TECHNICAL CONSIDERATIONS OF WELL DESIGN AND EQUIPMENT SELECTION FOR HIGH TEMPERATURE APPLICATIONS – A CANADIAN PERSPECTIVE

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ABSTRACT

The severe environments of high-temperature geothermal wells can pose a significant challenge in terms of well integrity, equipment performance, and reliability. Many of these challenges have also been faced by thermal oil recovery well operators in Western Canada; where high pressure steam as hot as 350°C is injected into relatively shallow reservoirs to mobilize the highly viscous heavy oil.

Given the nature of thermal oil recovery operations, well integrity is of critical importance to operators. Many thermal wells are run into relatively shallow reservoirs (500-1,000 m depth); thus, well barriers must be properly designed to prevent uncontrolled releases of reservoir fluids above the cap rock into potable aquifers and/or to surface. Cemented production casing strings are designed with the understanding that they will plastically deform under high temperature conditions as a result of axial confinement. Strain-based tubular design and the use of specially-designed premium connections for high-temperature applications in accordance with ISO/PAS 12835:2013 have become industry recommended practices in Western Canadian thermal operations.

Another key aspect of well performance for thermal well operators is the high-temperature performance and reliability of the artificial lift equipment installed in those wells. Significant strides have been made in the development of improved technologies for producing fluids in thermal oil recovery environments. These efforts are still ongoing, and have already resulted in improved capabilities and reliability of thermal artificial lift equipment. Though technology gaps still exist, adapting thermal artificial lift equipment to the geothermal industry has the potential to advance geothermal power production.

This paper highlights some of the fundamental thermal well design and artificial lift developments that have occurred over the past 30 years in Western Canada, and demonstrate how these developments may be applied to geothermal applications.

1. INTRODUCTION

Western Canada is home to some of the largest hydrocarbon deposits in the world, including the oil sands in the Provinces of Alberta and Saskatchewan. Unlike conventional oil deposits, these hydrocarbons are extremely viscous bitumen that require specialized methods to produce compared to conventional oil reserves. Operating companies with assets in the oil sands have developed a range of Enhanced Oil Recovery (EOR) processes to extract the bitumen either through surface mining, or (more commonly) in-situ thermal production.

1.1 Thermal EOR Methods

While there are a number of high-temperature EOR processes that have been developed and used by the oil and gas industry, two processes in particular have become very common in Western Canada: Cyclic Steam Stimulation (CSS), and Steam Assisted Gravity Drainage (SAGD).

1.1.1 Cyclic Steam Stimulation (CSS)

In the CSS process, high temperature (up to 350°C) saturated steam is injected into the reservoir, and then the well is shut in to allow the steam to permeate through as much of the reservoir as possible. After soaking for several months, the condensed steam and reservoir fluids are then produced through the same well. This process is repeated throughout the life of the well, typically between 15 to 20 years, and subjects the well to as many as 25 thermal cycles in some projects (Nowinka et al., 2007). Initial bottom-hole temperatures of the bitumen reservoirs in Western Canada range between 5°C and 20°C, and while reservoir temperatures rarely return to this temperature during the CSS process, considerable temperature differentials must be accounted for in the well design process.

CSS wells can be vertical or directional, depending on the operator's requirements. Typically, CSS wells are drilled in rows or in a set pattern to allow for continuous injection into and production from the same reservoir; however, CSS operators must manage their steaming process carefully to limit the thermal- and pressure-induced stresses in the reservoir and overlying formations that could result in formation movement and potential severe damage to the wells.

1.1.2 Steam Assisted Gravity Drainage (SAGD)

SAGD is an EOR process that was developed as an alternative to CSS which reduces the number of thermal cycles a well may experience over its service life. In SAGD, two wells are drilled in parallel and run horizontally through the reservoir, with one on top of the other. Figure 1 shows a schematic of a typical SAGD well pair.

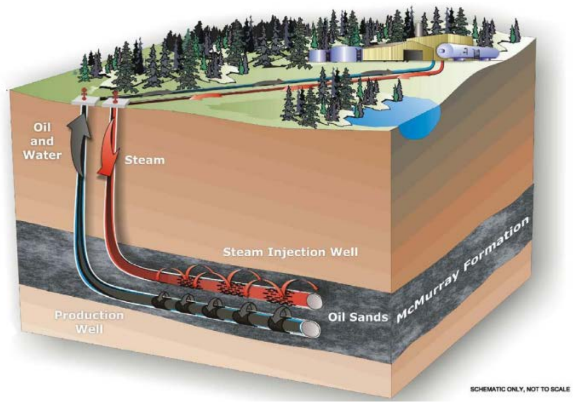

Figure 1: Example of a Steam-Assisted Gravity Drainage Well Pair (MEG Energy Corp., 2009)

The upper well in the pair injects saturated steam up to 290°C (slightly lower temperatures than used in the CSS process) which creates a steam chamber in the reservoir, mobilizing the bitumen. The lower well in the pair is the production well, which collects the heated, mobilized bitumen so it can be pumped to surface. Like CSS, multiple SAGD well pairs are pad-drilled near each other to maximize production from the reservoir.

While the SAGD process is designed to be a continuous process, thermal cycling does occur in situations such as facility shut downs, pump retrievals and workovers. These intermittent interruptions can, if prolonged, result in the reservoir cooling down to temperatures approaching the original bottom-hole conditions.

2. THERMAL WELL DESIGN

The unique and severe environments of thermal EOR operations require operators to come up with novel approaches and designs for their wells. Given that most thermal wells are run into shallow reservoirs, well barrier design is critical to prevent uncontrolled releases of reservoir fluids above the reservoir cap rock. While there are several components of thermal wells that can be considered critical well barriers including wellheads, sub-surface equipment and cement, the primary barriers that operators focus on are the intermediate and production casing strings.

2.1 Thermal Well Casing Design

The primary loading mechanism that intermediate and production casing strings in thermal wells are subjected to results from the temperature differential between the initial temperature of the well and the peak operating temperature of the thermal operation. Because the casing strings are cemented in place, such that thermal expansion of the casing is prevented in the axial direction, axial-compressive stresses may result that (for high enough temperatures) will plastically deform the casing material.

Figure 2 shows an example of an axial stress versus temperature profile of a cemented production or intermediate casing string in a thermal well.

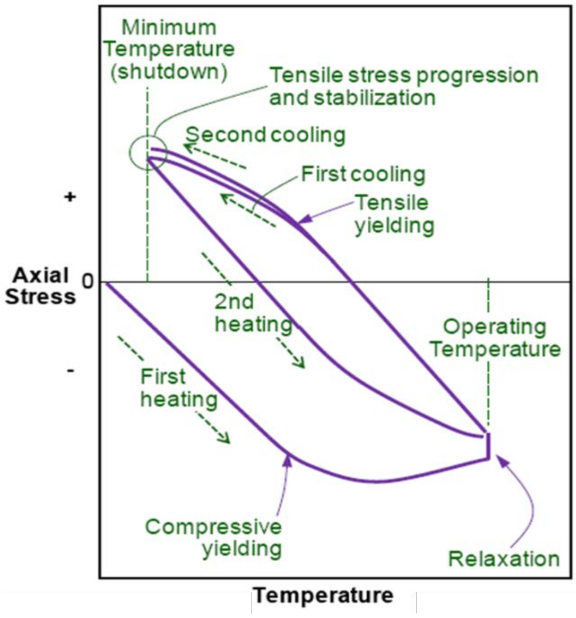

Figure 2: Thermal Well Casing Axial Stress versus Temperature Profile (Drilling and Completion Committee, 2012)

Over time, at the elevated temperature, the compressive stress in the casing will relax (as indicated in Figure 2) due to behaviors such as high-temperature creep. Once heating of the well stops, it will cool and the casing will develop high axial-tensile stresses as it is restrained from axial contraction, potentially sufficient to yield the casing in tension.

In both CSS and SAGD operations, this cycle is repeated multiple times and can lead to strain hardening in the casing material, in both tension and compression. Eventually, thermal cycling can result in low-cycle fatigue failure of the casing string, either in the pipe body or at the connection; as such, operators must be aware of the strain capacity of the casing and connections used in their wells. Industry regulators and operators in Western Canada recommend the use of a strain-based design approach for thermal wells to ensure sufficient strain capacity.

<u>2.1.1 Strain-Based Design Considerations</u>

Conventional oil and gas wells are designed such that the combined operational loads imposed on the casing strings do not exceed the yield strength of the casing material. However, as thermal wells often experience axial stresses that exceed the yield strength of the casing material, a traditional elastic design approach is generally not appropriate. Strain-based design, in which yielding of casing material is assumed and the resulting post-yield response is considered, are more applicable to thermal well design.

In the application of strain-based design concepts, there are a few key considerations, including: strain localization, material degradation, stress relaxation, and low-cycle fatigue loading effects. Although a comprehensive review of strain-based design is beyond the scope of this paper, strain localization and material degradation have both been postulated as key contributors to casing failures in thermal wells (Nowinka et al, 2007; Xie, 2008).

Strain localizations occur when post-yield strains are distributed non-uniformly and typically result from variations in load conditions, geometry, material properties and/or cement integrity in a specific interval of the well. Strain localizations can result in large magnitudes of plastic strain, which may be several times higher than the average casing strain. For example, a Finite Element Analysis (FEA) evaluation on a grade 80 casing string and a premium connection showed strain localizations occur in the thread roots of the connection, with plastic strains of 0.95% in the thread root versus 0.24% in the casing pipe body under the same load conditions (Xie, 2008).

Moreover, where variations in multiple factors (such as load conditions, material properties, geometry and/or cement integrity) occur in close proximity, the combined effect on strain localization could be severe and potentially invite further strain localization during subsequent loading. It has been hypothesized that failures in thermal wells are precipitated by compounded localization mechanisms that dramatically increase the magnitude of plastic deformation in a localized area (Nowinka et al., 2007). Therefore, mitigating the potential for strain localization through adequate control of contributory factors is critical to thermal well design.

Given the importance of material properties to strain-based design, casing material degradation throughout the life of a well is also an essential consideration. It has been suggested that the effect of material degradation could be considered by the reduction of material ductility, potentially due to the effects of strain hardening, strain-aging and/or corrosion. For example, coupon tests have shown more than a 10% reduction in ductility of API grade L80 steel as a result of the hardening induced by one thermal cycle. Accordingly, this reduction in ductility may reduce the post-yield strain capacity of the material. A cumulative damage measurement approach has therefore been proposed to consider the material degradation in the strain-based design approach, wherein material degradation due to mechanisms such as strain hardening, strain-aging, and environmental cracking are considered in the strain-based design approach (Xie, 2008).

2.1.2 Thermal Well Casing Material Selection

Thermal well designs typically utilize materials with favorable post-yield characteristics for intermediate and production casing strings. API grades such as K55 and L80 are the most commonly used grades in Western Canadian thermal operations due to their ability to withstand increasing strain beyond the material yield point (i.e., they have a relatively high ratio of ultimate strength to yield strength). Higher-strength casing grades, such as P110, are sometimes considered with the intention of increasing the elastic load capacity of the casing material; however, the post-yield strain capacity is lower in these materials, which may decrease the material's ability to accommodate large plastic deformations and strain localizations. Higher-strength grades also tend to have increased susceptibility to environmental effects such as hydrogen embrittlement or stress corrosion cracking.

Given the elevated operating temperatures of thermal wells, the impact of temperature on the stress-strain response of the casing material must also be considered. Generally, a higher operating temperature results in reduced yield strength, reduced ultimate strength and an increased magnitude of stress relaxation. Figure 3 provides an example of monotonic stress-strain curves at various temperatures, in which the reduction in yield strength is apparent for higher temperatures.

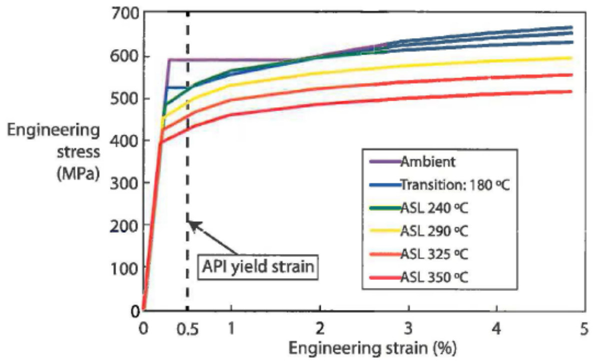

Figure 3: Example of Monotonic Stress-strain Curves at Various Temperatures (ISO, 2013)

2.1.3 Thermal Well Connection Selection

Casing connections are one of the most critical components of thermal wells. Literature has shown that most casing failures have historically occurred at connections (Xie & Tao, 2010).

The purpose of a connection is to join individual casing joints together while ensuring adequate structural integrity and sealability under the anticipated operating conditions of the well. The sealability requirements of a connection depend on the location of the connection within the well and requirements of the application. In thermal wells, the sealability requirements of intermediate or production casing will generally be higher than liners or tubing to ensure containment of pressure in the wellbore.

There are a few general types of connections used in the broader oil and gas industry, including: API round, API buttress, semi-premium and premium. Semi-premium and premium connections are typically based on proprietary designs intended to achieve enhanced structural capacity and/or sealability requirements, often specific to a particular application.

Connection designs intended for severe operating conditions are generally qualified to an existing standard, such as ISO 13679:2002, which provides design verification testing procedures for casing and tubing connections for the oil and gas industry. The scope of ISO 13679:2002 includes verification of galling resistance, sealability and structural integrity according to the manufacturer's claimed test load envelope and limit loads. Although ISO 13679:2002 includes thermal cycle testing (Test Series C), the maximum test temperature is 180°C and combined test loads are limited to 95% of the Von-Mises Equivalent material yield stress – i.e., post-yield connection performance is not evaluated (ISO, 2002).

Due to the severe, post-yield stresses imposed on casing strings in thermal wells, the casing connections selected for use should have tensile and compressive strength greater than or equal to the casing. API round thread connections, such as short-threaded and coupled (STC) and long-threaded and coupled (LTC), do not provide adequate axial load carrying capacity for most thermal well applications. API buttress connections (BTC) do have the potential to provide adequate structural capacity; however, the reliance of buttress connections on the thread compound in the helical gap between pin and box threads to provide sealing may not be sufficient when a high degree of sealability is required, such as for intermediate or production casing strings because thread compound typically deteriorates with prolonged exposure to elevated temperature. Premium connections designed for thermal applications, which typically provide structural capacity equal to or greater than the casing, often include a metal-to-metal radial seal to ensure adequate sealability during thermal operations. Therefore, premium connections are generally preferred for intermediate or production casing strings in thermal wells (Xie &Tao, 2010).

Alberta's Industry Recommended Practice for In Situ Heavy Oil Operations (IRP03) requires connection designs to be qualified using a documented connection evaluation protocol that assesses sealability, structural integrity, and galling resistance for representative field conditions. Specifically, IRP03 refers to the Thermal Well Casing Connection Evaluation Protocol (TWCCEP) as a suitable connection evaluation protocol (Drilling and Completion Committee, 2012).

2.1.4 TWCCEP and ISO/PAS 12835:2013

The TWCCEP provides procedures for the assessment of casing connections for intermediate and production casing strings in thermal wells. It was developed with input from thermal EOR operators, premium connection manufacturers and consulting engineering companies. More recently, the International Standards Organization (ISO) adopted the TWCCEP as a Publicly Available Specification (PAS) named ISO/PAS 12835:2013.

ISO/PAS 12835:2013 incorporates elements of FEA and full-scale physical testing to evaluate premium casing connections for thermal well applications. Like the ISO 13679 connection testing standard, ISO/PAS12835:2013 allows program assigners (the party seeking to qualify a connection for thermal operations) multiple application levels to qualify connections to; however, ISO/PAS 12835:2013 uses temperature as the sole criteria for the different qualification levels known as Application Severity Levels (ASL). Table 1 shows a breakdown of the ASLs as defined in the protocol with the corresponding temperatures, axial loads and internal pressures (equivalent to the saturated steam pressure at those temperatures).

Application Severity Level (ASL)	Maximum operating temperature	Lower-bound temperature	Upper-bound temperature
(°C)			
Not applicable	180		180
240	181-240	5	240
290	241-290	5	290
325	291-325	5	325
350	326-350	5	350

Table 1: ISO/PAS 12835 Application Severity Levels (ISO, 2013)

As in ISO 13679, a connection qualified to a higher ASL in ISO/PAS 12835:2013 is automatically qualified to all of the ASLs beneath it. For example, a connection design originally qualified to ASL-350 would also be considered qualified for a different thermal well application with a maximum operating temperature of 325°C.

The scope of the analysis in the protocol covers casing material characterization, evaluation of connection sealability, determination of worst-case connection geometries, and specifications for test specimen fabrication. The scope of the physical test program in the protocol consists of subjecting six specimens (either integral or threaded-and-coupled premium connections) to a combination of galling resistance tests, a 10-cycle thermal cycle test, limit-strain tests and an optional bending test.

2.2 Applicability to Geothermal Wells

Although geothermal well applications present unique design requirements from thermal EOR operations, some of the existing research and development can be applied to geothermal wells. In particular, the thermally-induced axial stresses experienced by thermal EOR wells are comparable to many geothermal wells.

2.2.1 Geothermal Well Casing Failures

There are two common modes of mechanical casing failure resulting from thermally-induced stresses in geothermal wells identified in literature: parting of casing and collapse due to trapped annular fluid. A study of geothermal wells in the South East Asia – Pacific region showed total well failure rates from thermally-induced stresses of 3.6% and 9.5% for standard hole and large hole single-string completions, respectively (Southon, 2005). Of the 577 standard hole, single-string wells considered in the study, 2.6% experienced parted casing failures. The study considered large hole completions as those with 13-3/8" or 10-3/4" diameter production casing, and standard hole completions with 9-5/8" diameter production casing.

As geothermal wells are drilled deeper and higher-temperature reservoirs are exploited, the resulting thermally-induced stresses become more severe. Accordingly, proper application of strain-based design concepts becomes increasingly important to the safe and reliable operation of geothermal wells.

As an extreme example, the Iceland Deep Drilling Project (IDDP) reported wellhead temperatures of 452°C at their IDDP-1 well, which was drilled in 2008 through to 2009. In addition to producing the highest-temperature geothermal well in the world, the project also underscored the severity of the thermal stresses involved, as parting of the production casing was observed when the well was killed (Ingason et al. 2015).

2.2.2 Cyclic Thermal Loading

As discussed earlier, thermal EOR wells inject steam into a reservoir to mobilize the highly-viscous heavy oil for production. Conversely, geothermal wells operate in the reverse direction, producing high-temperature water or steam directly. In both cases, thermal stresses are generated in the casing as a result of the temperature changes.

For a cemented casing string in a geothermal production well, the primary loading mechanism results from the temperature differential between the initial temperature at the time of cementing and the peak operating temperature during production. Once the cement is set, the casing is prevented from thermally expanding as the temperature increases to match the temperature of the produced fluids. If there is a large enough temperature differential, the resulting axial-compressive stresses will plastically deform the casing material. When production of the well is stopped, such as during a well kill for a workover operation, the casing will cool, resulting in axial-tensile stresses. Depending on the temperature differential and the amount of initial plastic deformation that occurs in compression, the resulting axial-tensile stress may be sufficient to yield the casing in tension.

Temperature differential is the primary driver of the thermal stress; as such, the temperature of the casing at the time of cementing is a key factor. Before a geothermal well is in production, the temperature of the casing will typically increase as a function of depth, corresponding with the temperature gradient of the ground. Therefore, the lowest reference temperature of a cemented casing string will typically be found at the shallowest depth of that string. As a result, the largest induced thermal stresses should be expected at the shallowest depth of a cemented casing string. Indeed, there are observations in literature that most casing connection failures occur in the shallow section of geothermal wells (Torres, 2014).

2.2.3 Geothermal Well Connection Selection

Due to the severe, post-yield loading environment encountered in some geothermal applications, the appropriate selection of casing connections is critical for well integrity. The standard API buttress connection is the most commonly used casing connection in geothermal wells; however, when a gas-tight seal is required by the well design, such as in tie-back systems, premium connections should be considered (Torres, 2014). Leakage may also contribute to issues such as degradation of cement bonds, weakening of water-sensitive formations and compromised connection integrity due to corrosion and/or erosion (IRP03, 2012). Based on evaluations performed for thermal well applications, premium connections have shown to be capable of providing both sufficient structural capacity and sealability for most thermal oil recovery conditions up to 350°C (Xie & Tao, 2010).

It has also been suggested that the selected casing connections should satisfy the requirement such as the TWCCEP (Torres, 2014). Further, some jurisdictions with geothermal operations, such as New Zealand, have referred to IRP03 and ISO/PAS 12835:2013 as references for casing design (NZS 2403-2015). To this end, the TWCCEP and the subsequent ISO/PAS 12835:2013 specification provides procedures for the assessment of threaded casing connections for applications with operating temperatures between 180°C and 350°C.

Although ISO/PAS 12835:2013 was not developed specifically for geothermal applications, many of the principles and procedures of the specification are transferable and may, at a minimum, serve as a basis for casing connection evaluation. Where differences exist between thermal EOR and geothermal applications, the procedures in ISO/PAS 12835:2013 would generally provide a conservative assessment of the casing connection for a geothermal application. For example, the lower-bound temperature of 5°C in ISO/PAS 12835:2013 was assumed for applications in colder climates such as Western Canada, and would therefore be a very conservative assumption for geothermal applications in warmer climates.

3. ARTIFICIAL LIFT DESIGN

A wide variety of Artificial Lift (AL) systems are utilized in the oil and gas industry. Though some forms of AL have become more common than others, each system generally has its own strengths and weaknesses. As such, no distinctive AL system or vendor has been universally acknowledged as “the best” under all conditions. Some of the more common AL methods in the Oil and Gas industry include: rod pumps, screw pumps or Progressing Cavity Pumps (PCPs), jet pumps, gas lift, and Electric Submersible Pumps (ESPs).

Thermal wells present unique operating conditions and challenges for AL systems. Aside from high operating temperatures, other conditions such as produced solids and sour fluids may limit the type of AL systems that can be used in these operations. Many forms of AL used in conventional systems struggle under the challenging conditions presented in thermal operations. For example, rod pumps do not operate well with gas/steam, solids, or in highly deviated wells. Additionally, gas lift, commonly used in conventional oil and gas, does not offer a significant improvement to SAGD as the produced fluids already contain significant volumes of gases (ConocoPhillips, 2006; Stonehouse, 2010)

The use of pumping systems in thermal wells can improve production performance and duration, which helps to improve the economics of thermal operations. The pumping systems which have emerged as the most popular in thermal operations have typically been ESPs and PCPs. Though limited in their capabilities during early thermal operations, the increased number of thermal projects, including SAGD and CSS production, have spurred technological advancements in these systems. For instance, traditional PCPs were not capable of handling high operating temperatures (greater than approximately 180°C). As an answer to this, the industry created Metal-to-Metal Progressing Cavity Pumps (MxM PCPs), which have a greater temperature threshold. These systems, however, are typically limited in their volumetric efficiency while pumping low-viscosity fluid (Mathieu, 2011; Solanki et al., 2005; Noonan et al., 2013).

As discussed further in Section 3.3, ESPs are likely the most adaptable pumping system to geothermal well conditions. As such, the following sections will focus on ESP design and reliability, as well as the current state of ESP capabilities.

3.1 ESP Pump Design

ESPs vary in design depending on the conditions they are intended to operate in. The main components of a typical ESP system consists of: a downhole centrifugal pump, a seal or protector section, an electrical cable (from surface), a pump intake, and a downhole motor with a high strength shaft (running from the motor to the centrifugal pump). The main components of an ESP are shown in Figure 4.

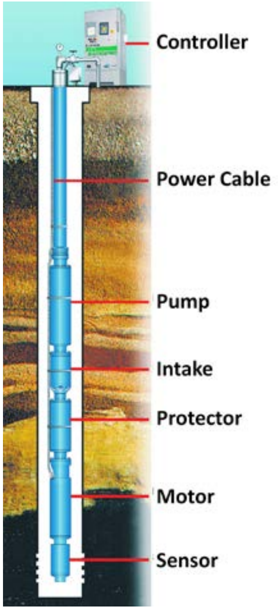

Figure 4: Main Components of a Typical ESP String (Bearden, 2007)

These components are typically manufactured in a modular configuration and assembled onsite. As such, ESPs can be assembled using different components to match the conditions of the well. For example, motors can be placed in tandem to provide higher output power, if required.

Additionally, peripheral components may be installed with the ESP to provide increased functionality or to handle specific conditions. Some peripheral ESP components may include: intake shrouds, gas separators, instrumentation, and variable speed drives (VSDs).

As ESPs are used in a wide variety of conditions (from conventional to thermal oil production), ESP manufacturers have responded to this demand by creating multiple designs and configurations of ESPs. For example, for relatively low operating temperatures (under 150°C), ESP systems with power capabilities extending beyond 2000 HP when used in tandem configuration exist. For high operating temperatures, manufacturers offer High Temperature ESP systems (HT ESPs). These HT ESP systems can operate reliably at operating temperatures up to approximately 250°C; however, their power output is typically limited to under 300 HP (Baker Hughes, 2014; Schlumberger, 2011; GE Oil & Gas, 2016).

3.1.1 Pump

The downhole centrifugal pump is comprised of a number of stacked impeller and diffuser stages packaged in an outer housing. This component typically is located at the top of the ESP system, with the motor shaft running through the center of the pump. The impellers rotate with the shaft, and each stage provides head pressure to the production fluid. The amount of head an ESP will produce is dependent on the design and number of stages in the pump. There are many varying designs for the impeller and diffuser, which are designed to handle specific conditions (such as high gas volume). Depending on the stage configuration, pumps may also house down-thrust washers to take up part of the load generated by the pump. Otherwise, the down-thrust will be taken by a thrust bearing located in the protector section.

3.1.2 Protector (Seal Section)

The protector is located between the downhole centrifugal pump and motor, with the shaft passing through the center. The protector acts as a barrier between the well fluid and motor oil, while allowing pressure between the motor and wellbore to equalize. Typically, this pressure equalization is accomplished through tortuous paths (also known as labyrinths), flexible elastomer seals, or metal bellows. Tortuous path seals are generally the most cost effective; however, they are not used in horizontal or highly deviated wells. Elastomer seals are a positive seal design, which prevent any contact between the motor oil and wellbore fluid. However, these elastomers are susceptible damage in high temperatures and sour fluids (Lobianco & Wardani, 2010). A failure of the protector typically leads to a quick failure of the motor; therefore, it is common to stack seal chambers for redundancy. The protector also serves to house the thrust bearing which carries the down thrust from the pump section through the motor shaft.

3.1.3 Motor/Cable

The motor is located at the bottom of the ESP system, and drives rotation of the shaft. Typically, these motors are three-phase, alternating current (AC), squirrel cage induction motors, with operating frequencies of 40 to 60 Hz, and power output ranging from approximately 100 to 1500 HP (Baker Hughes, 2014; Schlumberger, 2011; GE Oil & Gas, 2016). The inside of the motor is filled with a specialized non-conductive oil. As the motor heats up during operation, this oil will expand up into the protector section.

One of the key limiting factors to ESP temperature operating range is the motor winding temperature. Current high temperature ESP motors have a maximum winding temperature of around 300°C; however, as the motor will heat up during operation, the actual allowable wellbore operating temperature is significantly lower. Keeping the motor below the maximum operating temperature is critical for avoiding ESP system failures; as such, multiple tactics have been developed, such as adding pump intake shrouds (which direct produced fluid past the ESP motor), and adding temperature monitoring instrumentation.

The electrical cable runs from surface and provides power to the ESP motor. This cable typically consists of three conductors wrapped in insulation and an outer casing of armor. This armor provides protection from mechanical stresses (during installation) and corrosion from wellbore fluids. Cable failures can occur when the cable armor and/or insulation separate, allowing wellbore fluids to contact the conductor.

3.2 ESP Reliability

Though a pumping system may be able to operate in the required conditions and provide adequate production rates, the system may still not be economically viable if it cannot operate reliably. Costs associated with a failed pumping system include not only the replacement system, but workover costs and production downtime as well.

ESP reliability can be affected by a wide range of factors, including: equipment sizing and selection, well inflow performance, operating temperature, solids, gas, and corrosion (Vandevier, 2010). Typical ESP systems in the oil and gas industry may be expected to run for approximately 2 to 3 years, depending on conditions. However, ESP systems subjected to high operating temperatures (such as those used in thermal operations) generally have reduced run-life (Issa et al., 2011; Munro et al., 2016). Increasing ESP run-life continues to be a focus of current ESP research and development, and is a critical factor for improving the economics of ESPs in future applications.

Though the reliability of an installed ESP system is obviously heavily associated with the design of the system, the selection of the ESP system and peripherals is also critical to ensuring optimized ESP run-life. Preliminary well data is typically used to size an ESP system; however, choosing which particular system will run most reliably in a given well is often difficult. Experimental testing and field data may help determine which ESP system is most suited for specific conditions. To further aid operators in choosing the most appropriate ESP system for their application, tracking systems containing historical run-life data of previous and current ESP systems have been created (Alhanati, 2003). Utilizing tracking systems such as this can enable operators to make informed decisions on pump selection based on wells with similar characteristics.

Though field data and tracking systems may be used to select an ESP system for a well, it can be difficult to predict changes in conditions, or to foresee issues with the ESP system. Including instrumentation for monitoring certain parameters in the ESP (such as motor winding temperature) may allow the operator to adjust the system for varying conditions, or to identify issues with the ESP system before a failure occurs. Finally, analysis of a failed ESP system, including a Dismantle Inspection and Failure Analysis (DIFA) should be conducted whenever possible. Performing a DIFA can provide valuable information as to the cause of a pump system failure. This data can then be added into tracking systems to further refine the selection process. Knowing the causes of ESP systems failures can improve selection of future systems and increase the overall run-life.

3.3 Applicability to Geothermal Wells

While thermal operations in the oil and gas industry have many parallels with conditions experienced in geothermal operations, there are some critical differences in the requirements of AL systems between these industries.

Most high temperature AL systems operating near 250°C are relatively low power (typically no higher than 300 HP). In comparison, geothermal operations require AL systems capable of operating at high flow rates requiring over 800 HP (The Foundation for Geothermal Innovation, 2009). Additionally, production fluids in thermal oil operations are viscous oils, while geothermal wells produce low viscosity water. As PCPs typically operate with low flow rates and do not perform well with low viscosity fluids, they are likely not well suited for use in geothermal production.

Considering the difference in operating conditions in production wells in thermal oil recovery and geothermal wells, ESPs are likely the most suitable thermal AL system to be adopted by the geothermal industry. Though these systems may not yet match all requirements of geothermal operations, the need for a robust pumping system capable of operating in the challenging conditions presented in geothermal operations has been identified as a critical piece of equipment for advancement of geothermal power production (The Foundation for Geothermal Innovation, 2009; Idaho National Laboratory, 2006). Recent advances to ESP technology have focused on increasing operating temperatures and system reliability in harsh environments, and may advance ESP's suitability to geothermal conditions.

ESP systems have significant advantages over other systems used in the geothermal industry and have the potential to enhance the production of geothermal wells. As an example, Line Shaft Pumps (LSPs) are a common form of AL used in the geothermal industry. In an LSP system, the motor is mounted at surface and a shaft passes from the motor to a downhole centrifugal pump. This gives LSPs an advantage over ESPs, as LSP motors are not subjected to downhole conditions, allowing them to operate in high temperature environments. However, LSPs are typically limited in their power output to about 1100 HP due to maximum shaft torque capacity. Conversely, ESPs are capable of power outputs beyond 2000 HP. Additionally, ESPs can be installed at greater depths, can be used in deviated or horizontal wells, are typically more efficient, and eliminate the need for ancillary surface pumps. (The Foundation for Geothermal Innovation, 2009; Idaho National Laboratory, 2006).

Though ESP systems currently available on the market are capable of handling a wide range of geothermal operating conditions, high operating temperatures limit the power output of these systems. Conversely, high power ESP systems are also available; however, their operating temperatures are significantly lower than their high-temperature ESP system counterparts. Therefore, a technology gap marrying high operating temperatures with high power outputs exists, potentially limiting the value of current ESPs in the geothermal industry.

While the run-life of ESP systems have improved over earlier systems, extending this run-life further would increase the economic viability of these systems in the geothermal industry. As ESP systems have been designed mainly for the oil and gas industry, the varying conditions of geothermal wells may impact the performance and run-life of ESP systems. As such, optimizing the design and selection of ESP systems using techniques such as experimental testing, field data, and performance tracking systems may improve these system's suitability for use in the geothermal industry.

4. CONCLUSIONS

Given the similar well conditions in thermal EOR wells, opportunities exists for the geothermal industry to benefit from current research and technologies advanced by the thermal EOR industry. This may include the following developments:

- Application of strain-based thermal well design practices may allow for more effective and reliable geothermal well designs.
- Selection of appropriate casing materials and connections designed for thermal applications offer potential for enhanced well integrity.
- Thermal casing connections qualification procedures such as ISO/PAS 12835 may ensure selection of suitable connection designs in higher-temperature geothermal applications.
- Artificial lift systems developed for thermal EOR, particularly ESPs, provide potential for enhanced well production in thermal operating conditions.
- ESP systems are available in a wide variety of operating ranges; however, challenges still exist for high power systems operating in high temperature conditions.
- Progress is being made in advancing the run-life of high temperature ESPs making them more attractive for geothermal operations.

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