Co-Produced and Low-Temperature Geothermal Resources in the Williston Basin

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ABSTRACT

The University of North Dakota has conducted two projects for the Department of Energy to assess and demonstrate the feasibility of generating electricity using co-produced and low-temperature geothermal resources in the oil and gas producing areas of the Williston Basin in North Dakota. The co-production project was initiated with industry partner, Encore, Inc. in the Eland-Lodgepole field near Dickinson, North Dakota. The field consists of 12 oil and gas wells producing approximately 350 gallons per minute of 100 °C saline water at a central location. Soon after project start, Encore was purchased by Denbury who declined to partner in the demonstration project. The assessment phase of the project produced the key result that the widely distributed wells in the main water producing formations, Madison and Red River, cannot be used to concentrate sufficient quantities of water to generate economic amounts of power. However, the rapid development of multi-well pads in the Bakken and Three Forks has led to localized production of fluids at 120 °C to 130 °C. Our assessment indicates that a distributed network of (organic Rankine cycle) ORC engines in the Bakken fields could offset the need for future construction of fossil fuel power plants and a power grid that will be unneeded when the Bakken plays out. The low-temperature demonstration project is located at a Continental Resources (CLR) water flood site in Bowman County, ND where two CLR water supply wells supply the Davis Water Injection Plant a combined flow of 875 gallons per minute at a temperature of 98 °C. The demonstration project is designed to generate 250 kWh of power using two 125 kW Access Energy ORC engines. The water flood operation at the CLR site adds a new perspective for geothermal development in sedimentary basins in that the water supply wells were completed as kilometer-long open-hole laterals which greatly increases the volume of water that can be produced.

Introduction

Capturing the heat in the large volumes of fluids produced from oil and gas operations has been a promising concept for geothermal development for the past decade (Erdlac and Swift, 2004; McKenna, Blackwell and Moyes, 2005; Blackwell, 2006; Johnson and Schochet, 2007, Augustine and Falkenstern, 2012.) Using co-produced fluids at temperatures sufficient for power generation in binary power systems could produce up to 0.451 EJ or 125 TWh of power (Idaho National Engineering Laboratory, 2006), and there have been significant efforts to promote this concept. Southern Methodist University (SMU) has hosted six conferences on Geothermal Energy in Oil and Gas Fields between 2006 and 2015, the National Renewable Energy Laboratory (NREL) has conducted analyses of the electrical power that could be generated from co-produced water (Augustine and Falkenstern, 2012), and the Department of Energy Geothermal Technologies Office (GTO) has funded demonstration projects (Gosnold, Mann, and Salehfar, 2010, 2013, 2015.) In spite of the interest shown at the well-attended SMU conferences and by the efforts of NREL and GTO, the only active geothermal oil field project at present is the DOE low-temperature demonstration project in North Dakota (Gosnold, Mann, and Salehfar, 2015.) Reasons for the lack of development are partly economic and partly infrastructure related. The economic reasons could be summarized as follows:

1. This is a long term investment that has little return compared to the revenue gained by producing oil as fast as possible while the price is high.
2. The power industry is skeptical that it would result in significant revenue.
3. Large, 10s of MW, systems are not feasible and small systems are marginally economic as a revenue source for the geothermal power industry.

The infrastructure reasons affect economics and one factor dominates all others. That is, although the total volume of co-produced fluids is large (Curtice and Dalrymple, 2004), the volume of fluid produced from a single well or even ten wells in a multi-well pad can generate only a few hundred kW of power. Other infrastructure factors include engineering and construction costs, agreements with the local electrical power providers, legal issues and access to the power grid, and fluid handling. Another factor is that the petroleum industry, whose cooperation and collaboration are essential, has little interest.

The University of North Dakota (UND) has been involved in two demonstration projects, one for co-produced fluids and one for low-temperature resources. The data and information gathered in these projects provides insight into solutions for overcoming the factors that have delayed oil field geothermal development.

UND Co-Produced Project

The site selected for the co-produced project was the Eland-Lodgepole Field near Dickinson, ND (Figure 1). The Lodgepole Formation is the basal member of the carbonate and evaporate dominated Madison Formation (Mississippian) and is notable for the occurrence of reservoir forming "Waulsortian Reefs." The Eland Lodgepole Field consists of 12 oil and gas wells, 5 water injection wells and one disposal well. Water temperature at the collection site is slightly greater than 100 °C and flow averages more than 350 gallons per minute. Data from North Dakota Industrial Commission Oil & Gas web site (https://www.dmr.nd.gov/oilgas/) show that the field was in primary recovery mode from December 1994 through February 1997 and has been in secondary recovery mode by water flood since March 1997. Co-produced water has averaged 345,875 bbl per month (331 gallons per minute) since 2008 and total fluid (oil + water) production has averaged only 367 gpm since 2008 due to the wells being pumped slowly to reduce the Water to Oil Ratio (WOR). The WOR has increased steadily from an initial value of 1:1 to a 15:1 at present. Fluid production in bbls per month for the field show a typical decline in oil production and increase in water production over time (Figure 2). Water from the 12 producing wells in the unitized field is collected at a central location, thus the field has good potential for binary geothermal power development.

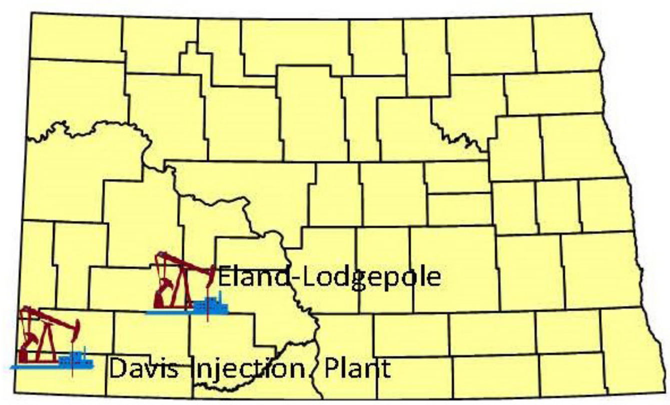

Figure 1. Locations of the UND geothermal demonstration projects.

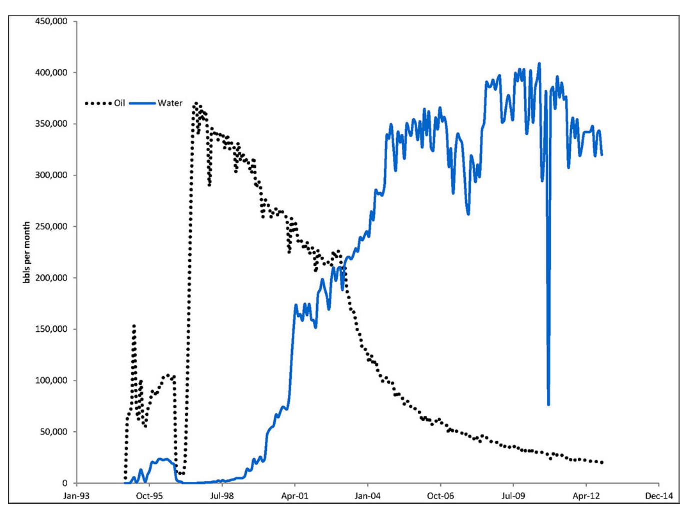

Figure 2. Oil and water production of the 12-well Eland-Lodgepole Field.

Eland-Lodgepole was selected for the co-produced geothermal demonstration and the Davis Injection Plant was selected for the low-temperature demonstration.

Unfortunately, during the first month of the project the original industry partner, Encore, Inc., was purchased by Denbury who later decided not to pursue this project due to complications with the site location and its proximity to Patterson Lake which is the water supply for Dickinson, ND. Consequently, the co-produced project ended with only a feasibility study.

UND Low-Temperature Project

The UND Low-temperature demonstration project is located at a Continental Resources (CLR) water flood site in Bowman County, ND (Figure 1). The project uses water from two CLR water supply wells, Davis 44-29, API No: 33-011-90121-00-00 and Homestead 43-33, API No:33-011-90127-00-00. The Davis well was drilled vertically to a depth of 2,163 m and horizontally 1,494 m in a high-porosity zone of the Lodgepole Formation (Miss.) for a total drill length of 3,658 m (Figure 3). The Homestead well was drilled vertically to a depth of 2,306 m and horizontally 810 m for a total drill length of 3,197 m. Both wells are 8.75 ″ (0.222 m) diameter open-hole laterals with casing only in the vertical segments. The hydrostatic head for the Lodgepole is at ground surface, but the down-hole pumps are set at 735 m and 967 m for the Davis and Homestead wells respectively. The two water wells supply the Davis Water Injection Plant a combined flow of 875 gallons per minute which is used to pressurize the Red River ‘B’ Zone (Ordovician) in the Cedar Hills oil field. Prior to installation of the ORC systems, CLR was cooling the water in two forced-air cooling towers. The water is still being cooled by CLR after passing through the ORC systems for safety reasons prior to injection.

The demonstration project features two 125 kW ORC engines that were provided as cost share by Access Energy. The economics of the system are highly favorable since it is a “piggyback” operation on existing infrastructure. The price for the 125 kW XLT systems used for this demonstration is expected to be $260,000 per unit for similar applications. Installation costs will vary depending upon existing site conditions. According to CLR, the cost of drilling and completing the two horizontal wells was more than $2M each. The Access Energy ORC is designed to sit on a gravel pad with easy connection to the water and electrical lines, but CLR required considerable construction including a concrete pad located 10 m from the water supply and burial of all water and electrical lines.

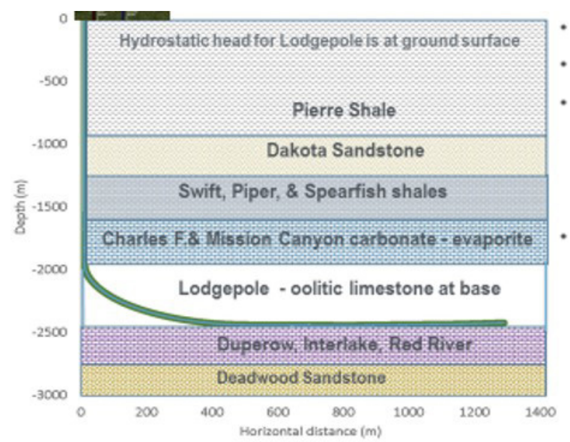

Figure 3. Cartoon cross section of the Davis well at the CLR site.

The ORC System

We analyzed six commercially available ORC systems based on the available fluid volume and temperature to determine the economic feasibility for co-produced and low-temperature geothermal development. The key parameters are available fluid volume, fluid temperature, and ambient air temperature. The analysis favored the ORC system designed by Access Energy, LLC although several of the other systems, e.g., Ormat and Pratt and Whitney (P & W), rated well. The overall efficiency of ORC systems is of the order of 6 to 10 percent with 6 percent being the expected operational performance. Due to innovative design and engineering the Access Energy machines currently operating with temperatures above 120 °C are 14 percent efficient. The Access Energy System, selected for the UND projects is rated to produce 125 kW for fluid temperatures of 95.6 °C and above. The system was developed specifically for the UND demonstration project by modification of a 50 kW system that operated with fluids at 135 °C. Characteristics of the system are: 125 kWe gross, 3-phase, 380 to 480 V L_L, frequency 50.60 Hz, and the working fluid is R245fa. The Integrated Power Module (IPM) contains a turbine expander and generator. It is hermetically sealed and uses magnetic bearings for high-efficiency. The design elements that favor the Access Energy ORC include the use of magnetic bearings and installation of magnets in the fan blades of the turbine. Thus the ORC has only one moving part and achieves a significant reduction in parasitic mechanical load. The power that could be produced at the Eland-Lodgepole site with a P&W PureCycle 200, 8 percent efficiency, is estimated to be 350 kW. We estimate the power production of the Eland-Lodgepole field using Access Energy equipment with 12 percent efficiency would be approximately 568 kW.

Fluid Volumes for Co-Production Geothermal Development in the Williston Basin

To assess the overall geothermal potential of the Williston Basin for geothermal fluids, we acquired fluid production data from the North Dakota Industrial Commission Oil & Gas web site (https://www.dmr.nd.gov/oilgas/). A critical issue in the Williston Basin is that wells are produced slowly to prevent watering out and consequently have low water-to-oil production ratios (WOR). The average WOR for 11,641 wells during July, 2014 in all formations in the basin was 3.4:1. The WOR for the Williston Basin is significantly different from the WORs for basins in Texas, Oklahoma and Louisiana, which can exceed 100:1. The overall WOR for the Williston Basin is skewed by data from 8,150 Bakken wells that have a WOR of 0.77:1. The Bakken (Ordovician/Mississippian) is a tight formation that can only be produced economically by hydraulic fracture of horizontal wells. Even excluding the Bakken, the WOR for the North Dakota portion of the Williston Basin is low, i.e., 9.8:1.

The greatest volumes of co-produced fluids are from the Madison (Mississippian) and the Red River (Ordovician) formations. The Madison lies at depths of approximately 3 km with temperatures of 100 °C to 110 °C. The Red River lies at depths of approximately 4 km with temperatures of approximately 130 °C to 140 °C. The total combined power production for the top ten producing wells in the Madison and Red River formations based on an exit temperature of 70 °C and an ambient air temperature of 10 °C (mean annual for ND) for an ORC with 6 percent efficiency would be approximately 700 kWh and 800 kWh respectively. Thus the volumes of co-produced fluids from individual wells in the Williston Basin are insufficient for economic development.

Unitized fields, which may include several tens of wells with common collection sites, produce enough fluid for development of several hundred kW installations, e.g., the Eland-Lodgepole field. Daily water production from all wells in the Madison and Red River formations in July, 2015 was 3,351 bbl/day and 8,861 bbl/day. Applying the same ORC parameters used for individual wells, we find that the total potential power for the unitized Madison and Red River fields amounts to only 3.9 MWh and 10.7 MWh respectively.

Power Generation from Multi-Well Pads in the Bakken Formation

Our analysis of overall fluid production from active wells, units, fields and formations in North Dakota showed that few sites produce sufficient fluid for significant power production with ORC technology. All sites included in the analysis were conventional oil production sites, and as mentioned previously, the depth of the oil producing formations in the Williston Basin, typically 3 km or greater, requires that wells are produced slowly to prevent watering out. However, oil and water production data from the recent horizontal drilling boom in the Williston Basin reveal that infill drilling between Bakken and Three Forks horizontal wells has created areas where large volumes of geothermal fluids are available on multi-well pads and in unitized fields (Figure 4). Multi-well pads in the Bakken and Three Forks have increased fluid production at an exponential rate since February, 2011 (Figure 5). Production for seven fields among 24 fields shown in Figure 4 reached 409,795 barrels of fluid per month in September, 2014 (Figure 4). Production has dropped with the drop in oil prices and was 326,511 barrels in January, 2015. According to ORC manufacturers (Ormat, Pratt & Whitney, TAS, Fuji Electric) the oil and water mix produced at the well head can be sent through the heat exchanger. Thus the full volume of produced fluid can be used for power generation. Bakken temperatures in the high production areas are on the order of 120 °C to 130 °C depending on depth (Figure 6).

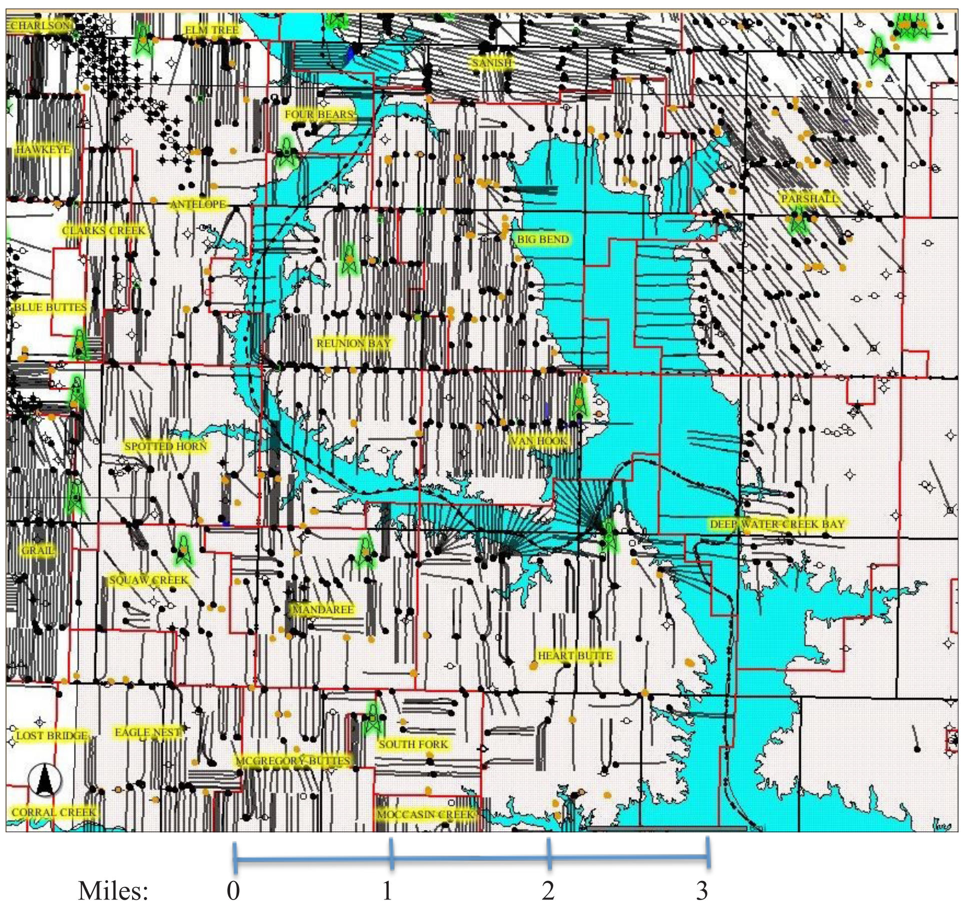

Figure 4. Horizontal wells in Bakken formation shown by black lines which are drawn to scale. Highlighted text identifies individual fields.

A Major Opportunity with Significant Impact

The North Dakota In-dustrial Commission has estimated that approximately 2,600 MW of additional power will be required to produce the Bakken and Three Forks oil by

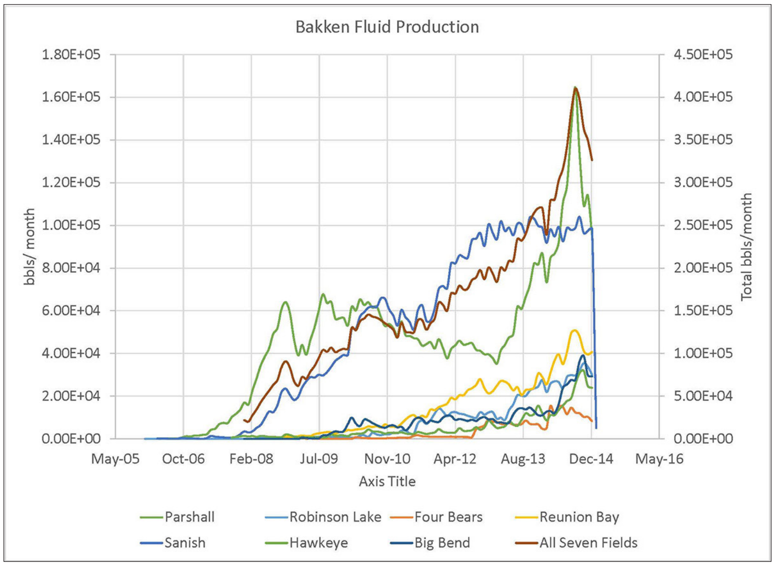

Figure 5. Total fluid production for seven oil fields among the 24 fields shown in Figure 4. Data are from the North Dakota Industrial Commission Oil and Gas website https://www.dmr.nd.gov/oilgas/feeservices/stateprod.asp. Individual field volumes are indicated on the left vertical axis and the total volume is indicated on the right vertical axis.

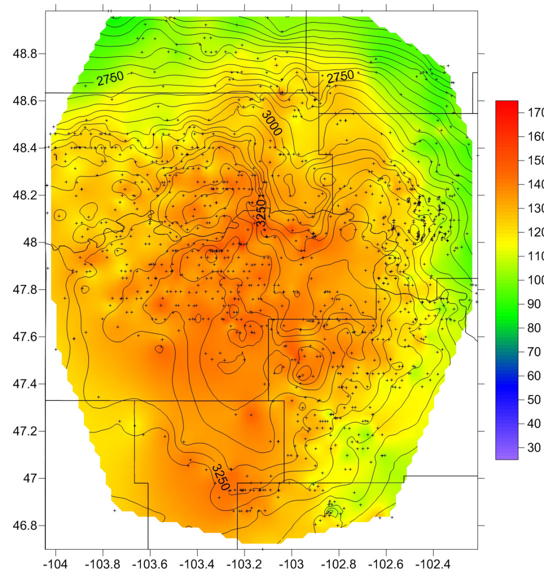

Figure 6. Temperature (colors) and depth (contours) for the Bakken Formation.

2032. The power supply for the North Dakota's conventional oil fields is provided by six coal-fired power plants located along the Missouri River (Figure 7). Currently, the petroleum industry is using diesel and propane powered generators and some operators are using produced gas to drive generators on site. The cost of the on-site electricity is more than five times the cost of electricity from the power grid. The conventional approach to adding new power would be to construct new coal or gas-fired power plants along the Missouri River and build thousands of miles of new transmission lines. The time required to build the new generation capacity and transmission infrastructure could be more than a decade. However, the need for this power and the grid to deliver it will exist only for the life of the Bakken and Three Forks plays which are projected to be 20 to 30 years. When the drilling phase for Bakken and Three Forks development is completed in 15 to 20 years, the oil-field service population of western North Dakota will decline to near pre-boom levels thus further reducing post-boom power demand.

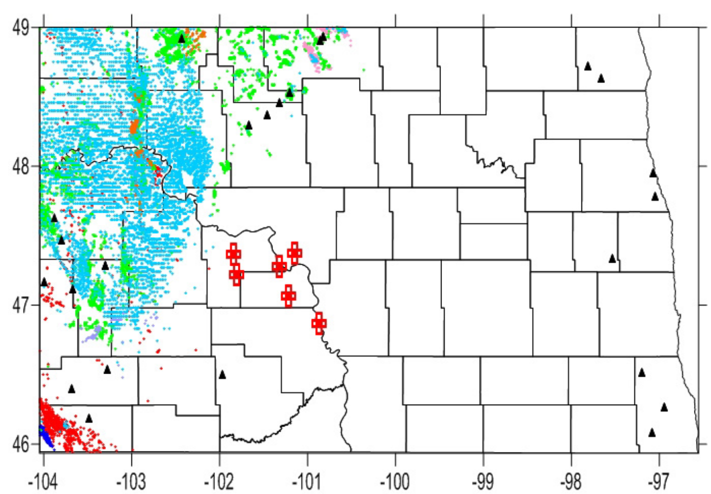

Figure 7. North Dakota oil wells, heat flow sites and power plant locations. Blue dots indicate Bakken-Three Forks wells, red dots indicate Red River wells, and green dots indicate Madison wells. Open red crosses indicate power plants and black triangles indicate heat flow measurements.

Some of the Bakken-Three Forks fields lie within the existing power grid, but many producing fields lie outside the existing infrastructure and rely on propane or diesel fuel to run generators for electrical power. A distributed ORC network could preclude construction of new fossil fuel burning power plants and the construction of a power grid that will be unneeded when the Bakken oil boom ends. Production of the 2,900 MW by geothermal power could avoid generation of approximately 10 million metric tons of CO_2 that would be generated by burning lignite at the six currently operating coal-fired power plants in western North Dakota. We propose that this is a major opportunity to use scalable ORC systems in an oil and gas setting. Adoption of the ORC technology would impact development of the Bakken and Three Forks production in several ways. First, it would provide mobile, low-cost, distributed electrical power to the oil fields that would result in large cost savings for oil production. Second, it would avoid the construction of additional coal-fired power plants and an extensive electrical grid that would become useless when the oil plays end in a few decades. Third, avoiding construction of additional coal-fired power plants would eliminate additional production of approximately 10 million metric tons of CO_2.

Impact of the Low-Temperature Demonstration Project

The water flood operation at the CLR site adds a new perspective for geothermal development in a sedimentary basin. Conventional development would be vertical wells drilled into geothermal aquifers. Drilling open-hole lateral wells within a relatively flat or gently dipping geothermal aquifer greatly increases the volume of water that can be produced. An intriguing possibility would be to drill 6 to 8 laterals radially from a single pad. Three moderately high temperature aquifers in the Williston Basin, the Deadwood (Cambrian), Red River (Ordovician), and Madison (Mississippian) offer potential for this type of development. The rocks are competent and laterals can be open-hole, i.e., without lateral casing, and they are permeable enough to yield significant amounts of water. Figures 8, 9, and 10 were developed from the National Geothermal Data System (NGDS) bottom-hole temperature data for North Dakota and show the temperatures and depths for these formations.

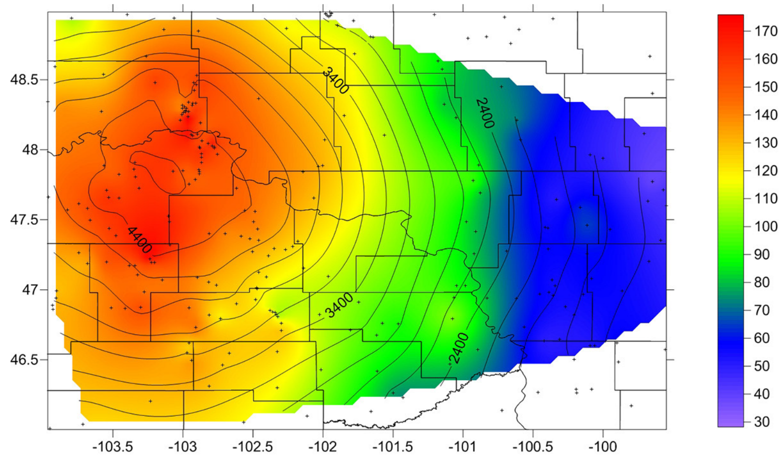

Figure 8. Temperature (colors) and depth (contours) for the Deadwood Formation.

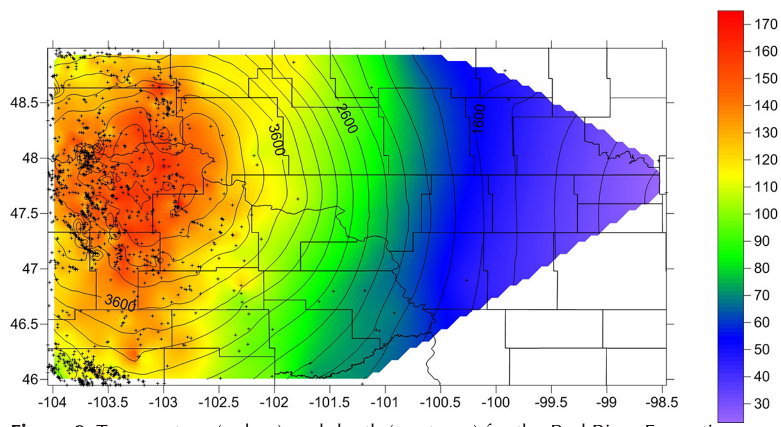

Figure 9. Temperature (colors) and depth (contours) for the Red River Formation.

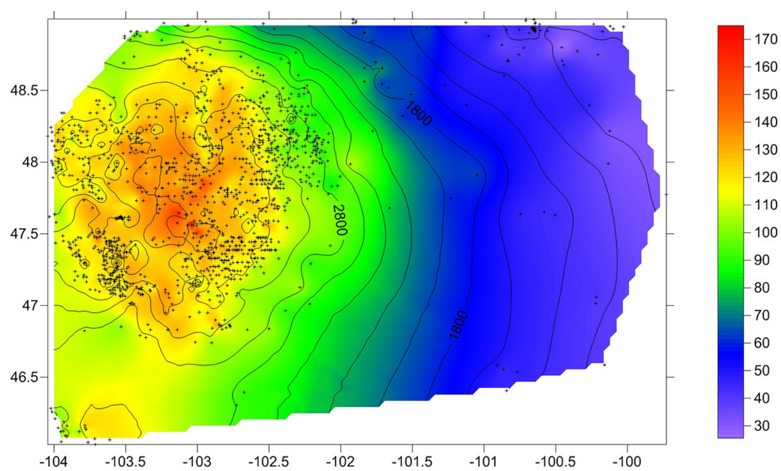

Figure 10. Temperature (colors) and depth (contours) for the Madison Formation.

Conclusions

Generating electricity economically from oil field fluids, either co-produced water or the complete oil and water mix, depends on the capacity to concentrate sufficient volumes of fluid at a power plant site. Formation temperatures in deep aquifers in the Williston Basin are adequate for power generation with binary systems, but the widely distributed wells in the main water producing formations, Madison and Red River, cannot concentrate sufficient quantities of water to generate economic amounts of power. However, the rapid development of multi-well pads in the Bakken and Three Forks has led to localized production of large volumes of fluids at 120 °C to 130 °C and many of the Bakken oil fields could provide enough fluid to generate several hundred MW of power. The water flood operation at the CLR site adds a new perspective for geothermal development in sedimentary basins in that the water supply wells were completed as kilometer-long open-hole laterals which greatly increases the volume of water that can be produced.

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