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Geothermal Well Design for Efficient Energy Extraction and Long-term Integrity

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Abstract

This paper presents the analysis of internally and externally insulated tubular in terms of heat loss preservation and tubing long-term structural integrity. The analysis is through modelling and simulation sensitivity studies. Results showed that the high flowrate leads to lower heat loss to the well's surrounding. When the heat conductivity of cement increases from 0.88-3.48 W/mK, the overall heat transfer coefficient in non-insulated well is increased by about 215%, which results in a huge amount of heat losses. Simulation study also showed that for a well-constructed with 0.88 W/mK cement conductivity, the externally, internally, -and both internally-externally insulated tubulars reduced the overall heat transfer coefficient of the non-insulated tube by 47%, 63% and-67%, respectively. For effective heat mining and long-term structural integrity, an appropriate material should be selected to withstand high temperature and corrosive environment. Insulators need to have a lower heat conductivity and thicker size, high resistance to flow and anti-corrosive properties. Moreover, it is essential to monitor the well and apply corrosion control additives regularly.

1. INTRODUCTION

The world population growth has a direct relationship with both the increasing energy consumption and the increasing energy demand. At present and the years to come, the nonrenewable fossil resources energy decline/shortage is one of the worldwide issues. Renewable resources among others geothermal, solar, and wind are environmentally friendly and abundant energy sources.

The main sources of geothermal energy are hydrothermal and hot dry rock resources, which are found in shallow and deep formations, respectively. In the field of geothermal energy, the power plant technology converts the hot geothermal fluids into electric power. The higher underground thermal energy extraction is the better for the power plant energy conversion. However, in a poorly designed wellbore, the up flowing geothermal fluid influxes heat radially from the well to the surrounding. To maintain/preserve heat transfer, it is therefore important to design geothermal well with appropriate material and identify the right operational parameters.

NORSOK D-10 standard defined well integrity as the application of technical, operational and organizational solution with the objective of reducing the risk level of undesired leak from subsurface to surface (NORSOK D-010, 2013). **Figure 1** show the well integrity survey study based on 75 producers, & injectors wells information obtained from 7 operators. Survey result showed that 11% (Casing), 11 % (Cement), 5 % (Packer), 12% (Annular safety valve, ASV) and 39% (Tubing) barrier problems (Vignes et al., 2010).

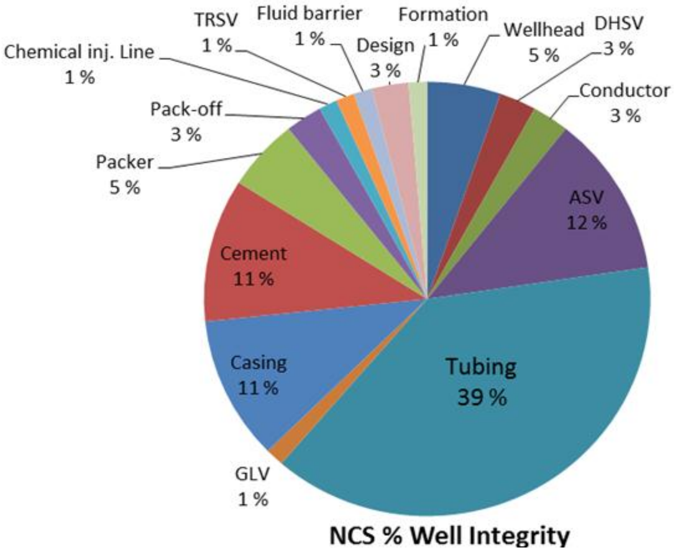

Figure 1: Well integrity problems on the North Sea wells (Vignes et al., 2010)

Watson and Bachu (2009) have assessed the CO_2 leakage potential of wells using 316,439 abandoned wells in Alberta, Canada. Of the 4.6% wells that experienced leakage, most of the leakage were above the top of the cement which indicates that the cement is a factor in preventing leaks. Cement bond logs showed channeling that allows formation fluid communication with the casing and resulted in casing corrosion (Watson and Bachu (2009). Case study on CO_2 injection wells in North Sea, Dutch sector, showed that CO_2 pitting depth was about 25% of the tubulars worn away (Mulders, 2006). Moreover, metal liners recovered prior to CO_2 injection had shown wide-ranging corrosion, which is possibly due to the presence of chloride ions in the formation water.

Unlike petroleum wells, geothermal wells are exposed to exposed to excessive thermal loads, corrosion and fatigue (Teodoriu,2015). Due to superheated steam temperature and high pressure in Iceland Deep Drilling Project, the well casing was collapsed, and the well was abandoned(Friðleifsson, 2017). It is also documented that casing failure and cement integrity are the key issues for geothermal wells (Teodoriu, 2009). Geothermal production wells require high production rates, often above 100 000 [kg/hr.] as compared to oil and gas wells(Finger,2010). The chemistry of geothermal well fluid is another issue, which comprises of complex multi-component corrosive ions such as Cl^- can be mentioned (Povarov et al., 2000). In addition, the corrosive gases presence in geothermal waters are carbon dioxide (60-95%) and hydrogen sulphide (2-15%) (Carvalho et al., 2006). .

The question to be addressed in this paper is how the internally and externally insulated production tubing in geothermal well maintain heat loss and provide long term structural integrity? Analysis results from the modelling indicated that insulators play important role in efficient energy preservation and prolong the well integrity by controlling corrosion, erosion as well as mechanical tubular failure problems.

2. LITERATURE REVIEW

In the following, the main issues will be reviewed. The possible consideration along with the remedial actions will be indicated.

Gases In Geothermal Fluids

The Energy Sector Management Assistance Program (ESMAP) reported that geothermal fluid contains corrosive gasses. As provided in Table 1, the typical geothermal gases include CO_2, H_2 S, H_2, N_2, CH_4, NH_3, and Ar (ESMAP, 2012). Among these, one can observe that concentration of CO_2 in geothermal fluids abundantly, which accounts more than 95 percent. Additionally, H_2S and N_2 are found significantly. Compared with coal-fired plants, the emission of CO_2 from the geothermal power plant is smaller. However, some investigators observed that the reinjection of CO_2 enhances the productivity and inhibiting the possible SiO_2 scaling (Kaya et al., 2011). Moreover, the concept of super critical $SCCO_2$ as working fluid is introduced for reservoir fracturing and heat transfer (Brown, 2000, Spycher & Pruess, 2010). Field experimental study showed that the reinjection of CO_2 in hard rock reservoir will lead to the calcite ($CaCO_3$) deposition. (Kaieda et. al, 2009).

Table 1: Typical composition of Geothermal Gases (Weight % Dry gas)(ESMAP, 2012)

	CO_2	*H_2S*	*H_2*	*CH_4*	*NH_3*	*N_2*	*AR*
Median	95.4	3.0	0.012	0.15	0.29	0.84	0.02
Maximum	99.8	21.2	2.2	1.7	1.8	3.0	0.04
Minimum	75.7	0.1	0.001	0.0045	0.005	0.17	0.004

Corrosive Brine Ions In Geothermal Fluid

Table 2 shows the chemical analysis of the geothermal wells and indicated that among others the concentration chloride ion is very high. (Dincer et al., 2018). Case studies from several Indonesian geothermal wells also reported similar analysis (Mahon et al., 2000). Provided that the application of CO_2 reinjection and using as working fluid found out to be positive in terms of productivity and heat transfer, the production tube will be continuously exposed to corrosive gases (CO_2, H_2S) and chloride (cl-) and sulfate (SO_4) ions.

Table 2: Element analysis of geothermal fluids (Dincer et al., 2018)

LOCATION	pH	B	HCO_3	Ca	K	Na	Mg	Cl	SO_4	SiO_2
Wairakei, New Zealand	8.3	28.8	23	12	210	1250	0.04	2210	28	670
Tauhara, New Zealand	8.0	38	19	14	223	1275	–	2222	30	726
Broadlands, New Zealand	8.4	51	233	1.43	224	1035	0.1	1705	2	848
Ngawha, New Zealand	7.6	1080	298	2.9	90	1025	0.11	1475	27	464
Cerro Prieto, Mexico	7.27	14.4	52	438	1660	7370	0.35	13,800	18	808
Mahia-Tongonan, Philippines	6.97	260	24	255	2184	7155	0.41	13,550	32	1010
Reykjanes, Iceland	6.4	8.8	87	1705	1720	11,150	1.44	22,835	28	631
Salton Sea, California	5.2	481.2	220	35,500	21,600	62,000	1690	191,000	6	1150
Paraso, Solomon Islands	2.9	5	–	51	27	136	11.1	295	300	81

As reviewed, the exposure of production tube with the corrosive gasses and geothermal fluid brine will lead to structural integrity issue due to corrosion. The possible corrosion type, consequences and remedial actions will be presented here.

Uniform Corrosion

Case studies in Italy and Russia have shown tubing leakage due to CO_2 corrosion (Marina Cabrini et al., 1998, Natalya et al., 2019). During Production or reinjection, the carbonic acid formed due to the mixture of CO_2 with water will dissolve the corrosive protecting passive layer (De Waard et al., 1975, Zhen, 2017). The surface becomes anodic so that it will continually release electrons. Consequently, the removal of the tubular surface will reduce the wall thickness uniformly. For the considered internal and external pressures loading, the example shown in **Figure 2** illustrates the state of stresses before and after the wall thickness has been reduced uniformly by 10% and 20% . The analysis shows that the von Mises stress in the damaged tubing increased by 10% and 23%, respectively. As a result, the risks for the tubing failure will be higher.

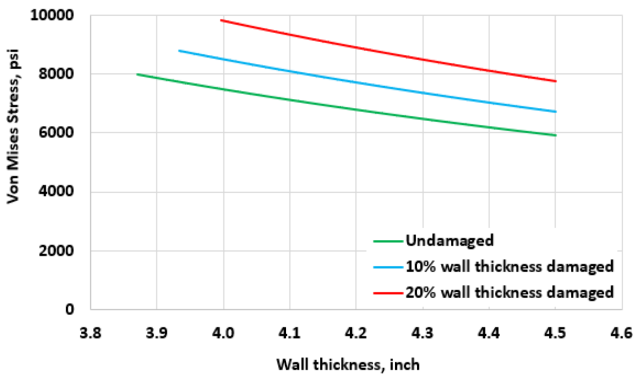

Figure 2: Stress analysis of undamaged and uniformly damaged tube

Pitting Corrosion

Tubulars in oil and gas wells experience localized type pitting corrosion, which creates holes on the surface and grows in vertical direction across the wall thickness (Natalya, 2019). Among others, the chloride ion accelerates the pitting corrosion and other ions such as sulfate are provided in Table 2. In an oil and gas wells, pitting corrosion is observed in in the presence of CO_2/H_2S gas. As displayed in **Figure 3**, Finite element method (FEM) simulation studies show that the stress concentration at crescent and wedge type local damage is higher and leads to structural failure with lower loading as compared with the uniform wall thickness simulated with the API Barlow model (Belayneh et al., 2019).

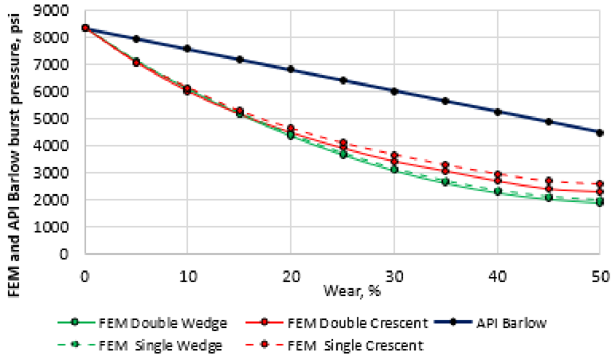

Figure 3: Comparison of tubing burst derated pressures of L-80 tube. (Belayneh et al., 2019)

Material selection as well as thicker tubular size are the commonly corrosion control methods. However, lining tumular would enhance the effectiveness of corrosion control. However, when it comes to heat preservation, the erosivity and heat conductivity of the insulator are the key parameters for consideration.

It is almost impossible to avoid corrosion in the wellbore. It is imperative to monitor and conduct a regular treatment to reduce the corrosion rate. A simple example is presented here using the NORSOKM560 CO_2 corrosion rate prediction model (NORSOKM560 Standard, 2005). For a given typical simulation input parameters, NORSOK M56 CO_2 corrosion rate predictions for 20% glycol treated tubular compared with absence of glycol are shown in **Figure 4**. The corrosion rate at 60°C shows a decline. This is due to the precipitation and formation of iron carbonate ($FeCO_3$) scale-film, which acts as a barrier and inhibiting steel dissolution (Gerhardus et al., 2002). However, the corrosion rate is also controlled by several other parameters such as CO_2 partial pressure, pressure, temperature, pH, velocity, shear stress and medium ions (Nesic, 2007, Liu et al., 2009, Zhao et al., 2005, Videm et al., 1993). **Figure 5** illustrates the effect of pH on corrosion rate. The examples presented show that with the right glycol concentration and regular treatment, the corrosion rate can be decreased and prolong the life of the tubular.

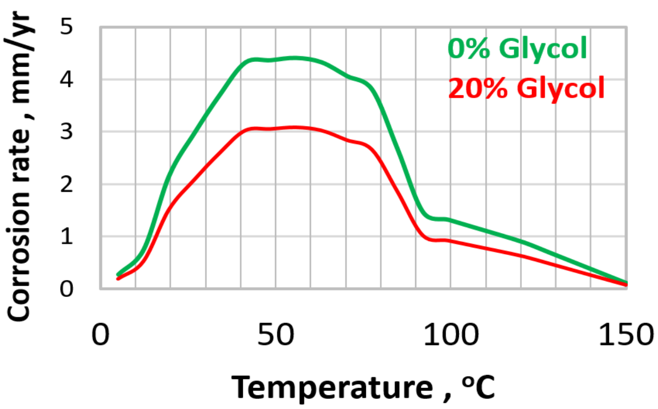

Figure 4: Effect of inhibitor on corrosion rate

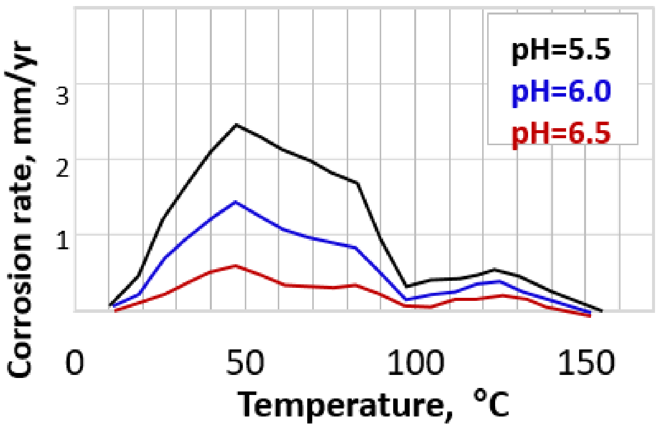

Figure 5: Effect of pH on corrosion rate

High temperature well

Geothermal wells are characterized by lower reservoir pressure and higher temperature. The temperature induces stresses in the wall thickness of the tubulars. Temperature is also another issue on annular pressure build-up. As fluid flows, heat transfer from well to annulus heat up annular fluid temperature and hence increases annular pressure. Adams (1991) presented case studies, which showed that annulus heat-up causes high burst/collapse stresses. This indicates the importance of the appropriate material selection during geothermal well construction process. Geothermal wells will therefore require a high-grade casings and cement to control the undesired heat loss, tolerate aggressive corrosive, high temperature and high-pressure environments.

Errosion corrosion

When the fluid flow velocity reaches to the critical erosional velocity, the tubular corrosion protective film layer will be removed. The tubular/metal surface becomes anodic, which results in corrosion. As illustrated in figure 3, the stress concentration in the local damage is higher and leads to tubular failure for lower loading rate. Moreover, cavitation is an issue in tubulars. When bubbles in fluid system hit tubular a sharp bended or unsmoothed surface creates a strong shock wave, which could be sufficient to remove the corrosive protective layer. Several wells in the North Sea show leak, which is due to erosional induced local damage (Torbergsen et al., 2012). In order to avoid erosional induced damage, API RP14E recommends the maximum production velocity, which is a function of tubular C-factor and density of multiphase flow (Bellarby 2009).

3. GEOTHERMAL WELL DESIGN AND ANALYSIS

In order to manage the issues of tubular integrity and maximum energy extraction, this section presents modeling and simulation sensitivity study.

3.1 Well flowing fluid temperature simulation

To evaluate the fluid flowing temperature with respect to various flow rates, a typical petroleum well has been designed in commercial Landmark software. As fluid flows from the reservoir to the surface, the heat transfer through fluid is governed by convention heat flow. The heat transfer between production tube and the surrounding wellbore is by conduction method. The well is drilled horizontally in the reservoir section. The production tubing is 4209 m, and production liner is extended to the reservoir. The fluid and well (casing/cement/insulator) thermal conductivities, geometry of the well structure, and completion fluid along with flow rate influence the thermal behavior of well flowing fluid. Due to the temperature difference between the fluid and the formation, the heat transfer would determine the heat loss during the life of the production. **Figure 6** displays the simulated fluid temperature profile for different production rates. The graph shows the typical undisturbed geothermal gradient of the well. Higher production rates produce fluids with higher temperatures on the surface as shown in the simulation for different flowrates.

The fluid temperature profile inside the tubing/working string for the initial production and produces 1-year production operation. It can be deducted from the graph that, the higher the production rate of fluid, the lesser the amount of heat loss to the wellbore and the higher the temperature of the fluid produced at the surface. Flow rate is one of the key parameters; however, it is important to design the production tubing with respect to the critical flow induced erosion.

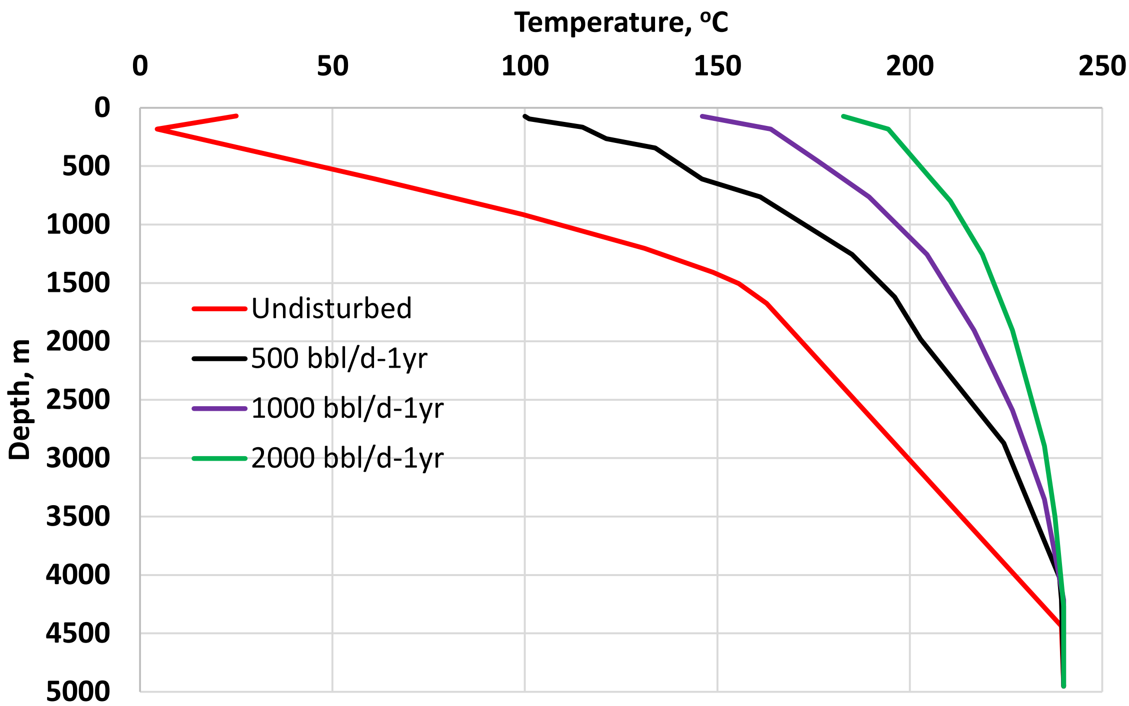

Figure 6: Tubing working fluid flowing temperature profile

3.2 Overall heat transfer coefficient modelling

Let as consider a simple geothermal well, which extracts energy from deep hard rock. Geothermal well is like petroleum well construction, which contains tubing, annular completion fluid, casing, cement and formation. **Figure 7** shows part of the vertical cross-sections of the well. The injection fluid as shown in the figure flows through reservoir and the boiled steam flows from the reservoir to the surface. Due to temperature difference between the flowing fluid and the formation, heat influx radially across the wellbore structure to the surrounding. The higher the temperature difference and the cross-sectional area is the higher rate of heat flow. This shows the direct proportional and the proportionality constant term is known as the over-all heat transfer coefficient. The physical meaning of the overall heat transfer coefficient is that it is analogues like a net resistance for flowing fluid, tubing, insulating material, casing completion fluid, casing wall and cement sheath to the flow of heat. Heat transfer rate in the annulus is due to the combined effect of natural convection and conduction (h_c) and radiation, (h_r). Heat loss attains a quasi-steady state at which the rate of heat loss monotonically decreases with as time increases (Willhite , 1967). However, for simplicity and analysis purpose, in this paper a steady state heat transfer around the wellbore assumption was considered.

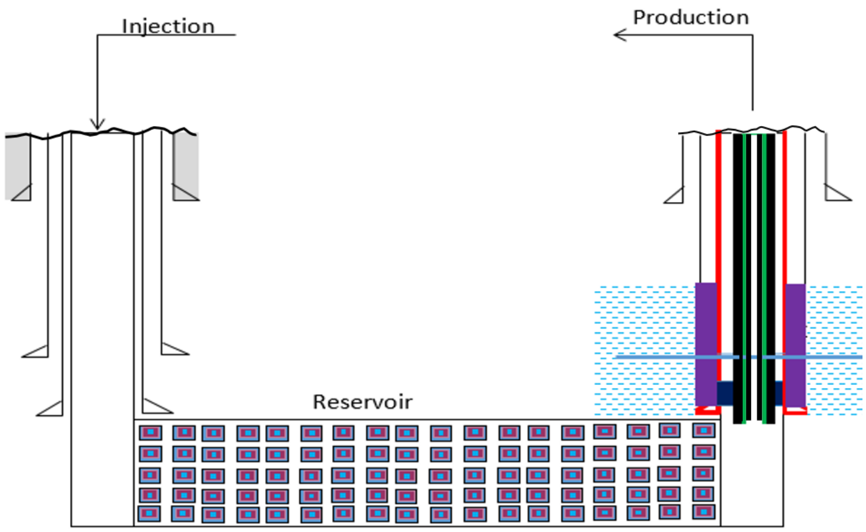

Figure 7: Illustration of geothermal injection/production and ideal dual porosity reservoir

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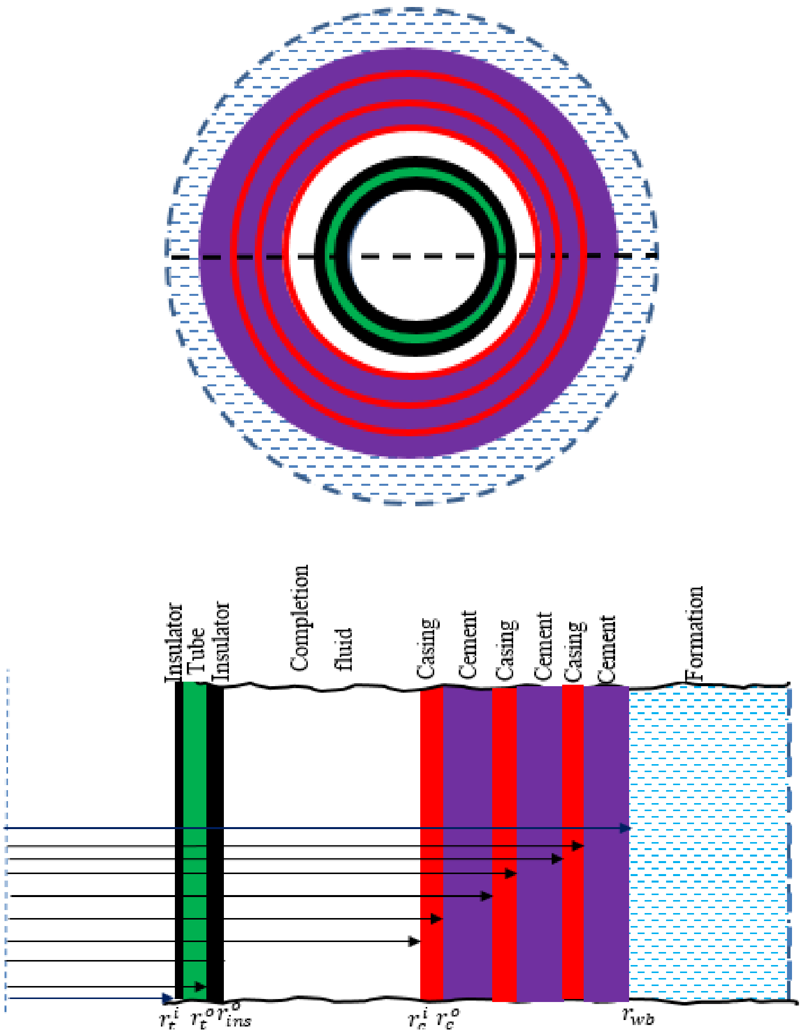

Figure 8: Illustration of the horizontal and vertical cross-section of the well

Model- At Top Section

In order to preserve as much heat as possible, it is important to select the right material properties and geometry. Assume that the top part of the geothermal well is cemented between the conductor, surface and intermediate casings. The production tube is insulated internally and externally. **Figures 8** shows the horizontal and vertical cross-sections of the well.

Based on the classical paper published (Willhite , 1967), the steady state overall heat transfer coefficient across the considered cross section can be derived as:

$$\frac{1}{U_{to}} = \frac{r_t^o}{r_{ins}^i h_f} + \frac{r_t^o \ln(\frac{r_t^o}{r_t^i})}{K_t} + \frac{r_t^o \ln(\frac{r_t^i}{(r_t^i - t_{ins}^i)})}{K_{ins}^i} + \frac{r_t^o \ln(\frac{r_t^o + t_{ins}^o}{r_t^o})}{K_{ins}^o} + \frac{r_t^o}{r_{ins}^i (h_c + h_r)} + \frac{r_t^o \ln(\frac{r_{prod}^o}{r_{prod}^i})_{prod}}{K_{csg}} + \frac{r_t^o \ln(\frac{r_{int}^i}{r_{prod}^o})_{prod}}{K_{cem}} + \frac{r_t^o \ln(\frac{r_{int}^o}{r_{int}^i})_{int}}{K_{csg}} + \frac{r_t^o \ln(\frac{r_{surf}^i}{r_{surf}^o})_{int}}{K_{cem}} + \frac{r_t^o \ln(\frac{r_{wb}}{r_{surf}^o})_{surf}}{K_{cem}} + \frac{r_t^o \ln(\frac{r_{surf}^o}{r_{surf}^i})_{surf}}{K_{csg}} \qquad (1)$$

Where, the parameters ***K*** is thermal conductivity of **cem**ent, **cas**ing, **ins**ulator, and **t**ube. Other symbols such as ***sc, int***, and ***cond*** are surface, intermediate and conductor casings. The symbols are defined in **Table 4**. The internal and the external insulator's thicknesses are t_{ins}^i and t_{ins}^o.

At steady state conditions, the rate of heat flow through the wellbore per unit of length (also defined as the overall heat transfer or heat exchange) is (Willhite , 1967):

$$Q = -2\pi r_{to} U_{to} (T_f - T_{wb}) \qquad (2)$$

Where, U_{to} represents the overall heat transfer coefficient, ($T_f - T_{wb}$) is the temperature difference between the wellbore/formation interface and the wellbore fluid.

4 Heat Transfer Simulation

4.1 Simulation Setup

Table 3 provides the geothermal simulation well, which is used for the assessment of the effect of insulation on the heat transfer. The initial reservoir temperature is assumed to be 240 ^{o}C. Liquid convective heat transfer coefficient, conductivity of tubing material, convective heat transfer coefficient, conductivity of casing material, radiative heat transfer coefficient is shown in shown in **Table 4**. The production fluid flow was assumed to be through 5″OD and 4.8″ID tubing. The differential temperature at the top section of the wellbore, where the simulation study conducted was 150^{o}C**.**

Asadia et al., (2018) have reviewed the thermal conductivity of cement-based materials like concrete along with their density. The data showed that the thermal conductivity of the considered dataset is being within the range of 0.08-3.863 W/m K. In this paper, therefore the simulation study was carried out based on the reviewed cement thermal conductivity, which was varied from 0.14-3.46 W/m K. Moreover, the thermal conductivity of insulating materials was obtained from engineering toolbox, which is in the range of 0.035-0.16 W/m K.

Table 3: Well Design Parameters

Tubular	Outer Diameter) [m]	Hole Size [m]
Conductor casing	0.7620	0.9144
Surface casing	0.508 0	0.6604
Intermediate casing	0.3397	0.4445
Production casing	0.2444	0.3175

Table 4: Input Parameters for Simulation

Input parameters	**Value [Unit]**
h_f-Liquid convective heat transfer coefficient inside tubing surface	499.7 [W/m^2-^{o}c]
K_t-Conductivity of tubing material	25.95 [W / (m K)]
h_c-Convective heat transfer coefficient outside insulation surface	102.2 [W/m^2-^{o}c]
K_c-Conductivity of Casing material	25.95 [W/ (m K]
h_r-Radiative heat transfer coefficient on outside insulation surface	11.4 [W/m^2-^{o}c]
$K_{int\ \&\ ext-}$ Internal and external thermal conductivity of insulation	0.05, 0.16 [W / (m K)]
$t_{\_int\ \&\ ext}$ – Internal and external thickness of insulation	0.008, 0.014, 0.020, 0.024 m.

4.2 Simulation Results And Discussion

The simulation results presented here deals with the analysis of insulated and uninsulated geothermal production tubular with regards to the heat preservation performance. For design purpose, the well parameters considered for the investigation were the size and the thermal conductivity of insulator placed at the inner, the external and both sides of the production tubing.

4.2.1 Effect Of Insulator's Thermal Conductivity

The heat preservation performance geothermal wells insulated internally, externally and their combination were compared with uninsulated geothermal well. The conductivity and the thickness of the insulating materials were assumed to be constant **Figures 9** and **10** show the simulation results. As displayed in **Figure 9**, in the absence of insulator, the overall heat loss coefficient increases significantly as the cement conductivity increases. On the other hand, in an insulated tube, the effect cement's thermal conductivity is insignificant. For instance, as the conductivity of cement increases from 0.88-3.48 W/mK, the overall heat transfer coefficient in non-insulated well is increased by about 215%. Simulation study also showed that for a well-constructed with 0.88 W/mK cement conductivity, the externally, internally, and both internally-externally insulated wells reduced the overall coefficient of the non-insulated well by 47%, 63% and-67%, respectively. F**igure 10** displays the expected heat loss(i.e., heat influx density per meter), which is directly proportional to the heat loss coefficient. The result illustrates the importance of insulating production tube both externally and internally regarding heat recovery, tubing structural integrity and hence increase the life of the well.

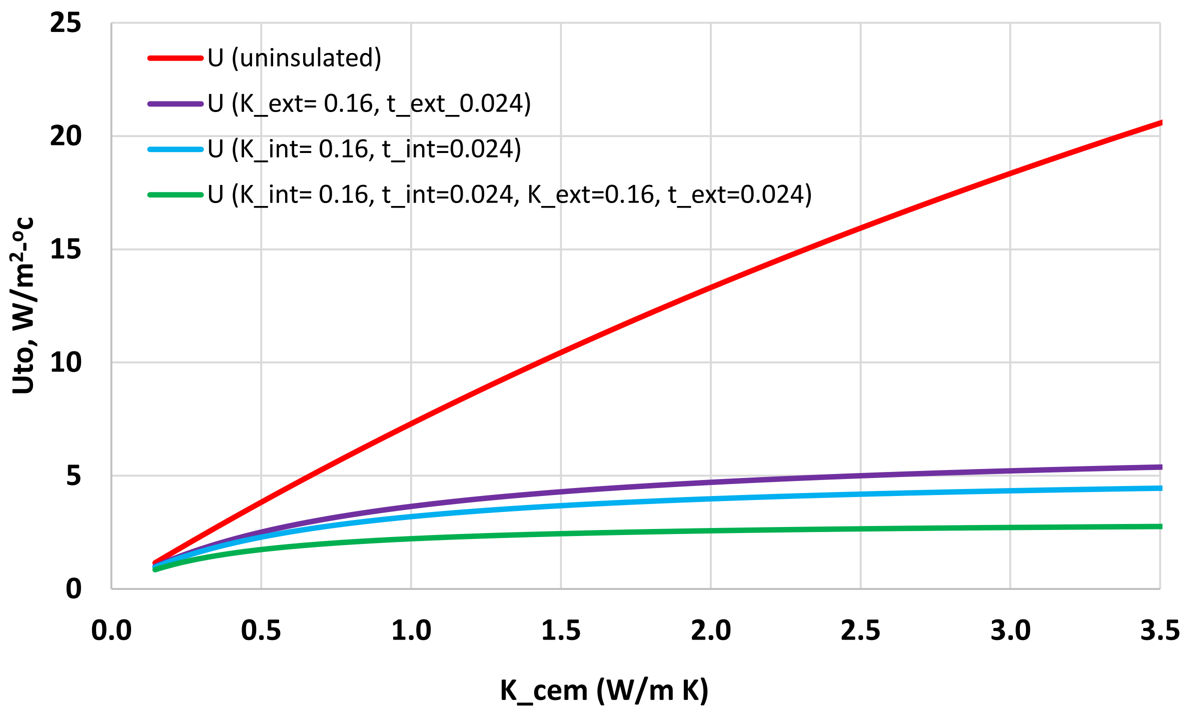

Figure 9: Overall heat transfer coefficient comparison between uninsulated and internal/external insulated tube

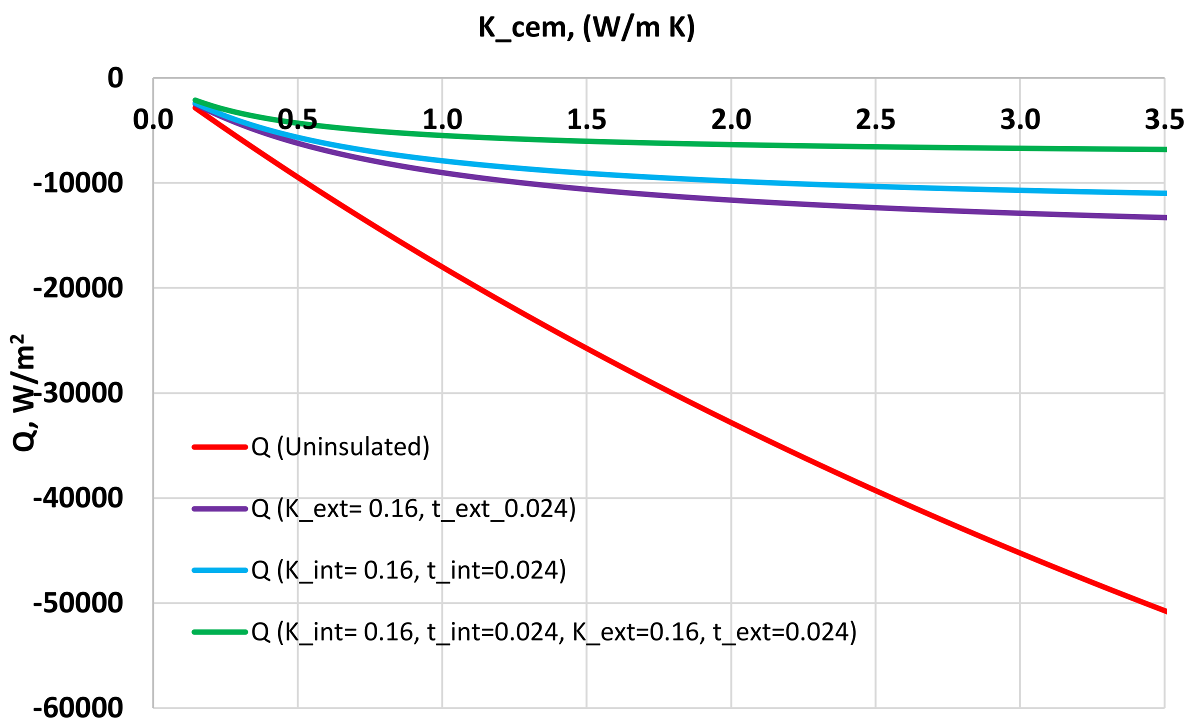

Figure 10: Heat loss comparison between uninsulated and internal/external insulated tube

4.2.2 Effect of internal insulation size

For the analysis, an experimental geothermal wellbore was constructed with constant external/internal conductivities (K_int = K_ext = 0.16 W/m K) and insulated externally with a thickness of 0.024m. In this wellbore, the sensitivity of internal insulator thickness in the range of 0.008-0.024 m was simulated. Results show that the thicker internal insulator reduces the overall heat transfer coefficient (**Figure 11)** and hence preserves significant amount of heat from begin loss (**Figure 12**). Since the heat loss with respect to the conductivity of cement increases gently. In the presence of external insulation, when the cement conductivities are 0.26, 0.52, 1.04 and 3.48 W/mK, the internal insulator sizes increase from 0.008m to 0.024 m result in heat loss reduction by 16%, 22%, 28% and 35%, respectively. Results show that the lower cement conductively along with the insulator sizes reduce the heat loss significantly.

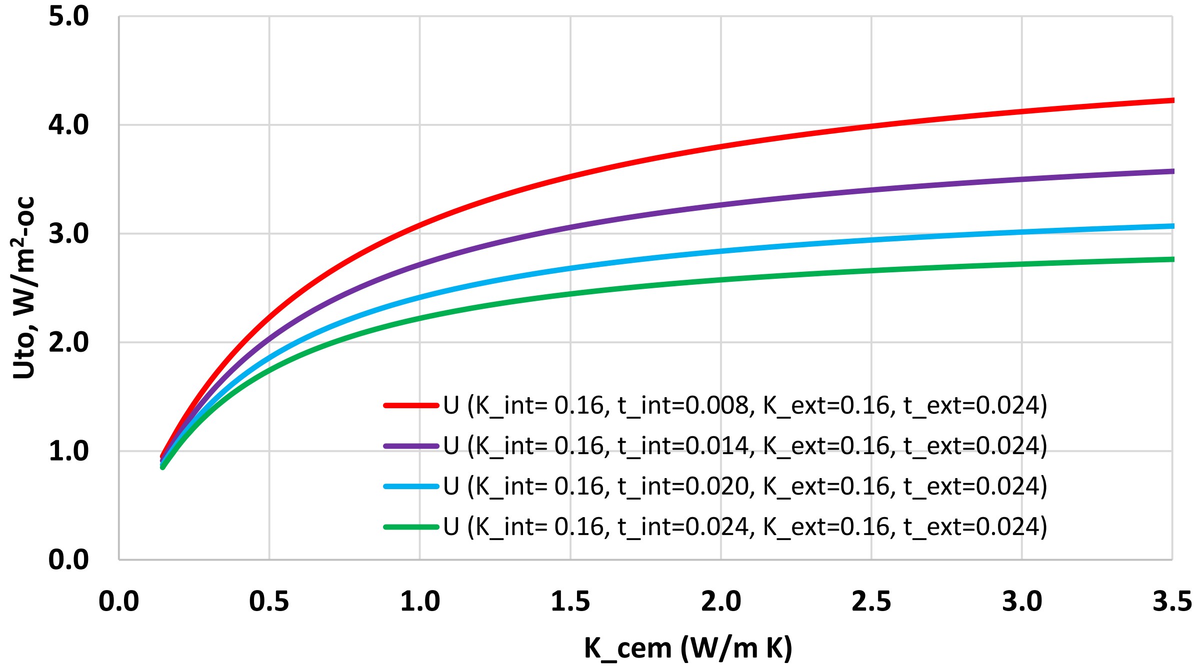

Figure 11: Effect of size of internal insulators on overall heat transfer coefficient.

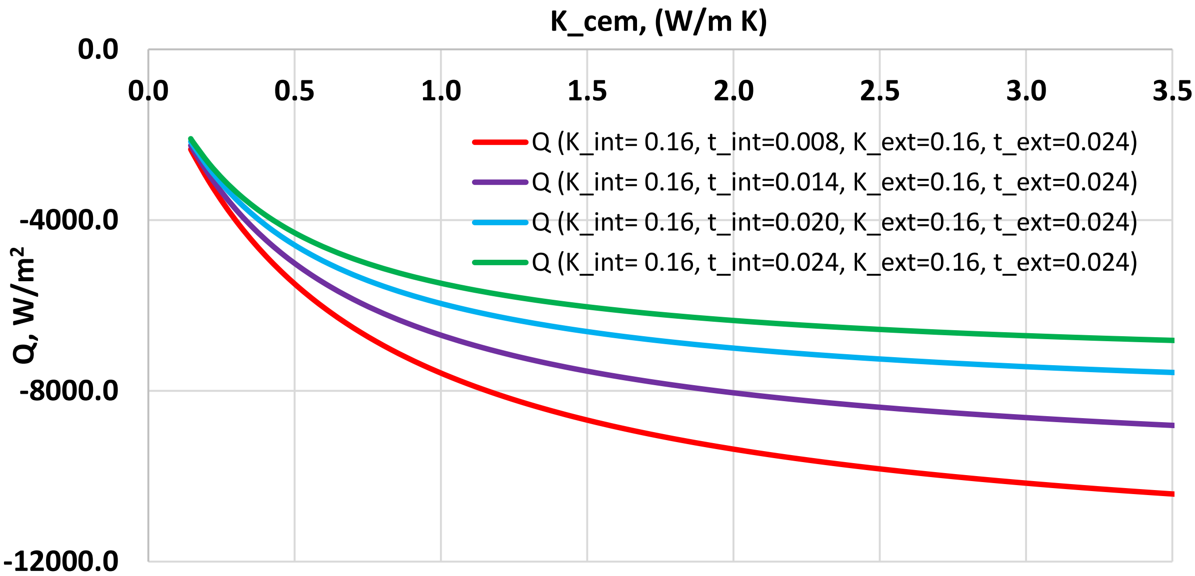

Figure 12: Effect of size of internal insulators on heat loss.

4.2.3 Effect of thermal conductivity and size

In this case examples (**Figure 13 and Figure 14)**, the geothermal wellbore was assumed to be insulated at externally, internally and at both sides of the production tube with the objective of studying the effect of thermal conductivity and sizes. Simulation result shows that for the higher conductivity, the internal insulator exhibited a lower heat loss as compared with the external one. When the conductivity of cement is 1.04 W/ mK, both sides insulated tubing with the lower conductivity reduced the heat loss by 38.7% and 49.3% as compared with the internal and the external insulators, respectively.

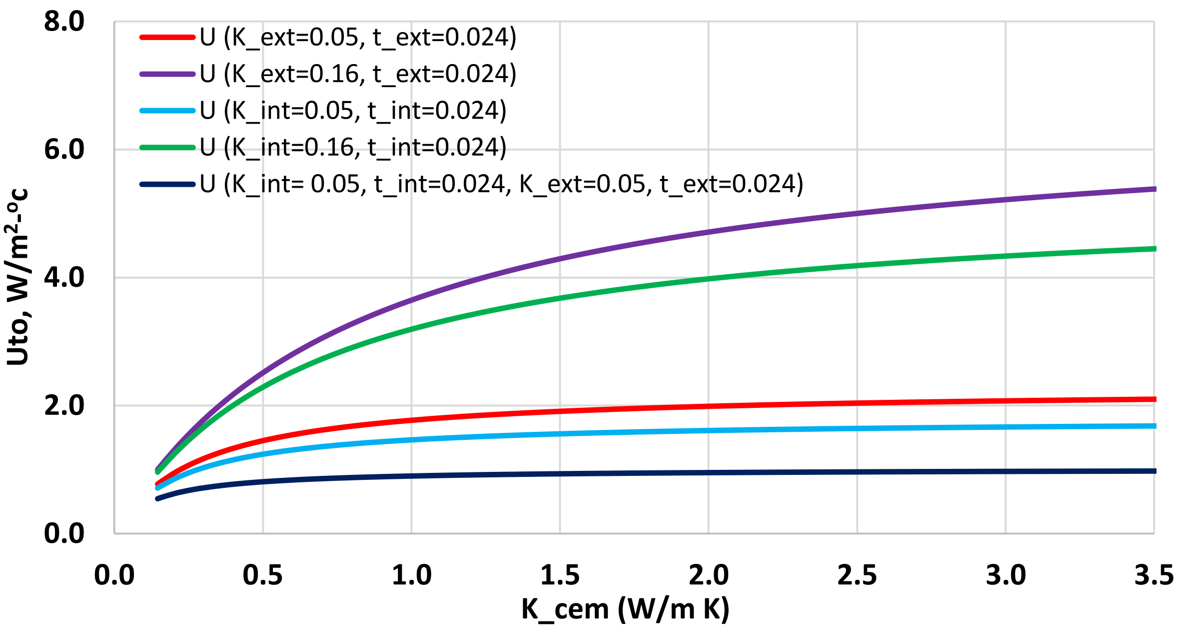

Figure 13: Effect of thermal conductivity and thickness of insulators on overall heat transfer coefficient.

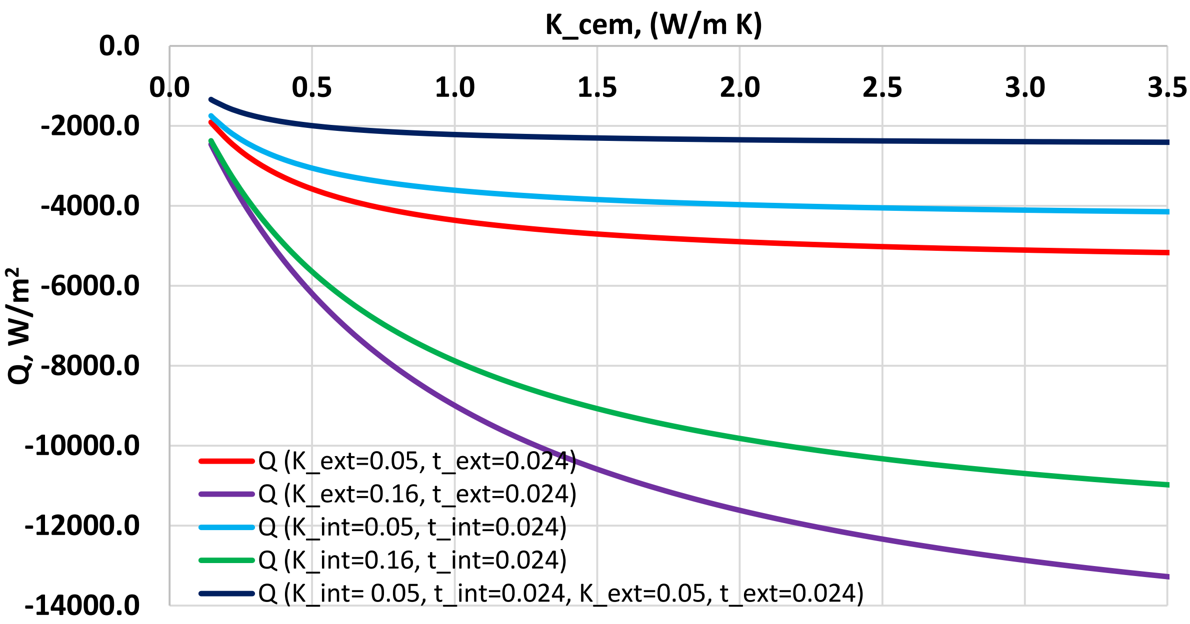

Figure 14: Effect of thermal conductivity and thickness of insulators on heat loss

5. CONCLUSION

In general, one can achieve an optimal heat productivity and prolong the operational life by designing an appropriate wellbore regarding operational parameter, material selection and monitoring and performing required well servicing. In the simulation part, the production tubing was insulated with the lowest and the highest values.

Results from the study summarized as:

- Provided that uninsulated well is used, it is important to construct a well with cement having very small thermal conductivity in order to reduce heat loss.
- On both sides insulated tubing, the cement conductivity has little or no significant impact in general.
- On externally or internally insulated tubing, the heat loss increases when the cement conductivity increases.
- The heat loss in internally insulated tubing is lower than the externally insulated tubing.
- High flow rate maintains well-flowing temperature. However, it is vital to insulate the production tube in order to protect tubing from being corroded and eroded.
- For efficient heat extraction and tubular integrity, production tube should be insulated with low thermal conductivity, thicker and high erosion resistance insulator.
- Since geothermal wells are exposed to corrosive gases (CO_2, H_2S) and ions (cl^-, SO_4), it is important to select the right material to control corrosion. The material should also suit temperature aggressive environment in order to reduce annular pressure build and tubular failure.
- It is imperative to monitor and perform remedial actions to control corrosion rate.

Please note that the analysis presented in the paper is based on the considered well structure and simulation parameters. From the overall all study, and reviewed material, fiberglass reinforced insulator material is believed to be the best solution for geothermal heat preservation.

Unit conversion

1 Btu /(hr-ft^2-°F)	=	5.678263 w/m^2-c
1 Btu ft / (hr- ft^2-°F)	=	1,73 Watt / (m K)
1 Btu /(hr-ft^2)	=	3.15 W/m^2
1 psi	=	6.89475729kpa
1 ft	=	0.3048 m
1 in	=	0.0254 m

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