BLUE CEDAR ENERGY

& THE UNIVERSITY OF OKLAHOMA

PERMITTING DOCUMENTS (PRELIMINARY)

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

DEQ

Prepared By

University of Oklahoma Geothermal Team

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Introduction

This document intends to partially fulfill the permitting requirements for the repurposing of oil and gas well for extracting geothermal energy in Oklahoma. Blue Cedar Energy and the University of Oklahoma's Mewbourne School of Petroleum and Geological Engineering are leading an innovative project that aims to transform abandoned and retired oil and gas wells into geothermal wells to provide direct-use geothermal energy to public schools in Oklahoma. This is a non-profit research project sponsored by the US Department of Energy DE-EE0009962.

The project will be developed in Tuttle, Grady County, Oklahoma. The cycling zone is placed in the Anadarko basin, which is a mature oil and gas basin. The typical reservoir rocks for hydrocarbons in the area are related to paleozoic formations. The Skinner, Hunton, Viola, and Mississippian groups are the usual targets for oil and gas production. However, since the project's objective is to access geothermal resources, the Haskell group is the primary target. Sandstones and limestones mostly compound Haskell formation rocks with porosities ranging from 8 to 17%, with permeability values between 0.2 to 100 md. According to electric logs, water saturation is expected to be above 80%. According to the Oklahoma Geological Survey (OGS, 1984), the geothermal gradient in the study area is 1.57°F/100 ft. The bottom hole temperatures are expected to be in the order of 135°F.

This project not only offers a practical application of geothermal technology but also provides mentorship opportunities for undergraduate and graduate students, government entities, and oil and gas and energy industries. With a commitment to reliable and sustainable energy solutions, the University of Oklahoma's Mewbourne College of Earth and Energy and Blue Cedar Energy are at the forefront of this groundbreaking initiative.

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1 Setting Criteria

1.1 Site map

The project is located in the city of Tuttle, Oklahoma. In **Figure 1**, a site map of the project is presented. The wells are located inside the blue square.

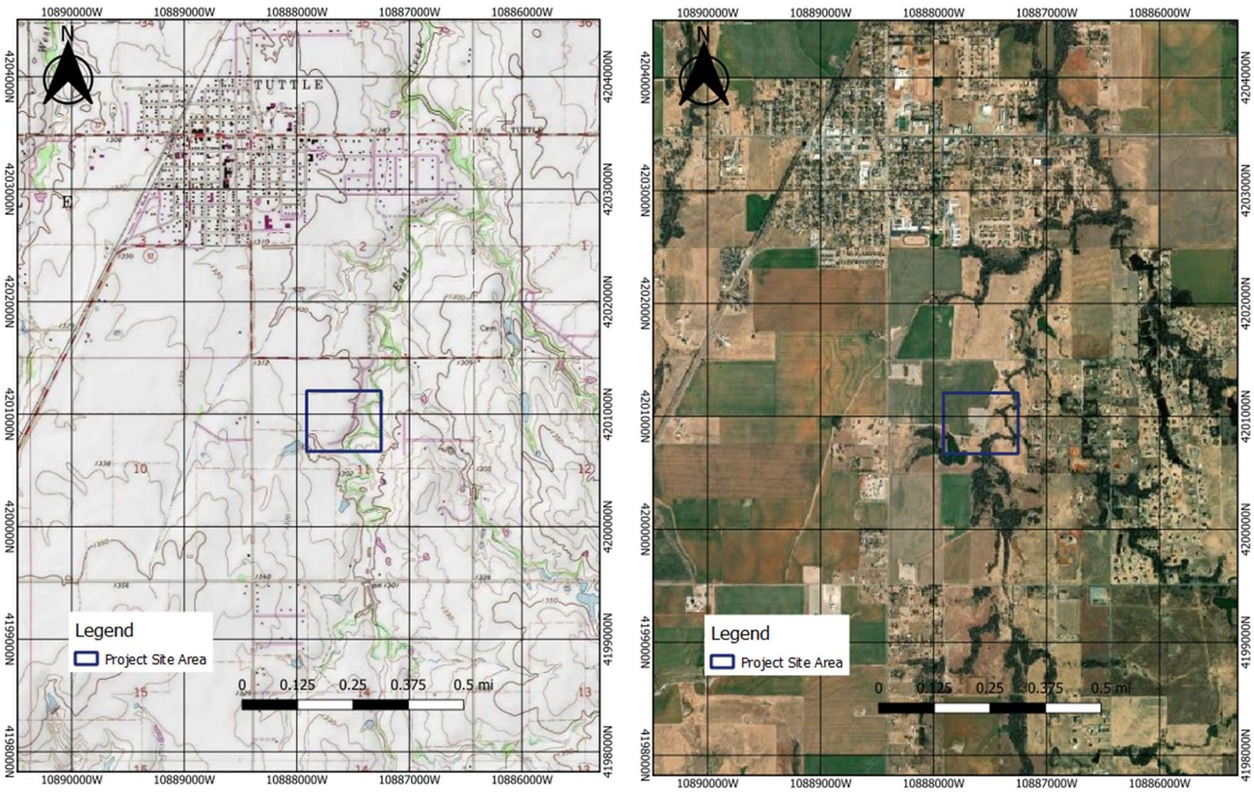

Figure 1: Tuttle project site map. Topographic map [left], and satelite map [right].

1.2 Ground water resources and recharge area.

In the project area there are nearby ground water sources. The geothermal project is close to the boundaries of the Canadian River alluvial aquifer, one of the largest alluvial aquifers in Oklahoma. This aquifer is a quaternary-age alluvial and terrace unit consisting of beds of clay, silt, sand, and fine gravel sediments unconformably overlying Tertiary-Permian and Pennsylvanian-age sedimentary rocks. The maximum aquifer thickness is 120 ft and the average thickness is 50 ft.

In the project wells area, there is a minor bedrock aquifer, the El Reno aquifer. The Permian-age formations of the El Reno group are comprised of reddish-brown shales, siltstones and sandstones interbedded with thin persistent beds of gypsum and dolomite and thick-bedded evaporite (gypsum/anhydrite/dolomite) units interbedded with shale (Belden, 2000).

The possible options of sources of water of the project are described as follows:

- *Formation Water*: The main objective of the project is cycling (recirculate) the formation water from Haskell formation as the first option. The formation is located at 6500 ft depth, and it is not communicated with any of the potable water aquifers.
- *Acquire Water*: For the project initialization, if required, water can be acquired by the city of Tuttle Utility service company, if necessary.

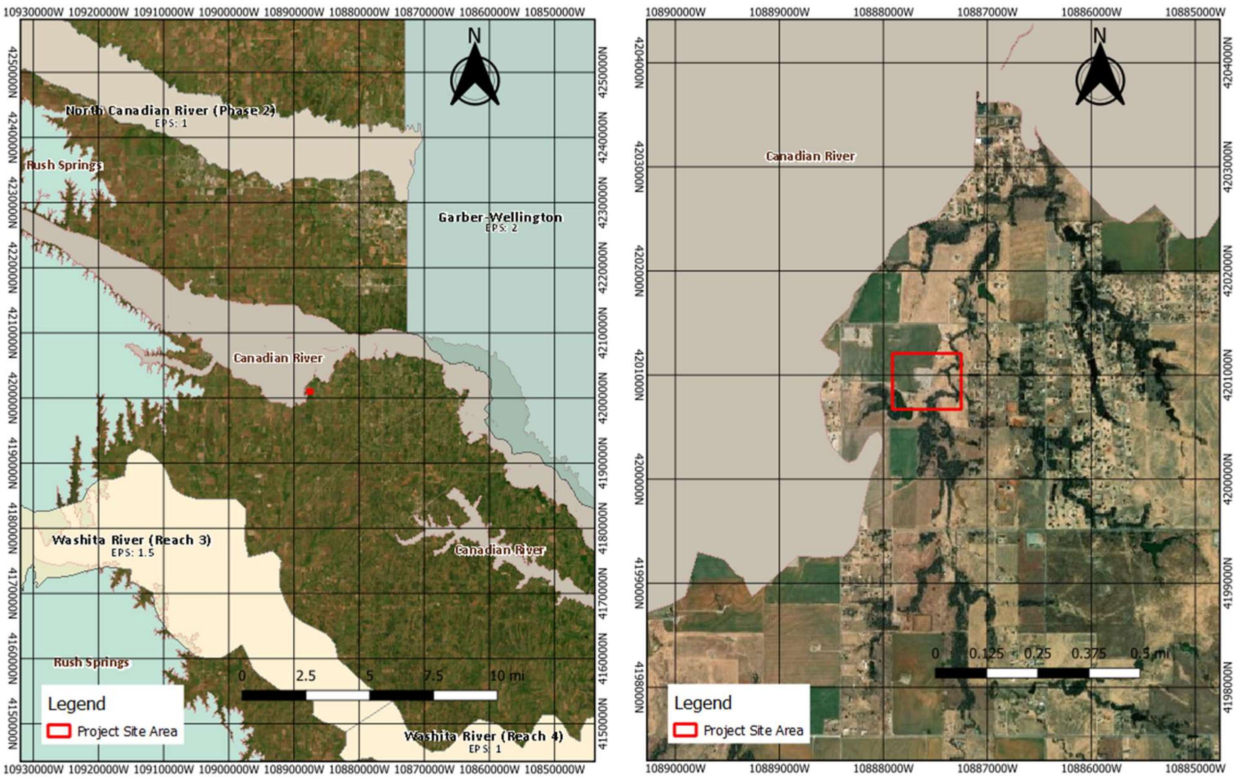

Figure 2: Ground water resources near the project area.

1.3 Water wells within 1/4 mile of the injection well

In **Figure 3** it is shown that no public or private groundwater wells are located from ¼ of a mile from the proposed injector well (Leon 1-11). **Table 1** shows a table of the closest groundwater wells information. These wells are reported by the Oklahoma Water Resources Board (OWRB) database.

Table 1 : Groundwater Wells nearby the AOR of the project.

ID	*Latitude*	*Longitude*	*County*	*TVD [ft]*	*First water [ft]*	*Approximate yield (GPM)*
32416	-97.804503	35.270008	Grady	190	65	10
108859	-97.8011833	35.2712667	Grady	300	115	25
210241	-97.8003925	35.2695957	Grady	200	100	15
45585	-97.800076	35.270008	Grady	220	13	12
76613	-97.793456	35.270008	Grady	250	104	N/A
19342	-97.797863	35.271815	Grady	180	75	8

19344	-97.797863	35.273622	Grady	196	40	16

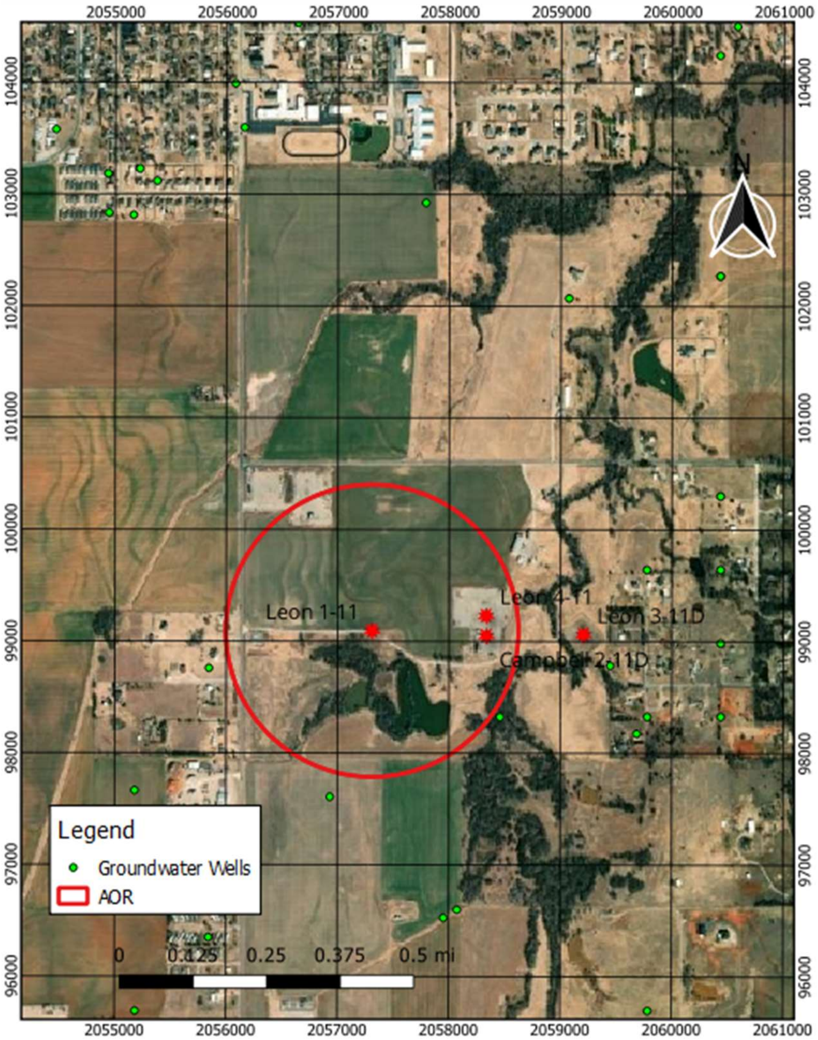

Figure 3: Groundwater wells nearby the project and 0.25 mile circle from injector well.

1.4 100 yrs flood plain

Per ruled by the Oklahoma Administrative Code (OAC) 252:652-3-1, no new injection well facility shall be permitted in the 100 year flood plain (unless the 100 year flood plain is subsequently redefined to not include the land area proposed for the new disposal area). The project area, as presented in the Federal Emergency Management Agency (FEMA) flood map showed in **Figure 4**, it is outside of the 100 year flood plain.

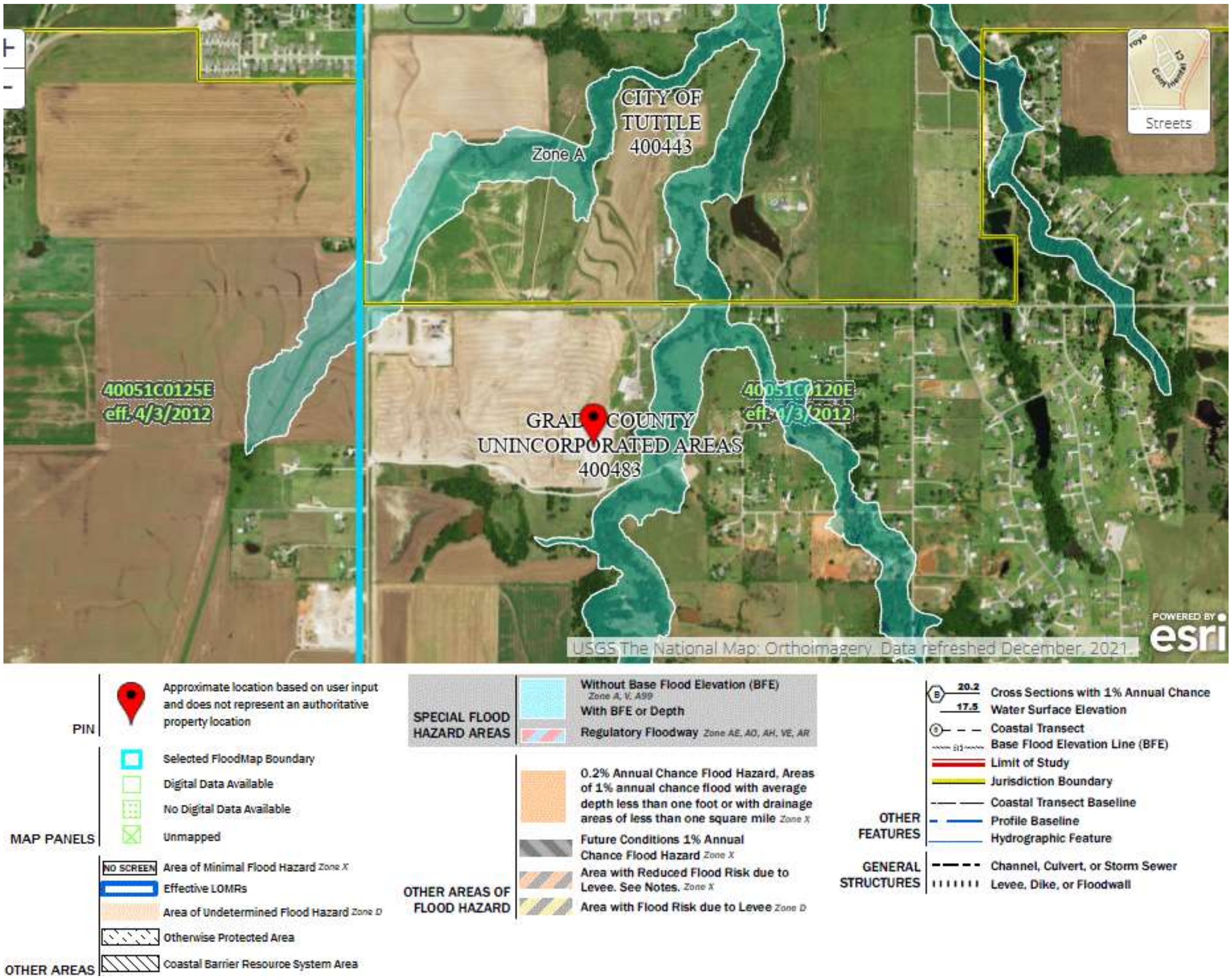

Figure 4: FEMA flood map of the project area (FEMA, 2023).

2 GENERAL INFORMATION

2.1 Area Of Review (AOR): 1/4 Miles Radius

The AOR is defined as the area of ¼ miles radius form the project. As the geothermal project considers one injection and one production wells, the AOR was defined from the area of ¼ miles radius from the injection well as presented in **Figure 5**.

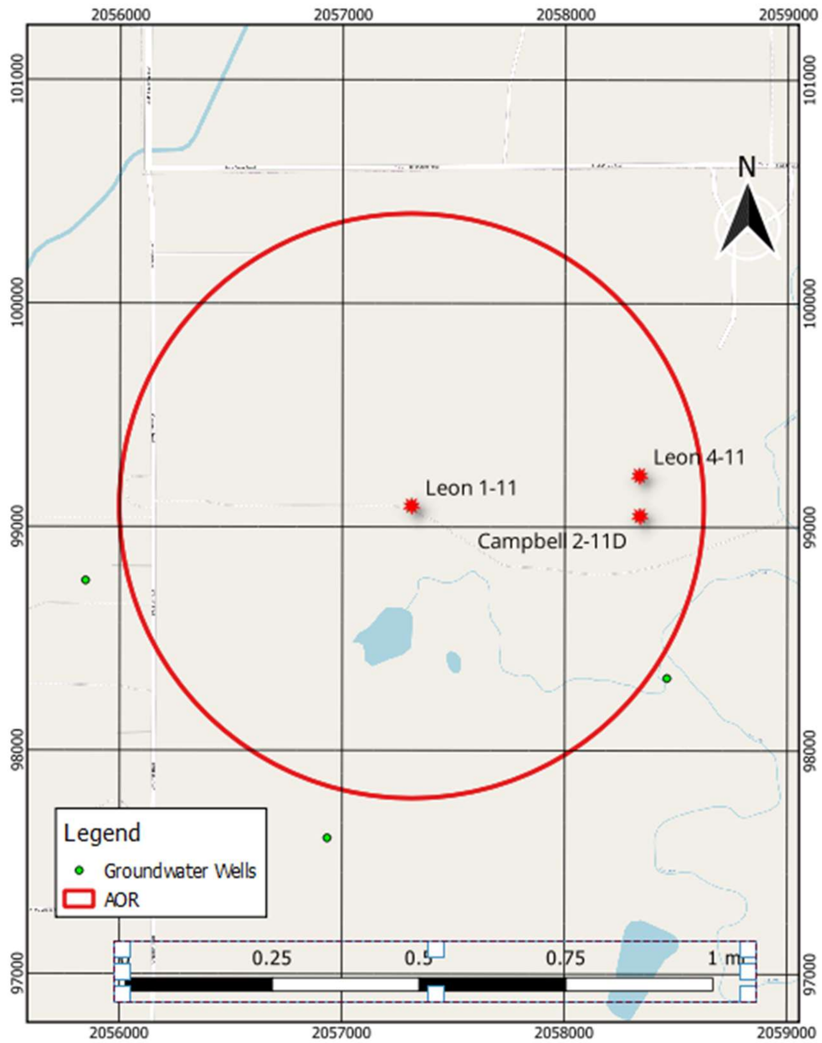

Figure 5: AOR of the Project Projected from Injection Well.

Figure 6 provides additional data about wells nearby the project, showing that the targeted wells are in Section 11, 09 North, 06 West.

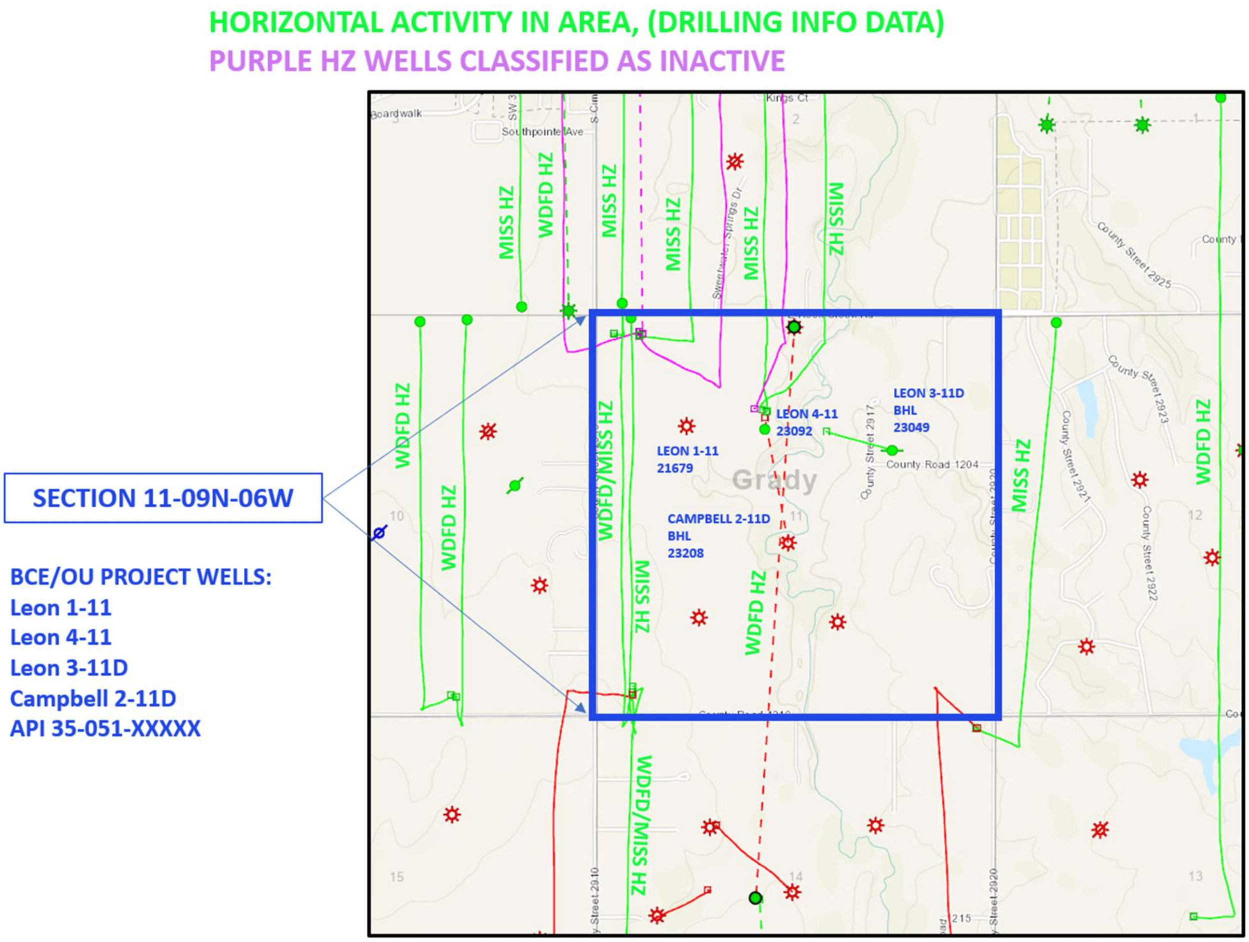

Figure 6: The Targeted Well Locations From The Study Area .

2.2 Tabulation Of AOR Wells (Artificial Penetrations and Water Wells)

In the AOR, there are 3 oil and gas wells, described in **Table 2**. The oil and gas wells in the AOR include the well proposed for injection (Leon 1-11), and the well proposed for production (Leon 4-11). All 3 wells are private wells.

Table 2 : Wells Information from Enverus

WellName	ENVWellboreStatus	Latitude	Longitude	TVD_FT	MD_FT
LEON 4-11	Inactive Producer	35.272011	-97.8049	10981	10981
CAMPBELL 2-11D	Inactive Producer	35.272498	-97.8049	10950	11180
LEON 1-11	Inactive Producer	35.264958	-97.8011	10700	10700

2.3 Maps and Cross Section of USDW in AOR

Protecting underground sources of drinking water (USDWs) is of paramount importance to ensure a healthy and sustainable environment. Contamination of drinking water can have disastrous consequences on human health and the ecosystem. To avoid such risks, it is imperative to have a thorough understanding of the depth of the drinking wells. As presented in **Figure 7**, the depth of the drinkable water in the AOR ranges from 300 to 400 feet. The surface casing depths of the wells that will be used for the water cycling (injection and production), are placed at 603 ft (Leon 4-11), and 1066 ft (Leon 1-11), at least 200 ft below the lowest surface of drinkable water contour line.

The flow towards to the Canadian river and southeast in the area of the facility. Within the area of AOR, the El Reno group dips southeast with 120 degrees at approximately 98.5 feet per mile.

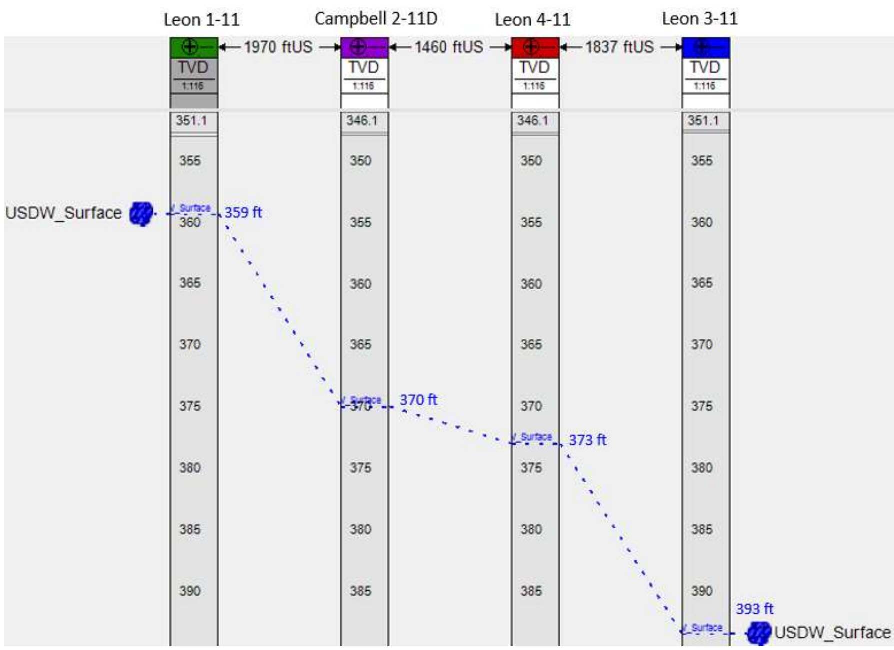

Figure 7: The cross-section of the targeted well in the base of USDW

The contour and structural maps, shown in **Figure 8** and **Figure 9** illustrates the hydrogeological trends within the USDW, revealing a discernible pattern in the depth of the water table which gradually increases from the northwest to the southeast, indicating a hydraulic gradient in that direction.

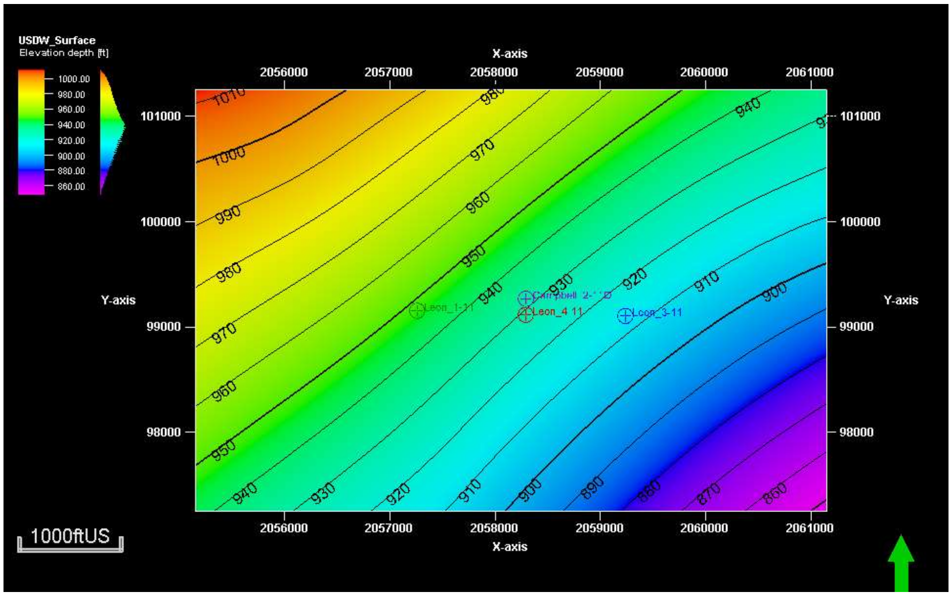

Figure 8: Structural map of the USDW in elevation with respect to the sea level.

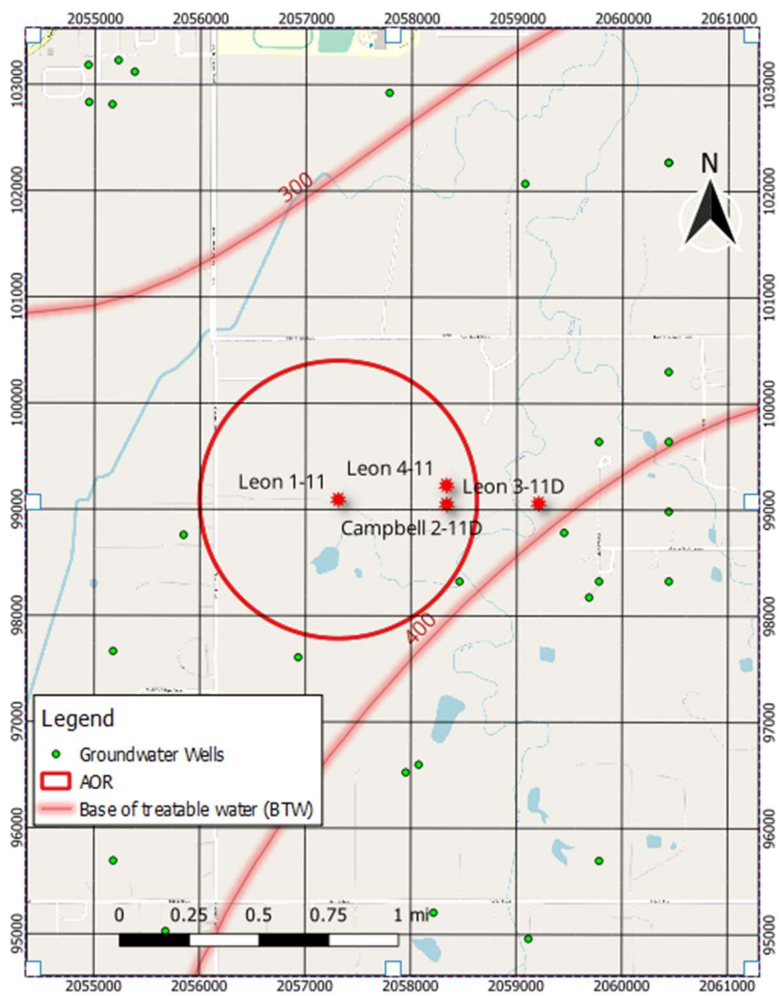

Figure 9: The Depth Range of Drinkable Underground Water Near the Targeted Wells.

2.4 Maps And Cross Section and Information of Regional Geology

The hydrogeology of the area is dominated by the White Horse Group, El Reno Group, and Hennessey Group. The project is in the El Reno minor aquifer, which is composed of reddish-brown shales, siltstones, and sandstones with thin persistent beds of gypsum and dolomite, as well as thick-bedded evaporite units interbedded with shale. These formations belong to the Permian-age formations.

Above the El Reno Group formations is a relatively thin layer of Quaternary-age unconsolidated deposits consisting of clay, silt, sand, and gravel, which were deposited by large rivers and smaller streams. The thickness of this layer is usually less than 100 feet.

The formations generally strike in a northwest direction, with the beds dipping west-southwest (toward the Anadarko Basin) with a variation of 4-30 feet per mile. The El Reno Group has a maximum thickness of about 950 feet in Blaine County and a minimum thickness of about 300 feet near the Oklahoma-Kansas border. The average thickness of the El Reno Group is estimated to be 600 feet.

In **Table 3** the characteristics of the water in El Reno Basin are presented.

Table 3 : Concentrations of Common Anions and Cations in Wells Sampled in the EI Reno Basin (Belden, 2000)**.**

Parameter	Maximum	Median	Minimum	# Samples (wells)
TDS [mg/l]	4430	980	252	70
Chloride [mg/l]	1016	70	16	70
Sodium + Potassium [mg/l]	908	95	10	70
Calcium + Magnesium [mg/l]	2350	500	30	70
Bicarbonate [mg/l]	900	274	30	70
Nitrates [mg/l]	N/A	9	N/A	59
Hardness [mg/l]	N/A	700	N/A	59
Sulfate [mg/l]	2688	220	10	70

2.4.1 Stratigraphy of El Reno Aquifer

The El Reno Group at Grandy, Oklahoma is a complex geological structure that comprises four distinct rock formations: the Dog Creek Shale, Blaine Formation, Flowerpot Shale, and Cedar Hills Sandstone Formation. These formations provide valuable insights into the environmental and depositional conditions that existed in the region during the Late Pennsylvanian and Early Permian periods, spanning a period of approximately 10 million years. The Dog Creek Shale, which dates to the Late Pennsylvanian period, is characterized by abundant marine fossils such as brachiopods, ammonites, and crinoids. The Blaine Formation, also dating back to the Late Pennsylvanian, contains several coal seams and is well-known for its red and brown-colored sandstones. The Flowerpot Shale, which was deposited during the Early Permian period, is distinguished by its distinctive red and green-colored shales and is a rich source of marine fossils such as ammonites and bivalves. Finally, the Cedar Hills Sandstone Formation, which also dates back to the Early Permian, consists of coarse-grained sandstones that were deposited in a braided river system.

Together, these formations provide valuable insights into the complex history of the El Reno Group at Grady, Oklahoma, and the wider region.

Table 4 : The Stratigraphic Column of the Permian Rocks Comprising the Hennessey Group, El Reno Group and White Horse Group (Belden, 2000)**.**

<table>
<tr><th>SYSTEM</th><th>SERIES</th><th>GROUP</th><th colspan="2">FORMATION</th></tr>
<tr><td rowspan="2">Upper Permian</td><td rowspan="2">Custerian</td><td rowspan="2">White Horse</td><td colspan="2">Rush Springs</td></tr>
<tr><td colspan="2">Marlow</td></tr>
<tr><td rowspan="8">Lower Permian</td><td rowspan="8">Cimarronian</td><td rowspan="4">El Reno</td><td>Dog Creek Shale</td><td rowspan="3">Chickasha Formation</td></tr>
<tr><td>Blaine Formation</td></tr>
<tr><td>Flowerpot Shale</td></tr>
<tr><td>Cedar Hills Sandstone</td><td>Duncan Formation</td></tr>
<tr><td rowspan="4">Hennessey</td><td colspan="2">Bison Formation</td></tr>
<tr><td colspan="2">Salt Plains Formation</td></tr>
<tr><td colspan="2">Kingman Siltstone</td></tr>
<tr><td colspan="2">Fairmont Shale</td></tr>
</table>

2.4.2 Regional Geology

The Anadarko basin is one of the deepest (40,000ft of sedimentary rock) and most prolific hydrocarbon producers (5.1 billion BBLS of liquids and 135 trillion cubic feet, total gas, ultimately recoverable) in the continental United States (Ball et al., 1991). It is bounded by on the east by the Nemaha uplift; on the southeast by the Arbuckle Mountains and Ardmore basin; and on the south by the Wichita Mountains and Amarillo uplift.

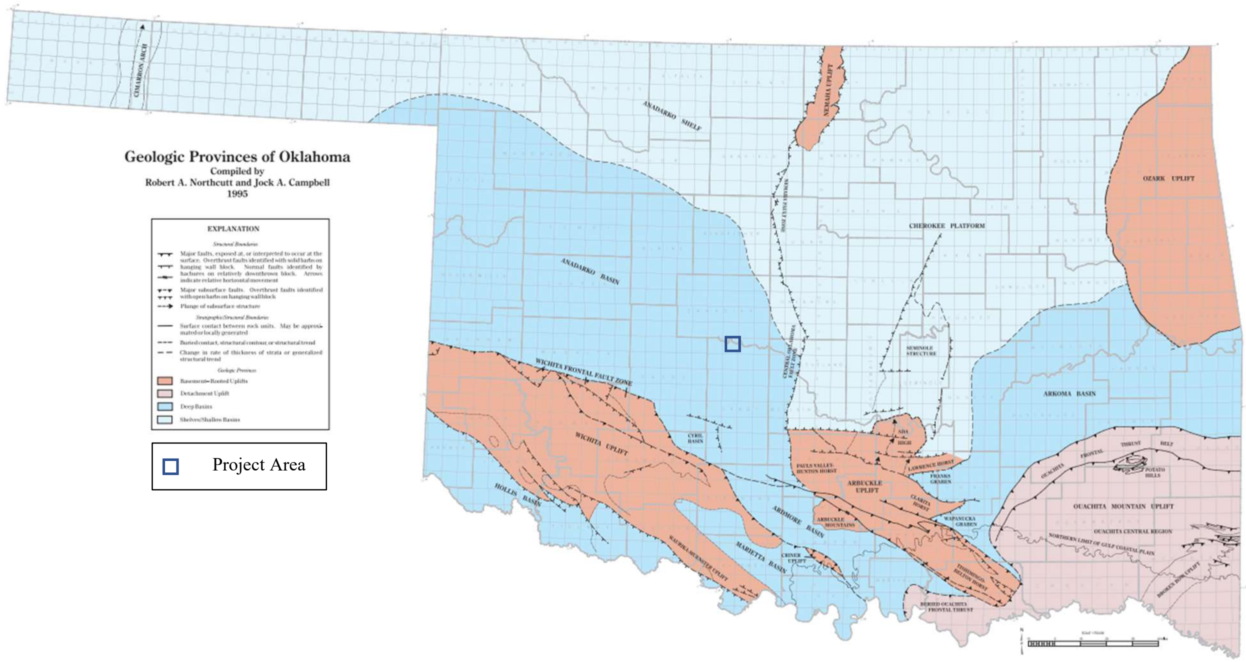

Figure 10: Map of geologic provinces of Oklahoma (Northcutt & Campbell, 1995).

In the Anadarko basin, the Southern Oklahoma province is a mature petroleum-rich province of Paleozoic age located in south-central Oklahoma (Ball et al., 1991). The geological evolution of the Paleozoic rocks that underlie the interest area is presented in **Figure 11.** The oldest (and deepest) formation is the Viola, an Ordovician unit composed mainly by Limestones deposited in Shallow and deep marine environments. A similar unit in the composition is the Hunton, deposited after the Viola in the Silurian-Devonian age. Upper in the section, we find the Mississippian units like Springer (sandstone) and the Mississippi (limestone, siltstone). Younger units considered for the study belong to the Pennsylvanian time (Skinner, Prue, Osborne-a.k.a. fifth Deese) composed of sandstones and shale. These formations are the typical hydrocarbon objectives, However, younger and shallower formations in the Upper Pennsylvanian, the Haskell group, are the primary objective of this project.

Upper Pennsylvanian and Wolfcampian quartz sands have been extensively studied for their porosity and permeability properties, with Harrison & Routh (1981) reporting a significant number of measurements. Desmoinesian sands, at depths of 1,000-8,000 ft, exhibit a consistent loss of porosity from 19% to 13%, with permeability decreasing from a few hundred to a few tens millidarcies. Missourian and Virgilian quartz sands, on the other hand, are somewhat cleaner, with porosities ranging from 24 to 17% and permeabilities dropping from a few hundreds to a few tens of millidarcies over a shallower depth range of less than 1,000 to 6,000 ft. Lower Permian, Wolfcampian sandstones have an average porosity of 20% and an average permeability of 65 md based on a few measurements (Ball et al., 1991).

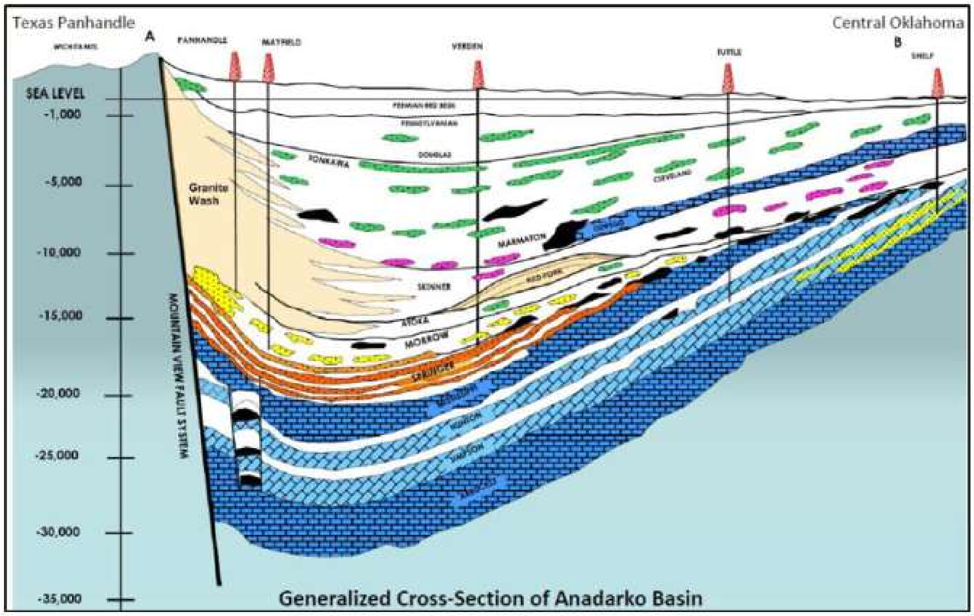

Figure 11: Anadarko Basin Cross Section Map (Noshi et al., 2019)**.**

2.5 Maps and cross section of the structure of local area

The horizontal cross-section of the local area at Grady County, Oklahoma, provides an excellent opportunity to examine the stratigraphy of the Haskell interval and contiguous formations above and below. **Figure 12** shows the cross section from west to east and **Figure 13** shows the cross section from north to south. As illustrated in **Figure 12** and **Figure 13**, the cross-sections show that the Haskell formation is separated from the Heebner shale for a zone denominated Upper Confining Zone (UCZ) conformed by shales that prevents fluid vertical communication. The lower surface of Haskell formation is separated from the Hoxbar formation by the Lower Confining Zone (LCZ), conformed by shales that prevent fluid vertical communication. The Haskell formation, the blue interval in the cross section, is shown to have lateral continuity that extends north, south, west, and east, with minor lateral discontinuities.

Figure 14 suggests a reasonable continuity in petrophysical properties exists between the Injector and the Producer wells, with the better reservoir quality found in the sandstone units.

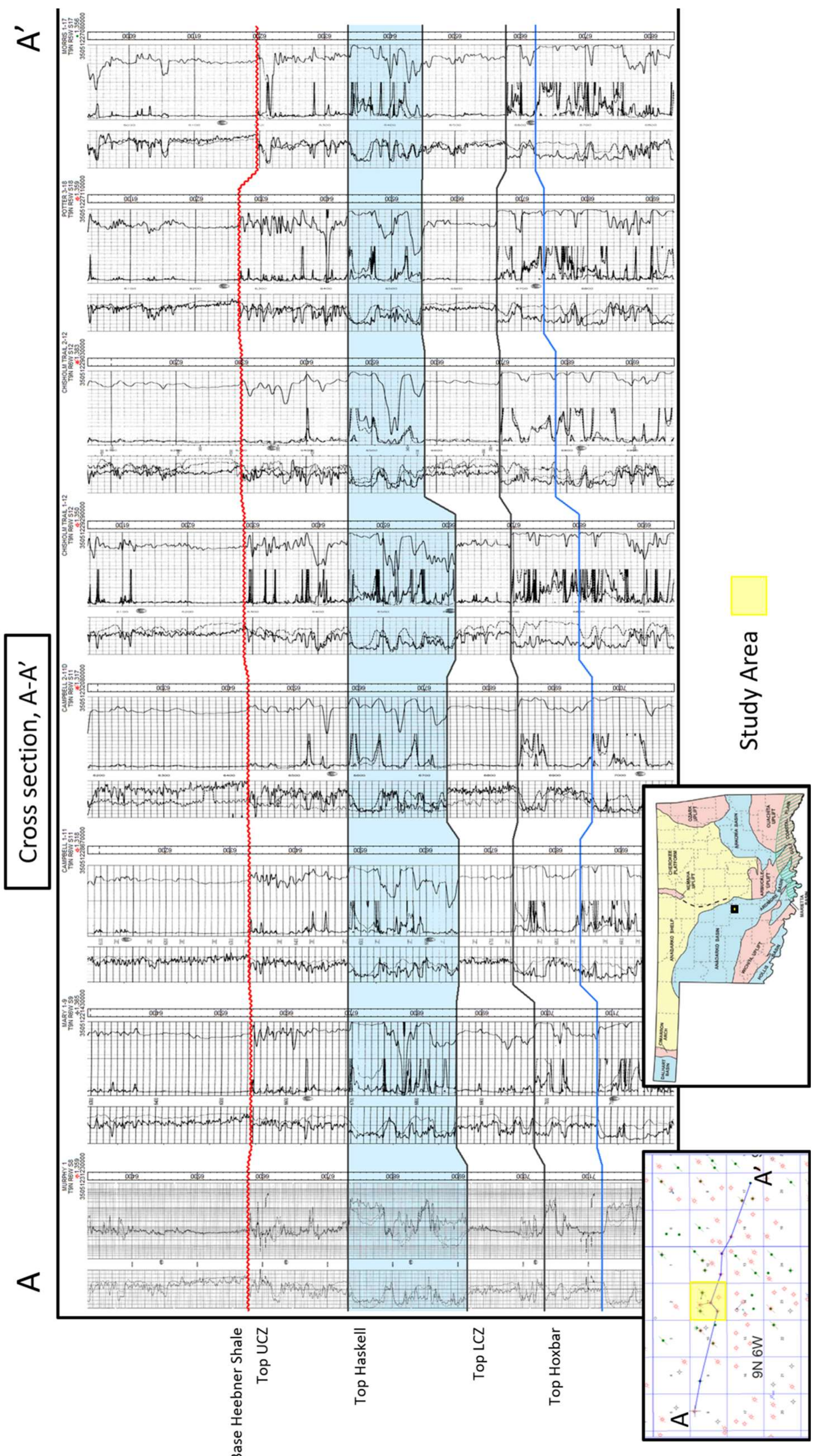

Figure 12: The West-East Cross Section and Logs of The Project Area.

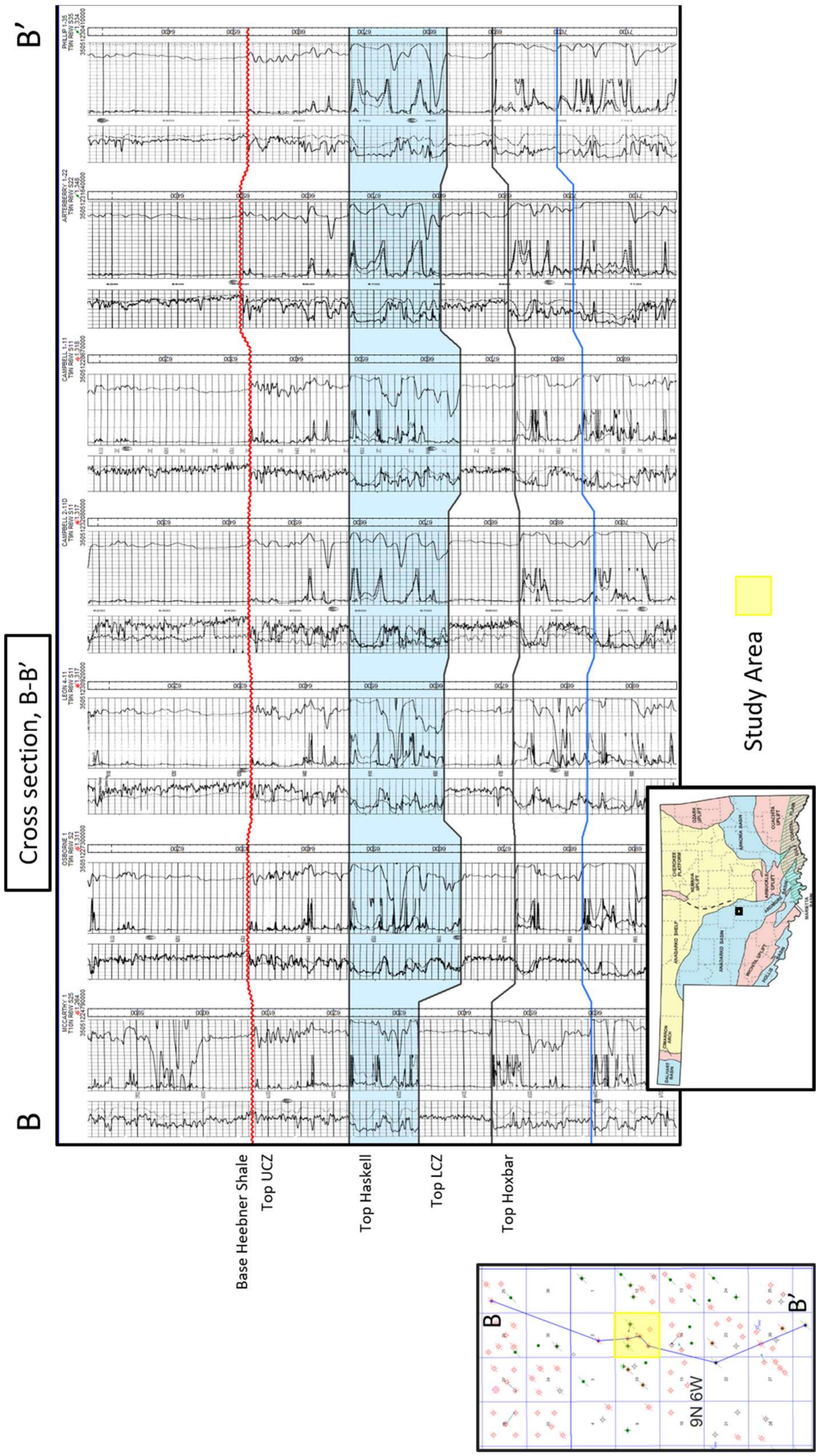

Figure 13: The North-South Cross Section and Logs of The Project Area.

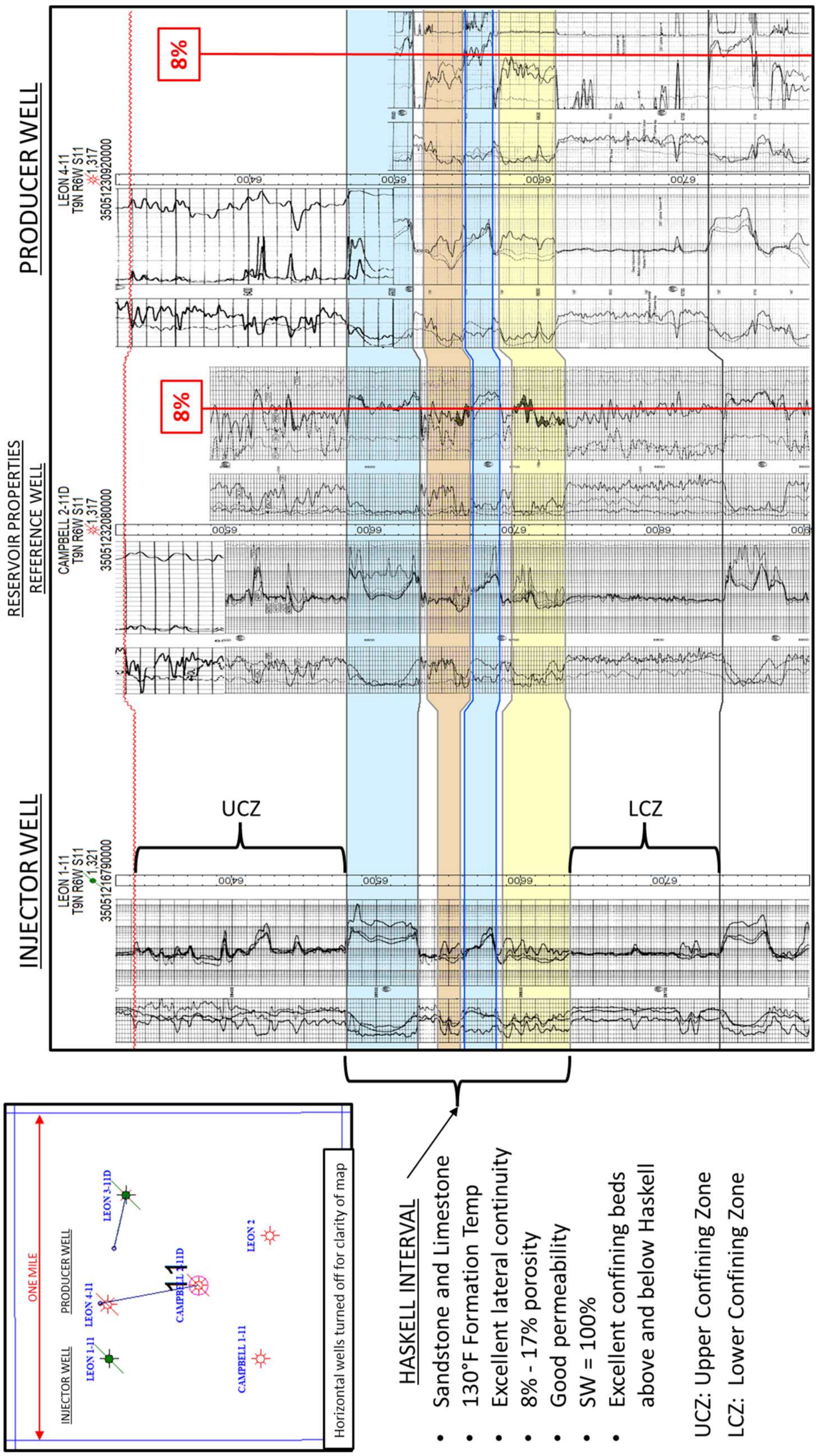

Figure 14: Cross section with logs and petrophysical properties of the injection and production wells.

2.6 Structural Maps of The Injection and Confining Zone

To complement the injection zone cross section presented in **Figure 14**, **Figure 15** presents the structural map of top section of Haskell Formation, showing that the injection zone dips towards east (slightly southeast). **Figure 16** shows the surfaces of the upper and lower confining formations.

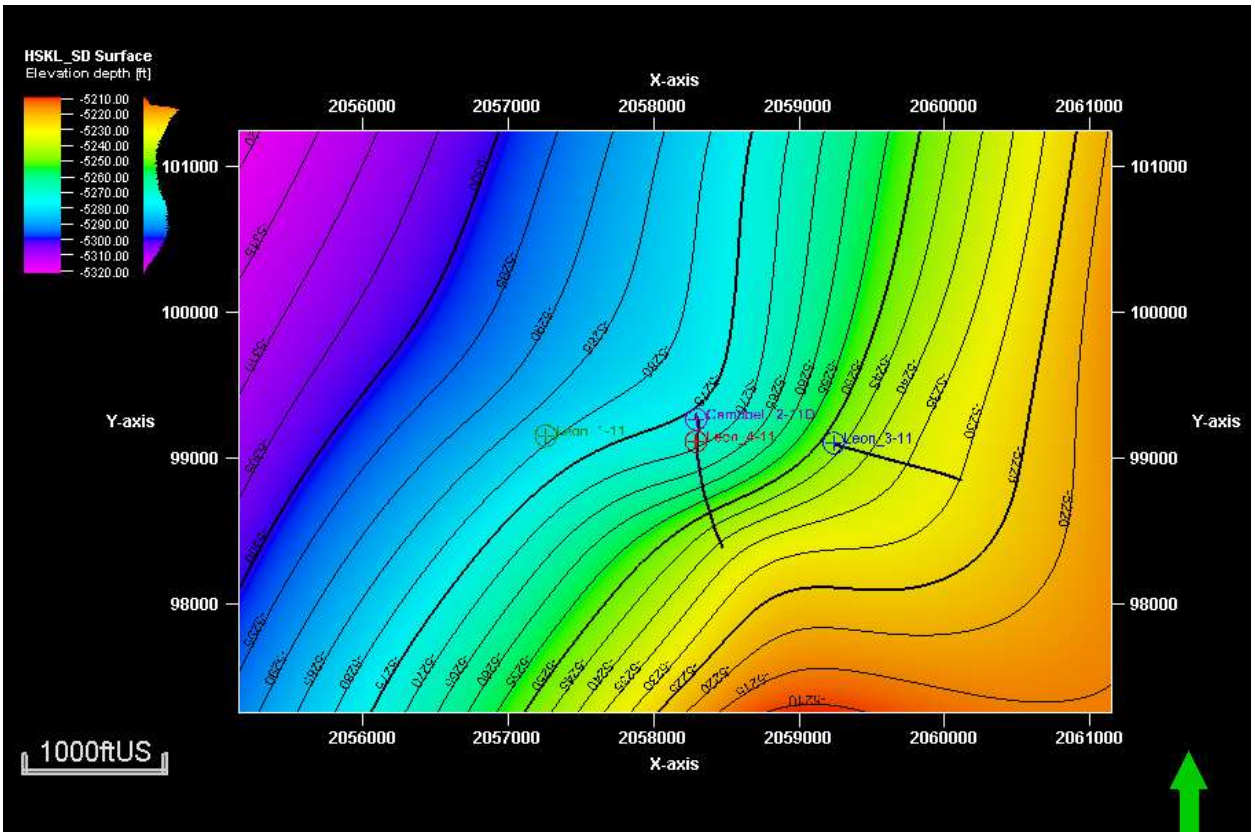

Figure 15: Structural Map of The Haskell Surface (Injection Zone).

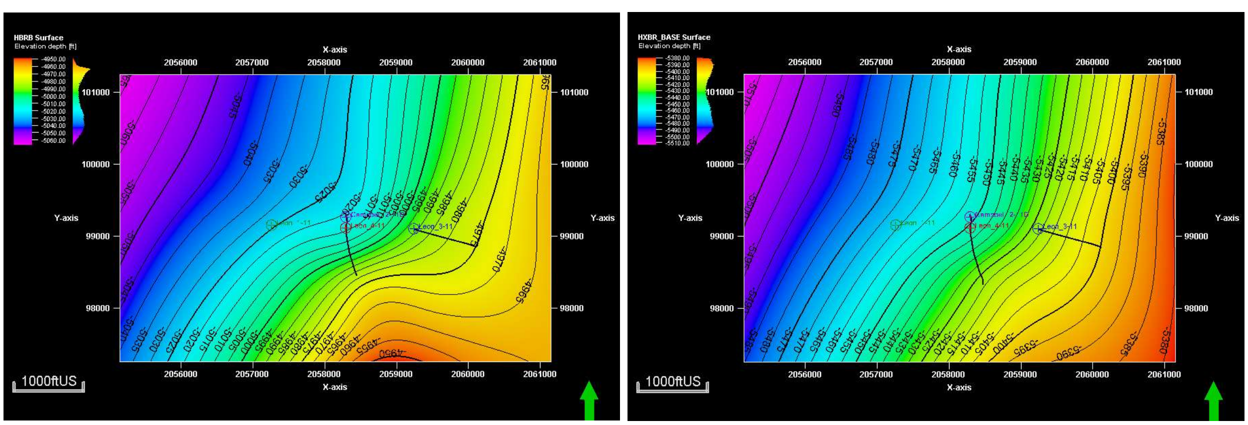

Figure 16: Structural Map of the UCZ [left] and LCZ [right].

2.7 Discussion of Known or Potential Fluid Flow Directions

According to the results of preliminary 3-D numerical simulations, the injected fluid moves radially from the Leon 1-11 well. For the 3 years of flow simulation, which covers the time stage 1 of the project. With an injection rate of 2,000 BPD the radial flow is around 400 ft from injection well.

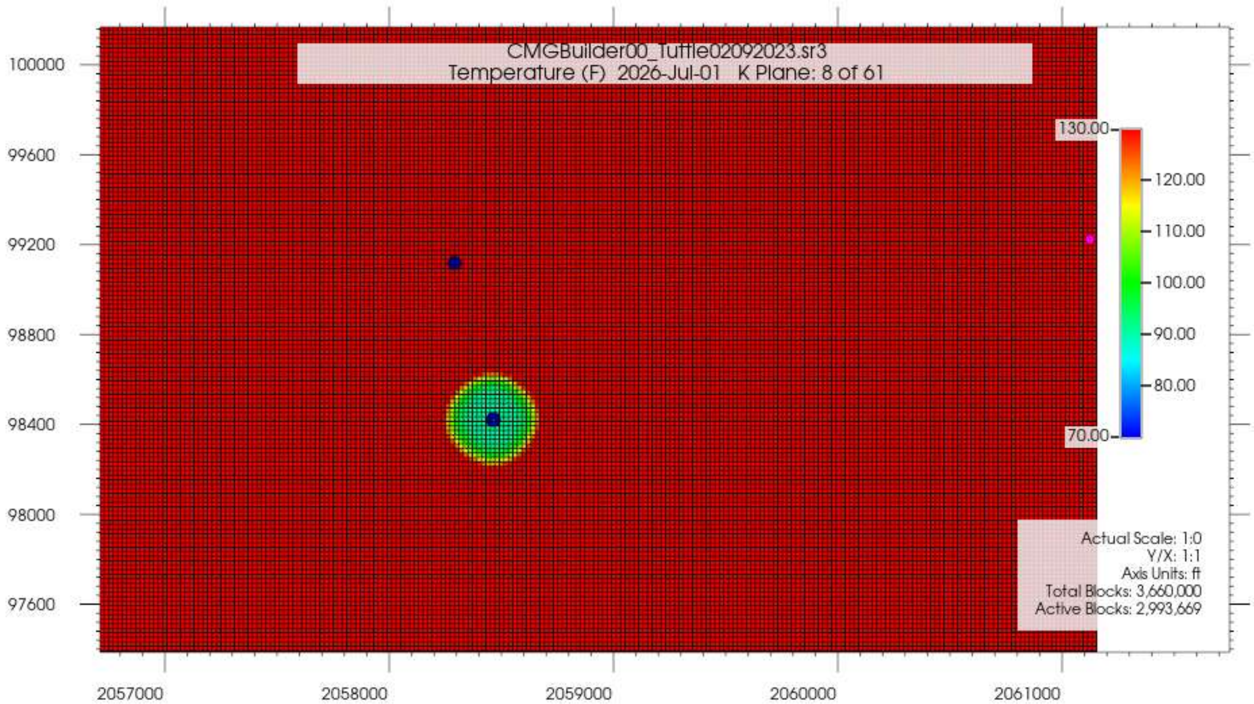

Figure 17: The Potential Fluid Flow Direction of the Injection and Producing Well.

3 INJECTION BELOW LOWER-MOST USDW

3.1 Cased And Cemented to Prevent Movement of Fluids Into USDW

According to the information presented in section 1, the USDW depth for the project area is located between the 300ft to 400ft contour lines of the drinkable water. The injector well (Leon 1-11), and the producer well (Leon 4-11) have surface casings that are set at more than 200 ft below the USDW depth. For both wells the surface casing, 601 ft for Leon 4-11 and 1066 ft for Leon 1-11, cover the lower USDW zone, preventing the contact of the water cycled in the geothermal project with the drinkable water.

The Leon 4-11 and Leon 1-11 are completed in the oil and gas formations, located deeper than 9,000 ft. As the objective of the project is using a shallower formation, the Haskell Group, a packer will be used as a barrier to prevent the water cycling affecting the lower oil and gas reservoirs. The packer specification and procedure will be communicated to the DEQ, once the wells are accessed, and then as final decision of the type of packers to be used and the respective depths are defined.

3.2 Log and tests during drilling of the well

The geothermal project does not consider drilling new wells, but instead, repurposing existing wells originally used to produce hydrocarbons. For the repurposing process this is the list of the logs and tests planed:

- Caliper
- CBL/VDL
- Pressure and Temperature logs
- Pressure tests

The tests are intended for obtaining information and evaluating the well integrity. A copy of the test reports will be send to the DEQ if requested.

3.3 Deviation Surveys

In **Table 5** the well trajectory of the Campbell 2-11D is presented. The well is a type S well.

Table 5 : Trajectory surveys of the Campbell 2-11D well.

MD [ft]	*TDV [ft]*	*INC [º]*	*AZM [º]*	*MD [ft]*	*TDV [ft]*	*INC [º]*	*AZM [º]*
400	400	0	1.11E-08	**5426.268**	5325	17.01542	166.0657
740.0276	740	0.706	4.15E-08	**5488.064**	5384	17.41408	163.808
1035.049	1035	0.627263	1.89E-08	**5553.088**	5446	17.34059	161.3549
1532.07	1532	0.571427	1.67E-08	**5615.88**	5506	17.2762	160.059
2103.103	2103	0.900031	1.51E-08	**5677.709**	5565	17.69059	161.5132
2582.197	2582	49.78868	161.4739	**5740.798**	5625	17.98459	163.7982
2639.953	2615	46.70535	161.5461	**5803.874**	5685	17.69736	164.0683
2921.985	2897	0.987758	179.1663	**5867.808**	5746	17.20187	163.3388
2999.998	2975	1.240313	169.7444	**5930.544**	5806	17.34524	162.2978

3033.007	3008	1.573536	162.9181	**5993.529**	5866	18.01202	162.3657
3065.022	3040	2.046454	160.0599	**6056.732**	5926	18.00894	163.8717
3097.048	3072	2.544297	159.8446	**6119.714**	5986	17.18815	164.2537
3129.086	3104	2.972709	160.8562	**6184.431**	6048	16.60515	163.0382
3161.135	3136	3.288609	161.6143	**6247.026**	6108	16.27153	160.4555
3193.192	3168	3.683824	162.488	**6311.523**	6170	16.19982	156.3438
3225.268	3200	4.320155	165.2919	**6374.073**	6230	16.74542	152.7067
3256.372	3231	4.654887	168.1507	**6437.892**	6291	16.98877	152.1508
3288.476	3263	4.656998	170.5014	**6531.927**	6381	16.30942	157.6957
3319.581	3294	4.731263	173.2328	**6627.562**	6473	15.78331	166.5711
3351.692	3326	4.92129	176.3581	**6723.18**	6565	16.1432	173.7758
3383.818	3358	5.28612	178.3303	**6785.718**	6625	16.28846	177.2012
3413.956	3388	5.528105	178.8813	**6818.008**	6656	16.39596	177.8395
3448.118	3422	5.418168	178.8023	**6913.082**	6747	16.79722	177.0944
3480.253	3454	5.205614	178.0356	**6946.506**	6779	16.78523	176.8856
3510.375	3484	5.160962	178.6903	**7041.557**	6870	16.55272	174.6064
3542.506	3516	5.419509	184.1291	**7105.145**	6931	16.49728	174.417
3605.849	3579	6.632323	194.1091	**7200.126**	7022	16.24093	174.3258
3668.356	3641	7.611283	195.8751	**7295.759**	7114	15.83549	171.449
3731.964	3704	8.310167	195.5471	**7393.467**	7208	15.7249	171.4335
3794.684	3766	80.69545	194.8031	**7486.921**	7298	15.06205	173.8577
3805.346	3766	80.96544	194.631	**7581.946**	7390	14.68862	176.3042
3869.393	3829	7.650023	189.0889	**7645.045**	7451	14.88759	176.4711
3963.583	3923	8.846734	185.3997	**7678.162**	7483	15.12614	175.8903
4027.052	3985	12.90088	184.2833	**7772.692**	7574	15.96197	172.6922
4090.802	4047	13.97725	183.3897	**7868.519**	7666	16.62363	170.1123
4153.807	4108	15.31475	183.1809	**7963.675**	7757	16.6808	172.6229
4218.357	4170	17.00802	181.9426	**8059.576**	7849	16.33159	176.9174
4282.444	4231	17.97488	179.082	**8154.376**	7940	16.04562	177.2601
4345.571	4291	18.30289	175.6118	**8248.959**	8031	15.58223	174.1235
4408.845	4351	18.4558	172.1926	**8344.366**	8123	15.70438	168.5984
4472.083	4411	18.25654	169.8777	**8440.124**	8215	16.48357	163.721
4536.258	4472	17.91173	170.028	**8536.264**	8307	16.97448	162.5765
4600.3	4533	17.52966	170.9537	**8630.413**	8397	16.744	162.324
4664.2	4594	17.12706	171.2101	**8726.32**	8489	16.27426	161.594
4726.918	4654	16.79405	170.8225	**8821.054**	8580	15.86886	162.8596
4791.633	4716	16.99758	170.266	**8916.575**	8672	14.69473	166.5821
4852.387	4774	17.30597	170.6391	**9011.316**	8764	12.81746	172.1185
4915.229	4834	17.03007	171.2649	**9043.067**	8795	11.94781	174.9285
4979.978	4896	16.3915	171.2581	**9106.207**	8857	10.40333	180.0793
5043.447	4957	15.91451	170.6861	**9201.559**	8951	9.085813	180.8144
5106.841	5018	15.65793	169.912	**9296.608**	9045	7.660798	178.0458
5170.15	5079	15.56388	169.156	**9392.281**	9140	6.140448	176.5231

5234.524	5141	15.82321	168.2904	**9487.718**	9235	4.932596	176.4346
5297.993	5202	16.14135	167.6458	**9582.996**	9330	3.940882	177.6465
5362.573	5264	16.48949	167.2709	**9615.067**	9362	3.792118	178.1089

The Leon 4-11 is a vertical well, with a Kelly Bushing datum of 1302 ft, and the MD and TVD are 12,866.1 ft.

The Leon 1-11 is a vertical well, with a Kelly Bushing datum of 1307 ft, and the MD and TVD are 10,700 ft.

4 INJECTION ZONE INFORMATION

4.1 Pressure and Temperature

4.1.1 Geothermal Gradient and temperature

Geothermal gradient is the rate at which the temperature increases as a factor of depth in the earth. Previous studies in Oklahoma, mostly map-based, reflect a general trend of increasing geothermal gradients from SW (14°-20°C km) to NE (26°-42° km). After the map provided by the Oklahoma Geological survey in 1984 (**Figure 18**) a zoomed-in view is provided to show how the geothermal gradient for the study area is between 22.6°C/km and 22.8° C /km. These gradients were determined from reliable temperature data at different depths according to the map legend. In the work performed by Kwong-Shun (1975), the study area lies on the 1.2 ˚F/100km geothermal gradient area. Additionally, Cranganu et al (1998) pointed out that heat flow is a better indicator of the thermal state of the crust and upper mantle. They used well measurements and corrected for anisotropy, temperature, and porosity. Their results show a range for in situ thermal conductivity estimates of 70-80 m W m-2.

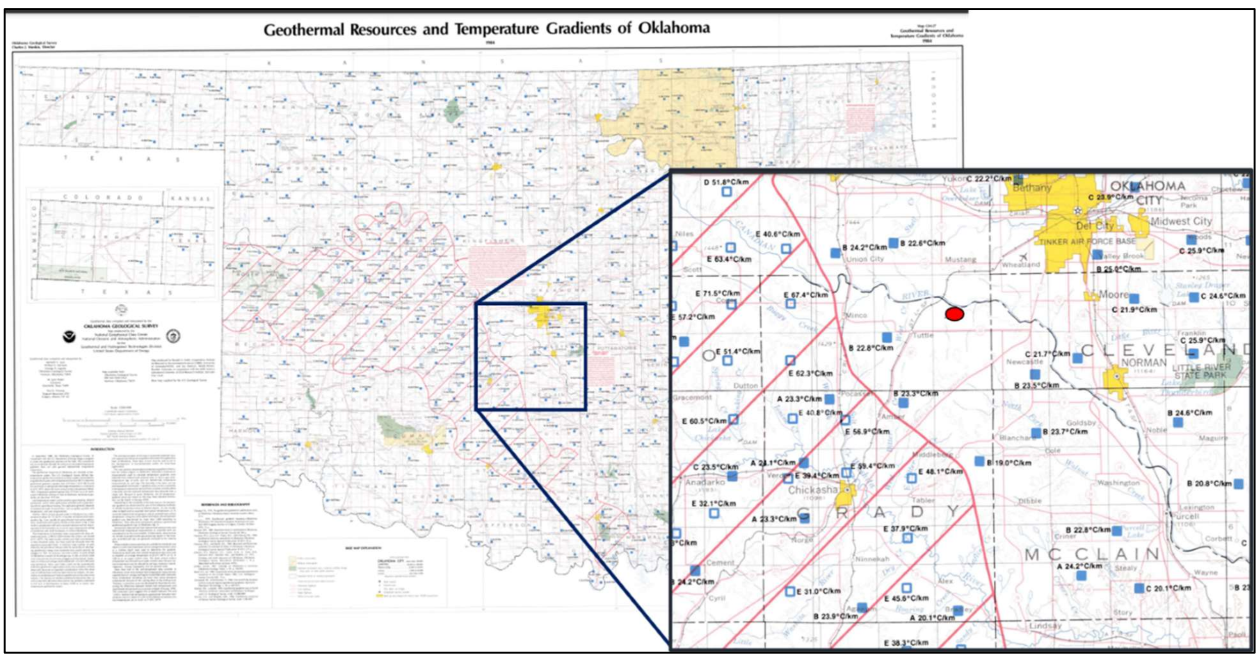

Figure 18: Geothermal Gradient of Central Oklahoma (Modified after OGS, 1984). **Study area represented by a red dot.**

Using the data present in **Figure 18**, a geothermal gradient heat map was generated and presented in **Figure 19**.

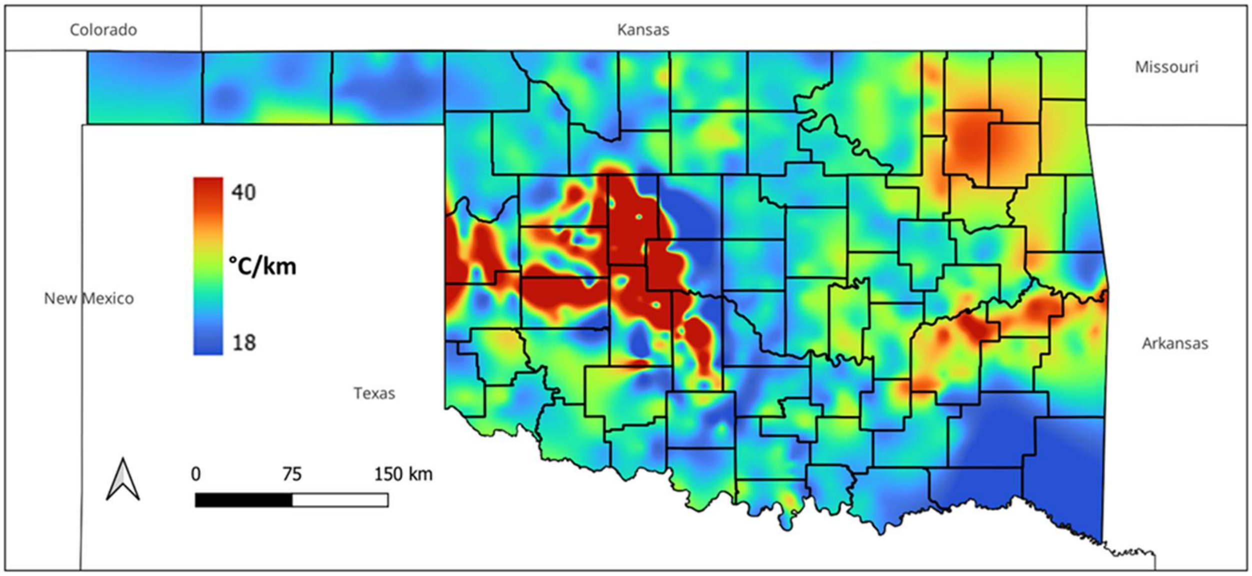

Figure 19: Geothermal gradient heat map of the state of Oklahoma

To perform the case simulations, it is important to know the subsurface temperature, the geothermal gradient, and the surface average temperature in the area. **Figure 20** shows the average monthly surface temperature in Tuttle, Oklahoma which is around 89.5˚F in the hot season and 53˚F in the cold season.

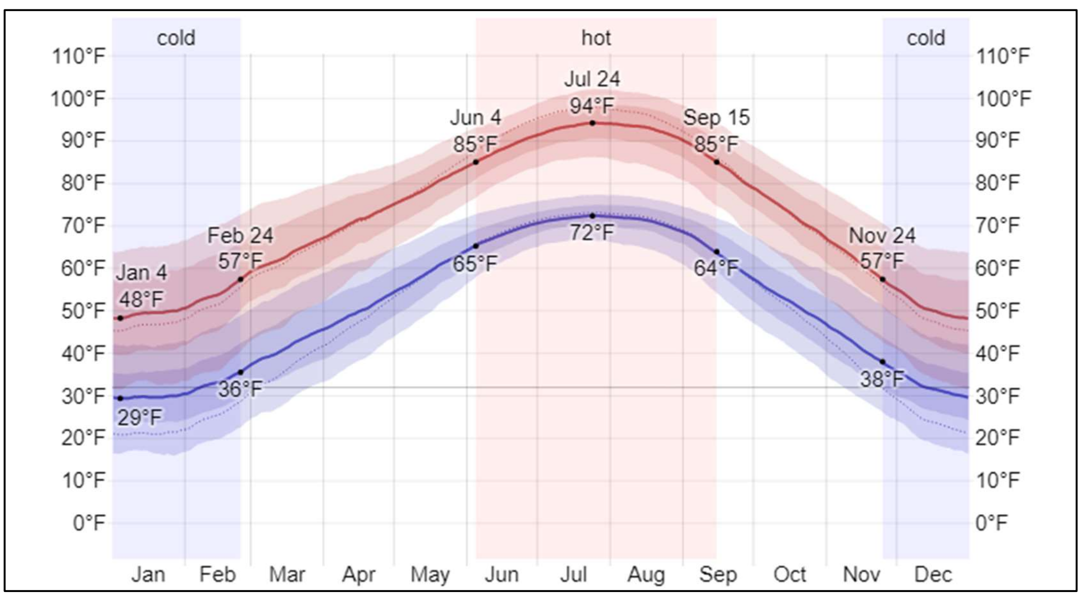

Figure 20: Average surface temperature in Tuttle- Oklahoma per month. Source: © WeatherSpark.com

The temperature expected at the Haskell formation depth, **6,500 ft**, it is between **130ºF** to **140ºF**.

4.1.2 Pressure gradient and expected reservoir pressure.

The Grady County is located in a region with a normal pressure gradient of 0.44 psi/ft (Ordonez, 2019). In the mud log of the Campbell 2-11D the mud weight for drilling the Haskell formation was 9.0 ppg, showing that not abnormal pressure regimes are in the area and the target formation for the project.

4.2 Fracture Pressure

Jackson et al. (2018) multiple fracture gradients were analyzed for well drilled in Grady County. The overburden gradient in the zone is 1.0 psi/ft (Ordonez, 2019).

4.3 Physical And Chemical Characteristics of The Injection Zone Matrix

For the water cycling process, the water will be injected in the Haskell Formation. In the **Table 6** characteristics of the injection matrix are presented:

Table 6 : Reservoir Properties

Property	Haskell Lime FM	Haskell Sandtone-Lime FM
Lithology	Limestone, ~6500' MD	Sandstone and Limestone, ~6600' MD
Lateral Continuity	Excellent lateral continuity	Less consistency in lateral continuity
Reservoir Description	30' connected, blocky, porous and permeable zone	12' – 35' partially connected, laminated, porous and permeable sands and sandy-lime sequences.
Porosity Expected	8% porosity	12% - 17% porosity (better porosity than Haskell Lime above)
Permeability Expected	Very good permeability from microlog and res curves	Very good permeability from microlog and res curves
Formation Top Marker	190+' above Top of Hoxbar Lime	100+' above Top of Hoxbar Lime

4.4 Physical And Chemical Characteristics of The Formation Fluids

Samples of formation water will be collected and analyzed every month. There are several chemical analyses that are commonly performed on water to assess its quality and composition.

- Total Dissolved Solids (TDS): TDS measures the total amount of dissolved minerals and salts in water. TDS can be an important indicator of water quality, as high levels of TDS can indicate water that is unsuitable for certain uses.
- pH: pH is a measure of the acidity or alkalinity of water. The pH of produced water can affect its corrosivity, scaling potential, and biological activity.
- Oil and grease: The amount of oil and grease in produced water can be an important indicator of the efficiency of the separation process and can also indicate potential environmental impacts.
- Metals: Analysis of metals in produced water, such as iron, manganese, and copper, can provide important information about the source and quality of the water.
- Chlorides: High levels of chloride in produced water can indicate the presence of saltwater intrusion, which can be a concern for water management.

- Bacteria: Analysis of bacteria in produced water can provide important information about the biological activity of the water, which can affect the efficiency of treatment processes and potential environmental impacts.

5 CONSTRUCTION REQUIRMENTS

5.1 Annulus Pressure and Fluids

The annular pressure will be established from the well tests. All tests will be performed with water with no special additives. The testing program will be generated once the current well condition is assessed.

5.2 Sensors/Gauges

- Surface: The surface sensors are expected to be continuously monitoring the operational conditions:
  - Temperature
  - Pressure
  - Flow rate
- Downhole sensors can be used for specific tests, such as transient pressure tests required to assess the reservoir.
  - Memory gages.

5.3 Monitoring Taps

Injection and annulus pressure monitoring taps will be provided for the use of the DEQ. The taps shall be connected near the locations on the well of the facility pressure monitor recorders. The taps shall be a one fourth (1/4) inch diameter National Pipe Thread female pipe fitting, valved and capped to prevent fluid loss when not in use in accordance with §252:652-7-1. The taps will be located to allow simultaneous pressure monitoring by facility pressure recorders and DEQ pressure gauges.

5.4 Surface Casing and Cemented 50 Feet Below Lower-Most USDW

The surface casing of the injector and producer wells are located more than 200 ft below the lower-most USDW, as mentioned in section 3.1 of the present document. Casing design diagram is presented in section 7.5.

5.5 Ambient Monitoring and Monitoring of Lowermost USDW

Specifications for the location, construction and maintenance of monitoring and/or observation wells will be send to approval of the DEQ prior to installation in accordance with §252:652-7-1.

- At least one of the wells will monitor the lowest underground source of drinking water beneath the site.
- The mentioned well will be located so that one or more wells are placed hydraulically downgradient from the site.

The objective of the monitoring will determine what parameters need to be measured, how often the measurements should be taken, and the duration of the monitoring period. Here is a general outline of the process that will be adjusted once we have all the data available:

- Install the monitoring well: The monitoring well should be installed according to established industry standards to ensure that the well screen is placed in the desired location and that the well casing is properly sealed to prevent contamination.
- Calibrate the monitoring equipment: The monitoring equipment, including the water level sensor and any water quality sensors, should be calibrated before taking measurements.
- Collect water level data: Water level data should be collected at regular intervals of one month (or the periodicity suggested by the DEQ) to monitor changes in the water table.
- Collect water quality data: Water quality data should be collected at regular intervals of one month (or the periodicity suggested by the DEQ) to monitor changes in the concentration of contaminants or other parameters of interest.
- Analyze the data: The data collected should be analyzed to identify any trends or changes in the groundwater system. This analysis should include statistical methods to determine if any changes are significant.
- Report the results: The results of the monitoring should be reported to DEQ, to ensure that they are informed about the status of the groundwater system.
- Adjust the monitoring plan: If any changes are detected in the groundwater system, the monitoring plan should be adjusted accordingly to ensure that the system is being monitored effectively.

6 OPERATING MONITORING AND REPORTING REQUIREMENTS

6.1 Operating

The project consists of cycling formation water of Haskell formation, using a well producer and a well injector as depicted in **Figure 21**. The plan consists of producing hot water and reinjecting the water into the reservoir maintaining the same rates of production and injection. The intention is to maintain the reservoir pressure as unaltered as possible to prevent drastic changes in the stress state of the rock. For the geothermal cycling, existing inactive oil and gas wells will be adapted to the project. That means that no drilling operations are expected for the project execution. However, multiple workover operations, well tests and production tests will we executed, and some details are introduced in this section. As the intention of this project is to obtain data, it is planned to perform different tests with different conditions to obtain scientific data that can be used to support the development of geothermal energy in Oklahoma.

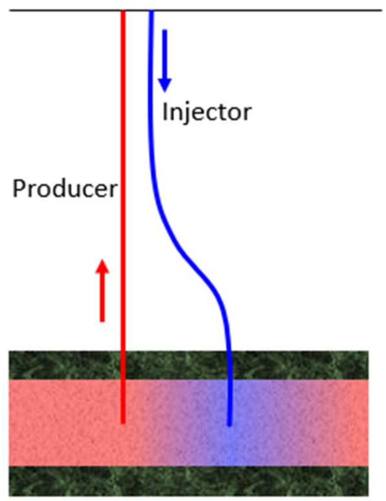

Figure 21: Schematic of the injection and production well

6.1.1 Proposed average, maximum daily injection rate and injection pressure

For the Tuttle geothermal project is anticipated an average daily flow to the injection well of 84,000 gallons per day (gpd), (2,000 BPD), based on an average injection rate of 58.33 gallons per minute (gpm) at normal operation. During the demonstration phase of the project, expected to last at least 1 year, we expect to test different production rates temporarily to analyze the capability of the reservoir of accepting an increased flow rate. The maximum will not be higher than 210,000 gpd (5,000 BPD, or 145.8 gpm) for a short period of time that is not expected to last more than 10 days. Numerical simulations will be performed previous any cycling rate change to ensure the reservoir is capable of accepting the flow rate.

Table 7 : Injection Rate limitations

Injection Interval	Instantaneous Injection Rate in normal operations [gpm]	Maximum Instantaneous Injection rate [gpm]	Cumulative Annual Volume [gallons]
Haskell Sandstone-Limestone	58.33	145.8	30,660,000

6.1.2 Analysis of Chemical, Physical, Radiological, and Biological Characteristics of Fluids

In the section 4.4 it is described the tests to analyze the chemical, physical, radiological, And biological characteristics of fluids:

- Total Dissolved Solids (TDS)
- pH
- Oil and grease
- Metals
- Chlorides
- Bacteria

6.1.3 Maximum Pressure At Wellhead

The maximum allowable surface injection pressure (MASIP) is the maximum surface pressure that an injection well is allowed to inject fluid into the injection well. The Oklahoma Administrative Code, § 252:652-9-1, subchapter 9, section 1B states the following: "*If the effective overburden pressure gradient is not established, the maximum total pressure gradient shall not exceed 0.65 psi/ft of depth from ground surface to the top of the disposal zone*". According with the regulation, the maximum total pressure gradient (applied injection pressure plus fluid pressure plus allowances for friction pressure loss) shall not exceed 0.65 psi/ft of depth from ground surface to the top of the injection zone.

$$MASIP = \left(Depth \times 0.65\frac{psi}{ft}\right) - P_{Hydro} + P_{friction}$$

$$P_{friction} = 50\, psi\ [calculated\ friction\ loss]$$

$$MASIP = (6{,}500ft \times 0.65\text{psi/ft}) - 2{,}860\text{ psi} + 50\text{ psi}$$

$$MASIP = 1{,}415\, psi$$

The MASIP allowed by Oklahoma Department of Environmental Quality (DEQ) is 1,415 psi.

6.1.4 Annulus Filled with Fluid

To meet the criteria specified in the OAC § 252:652-9-1, for nonhazardous facilities, the annulus fluid shall be maintained at a minimum positive pressure of 10 psig at the well head. The annulus of the well will be maintained filled with fluid, usually drilling mud or completion fluid, to:

- Pressure Control: Filling the annulus with fluid helps to control the pressure in the wellbore. This is particularly important during drilling and completion operations when there is a risk of a blowout (uncontrolled release of pressure and fluids from the wellbore).
- Formation Protection: The fluid in the annulus helps to protect the formation from damage during drilling and completion operations. It prevents the drilling mud or completion fluid from entering the formation and potentially causing damage to the rock or interfering with the flow of oil or gas.
- Corrosion Prevention: The fluid in the annulus can also help to prevent corrosion of the casing and other equipment in the wellbore. It acts as a barrier between the metal surfaces and the corrosive fluids that may be present in the formation or produced by the well.
- Cement Bonding: When cement is used to seal the annulus, the fluid can help to improve the bonding between the cement and the casing and formation rock. This is important for ensuring the integrity of the wellbore and preventing fluid migration between different zones.

6.2 Monitoring

As described earlier in the document, the well will be constantly monitored, not only for met regulations, but monitoring is expected to collect valuable data in the sense that this is a scientific project.

6.2.1 Injectate Analysis

Injectivity analysis will be performed for evaluating the ability of a well to accept injected fluids, for this project formation water, and to distribute this fluid uniformly within the reservoir. The injectivity analysis a part of the reservoir engineering and production optimization data process.

During the injectivity analysis, several factors will be evaluated to determine the effectiveness of the injection operations. These factors include:

- Formation Permeability: The permeability of the reservoir formation is an essential parameter for determining injectivity. It describes how easily fluids can flow through the rock, and a high permeability indicates that the formation is more likely to accept injected fluids.
- Formation Damage: Formation damage can occur due to drilling and completion operations, and it can negatively affect injectivity. The injectivity analysis assesses the extent of formation damage and evaluates whether it can be remediated.
- Fluid Properties: The properties of the injected fluid, such as viscosity, density, and chemical composition, can impact injectivity. The injectivity analysis evaluates these factors and determines the appropriate fluid type and injection rate.
- Well Completion: The completion design of the well, including the placement of the injection interval, the number of perforations, and the type of completion, can also affect

injectivity. The injectivity analysis evaluates the well completion design and identifies any potential issues that may impact injectivity.

- Reservoir Pressure: The pressure in the reservoir is an important factor in injectivity, as it affects the ability of the injected fluid to flow through the rock. The injectivity analysis evaluates the reservoir pressure and determines the optimal injection pressure for the well.

6.2.2 Semi-Annual Internal MIT (Annulus Pressure Test)

The Mechanical Integrity Test (MIT) will be performed to ensure that the production and injection wells are functioning correctly and safely. To satisfy 40 CFR 146.8(b)(2), the operator shall shut the well in semi-annually and pressurize the annulus for two (2) hours. Test pressure shall be at a minimum of 300 psi or 125 % of the highest operating annulus pressure, whichever is greater. Pressure loss or gain exceeding -5 % or +10 % respectively, from initial test pressure, will require additional tests and/or immediate repairs to ensure the mechanical integrity of the well. The main objective is to confirm that wells can be operated safely and efficiently.

The MITs will include a range of tests that evaluate different components of the well equipment. Some of the MITs for the project will include:

- Pressure Tests: Pressure tests evaluate the integrity of the well casing and tubing. They involve applying pressure to the well equipment and monitoring for leaks or other failures.
- Corrosion Tests: Corrosion tests evaluate the level of corrosion on the well equipment, including the casing, tubing, and other components. They help to identify potential issues with the equipment and prevent failure due to corrosion.
- Cement Bond Logs: Cement bond logs evaluate the integrity of the cement bond between the casing and the formation rock. They help to identify any gaps or channels in the cement, which can lead to fluid migration and other issues.
- Ultrasonic Thickness Tests: Ultrasonic thickness tests evaluate the thickness of the well equipment, including the casing and tubing. They help to identify potential weaknesses or areas of wear and tear.
- Visual Inspections: Visual inspections involve inspecting the well equipment for signs of damage, wear, or other issues. This includes inspecting the wellhead, casing, tubing, and other components for corrosion, leaks, or other signs of damage.
- Electrical Tests: Electrical tests evaluate the performance of the well equipment's electrical systems, including sensors, gauges, and other electronic components. These tests ensure that the equipment is functioning correctly and providing accurate data.

6.2.3 Continuous Recording Devices for Pressure, Flow Rate, Injected Volume, And Annulus Pressure

Continuous recording devices for pressure, flow rate, injected volume, and annulus pressure will be used to monitor the cycling process and collect scientific data. Information will be collected as time series, and the time collection intervals will be adjusting to meet the regulatory agencies specifications, and to generate data that serves as input for research analysis (in that case the recording data will be significantly more to cover the scientific goals). Monthly average, maximum and minimum values for injection pressure, injection rate and annulus pressure will be reported quarterly to the DEQ per 40 CFR 146.13(c)(ii). Here is a general procedure, that will be adjusted according with the project necessities:

- Equipment Selection: Continuous recording devices for pressure, flow rate, injected volume, and annulus pressure based on the specific needs of the well operation. We need to ensure that the devices are compatible with the well equipment and can operate in the environmental conditions of the well site.
- Installation: Install the devices at appropriate locations on the well equipment, such as the wellhead, production tree, or flowlines. Ensure that the devices are securely installed and properly calibrated.
- Data Acquisition: Set up a data acquisition system to continuously record the data from the devices. This may involve connecting the devices to a data logger or programmable logic controller (PLC) that can record and transmit the data to a central database or monitoring system.
- Data Analysis: Monitor and analyze the recorded data to optimize the well operation. This may involve using software tools to generate graphs, charts, or other visualizations of the data to identify trends or anomalies. Use this information to make informed decisions about cycling monitoring.
- Maintenance: Regularly inspect and maintain the continuous recording devices to ensure they are functioning correctly. This may involve cleaning or replacing sensors, replacing batteries, or updating software.
- Troubleshooting: Address any issues with the continuous recording devices promptly to prevent production interruptions. Troubleshoot the devices by checking for loose connections, faulty sensors, or other common issues.

6.2.4 5 yrs External MIT

MIT is performed for the injection well at least once every 5 years and a pressure fall off test will be performed at least annually in accordance with 40 CFR 146.13(b)(3) and 40 CFR 146.13(d). Tests may be required more frequently by DEQ regulations, in that case, the tests frequency will by match the DEQ regulations. Tests results will be submitted pre the reporting frequencies stablished in DEQ per 40 CFR 146.13(c)(ii).

6.2.5 Type, Number, And Location of Groundwater Monitor Well

Two ground water monitor wells are located as described in section 1.3 of this document. Groundwater from monitoring wells shall be analyzed for parameters specified in the permit at least once each month per OAC § 252:652-9-1. The analyses and water levels shall be submitted as part of the quarterly report.

6.3 Reporting

Reporting of the geothermal cycling project will meet the requirements and frequency stablished by DEQ regulations:

- Quarterly Report:
    1) Physical and Chemical Characteristics of Injection Fluids
    2) Monthly Average, Max, And Min Values for Injection Pressure, Flow Rate, Volume, And Annulus Pressure
    3) Any Work Over Information
- Groundwater Test Results
- Groundwater Monitoring

7 PLANS AND OTHER REQUIRED DOCUMENTATION

7.1 Drilling / Workover Plan

The geothermal project envisions using retired/inactive oil and gas wells to repurpose them to extract the geothermal energy stored in the subsurface. In that sense, as described earlier in the present document, 2 existing wells will be used for geothermal cycling. In that case the operational plans are related to the workover operations necessary to repurpose the existing wells. All the plans and programs presented in this section of the document are preliminary and will be adjusted according to the information we obtain once we can access the wells and assess their current condition. Nevertheless, all procedures will adhere to the DEQ regulations.

7.2 Proposed Formation Testing Program

The formation testing program will involve the collection and analysis of data from downhole tools to evaluate the reservoir's properties and characteristics. The following is a general description of the formation testing program:

- Review the geological and geophysical data to determine the location of the zones of interest and the optimal depth for in the Haskell formation testing. A formation testing plan is then developed to outline the test objectives, tools, and procedures. The main objectives of the testing are to determine:
    - Permeability
    - flow rate and pressure
    - Temperature
- The testing tools will include a downhole sampler (memory gauge), a pressure measurement tool, and a temperature measurement tool. Other tools, such as a fluid analyzer or a fluid imaging tool, may also be used depending on the initial results of the tests.
- Testing general procedure:
    - Run the testing equipment into the well and ensure it is securely attached to the drill string.
    - Monitor pressure and temperature readings during the test and record them at regular intervals.
    - Conduct a drawdown test to determine the formation pressure and observe the pressure buildup to determine the formation permeability.
    - Conduct a production test to determine the well flow rate and temperature.
    - Conduct a falloff test to determine the wellbore storage capacity and skin factor.
    - If necessary, perform interference testing with nearby wells to determine the reservoir connectivity and pressure communication.
- Once the data is obtained, we will analyze the data for adjusting the cycling plan and for research purposes. This involve analyzing the pressure and temperature measurements, as

well as the fluid sample analysis, to determine the properties of the reservoir. The data is then used to make decisions about the project strategy.

- Plot the pressure and temperature data collected during the tests to identify formation properties and boundaries.
- Analyze the wellbore storage capacity and skin factor to determine the well productivity.
- Use the well flow rate and temperature data to estimate the reservoir capacity and heat transfer.
- Interpret the interference testing results to understand the reservoir connectivity and pressure communication.

7.3 Proposed Stimulation Program

Analyzing the results of the well testing will be define the need of any methods of stimulation. In the case well stimulation is required, the following are the main steps that are preliminary planned (and will be adjusted as more information is obtained from previous tests):

- Cleaning out the wellbore and isolating the formation to be stimulated.
- Inject hydraulic fracturing fluids or acidizing solutions into the formation.
- If it is considered that we need to improve the formation water transmissibility for the cycling process, we will apply pressure to fracture the rock and create pathways for formation water to flow.
- If needed, pump proppants, such as sand or ceramic beads, into the fractures to hold them open.
- Monitor the pressure, flow rate, and fluid composition during the stimulation process.
- Remove the equipment and clean up the site.
- Conduct post-stimulation testing to evaluate the well's production rates and determine the success of the stimulation process.
- Analyze the data to determine if additional stimulation is necessary or if the well has reached its maximum potential.

7.4 Proposed Injection Pressure

The injection pressure was defined in the sections 6.1.1 and 6.1.3 of the present document. We anticipate that the maximum daily flow to the injection well will be no more than 210,000 gpd (5,000 BPD, or 145.8 gpm). The MASIP calculated to the project depth, described in the section 6.1.3 is 1,415 psi.

7.5 Schematic of the Well

Wellbore diagrams of the Leon 4-11 (producer) and Leon 1-11 (injector), are presented in **Figure 22**.

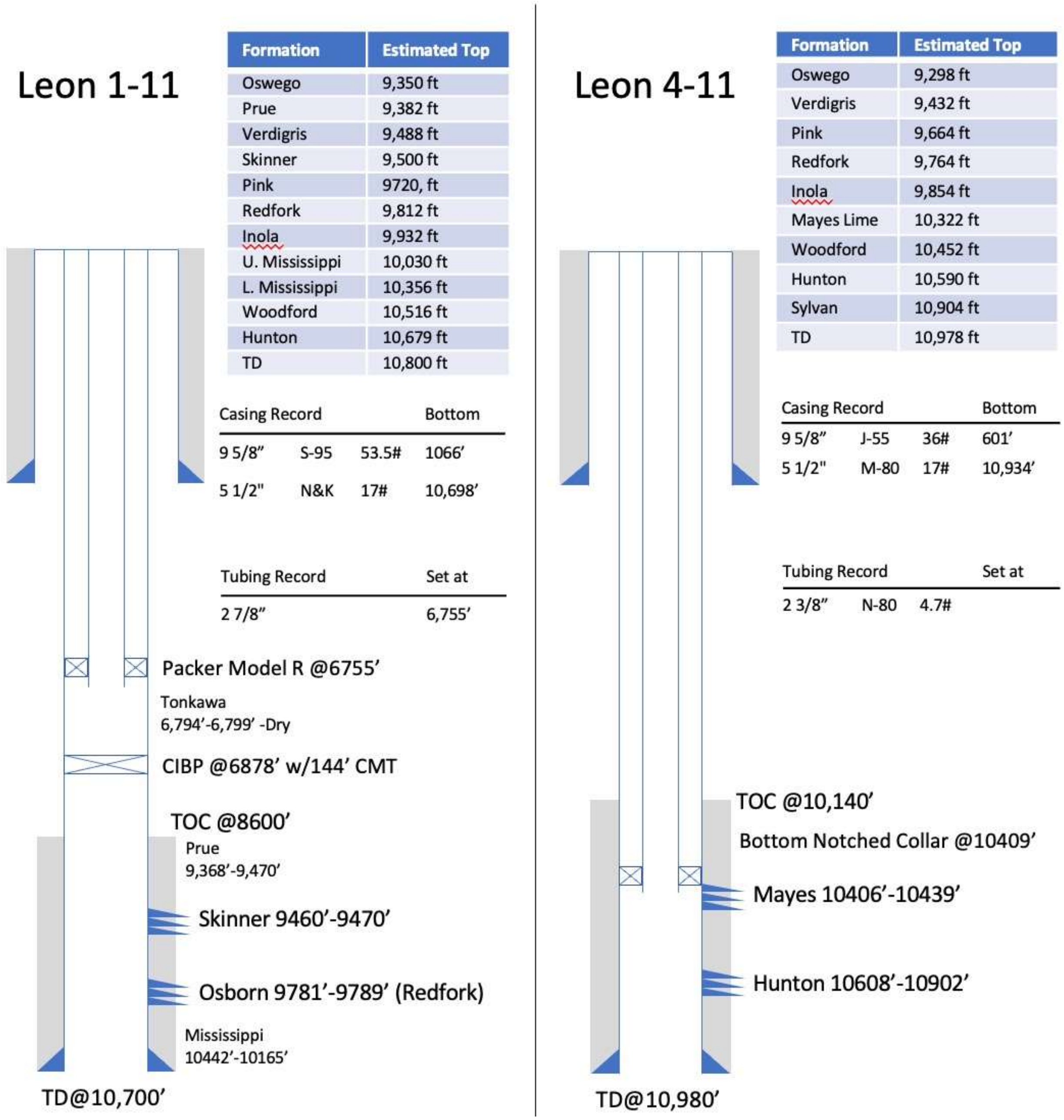

Figure 22: The Well Construction of the Injection and Producing Well.

7.6 Demonstration Of Mechanical Integrity

For demonstrate the mechanical integrity of the wells, the tests described in the section 6.2.2 and section 6.2.4 will be executed, and test results will be presented to DEQ. If a loss of mechanical integrity is discovered during any part of the project, Blue Cedar will:

- Immediately cease production/injection of the formation water.
- Take reasonable steps necessary to determine if there has been a release of fluid into any unauthorized zone.

- Notify DEQ within 24 hours after the loss of mechanical integrity is discovered.
- Notify DEQ when production/injection can be expected to resume.
- Restore and demonstrate mechanical integrity to the satisfaction of DEQ prior resuming injection.

7.7 Injection Procedure

We anticipate that the maximum daily flow to the injection well will be no more than 210,000 gpd (5,000 BPD, or 145.8 gpm). The MASIP calculated to the project depth, described in the section 6.1.3 is 1,415 psi. .

7.8 Contingency Plan

If there is evidence that there has been a release to an unauthorized zone we will:

- Notify DEQ within 24 of obtaining such evidence.
- Take the necessary steps to identify and characterize the extent of any release.
- Propose a remediation plan for review and approval.
- Comply with and implement any remediation plan specified by DEQ.
- Notify the local health authority, place a notice in a newspaper of general circulation, and send notification by mail to adjacent landowners when there has been a release into a USDW or freshwater aquifer currently serving as a water supply.

7.9 Monitoring Plan

Automatic alarms and automatic shut-off systems will be in place in the event that pressures, flow rates, or other parameters designated by DEQ exceed a range or gradient specified in the injection permit. When a qualified/trained operator is not on location, the automatic alarm and automatic shut-off systems are designed to sound a d shut-in the well. If an alarm is triggered, Blue Cedar with the support of OU will immediately investigate and, as expeditiously as possible, identify the cause of the alarm or shutoff. If upon investigation the injection well appears to lack mechanical integrity, the steps described in section 7.6 will be executed.

7.10 Proposed Corrective Action for Undocumented Wells

The AOR for the present project has no undocumented wells.

7.11 Construction Procedures Plan

No additional construction well be executed at this stage of the project. If, in the future, any construction is required, a procedure plan will be presented for DEQ approval before any construction is initiated.

7.12 Plugging and Abandonment Plan/Procedure

Any well to be permanently abandoned shall be immediately plugged in a manner to permanently prevent the migration of any disposed substances out of the disposal zone, as well as the migration of oil, gas, or salt water into or out of any productive formations by means of the well bore.

(A) Plugging shall be by a series of continuous cement plugs from the total depth of the well to ground level.

(B) The top of any plugged well shall clearly show the well permit number and date of plugging by permanent marking on a steel plate welded to the surface casing.

(C) The operator shall submit for DEQ approval updated plans for the proper disassembly, decontamination and restoration of the site at least one hundred-eighty (180) days prior to cessation of operations. The plans shall include the following:

> (i) Methods for reconditioning, recycling, or disposal of all contaminated materials, residual liquids, sludges, soils, and ancillary equipment such as pumps, piping, tubing, and tanks;
>
> (ii) Plans for restoration of the site, including provisions for proper cover to prevent excessive runoff and erosion; and
>
> (iii) Narrative description of methods for proper closure of all permitted nonhazardous impoundments.

(D) The approved plugging and abandonment plan shall be implemented and completed within six (6) months, unless otherwise specified by the DEQ.

(E) The operator shall notify the DEQ of the exact time when plugging operations will take place.

(F) Within thirty (30) days after a well has been plugged, the owner or operator shall file a plugging record with the DEQ

7.12.1 Cost Estimate

A cost estimate for plugging and abandonment, as described by 40 CFR 144.62 will be provided.

7.12.2 Financial Assurance

Financial assurance for all Class I waste injection wells as required by 40 CFR 144 Subpart F will be provided

References

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