UNCONVENTIONAL RESOURCES TECHNOLOGY CONFERENCE
FUELED BY SPE • AAPG • SEG

URTeC: 1920520

MaxG Basin Temperature Modelling Using Bottom Hole Temperature Datasets

Ian Deighton*, Erika Tibocha, Pete Dotsey TGS

Abstract

A new methodology for basin temperature modelling has been developed that utilizes large volumes (~10,000 points) of properly indexed and QC'd bottom-hole temperature (BHT) data for an onshore basin or area. This methodology honors the observation that borehole temperatures equilibrate, increasing towards formation temperature with elapsed time since fluid circulation. We thus use the maximum BHTs recorded in a layer (normalized for depth) or cell, rather than a corrected average or regression based model.

Two main models have been developed to construct a present day temperature volume (cube): MaxG and MaxBHT. In the MaxG cube, we first define a depth varying interval geothermal gradient (IGG) function that models the maximum envelope of the BHT cloud for each major lithostratigraphic unit. If there is significant erosion in the basin, then the IGG used is adjusted for the maximum burial conditions. The MaxG cube is constructed by stacking the IGG calculated temperatures for all the units in the basin. In the MaxBHT cube, we use the maximum BHT within each cell to populate the cube provided we have sufficiently dense data. If data are lacking in a cell, we can infill the voids using the MaxG cube values or a moving average.

For both the MaxG and MaxBHT cubes, we can apply a temperature shift related to interval thermal conductivity to more closely approximate formation temperature, if appropriate. Both temperature cubes can be used to identify where favorable gas-to-oil ratios (GOR) exist for shale gas formations. The concept is illustrated with examples from the Delaware Basin.

Introduction

Basin formation temperatures are an important consideration in oil and gas exploration and development because temperature controls the rates of chemical reactions in rocks such as kerogen transformation in source rocks, cementation in reservoir and permeability (seal) development. Since temperature is such an important requirement for many borehole management procedures it is measured while drilling.

While basin (paleo)temperature models are commonly built with sparse data sets from a variety of sources such as bottom hole temperature (BHT) data from logging runs, down-hole drill stem test (DST) data and vitrinite reflectance (Ro) data, this article will focus on present-day basin temperature models constructed from BHT data. BHT data is recorded in the log header of most down-hole logs. The temperature is commonly recorded with a maximum reading thermostat attached to or incorporated into the logging tool. Of the millions of wells that have been drilled and logged around the world, most were drilled and the results were recorded in analog form, either on paper and or microfilm. Over time many of these logs have been converted back to a digital format by first scanning to an image format and then digitizing to a vector format.

The capture of well log header data is most commonly done by indexing technicians; however, only a few studies showing the evaluation of large amounts of indexed BHT data have been undertaken on a basin or large area scale. A notable study was undertaken at SMU where BHT data for approximately 1,000 wells was used to assess

geothermal generation of electricity from high-temperature waters produced with hydrocarbons from oil and gas industry wells (Blackwell et al, 2010). A critical review of this work was the basis for the new MaxG methodology that was first applied to generate a basin temperature model for the Delaware Basin.

Previous Work

BHT Data Evaluation

BHT temperature data is evaluated to determine or approximate formation temperature. Bottom hole temperature log readings for a formation in an area can vary greatly. The variation can result from several factors such as how long the well was open (time since circulation, TSC) and when the well was drilled (i.e. drilling fluids circulated to the surface during drilling during winter months may result in the drill mud cooling-off more which reduces the loggers bottom hole temperature reading). A few "self-evident truths" regarding BHT data evaluation are as follows:

- The longer a well has to equilibrate (i.e. the greater the TSC value) the closer the BHT will be to formation temperature
- The longer a well is circulated, the longer it takes for the BHT to equilibrate.
- Historic TSC data is rarely collected consistently or accurately enough to allow for Horner type corrections.
- The higher BHTs measured for a formation in an area are considered closer to formation temperature
- Different lithologies transmit heat at different rates (sandstone > limestone > shale), therefore, the lithology at total depth will affect the amount of time it takes for the BHT to approach formation temperature.

Methods of estimating Rock Temperature from BHT data

Sprensky (1992 and online) provides a very succinct summary of the problems and treatments of small to large temperature datasets of various types. He notes "The original (and also the simplest) method to determine formation temperature and temperature gradients, is the two-point, or multiple-point average temperature gradient. A linear relationship is generally assumed between the ambient surface temperature and BHT temperatures at other depths within the well-bore are determined by interpolation. Regression techniques have commonly been used to correct BHTs and to calculate geothermal gradients for large data sets.

Most techniques (using algorithms or time-temperature curves) treat temperature as a transient function, i.e., they involve progressive measurements of temperature with time after cessation of circulation, to extrapolate the temperature at static conditions. The most commonly used method is the time-sequential, Horner-type extrapolation of BHT data

Review of Regression Based techniques

Figure 1 below (Blackwell et. al., 2010, Figure 9b) illustrates the most common assumptions associated with using BHT data to evaluate formation temperature. More importantly, the evaluation of this figure and other figures presented by Blackwell (l.c) led to the development of the MaxG basin temperature model methodology.

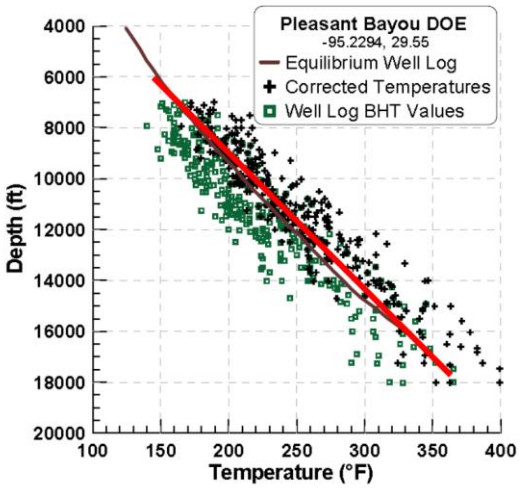

Figure 1: Distribution of recorded and corrected BHT values within 0.5 degrees (~55km) of an equilibrium well from Blackwell et al (2010). Green squares are recorded BHT values and black crosses are corrected BHT values using regression analysis techniques and comparison with nearby DST's. The thin black line is an equilibrium well log recorded 3 months after drilling. The heavier red line, drawn tangent to the maximum cloud of the BHT envelope is added here-in and in this case coincides closely with the equilibrium line.

As noted in the caption, the green squares represent the recorded BHT that occurs within 0.5 degrees of a study well. The range of BHT values varies greatly at all depths. The historical approach is to apply regression analysis (based on correlation with DST data) to correct each BHT to obtain an "accurate" bottom-hole temperature (black crosses), often using a depth based correction function. We believe this approach is flawed, for three main reasons: a) because many values are extremely low (small TSC value, logged in winter etc.) so the correction does not come close to estimating formation temperature; b) a small group of BHTs may be very close to having equilibrated to actual formation temperature in which case any average correction would result with a corrected BHT that is greater than formation temperature (and is physically impossible), and c) since the correction is equally applied over the whole basin, which would seem to imply to that the layers are relatively flat lying.

Careful examination of Figure 1 leads to the observation that a line, which we call the MaxG line (shown in red), can be drawn tangent to the maximum envelope of the cloud of recorded BHTs. Note that the MaxG line is nearly parallel to the slope of the equilibrium well log for the Pleasant Bayou well, though this is not the case in other wells presented by Blackwell (2010) largely due to the transient fluid flow effects recorded by workover temperature logging. Additionally, the average of the corrected values is very close to our MaxG line, so we infer the MaxG line has a direct relationship to formation temperature.

The SMU study (Blackwell *et al*, 2010) used two corrections for raw BHT. The first, based on Harrison et al (1983) is:

$$\text{BHT Correction } (^{o}C) = -16.5 + 0.0182*z - 0.0000023449*z^{2}, \text{ (z in meters)}$$

The second is that of Kehle (Gregory *et al*, 1980)

$$\text{BHT Correction } (^{o}C) = -1.73\times10^{-10}*z^{3} - 1.28\times10^{-7}*z^{2} + 7.97\times10^{-3}*z - 0.565 \text{ [z in meters]}$$

In the Uinta Basin, Willet & Chapman (1987) proposed the following function:

$$\text{BHT Correction } (^{o}C) = 6.93*z - 1.67*z^{2} + 0.101*z^{3} + 0.026*z^{4}, \text{ (z in meters)}$$

These functions are plotted against depth in Figure 2 which shows that there is unlikely to be any physical basis for these corrections.

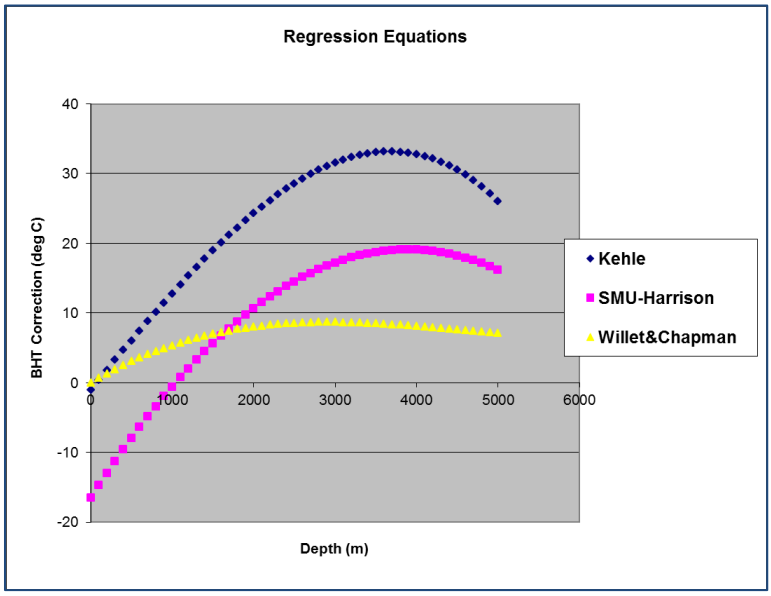

Figure 2: BHT regression based corrections for different basins/models – In most onshore US basins depths of each lithologic unit vary dramatically, thus these corrections are independent of lithology, which seems inappropriate

Horner Method

The well-known Horner method is often used to estimate formation temperature when valid temperature data is available from successive logging runs for a well (common practice before the advent of combination down-hole logging tools). The critical components that need to be recorded are the time since circulation (TSC) and BHT, values which should increase for each successive logging run.

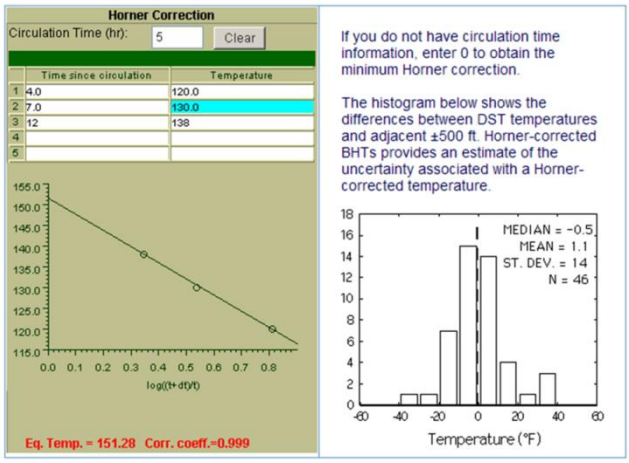

Figure 3: Horner plot assessment is very common when DST measurements are not available. The Zetaware website tool shown (http://zetaware.com/utilities/bht/horner.html) can estimate the temperature from successive measurements at the same depth in a well.

There are various problems with the method, including problems with bad recordings, errors in time entry (often rounded to the nearest half hour). It should be noted that for the over 3,000 wells which had successive logging run data and were used for building the Delaware Basin temperature models, approximately 80% of these wells had the same temperature recorded for each of the successive logging runs. Therefore, there is a limited amount of Horner data available to generate a basin temperature model.

Geothermal Gradient Discussion

Most sedimentary basins are layered with lithostratigraphic units (units with common lithologies) and each of these units has an interval geothermal gradient that can be significantly different from the overlying and underlying unit. Additionally, the IGG for a specific lithologic unit varies with depth. Therefore, the interval temperature gradient within each lithostratigraphic unit needs to be determined based on depth and lithology. These additional considerations need to be taken into account when building a basin temperature model. Figure 4 below shows a graph of a well that demonstrates that lithologic units have varying IGGs.

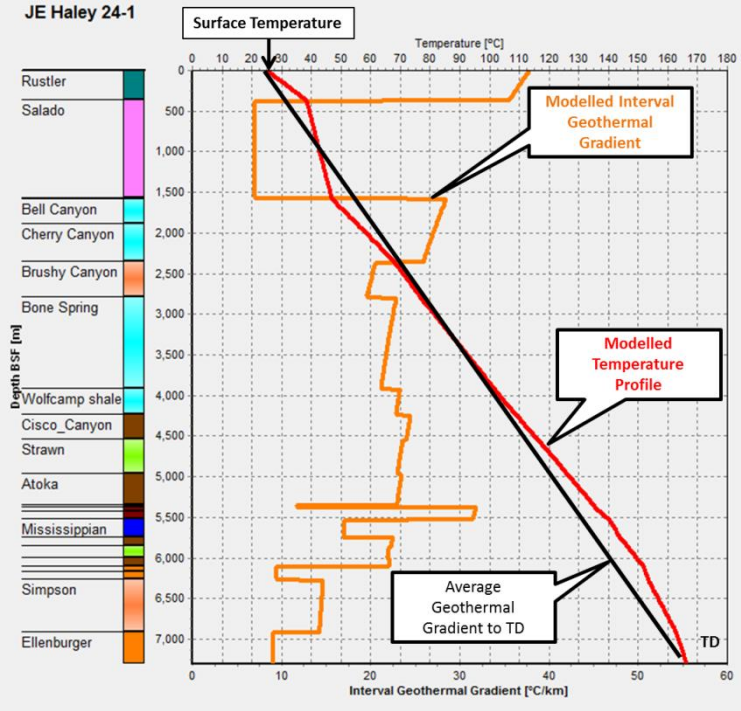

Figure 4: Downhole thermal parameters from the Delaware Basin showing lithology on left, predicted down-hole temperatures measurements in red and the disparity between modelled down-hole temperatures and a straight-line geothermal gradient (black). The interval geothermal gradient is shown in orange.

Figure 4 above leads to several observations:

- Average Geothermal Gradient (AGG) is a simple parameter to use ($T_z=T_o+AGG*z$, where T_o is surface temperature, z is depth and T_z is temperature at z) , but is a poor approximation at many depths and therefore, may not be representative of the temperatures up and down the borehole
- AGG (usually calculated to TD) may under-estimate the actual temperature above TD by 5-10°C (up to 30°C in other basins studied).
- Interval Geothermal Gradient (IGG) is depth and lithology dependent

Given that many source rock and reservoir parameters are very sensitive to temperature: oil expulsion takes place at 110-120°C; the optimum conventional reservoir hydrocarbon window is generally estimated to be between 60-120°C, and many GOR changes take place at around 95-100°C, the use of whole basin AGG models would seem to be inappropriate for the thermal modelling.

A discussion on generating depth-varying interval geothermal gradients (IGG) for Delaware Basin is presented later in this paper.

Theory: The MaxG temperature model.

Horner Experiment

A simple spreadsheet experiment was designed to test the observations made above in Figure 1- the first being that a line tangent to the maximum of the recorded BHT values might be used to approximate formation temperature and the second being that the MaxG tangent line parallels the interval geothermal gradient.

In the spreadsheet experiment, a one kilometer thick formation with an IGG of 30°C/km and a constant lithologic thermal conductivity was assumed. Next, one thousand random TSC values between 1 and 10 hours were generated for equally spaced depths using a standard Excel function. With each random TSC input value a BHT was "back-calculated" from the following equation:

$BHT = VRT + (H/4\pi K) * \ln(1 + Tc/dT)$ (Lachenbruch and Brewer, 1959) where:

- VRT is virgin rock temperature (in this case modelled gradient values for a single layer).
- H is heat supply (not the same as heat flow),
- K is thermal conductivity of the strata,
- Tc = circulation time, minimum is 4 hours – depths are 3-4km. For offshore wells, according to Hermanrud et al (1990): Tc = (1.3 + D)/(1.3-0.91*D) where D is depth in km (see Beardsmore & Cull, 2001, p 63). While there may be some differences in onshore drilling we do not have access to the drilling reports to assess this.
- dT is TSC (time since circulation stopped - usually 1 to 10 hrs for offshore wells but may be greater onshore, depending on number of logging runs and other factors, eg. delay in supply of logging equipment from distant city/log service hub).

Figure 5 below shows the graphic display of the back-calculated BHTs where a shale lithology and conductivity were used. Analysis of the test results confirmed our expectations: given random TSC values, the BHTs observed should be distributed with depth in such a way that the outer envelope of the BHT cloud is sub-parallel to the actual formation temperature profile.

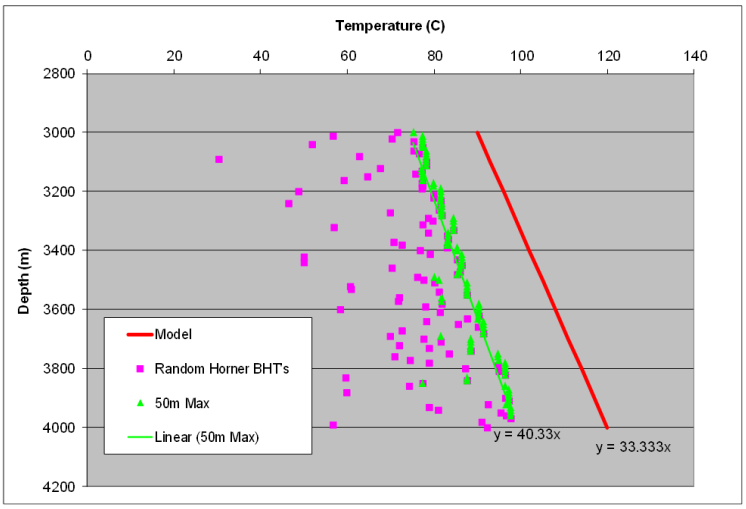

Figure 5: Back-calculated BHT values as magenta squares based on the Horner experiment. Note that the green MaxG line is drawn through the 50-meter maximum average green triangles based on the back-calculated BHT values. – redo with more points. The red line is the input temperature profile, representing a 30ºC/km geothermal gradient.

The Horner experiment was repeated using appropriate thermal conductivity values for limestone and sandstone. The MaxG line (red) and maximum back-calculated BHT line fits are shown on Figure 6 below.

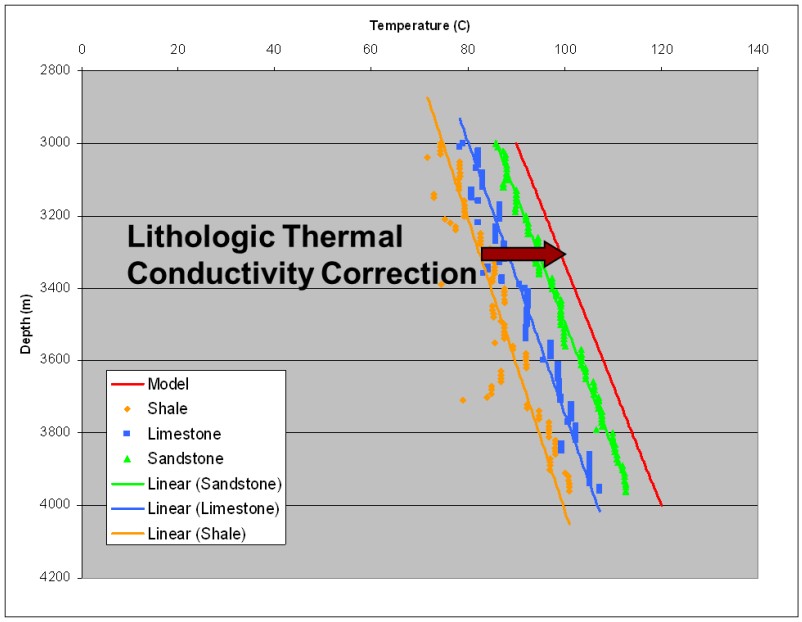

Figure 6: Back-calculated 50-meter maximum average BHT lines based on the Horner experiment for a shale, limestone and sandstone lithology. The red line is the input temperature profile, as for Figure 5.

Variation of Thermal Conductivity with depth

In addition to varying with lithology, interval geothermal gradient varies with depth, mostly due to porosity loss, but also due to temperature effects. Most basin modelling packages provide a variety of mixing solutions for such functions. In this paper, we use the thermal conductivity parameters provided in Fobos Pro® (TGS in-house basin modelling software). Figure 7 below shows how interval geothermal gradients vary with depth and lithology for the main layers defined in our Delaware model. Clearly when there is extra burial and erosion of the layers then the IGG that should apply to the unit is deeper on the curves, and therefore lower than a non-eroded case. Therefore, this is taken into account when build our models since for many of the basins within the continental US, significant erosion is the norm.

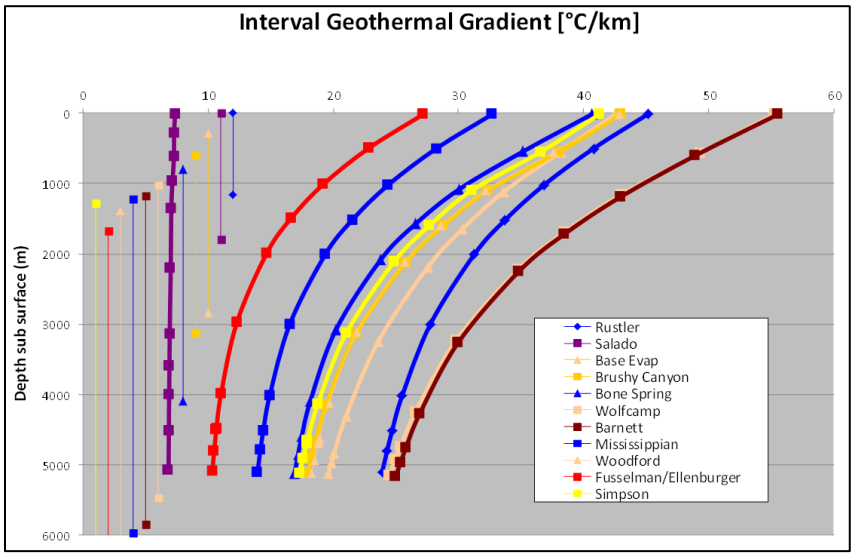

Figure 7: Variation of geothermal gradient with depth for the Delaware Basin lithostratigraphic units mapped in this study (thick lines). Thin lines (left) show the range of present depths for these units. Note that mixed lithologies were used for some of the units,

Since the interval geothermal gradients vary with depth for the lithostratigraphic units, a depth varying function was applied to the MaxG line drawn tangent to the cloud for each of the 12 major lithostratigraphic units that were mapped. To parameterize this variation, we use an inverse relationship similar that for porosity defined by Falvey and Middleton (1981), see Figure 8.

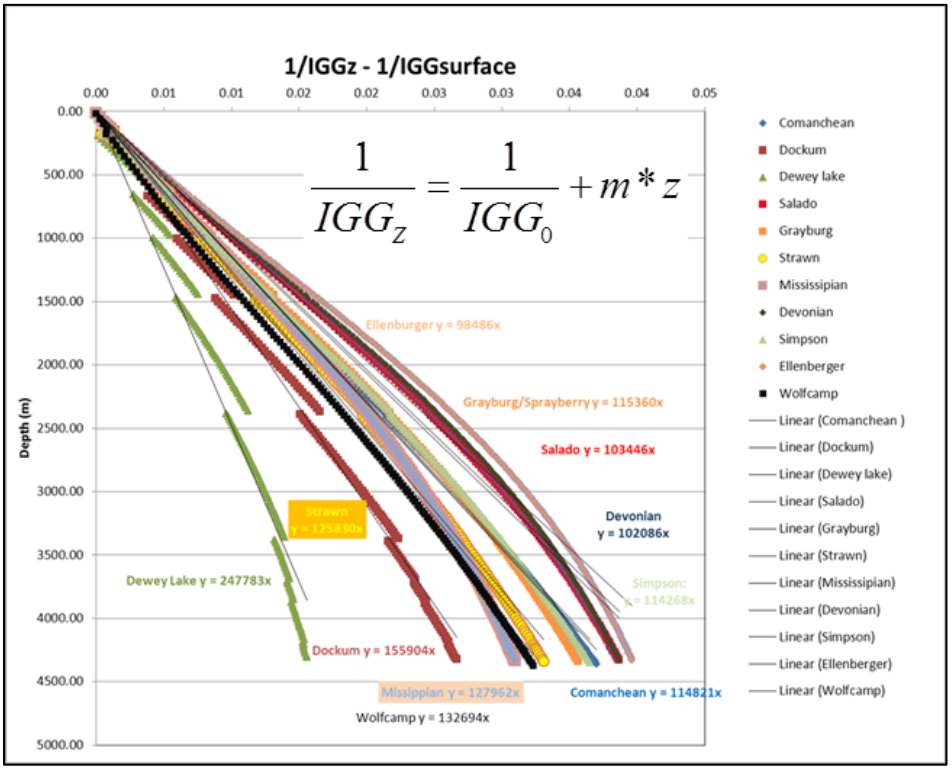

Figure 8: The data of Figure 7, transposed using inverse values to allow simple mathematical models of IGG with depth.

Building and Calibrating the Basin Temperature Model

The procedure is to construct a layered model from the surface down and to normalize the BHT data from each layer by subtracting out the overlying layers, thus eliminating variations that occur due to differences in thickening and thinning of overlying intervals. Here is the stepwise approach as shown on Figure 9 below:

- Depth values for each layer are normalized (i.e. subtract Z1 from all depths) of BHT point data: shifts layer to surface
- Temperature values for each layer are normalized (i.e. subtract T1 from all temperatures) from BHT point data: intercept of G2 (the IGG for this layer) is now 0,0
- Blue MaxG line on Figure 9 is now estimated (average of maximums) and/or may be adjusted for thermal conductivity of the layer to get green line shown on Figure 10.
- T2, which is the grid temperature at the base of the layer, is calculated from G2 (calculated previous step, and if necessary adjusted for variation with burial depth)*Z2-Z1 (isopach) plus T1 (grid)
- This process is applied iteratively for each layer moving downwards.

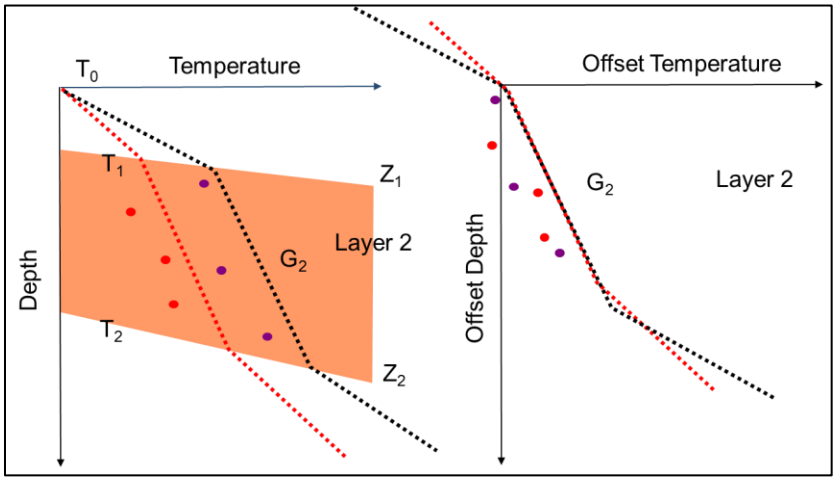

Figure 9: MaxG method for constructing offset datasets that are effectively equivalent to that shown on Figure 6, but for a basin wide depth varying layer. The left hand data is transposed to the right, by offsetting or normalizing against the top of the layer. To simplify the concept we have only shown 3 BHT points for each idealized well. In practice, hundreds of BHT points are offset for most layers (see Figure 13).

The random BHT theory, shown on the previous slides for a flat layer, has been extended to use the shape of the actual layer in the basin model (Figure 10) using Geocap® software (www.geocap.no). Random depth points are generated for large numbers of theoretical wells in the layer, and then have a random TSC applied. The predicted BHT's are the black dots, and the density of dots can be contoured, as shown in red tones, to indicate the predicted distribution of BHT data

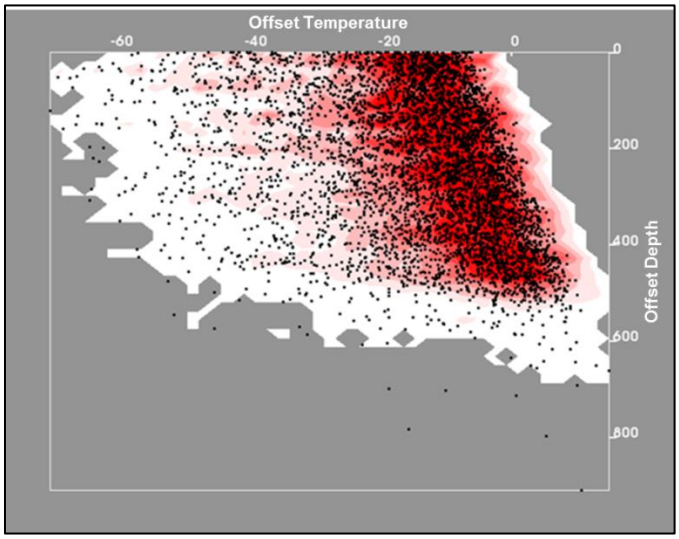

Figure 10: Expected offset BHT data points and density contours expected for random depths and TSC within a layer.

Example MaxG Basin Temperature Model: Delaware Basin

The Delaware Basin is the western most basinal area of the Permian Basin located in West Texas, USA. The study area and data are shown below on Figure 11.

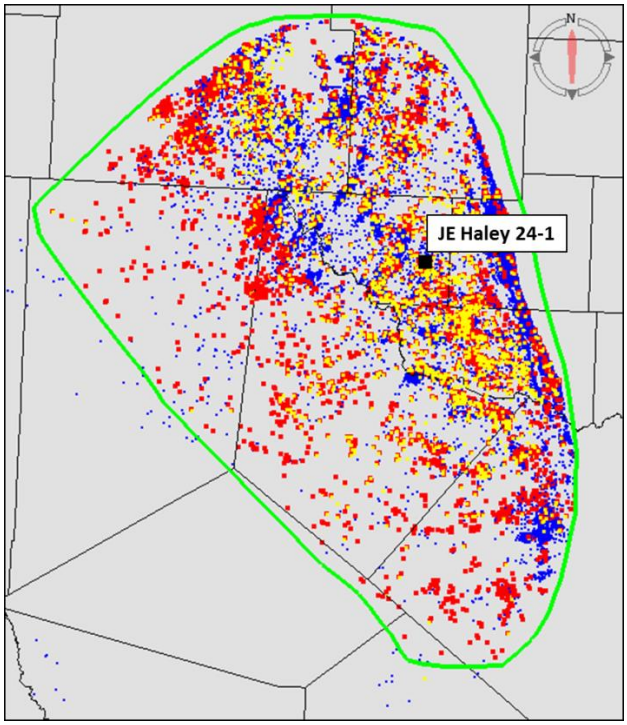

Figure 11: Delaware Basin study area (yellow outline). Small dots are all wells, large red dots are wells with indexed BHT, and yellow dots are wells with TGS interpreted tops. The location of JE Haley 24-1 that was modeled using TGS basin modelling software (Fobos Pro®) and will be discussed later in this paper, is highlighted.

Figure 12 shows a regional cross-section through the Permian Basin. In the thought process for selecting an area for basin temperature modelling, a large area the size of the entire Permian Basin was considered too complex due to presumed lateral heat flow and facies based thermal conductivity variations associated with the structural complexity of the Central Basin Platform. Therefore, the Delaware Basin and Midland Basins are treated separately because each offers an area of presumed minimal lateral variations and can be described structurally as fairly evenly-layered asymmetrical synclinal basins.

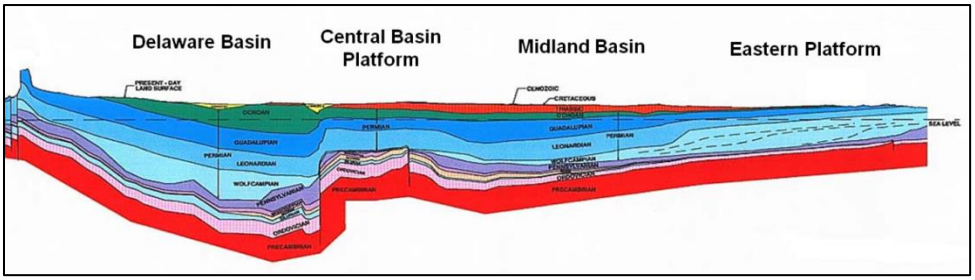

Figure 12: Regional cross section through the Permian Basin from UTPB web-site generated by R.F Lindsay.

The TGS library of available wells and the number of wells used in the Delaware BTM study are shown above on Figure 11 and include:

- 22,865 Wells in Delaware Basin – 14,702 that are digitized (blue dots inside Delaware Basin outline)
- 5,249 BHT Indexed Wells - 4,055 with valid Elevation Data (red dots inside Delaware Basin outline)
- 2,013 Wells used to generate a lithostratigraphic framework (yellow dots inside Delaware Basin outline)

The wells indexed for BHT data and used for defining the lithostratigraphic intervals were selected based on vertical and areal distribution as well as curve content. The vertical distribution consideration was important since in order to assess the MaxG cloud of BHT data for each layer, a significant number of wells that reached total depth or were cased within each lithostratigraphic interval were needed. The JE Haley 24-1 well, which was modeled using Fobos Pro® is also shown on Figure 11 and will be discussed later in this paper.

Figure 13 below shows MaxG graphs for 2 of the 13 lithostratigraphic intervals within the Delaware Basin temperature model. Also note that the process for determining the MaxG line and building the model is iterative and that each time the line is re-drawn for an interval, all underlying layers need to be re-evaluated. This shows that even though the MaxG line is not aesthetically located for the Bone Spring, the Wolfcamp unit that directly underlies the Bone Spring and subsequent underlying layers align better with this MaxG line. Figure 14 shows the effect of variable near-surface erosion on the distribution of points on the offset graph; increased burial results in lower IGG values (Figure 7) and thus higher temperatures in the model.

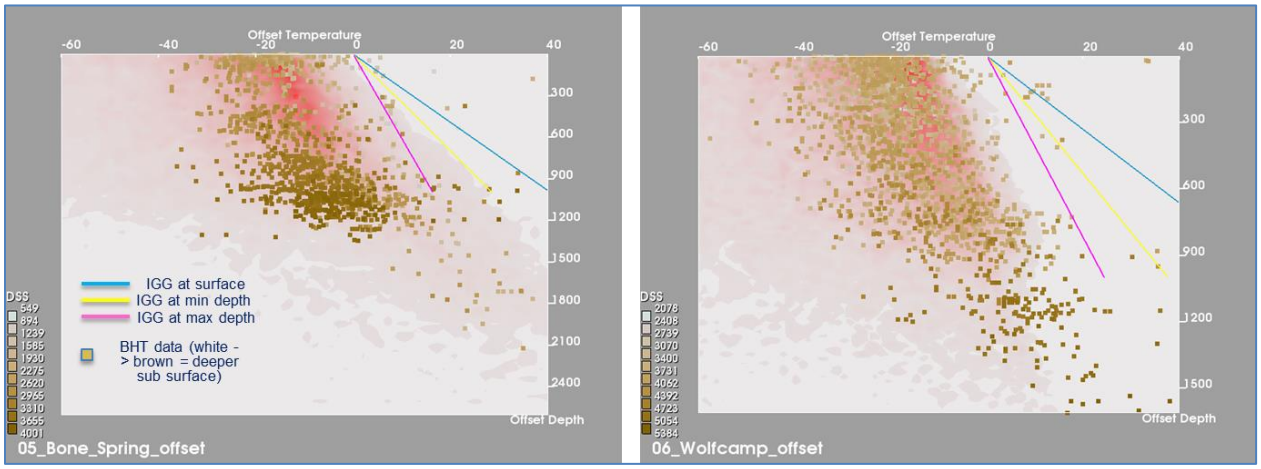

Figure 13: Offset graphs for two interval lithologic layers in the Delaware Basin temperature model. Since the IGG curve is a depth varying function, it is shown as a cyan line to show surface tangent value, as a yellow line to show the shallowest tangent value for the formation, and as a magenta line to show the deepest tangent value for the formation. Compare with Figure 5

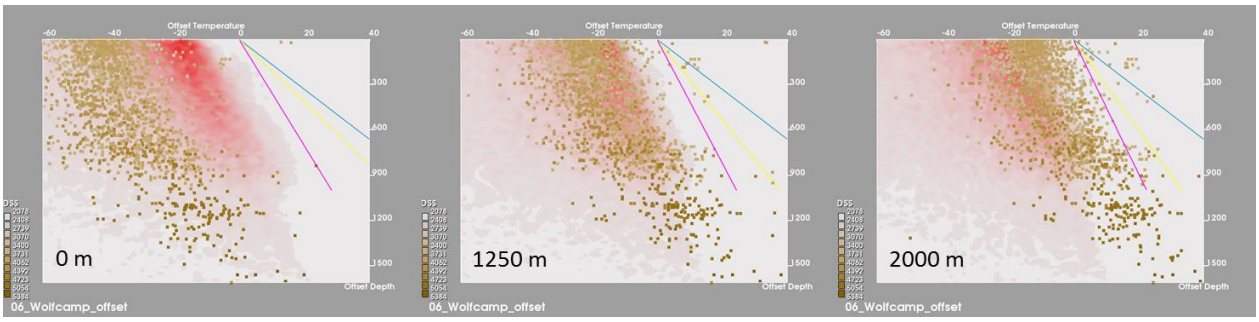

Figure 14: Offset graphs for the Wolfcamp layer, showing the effect of varying Tertiary erosion. With no erosion (0m), the offset data is too far left of the MaxG lines; with 2000m erosion the data is too far to the right compared to the predicted background. With 1250m erosion, the scatter of offset data matches the predicted model. This shows that the offset graphs can be used as a gross indicator of erosion.

Figure 15 below shows a 3D view of the layers and the BHT data points used to construct the model.

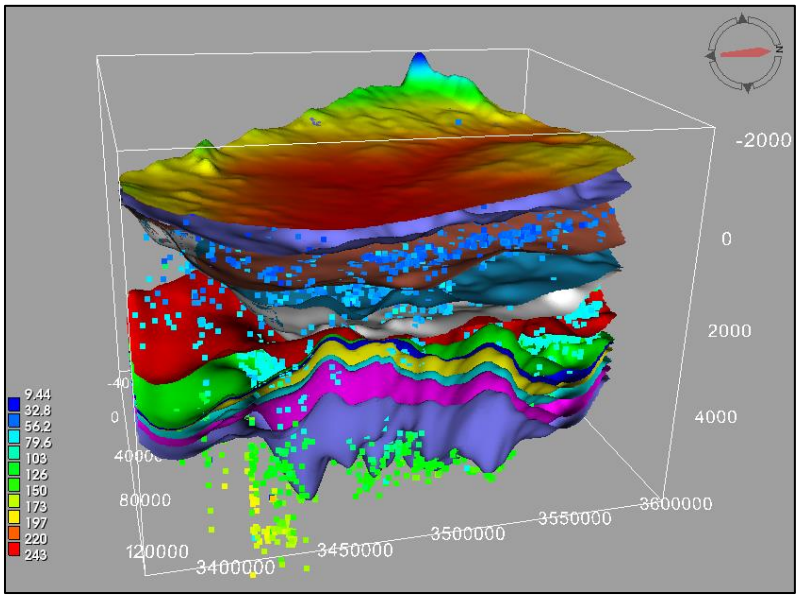

Figure 15: 3D view of BHT values (dots colored in ºC) with respect to the lithostratigraphic layered model. The surface layer is the digital elevation model; the deepest layer is the Ellenburger Fm.

The final MaxG temperature volume (cube) is interpolated from the calculated depth and temperature values for each lithostratigraphic layer in the model. Figure 16 shows three planes of section through the cube for the Delaware Basin temperature model.

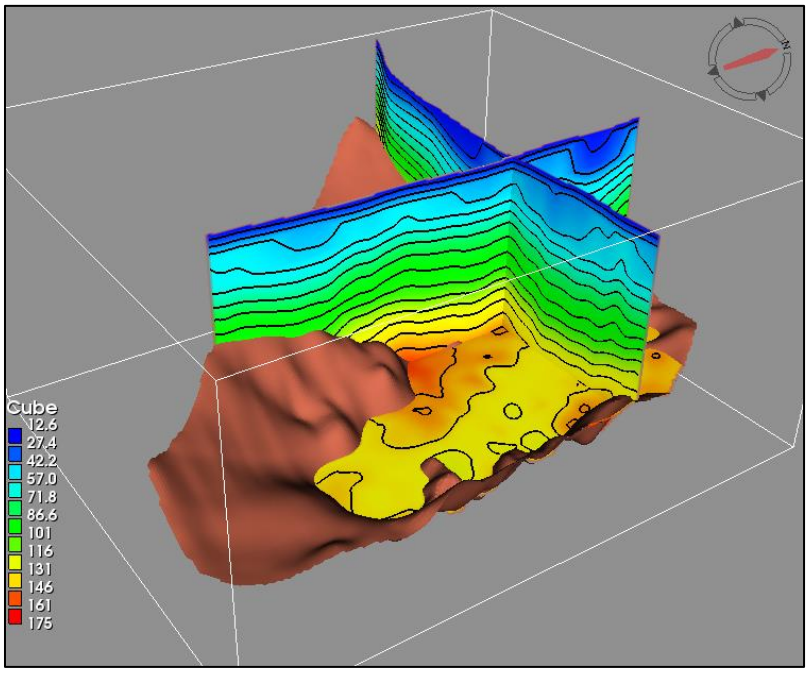

Figure 16: Delaware Basin MaxG temperature model. Note that the cube is cropped at the surface and the basal unit (magenta, Ellenburger). Near surface variation is primarily due to varying salt and reef distribution

To test the MaxG model, the temperature results were fed back into a Fobos Pro® basin model simulation for JE Whaley 24-1, which was modelled in great detail by Sinclair (2007), who included a comprehensive set of VR data (acquired by BP) and AFTA data (Geotrack International). The BTM modelled temperatures agree well with the

simulations for temperature (Figure 17, bottom left), partly because the IGG model was also developed in Fobos Pro®, though using other wells than JE Haley 24-1. The uplift required in our model to calibrate with the BP reflectance data used an erosion thickness of 1250m, which is somewhat less than that modelled by Sinclair (l.c) but agreeing with the estimate based on the offset plot distribution (Figure 14).

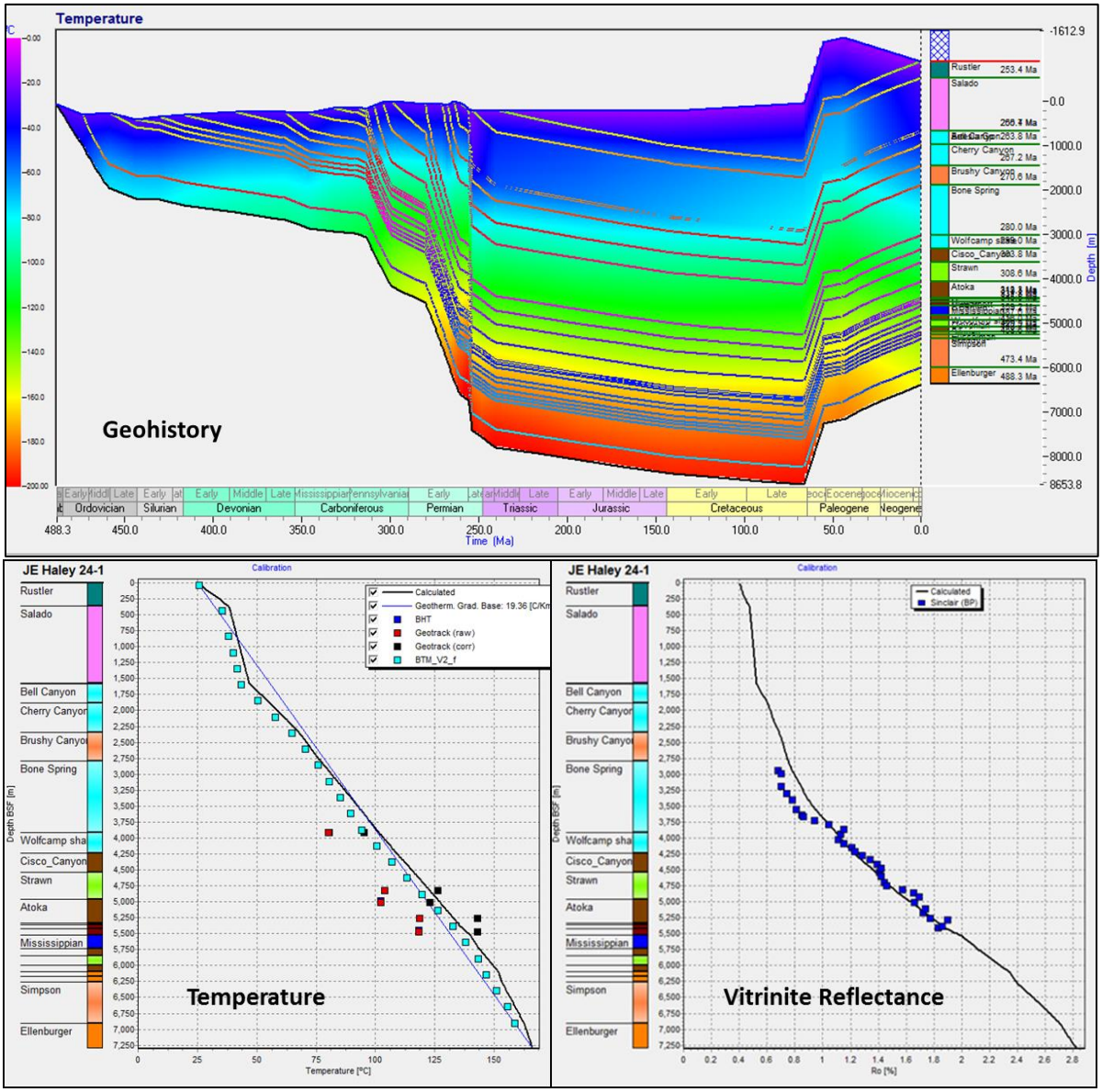

Figure 17: Geohistory, Temperature calibration and Maturity calibration plots for JE Haley 24-1. 1250 m of later Tertiary erosion was applied in the model. In the Temperature plot: the black line is the modelled temperature; BHT data labelled Geotrack are the raw (red dots) and corrected values (blue dots) from the well data; blue dots (BTM_v2_f) is the extract from the MaxG cube based on the IGG and MaxG model, herein. In the Maturity plot, the black line is the modelled maturity; blue dots are from a BP analysis of Ro%.

Other Temperature Cube Types

The MaxG cube defined above generally produces a smooth and conservative model of temperatures in a basin. Clearly there may be temperature anomalies in the basin which are hidden in the raw BHT data, but masked by the MaxG/IGG methodology. To capture these possibly significant anomalies, several new cubes have been developed that use 3D cube math provided in Geocap®.

MaxBHT

The MaxBHT cube is built using the maximum indexed BHT in each cell (~1km x 1km x 200m, or similar imperial units) and using a 3D moving average interpolation to infill. Its construction is independent of the layer model. The grid dimensions and top and base surfaces are identical to the MaxG cube, to facilitate mathematical cube comparison. The cube naturally has more variability than MaxG cube as it includes cells that are hotter and cells that are cooler: due partly to the moving average gridding, especially near the surface; and because the MaxG method is an outer tangent to most of the BHT data already.

MaxBHT(G20+)

The MaxBHT(G20+) cube is built similarly to MaxBHT, however the input BHT data is first clipped to exclude any BHT values that are hotter than MaxG plus 20ºC since temperature differentials greater than this are probably unsustainable over geologic time.

MaxCombo

The MaxCombo cube is a combination of the MaxG and MaxBHT(G20+). The cube uses for any cell, the maximum temperature of the two input cubes. The cube will have the MaxG values as background, but show where the indexed BHT values are higher by 0-20ºC. In many cases (as here) it is identical to MaxG.

Figure 18 below shows a comparison of a single temperature surface (130ºC) in the three cubes.

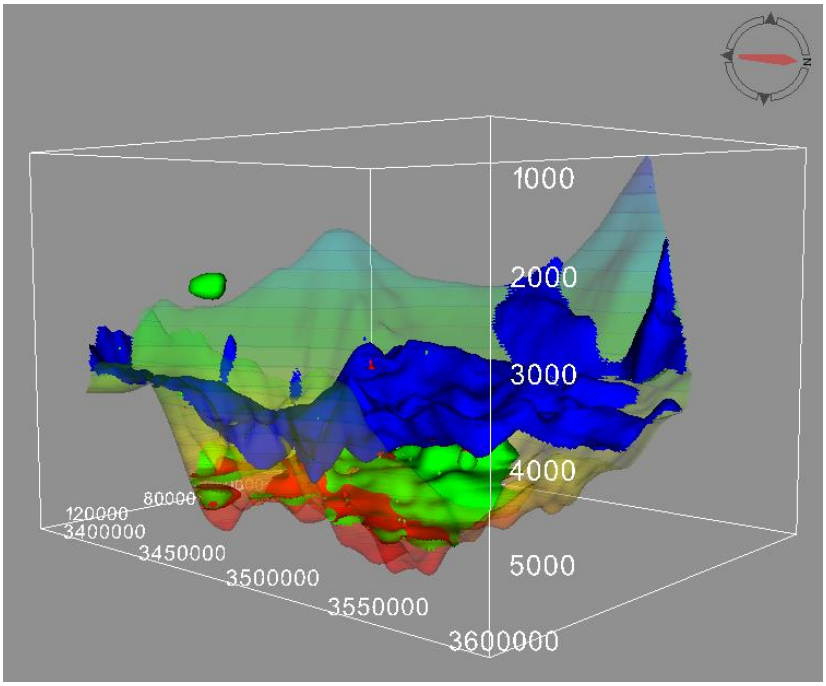

Figure 18: Delaware Basin temperature cube variation.. Background (in transparent contour) is the Ellenburger surface. Dark blue is the 130ºC surface in the MaxG/MaxCombo cubes. The green and red surfaces are the 130ºC surface in the MaxBHT and MaxBHT(G20+) cubes. Depths are subsea in meters

Summary

New methodologies for building regional scale basin temperature models have been developed. The initial MaxG method is based on modelling a line tangent to the maximum BHT envelope of the depth-varying interval geothermal gradients for each lithostratigraphic unit. The results are in close agreement with those predicted from independent basin modelling studies. The MaxG method is best suited for predicting formation temperature for each interval in a basin. Variations to the analysis of the BHT data has led to construction of three additional cubes to help identify temperature anomalies within each layer

As with any basin-wide temperature models the potential uses include:

- Cross-correlate prospective zones with temperature cube to identify temperature optimum prospective areas
- Cross-correlate temperature log data with temperature cube to identify areas of anomalous fluid flow and heat flow. Anomalies may be compared with:
  - gravity and magnetic data to evaluate basement architecture effects
  - production data such as gas-to-oil ratio to identify prospective trends
- Compare calculated pseudo-maturity (assuming present temperature is maximum) with measured maturity to identify paleo-temperature anomalies associated with high heat flow, uplift or volcanic activity

The basin temperature volumes can be readily imported into 3D viewing and modeling software packages.

Acknowledgements

We thank TGS for permission to publish this paper. It is appropriate to acknowledge Carrie Newhouse, Supervisor Well Log Scheduling/QC Well Data Processing at TGS, and her group of indexers who pored through the well log data, and Olav Egeland at Geocap (www.geocap.no), who coded most of the modelling and graphical tools for the Offset Graph methodology.

References

Beardsmore, G. R., and Cull, J. P., 2001. *Crustal Heat Flow: A Guide to Measurement and Modeling*. Cambridge University Press, New York.

Blackwell, D., Richards, M. and Stepp, P., 2010. Texas Geothermal Assessment for the I35 Corridor East. Roy M. Huffington Department of Earth Sciences, Southern Methodist University, Dallas.

Falvey, D.A. and Middleton M.F.,1981. Passive continental margins: Evidence for a prebreakup deep crustal metamorphic subsidence mechanism. Oceanologica ACTA, 4, 1981 No SP pp 103-114.

Gregory, A.R., Dodge, M.M., Posey, J.S., and Morton, R.A., 1980. *Volume and accessibility of entrained (solution) methane in deep geopressured reservoirs-Tertiary formations of the Texas Gulf Coast*. DOE Final Report DOE/ET/11397-1, 361 p. OSTI # 5282675. (Data used from report for this 2010 assessment.)

Hermanrud, C., Cao, S. and Lerche, I. 1990. Estimates of virgin rock temperature derived from BHT measurements: Bias and Error. *Geophysics*, 55(7), 924-31

Lachenbruch, A.H and Brewer, M.C. 1959. Dissipation of the temperature effect of drilling a well in Arctic Alaska. *USGS Bull*, 1083-C, 73-109

Sinclair, T. D., 2007. *The generation and continued existence of overpressure in the Delaware Basin, Texas*, Durham theses, Durham University. Available at Durham E-Theses Online: http://etheses.dur.ac.uk/2289/

Prensky, S., 1992. Temperature Measurements in Boreholes: An Overview of Engineering and Scientific Applications, *The Log Analyst*, v. 33, no. 3, p.313-333. Online version at http://www.sprensky.com/publishd/temper2.html,

Willett, S.D. and Chapman, D.S. 1987. Analysis of Temperatures and Thermal Processes in the Uinta Basin. in: *Sedimentary Basins and Basin-Forming Mechanisms*, Canadian Society of Petroleum Geologists, Memoir 12 eds. C. Beaumont and A. J. Tankard