Considering axial loading (Figs 10 and 11) and temperature effects (Tab. 4), new derated yield strength is calculated as follows:

$$Y_{pa} = Y_p \cdot \left[\sqrt{1 - 0.75 \cdot \left(\frac{S_a}{Y_p} \right)^2} - 0.5 \cdot \frac{S_a}{Y_p} \right] \cdot 0.8 \tag{25}$$

where:

- Y_p – yield strength of casing, MPa,
- Y_{pa} – reduced yield strength of casing by temperature effects and axial stress, MPa,
- S_a – axial stress, N,
- t – pipe wall thickness, m.

Table 5

Formulas for calculating critical collapse resistance in accordance to API Bulletin 5C3

Failure model		Applicable D/t range
Elastic collapse	$p_c = \dfrac{46.95 \cdot 10^6}{\dfrac{D}{t} \cdot \left(\dfrac{D}{t} - 1\right)^2}$ (26)	$\dfrac{D}{t} \geq \dfrac{2 + \dfrac{B}{A}}{\dfrac{3B}{A}}$ (30)
Transition collapse	$p_t = \left(\dfrac{F}{\dfrac{D}{t}} - G\right) \cdot Y_p$ (27)	$\dfrac{Y_p \cdot (A - F)}{C + Y_p \cdot (B - G)} \leq \dfrac{D}{t} \leq \dfrac{2 + \dfrac{B}{A}}{\dfrac{3B}{A}}$ (31)
Plastic collapse	$p_p = Y_p \cdot \left(\dfrac{A}{\dfrac{D}{t}} - B\right) - C$ (28)	$\dfrac{\left[(A-2)^2 + 8\left(B + \dfrac{C}{Y_p}\right)\right]^{1/2} + (A-2)}{2 \cdot \left(B + \dfrac{C}{Y_p}\right)} \leq$ $\leq \dfrac{D}{t} \leq \dfrac{Y_p \cdot (A - F)}{C + Y_p \cdot (B - G)}$ (32)
Yield collapse	$p_y = Y_p \cdot \dfrac{\left(\dfrac{D}{t}\right) - 1}{(D/t)^2}$ (29)	$\dfrac{D}{t} \leq \dfrac{\left[(A-2)^2 + 8\left(B + \dfrac{C}{Y_p}\right)\right]^{\frac{1}{2}} + (A-2)}{2 \cdot \left(B + \dfrac{C}{Y_p}\right)}$ (33)

Table 6

Results for critical collapse strength and minimum burst resistance in accordance to API Bulletin 5C3

Casing	With zero axial loads		With axial loads and temperature effect	
	Production	Anchor	Production	Anchor
Yield strength	55 000 psi		43 940 psi	43 810 psi
A	2.991		2.960	2.959
B	0.054		0.048	0.048
C	1206		873.261	869.465

Table 6 cont.

D	21.808				14.301		14.222	
F	1.989				2.033		2.033	
G	0.036				0.033		0.033	
D/t ratio	22.082		22.126		22.082		22.126	
Failure model	Plastic		Plastic		Plastic		Plastic	
Minimum Burst Resistance	4 359 psi	30.0 MPa	4 350 psi	30.0 MPa	3 482 psi	24.0 MPa	3 465 psi	23.9 MPa
Collapse resistance	3 269 psi	22.5 MPa	3 254 psi	22.4 MPa	2 886 psi	19.9 MPa	2 870 psi	19.8 MPa

Minimum burst resistance in accordance to API

To calculate minimum burst resistance of the casing, Barlow's equation was used [15]. Same as collapse resistance, yield strength of the material should also be derated with temperature coefficient of 0.8 (Tab. 4) and axial loading. Results for minimum burst resistance are shown in Table 6. Thickness of both casing strings was increased in order to withstand the burst pressure load.

$$P_{B\,res} = 0.875 \cdot \left(\frac{2 \cdot Y_{pa} \cdot t}{D} \right) \cdot 0.8 \tag{34}$$

4.3. Casing joints

The most common type of casing joints in geothermal industry are API Buttress Standard thread connections (API BTC), with proven strength both in compression and tension. These "trapezoid-shaped" threads are easily accessible and have lower amount of threads per inch [8, 14, 16].

The highest tensile loads on joints are occurring while running the casing. Thus calculations were made with casing strings filled with pure water inside and outside of the pipe (Figs 12 and 13). To meet safety requirements, design factor of 1.8 was applied. Calculated tension loads are minor and are far from exceeding the tensile strength of the join ($232 \cdot 10^3$daN for production casing and for anchor casing $411 \cdot 10^3$daN) [14].

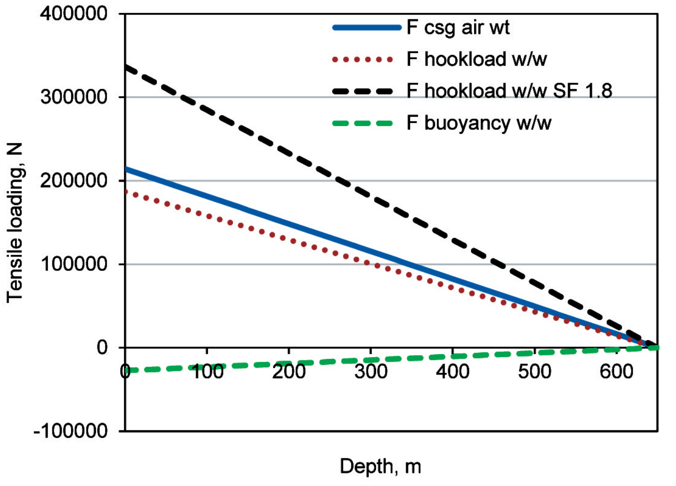

Fig. 12. Production casing tensile loading while running the casing with water inside the casing and in annulus

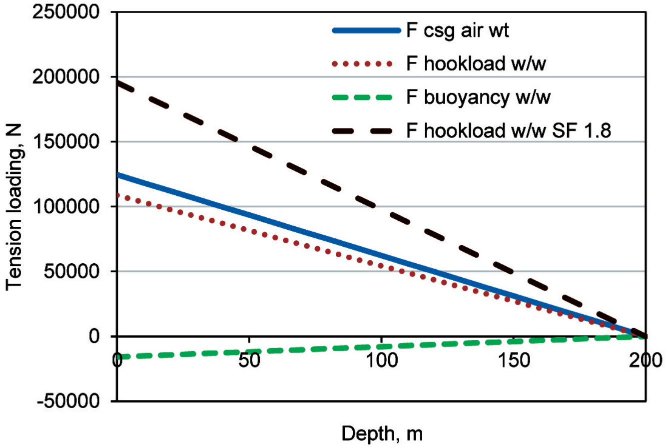

Fig. 13. Anchor casing tensile loading while running the casing with water inside the casing and in annulus

4.4. Casing selection

Based on the results of the design calculations made in section 3, two examples of casing set were selected according to API standards (Tab. 7) and Diamond Core Drilling Manufacturers Association (DCDMA) coring standards (Tab. 8). Schematic drawing of both casing programs is presented in Figure 14.

Table 7

Casing strings selected according to API standards for conventional, rotary drilling method

Casing string	Depth, m	Weight, lb/ft	OD, mm	ID, mm	Wall thickness, mm	Connection OD, mm	Drift diameter, mm
Conductor	30	54.5	339.7	320.4	9.7	365.1	316.5
Anchor	200	43.5	244.5	222.4	11.0	269.9	218.4
Production	650	23.0	177.8	161.7	8.1	194.5	158.5
Liner	2 000	10.5	114.3	102.9	5.7	127.0	99.7

Table 8

Casing program selected for wireline coring method
(*values chosen from Boart Longyear catalogue) [7]

Casing	Cementing	OD, mm	ID, mm	Weight, kg/m	Content, l/m	Pipe Length, m	Depth, m
Perforated NQ drilling rod*	Perforated	69.90	60.30	7.80	2.86	3	2 000
NW*	Cemented	88.90	76.20	12.80	4.56	3	650
HW*	Cemented	114.30	101.60	17.40	8.10	3	200
API 7” conductor casing	Cemented	177.80	164.00	20.00	21.12	–	10

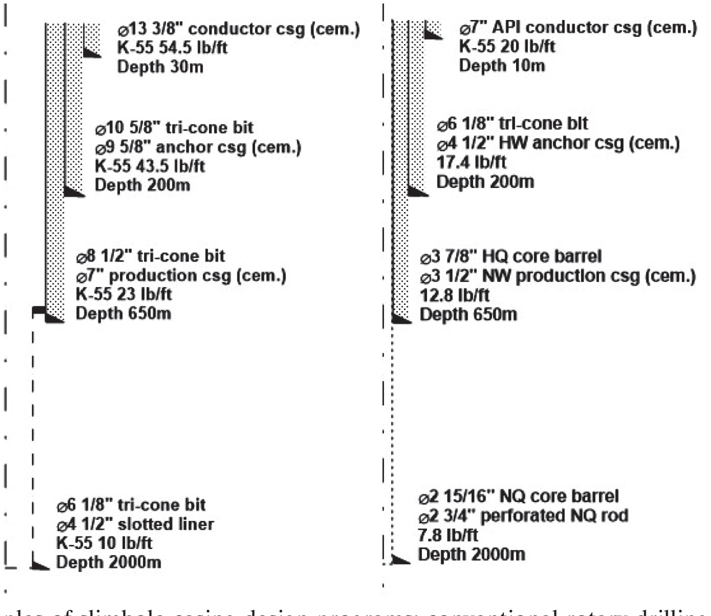

Fig. 14. Examples of slimhole casing design programs: conventional rotary drilling method (according to API) (left) and combined method using rotary drilling and wireline coring (according to Boart Longyear catalogue) (right)

4.5. Wellhead

The permanent wellhead for high-temperature wells consists of a Casing Head Flange (CHF) which is typically attached to anchor casing, optional expansion spool (which gives production casing room for thermal expansion), master and side valves. Design basis for a wellhead should consider the maximum possible pressure and temperature exposure at surface. For estimating temperature and pressure, steam column pressure from bottom hole to the surface is considered, where pressure drop is caused only by the weight of steam column. Thus reservoir and wellheads temperatures are never equal, but similar. Top of the casings as well as wellhead should be protected from corrosive environments of atmosphere and fluids within the well [8, 10, 17].

Calculated wellhead pressure and temperature using X-steam amounts to 126 bars and 329°C, considering only the steam density as a function of pressure. Flange ANSI 1500 was selected in accordance with *ASME B16.5* and *ASTM A-105* specifications. Casing Head Flange can be attached to the top of production casing (no expansion spool) or to the anchor casing (with expansion spool) as shown on Figure 15 [6].

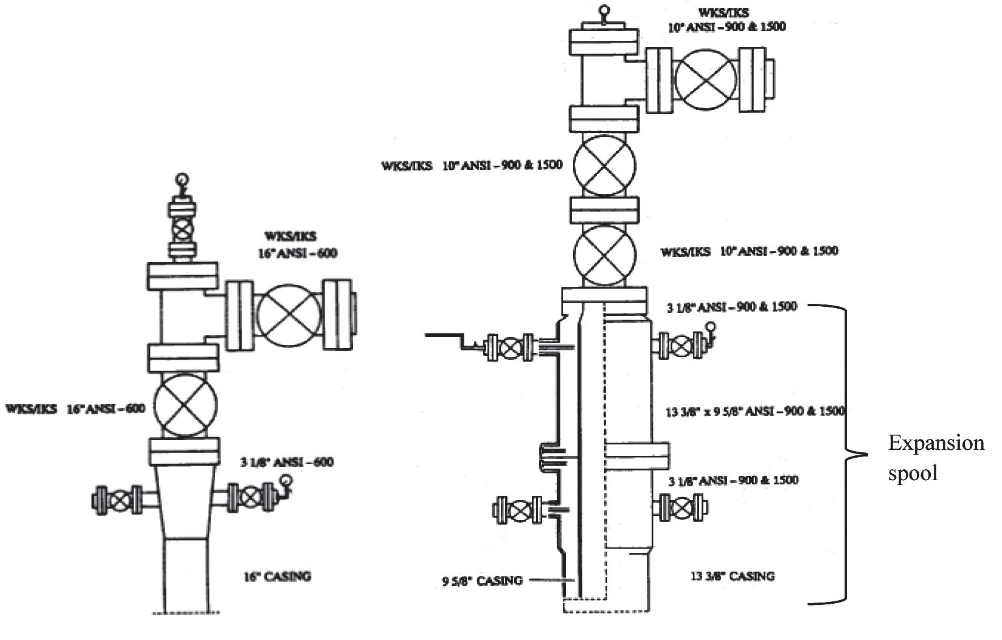

Fig. 15. Typical wellheads used to anchor high-temperature geothermal wells: A. without expansion spool, B. with expansion spool [6]

5. CONCLUSIONS

1. Slim wells are drilled with much lower costs than regular or large size geothermal wells and with less environmental impact. Such wells provide equally informative geological and reservoir engineering data as large size holes. Slimhole technology allows drilling three to four wells in cost of one large size well for better assessment of geothermal reservoir and with lower economic rick.
2. Depending on geological characteristic of area different methods of slimhole drilling can be used. Wireline coring method has lower environmental impact and drilling costs (with core barrel can be used as casing string), than conventional rotary drilling method. On the other hand, rotary method provides faster drilling and there are no depth limitations. Casing loads calculations for rotary method are already well described by API standards, where there are no well-established methods of calculating casing loads in wireline casing strings.
3. This study shows that the casing setting depth methods assuming steam filled well or two-phase flow, which is commonly used in geothermal industry, gives comparable results to the Boiling Point Depth curve. Actual casing setting depths are usually based on minimum temperature (e.g. 210°C for high-temperature wells) at the production casing shoe and may be considerably deeper than the minimum criteria. Then the minimum casing depths of the anchor and surface casings need to be reassessed.
4. Properties of casing, found in API standards, do not include minimum strength requirements at elevated temperatures. As yield strength of the casing material decreases significantly at higher temperatures, temperature correction factor from New Zealand Standard 2015 should be used for geothermal well designs.
5. Internal pressure (burst) is the highest at the surface, while collapse pressure is the highest at casing shoe. Tensile loads depend mostly on the weight of the casing. Quite shallow setting of cemented casing strings in slimhole well results in high burst loads and low collapse loads. Tensile loads are minor, due to the lightweight of the casing. For exploratory geothermal wells, casing should be of low grade steel (K-55) and casing joint should be of API Standard Buttpress.
6. While estimating the wellhead's temperature and pressure, isenthalpic steam column from bottom hole to the surface should considered, where pressure drop is caused only by vapour density. Permanent wellhead can be installed either on the top of the anchor or the production casing.

7. During drilling for geothermal resources, one can encounter high-temperature formations containing corrosive fluids. As slotted liner is the deepest casing string and it is installed in the open hole, it can experience severe corrosion, which can radiate to shallower casing. Thus, revision of the slotted liner material (e.g. fiber glass) should be considered in the future casing designs for slimhole wells.

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APPENDIX

Table A

Wellhead pressure estimation

Depth, m	Formation fluid temperature with BPD conditions, °C	Formation fluid pressure with BPD conditions, bar	Liquid Density, kg/m^3	Vapour density, kg/m^3	Wellhead Pressure, bar
0	0.0	0.0	0.0	0.0	**126.1**
50	0.0	0.0	0.0	0.0	126.1
100	0.0	0.0	0.0	0.0	126.1
150	0.0	0.0	0.0	0.0	126.1
200 (water level)	99.6	1.0	958.6	0.6	126.1
250	156.1	5.6	911.3	3.0	126.2
300	179.9	10.0	887.1	5.1	126.2
350	196.1	14.3	869.2	7.3	126.2
400	208.6	18.6	854.4	9.3	126.2
450	218.9	22.7	841.6	11.4	126.3
500	227.7	26.8	830.1	13.4	126.4
550	235.5	30.9	819.7	15.4	126.4
600	242.4	34.9	810.0	17.5	126.5
650	248.6	38.8	801.0	19.5	126.6
700	254.3	42.7	792.4	21.5	126.7
750	259.6	46.6	784.2	23.5	126.8
800	264.5	50.4	776.5	25.6	126.9
850	269.1	54.2	769.0	27.6	127.0
900	273.4	58.0	761.8	29.7	127.2
950	277.4	61.7	754.8	31.8	127.3
1 000	281.3	65.4	748.0	33.9	127.5
1 050	284.9	69.1	741.4	36.0	127.7
1 100	288.4	72.7	734.9	38.1	127.8
1 150	291.7	76.3	728.6	40.2	128.0

Table A cont.

1 200	294.9	79.8	722.5	42.4	128.2
1 250	297.9	83.4	716.4	44.6	128.5
1 300	300.8	86.9	710.4	46.8	128.7
1 350	303.6	90.4	704.6	49.0	128.9
1 400	306.3	93.8	698.8	51.3	129.2
1 450	308.9	97.2	693.1	53.6	129.4
1 500	311.4	100.6	687.4	55.9	129.7
1 550	313.9	104.0	681.8	58.2	130.0
1 600	316.2	107.3	676.3	60.6	130.2
1 650	318.5	110.6	670.8	63.0	130.5
1 700	320.7	113.9	665.4	65.4	130.9
1 750	322.8	117.1	659.9	67.9	131.2
1 800	324.9	120.4	654.6	70.4	131.5
1 850	326.9	123.6	649.2	72.9	131.9
1 900	328.9	126.7	643.9	75.5	132.2
1 950	330.8	129.9	638.6	78.1	132.6
2 000	**332.6**	**133.0**	**633.3**	**80.8**	**133.0**