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EFFECTS OF COUPLED CONVECTION AND CO_2 INJECTION IN STIMULATION OF GEOPRESSURED GEOTHERMAL RESERVOIRS

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ABSTRACT

Geopressured brines are a vast geothermal resource in the US Gulf of Mexico region. In particular, geopressured sandstones near salt domes are potential sources of geothermal energy because salt diapirs with high thermal conductivity may pierce younger, cooler strata. These characteristics enhance transfer heat from older, hotter strata at the base of the diapir into shallower strata. Moreover, widespread geopressure in the Gulf region tends to preserve permeability, enhancing productivity. As an example, the Camerina A sand of South Louisiana was chosen as a geomodel for a numerical simulation study of effects of CO_2 injection and wellbore cooling as the innovative method of geothermal development. This paper presents scenarios for heat harvesting from typical Gulf of Mexico geopressured aquifers including Camerina A that take advantage of coupled convection and simultaneous CO_2 sequestration. A suite of TOUGH2 numerical simulations demonstrates benefits of introducing CO_2 injection wells, varying locations of injection/production segments of wells, and exploiting gravity segregation of the fluids.

GEOPRESSURED GEOTHERMAL RESOURCE DEVELOPMENT

Geothermal systems provide abundant and emission-free thermal energy for electricity generation, space heating and air-conditioning. According to the most recent and conservative USGS estimate, in the US alone the geothermal resource base of the crust down to the 10 km comprises about 13.5 million exajoules (1 exajoule = 10^{18} joules) or quads (MIT, 2006). This amount of energy is equivalent to 2.5×10^{15} barrels of oil, 4.86×10^{14} tones of coal, and 1.35×10^{16} Mscf of natural gas. Despite these impressive figures, extraction of geothermal energy is mostly confined to a few high-grade (or high temperature) hydrothermal fields, leaving other geothermal systems virtually untapped.

One underexploited type of geothermal systems is geopressured sedimentary aquifers. Geopressured aquifers are undercompacted, brine-saturated, porous, and permeable formations that have anomalously high pore pressures and temperatures over 100 degrees Celsius. Geofluids in these systems tend to have high concentrations of minerals and dissolved gases. Geopressured fields are considered a medium- and low-grade (or low-enthalpy) geothermal resource. They occupy vast subsurface areas in coastal regions and in the US contain approximately 170,000 EJ of energy. The US states of Louisiana and Texas are examples of geographic locations where geopressured systems occur frequently.

Several major technical obstacles render many low-grade geopressured systems subcommercial. These include a necessity to drill multiple wells to access remote parts of a reservoir in order to improve heat sweep, the high cost of pressure maintenance programs, and burdensome surface handling of withdrawn geofluids. Low-enthalpy systems have lower heat content and thermal efficiency. In addition to these problems, geothermal development might cause land subsidence due to compaction in the producing geologic formation. As a result, pilot commercial projects exploit only those sites that have anomalously high geothermal gradients and strong water drives – the so-called "low-hanging fruit" of the tremendous resource. This paper investigates a new method to improve heat recovery from the geopressured aquifers by combining the effects of natural and forced convection.

This study demonstrates advantages of the new method of zero net mass withdrawal for heat harvesting. First, the discussion focuses on ideas about natural fluid convection in flat and dipping aquifers. Then, the behavior of geologic systems under natural convection is coupled with forced convection due to wellbore production and injection. In the final part, the paper examines the effect of carbon dioxide injection on the engineered convection pattern and applies the finding to geomodels of South Louisiana geopressured aquifer called Camerina A.

ENGINEERED (OR COUPLED) CONVECTION CONCEPTS

Convection-based development of geopressured aquifers relies on displacement of hot geofluid with reinjected cool one, pure depletion production with cool brine disposal into a shallower formation, or a combination of both. Either technique, however, produces serious side effects that make potential of many hot saline aquifers commercially unattractive. Among these effects are the necessity to build large surface facilities to handle thousands of barrels of brine, land subsidence in geologically sensitive areas, and drilling of multiple injection wells for improved heat sweep. Though serious problems for any geopressured geothermal development, these difficulties can be overcome with a production plan that exploits the natural convective pattern in a reservoir of interest.

Natural Convection in Flat Systems

Natural convection results from non-uniform heating of a porous medium saturated with a fluid, density of which is temperature dependent. One of the major contributors to research about natural convection in flat geothermal reservoirs is Horne (1975). He uses Rayleigh number defined as follows

$$Ra = \frac{k\rho_f^2 c_f \beta_f \Delta T g h}{\mu \kappa_m} \qquad (1)$$

k – permeability of porous medium
ρ_f – fluid density
c_f – fluid specific heat
β_f – fluid thermal expansivity
$\Delta T = (T_{max}-T_{min})$ – temperature difference
g – acceleration due gravity
μ – fluid viscosity
$\kappa_m = \kappa_f^{\phi} + \kappa_r^{1-\phi}$ – composite thermal conductivity (including rock and fluid conductivities)

and investigates behavior of geosystems with Rayleigh numbers above the critical value of $4\pi^2$ (Horne, 1975). Under such condition flow pattern within the porous medium shifts from conduction to convection and mass and heat transfer become more vigorous as Rayleigh number increases. Horne stresses that to extract more heat from convection dominated systems with reinjection, cold fluid should be introduced in the descending portion of the convective pattern. This finding will become important in later in this study.

Natural Convection in Inclined Systems

Though convection in flat systems could be of interest in some development cases, in the Gulf of Mexico region many hot saline aquifers are dipping. Dips in such geologic formations can be local or sustained for the entire length of the reservoir. Tilted geopressured formations are particularly common around salt structures that cause deformation of adjacent sand deposits. The base case of this study, the Camerina A sand, is a dipping system due to its proximity to Guyedan salt dome. Therefore, a more careful examination of natural convection in inclined reservoirs is instrumental.

Nield and Bejan discuss such tilted systems and use a modified definition of the Rayleigh number that accounts for elevation change due dip:

$$Ra = \frac{k\rho_f^2 c_f \beta_f \Delta T g L}{\mu \kappa_m} \sin\theta \qquad (2)$$

where θ is the dip angle. Thus, the critical Rayleigh number, above which convection dominates conduction, becomes $4\pi^2 \sin\theta$. Inclined systems in their analysis have uniformly heated boundary layers and form unicellular convective flow patterns (Nield and Bejan, 2006). Inclination, non-uniform permeability, and salt dissolution and presipitation have been found to promote thermohaline convection in Gulf Coast sediments (Hanor, 1987).

To extend Nield's and Bejan's work and approximate inclined geologic systems even further, we remove the condition of uniform temperature boundary layers and let their temperature vary with depth. Figure 1 below shows that for the model with constant thickness, width, and rock and fluid properties (length 2000 m, thickness 30 m, porosity 20%, permeability 300 md) increasing dip causes greater temperature contrast and, thus, more vigorous convection expressed as higher Rayleigh number.

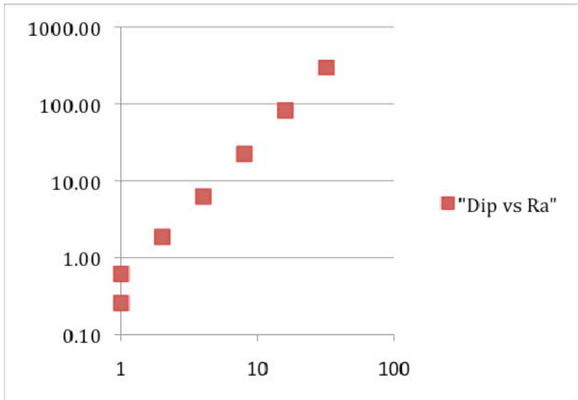

Figure 1: Dependence of Rayleigh number values on dip of a geologic system. The abscissa in dip degrees.

Dipping systems of various geometric dimensions have stable large-scale convective loops even at relatively low Rayleigh numbers for nonzero dips.

Figure 2 below shows orientation of heat transport vectors in a tilted aquifer modeled as a quiescent system for 1000 years. In absence of production/injection wells and presence of a uniform geothermal gradient of 18 C/km, the system exhibits unicellular heat convection pattern.

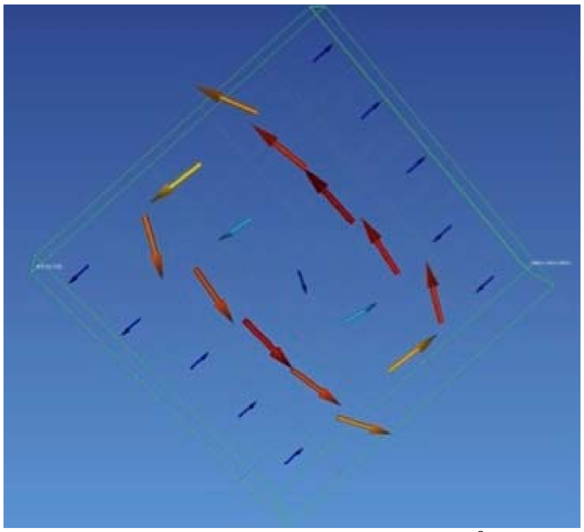

Figure 2: Heat transport vectors for a 45^o inclined system. Modeled with TOUGH2 (Pruess, Oldenburg, and Moridis 1999) and visualized with PetraSim software. Heat is conducted into the bounding layers high in the reservoir, and into the reservoir at greater depths.

Thus, by characterizing the reservoir's natural convective pattern and forcing additional heat transport with wells, we can engineer convection to meet an increasing demand for geothermal energy.

ENGINEERED CONVECTION MODELLING

In this section several heat harvesting scenarios are considered. First, we investigate whether natural convection can be an effective heat transport mechanism. Second, this natural convective pattern is coupled with monobore, which is a single wellbore for production/injection and heat exchange with a low boiling point working fluid within the wellbore. Engineered convection could also be used with convectional production to the surface, heat exchange, and reinjection. This study examines varying flow rates of geofluid. Last, we augment the previous production arrangement with an additional injection well that sequesters CO_2 into the geothermal reservoir. This allows assessment of the effect of simultaneous heat extraction and CO_2 sequestration on energy output.

Because geologic systems in the Gulf of Mexico region have a great variety of geometries and rock properties, it is important to model heat extraction from geopressured reservoirs with distinct parameters. The following Table 1 presents values for the key variables used for 2D simulations in TOUGH2.

Table 1: Values for geometric, petrophysical, and production design parameters

Parameter	Values Used	Units
Thickness	100, 200	M
Permeability	300, 600	md
Dip	0, 2, 15	degrees
Flow rate	0.2, 2, 20	Kg/s

The width of the models is 100 m and is a symmetry element; it corresponds to 1/10 of a hypothetical 1 km wide 3D basis considered in the comparisons below. Thus, the flow rates are scaled for the 100 m 2D simulations from 2, 20, and 200 kg/s, respectively, for the 1 km basis. All modeled systems have a rock compressibility of 2×10^{-8} Pa^{-1}.

Other important considerations in the modeling process are (1) the impermeable boundary layers which conduct heat in and out of the reservoir; and (2) a vertical temperature gradient during initialization. In these simulations, the bounding layers are modeled as constant temperature boundaries by assigning very high heat capacities. The vertical temperature gradient of 18 C/km is a realistic value for the Gulf of Mexico region and is included into an initialization step for all geomodels by means of a preprocessing script. The result of such initialization and running an idle period of 1000 years for stable temperature profile is illustrated in Figure 3.

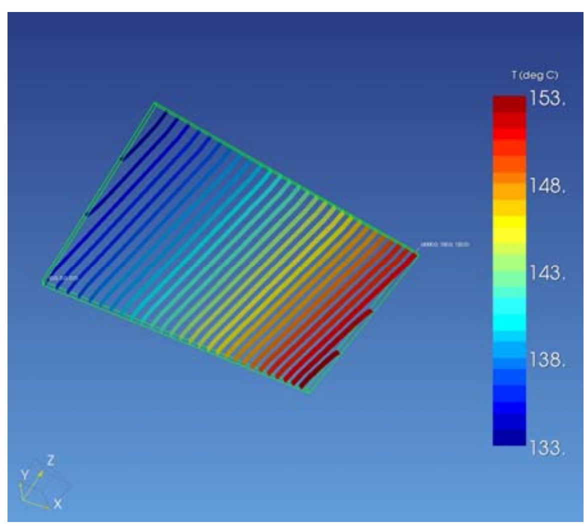

Figure 3: Temperature profile for a 4000×100×100 m model with the boundary layers, the vertical gradient of 18 C/km and 15 degrees dip (plotted in PetraSim with the 20 fold exaggeration in z-direction). Temperature contours appear flat in an unexaggerated view and their slight curvature is due to transitions between reservoir and boundary layers rocks.

The presence of impermeable top and bottom layers with the large heat capacity produces the smooth temperature profile as on the plot above. When the boundary layers are removed and the model is run for the same idle period of 1000 years, the range of temperatures decreases, and the effect of the temperature gradient is slightly muted. The result of the initialization without the bounding layers is shown in Figure 4.

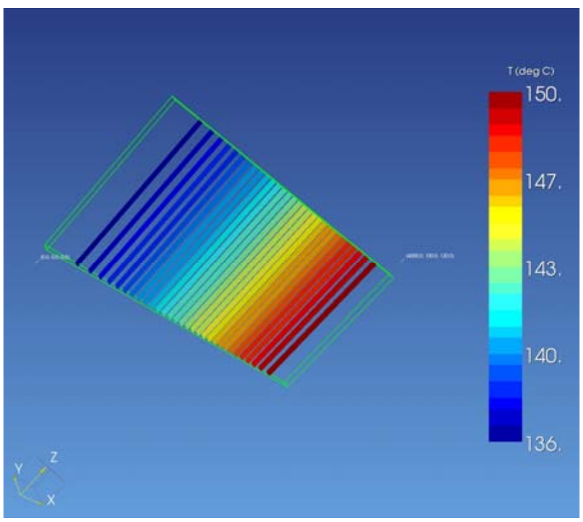

Figure 4: Temperature profile for a 4000×100×100 m model with the vertical gradient of 18 C/km and 15 degrees dip initialized without boundary layers (plotted in PetraSim with the 20 fold exaggeration in z-direction). Note that even though the reservoir has uniform petrophysical properties, the range of temperatures without bounding layers is 6 degrees smaller than in the previous case and the contours are not equally spaced.

Because the boundary layers give a wider, gradual and more realistic temperature profile (realistic in a sense that any Gulf of Mexico geopressured aquifer is bounded by other formations that conduct heat in and out of the reservoir), all production cases discussed below are initialized and idled for 1000 years with them. Complications with calculating conductive heat fluxes from the boundary layers, however, make us exclude them from energy balance computations for production simulations during 30 year production intervals.

For cases when no CO_2 is injected into the formation, the simulation runs use TOUGH2 EOS1 (equation of state module). This module is particularly convenient and simple, since no salinity effect is considered. For simultaneous heat extraction and CO_2 sequestration runs we take advantage of EWASG module capabilities. EWASG allows modeling mixtures of water and gases under high pressures (34.5 MPa) and relatively low temperatures (135 C average), matching exactly the conditions in many Gulf of Mexico geopressured aquifers (Battistell et al., 2007).

<u>Cooling wellbore effect</u>

This scenario requires only one horizontal well through which a refrigerant is circulated from the surface to the formation and back to a facility with power generation equipment. For low-enthalpy systems the refrigerant would be a low boiling point fluid, and the turbine would be powered by an organic Rankine cycle. This heat harvesting configuration can be summarized by the schematic in Figure 5.

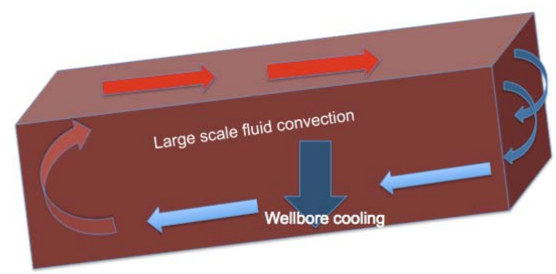

Figure 5: Geothermal system with a horizontal cooling well.

A suite of 2D TOUGH2 simulations for geologic systems with parameters from Table 1 demonstrates that having only one horizontal cooling wellbore is not economic. This design removes less than 1 percent of thermal energy in-place as follows from Figure 6.

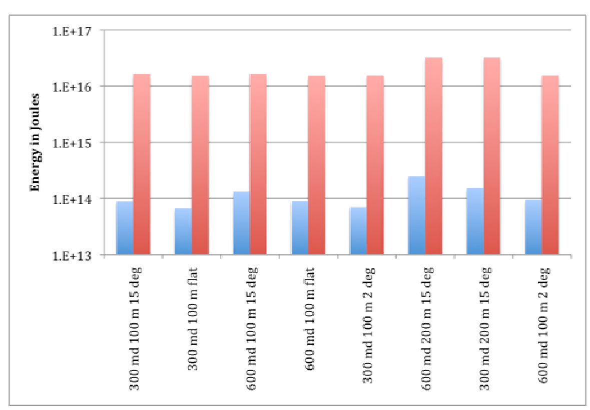

Figure 6: Thermal energy of the reservoir harvested after 30 years of maintaining the wellbore at a constant temperature of 50 C. Wellbore chilling can be obtained by circulating a refrigerant. Extracted heat in blue and initial energy content is in red.

From Figure 6 it is clear that wellbore cooling technique requires permeabilities much higher than usually found in geopressured aquifers of Gulf of Mexico. Figure 7 shows the temperature profile of one of the simulation runs (dip 2 degrees, permeability 300 md, thickness 100 m), which vividly shows that only a tiny part of the reservoir is swept for heat.

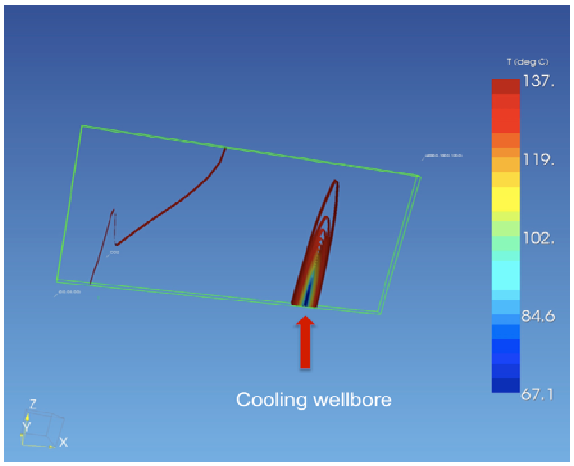

Figure 7: PetraSim visualization of the reservoir's temperature profile after 30 years of wellbore cooling (plotted in PetraSim with the 20 fold exaggeration in z-direction). The well is located on the bottom of the reservoir.

Though only a marginally economic heat extraction technique, the wellbore cooling approach provides an insight into importance of characterization of natural convection pattern. Comparing the results of 30 years production from Figure 8 and values of Rayleigh number from Table 2, we conclude that systems with Ra's above their critical values Ra_{cr} tend to yield more thermal energy. This phenomenon can be attributed to natural convection.

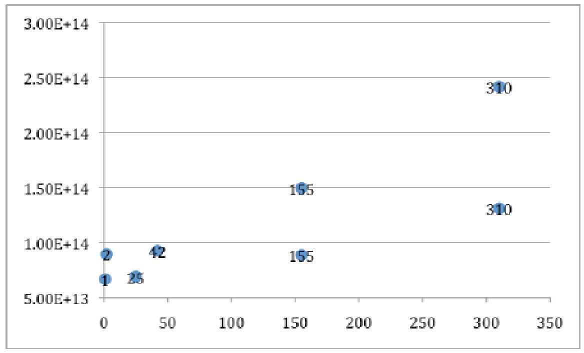

Figure 8: Ra vs. energy extracted in Joules diagram for cooling wellbore method after 30 years of heat harvesting.

Table 2: Rayleigh number and critical Rayleigh number values for all simulation runs.

System Specification	Rayleigh Number (Ra)	Critical Rayleigh Number (Ra_{cr})
300 md 100 m 15 deg	155	$4\pi^2 \sin 15 = 10.2$
300 md 100 m flat	1	$4\pi^2 = 39.5$
600 md 100 m 15 deg	310	10.2
600 md 100 m flat	2	39.5
300 md 100 m 2 deg	25	1.38
600 md 200 m 15 deg	310	10.2
300 md 200 m 15 deg	155	10.2
600 md 100 m 2 deg	42	1.38

Engineered (or coupled) convection

This heat extraction strategy takes advantage of natural convective pattern and enhances it with geofluid production/injection. Schematically this heat harvesting technique is summarized in Figure 9 below. We envision an in-wellbore heat exchanger being used to heat a low-boiling point working fluid in this arrangement.

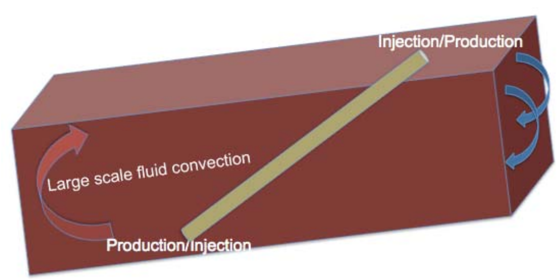

Figure 9: Geothermal system with an inclined production/injection well.

In addition to varying production/injection flow rates, in this study we investigate possible benefits of switching locations of production and injection segments of the well. Changing locations of geofluid withdrawal and injection should give an idea of the optimal well placement in the clockwise large-scale natural convection loop. For the purposes of this paper, we consider two production arrangements: regular and reverse. Regular design produces hot geofluid at the bottom of the reservoir downdip and reinjects it back into the formation at the top updip. This design is illustrated in Figure 10.

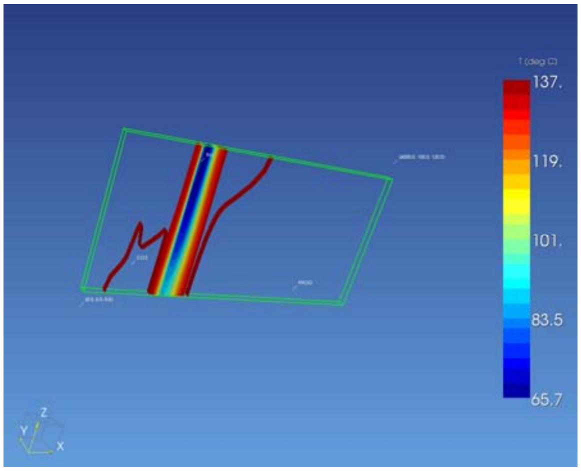

Figure 10: Regular production design with production segment on the bottom and injection segment on the top. Visualized with PetraSim with 20 fold exaggeration in z-direction for the system of 2 degrees dip, 300 md permeability, and 100 m thickness after 30 years of production at a rate of 2 kg/s.

Reverse design, on the other hand, withdraws hot geofluid from the top and reinjects cold water at the bottom downdip as shown in Figure 11.

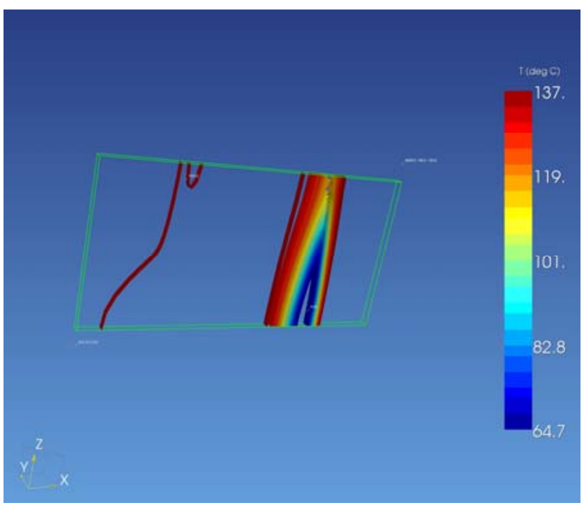

Figure 11: Reverse production design with production segment on the top and injection segment on the bottom. Visualized with PetraSim with 20 fold exaggeration in z-direction for the system of 2 degrees dip, 300 md permeability, and 100 m thickness after 30 years of production at a rate of 2 kg/s.

Simulation test runs were performed for the eight geomodels from Table 2 that were produced with both types of designs. For small flow rates such as 0.2 and 2 kg/s per 100 m of well regular design shows slightly better heat recovery after 30 years of production (Figure 12).

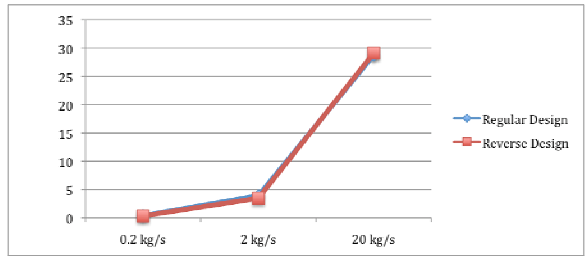

Figure 12: Comparative study of two production arrangements after 30 years of production at varying flow rates for the system with permeability 300 md, thickness 100 m, and dip 15 deg. Y-axis displays the percent of initial energy content recovered.

Reverse design, however, starts to outperform the regular one at high flow rates (i.e. 20 kg/s per 100 m of well) at later stages of production, for instance, after 20 years (Figure 13).

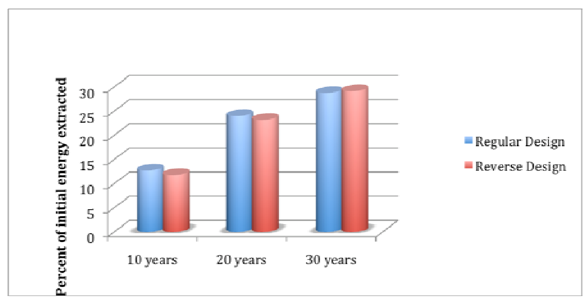

Figure 13: Comparative study of two production arrangements during 30 years of production at 20 kg/s flow rate for the system with permeability 300 md, thickness 100 m, and dip 15 deg.

Unlike in the case of wellbore cooling, the scenarios with coupled convection demonstrate an impressive congruence with the Table 2. In summary, high Ra's produce high thermal energy output (see Figure 14).

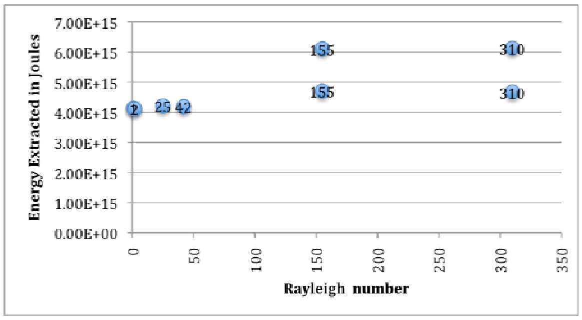

Figure 14; Ra vs. Plot of energy extracted. Higher points with values 155 and 310 correspond to the systems with 200 m thickness. The reservoirs produced at a geofluid flow rate of 20 kg/s for 30 years.

Thus, the analysis of coupled convection simulations indicates that the choice of production design (regular or reverse) depends on the scale of a geothermal development project. In other words, if desired geofluid flow rates are relatively low and production period in the order of 20 years, it is worth considering regular design. If the project is large and desired energy output is high, reverse design is more suitable. However, the differences are modest (Figs. 12, 13).

CO_2 effect

Though natural convection resulting from non-uniform heating and forced convection due to injection and production are the dominant transport, there are other effects that launch energy transfer within the system of interest. One such additional mechanism is a change in the geofluid's composition due to mixing with CO_2. According to Garcia, dissolution of CO_2 in water or brine increases its density by 0.1 – 1 percent (Garcia, 2001) and starts compositionally driven convection. Kneafsey and Pruess (2009) provide additional experimental and numerical verification that CO_2 injection leads to gravitational instability in the system and triggers convective fingering under favorable conditions. Thus, strategic placement of a CO_2 injection well might intensify coupled convection and ensure sequestration of the greenhouse gas.

Characterization of the natural convective pattern in the reservoir is also instrumental when deciding whether CO_2 injection is feasible. In their analysis Farajzadeh and others (2007) confirm that dissolution of CO_2 does enhance natural convection and that the effect becomes more pronounced with increasing Rayleigh numbers. In addition to these findings, those authors establish that initially for all Rayleigh numbers greater than $4\pi^2$, the CO_2 propagation front moves as a square-root function of time. Later this function becomes linear and fingering continues until the convection stops. For higher Rayleigh numbers, however, transition to the linear behavior happens faster than for lower. This is an interesting observation, because the magnitude of the Rayleigh number for this study might predict if compositionally-driven convection is going to persist for a long period of time.

Conceptually geothermal heat extraction with simultaneous CO_2 sequestration is presented in Figure 15.

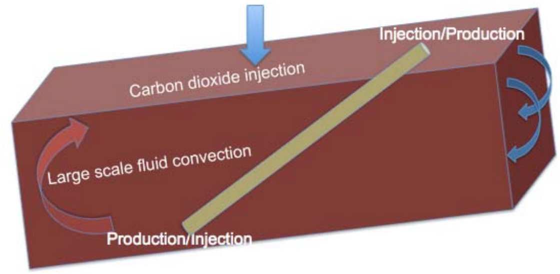

Figure 15: Geothermal system with an inclined production/injection well and a CO_2 injection well.

When choosing a location for a CO_2 injection well, it is important to avoid the regions of geofluid production and injection. If the supercritical greenhouse gas injected in proximity of hot water production, we will extract enthalpy of the gas mixture instead of that of the geofluid. This might significantly reduce heat recovery from the reservoir. If CO_2 is injected close to the geofluid injection region, the volume of the injected gas will drop, because formation pressure in this portion of the reservoir is elevated.

The analysis of the CO_2 injection simulations for all eight systems (Figure 16) is very similar to energy output presented in Figure 14. This implies that CO_2 plume does not interact with coupled convection pattern in a negative way; we did not produce from the injected low-enthalpy supercritical gas, yet sequestered it into the same geothermal reservoir. In fact, a more detailed examination of the energy balance reveals that CO_2 injection cases produce slightly more thermal energy (about 0.02-0.05 percent increment of the initial thermal energy in-place) in most cases.

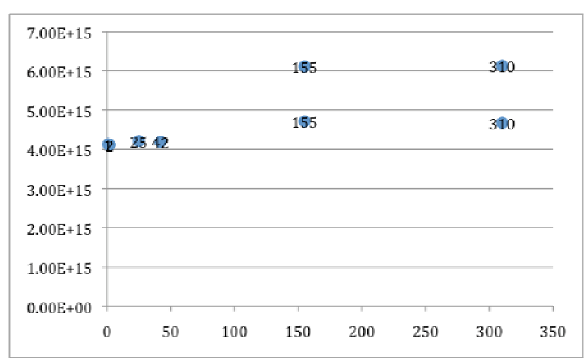

Figure 16: Comparison of production runs with simultaneous CO_2 injection after 30 years at a constant geofluid flow rate of 20 kg/s per 100 m of well. CO_2 is injected at a rate of 0.002 kg/s. Plotted as difference between energy outputs of CO_2 injection runs and regular production runs. Second point with Ra=310 (correspond to the system 600 md 100 m 15 deg) is absent because the difference is negative.

Development scenario for Camerina A sand

Because the main objective of the current study is to investigate production scenarios that might maximize heat extraction from Gulf of Mexico geopressured geothermal aquifers, we incorporate geometric and petrophysical properties of Camerina A sand into our analysis. Camerina A is a part of a larger late Oligocene deltaic deposit adjacent to Guyedan salt dome. Due to its physical properties, the salt diapir conducts heat from older, hotter strata at the base to younger and cooler ones on sides. As a result of such heat transfer, we observe anomalously high temperatures in formations that otherwise should be much colder (Evans, 1991). Proximity to Guyedan salt dome as illustrated in Figure 17 causes Camerina A's formation temperature to go as high as 135 C. In addition to this thermophysical property, the sand deposit has high permeability (circa 300 md), high porosity (circa 20 percent), and a thick pay zone (circa 100 m). Its formation pressure is about 34.5 MPa according to well test performed at the depth of interest. As it was mentioned above, salinity of the geofluid is not modeled.

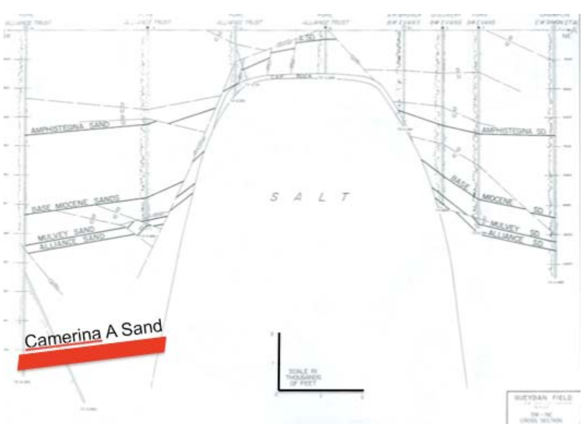

Figure 17: Side view of Guyedan salt dome with adjacent sand deposits. Adopted from Robinson, E. C. 1964, Gueydan Field, Acadia and Vermilion Parishes, LA.

The geomodel of the Camerina A sand was produced with all heat harvesting techniques starting from wellbore cooling and ending with CO_2 injection. Similar to the results discussed above, the wellbore chilling approach is the least efficient leaving behind about 99.6 percent of initial thermal energy in-place. Coupled convection strategy at a rate of 20 kg/s per 100 m of well can extract up to 27.2 percent of initial energy content in case of regular design and 27.6 percent in case of reverse design after 30 years of development. To appreciate these numbers more, it is worth expressing them as equivalent energy of oil. Taking extracted energy for the entire 1 km reservoir as 4.21×10^{16} J and dividing it by 6.1×10^{9} **J** (a conventional value for the heat content of a barrel of oil), we obtain energy equivalent of about 7 MMBOE or 630 BOE/day. This yield does not include thermal or turbine efficiency.

Additional revenue can be generated from the greenhouse gas sequestration and tax rules. Since thermal energy output does not suffer from simultaneous CO_2 injection, this is an appealing development scenario. Over 30 years even at a small rate of 0.002 kg/s per 100 m of well, we were able to sequester about 20 million kg of CO_2 (see Figure 18). This number can be substantially augmented if the initial reservoir pressure is lowered from 34.5 MPa to a value more suitable for a sequestration project.

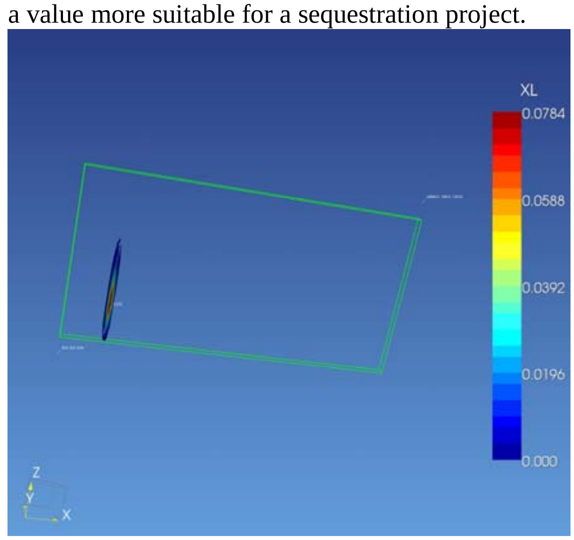

Figure 18: Illustration of CO2 distribution after 30 years injection at 0.002 kg/s per 100 m of well rate (plotted in PetraSim with the 20 fold exaggeration in z-direction).

CONCLUSIONS

In this study we investigated a range of production techniques that can be applied to geopressured aquifers of the Gulf of Mexico region. For a long time these reservoirs were not considered for commercial geothermal development due to their relatively low temperatures. Recent findings, however, demonstrate that sand deposits within the extensive salt dome province have sufficiently high formation temperatures and can yield up to 27-28 percent of their initial energy content within 30 years of production time. Moreover, thermal energy recovery can be performed simultaneously with injection of CO_2. The greenhouse gas slightly improves the heat sweep, and also provides additional revenue qualifying the geothermal project as CO_2 sequestration endeavor.

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