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Authors
Winn, Carmen
Dobson, Patrick
Ulrich, Craig
et al.

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Context and mitigation of lost circulation during geothermal drilling in diverse geologic settings

Carmen Winn [a,1], Patrick Dobson [b,*], Craig Ulrich [b], Timothy Kneafsey [b], Thomas S. Lowry [a], John Akerley [c], Ben Delwiche [c], Abraham Samuel [d], Stephen Bauer [a]

[a] *Sandia National Laboratories, Albuquerque, NM, United States*
[b] *Energy Geosciences Division, Lawrence Berkeley National Laboratory, MS 74-316C, Berkeley, CA 94720, United States*
[c] *Ormat Technologies Inc., Reno, NV, United States*
[d] *Geothermal Resource Group Inc., Palm Desert, CA, United States*

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ABSTRACT

Lost circulation is one of the most common and expensive problems facing geothermal energy development, representing up to 30% of drilling costs. We examined drilling records from four geothermal fields—McGinness Hills in central Nevada, Don A. Campbell and Steamboat Hills in western Nevada, and Puna Geothermal Venture on the Big Island of Hawai'i— to identify geologies most prone to lost circulation, as well as common mitigation strategies. Depths of lost circulation events varied, but their frequency often increased in the production interval. Lost circulation commonly occurred near fault intersections, and heavily faulted fields like McGinness Hills and Don A. Campbell showed secondary mineralization within approximately 100 m (328 ft) or less of where circulation was lost. Lost circulation mitigation strategies included using locally available materials (e.g., cotton seed hulls) as well as more expensive proprietary lost circulation materials, cement plugs above the reservoir, and drilling blind with aerated, polymer-based mud in the production zone. Addressing lost circulation using a well thought out decision-making approach and materials above the reservoir will save time and cost, and provide needed well integrity. Mitigation often requires a series of steps, typically applied from perceived least expensive to most, and are dependent on the severity and location in the well where circulation was lost and availability of materials. Placing cement plugs can cure lost circulation events, however these plugs are often expensive, time-consuming, and may not be successful.

1. Introduction

Geothermal energy in the United States is an under-utilized natural resource with significant potential for growth as part of the clean energy transition. However, development costs can be high, primarily due to the high cost of drilling geothermal wells, which accounts for 35–50% of the total cost of new geothermal projects (Finger and Blankenship, 2010). Drilling costs for geothermal wells are high due to various challenging conditions including hot, hard, abrasive, under-pressured, and heavily fractured geologic formations. Highly permeable formations such as poorly consolidated sediments, faulted and fractured formations, and porous lava and flows that have lower fluid/formation pressure relative to the column of drilling fluid (under-pressured) can lead to lost circulation (LC), which is the loss of some or all of the circulating drilling fluid or "mud" to the surrounding formation and a common occurrence during drilling geothermal wells (e.g., Lavrov 2016). Drilling fluid that is over-pressured relative to the formation can also damage and hydraulically fracture the formation, as well as drive mud out of the wellbore during drilling. Faulted and fractured parts of the deeper reservoir are often drilling targets because they are permeable and therefore attractive zones for geothermal production and injection. Losing circulation in these zones can be an indicator of a potential feed zone for the well; however, expensive drilling and cementing complications are still likely as a result and the LC may limit drilling farther.

LC can account for over 20% of exploratory drilling costs and 10% of drilling costs in developed fields, about 3.5–10% of the total cost for a typical geothermal project (Finger and Blankenship, 2010). Cole et al.

* Corresponding author.
E-mail address: pfdobson@lbl.gov (P. Dobson).
[1] Now at: Geologica Geothermal Group, Inc., Reno, NV, United States

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(2017) found that LC was the leading cause of nonproductive drilling time on a geothermal project. Even moderate LC can lead to significant and expensive, nonproductive drilling time. Lowry et al. (2022) examined costs related to LC for the fields of interest here and concluded that reducing LC-related downtime, rather than minimizing material costs (e.g., lost circulation material (LCM)) is more likely to reduce overall drilling costs. A survey of 77 wells showed that 20% took longer to complete and cost more due to LC and collapsing formations (Sveinbjornsson and Thorhallsson, 2014). Losses can be relatively minor or "partial" (e.g., ~10–100 bbl/hr) or severe (>100 bbl/hr or total). According to Finger and Blankenship (2010), severe LC can also decrease reservoir productivity and lead to poor cement jobs, a stuck drill string, a packed annulus from inadequate cleaning, a collapsed wellbore, and potential well abandonment, as well as the inability to drill to the desired depth/location. Improving predictive capabilities, mitigation strategies, and material used to control LC may considerably lower the costs of developing new geothermal resources.

Common strategies for mitigating LC include lowering the weight of the drilling fluid to decrease wellbore pressure, drilling with reverse circulation, utilizing fibrous or granular LCM to block fluid entry into the formation, injecting cement to seal the loss zones, and drilling "blind" with no return of fluid or drill cuttings to the surface (Finger and Blankenship, 2010). Utilization of these strategies is often a balancing act depending on whether the LC is encountered above or within the reservoir, as non-thermally degrading materials can permanently damage reservoir permeability if used in the production zone of a hot geothermal well (e.g., bentonite).

Geothermal drilling occurs in diverse geologic settings, often in hard crystalline rocks (e.g., metamorphic, plutonic, or volcanic) and more rarely in alluvial basin fill. Mild to severe circulation loss can occur in all these settings and at varying depths and temperatures in and above geothermal reservoirs. Detailed drilling records and 3D geologic models from four active geothermal fields were provided by Ormat Technologies to determine similarities and differences between the context of and responses to LC in diverse geologic and geothermal conditions. These fields are McGinness Hills in central Nevada (Winn et al., 2021a), Don A. Campbell (Winn et al., 2021b) and Steamboat Hills in western Nevada (Winn et al., 2022), and Puna Geothermal Venture (Puna) on the Big

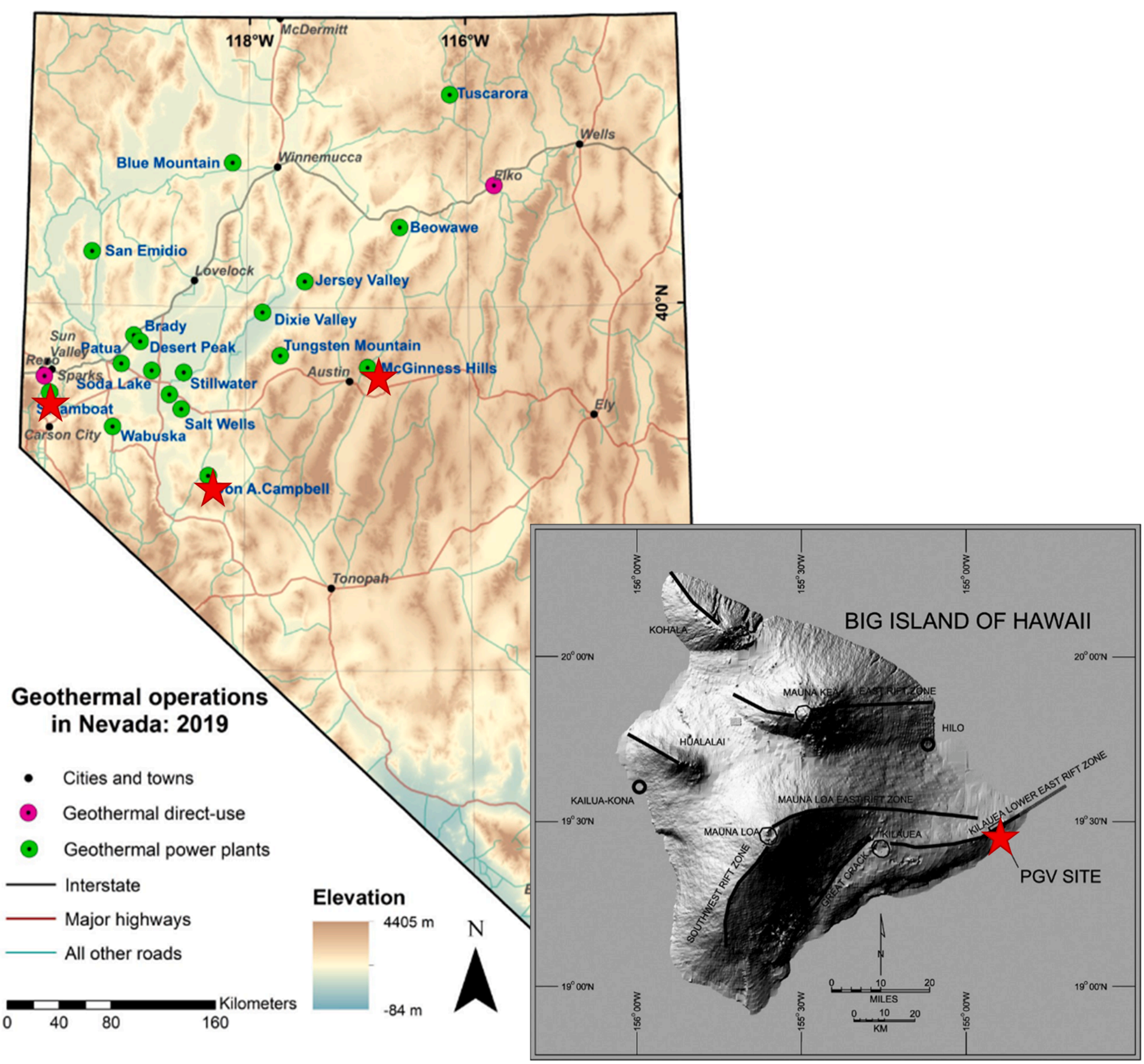

Fig. 1. Left: Locations of active geothermal fields in Nevada, US. Red stars mark the fields of interest for this study (modified from Ayling, 2020). Right: Location of the Puna Geothermal Venture on the Big Island of Hawai'i (Teplow et al., 2009).

Island of Hawai'i (Fig. 1). Careful attention was paid to how successful different mitigation strategies were in avoiding expensive problems due to LC in each geologic setting and potential warning signs prior to severe losses.

2. Methods

Proprietary drilling records for 28 wells from McGinness Hills, 10 wells from Don A. Campbell, 12 wells from Steamboat Hills, and 11 wells from Puna were provided by Ormat. RIMBase, an integrated wellsite information system that covers all aspects of well construction, completion, and intervention which facilitates data visualization and analysis, was used in the evaluation of the data. Production, injection, and monitoring well drilling records, especially operations activity reports and comments, were reviewed to identify conditions of LC and the approaches to address it. Where circulation loss was noted in the records, attention was paid to the lithology, potential warning signs like secondary mineralization, whether responses varied between the shallow nonproductive and reservoir intervals of the well, the LCM or mitigation strategy that was used, and whether any change in the severity of the losses occurred after each mitigation attempt. Individual wells that experienced severe circulation loss were selected from each field for a more detailed examination of the LCMs used, lithology and alteration from mud logs, and well geometries and fault intersections from the three 3D geologic models provided by Ormat.

Three-dimensional geologic models for geothermal fields may incorporate many types of data such as well data (drilling and production), surface geophysical data (magnetics, magnetotellurics, seismic, airborne electromagnetics, etc.), geologic mapping, and many others. Geological modeling software packages, such as Leapfrog, have been developed to enable 3D spatial analysis, visualization of trends, and identification of correlations (e.g., Poux et al. 2018, Baxter et al. 2019, Poux and O'Brien 2020). Models using Leapfrog provide a 3D depiction of the subsurface geology, including directionally drilled wellbores, stratigraphy, and feed zones along the wellbore and faults as well as their estimated subsurface projections and intersections. Available models using Leapfrog of McGinness Hills, Don A. Campbell, and Steamboat Hills provide a wealth of information about the intervals,

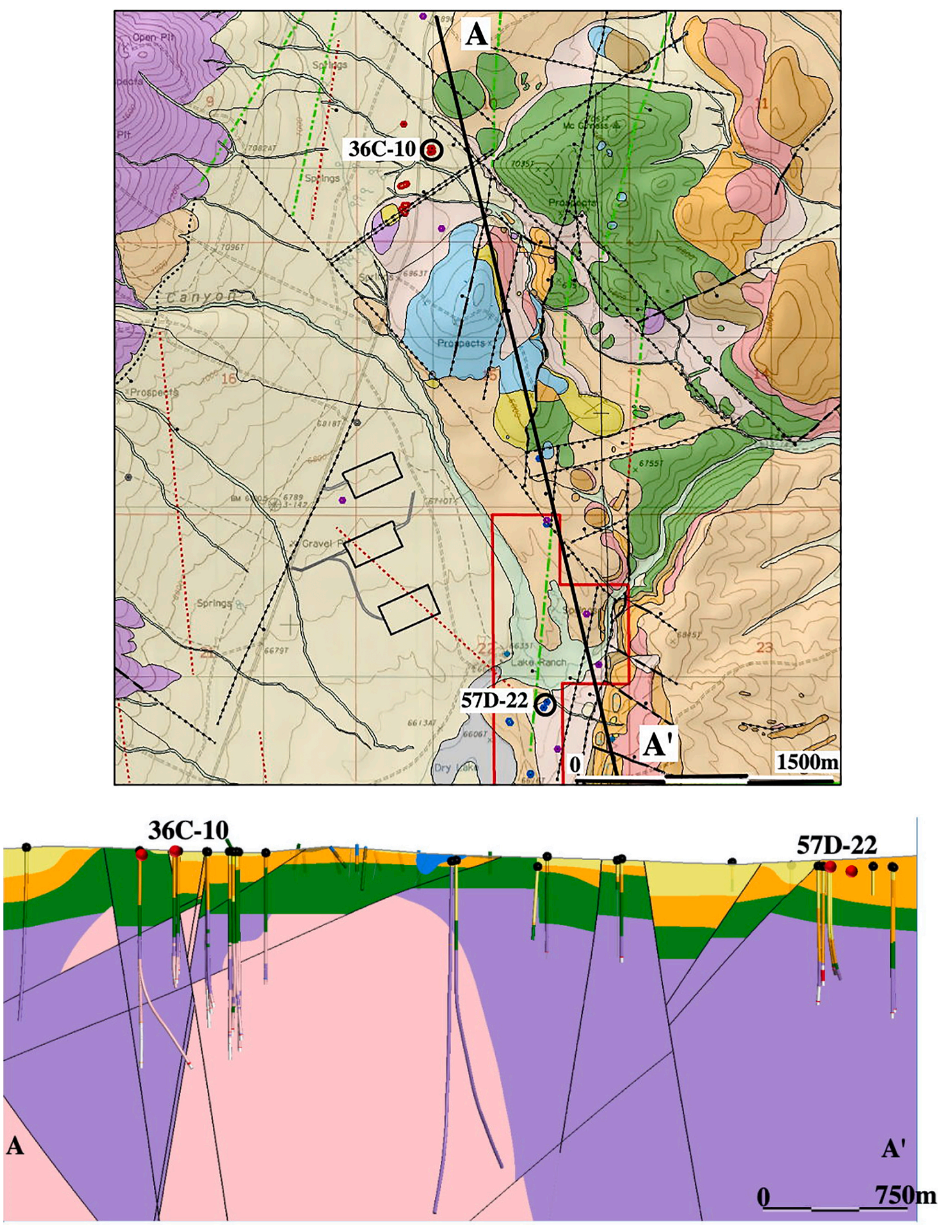

Fig. 2. Geologic map (top) and cross section (bottom) of the McGinness Hills geothermal field from Ormat's 3D geologic model. Geologic map is based on Akerley et al. (2019). Faults are shown as black lines (including dashed or dotted on the map, indicating some uncertainty about the location). Purple and gray represent Paleozoic metasediments; pink represents granitic intrusions; green and orange are Tertiary volcanics; various shades of yellow and beige are Quaternary basin fill; and blue represents sinter deposits. Colors along the wells in the cross section represent the same units, with additional white zones representing blind drilling (e.g., total loss of circulation). Small red zones are the feed zones of the well. Production well heads are shown in red on the map; injection well heads are in blue, and monitoring well heads are purple. Case study wells are circled in black on the map, shown by red wellheads on the cross section, and labeled.

lithologies, and proximity to faults of loss zones due to LC along wellbore paths, as well as offering visual representation of geologic patterns underground. It should be noted however that the utility of both software platforms depend on actual data collected and implemented in the software, which is often incomplete.

3. Geothermal field case studies

3.1. McGinness Hills geothermal system

3.1.1. Geologic setting

The McGinness Hills geothermal system (McGinness Hills) is located in the central Basin and Range Province of Nevada on the eastern flank of the Toiyabe Range (Fig. 1). Structurally, this geothermal system is in an accommodation zone where extension transfers from one major basin-bounding fault to another along steeply dipping, NW-striking and NNE-striking faults (Faulds et al., 2013). As is common in the Basin and Range, the stratigraphic sequence of the area consists of a metasedimentary basement (the Valmy Formation, an Ordovician orthoquartzite, and the Devonian Slaven Chert) intruded by Mesozoic granites, which are unconformably overlain by Tertiary intermediate to felsic volcanic units and Quaternary basin fill (Wendell, 1985) as shown in Fig. 2. Large Plio-Pleistocene sinter deposits (~2 km^2) and fossil hydrothermal alteration spurred exploration for precious minerals in the area (Casaceli et al., 1986), which helped lead to the discovery of the geothermal reservoir. Near-boiling water was found in mineral prospecting wells drilled to 300 m (1000 ft) with geochemistry indicating temperatures of 150–200 °C at greater depths (Coolbaugh et al., 2006). The permeability of the geothermal reservoir, which is located in the crystalline metasediments and granites (Knudsen et al., 2014), is controlled by faulting and related fractures and is highest near major fault intersections (Faulds, 2013; Faulds et al., 2013).

The McGinness Hills geothermal field is the largest producing geothermal system in Nevada (Ayling, 2020) and the fourth largest in the United States, with a net generation output of ~160 MWe (Nordquist and Delwiche, 2013; Lovekin et al., 2016; Akerley et al., 2019; Ayling, 2020; Ormat, 2022). The geothermal field was developed in three stages: the first unit came online in 2012; the second unit came online in 2015; and production at the third unit was initiated in 2018; a 15 MWe enhancement was completed in 2021 (Ormat, 2022). The field has a total of fifteen production wells, with an average brine temperature of 168 °C, and eight injection wells. Production wells are located in the main part of the accommodation zone to the north, and the injection wells are to the south along one of the basin-bounding fault systems (Fig. 2). The NNE-striking faults that define these structural features are favorably oriented for oblique slip with both normal and strike-slip components (Lovekin et al., 2016; Akerley et al., 2019)

3.1.2. Lost circulation

LC in the McGinness Hills geothermal field was generally reported at

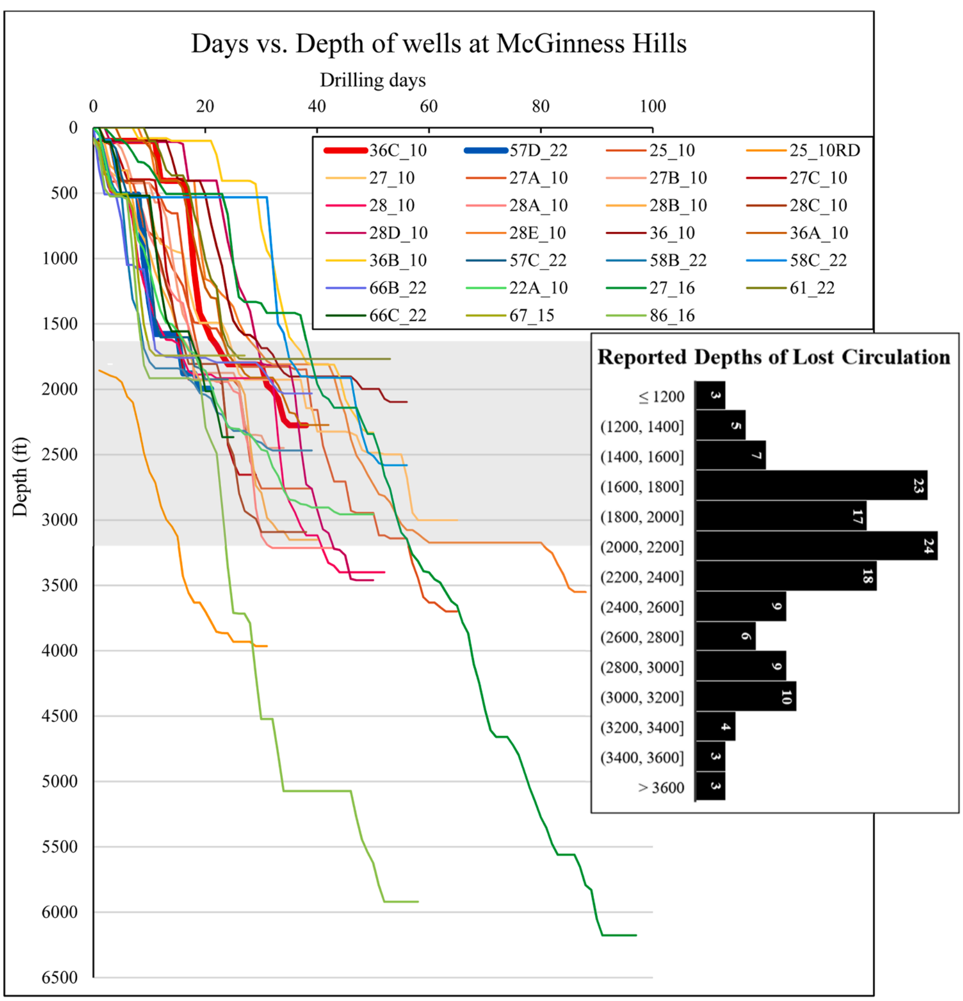

Fig. 3. Drilling rate for wells at McGinniss Hills. Horizontal segments indicate delays, some of which are LC-related. Inset - Histogram for different measured depth intervals at which LC was first reported in the McGinness Hills drilling records (analysis of 28 wells). The depth zone where LC was most frequently reported is shaded gray, and shown in the inset. Note that many wells have multiple occurrences of LC.

average depths of approximately 670 m (2200 ft) and predominantly occurred at depths between 490 m and 975 m (1600 ft and 3200 ft) (Fig. 3). LC was found in production, injection, and monitoring wells and is usually associated with the intersection of the well with a fault. These depths generally represent the production interval or are slightly above it, and are below the depths of valley-fill alluvium and into the Valmy Quartzite, Slaven Chert, and granitic intrusions.

Injection wells are mainly located in the southern portion of the field, are drilled to ~610 m (~2000 ft) depths and intersect very little of the Jurassic intrusions and significantly more alluvium and tuffaceous material. LC in these wells occurred in the Bates Mountain Tuff (~550 m [~1800 ft]), underlying andesites and dacites, and the Valmy Quartzite. In injection wells, severe LC (>100 bbl/hr) frequently initiated when drilling across a NNE-trending, W-dipping normal fault or system of faults. The most common strategy for LC for the injection wells at McGinness Hills within the reservoir interval is to drill blind using aerated mud.

Production wells, in contrast, are located in the northern portion of the field, closer to Quaternary sinter deposits and are typically drilled to ~900 m (~3000 ft) depths. These wells encounter very little basin-fill alluvium but noticeably thicker Bates Mountain Tuff and the underlying andesites and dacites, and significant amounts of granitic intrusions into the Valmy Quartzite. LC in the production wells was initially reported at slightly greater depths (~610 m [~2000 ft]) with some overlap, and most frequently occurred in the granitic intrusions. In the production wells, severe LC is associated with drilling through NNE- to NE-trending normal faults that dominantly dip northwest and appear as part of a NW-trending accommodation zone. Like the injection wells, the most common strategy upon encountering severe LC within the reservoir interval was to drill blind with aerated mud and occasionally pump LCM sweeps (a "sweep" is a small volume of high viscosity drilling fluid designed to clean the hole of cuttings, in this case containing LCM as well).

Monitoring wells are distributed throughout the valley, although they are typically drilled within or near the faults defining the left stepover noted by Faulds (2013). As such, the thickness of different strata varies according to the location of the well within the field. Wells in the southern area are drilled through more alluvium and less granitic material, while wells in the northern part of the field are drilled through more volcanic and intrusive rocks. Most of these wells were drilled relatively early in the field's development (2009–2013), and at least one was drilled as an exploratory deep core well. The diameters of these wells are similar to the production and injection wells, and there are no difference in the responses to LC. These wells were drilled to similar depths as the injection wells with two notable exceptions drilled in excess of 1520 m (5000 ft) deep.

Fig. 3 shows the drilling rate over the duration of drilling and the inset shows initial depths of LC as reported in the McGinness Hills drilling records. LC frequently occurred at depths greater than 460 m (1500 ft) and often in association with a fault. One monitoring well experienced more than 20,000 bbl of mud loss when drilling along the intersection of a NE-trending, W-dipping normal fault and one of the major NW-trending stepover faults, although this appears to be an outlier and not the norm.

The records reveal a common pattern in efforts to address LC. Mitigation efforts differ for the portion of the well above, and within the production zone of the reservoir. Above the reservoir, much of the drilling occurs in alluvium and the Bates Mountain Tuff. In this zone, like in the oil and gas industry, the drilling fluid is generally modified by increasing viscosity and adding fibrous materials (see Table 1). These materials aid in building an effective filter cake on the borehole walls, hindering fluid loss to the host rock, and limiting severe fluid loss into some fractures while still allowing the mud to carry cuttings out of the hole. In the hot basement rock, many records indicate that when severe fluid loss occurred, LCMs were no longer added to the mud, and the hole was further drilled using water, air, and compounds that optimize the use of water and air to carry the cuttings *to the location of the loss*—not to the top of the hole. This change in strategy is most likely undertaken because it is not desired to plug the fracture intersections within the well in the production zone, since these may be key feed zones for the well. Drilling records rarely indicate that circulation was restored while drilling blind within the production interval.

Table 1
Common LCM and viscosity-adjusting materials mentioned in drilling records from McGinness Hills.

LCM	Viscosity and filtration control
Calcium carbonate squeeze material	Gel
Cedar fiber	High molecular weight polymers
CSH	Cross-link polymer plug
Diatomaceous earth squeeze material	Crystalline synthetic polymer
Fine grained cellulose	Xanthan gum
Flaked calcium carbonate	
Graded mica	
Graphite	
Ground pecan shell	
Magnesia based plug	
Micronized cellulose	
Mineral fiber	
Pelletized CSH	
Seepage loss additive (e.g., Drispac®)	
Sized calcium carbonate	
Proprietary blends of sized LCM (e.g. Fiberseal™, Prima-Seal™, Premium Seal™)	
Sized magnesium oxide	
Sized salt	
Walnut shells	
Water insoluble sized cellulose material	
Wood sawdust	

When using LCM, the first choice tends to be less expensive and readily available materials such as sawdust, nut shells, cottonseed hulls (CSH), and sized minerals (e.g., calcium carbonate, graphite, mica). More expensive proprietary blends such as Prima-Seal™, FiberSeal™, or Premium Seal™ were less frequently used, but often used after other materials failed to lessen losses. These products are often customized blends of more common LCMs. The proprietary blends Prima-Seal™ and FiberSeal™ cost twice as much as sawdust and Premium Seal™ is three times more expensive than sawdust.

3.1.3. Well case studies

Production Well 36C-10. We examined a production and an injection well in detail for strategies used to combat LC in each case. Well 36C-10 (Fig. 4) is a production well drilled in 2018 as part of the third stage of expansion of production at McGinness Hills. It is part of a cluster of four distinct wells, all targeting the same set of NE-trending, NW-dipping faults. These faults also intersect other production wells west and south of Well 36C-10 at greater depths. Tertiary volcanic units extend to ~430 m (~1425 ft) depth along this wellbore and are underlain by a mix of Paleozoic metasediments and Mesozoic granites to ~530 m (~1750 ft). From there to the total depth of 693 m (2275 ft) the well is drilled through granite. In the nonproductive section of the well above 550 m (1800 ft), drilling fluid loss was controlled by increasing viscosity with gel and using cottonseed pellets and sawdust. High viscosity sweeps of these materials were also pumped immediately before cementing to clean the hole and ensure a good cement job. Little loss of fluid was reported until crossing a fault splay at ~620 m (2040 ft). Circulation was lost at 629 m (2063 ft), subsequently regained, and lost again at 630 m (2067 ft). This loss is most likely related to increased permeability along the fault splay. Circulation was lost again at 630 m and the remainder of the hole was drilled blind with air assist and large amounts of xanthan gum and soap to increase gelling and foaming to carry cuttings. Another

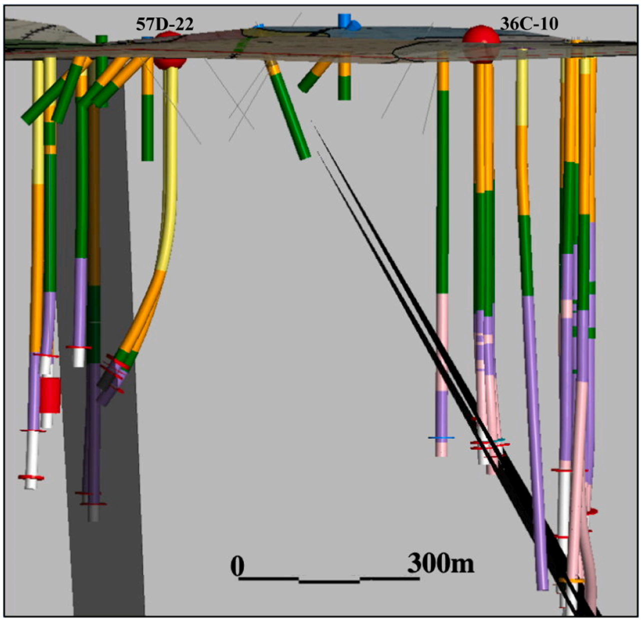

Fig. 4. 3D geologic cross section of McGinness Hills showing Wells 36C-10 and 57D-22 looking due south. Wellbore colors indicate stratigraphy: alluvium is yellow; Tertiary volcanic units are orange and green, the Valmy Quartzite is purple, the Slaven Chert is gray, and Mesozoic granitic intrusions are pink. White intervals indicate blind drilling zones where no cuttings were captured (e.g., LC). Larger red cylinders indicate feed zones for the wells. Note: only faults that intersect the wells of interest are shown. Scale bar is in meters.

fault splay was intersected at ~655 m (~2150 ft); this intersection spatially correlates with the main feed zones of the well.

Alteration mineralogy may provide evidence for nearby LC zones. Notes in the mud log indicate that while secondary minerals like quartz, calcite, and pyrite were present at all depths in varying amounts, the amount of chlorite increased gradually from rare (<1%) and trace (1–3%) amounts at ~460 m (~1500 ft) to common (6–10%) at ~550 m (~1800 ft), approximately 80 m before total losses were encountered. Minor (3–6%) amounts of epidote appeared at ~580 m (~1900 ft), approximately 50 m before total losses were encountered. These mineralogical changes may indicate nearby flow zones where circulation might be lost.

Injection Well 57D-22. Injection well 57D-22 (Fig. 4) is located southeast of well 36C-10 and was drilled in 2017 as part of the third stage of expansion of the McGinness Hills geothermal field. This well was drilled near another injection well, both intersecting a NE-trending, NW-dipping fault that intersects the major NW-trending stepover faults. Circulation was maintained through the upper portion of the well where it intersected porous sands, alluvium, and tuff by using small amounts of gel, finely ground walnut shells, sawdust, and CSH. Intermittent sweeps of the borehole required increasing amounts of gelling agents and CSH pellets to maintain wellbore stability and clean the hole. A loss of 120 bbl occurred while drilling through slate, most likely a unit within the Slaven Chert, at 550 m (1813 ft) and is likely related to crossing the fault zone. This depth is within the injection interval and is spatially correlated with the feed zone of the well - 553 m (1814 ft) [base of the casing at 480 m (1573 ft)]. The response was to use a significant quantity of xanthan gum and gel to recover and sweep the well. Drilling records indicate that from 567 m (1859 ft) the well was drilled blind with water and air assist to a final depth of 608 m (1995 ft). The mud log for 57D-22 shows quartz increasing in the veins progressively beginning about 30 m (~100 feet) above 567 m (1859 ft), perhaps providing an indication of approaching a flow zone. The drilling of both holes followed the general strategy described earlier— conventional LC methods in the section above the reservoir to maintain wellbore integrity, sweeping the hole with higher viscosity mud to clean it prior to setting and cementing casing. Drilling blind with aerated mud was used in the production or injection interval to avoid fouling permeable zones.

3.2. Don A. Campbell geothermal system

3.2.1. Geologic setting

The Don A. Campbell geothermal system (Don A. Campbell) is in western Nevada, approximately 45 km northeast of Hawthorne, Nevada, in the southwestern part of Gabbs Valley. Don A. Campbell's nominal power-generating capacity is currently 32 MWe, consisting of two power plants (Ormat, 2022). The first plant began operation in 2013 and the second in 2015. There are seven production wells, three injection wells, and multiple monitoring wells. This field is structurally characterized by NW-striking dextral-normal faults and NE-striking normal faults accommodating a transfer zone from the Walker Lane dextral shear zone and E–W Basin and Range extension. The Don A. Campbell has typical stratigraphy for the Basin and Range, with Paleozoic and Mesozoic metasedimentary and metavolcanic rocks intruded by Mesozoic granitic rocks forming the basement, which are overlain by Tertiary volcanic units and deep basin fill. Deep core hole drilling indicates at least 600–900 m (2000–3000 ft) of lacustrine and alluvial deposits overlying the volcanic units (Delwiche, 2013).

Deep exploration drilling at Don A. Campbell commenced in 2011 (Delwiche, 2013; Orenstein and Delwiche, 2014; Orenstein et al., 2015) with two core holes, both experiencing problems, some severe, with loss of circulation. These wells, along with geophysical surveys and shallow core holes, found production temperatures at shallow depths associated with silicification along numerous fault zones intersecting the wells. Further exploration and full-sized wells found very high flow rates (250–315 L/s) and modest temperatures (120–125℃) at depths shallower than 150 m (500 ft) down to depths exceeding 600 m (2000 ft) (Delwiche, 2013; Ayling, 2020). High permeability was associated with fractured, silicified basin fill surrounding the NE-striking normal faults. Limited information is available regarding the character of the near-vertical NW-striking faults as few wells intersect them. Most feed zones (high flow zones) for the production wells are shallower than 600 m (2000 ft), significantly shallower than the contact with the underlying volcanic units (Delwiche, 2013) shown in Fig. 5.

3.2.2. Lost circulation

As shown in Fig. 6, LC in the Don A. Campbell Geothermal Field is reported at depths averaging 300 m (1000 ft) and occurs almost entirely between 240 and 430 m (800–1400 ft). Deeper occurrences of LC can be inferred from the "drilled blind" stratigraphic sections in the 3D geologic model (Fig. 7) below 600 m (2000 ft). LC is reported in the drilling records in both core/monitoring wells and production wells. Although no records were provided for the injection wells, the blind drilling indicated in the 3D model identifies LC occurring there also. Of the few wells that penetrate through the basin fill alluvium to the basement, LC primarily occurs in the sections of alluvium that are hydrothermally altered, silicified, and fractured rather than basement rocks or volcanic units. Injection wells are primarily located in the northeastern part of the field and across one major NW-trending dextral fault from the production wells; however, they were not closely considered in this study.

Fig. 7 depicts a view from the 3D geologic model of the Don A. Campbell wellfield looking toward the northwest. The production wells are located primarily in the western part of the field and have been drilled near and sometimes into one of the major NW-trending dextral faults. All production wells intersect at least one NE-striking normal fault and nearly all of these intersections are spatially correlated with drilling blind indicating LC. While not all LC is associated with drilling across a fault, nearly every intersection is associated with blind drilling. Production wells are typically drilled to about 420 m (1400 ft), and fully cased down to about 300 m (1000 ft). LC is typically reported at slightly

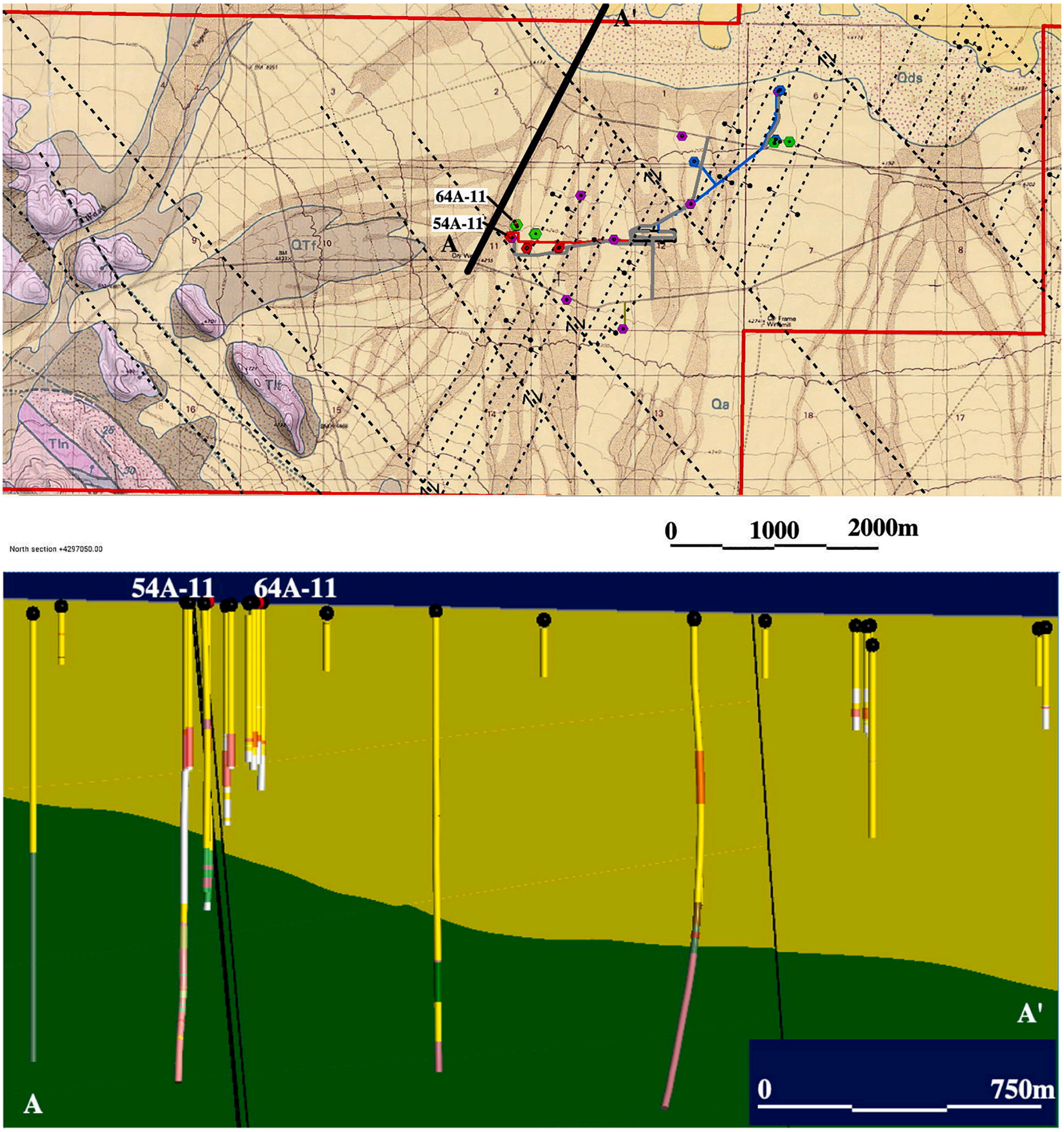

Fig. 5. Top: Geologic map of the Don A. Campbell Geothermal Field from Ormat's 3D Leapfrog geologic model, based on Delwiche (2013). Production wells are shown in red and green, injection wells are shown in blue, and monitoring wells are shown in purple. All of the surface geology, shown in varying shades of yellow and beige, are Quaternary alluvial basin fill and Tertiary volcanics shown in purple and orange. Black dashed lines are faults. Bottom: Geologic cross section depicting wells projected along A–A' (shown on map), looking NW, showing the NW trending strike-slip faults (black), Quaternary basin fill (yellow), and Tertiary volcanics (green and pink), from Ormat's 3D geologic model. White zones along the wellbores indicate blind drilling, or total LC. Red zones are the feed zones of the well. The two red wellheads are the wells examined in the case studies below.

more than 300 m (1000 ft), within the production interval of the well.

Monitoring wells in the field are typically located between the westernmost production wells and the easternmost injection wells. The depths for the three monitoring wells are approximately 150 m (500 ft), 800 m (2663 ft), and 1200 m (4000 ft). These wells were cored exploratory wells, and the two deepest were among the earliest wells drilled at Don A. Campbell. Both of these deeper wells experienced twist offs at depths over 300 m and experienced severe LC. In the shallower of the two wells, the drillers encountered a large void and total loss of circulation associated with drilling through volcanic units at 790 m depth. The well was ultimately completed at a depth of 650 m (2129 ft) above twisted-off equipment remaining in the hole. No LC was reported in the shallowest monitoring well (150 m).

Drilling records and mud consumable reports indicate the most common strategies used to address LC at the Don A. Campbell Geothermal Field are using LCM and drilling with aerated mud, as was done at McGinness Hills. In zones without significant LC, standard drilling strategies were followed including increasing the viscosity of the mud and adding fibrous materials to the drilling fluids, commonly some form of micronized cellulose.

Aerating the mud is frequently the immediate response in wells that experienced LC in the production zone. Interestingly, in at least two wells in this field, returns were regained shortly after beginning to drill in the production zone using foam. Higher concentrations of xanthan

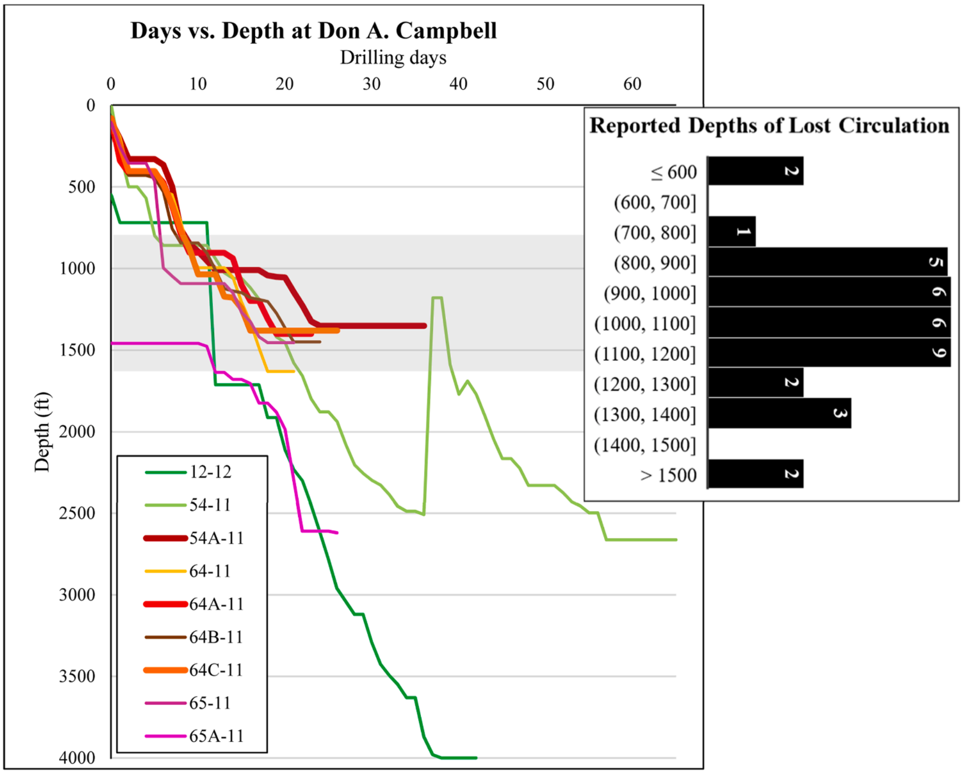

Fig. 6. Rate of drilling in days for wells in Don A. Campbell. Pauses (plateaus in depth reached) may be due to running and cementing casing or delays from LC. The depth zone where LC was most frequently reported is shown in gray and in the histogram to the right. The wells considered below as case studies are shown as thicker lines. Monitoring wells are shown in shades of green and productions wells are in warm colors. Histogram shows reported depths (in feet) of where LC began for ten wells in the Don A. Campbell field. The depth of the contact between basin fill and underlying volcanic units is usually greater than 610 m (2000 ft), indicating that LC primarily occurs in the basin fill – the silicified basin fill also constitutes the producing reservoir. Note that wells can have multiple occurrences of LC.

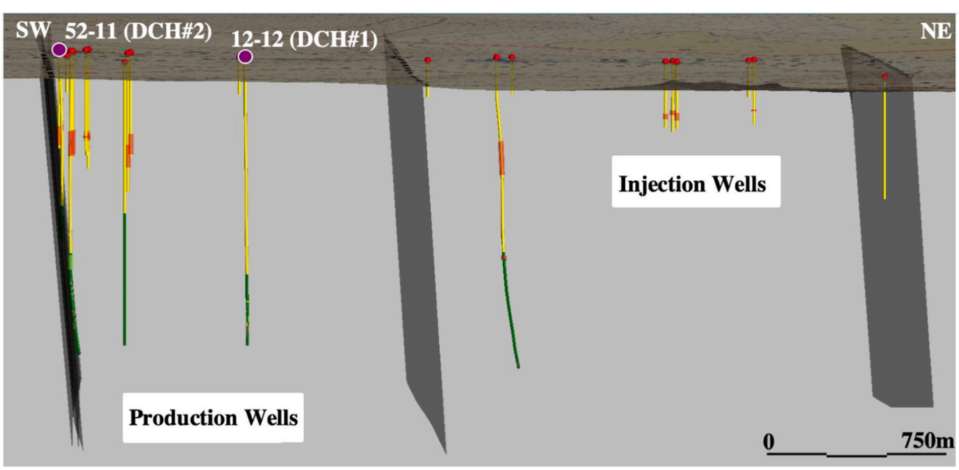

Fig. 7. 3D geologic model of the Don A. Campbell wellfield looking northwest. Dark gray planes are NW-striking dextral shear faults; NE-striking normal faults are not shown. Production wells are in the western portion of the field, while injection wells are in the northeast. Monitoring wells are scattered throughout, and the two exploratory wells are shown with purple dots and labeled. Yellow along the well path represents basin alluvial fill and green represents volcanic units. Red shaded sections of the well traces denote feed zones, indicating elevated permeability.

gum polymers were added to increase the fluid viscosity when rigged to drill with an air assist system. In some cases, the 3D geologic model often indicates blind drilling from the point where LC is first encountered and thus no returns from that point on.

At the Don A. Campbell field, LCM included varying forms of micronized cellulose, sawdust, and walnut shells. Micronized cellulose was used consistently during drilling as a preventative measure, and amounts were increased when circulation was lost. Sawdust was used next in large quantities, and where circulation loss was severe, walnuts shells were used in conjunction with micronized cellulose and sawdust. Unlike at the McGinness Hills geothermal field, there does not seem to be a significant difference in LCM use between the shallow nonproductive and production intervals, although drilling with an air assist system is only done in the production interval. Only one of the studied wells reported using a cement plug when severe circulation loss occurred immediately below the shallow nonproductive interval, which we will consider in further detail in the next section.

3.2.3. *Well case studies*

Production Well 54A-11. Well 54A-11 is a production well that was completed in September of 2012 as part of the first phase of development at Don A. Campbell (Fig. 8). This well is part of a cluster of two wells. The other well in the cluster, Well 54–11, was the second early exploration core hole, and experienced severe LC and a twist-off, leading to completion of the well at 650 m depth. Well 54A-11 was drilled to a total depth (TD) of 412 m (1351 ft) and cased to a depth of 305 m (1002 ft).

Initial depths of reported LC in the shallow nonproductive interval at 250 m (821 ft) were relatively mild (18–80 bbl/hr). This LC event coincided with a lithology change from relatively unconsolidated sandy alluvium to harder silicified conglomerate and resulted in a decrease in

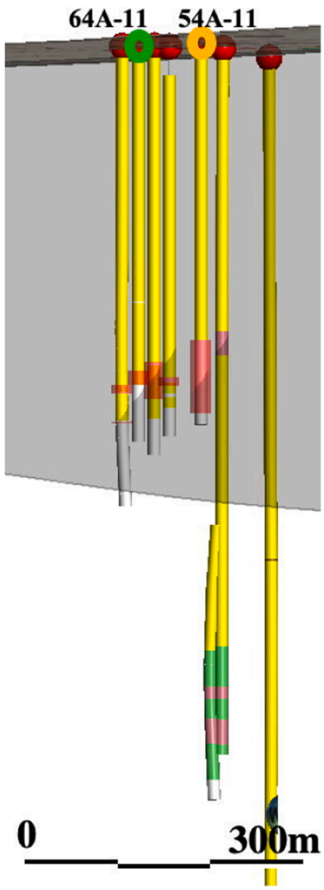

Fig. 8. 3D geologic model looking southeast and showing wells 54A-11 (wellhead indicated by orange circle) and 64A-11 (wellhead indicated by green circle). These wells are located within the cluster of production wells shown in Fig. 7. Gray plane (lower section removed for clarity) intersecting wells is a NE-striking normal fault. A NW-striking dextral shear fault (not shown) intersects the deeper wells at the contact of the basin fill and volcanic units. Yellow intervals along the wellbore correspond to basin alluvium, green and pink are volcanic units, and white is blind drilling. Red shaded transparent zones are well feed zones.

the average rate of penetration (ROP) from 3.8 to 1.8 m/hr (12.7 to 6 ft/hr). Severe LC (123 bbl/hr) occurred at 266 m (873 ft) at which point large quantities of PrimaSeal™ (a blend of granular and fibrous LCM) were introduced and stopped the circulation loss long enough to run and successfully cement the casing. Minor LC was encountered several meters below the cased interval and total loss of circulation occurred at 320 m (1051 ft) depth. At this point, drilling continued with aerated mud and increased quantities of xanthan gum polymer and sawdust. Circulation was not restored and the rest of the well down to TD was drilled blind (Fig. 8) with spotty returns reported in the mud log. This total LC zone coincides with a zone ~50 m above and below the intersection with a NE-striking normal fault and serves as the primary feed zone of the well. This fault is also intersected by four of the other production wells in Don A. Campbell, along with Well 54–11 and is associated with LC in several of the other production wells.

Although not consistently recorded throughout the log, the mud log also reported secondary mineralization, including quartz, pyrite, hematite, and chlorite, in the 90 m preceding the total loss zone. Quartz (silica) becomes abundant (7–10%) at 265 m (870 ft) and stays abundant to TD. Pyrite is common (4–7%) below 320 m, and hematite is common to abundant between 230 and 250 m (770 to 830 ft). Chlorite is common from 245 m (810 ft) until the total loss zone at 320 m (1051 ft). Like McGinness Hills, the presence of secondary mineralization may be indicative of an increased permeability feature and corresponding hydrothermal alteration in the zones surrounding faults.

Production Well 64A-11. Well 64A-11 is a production well drilled in the vicinity of three other production wells and was completed in April 2015 (Fig. 8). These four wells represent a second phase of expansion to provide for the power plant that came online in 2018. This well was drilled to a TD of 427 m (1400 ft) and cased to 266 m (873 ft). LC was first reported at 275 m (903 ft) with no returns at 283 m (930 ft); the formation changes from sandstone to conglomerate over the range 290–296 m (950–970 ft). The mud log shows increasing quartz from rare (< 1%) to abundant (7–10%) over the 21 m (70 ft) above the loss zone, and an increase in chlorite from rare to common (4–7%) over the 30 m (100 ft) preceding the loss zone.

In response to the loss, an LCM pill containing walnut shells, sawdust, and micronized cellulose was spotted (a "pill" is a small quantity of drilling fluid specially formulated for a specific task such as addressing LC placed at a specific location and allowed to remain in place for a time). Xanthan gum polymer was also added; however, circulation loss continued with intermittent returns. At this point, the borehole was backfilled with 4.5 m of sand (15 ft) and a 6 m (20 ft) cement plug was placed above the sand. Once this plug was drilled through, casing was run and cemented. When drilling recommenced after running casing, ~300 bbl of mud was lost between 275 and 285 m (904 and 938 ft) through a "very hard formation."

Circulation was lost again at 365 m (1199 ft), at which point drilling continued with an air assist. About 24 m (80 ft) prior to losing circulation, increases in abundances of quartz (from < 1% to 7 to 10%) and chlorite (from < 1% to 4–7%) were observed in the mud log. From 413 m (1354 ft) to TD, the records note that the well was drilled blind with aerated mud, and no further reports were available to indicate additions to the mud. The region of drilling blind with no returns is spatially correlated with intersecting the same fault that Well 54A-11 intersects. This section is also the main feed zone of the well (Fig. 8).

3.3. Steamboat Hills geothermal system

3.3.1. Geologic setting

The Steamboat Hills geothermal system consists of a lower area known as Steamboat Springs and a higher area generally called Steamboat Hills. However, both names are frequently used to describe the whole system and thus "Steamboat Hills" will subsequently be used to refer the system as a whole. This geothermal system is located just south of Reno, Nevada along the western margin of the Basin and Range province. It differs from most Basin and Range geothermal systems in that it is associated with Quaternary volcanism. At least four Pleistocene-age rhyolite domes have intruded into Tertiary volcanics and Mesozoic basement rocks (metasediments and intrusives) (White, 1968; Silberman et al., 1979; Flynn et al., 1994; Ramelli et al., 2011). The geothermal reservoir is primarily within fractured and faulted Cretaceous granodiorite. Several different steeply dipping fault systems have been mapped in the area, striking NE–SW, N–S, and NW–SE (Fig. 9). The structural setting for this area is a combination of fault terminations, fault intersections, and accommodation zones (Faulds et al., 2013).

Flow from geothermal springs discharge into Steamboat Creek. These discharges have remained relatively constant over time, likely due to replenishment from the reinjection of produced fluids (White, 1968; Sorey and Spielman, 2017). There is an extensive siliceous sinter that blankets much of the lower elevation regions near where the springs once discharged silica-rich fluids (White, 1968; Lynne et al., 2008). Hot spring resorts were developed in the area beginning in the late 1800s, and the first geothermal wells were drilled in the 1920s to supply hot water to these resorts (Garside and Schilling, 1979; Combs and Goranson, 1994). The first commercial geothermal power generation began in 1987, and field operations have recently been upgraded, with current

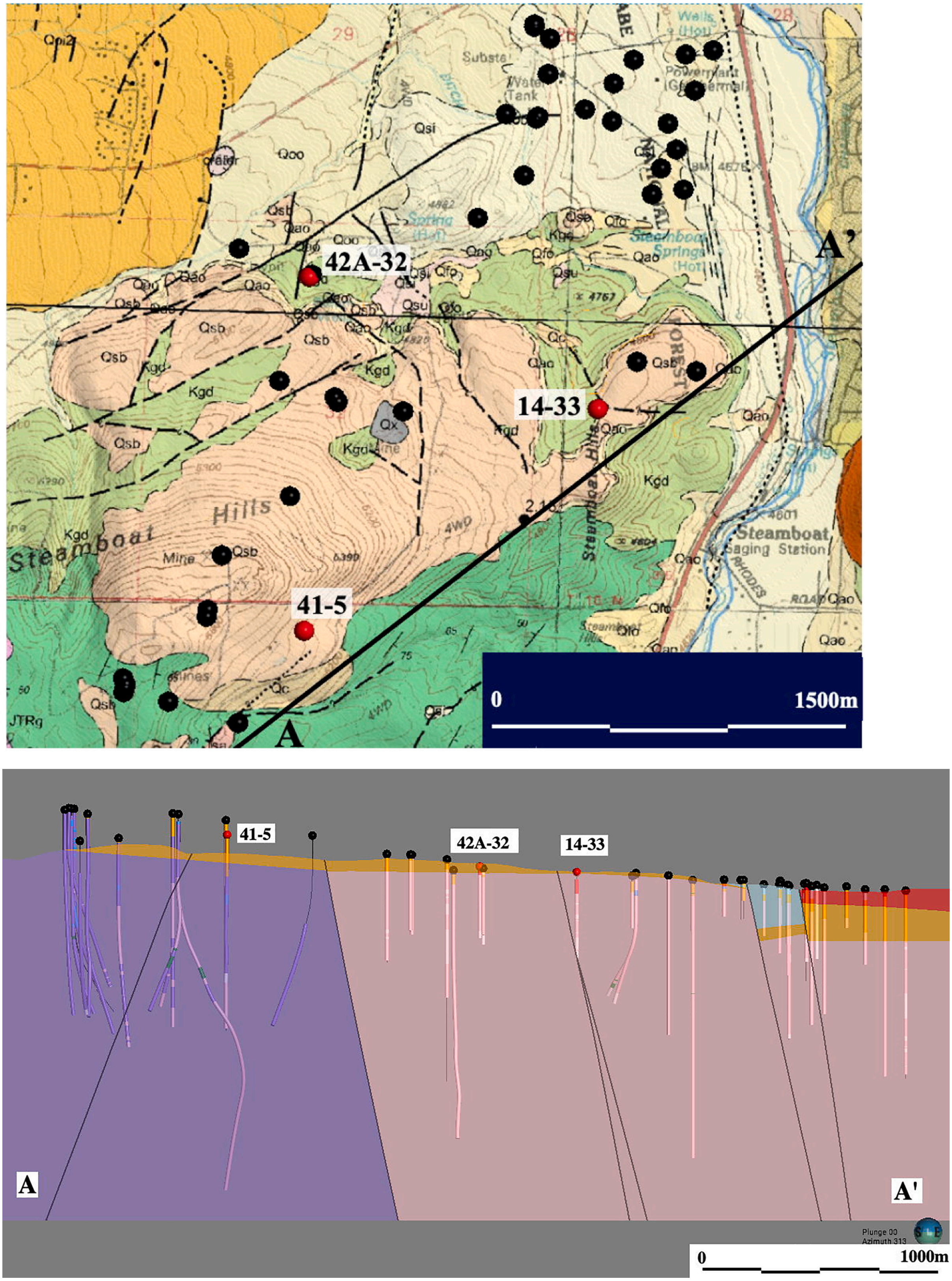

Fig. 9. Top: Geologic map of the Steamboat geothermal system based on Ramelli et al. (2011). The geologic units are as follows: JTRg: Jurassic-Triassic meta-sedimentary rocks; Kgd: Cretaceous granodiorite; Qsb: Quaternary Steamboat Hills basaltic andesite; Qoo: Quaternary older outwash; Qoi2: Quaternary intermediate outwash; Qfo: Quaternary older fan deposits; Qao: Quaternary older alluvium; Qsu: Quaternary sands; Qc: Quaternary colluvium; Qsi: Quaternary sinter. Bottom: Wells examined as case studies are shown in red and labeled. Wells are projected against a cross section from A–A' (shown on map), looking SE, showing faults (black), Mesozoic granodiorite (pink) and metasediments (purple), Tertiary volcanics (orange), and Quaternary sinter (light blue) and alluvium (pale yellow). Zones of no returns (LC) in the wells are shown in white.

generation of 79 MWe (Combs and Goranson, 1994; Walsh et al., 2010; Akerley et al., 2021; Ormat, 2022).

The conceptual model for the Steamboat geothermal system (Fig. 10) consists of upflow in the Steamboat Hills area to the southwest where the highest temperatures are observed, with outflow and surface discharge to the northeast in the Steamboat Springs area (Mariner and Janik, 1995; Walsh et al., 2010). Much of the permeability within the basement rocks that host the geothermal reservoir appears to be controlled by faults and fractures, which have been observed in cores, pressure/temperature/spinner logs, and image logs in production, injection, and slimhole wells (e.g., Finger et al., 1994; Flynn et al., 1994; Combs and Goranson, 1994, 1995; Goranson and Combs, 1995,2000; Walsh et al., 2010).

3.3.2. Lost circulation

Well depths at Steamboat Hills vary between 259 m (850 ft) and nearly 1219 m (4000 ft), with shallower wells typically in Steamboat Springs ("Lower Steamboat") to the northeast and deeper production wells in the Steamboat Hills ("Upper Steamboat") to the southwest (Fig. 11). Wells in Lower Steamboat are predominantly drilled through granodiorites and wells in Upper Steamboat are drilled through Tertiary volcanics and metasediments. Wells were frequently targeted to intersect faults or fault intersections, and zones of total LC often coincide with faults (no returns are indicated in the 3D model; refer to the white colored intervals shown along the wellbore in Fig. 12). Secondary mineralization that is commonly associated with hydrothermal alteration along faults, such as clay minerals and epidote, are commonly reported in the mud logs *preceding* loss of circulation. Three wells that experienced severe LC, two production and one injection, were examined more closely to assess the mitigation responses and potential warning signs for severe LC.

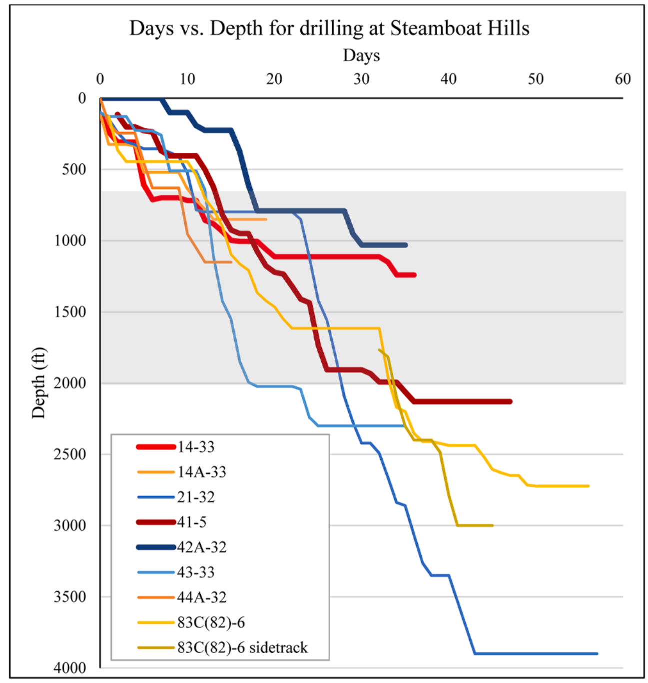

Fig. 11. Rate of drilling in days for wells in Steamboat Hills. Pauses (plateaus in depth reached) may be due to running and cementing casing or delays to LC. The depth zone where LC was most frequently reported is in gray. Production wells are in warm colors and injection wells are in cool colors, and the wells considered below as case studies are shown as thicker lines.

3.3.3. Well case studies

Production Well 14–33. Production Well 14–33 is in Lower Steamboat in the northeastern part of the field and was drilled to a total depth of 378 m (1240 ft) and cased to 335 m (1100 ft) in 2007 (Fig. 12). It extends through several hundred feet of alluvium prior to encountering granodiorite and episodes of LC. The 3D geologic model indicates the well intersects a steeply dipping fault at ~250 m (~ 820 ft) near the depth where total losses occurred. Although the mud log indicates some mineralogy changes prior to intersecting the zone of lost circulation, the observations are not distinct. There is a significant increase in calcite, pyrite, and chlorite prior to the significant losses at 265 m (871 ft) and 288 m (947 ft), however the increases in abundance occur over a region 150 to 200 m prior to these loss zones.

Multiple instances of LC occurred while drilling this well. Many of the details are included here to provide an example of the difficulties dealing with lost circulation in some wells. At 136–140 m (446–458 ft), a small loss was healed by a sweep of undetermined LCM. From 170–198 m (558 to 649 ft), 204 bbl were lost; this loss was stopped by another sweep of LCM at 198 m (649 ft). During continued drilling, losses of over 200 bbl/hr occurred. The mud log indicates increased quartz veining and weak to moderate argillitic alteration in this region. In response to the loss, LCM (100 bbl of UltraSeal™) was spotted at 213 m (698 ft) and an LCM pill (40 bbl of StopLoss™) was spotted at 198 m (650 ft). Time was allowed for the LCM to set up and these remediations enabled partial returns. No flow was returned after pumping 100 bbl mud, and a 100 bbl UltraSeal™ LCM pill was mixed. A high-viscosity LCM pill was spotted at 213 m (698 ft), but circulation was not recovered. A 100 bbl StopLoss™ pill and 40 bbl of CSH were pumped in, which restored circulation with no losses. Then 144 bbl was lost washing down the last three joints from 171 to 198 m (560 to 650 ft), followed by the total loss of circulation. Another 114 bbl of drilling fluid was lost

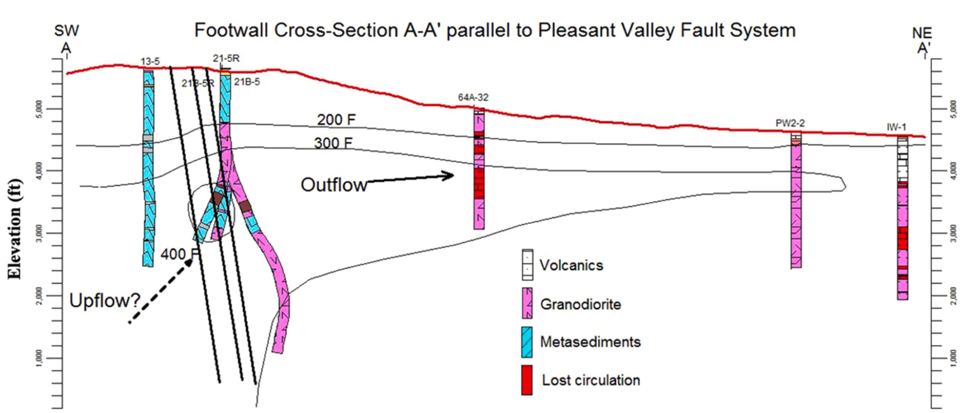

Fig. 10. Conceptual model of Steamboat system looking NW (Walsh et al., 2010). Upflow occurs along faults and fractures to the southwest (Steamboat Hills area), with outflow to the northeast (Steamboat Springs area).

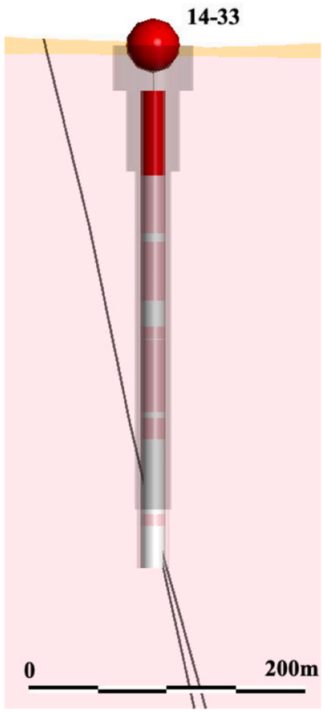

Fig. 12. 3D geologic model of Well 14–33. Left: Stratigraphy and blind drilling zones; bright pink is basin fill, light pink is Mesozoic granodiorites, and white is blind drilling indicating LC. Note that severe LC occurs near the intersection of the well with the fault zone (black lines). Cased interval indicated by gray shading. Note the production/injection zone is associated with the intersection of the well with the fault zone as well.

trying to regain circulation. A 50 bbl StopLoss™ LCM pill was spotted at 213 m (698 ft) and 100 bbl containing CSH pellets was spotted at 210 m (690 ft), which restored circulation. Circulation was lost while mixing the next LCM pill, which was spotted at 213 m (698 ft). Finally, after these attempts to use LCM to address the LC at this depth, a cement plug was placed at 213 m (698 ft). Overall, no drilling gains were accomplished over 5 days, including the time spent waiting for the cement plug to cure at a cost on the order of $200,000.

As drilling continued, total circulation was lost at 265 m (871 ft). The mud log indicates a slight increase in calcite in veins in the ~12 m (40 ft) prior to reaching this depth along with quartz veins with pyrite. An LCM sweep was pumped, and an LCM pill was spotted on the bottom. The drill string was pulled out and an open-ended drill pipe tripped in to 265 m (871 ft). Another LCM pill was then mixed and pumped as follows. The drill string was pulled out to 152 m (500 ft), and LCM was mixed in. The drill string was tripped in to 244 m (800 ft), and the LCM pill was pumped in. An open drill pipe was tripped in to 266 m (872 ft) and cement was placed. The drill string was tripped out of hole, and then tripped in to 265 m (871 ft) to drill the 44.5 cm (17–1/2 in.) hole with no returns to 269 m (882 ft). Drilling continued with losses of about 40 to 45 bbl/hr while adding LCM pills at 285 m (935 ft), following which, a 46 linear meters (150 linear ft) cement plug was pumped. The cement was tagged at 244 m (800 ft) and drilling continued to 289 m (947 ft). At 289 m (947 ft), all returns were lost and drilling continued to 306 m (1004 ft) without returns. At 306 m (1004 ft), an LCM pill was mixed and pumped, followed by 46 linear meters (150 linear feet) of cement. When the drill string was tripped back in, no cement was encountered. Another 110 bbl of LCM was mixed and pumped in, followed by 30 linear meters (100 linear feet) of 1.74 specific gravity (SG) (14.5 ppg) cement. When the drill string was tripped in, cement was not encountered again. Next, 100 bbl of LCM was mixed and pumped, followed by 30 linear meters (100 linear feet) of 1.74 SG (14.5 ppg) cement. When tripping back in, no cement was encountered. Another 30 m (100 linear ft) cement plug was placed, and then tagged at 271 m (890 ft). Circulation was attempted at 268 m (880 ft) and all returns were lost. The drill string was tripped in and tagged "bottom" at 269 m (883 ft). Another 30 linear m (100 ft) cement plug was placed and tagged at 830 ft. The cement was drilled with no losses to 265 m (871 ft) where the string fell through to 269 m (883 ft), and all returns were lost. A total of nine bales of rice straw were dumped into the hole between numerous trips in and out, and the straw was pushed to 270 m (886 ft).

Numerous additional attempts to mitigate LC in this well were unsuccessful. The materials introduced included bentonite, rock, gel, and synthetic polymer from the surface and flushed to the bottom of the hole with water. The drill string with bit and bottom hole assembly (BHA) was tripped into the hole and the LCM was tagged at 267 m (875 ft). Despite attempts to fill the hole and circulate, fluid losses of 180 bbl/hr occurred, and drilling continued without any returns. At 339 m (1112 ft), the well was cased, but the casing required repair. The remainder of the hole through the production interval was drilled blind to the total depth of 378 m (1240 ft). The cost to drill from 269 m (882 ft) to 378 m (1240 ft) to address the numerous lost circulation locations including casing was on the order of $1,000,000.

Production Well 41–5. Fig. 13 shows the 3D geologic model of Well 41–5, which was drilled to 649 m (2130 ft) through Tertiary volcanics and metasediments and cased to a depth of 579 m (1900 ft). Losses of up to 65 bbl/hr occurred and sudden losses occurred in the upper regions of the well, which were cured with PrimaSeal™ and sawdust (one sack of each per hour). At a depth of 512 m (1680 ft), rapid losses of about 30 to 60 bbl occurred with continued minor seepage of about 10 bbl/hr. An LCM sweep was run at 581 m (1906 ft) curing losses. All returns were lost between 596 and 597 m (1954 and 1957 ft), but this was healed with PrimaSeal™. All returns were lost again between 606.9 and 607 m

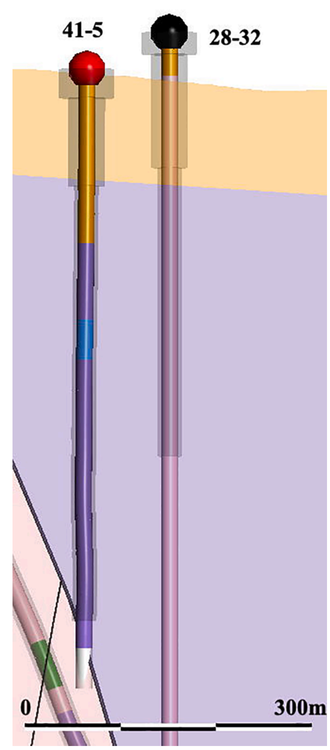

Fig. 13. 3D geologic model schematic of Well 41–5. Stratigraphy and blind drilling indicating LC. Orange is Tertiary volcanics, green is Paleozoic metasediments, purple is predominantly clay minerals, and white is blind drilling. Note that the LC zone is associated with the intersection of the well with the fault zone (dark gray). Cased intervals are shaded gray.

(1991 and 1992 ft), and the remainder of the hole was drilled blind to 649 m (2130 ft). Note that this section of blind drilling, shown in white in Fig. 13, corresponds with the intersection of the well and a steeply dipping fault. The mud log for this hole did not show mineralogical indicators when approaching a region where significant LC occurred.

Injection Well 42A-32. Fig. 14 shows the 3D geologic model of Well 42A-32, which was drilled through 61 m (200 ft) of alluvium before continuing to the total depth of 314 m (1030 ft) in granodiorite and cased to 229 m (750 ft). At shallow depths, small losses of about 35 bbl/hr occurred. These were healed using a high viscosity LCM pill (unspecified composition). At 241 m (790 ft), losses were about 90 to 300 bbl/hr, and a 50 bbl pill of FRAC-ATTACK™ LCM (a proprietary diatomaceous earth blend) was spotted, after which 0.4 m^3 (15.4 ft^3) of cinders to act as a filling material in the LCM were dumped into the hole and allowed to settle to the bottom. The cinders were tagged at 234 m (4.3 m of fill) [768 ft (14 ft of fill)], and it was thought that the previous pill of FRAC-ATTACK™ had not hardened when some reached the surface, so the remainder was circulated out slowly and the cinders allowed to settle again. A small amount of sand was added and allowed to settle along with the cinders. After several hours, the hole was circulated clean and mud loss of 30 to 90 bbl/hr occurred. A high viscosity LCM sweep was performed but losses of 30–40 bbl/hr continued, after which a high viscosity microfiber plug was spotted on the bottom of the well and cleaned out to 232 m (760 ft), restoring full returns. A plug of foamed Thermalock™ cement was injected, the top of which was tagged at 214 m (701 ft), and then the plug was drilled out to 230 m (752 ft) with full returns, after which casing was run and successfully cemented. This LC event consumed four days of rig time. In continuing drilling below the casing shoe, losses of about 130 to 200 bbl/hr began at 264 m (867 ft) and continued until all returns were lost at 283 m (930 ft). Several 40 bbl high viscosity sweeps were pumped, followed by drilling blind for the remainder of the well to the TD of 314 m (1030 ft).

The mud log was provided for this well and review of the secondary mineralization does not indicate a clear correlation with any minerals preceding LC. Rare (<1%) sericite (clay mineralization) appears intermittently between 200 m (~650 ft) and 265 m (~875 ft), approximately 40 m (130 ft) prior to significant losses beginning at 241 m (790 ft). Chlorite varies between rare (<1%) and common (6–9%) abundance for the 180 m (600 ft) between ~100 m (330 ft) and 283 m (930 ft) where total circulation was lost. Calcite varies between rare and occasional (3–6%) at depths of 180 m (~600 ft) to 283 m (930 ft) but is present

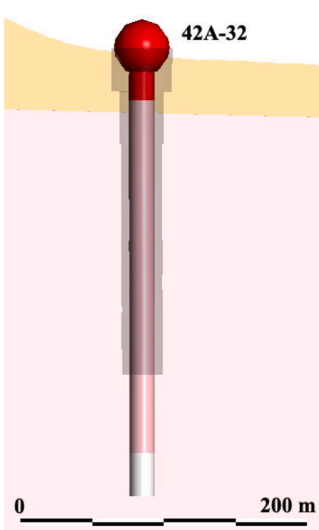

Fig. 14. 3D geologic schematic of Well 42A-33. Left: Stratigraphy; bright pink is basin fill; light pink is Mesozoic granodiorites, and white is blind drilling indicating a LC zone. The cased interval is shaded gray.

intermittently at shallower depths, as well. All other secondary minerals are present intermittently throughout the entire section of the well in granodiorite.

3.4. Puna Geothermal Venture geothermal system

3.4.1. Geologic setting

The Big Island of Hawai'i, resulting from a mantle hotspot, is the youngest subaerial island in the Hawaiian island chain and has five basaltic shield volcanic centers, two of which are currently active. The Puna Geothermal Venture (Puna) geothermal system is located on the lower East Rift Zone (ERZ) of Kilauea volcano, the youngest and most active volcano on the Island of Hawai'i (Thomas, 1986; Lautze et al., 2017). A series of feeder dikes underlie the ERZ, running along the strike of the rift zone from the magma chamber beneath the summit caldera of Kilauea volcano, which serves as the primary source of the erupted magma. Volcanism along the ERZ is dominantly basaltic in composition, but minor andesite lavas and even dacitic magma have been reported (Gansecki et al., 2019; Teplow et al., 2009). Typical rock types encountered in deep wells drilled into the lower ERZ include basaltic lava flows, hyaloclastite, basaltic andesite and andesite tuff, and intrusive diabase dikes (e.g., Spielman et al., 2006; Teplow et al., 2009). The diabase dikes are associated with near-vertical large-aperture fractures, which are the main production zones for geothermal wells, and are related to the rift zone faults exposed on the surface.

The Kilauea ERZ has been the site of geothermal exploration since the 1960s, when the first shallow exploration wells were drilled (Thomas, 1986). A second phase of exploratory drilling was kicked off by Well HGP-A in 1975, which was drilled to a depth of 1960 m, with a bottom hole temperature of 358 °C (Thomas, 1986). The success of this well led to subsequent drilling activity (Fig. 15) and development of the Puna Geothermal Venture (Iovenitti and D'Olier, 1985; Kaleikini et al., 2011; Teplow et al., 2009; Nordquist et al., 2013; Lautze et al., 2017). An experimental 3 MWe power plant was installed in 1981 using Well HGP-A as the source of steam and was shut down in 1989. This facility was replaced by a 25 MWe power plant consisting of ten combined cycle units (this system later produced up to 30 MWe), which commenced operations in 1993. Two Ormat binary systems were installed in 2012, expanding total power production of the field to 38 MWe and allowing for ramping of the system. Geothermal field operations were halted with the 2018 lower ERZ eruption, with the wells shut in and bridge plugs installed to prevent any damage from the lava flows (Spielman et al., 2020). After the eruption ended later that year, Ormat undertook activities to restore the field to normal operations, and the plant came back online in November 2020.

3.4.2. Lost circulation

Several earlier studies have reported on LC issues while drilling at Puna. Iovenitti and D'Olier (1985) noted that the two early wells drilled in the field (KS-1 and KS-2) experienced severe LC problems in the upper (0–450 m (0–1500 ft)) portions of the wells within the sequence of subaerial basalts, leading to less-than-ideal casing cement jobs. Most of the LC within the reservoir for these two wells occurred at depths greater than 2130 m (7000 ft), resulting from intersecting large open fractures. Spielman et al. (2006) provide LC details for three wells drilled at Puna in 2005. The presence of hyaloclastite, which is highly permeable and unstable, presented challenges related to both mud losses and hole stability, and water and gel sweeps were used while drilling through these high loss zones in KS-6. Micronized cellulose (CHEK-LOSS) was used to successfully control LC within low to moderate permeability zones for well KS-13, while preventing these zones from becoming permanently plugged. Rickard et al. (2010, 2011) also noted high loss zones in the shallow (~300 m (~1000 ft)) intervals of the boreholes within basalt, and commented that sodium silicate pre-flushes were used prior to cementing casing to minimize losses. For well KS-14, a mud motor and aerated mud, consisting of foaming agents, drilling detergent,

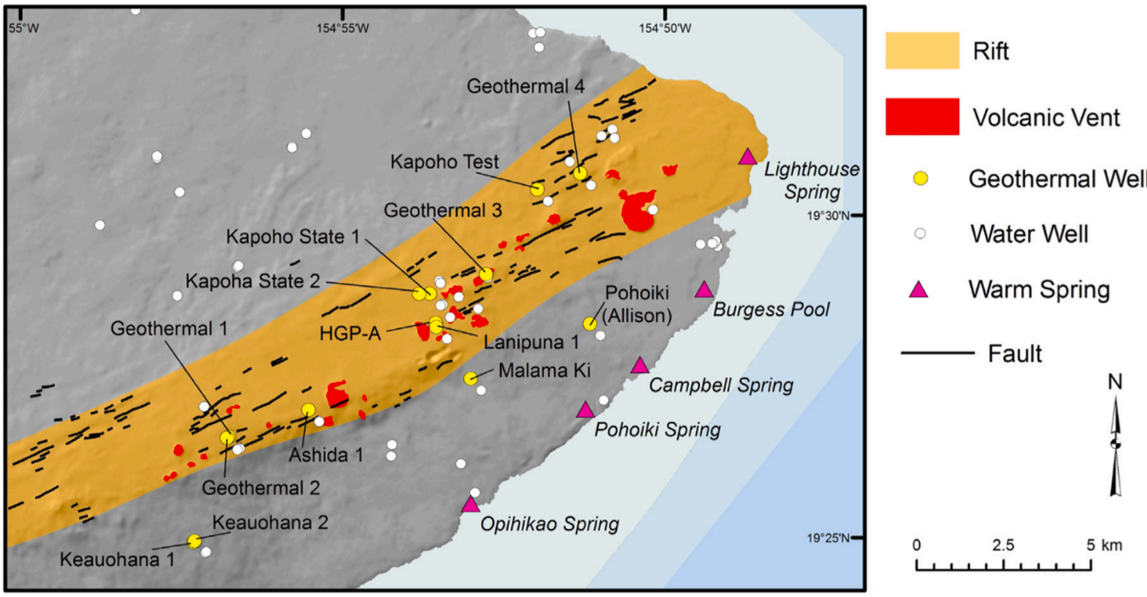

Fig. 15. The lower East Rift Zone of Kilauea volcano (Puna region), highlighting the rift, volcanic vents, geothermal and water wells, and warm springs related to geothermal outflow along the coast. The Kapoho State (KS-series) wells are related to the Puna Geothermal Venture geothermal field (Lautze et al., 2017).

and xanthan gum polymer, were used to drill the surface section of the well where high mud losses were encountered, resulting in improved drilling performance compared with previous wells. When drilling the intermediate sections of KS-14, micronized cellulose was used proactively to minimize LC problems and improve borehole conditioning. This material thermally degrades, so that it will not permanently damage high permeability features (which act as feed or injection zones) in the reservoir. In upper and intermediate sections where significant LC occurred, reverse circulation of foamed cement was used to improve casing cement jobs in KS-14. Shallow sections of the wells were drilled using bentonite mud treated with lime; this was changed to gel/polymer drilling fluids (such as xanthan gum) for intermediate depths, and a high temperature copolymer was used for the deepest portions of the wells where high temperatures were encountered. Low mud weights were used to minimize LC throughout. AlMuhaideb and Noynaert (2021) conducted a general review of past drilling operations at Puna, and also noted that the main issues with LC of the seven wells that they evaluated occurred in the shallower portions of the boreholes, and suggested that proper LCM selection is important in addressing this issue.

For this review, data provided regarding the geology and drilling records for Puna allow us to generally summarize mitigation approaches, and two case studies of wells are examined in more detail. LC occurred at all depths in the wells of Puna but most often in the shallower, larger diameter sections of the wells (e.g., where surface casing was run) or the LC was instrumental in determining TD. Mitigation strategies for LC in Puna include drilling with aerated fluid (foam), sometimes blind; frequent use of micronized cellulose; bentonite gel (in the intermediate section between the surface casing and the production interval); and in serious loss conditions, at least 2 wells used cement plugs. LCMs in wells at Puna include cottonseed pellets, finely ground almond hulls, walnut pellets, and proprietary blends such as Prima-Seal™, Kwik-Seal™, and CHEK-LOSS™.

Partial to total LC occurred in the shallowest section of wells ($<\sim 60$ m or 200 ft). This was not noted in the other fields reviewed here. Significant issues occurred in sections of total losses and drilling blind where cuttings packed around the BHA and caused the drill string to stick. This differential sticking often happened after a pipe connection when the drill string was stationary and usually occurred in permeable areas of the formation with thick filter cake. While this sticking could not be eliminated, it was possible to unstick the drill string by having more force available to pull the pipe (AlMuhaideb and Noynaert, 2021). These shallow sections were drilled using spud mud (bentonite gel treated with lime to increase viscosity), water and gel sweeps, aerated fluid (foam), and additional additives for specific purposes in several wells that experienced total losses. Micronized cellulose was maintained in the drilling fluids with varying concentration depending on the amount of fluid loss and drill cuttings assisted in bridging of pores and fractures. Partially hydrolyzed polyacrylamide (PHPA) was used to encapsulate drill cuttings and provide lubrication for the drilling tools and wellbore. Xanthan gum polymer was used to increase viscosity and gel strength for hole cleaning and to better suspend cuttings. This combination of additives and base mud worked adequately to limit fluid losses and clean cuttings from the hole.

Losses were also encountered when the wells intersected high permeability features such as empty lava tubes, fault zones, hyaloclastites, or contacts between lava flows. These losses were partial to total and often required sealing with micronized cellulose or cement plugs. Problems with stuck pipes were further aggravated by lack of hole cleaning, directional drilling of the well, stationary string during pipe connection, and packing of the cuttings around the drill string. A complete set of fishing tools was available onsite due to the remoteness of the project location. There was also an air package on standby to pump air around the well to dislodge cuttings, if needed.

In the 51 cm (20 in.) diameter intermediate section of wells drilled at Puna, partial losses ranging from minor seepage to 40 bbl/hr losses were encountered. These sections were drilled with bentonite gel or polymer drilling fluids. While drilling the second intermediate sections (37.5 cm or 14.75 in. diameter) most of the wells had full returns to the end of the shallow nonproductive section, which was generally around 1460 m (4800 ft). Some wells experienced partial losses up to 60 bbl/hr but regained full returns after pumping LCM. Directional drilling was required in the intermediate intervals to reach the production targets.

Finally, in the production section of wells at Puna (27 cm or 10.625 in. diameter), most of the wells had full returns up until the well intersected fractures and total loss of returns occurred. At this point drilling generally continued blind and water was pumped down the annulus and drill string for lubrication and to help wash the cuttings away into the formation. High viscosity sweeps were pumped prior to making connections to keep the drilled cuttings from packing off around the BHA while the drill string was stationary. Polymers used in the drilling fluid provided cuttings encapsulation (PHPA), filtration control (polyanionic cellulose - PAC), and increased low shear viscosity. Micronized cellulose LCM prevented mud and cuttings from permanently plugging moderate permeability zones while swabbing and hydrostatic bailing helped clean the LCM, mud, and cuttings back out of the zones (Spielman et al., 2006).

3.4.3. Well case studies

Well KS-14. Well KS-14 was drilled to a total depth of 1742 m (5717 ft) through the basaltic rocks of the ERZ (Fig. 16, left), and several episodes of LC occurred during drilling. During drilling of the 66 cm (26 in.) diameter hole, there were tight hole issues and the drill string got stuck at 296 m (970 ft) during blind drilling. Aerated foam was used to work pipe down the holes until it was freed, and 56 cm (22 in.) casing was run to 305 m (1000 ft). In the next section of the well (37.5 cm or 14.75 in. diameter), the drilling fluid included 3–5 lb/bbl of micronized cellulose that helped seal the partial losses during directional drilling. The final production section of the well was drilled with a diameter of 27 cm (10–5/8 in.), and total loss of returns occurred at 1798 m (5603 ft) at which point the drill string became stuck. The pipe was worked down and jarred free and then back-reamed out to the previous casing shoe at 1490 m (4890 ft) prior to pulling out of the hole. In this section of the well, high viscosity sweeps of proprietary LCM blends were added to the drilling fluid to flush cuttings from the hole.

There is no indication of advanced warning signs of LC in the mud log identifying secondary mineralization in the production interval. Hematite was abundant (7–10%) when there were intermittent returns in the larger diameter section of the well, but no other secondary minerals are present in conjunction with severe loss of circulation in this section of the well or closer to the TD.

Well KS-15. Well KS-15 was directionally drilled to a TD of 2445 m (8020 ft) and cased to a depth of 1434 m (4705 ft) with three redrills branching off from the original well. The original plan was to drill this well in 70 days; however, actual drilling time took 131 days and required three sidetracks, one branching off at 912 m (2992 ft), one at 1437 m (4716 ft), and one at 1594 m (5230 ft). Losses were not significant in the reservoir section, hence the various sidetracks to find permeability. These depths correspond to the narrowest cased interval (30 cm or 11.75 in.) of the original well for the first and the open hole

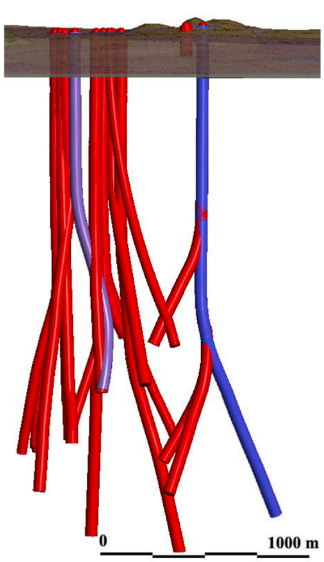

Fig. 16. Geothermal wells of Puna Geothermal Venture. View looking west with KS-14 highlighted in purple and KS-15 highlighted in blue. Note the redrills branching off of KS-15.

(27 cm or 10.625 in.) for the latter two sidetracks. The first sidetrack was lined to its TD of 1579 m (5182 ft); the second was left as an open hole to its TD of 2286 m (7500 ft); and the third was drilled to a TD of 2130 m (6987 ft). All sidetracks experienced problems with LC to varying degrees, usually influencing the TD (~ 100 m beyond the significant loss zone) by each branch of the well. The response at these depths was consistently to drill blind with aerated fluid with frequent high viscosity LCM (unspecified) sweeps.

Multiple instances of LC occurred in the shallow unproductive interval of the original well. Partial to total circulation loss was encountered in the original wellbore between 40 and 120 m (132–392 ft) while drilling the 66 cm (26 in.) diameter section with aerated fluids. The drill pipe became stuck several times as a result. While reaming this section between 258 and 305 m (845–1000 ft) the drill pipe became stuck again, which resulted in several days of delay as they worked to free the pipe, and fishing operations removed the stuck pipe. Once the pipe was freed, casing was run to a depth of 305 m (1000 ft). Two top jobs were required to bring cement in the annulus back to surface due to the loss zones in this section. Total losses were again encountered between 358 and 361 m (1177–1185 ft) and required sweeps of unspecified LCM and a cement plug to cure the losses.

While mud logs were provided for each of the sidetracks, there is limited correlation with LC occurrences and secondary mineralization in these wellbores. Hematite is the one exception at shallow depths and is frequently present surrounding LC events.

4. Cementing in response to lost circulation

A review of the well summary reports was conducted to understand the use of cement plugs to control lost circulation. Cementing is performed on wells for a number of reasons, such as cementing casing, top jobs, plugging, supporting a whip stock, and regaining circulation when lost. Our evaluation examined non-casing cement jobs performed in wells where LC was significant (either at many locations, or large at a single location). It is possible that in some cases, casing was placed and cemented to eliminate lost circulation, but the well summary reports primarily indicate that the casing was placed for other reasons.

Cementing to address lost circulation is typically a last resort, because it requires a separate crew to do the job, rigging-up cementing equipment, placing the cement, testing cement samples, waiting for the cement to set, finding the cement if it didn't get lost in fractures, rigging down the cementing equipment, and drilling back through the cement to continue on. It is also not guaranteed to succeed (see Table 2) as it is often applied in an attempt to resolve a difficult drilling situation. In our analysis separating cementing operations to regain circulation from other cementing operations, just over 30% of the cement jobs were

Table 2
Cement plugs used to restore circulation and number of successes.

Field	Well	Number of LC-related cementing attempts	Number of successes
Steamboat	14–33	9	3
McGinness Hills	25–10	7	1
	66B-22	8	2 or 3 (notes not clear)
Don A. Campbell	64A-11	2	0
Puna	KS-5RD (redrill)	2	2
	KS-10RD	4	1
	KS-11RD2 (redrill 2)	9	1
	KS-13	1	1
	KS-14	1	1
	KS-15	5	3
	KS-17	3	1
Total		51	16 or 17

successful and in some cases numerous attempts were required at a single location. Workovers were not evaluated in the analysis. The time required for the complete cementing operation includes "waiting on cement" ranging from 1 day to several days. During that time, *costs are still incurred* without drilling progress. In the case of plugging and abandoning wells (also not included in the analysis), several plugs could often be placed in a single day. In contrast, in response to circulation loss in the available data, one well had two plugs set in one day, however typically 1 to 4 days were needed for *each* plug. In many cases when the plug was encountered, the quality of the cement was less-than-desired, and often after drilling through the cement (regardless of its quality) losses occurred again at the same location or a nearby location. These cases were considered unsuccessful.

Because cementing is not desired, often numerous attempts were made to regain circulation prior to cementing. These attempts included the use of LC materials in sweeps if possible or pills, and drilling blind. In some cases, these methods resulted in recovering some or all circulation, but in many cases the success was short-lived. Interestingly, some wells that had very serious lost circulation problems were successfully redrilled directionally from the original well after plugging the old well to a certain depth with limited lost circulation.

5. Conclusions

High drilling costs associated with developing geothermal resources, which usually exist in hot, corrosive, hard rock formations with large fractures and complex geologies, represent a major challenge that must be overcome for widespread adoption of geothermal energy. A significant component of these drilling costs is associated with loss of circulation. This study examined four geothermal fields located in diverse geologic settings to identify causes of LC to help mitigate and/or address LC as it occurs in holes drilled for geothermal exploration, development, and production.

Wells that experienced severe circulation loss were examined in detail using well records, mud logs, and 3D geologic models. Drilling records, especially operations activity reports, were analyzed to determine common patterns and differences between geothermal fields to determine the most effective and efficient responses and to identify potential warning signs of LC depending on geologic context. LC is most frequently encountered near intersections with faults in all fields reviewed here except Puna, where the fault presence was not identified in the geologic model. The more heavily faulted fields, like McGinness Hills and Don A. Campbell, show increased secondary mineralization (e.g. quartz, chlorite) occurring within approximately 100 m (328 ft) or less of loss events.

Loss of circulation above the reservoir is often mitigated by using conventional or proprietary blended LCMs, generally in the order that is perceived to be the most economic. The least expensive material is used first, followed by more expensive materials until the loss is addressed. Alternately addressing the loss can start with more expensive products in hope of saving time as recommended by Lowry et al. (2022). Base muds treated with micronized cellulose fibers work in conjunction with larger solids such as drill cuttings and/or larger LCM. The drill cuttings and/or coarse LCM impede flow in larger fractures and micronized cellulose can seal around the larger particles curing the loss. Maintaining a larger concentration of these coarse solids is desirable to seal off larger fractures but results in inefficient cuttings removal.

In the production zone, aerating the drilling mud is usually the first response when circulation is lost to reduce the mud density. Drilling blind can be performed if all circulation is lost. LCM may be added to the drilling mud as was done in all geothermal systems examined here, although the type of LCMs varied greatly. When the LCMs are not effective in the production zone and the fluid loss is severe, the drilling fluid can be switched from mud to water, air, and compounds that optimize the use of water and air to carry cuttings to the location of the loss— but not typically to the top of the hole.

Placing cement plugs is a last-ditch alternative to curing lost circulation. Placing these plugs is expensive and time-consuming, and not always successful because the cement can be lost to the formation just like the drilling fluids.

Although the observation of secondary minerals is correlated with lost circulation, the observation is imprecise. Detailed characterization of drill cuttings may improve precision in predicting upcoming loss zones. The characteristics of the loss zone are only known by loss rate, cuttings, and drill behavior. These do not inform the driller about the aperture of an intersected fracture. Developing techniques to estimate the aperture(s) could help drillers use appropriately sized LCM immediately instead of trying materials sequentially.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data Availability

The authors do not have permission to share data.

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