Geothermal Energy and Waste Heat to Power: Utilizing Oil and Gas Plays
March 13-14, 2013

Conference Summary

There has been a new focus for the geothermal industry to use data from oil and gas fields to develop coproduction of all fluids and in turn extract the heat to generate power. Since the first SMU Geothermal Energy Utilization Conference in 2006, numerous improvements in technology, resource evaluation, and associated economics have occurred. The paradigm shift in the geothermal industry from high temperature - hydrothermal geothermal development in the western US, to today's focus including low temperature - coproduction sedimentary basins, represents the broader interest in pushing the envelope for producing electricity. The expectation of early adoption by the oil and gas community has fallen short, yet interest and expectation that someday it will happen is generally accepted. For the first time, this event combined the surface waste heat to power (WHP) industry and equipment with geothermal energy projects, realizing the need for the oil and gas industry to be able to "kick the tires" on equipment and in the process immediately be able to take advantage of the heat and pressure currently created by their surface equipment. This is of special interest in the oil and gas industry as indicated by Texas Railroad Commissioner David Porter hosting a workshop on using excess natural gas for electrical power on drilling leases, along with other options for on-site power generation such as waste heat energy capture in December of 2012.

Presentations

Opening remarks by the Maguire Energy Institute's **Bud Weinstein** stating "Heat is a terrible thing to waste!" grabbed the attention of the attendees and set the groundwork for covering all aspects of electrical production from heat sources in oil and gas fields. The source could be from surface equipment, referred to as "waste heat", or geothermal heat brought to the surface with oil/gas/water from the reservoir.

Federal Energy Regulatory Commission (FERC) Chairman **Jon Wellinghoff** impressed the attendees during his keynote address with his in-depth knowledge of the geothermal and waste heat resources and applicable technologies. Wellinghoff emphasized FERC's focus to open the generation market to small, independent producers as a method to improve US electrical security, consistency, and ability to deal with natural hazards. Use of geothermal resources, in all forms from home loop systems to direct use to electrical production along with the vast applications for waste heat power are seen by Wellinghoff as part of the necessary energy mix for the US to meet the projected electricity generation needs for the future.

The conference structure took attendees through all aspects of oil and gas field development, representing the vast applications for both geothermal and waste heat to apply to improved field operations. The Environmentally Friendly Drilling Systems Program (EFD) presenter, **David Burnett**, explained how society's acceptance of environmental issues either slows or speeds up changes from innovative technology improvements. Texas A & M University has been the coordinator of the EDF program working with US DOE, HARC, RPSEA, oil/gas companies, universities, national labs, and environmental organizations to develop and improve hydraulic fracturing water use and drilling air emissions. An EDF scorecard was developed and is available to see how any site ranks within the defined criteria. Although geothermal is a smaller industry, as developers move into sedimentary basins for coproduced geothermal or larger scale projects using enhanced geothermal systems, Burnett emphasized the need to engage all stakeholders, public and private, for successful project completion.

Maceij Lukawski, a PhD candidate at Cornell University, compared geothermal drilling to oil and gas drilling costs. Flow rates in geothermal wells are substantially higher than in most oil and gas environments as they start for geothermal typically in the 10,000 BPD range. Well drilling and completion contribute 20 – 75% of the capital investment in geothermal power plants, with enhanced geothermal systems (EGS) having the most costly upfront expenditures because of the deeper depths into harder rock types typical of EGS projects. One difference from oil and gas completions is the cementing of the full annulus because of the pressure and flow rates needed for geothermal projects. Yet the study showed that while the cost of drilling has increased for oil and gas wells, geothermal well costs have leveled off because of improvements in drilling techniques for deeper depths. In fact, at shallow depths (<6,000 ft) geothermal wells are similar to slightly less in cost than an oil or gas well. Lukawski concluded that the geothermal community should not use the oil and gas cost indices to normalize the cost of geothermal wells.

Once the reservoir is drilled, testing is needed; **Randy Normann** of Perma Works discussed how the Hydro-Fracturing Monitoring Tool is able to 'run barefoot' (no heat shield) up to 570°F under high pressure and stay in the reservoir for weeks to years without removing the logging tool. This allows for long term monitoring of changes in the well and reservoir such as changes in injection or production, well connectivity, shut-in testing, reservoir pull down testing, and power plant maintenance. This capability will change our understanding of the life of a reservoir system, pressure fluxes, and how to improve stimulation. Tools capable of these harsh conditions make high temperature EGS projects more viable.

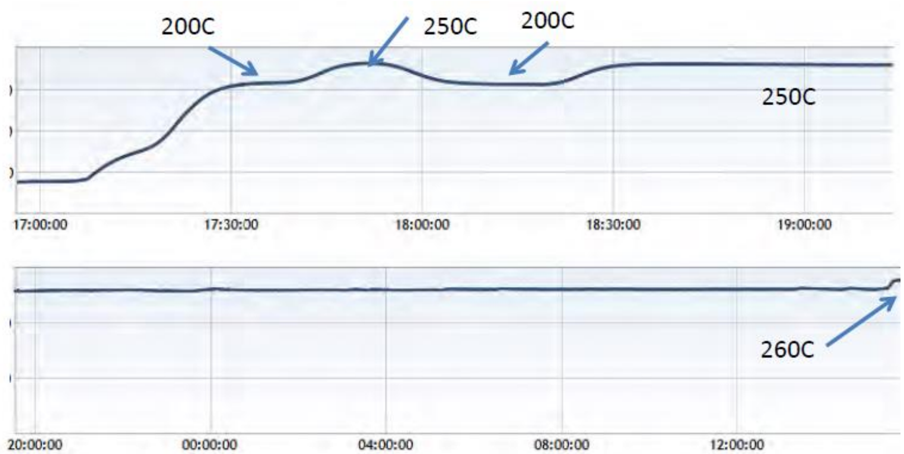

Figure 1. Graph of Perma Works continuous tool temperatures in a well from 17 hr to 36 hr (12:00 on graph).

A key factor driving the rapid improvement in equipment is the ability for manufacturers to meet the needs of both the geothermal and waste-heat to power communities with the same technology. Highlighting the small-scale (<100 kW) environments, **John Fox** of ElectraTherm discussed improvements in their Green Machine after a demo at an oil well in Mississippi (below) and how the same technology is being deployed rapidly into the European market to meet the demand for waste-heat applications. With fluid temperatures in the 190-240°F temperature range, a number of oil and gas operations become viable for waste heat energy capture including coproduced hot fluids, compressor stations, natural gas well head flaring, and amine sweetening plants.


Figure 2. Trailer mounted Green Machine on site in Mississippi for Demo on an oil well.

Mike Ronzello of Pratt and Whitney Power Systems discussed the expected outcome from the acquisition by Mitsubishi Heavy Industries of the PWPS/Turboden ORC equipment line, which ranges from small to medium sized (1 – 10 MW). Ronzello's graphic on efficiency as a function of resource and surface temperature clearly explained the benefit of utilizing the highest heat sources. In his example, similar equipment efficiency can range between 7.5% and 25%, depending upon the source temperature variations, i.e., 195°F and 590°F respectively. This chart emphasizes the importance of the fluid temperature, for every industry using electrical generation technology: biomass, geothermal, waste-heat, CHP etc.

EFFICIENCY	APPLICATION	HEAT CARRIER	HEAT RELEASE
25%	Biomass / Heat Recovery / CSP	Thermal Oil 590° F	Water 80° F
19%	Biomass (CHP)	Thermal Oil 590° F	Water 170° F
19%	Heat Recovery	Thermal Oil 530° F	Water 80° F
16%	Geothermal / Heat Recovery	Water 355° F	Water 85° F
10%	Geothermal	Water 220° F	Water 50° F
7.5%	Geothermal / Heat Recovery	Water 195° F	Air 60° F

Figure 3. PWPS Chart of efficiency versus temperature for different applications.

Trying to contain excitement, **Halley Dickey** of TAS Energy (Turbine Air Systems), showed pictures of their first project on "un-separated mixed hydrocarbons" in California (below) at a mid-stream oil production facility. This project uses ground fluid temperatures of 300°F at 38,000 lbs/hr as part of a steam flood operation. The expander is designed for a 1.2 MW output with actual gross output of 750 kW and a net of 500 kW. It is expected that the potential from this site is 1 MW gross output. The second part of Halley's talk was on a "geopressured integrated hybrid system" that TAS is working on in the Gulf Coast region. Geopressured hybrid systems were proven at Pleasant Bayou in Brazoria County, Texas in the late 1980s with a nominal 1.0+ MW output from heat in the produced water and natural gas burned on site. This project will expand this work by incorporating a binary system with the un-separated mixed hydrocarbon approach along with waste heat recovery from engine exhaust and jacket water, along with other efficiency improvements, for an integrated hybrid system producing 3.5 MW from some 25,000 BPD of produced fluid. Filters will be used for particulate capture should this be necessary.

Figure 4. TAS Energy installed equipment in California on a mixed hydrocarbon well.

For the first time, two newly developed pressure related power systems were publicly viewable on the SMU Campus for the Geothermal Conference. **Kevin** and **Andy Kerlin** displayed their Helidyne planetary expander, named after the similarities to the sun/planets relationship for the machine's extremely high precision rotating system with no belts or gears. This state-of-the art expander is designed to work with natural gas applications such as J-T valves, wellhead chokes, gas processing plants, let-down stations and where possible, geothermal-geopressured wells.

The second system, the Langson Helical Screw Energy Converter, developed by **Richard Langson**, was installed in the SMU Campus boiler room to run the pressure equipment and show how it is capable of installation/removal in just hours. The machine greened-up campus electricity for a few hours during the day of its installation. Capable of using either water or steam it allows for fluctuating flow rates or pressure changes, making it applicable in numerous industry applications, such as geothermal/geopressure, petrochemical, power plants, biogas, and on equipment in the oil and gas field. The system is scalable with sizing variations between 1 to 50 MW. Langson indicated that installation costs could be ≤ $1,500/kW with return on investment in 1.85 years.

Instead of line shaft and submersible pumps for a high water cut well, the Gravity Head Pump is designed for installation without shafts, rods or electrical cables. **Michael Pierce** of Geotek Energy explained how with one additional string in a well the expander-pump is capable of lifting fluids from deeper depths and generating power from high temperature sites. The technology patent is pending and locations to demonstrate the technology are under consideration.

Setting the example in the gas compressor station business is the Canadian Gas Pipeline industry. **Tony Straquadine** of NRGreen Power gave examples of what the US could be accomplishing based on the already successful power generation in Canada. Using ORC technology, the waste-heat to power facilities in Saskatchewan are producing over 20 MW currently, and in Alberta additional sites will bring the total generation to approximately 40 MW. Straquadine conveyed the frustration of the waste heat to power industry (WHP) not being included as a renewable energy equivalent since it's not defined in PURPA or the Energy Independence and Security Act of 2007. This sentiment was highlighted by **Kelsey Southerland** representing the WHP industry trade association, Heat is Power. This energy source is application based for generation capability, therefore the individual states have determined if it will be considered part of the renewable portfolio or considered separate. Being considered part of the renewable package option opens the door to improved financing, electrical purchase price, and tax credits. For the oil and gas industry, through inclusion of surface waste heat in their operations they have an opportunity to improve their energy efficiency and in addition, generate income through renewable energy credits and/or carbon offsets in those states with WHP incentives.

Presenter **Trevor Demayo**, Energy Management Coordinator for Chevron's San Joaquin Valley Operations detailed the competing uses for waste heat in a field before it can be used to generate electricity. The challenges are to find the locations where incremental power is needed, the cost of power is high, or safety/security could be improved with additional on-site electrical generation. Often the changes in the oil and gas industry are driven from regulations in other countries raising the bar to efficiency. Demayo included offsetting building loads for field operators as a first step to reducing known expenses, with little permitting/regulation concerns.

Although the conference focused on generating electricity, the need to off-set heating/cooling of buildings was highlighted by multiple presenters. The use of wells for district heating or green commercial building sites is another substantial resource currently being under-utilized. Two examples highlighted during the conference were a district heating project underway at West Chester University in Pennsylvania discussed by **Denise Gatlin** (WCU) and **James Hootsmans** (Colby College)'s poster presentation on the state of Maine's geothermal potential with economically designed systems for buildings. Other areas in the northeast were discussed with potential for geothermal development with **Andrea Aguirre** (Cornell University) displaying information on bottom hole temperature (BHT) data from over 8,000 wells drilled for unconventional natural gas in Pennsylvania and New York. Temperatures reaching 300°F at depths of 18,000 feet can be utilized for district heating and determined economical.

High water volumes historically may have been the bane of the oil and gas industry, but as **Will Gosnold** (University of North Dakota) showed, in the Williston Basin there is no way to avoid it. High water volumes are exactly what is needed for oil and gas wells to be economically viable for geothermal energy production. By switching focus to producing higher water volumes, geothermal sites are possible using the Bakken, Red River, Madison and Cedar Hills formations. Finding companies to work with on demonstration of equipment has been difficult. Denbury Resources is one company who has stepped-up to help multiple times, allowing for comparison of various companies' equipment for the same field conditions both in the Williston Basin and central Mississippi. Gosnold's 2011/13 presentations compare output efficiency and cost for the power production equipment available. In the US with the 30% Investment Tax Credit, the payback for geothermal energy coproduced in an oil field is typically less than 5 years if the cost of power is 10 cents per kW. As the MWs produced increases, the price/kilowatt hour needed to break even within 5 years drops to as low as 5 cents (**Ronzello**, PWPS).

High water cut is also found to the west in Montana, where **Gary Carlson** reported on work underway on the Fort Peck Reservation. The area has a significant number of wells where coproduced geothermal energy has potential. Some 760 BHT have been analyzed to date with the highest temperature recorded at 278°F; nearly 90 BHTs are equal or greater than 200°F. In addition to working with existing wells, the project seeks to identify the geothermal potential in undrilled areas on the Reservation. Economic analysis toward power generation and greenhouse heating options are part of the project.

Through the increased ability to use BHT data from oil and gas wells, the geothermal industry has studied how to correct the temperatures for drilling impact and then determine the geothermal resource. Discussed at this meeting were the reserves for Maine, New York, Pennsylvania, North Dakota, Oklahoma, Texas, Colorado, and Montana. The outcome of these studies shows that within sedimentary basins there are numerous areas with temperature differentials between surface and current drilling depths possible of generating electricity. In states with high winter heat loads, there is also the ability to use the under 200°F fluids to heat buildings and thus reduce our nation's need for fossil fuel generated electricity. Texas Christian University has received an NSF grant to fund further research on stored energy within sedimentary basins. **John Holbrook**, lead of the SEDHEAT program, emphasized the importance of removing hurdles for the geothermal and oil and gas industries to work together on defining and developing the next generation of combined plays. Fluid flow pathways must be defined at a broader scale as well as more refined for greatest heat extraction. Inclusion in the SEDHEAT program is open to all researchers and companies.

Three posters were shown involving the Mid-Continent resources. The Lower Cretaceous formations in the Denver Basin were evaluated by **Anna Crowell** (University of North Dakota) for recoverable thermal energy. Using a volumetric approach for assessing recoverable energy Crowell indicated that these formations, including the "D" and "J" oil producing sandstones, have high capacity for heat production with target temperature being around 280^{o}F. **Paul Morgan** of the Colorado Geological Survey also presented on the Colorado geothermal gradients and opportunities within the Piceance Basin using BHT data from over 10,000 hydrocarbon wells. Morgan speculated how geothermal energy could be used for preheating in-place oil shales prior to extraction of the hydrocarbon. **Randy Keller** of the Oklahoma Geological Survey presented a study of thermal regimes and geothermal potential within Oklahoma. Discussion of the Meers fault, near the Wichita Mountains, brought to light the fact that even in the mid-continent, earthquakes naturally occur.

To the far north in central Alaska, **Bernie Karl** of Chena Hot Springs gave a rousing presentation involving several new geothermal applications currently in use at the resort in Alaska. Besides approximately 400 kW of power generation from two PWPS PureCycle units, Chena uses hot water for heating buildings, greenhouse support, and a 15 ton absorption chiller for temperature control inside their Ice Museum. A new 300 kW screw expander produced by Kaishan Compressor Co. is being installed to increase on-site production of additional electricity. Chena Power is also completing two mobile ORC demonstrations in Utah that can be used in oil and gas fields.

Heading south to a warmer climate **Bruce Cutright** of the UT Austin BEG spoke on the state-wide database of well temperature being compiled and that will be available in September, 2013 as part of the new National Geothermal Data System (geothermaldata.org). He discussed data analysis results, site identification, economics of geothermal and its competitiveness, and alternative heat extraction fluids such as CO_2. The largest area of higher geothermal gradients was shown to be along the Balcones fault system into East Texas and the Gulf of Mexico regions. Other local areas of interest included the Crockett and Val Verde County area, the Trans-Pecos region along the border with Mexico, the deepest part of the Delaware Basin, a portion of the Texas Panhandle, and in the Fort Worth Basin.

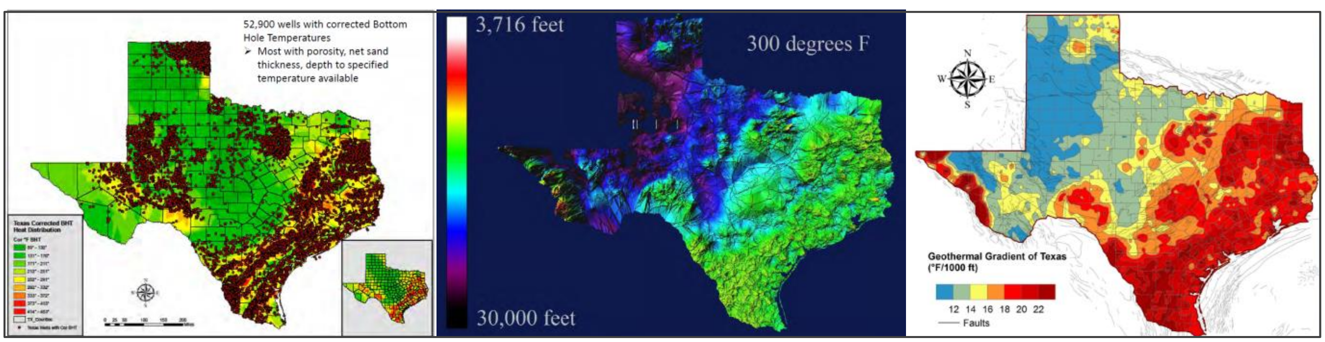

Figure 5. Texas geothermal resources: a) well locations with BHT data, b) depth to 300°F, c) Geothermal gradients.

The use of CO_2 for heat transport was continued by **Paul Dunn** (Enhanced Energy Group) as he spoke on its use in enhanced oil recovery and its potential use in engineered geothermal systems. He contrasted the use of CO_2 and water for heat transport. CO_2 has advantages over water in fields with reduced natural fluids. A current problem is the quantities of CO_2 required makes cost a major factor. New technology is reducing the cost to produce the CO_2 and is designed for large scale production of 2 to 12 MW of electricity generated while consuming the CO_2 into the geothermal reservoir. It can also be used for enhanced oil recovery and is beneficial for a combined geothermal/oil operation.

The expectation by the geothermal industry is for low temperature coproduction projects within sedimentary basins to expand into the large-scale enhanced/engineered geothermal system (EGS). The US DOE is funding projects to move the "future of geothermal" forward. As results of experiments in EGS during the past few months, that future is now today. **Matt Uddenberg** of AltaRock Energy highlighted how the project at Newberry Volcano in Oregon has successfully hydrosheared (created shear failure along existing fractures) the reservoir thereby increasing the reservoir capacity from approximately 10 l/s to 20 l/s over a one month cycling injection procedure, thus opening the reservoir for production in an otherwise dry environment.

Falling into the more conventional arena for geothermal energy was a presentation of an EGS project at Desert Peak, Nevada. The poster offered a new, plausible explanation for the location of observed deep micro-earthquakes and for the potential mechanisms that controlled permeability changes during the main stimulation operations. The study defined key geological structures involved in the experiment and original permeability in the rock volume around the well. The continuum mechanics model (FLAC^{3D}) used in the study showed that fluid pressure diffusion generated during the low-flow rate injection phase is consistent with the activation of hydraulically-induced shear failure along the identified structures. The project was discussed by PhD Candidate, **Stefano Benato** of the Desert Research Institute (University of Nevada, Reno). This project is part of the US DOE funding for EGS and the Itasca Education Partnership program.

On the water side of project development, **Steve Erdahl** of GreenTech Petroleum presented information on re-using produced oilfield water, not just in geothermal development but also the impact of hydraulic fracturing. He reviewed aspects of macro market trends, economic analysis, and the growth of water usage in the oil and gas industry. He contrasted some of the differences such as cost of water usage between the geothermal and oil and gas industry.

With the attendees ready for project development, the overview of energy financing for geothermal power by **Daniel East** of The Carlyle Group explained the investment structure and compared bank debt and private equity with mezzanine financing. He spoke on the various types of energy related projects that Carlyle's Energy Mezzanine Group supports, with their focus on the initial investment at least $25 million and designed for late stage development. **East** stated the importance of strong management teams with a proven track record. He also discussed the typical geothermal project life cycle as it presently exists.

Electrical connectivity and various legal issues helped to round out the broad arena of topics. **James Schue** (ERCOT) focused on Texas regulation of geothermal and the various agencies involved. This included past laws enacted by the state legislations that defines geothermal as a mineral. He also listed the tax codes that allow certain amounts of oil and gas to be "incidentally produced" from a geothermal well as being exempt from production taxes. He spoke on various legal issues of mineral ownership along with unknowns involving rule of capture with regards to heat. Schue also presented information on various legislative actions underway along with ERCOT and their concern on having reliable power generation, a plus for geothermal as a baseload energy resource.

The SMU Geothermal Lab was pleased to have two presenters from the DOE Geothermal Technologies Office. Current Program Director, **Douglas Hollett**, attended the event, openly contributing to the discussion and answering related questions on the DOE program throughout the two days. Hollett gave the reception presentation, which was taped for a YouTube video, clearly informing the attendees on various short and long term goals and project activities related to all aspects of geothermal from identifying new geothermal plays to an "underground field observatory" for EGS R&D. Coproduction development, blind hydrothermal systems, and EGS are all in the DOE's plan through 2030. The ability to add additional value with the inclusion of geothermal energy for projects using waste heat or storage technologies was a connector between the industries. Coming from the oil and gas industry, Hollett showed how current use of the word "Play" in the oil and gas industry is now being expanded to include geothermal energy as new drilling and hydroshearing techniques are changing the reservoir evolution.

DOE Coproduction Technology Manager, **Timothy Reinhardt**, presented a poster on low-temperature and coproduced resources below 300^{o}F and the various projects completed, ongoing, and being proposed for future activities. Proposed activities included an innovative rotating heat exchanger prototype and potential funding opportunities for FY 2014. Of interest to many was the new technique to extract strategic minerals from the geothermal brines. Lithium extraction is possible for incorporation into projects, where applicable. For the low temperature community, significant research is being completed by the Pacific Northwest National Lab to develop microporous metal-organic solids for heat-carrier and transfer mediums, expected to increase power generation by 15%.

The conference concluded with attendees re-energized to find ways to work with the oil and gas industry to develop geothermal and waste heat in existing fields. Waste heat applications already exist in almost every field across the nation. The Geothermal Industry was shown that financing larger projects may be easier, and if that is the case, producing the high fluid volumes shown to exist in the resource assessments can get projects to market with much needed clean energy for the local community. As **Bud Weinstein** stated, "Heat is a terrible thing to waste"!