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Reservoir Analysis for Deep Direct-Use Feasibility Study in East Texas

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Keywords

Deep direct-use, Heat flow, Reservoir modeling, Oil and gas, East Texas, Sabine Uplift

ABSTRACT

The National Renewable Energy Laboratory, Southern Methodist University Geothermal Laboratory, Eastman Chemical, and Turbine Air Systems are evaluating the feasibility of using geothermal heat to improve the efficiency of natural gas power plants. The area of interest is the Eastman Chemical plant in Longview, Texas, which is on the northwestern margin of the Sabine Uplift. The feasibility study is focused on determining the potential for a geothermal reservoir within a 10 km radius of the site as defined by data from existing geological studies and cross-sections within the depths of 2,100 to 3,400 meters. Wells within a 20 km radius are included for broader geological comparison to determine the heat flow, temperature-at-depth, and oil and gas field porosity and permeability. The lithologies of most interest are the Lower Cretaceous Trinity Group (Hosston or Travis Peak, Rodessa, James, Pettet, and Sligo) and Upper Jurassic Cotton Valley Group (Schuler and Bossier). Below these are the Haynesville and/or Smackover formations that are expected to be uneconomic because of drilling costs. The region fluctuated between shallow marine to shoreline depositional environments from the Middle Jurassic to the Early Cretaceous. The gas fields at these depths produce from low permeability and porosity zones. The deeper Cotton Valley formations are hotter (averaging 120°C), yet permeability is primarily 0 to 0.01 md and porosity from 0 to 10%. The shallower Trinity Group contains much more variability, 0.01 to 2000 md permeability and 1 to 23 % porosity with lower temperatures averaging about 94°C. The geothermal reservoir model is based on the multiple formation top data sources, published literature data, and well log interpretations within the 10 km radius. Area thickness estimates, reservoir extent bounding parameters, potential flow rates, and temperatures are combined to calculate a reservoir productivity index and develop a reservoir production model. Historical fluid volumes production data are used as an independent check for the reservoir productivity index and production model results. The reservoir parameters calculated here are being used for the surface engineering model to determine the economic viability of using geothermal fluids for a deep direct-use application at this site.

1. Introduction

The National Renewable Energy Laboratory (NREL), Southern Methodist University Geothermal Laboratory (SMU), Eastman Chemical, and Turbine Air Systems (TAS) are evaluating the deep direct-use application of using geothermal fluids to improve the efficiency of a natural gas power plant. The primary focus area is a 10 km radius from the Eastman Chemical plant in Longview, Texas at the intersection of Gregg, Rusk, Harrison, and Panola counties in East Texas (Figures 1 and 2). The Eastman Chemical site was chosen because of their interest in using the geothermal resource that are related to the relatively higher heat flow of the geological Sabine Uplift region (Blackwell and Richards, 2004). The eastern side of the 10 km radius is on the northwestern margin of the Sabine Uplift. Within a 30 km radius of the site there are six other natural gas plants that could use the information collected during this feasibility study, most of them within the Sabine Uplift boundaries.

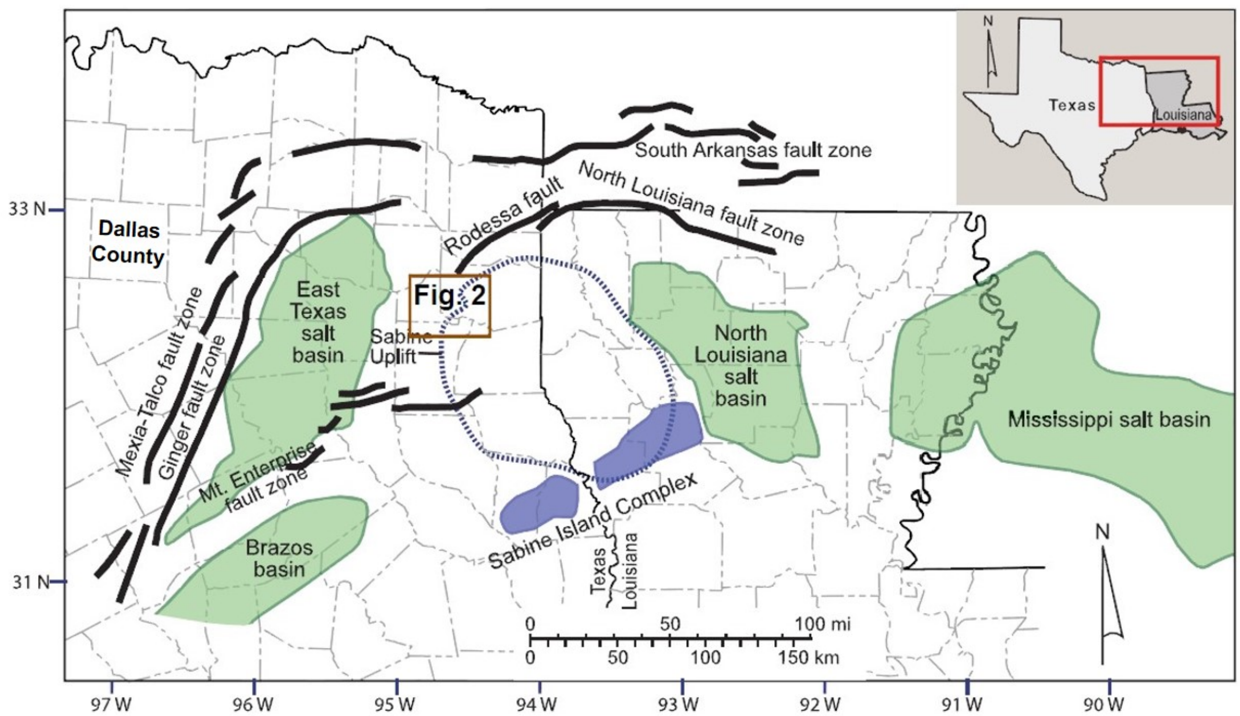


Figure 1: Regional Tectonic Geology of east Texas and Louisiana (modified after Hammes et al., 2011). The study area (Figure 2, brown square) is over the northwestern margin of the Sabine Uplift and near the eastern margin of the East Texas salt basin.

The SMU aspect of this feasibility study examines in detail the geology within the 10 km radius for its geothermal reservoir potential. This is accomplished using existing geological publications and collected well log data for reservoir models. We also are building cross-sections within the depths of 2,100 to 3,400 meters. These depths incorporate the Trinity and Cotton Valley Groups chosen for their measured temperatures and expected flow rates based on gas well data and published reports. Wells within a 20 km radius are included for broader geological comparison - to determine regional heat flow and possible variability of porosity and permeability within the reservoir in the 10 km radius. The reservoir parameters are incorporated into the surface engineering model to determine the economic viability of using geothermal fluids as a deep direct-use application at this site and possibly nearby power plant sites for increasing efficiency of these natural gas turbines.

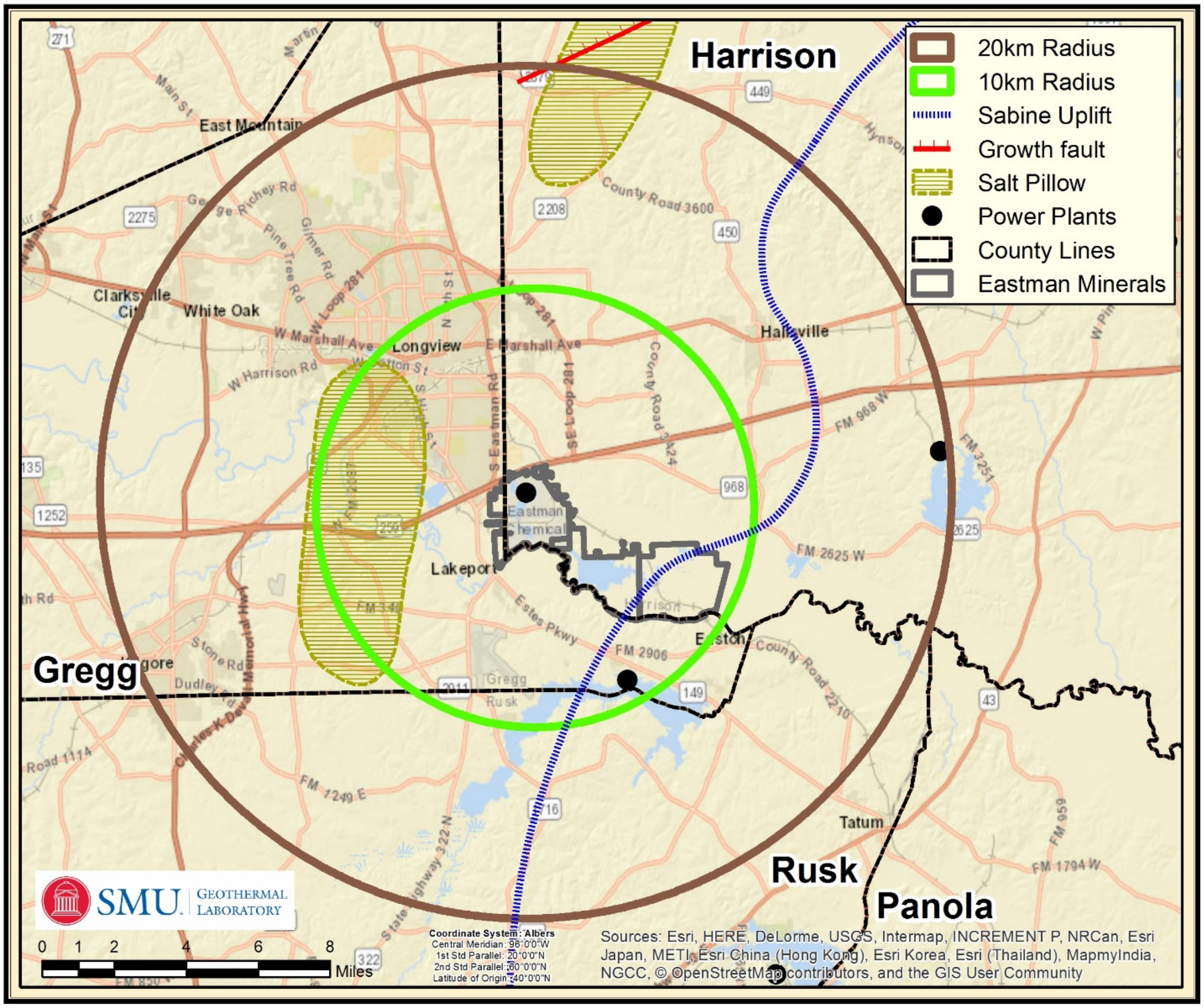


Figure 2: Tectonic Map of Feasibility Area. The Eastman owned mineral rights lie along the boundary of the Sabine Uplift (blue dashed line). The only known fault is directly north (red line). Salt pillows are located to the west and north, yet too deep to impact the local thermal regime. Counties in the area: Gregg to northwest, Harrison to northeast, Panola to southeast, and Rusk to south are a base map for other figures in this paper.

2. Regional Geology

East Texas and Western Louisiana are active oil and gas plays that include the East Texas oil field, the broader East Texas Basin including the current Haynesville Shale play, and the Sabine

Uplift. The oil formations are shallow (Woodbine), the deeper gas formations are tight with narrow lenses of production (Dyman and Condon, 2006; Ambrose et al., 2009; Dutton et al., 1991). This geological region today is north of the Gulf Coastal plains, yet during the depositional timeframe of Middle Jurassic to the Middle Cretaceous the region varied between shallow marine to shoreline depositional environments (Hammes et al., 2011; Ewing, 2001). A recent core review (Ambrose et al., 2017) of the Cotton Valley to the northeast of our area of interest in Harrison County, highlights the site-specific lenses of sands from very fine to medium sandstone to mudstones as the site moves through the shallow marine shelf, shoreface, tidal channel, to transgressional deposits similar to the Gulf Coastal depositional settings of today.

The lithologies of interest in this feasibility study are the Lower Cretaceous Trinity Group (Travis Peak or Hosston, Rodessa, James, Pettet, and Sligo) at depths between approximately 1700 m to 2500 m and the Upper Jurassic Cotton Valley Group (Schuler and Bossier) (approximately 2500 m to 3350 m). Below these are the Haynesville and/or Smackover formations expected to be 150°C+ at approximately 3.5 km. As drilling costs are reduced these formations could be considered for future geothermal exploration opportunities for both deep direct-use and electrical production (Figure 3). Two salt pillows, one on the west side of the 10 km radius and another directly north along the 20 km radius are an extension of the deeper Louann Salt just above the basement rocks (Figure 2).

3. Data Compilation

Reservoir productivity was calculated as two separate entities: the thermal regime and the reservoir flow properties. The primary parameters needed for the thermal regime were temperature as a function of depth and thermal conductivity to calculate surface heat flow. The reservoir flow properties needed were reservoir volume, porosity, and permeability. The SMU Team first compiled all publicly available data (Richards and Blackwell, 2012; Blackwell et al., 2014) starting with well data uploaded into the National Geothermal Data System (NGDS), which included temperature-depth, thermal conductivity, surface heat flow, and historic well fluid production tests. Initial geologic reservoir properties were collected from publications discussing the greater regional oil and gas fields (fields near the study area, but not necessarily within the 20 km radius study area). These oil field publications included data such as average field porosity, permeability, produced thickness, average depth, and sometimes included pressure information, temperature, and historic production volumes. The main fields with published reservoir data include: Bethany, Carthage, Danville, Dirgin, Hallsville, Henderson, Lansing North, Oak Hill, Scoober Creek, Waskom, Whelan, Willow Springs, and Woodlawn (Figure 4).

There were only 121 existing surface heat flow data points within the 20 km radius study area at the beginning of this feasibility study, but approximately 2000 existing well sites; therefore, additional oil and gas well data were downloaded to increase the number of temperature-depth data points and obtain geophysical well logs for mapping the formation tops. These additional wells were downloaded from DrillingInfo.com (.Tiff format) and the Texas Railroad Commission (.LAS and .Tiff format). Within the 20-km radius there are now approximately 1400 heat flow points and within the 10-km radius there are approximately 500 sites (Figure 5).

XTO Energy donated well data as digital files (.LAS) for us to use for higher resolution reservoir analysis.

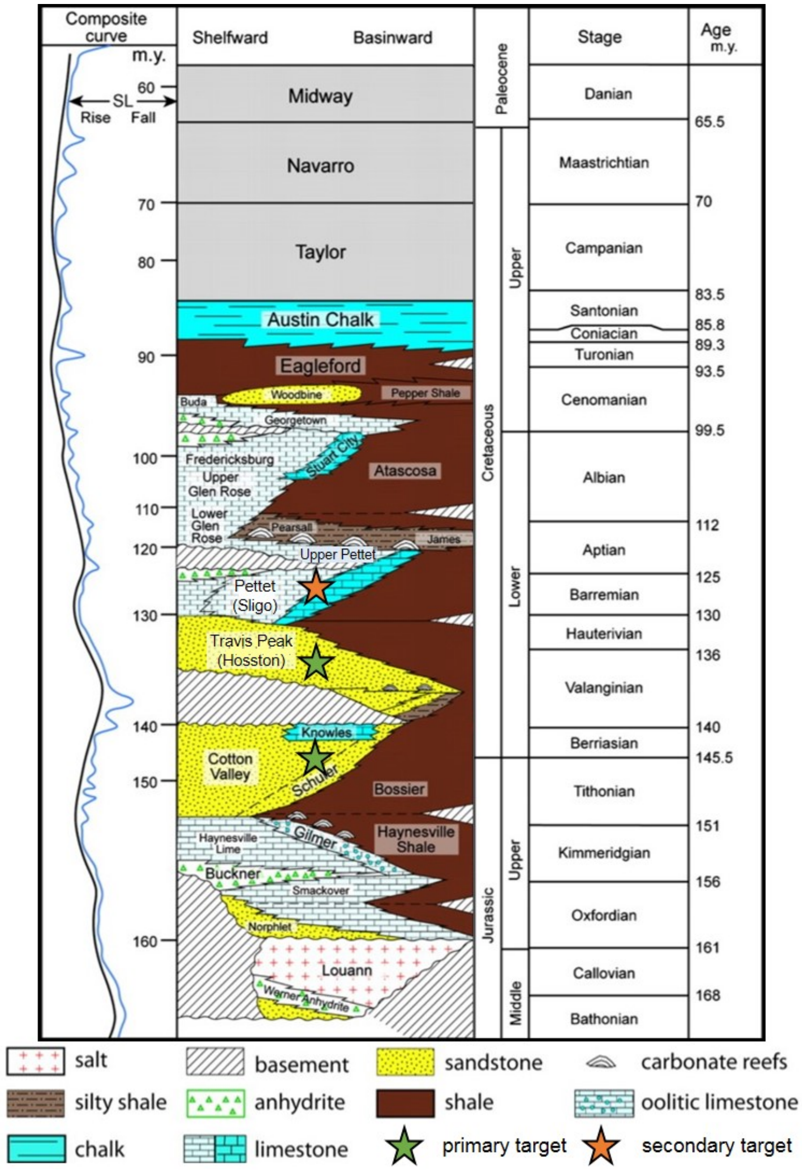


Figure 3: Generalized lithology-stratigraphic section for East Texas (modified after Hammes et al., 2011). The section shows how the rock type varies spatially for a given time period depending on proximity to the shelf (near shore shallow water) or basin (offshore deeper water). Target formations are marked by stars within the Upper Jurassic and Lower Cretaceous.

4. Methods

This feasibility study is a conglomeration of different methods developed during the SMU Google Temperatures-at-Depth project (Blackwell et al., 2011), National Geothermal Data

Systems (NGDS) collaboration (Blackwell et al., 2014; Stutz et al., 2012; Uddenberg 2012; Zafar and Cutright, 2014), Geothermal Play Fairway Analysis (GPFA) research (Camp et al., 2018; Jordan et al., 2017; Smith, 2016) and smaller related projects. Below are brief descriptions of how and why these previous research projects are incorporated.

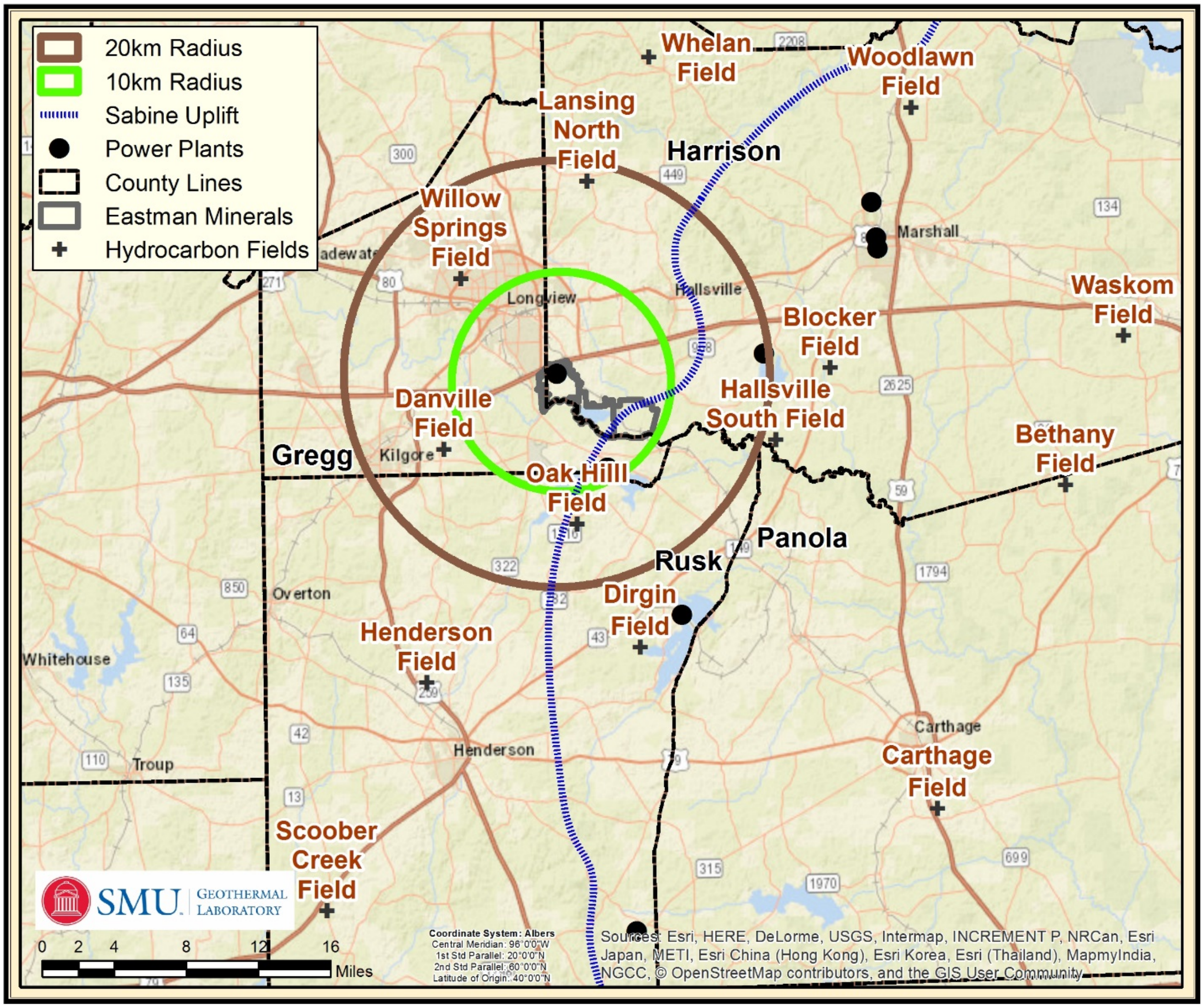


Figure 4: Map of Oil and Gas Field Locations. Plus symbol is at approximate center point of contributing well data for each field.

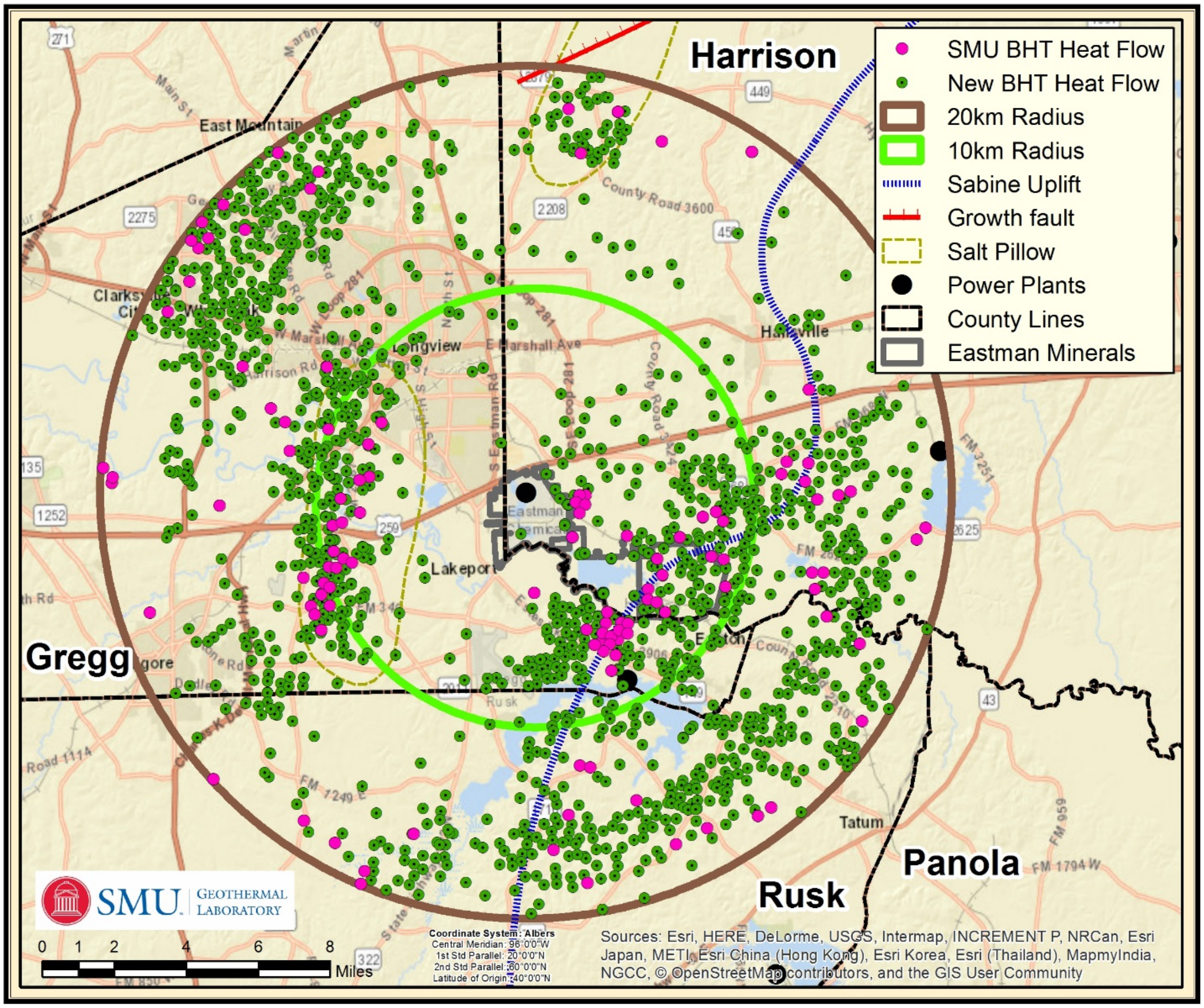


Figure 5: Bottom Hole Temperature Derived Heat Flow Locations. The area contains no previously published equilibrium temperature logs and only a low number of BHT derived heat flow sites (pink sold circles); new BHT measurements (green circles with black dot) are publically available well logs used to collect additional BHTs to improve the resolution of the thermal regime calculations. The depths of these wells vary from 1000 meters to 4400 meters.

4.1 Heat Flow, Temperature-at-Depth, Heat-in-Place

The surface heat flow calculations follow the previous work by Blackwell et al. (2011) for the U.S. and the updated codes written by Cornell (Smith, 2016; Smith and Horowitz, 2016). Well-site specific temperatures generate the thermal gradient by subtracting the surface groundwater temperature (Gass, 1982) from the site well-log header's bottom-logged depth temperature (aka Bottom Hole Temperature, BHT). The thermal conductivity model incorporates published formation estimates for the Gulf Coast (Pitman and Rowan, 2012), and for the deeper Louann salt formation, the Anadarko Basin evaporite value was used (Gallardo and Blackwell, 1999). The thermal conductivity for each well is given a weighted average value to use in the heat flow calculation, i.e., thermal conductivity times gradient. From the site by site surface heat flow values, the dataset is gridded to depict a regional heat flow map (see Figure 8 under Results). For additional understanding of parameters and calculations see MEMO in the reference section.

The Temperature-at-Depth (TaD) calculations are an add-on to the heat flow calculations. It is helpful to be able to generate layers depicting the depth to a specific temperature or layers representing what the temperatures are at a specific depth. Examples are using these calculations for total heat capacity of a volume (height times area times temperature), or drilling expenses (drill cost per meter times depth to a specific temperature isotherm) are two possible applications of the temperature-depth calculations (Stutz et al., 2012). The Stutz et al. (2012) code is designed to determine temperatures to the basement formation and incorporates surface heat flow, radiogenic heat production, sediment thickness, and known BHT. The results of these calculations are used for the inputs in the GEOPHIRES model and others related to reservoir potential. For additional understanding of parameters and calculations see MEMO in the reference section.

Heat-in-Place calculations follow the Zafar and Cutright (2014) use of ArcGIS raster data previously generated in the Heat Flow and Temperature-at-Depth calculations. The Heat-in-Place outputs provide the total thermal energy stored within a defined 3D volume. This is not the total amount possible to extract, as that changes with new technology or the life span of a project. These calculations are instead based on cell size, it can then be changed to examine different reservoir sizes based on project consumption, surface mineral right leases, or direct use application requirements.

In reviewing the heat flow, temperature-at-depth, and heat-in-place values we took into consideration the two large salt pillows shown on the Tectonic Map of Texas (Ewing et al., 1991) (Figure 2). Although these are both outside the primary area of interest (closest one west of Longview city limits), we reviewed their potential for a thermal impact in our overall calculations. Two factors were reviewed with respect to the vicinity over the salt pillows: 1) a change in elevation (BSL) of formation tops, and 2) change in trend of temperatures in the area. Neither of these factors show any direct impact of a large salt body. Therefore, it was determined that these are too deep (below the Haynesville (Hammes et al., 2011)) and too small of structures to impact this study. If the results were applied to the other power plants in the broader area being mapped, these are even further from the mapped salt pillows than the Eastman Chemical mineral land area.

4.2 Reservoir Potential Calculations

There are three reservoir models (Reservoir Productivity Index, Reservoir Flow Capacity, and Lumped Parameter Model) used to determine and compare the results for the potential reservoir characteristics. A fourth method of building cross-sections through the prime area of interest will be completed later in the study. Here for each method, there are detailed Memos explaining the codes, parameters, and files used for a step-by-step process of how the results were accomplished. These Memos will be included in the Final Report uploaded by NREL for this feasibility study. Each method is briefly described below for an understanding of the results.

4.21 Reservoir Productivity Index and Reservoir Flow Capacity

For the Reservoir Flow Capacity (RFC) and Reservoir Productivity Index (RPI) models we collected raw data from oil and gas producing zones within regional fields to gain the extremes of temperature and formation parameters (most commonly available are thickness, porosity, permeability, and water saturation). As the producing zone for the oil and gas industry is usually only the upper portion of the liquids in the formation, to improve on the possible reservoir thickness, we reviewed the injection data for length of casing perforations for a different thickness constraint within the formations. The maximum thickness possible for each formation is the average of the total thickness across the area of interest.

These reservoir parameters are used to calculate the Reservoir Flow Capacity (RFC). The RFC is based on the permeability in mD (k) times reservoir thickness in meters (H) of each formation within a field and is a simple comparison of potential total fluid flow. Camp et al. (2018) assigned reservoirs as favorable with RFC of ≥1000 mD-m.

The Reservoir Productivity Index (RPI) calculation is designed to look at the productivity based on additional input parameters for a field. Values less than an RPI of 10 kg/MPa-s represent reservoirs needing stimulation. The higher the RPI the more likely a well is to be productive in a specific field/formation.

A series of Monte Carlo calculations incorporate the above data using a code initially developed by Camp et al. (2018) and outputs both RPI and RFC. The updated code now input from and output to related NGDS Content Models (data input – Hydraulic Properties Observations, data output –Geologic Reservoir). The code also outputs the RFC for each geologic unit at defined locations (fields). The Monte Carlo simulation of RPI and RFC provides the 10^{th}, 25^{th}, 50^{th}, 75^{th}, and 90^{th} percentiles along with their Coefficient of Variation (CV) to analyze the probability of the reservoir characteristics. The lower the CV the smaller the standard deviation relative to the mean and are more predictable RFC and RPI values.

The RPI formula is shown below (Equation 1) with permeability (k) in meters squared, formation/field thickness (H) in meters, viscosity (μ) in pascals per second, D the distance between the injection and production wells in meters, and the wellbore radius (r_w) in meters.

$$RPI = \frac{2\pi k H}{\mu \ln \frac{D}{r_w}} \tag{1}$$

A few assumptions were made for variables in the RPI formula. Since the wellbore radius and the distance between the injection and production wells are not current feasibility study values, D was set equal to 1000 m and r_w was set to 0.1 m, following values used by Camp (2016). Water viscosity is a function of temperature and pressure, which vary depending on the specific modeled formation. For simplicity, we used Camp's (2016) value of μ = 0.000299 Pa-s for water at temperatures greater than 90°C because that is the minimum temperature being examined within this study. Most of the data sources did not specify if the recorded permeability values were the permeability of gas or water; therefore, no correction was made to these values. To create random values for the simulation that reflect the variables' most likely occurrence, a log-normal distribution was used for permeability and a triangular distribution for thickness.

4.22 Lumped Parameter Model

The Lumped Parameter Model (LPM) follows the work completed by Matthew Uddenberg (2012) as part of his University of Texas Austin Masters of Science Thesis and the Bureau of Economic Geology (BEG) NGDS research. The LPM uses reservoir parameters for total reservoir potential and computations for the estimated power output, and decline curves for pressure and temperature based on production rates. This feasibility study is a deep direct-use study, not power production, therefore reservoir temperatures in the Longview area are lower ($<$ 120°C) than those necessary for a viable power project in Texas ($>$120 °C). The model also outputs economic results as a subroutine if these related parameters are supplied as input values. For this portion of the feasibility study, our focus was on the reservoir potential and did not include the economic subroutine.

As in the other models run, this code focuses on the initial parameters of the formations: pressure, temperature, volume, and porosity. The intrinsic rock properties are based on the rock type (shale versus sandstone), and then the related heat capacity, fluid viscosity, and density. The model allows the user to fluctuate the permeability, production time and flow rates, temperature change, and distance between well bores for production and injection.

Using the equations and code from Uddenberg (2012), we calculated the total heat in place (Q_{tot}) (Equation 2) for each formation of interest within the 10 km (A, area), utilizing formation thickness (h), average density (p_{av}), temperature start (T_i), and temperature brine reinjected (T_o). Next the maximum energy output (*m*W) that is possible was determined based on surface and formation temperature drawdown and length of time (Equation 3). Input variables include those from equation 2 plus the efficiency of plant (y), thermal recovery factor (r), average heat capacity (C_{av}), volume (V), and length of formation (L_f). Initially, we are focused on total MW_t potential for the direct use application at Eastman Chemical Company. As time allows, Equation 3 will be used as a secondary check to NREL's GEOPHIRES calculations.

$$\mathbf{Q_{tot} = A*h*p_{av}*(T_i - T_o)} \tag{2}$$

$$mW = \gamma r \int p_{av}\, C_{av}(T - T_o)dV/(L_f * years * 10^6\,(\tfrac{Joules}{mW}) * 3.05 * 10^7) \tag{3}$$

4.23 Cross-Sectional Model

Three purple cross-section lines (A-A', B-B', C-C') (Figure 6) define the area of most reservoir focus to depict a pseudo three-dimensional model of the reservoir at depths of the Trinity Group and Cotton Valley Group for the 10 km area. The lines overlap within the Eastman Chemical minerals land. The cross sections are extended beyond the 20 km radius for us to understand the broader geology for the purpose of extrapolation to the nearby power plant facilities (Figure 6). The cross sections connect digital .LAS file formats and well sites with color raster logs for additional ability to digitize the geophysical lines, allowing us to extract additional parameter details for computational purposes.

In addition to mapping formations for the cross sections, the geophysical logs will be used to estimate reservoir properties (porosity, permeability, and water saturation) in a different manner (Tittman, 1987). The electrical resistivity, neutron porosity, density, spontaneous potential, and gamma ray logs are used to calculate where there is water (fresh versus salt) and potential for fluid production and injection. This work is an important refining of the reservoir models because the previously mentioned values extracted from publications are specifically for the hydrocarbon zones within the formations. The hydrocarbon zones are only a small portion of the total rock volume accessible for fluid production to extract the heat and reinjection of these fluids, and intentionally avoid large water zones, which is the primary target here. Using the full geophysical log is included as a way to calculate the expected reservoir parameter values to extend beyond the perforation zones that are currently published.

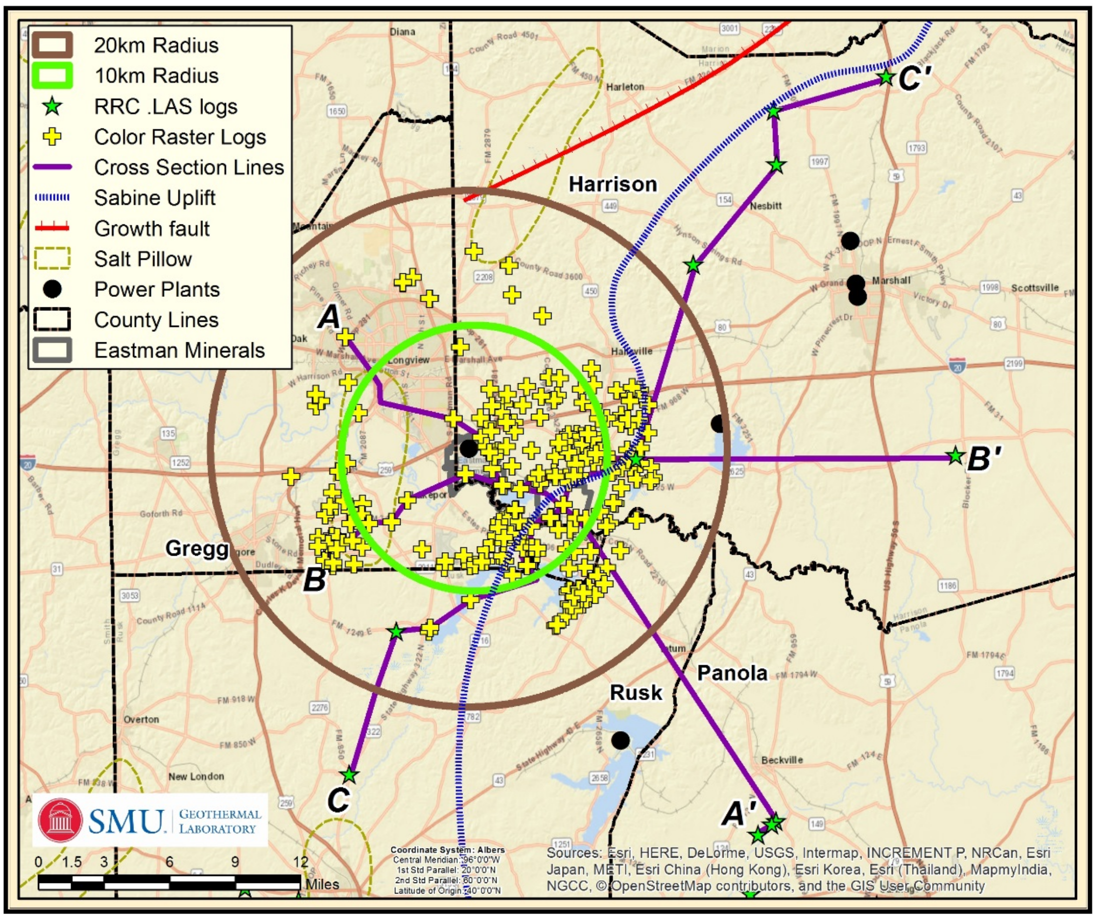


Figure 6: Cross-Section Lines through Wells of Interest. Green stars locate publicly available digital .LAS geophysical logs and yellow crosses are well sites with colored raster geophysical logs. These wells of interest were used to determine cross-section lines A-A', B-B' and C-C" that are being considered for further evaluation of the possible reservoirs. The cross-section lines extend beyond the 20 km circle to review the broad geologic context of our study area and that of near-by power plants.

5. Current Results

Comparing data from different fields and rock units highlights the general patterns that can then be used to assess the probability of certain rock properties on or near the Eastman Chemical property to occur and provide the potential to determine if drilling is appropriate as a next step.

The gas fields in this area produce from low permeability and porosity zones (Ahr et al., 1984; Becker et al., 2010; Vavra et al., 1991). The deeper Cotton Valley formation is typically hotter (from approximately 117 to 130°C), yet permeability is primarily 0.01 to 1.0 md and porosity less than 12% (Table 1). The shallower Trinity Group (Pettet /Sligo/Rodessa, and Travis Peak/ Hosston) contains much more variability, 0.01 to 2000 md permeability and 1 to 23 % porosity, yet has lower temperatures (from approximately 98 to 117°C) as expected with the shallower depths. The shallower formations are being considered though because of increased ability to produce larger volumes of water and extract enough heat before reinjection.

Table 1. Estimated reservoir characteristics based on published and well data. Geologic units are in order of depth and age.

Geologic Unit Name	Other ID	Porosity (%)	Permeability (mD)	Thickness[+] (m)	RFC*	RPI**
Pettet Limestone	10 km AVE	14	110	38	4176	9
	10 km MAX	21	900	100	89964	200
	10 km MIN	11	4	2	8	0.0
Travis Peak Sandstone	10 km AVE	13	65	383	24863	55
	10 km MAX	15	90	550	49427	110
	10 km MIN	8	15	200	2984	7
Cotton Valley Sandstone	10 km AVE	7	0.3	120	30	0.1
	10 km MAX	12	4	450	1770	4
	10 km MIN	2	0.01	25	0.1	0.0

*** RFC = Reservoir Flow Capacity**

****RPI = Reservoir Productivity Index**

[+] **Thickness is an average based on the difference between formation tops/bottoms (MAX) and injection perforations (AVE) and hydrocarbon productivity zones (MIN).**

5.1 Heat Flow and Heat-in-Place

One of the first steps in calculating heat flow is determining the regional geothermal gradient for the study area (Figure 7). The gradient (°C/km) is from BHT to surface and smoothed to show trends, which generally increases to the East, corresponding to the Sabine Uplift increased heat production and decrease in sediment thickness. The gradient map is a way to confirm that the salt pillows (Figure 7) are not influencing the nearby temperatures to the sides or above them.

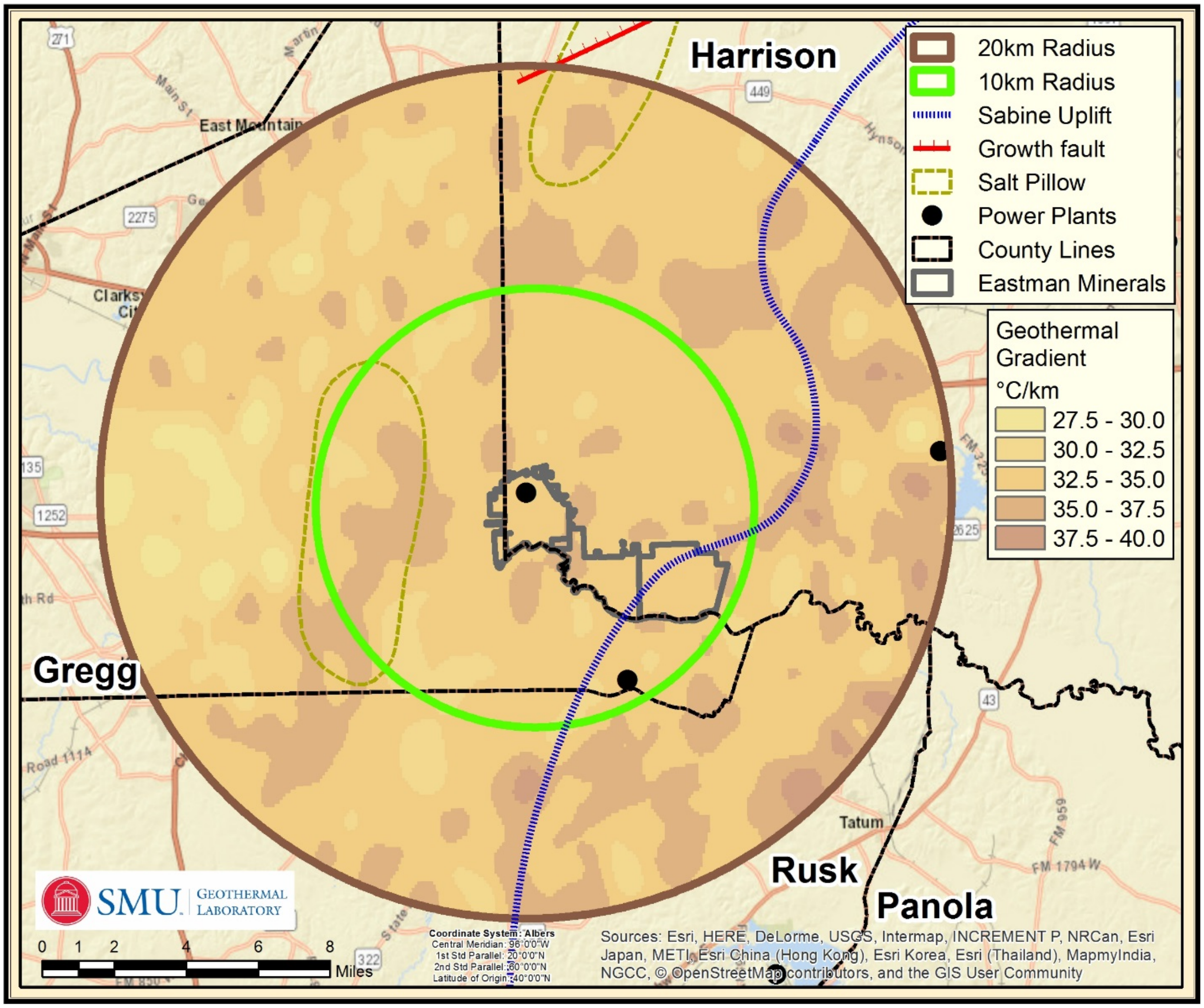


Figure 7: Geothermal Gradient of the Feasibility Study Area. The primary tectonics and salt pillow locations are overlaid the gradient map. The gradient contour interval is 2.5 °C/km with a general trend of warming to the East.

The regional heat flow for this 20 km radius area varies from 65 to 95 mW/m^2 (Figure 8). These values are on average about 5 to 10 mW/m^2 higher than the previously calculated heat flows for the 2011 Geothermal Map of United States (Blackwell et al., 2011). The primary reason for the increase is the thermal conductivity values used are specific to the formations within the Gulf Coast (Pitman and Rowan, 2012) unlike the U.S. map that used similar values for all basins related to the type of lithology or a generalized model (Blackwell et al., 2011). There is some variability in the heat flow, although similar to the gradient, the values tend to be highest in the eastern half. A heat flow of 55 to 65 mW/m^2 is considered normal for the Great Plains, therefore there is more stored thermal energy in the Longview area than in many portions of the Central United States.

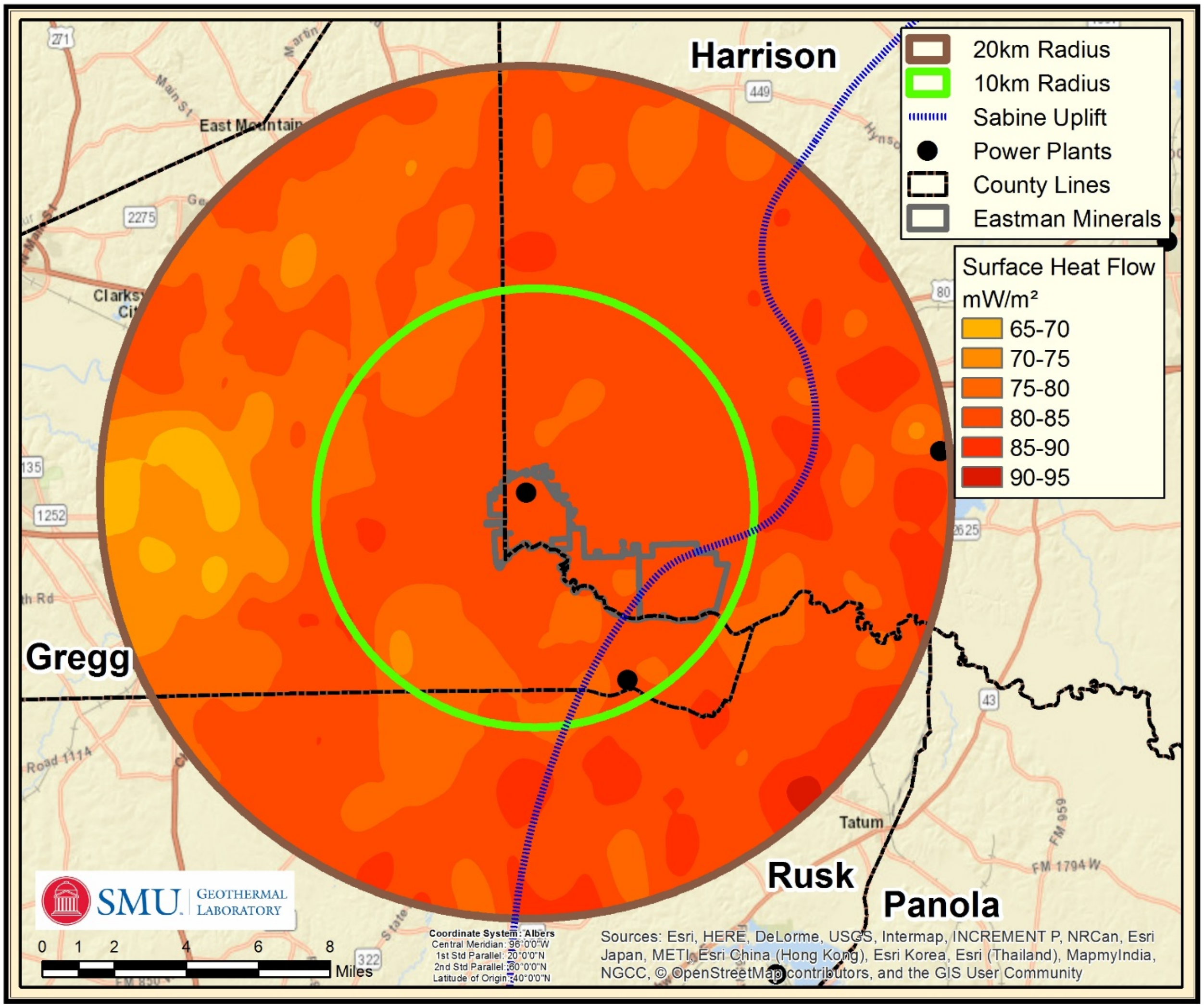
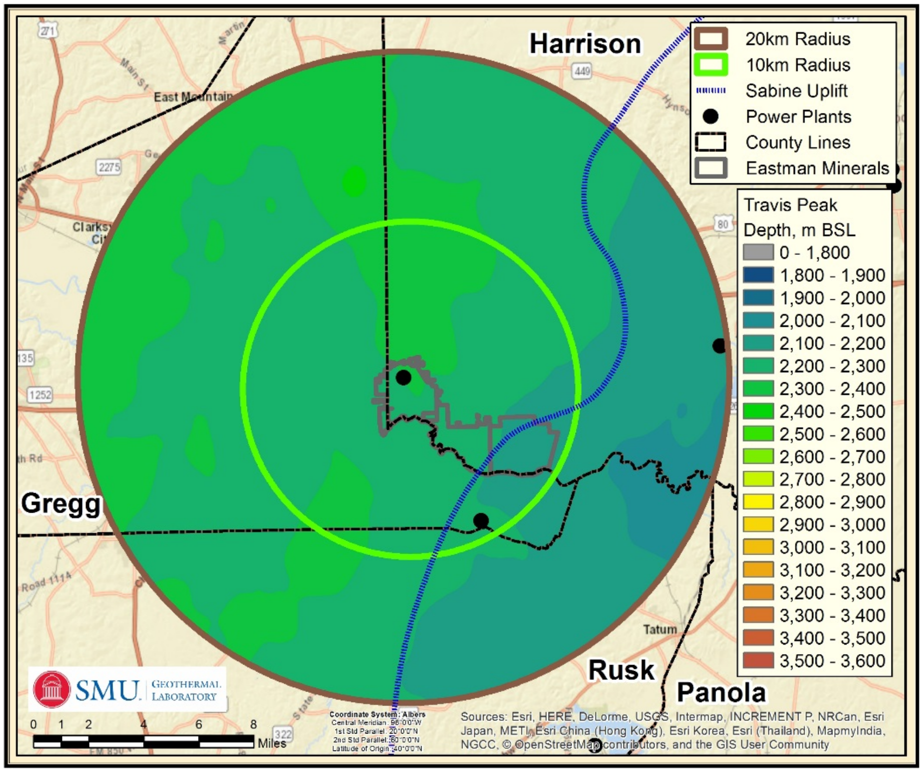


Figure 8: Surface Heat Flow of the Feasibility Study Area. The surface heat flow contour is 5 mW/m^2 with a general trend of higher heat flow to the East.

This geothermal exploration feasibility study is focusing on extractable heat-in-place for direct use rather than electrical consumption. The goal is to determine how much thermal energy is stored within the specific formations and estimate the amount of fluid flow possible. Heat Flow is part of the stored thermal energy determination. The primary (Rodessa, Pettet, Travis Peak, Cotton Valley) formation thicknesses are used to calculate the volume. The Pettet and Travis Peak are considered top candidates for this feasibility study based on their total thickness from the Railroad Commission Tops (Travis Peak, Figure 9) and from their production and injection intervals (Table 1). The Top of the Travis Peak formation deepens to the west (2,300 m) along the 20 km circle. This is where the East Texas Basin oil field (the first one in Texas) is located. The oil field is shallow; therefore many western oil wells are not drilled into the Travis Peak in that field creating lack of data control for contouring (Figure 9 bottom). Longview city proper, and lack of other area fields creates other data gaps where we used interpolation and wider grid spacing.



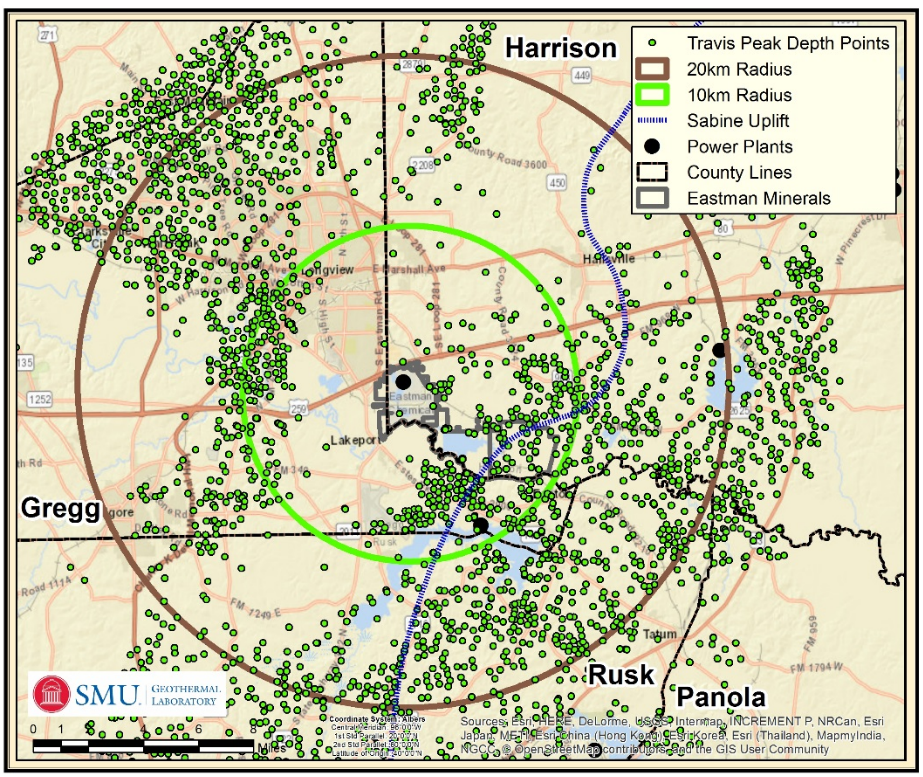


Figure 9: Travis Peak Average Depth to Formation Tops in meters (upper map) and Oil and Gas Well Locations (lower map). Top of the Travis Peak Formation in the NW quadrant is approximately 2,500 m depth then shallows toward the east to 2,000 m depth below sea level. The well locations represent only wells drilled into the Travis Peak, thus more wells exist at the surface than shown here.

As part of the feasibility study there are different models for determining the potential for stored thermal energy at different reservoir depths. An example of the heat-in-place estimation technique most recently updated by Zafar and Cutright (2014) is shown here as a heat density map in Figure 10. For this map the difference between the Travis Peak Top and Cotton Valley Top (i.e., Travis Peak formation thickness) is used as the third dimension for volume (meter^3) to provide heat (joules) for this density calculation (MJ/m^3). Higher values (yellows or 275-300 MJ/m^3) are primarily from higher gradients or thickness increases. There are a few higher heat density areas adjacent to the Eastman Minerals property of interest. Locations such as these can be looked into further with the details of the well logs along the cross-sections.

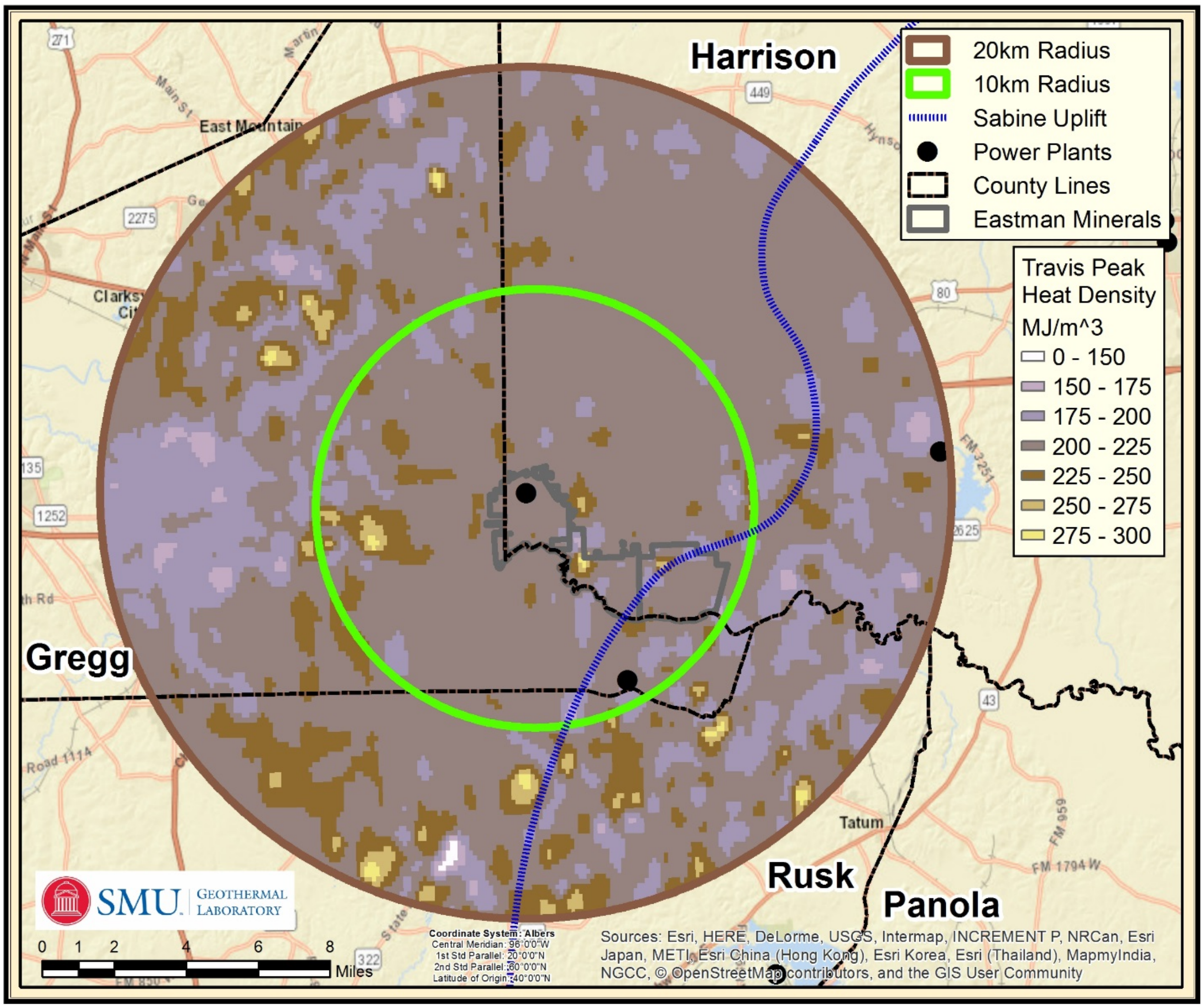


Figure 10: Travis Peak Heat Density Map based on the model of Zafar and Cutright (2014). This map represents the amount of heat contained in a slice of Earth, e.g., Travis Peak formation. The center of the map, where the Eastman Chemical mineral rights are located (dark grey outline), is within a zone of 200 to 225 MJ/m^3. This map also shows the potential for variability even at formation scale.

6. Conclusions

This research effort is providing an opportunity to look in more detail to a broader area of eastern Texas considered by many as having elevated heat flow and therefore increased potential for geothermal resources (Negraru et al., 2008). It is also an opportunity to use the data collected during the development of the National Geothermal Data System and continue to improve upon it. An area of 20 km radius is considered small in terms of the usual geothermal resource assessments of Blackwell et al. (2011), Augustine (2014), and even the smaller Appalachian Basin effort by Jordan et al. (2017), yet there are still 1000s of wells drilled in this feasibility study area allowing for a detailed review without having to drill new wells, and all results presented here were produced from data that are publically accessible through the Texas Railroad Commission or the National Geothermal Data System. The numerous oil and gas fields in or near the circle of focus also provided additional understanding of the lithology and depositional environments of each formation of interest.

The data show that there is potential for enough heat at reasonable depths for a deep direct-use feasibility study within the 10 km radius. The additional modeling and the ability to locate the resource within a detailed cross-section will provide more confidence to the decision making process.

There are additional natural gas power plants that overlap with the study area. The results of the research will be an opportunity for these power plant operators to learn more about geothermal resources and if the economics permit, use them to become a more efficient energy provider.

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MEMO SMU DDDU HeatFlowExplanationforEastTexas;
MEMO SMU DDU StepsPythonCodeCalc Q and TaD
MEMO SMU DDU FormationTopMapping;
MEMO SMU DDU ReservoirModelingNotes
MEMO SMU DDU RPI RFC HydraulicPropertiesModel

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