Full Field Array Electromagnetics: A tool kit for 3D applications to unconventional resources

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Abstract

In an unconventional resource play some of the key questions are: mapping of the fractures and reservoir depletion monitoring. As the hydrocarbons in shale gas or shale oil reservoirs are mostly resistive and the reservoir is relative thin, they give an anomalous electromagnetic response. This effect gave rise to the entire marine EM industry and is known as Direct Hydrocarbon Indicator (DHI) or in geophysical terms the ‘ thin resistive layer effect’ (Passalacqua, 1983, Eadie, 1980).

The response can be measured from the surface in a time lapse sense as the anomalous response is in the order of several percent. Combining borehole and surface electromagnetic measurements gives calibration points in addition to more sensitivity to fluid variations in the pore space. At the same time linking the electromagnetic (EM) information to 3D surface and borehole seismic data permits extrapolation away from the well bore. Our implementation includes marine and land sources and receivers, surface-to-borehole arrays and a single well system that can look tens or even 100 m around the wellbore and ahead of the drill bit.

For tight shale reservoirs, two key technical elements that were hereto not possible are the inclusion of electrical anisotropy and directional/tensor measurements, which lead to fracture directions and better hydrocarbon volume estimates.

On land, for resistive targets such as unconventional hydrocarbon reservoirs, we use Controlled Source ElectroMagnetics (CSEM) with a dipole transmitter. In this case it is preferred over natural source magnetotellurics because of the increased coupling and it’s enhance sensitivity to the hydrocarbon bearing strata. For ease of operation, it is best to measure all EM components.

In the marine environment, the receiver is included in seismic spreads with electromagnetic sensors. CSEM is only needed when the resistive strata are thin. Multi-component acquisition and dense station spacing are essential to measure anisotropy and lateral structural changes, and to extend the application from exploration to production.

For borehole application we combine EM sensor packages with a borehole seismic acquisition system or build special purpose Logging While Drilling (LWD) sub-assemblies. So far, we finished building the various critical components for an integrated land and borehole monitoring experiment based on a commercial seismic acquisition systems.

One of the major outcomes of the various feasibility projects was that surface electromagnetic methods alone are ambiguous if they are not used in combination with surface-to-borehole measurements. The reason lies in the up-scaling associated with the inherent averaging nature of electromagnetic (EM) methods.

Introduction

Unconventional reservoirs like shale, tight-gas reservoirs, geothermal, tight sands, and heavy oils are the main sources of what is generally known as unconventional hydrocarbon. In its early days, exploring for shale gas requires traditional petroleum exploration methods like seismic but now advances in technology like electromagnetic has helped to increase the growth in unconventional exploration techniques unique to shale gas deposits. The industry is looking for a less expensive additional technique that gives additional information. Electromagnetic techniques measure the changes in the electrical resistivity that can characterize the reservoir property. For tight reservoirs with hydrocarbon fluid content the electromagnetic target would be resistive (hydrocarbons) and for a geothermal the hotter rock and fluids would be a conductive target. We will exclude geothermal applications here as several applications describe its use in sufficient details (Tulinius et al., 2010; Yu et al., 2010).

Seismic methods have been the major choice in the oil and gas exploration to locate and to identify the extent of hydrocarbon reservoirs. Seismic techniques are preferred because of their ability to identify structures. Crosswell and surface-to-borehole seismic measurements are superior in mapping the *structural distribution* in the interwell space (Wilt et al., 1998). Their differentiation between the various pore fluids is still a challenge because seismic waves travel primarily through the mineral grains. For fluids typing, *electromagnetics will complement* seismics. Electrical conductivity measurements allow pore fluid monitoring because of their sensitivity to porosity, pore fluid type, saturation and temperature.

To optimize the productivity of a gas shale reservoir, monitoring microseismic event is one of the key techniques to map the fracture. Detecting and characterizing the microseismic event helps us to understand the fracture network and the path of the fractures. To perform the monitoring of a microseismic event, an array of semi-permanent or permanent electromagnetic sensors are installed either on the surface and in the downhole to detect the changes in the electrical property of the reservoir over time. We are proposing to install additional sensors that measure the electromagnetic energy caused by a microseismic event or the fluid flow itself. This type of electromagnetic recording is done in a time lapse mode.

Electromagnetic (EM) methods are some of the oldest geophysical methods. In the mining industry they are accepted as key technology while in the hydrocarbon industry they are still used for trial purposes in exploration only (Nabighian and Macnae. 2005). There has been some progress with marine electromagnetics, which has stabilized in the market place at a just over 100 Million $ global revenues. This limitation is unusual, as in the borehole environment electromagnetic (EM) logging tools are the most important of all and in most cases used for reserve estimates.

The electromagnetic reservoir monitoring concept is based on a resistive target being depleted (Wirianto et al., 2010) and the fluid being substituted by conductive brine. Enhanced oil recovery methods into an unconventional reservoir will further decrease the formation resistivity and create an even stronger resistivity contrast. This is detectable by time-lapse electromagnetic surface or downhole measurement. The significant resistivity contrast between water-bearing and hydrocarbon-bearing reservoir is the fundamental idea for reservoir monitoring using electromagnetic techniques (Hu et al., 2008). Unlike time-lapse seismic which requires at least 30% of porosity to have a significant velocity difference between hydrocarbon bearing reservoir and water, electromagnetic measurement gives a large resistivity difference between the water and the reservoir for at least two or three orders of magnitude (Wirianto et al., 2010).

Motivation

One of the active areas in shale plays is the Bakken formation, located in Montana and North Dakota. Bakken has immense potential and has driven tremendous acquisition activity. In 2008, the United States Geological Survey (USGS) estimated that the U.S. portion of the Bakken formation contains between 3 and 4.3 billion barrels (a mean of 3.63 billion barrels) of undiscovered, recoverable oil, ranking it among the very largest U.S. oil plays (USGS). Although the Bakken resource is immense, exploiting its full potential will require development and further refinement of a number of technologies including reservoir monitoring. Monitoring the reservoir allows us to enhance the understanding of the extent of Bakken system and as a result we will be able to enhance the existing production, potentially extend the production and increase the recovery factor.

The Bakken Formation is rapidly emerging as an important source of oil in the Williston Basin. The formation consists of three members, with the upper and lower members made up of shale and the middle member composed of dolomitic siltstone and sandstone. Total organic carbon within the shales may be as high as 40%, with estimates of total hydrocarbon generation across the entire Bakken Formation ranging from 200 to 400 billion barrels (Yevhen et al., 2011).

The Bakken system covers parts of North Dakota and Montana in addition to parts of Saskatchewan and Manitoba, Canada and includes the Bakken, Lower Lodgepole and Upper Three Forks Formations (Figure 1). The Bakken Formation is comprised of three distinct members, the upper and lower Bakken's organic rich shale layers, and the middle Bakken member, which is primarily sandstone and siltstone. The middle Bakken is the primary reservoir rock (LaFever, 2005) as shown in Figure 2.

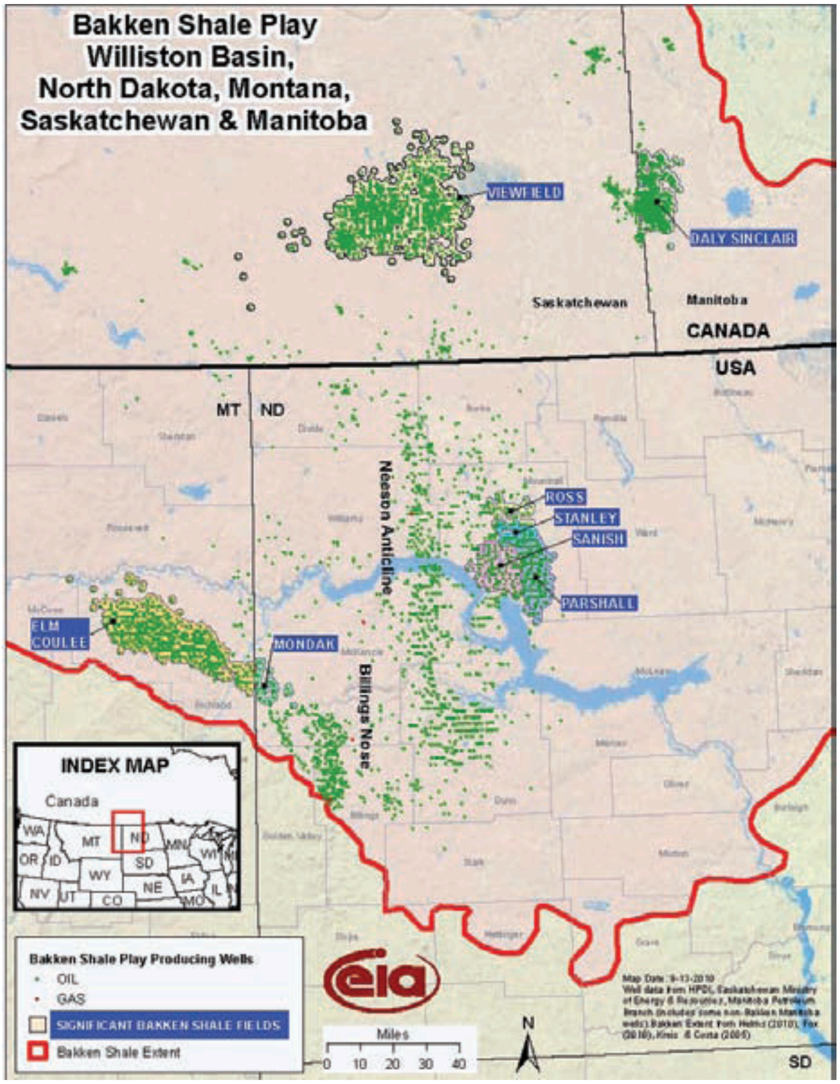

Figure 1: Map of the Bakken Shale play with significant fields identified. Image courtesy: Energy Information Administration, U.S. Department of Energy.

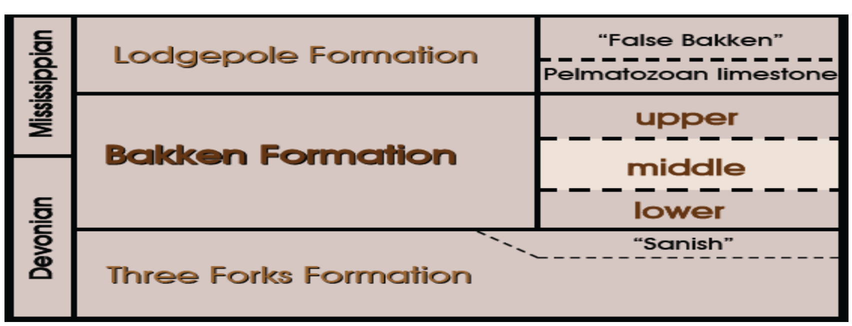

Figure 2: The Bakken Formation is comprised of three distinct members, the upper and lower Bakken's organic rich shale layers, and the middle Bakken member, which is primarily sandstone and siltstone. The middle Bakken is the primary reservoir rock (LaFever, 2005).

In order to understand this effect in more detail we analyzed induction logs from the Bakken formation and built a 1-D geoelectric model. The model clearly showed the high resistivity layers are identified as the Upper Bakken and the Lower Bakken.
Then, we carried out computer simulation for a specific Controlled Source ElectroMagnetic (CSEM) array by modeling to the received voltage for when the reservoir is hydrocarbon saturated partially depleted or brine saturated. (Resistivities for the reservoir are 230 ohm-m (R_v - vertical), 120 ohm-m (R_h - horizontal) and 8.16 ohm-m (R_w).) Then we calculated the percentage difference of the measured voltage when the formation resistivity is 230 ohm-m (R_v) and when the formation is fully water saturated. The same measurement was done to the reservoir when the formation resistivity is 230 ohm-m (R_v) and when the formation is fully water saturated.

Figure 3 shows the results of this simulation in terms of the percentage difference between the different saturation scenarios. Electrical anisotropy MUST be considered, as shale reservoirs are intrinsically anisotropic. The anisotropy originates from alternating thin laminations of differing resistivity, where individual thicknesses (about cm to 10 cm) are less than the resistivity log vertical resolution (2-3 m) (Klein, 1993). Horizontal resistivity, $R_{h,}$ is the resistivity when we measure parallel to the formation bedding plane while vertical resistivity, R_v when we measure perpendicular to the formation bedding plane. Usually, in vertical wells, horizontal resistivities come from standard induction logs and the vertical ones from triaxial induction logs. In horizontal bedding, the formation response acts as a resistor in parallel circuit and the horizontal measurement; R_h is dominated by low resistivity shale. The vertical response acts as resistors-in – series circuit and the vertical resistivity measurement R_v is dominated by the high resistivity hydrocarbon bearing sand.

In addition, anisotropy is intrinsic to shale reservoir and is only - since the introduction of the 3D induction log - considered in shale reservoir characterization. It is crucial to include anisotropy in shale reservoir characterization because of the high anisotropy in shale reservoir (Yu et al., 2001).

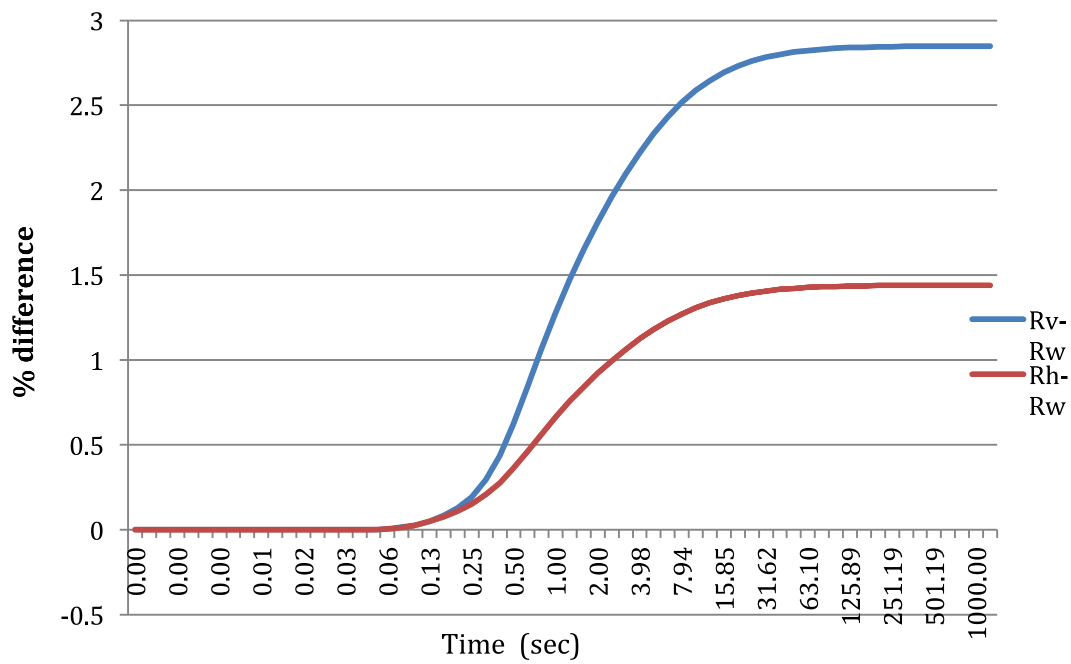

Figure 3: Percentage differences plot of Upper Bakken formation as function of measurement time. Both vertical and horizontal resistivities are used in the modeling (of a time domain system) to see the difference when the reservoir is fully saturated with hydrocarbon (120 ohm-m and 230 ohm-m) and when the reservoir is fully saturated with water (8.16 ohm-m).

Another important factor contributing to the resistivity contrast are enhanced oil recovery (EOR) processes. All of the increase the hydrocarbon mobility and thus increase significantly the electron flow and increase electrical conduction resulting in significant resistivity drop. It shows a significant resistivity difference when we flood the reservoir either with water or steam. To illustrate, figure 4 shows an example of time lapse through Casing Resistivity (TCR) logging. Two separate logging operations from different contractors were compared (Zhou et al., 2000). The left track shows the deep induction (black curve) with the two TCR measurements (red and blue curves). The right track displays the differences between the two TCR measurements. It is obvious the two measurements are consistent but it can be seen that one of the tools has lower vertical resolution. Hence, steam flooding makes local changes in resistivity that is large enough to be easily detected.

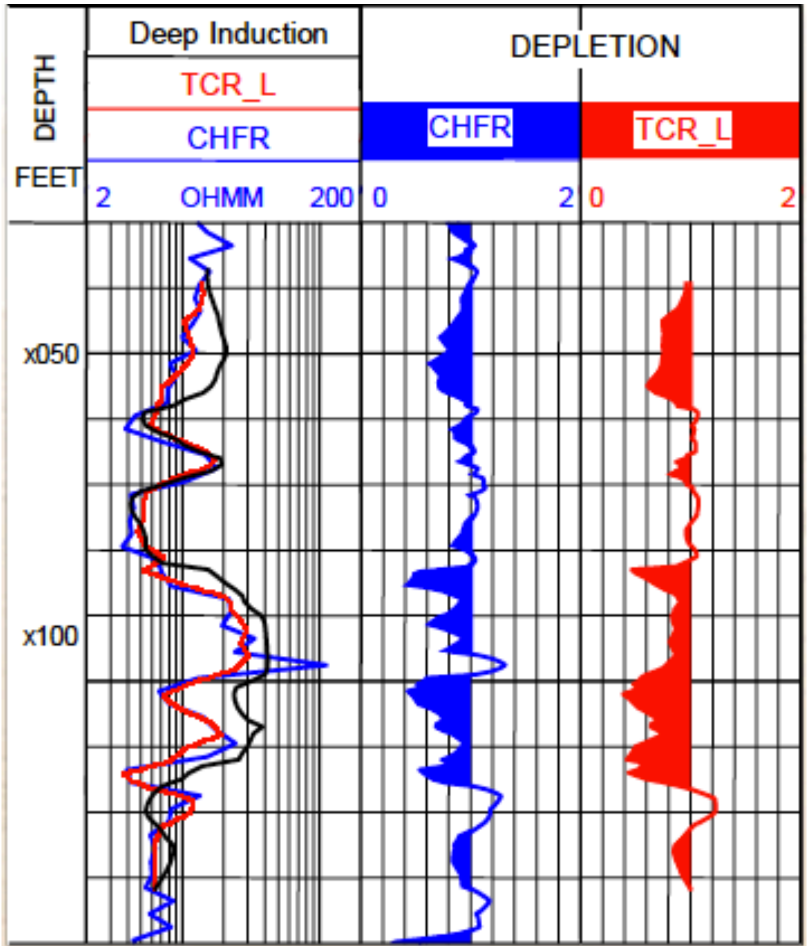

Figure 4: Example of Through Casing Resistivity (TCR) measurements after steam flood. On the left side in the baseline from induction logs in red with the other measurements being TCR measurements from different contractors done after the reservoir was steam flooded (after Zhou et. al., 2002).

Full Field Array EM

In order to illuminate the subsurface in an unconventional resources context we need to look at the key issues where electromagnetics can contribute. Except for geothermal, unconventional plays depend on following the producing horizon. This means deviated or horizontal wells that already make up 60% of all well are here even more important. Placing these wells at the right place is very important. Once the well is placed, the reservoir gets drained for a relatively short period before being abandoned again. Increasing or controlling this draining period by monitoring is the second highest value. Since many unconventional plays are in shales, which are intrinsically anisotropic. The hydrocarbon target being a thin resistive layer or fracture gives rise to another source of anisotropy. This leads to anisotropy and fracture being essential.

Last but not least a lot of these reservoirs are at depth of 2000 m and deeper, which means the sensitivity to target parameter changes for surface EM methods will be low and surface –to-borehole methods are required.

This leads us to look at our Full Field Array concept in a different light. Our Full Field Array EM concept is the generation of a 3D data cube that has as many calibration points as possible and allows the user to extrapolate the calibrated information into an interpretation of the non-calibrated space. Figure 5 shows an artists rendition of such a cube. For EM technologies, we can now phrase the high value problems in terms of unconventional resources objectives:

- The well placement is addressed by improved Geosteering – placing the borehole in the right location in the subsurface by using new EM technology that can look ahead and around the bit for 50 m and more.
- Production drainage is monitored by early installed sensors arrays covering the surface and any available well bores. The coupling to small anomalies is increased by using controlled source electromagnetics instead of passive magnetotellurics. This monitoring will allow observing of fluid movement and optimization of reservoir completion.
- Anisotropy is understood by multi-component measurements and better accuracy and a calibration is achieved by adding borehole-to-surface arrays. This guarantees at the same time the depth coverage.

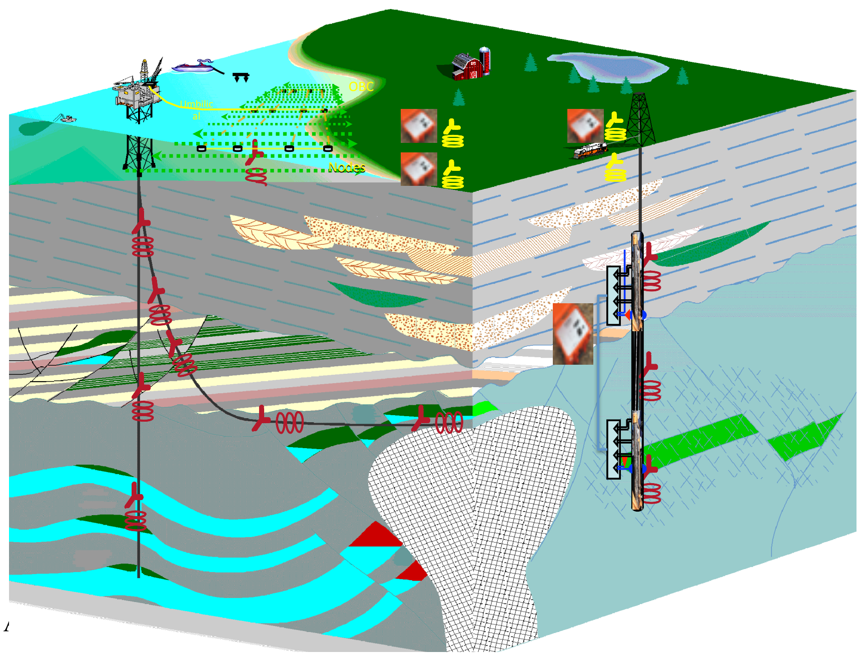

Figure 5: ... le the borehole as well as on the

The figure shows subsurface as well as surface measurement setups. In addition on the right is the borehole-to-surface setup depicted. Electromagnetic sensors are represented by the coil (symbolizing magnetic sensors (H)) and the coordinate indicator representing electric field measurements (E) as well as tensors measurements for both E and H.

In order to significantly improve the production from the low permeability zone like in gas shale and tight gas reservoirs, accurate well bore positioning is crucial to optimize the production while keeping drilling cost at minimum. This key problem requires extensive use of logging while drilling (LWD) modeling and advanced geosteering technique based on electromagnetic method. LWD data includes gamma ray, resistivity, density- neutron and sonic. The LWD real-time data is compared with the model to produce a cost-effective solution in driving the well bore to the target and keeping it within the tight and dispersed reservoir.

The availability of high-resolution azimuthal resistivity LWD imaging tool along with 100% borehole coverage has brought the fracture characterization and formation evaluation to a higher level in unconventional plays. Figure 6 shows a case study of how the application of geosteering improves the decision of landing the well bore at the right location and maintaining it within the Bakken formation. The figure shows LWD measurements along with other geological information from offset wells come into play in placing the well bore in the right position along the trajectory of the thin (15 feet thick) Middle Bakken without drilling into the limestone despite the arduous interpretation. The geological interpretation between the tight limestone and the Lower Bakken was formidable because the resistivity and the gamma ray information in the Middle Bakken do not show any distinguished characteristics for the geosteering decision-making (O'Connell et al., 2012).

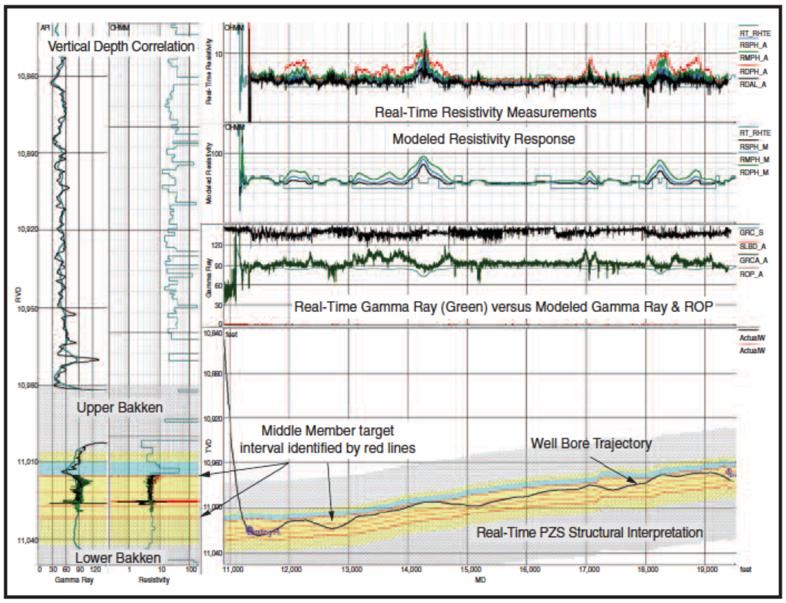

Figure 6: Correlations displaying LWD measurements utilized for geosteering decision at Bakken formation. LWD measurements along with other geological information from offset wells assist in placing the well bore in the right position along the trajectory without drilling into the limestone despite the arduous interpretation (O'Connell et al., 2012).

The problem with populating this 3D cube is cost of data acquisition, resolution of the electromagnetic methods and information value as their sensitivity decreases with distance from the source. We address this by adding the borehole as calibration point and acquiring more data. Since EM methods and equipment are in many cases custom made, the cost is still many times higher than for surface seismic. Our array system is the second attempt (Rueter et al., 1995) to reduce the cost of EM hardware. For borehole measurements the cost is a secondary issue because the information value of placing a borehole in the subsurface is significantly higher than the EM measurement cost.

The drivers for the integration need to be the oil companies (or geothermal producers) as they are the ultimate beneficiaries of the technology integration value. So far, in all cases, data density is insufficient. Since this vision of the technical integration was outlined in 1996 (Strack and Vozoff, 1996) two necessary improvements have happened: First, hardware has made significant progress and electromagnetic data can now be acquired with fairly broadband systems that have, at the same time long-term-stability, low noise and are significantly cheaper than electromagnetic systems were 20 years ago. Issues such as synchronization, data formats, and data storage are well in the past. Figure 7 looks more like a seismic layout of a regular gridded surface and irregular lines linked

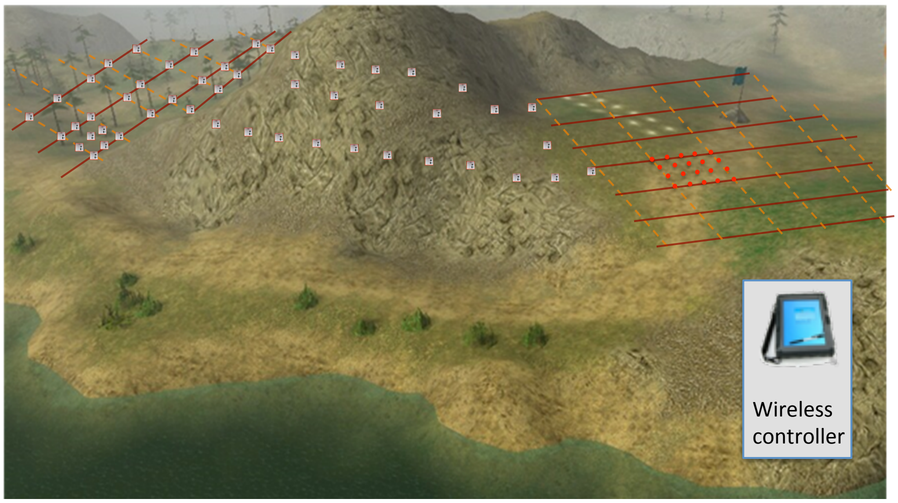

Figure 7: Seismic-style layout example of an electromagnetic survey using wireless nodes in a regular grid layout and also in irregular lines.

with rough terrain line, where nodes are carried or helicopter-deployed. Second, borehole anisotropy measurements are now available everywhere as the two largest service companies provide them. In addition, borehole seismic systems are today often manufactured by 3rd party vendors, which allow us to more easily integrate electromagnetics add-ons.

Technology components

The motivation outlined above leads us to the following key technologies:

- Placing the wellbore more accurately by locking around and ahead of the bit: For this we have experimented with innovative borehole EM technology and carried it to the proof-of-concept stage.
- Monitoring hydrocarbon production for more effective drainage: A surface-to-borehole system is a reliable approach as it can be deployed along existing commercial delivery path.
- The understanding of anisotropy in terms of reservoir characterization, and data calibration as well as fracture mapping has been great improved since the event of 3D induction logging. This allows effective integration of borehole and surface measurements onshore as well as offshore.
- Mapping thin resistive hydrocarbon reservoirs is still a unique capability of electromagnetics, which allows separation of more saturated reservoirs from less saturated ones.
- Integration with other methods is essential for placing final drill locations. This is greatly aided by more dense and more advanced data sets

One of the key issues in placing the wellbore inside the reservoir is to predict ahead and around the bit. Present technology can only look a few meters to the side. Zhou et al. (2000) proposed technology that could actually do this. It is a time domain system with short transmitter-to-receiver spacing and multi-components (Strack, 2003a & 2003b). The systems were developed through proof-of-concept phase and sideways and look ahead capability to tens of meters demonstrated (Banning et al., 2007). In order to remove the effect of the LWD tool string special deconvolution methods need to be applied (Hanstein et al., 2003). Figure 8 shows an example of simulations for such a time domain system for a horizontal well when water is being coned by production. It can be seen that the signal varies significantly with distance from the wellbore. The curves display the measured voltage from a 3-component receiver system. The arrow in red in the figure symbolizes the large dynamic range required (13 decades) and demonstrating that this can actually be done was key to the proof-of-concept. Banning et al. (2007) showed some results where side ways and look-ahead capabilities were demonstrated. Since the data is proprietary it cannot be shown here, but what can be said is that the field data confirmed the theoretical predictions.

This concept can be extended to the outer reservoir space going several kilometers away from the well bore (say 2-3 km). To overcome downhole power issues and high voltage safety concerns, a surface-to-borehole approach is the right path. Together with surface measurements this allows us to monitor the details near wellbore for calibration and borehole –to-surface to tie into the surface 3D volume and further surface measurements (Strack, 2004). Figure 8 shows an example from feasibility in the Middle East (Colombo et al., 2010). Here the time-lapse model was derived from different reservoir simulator time steps and appropriate fluid substitution in the induction logs. Using different time steps and building the differences yielded a difference model of ‘removed oil’. This model was then used to model surface-to-borehole and surface-to-surface measurements. Only the surface-to-borehole measurements gave reasonable anomalies as the target was below an anhydrite layer.

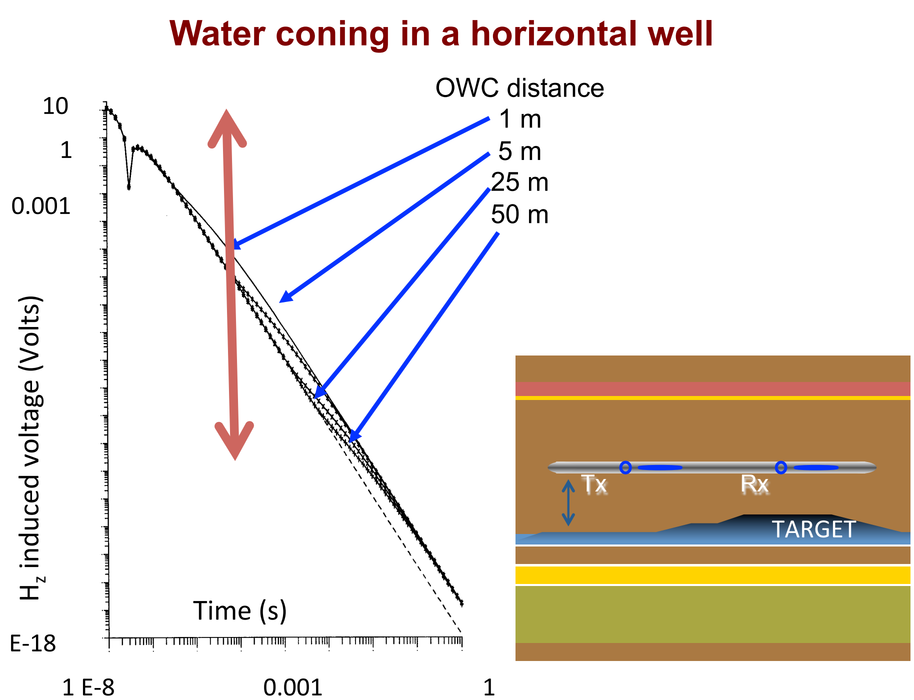

Figure 8: Synthetic mode

In Figure 9 we see the survey layout on the top right. A transmitter with several tens of amperes is used (though for modeling purposes everything was normalized to unity values). The receiver array is at about 1900 m depth below an anhydrite layer. The feasibility is for the Ghawar field test site. Source positions are placed in a circular array with a walk away test. The 3 images are for this walk away test. The four beige and dark brown horizontal slices are reservoir simulator driven removed oil projections, which build the underlying models for the color images. We can see that with increasing time the oil in this depth slice is getting less and we also see that the images reflect this (the red anomaly is moving to the right). The anomaly is still relatively low, which is why the test has so far not been carried out.

Immediately this leads to permanently installed sensors where the sensors continuously record.

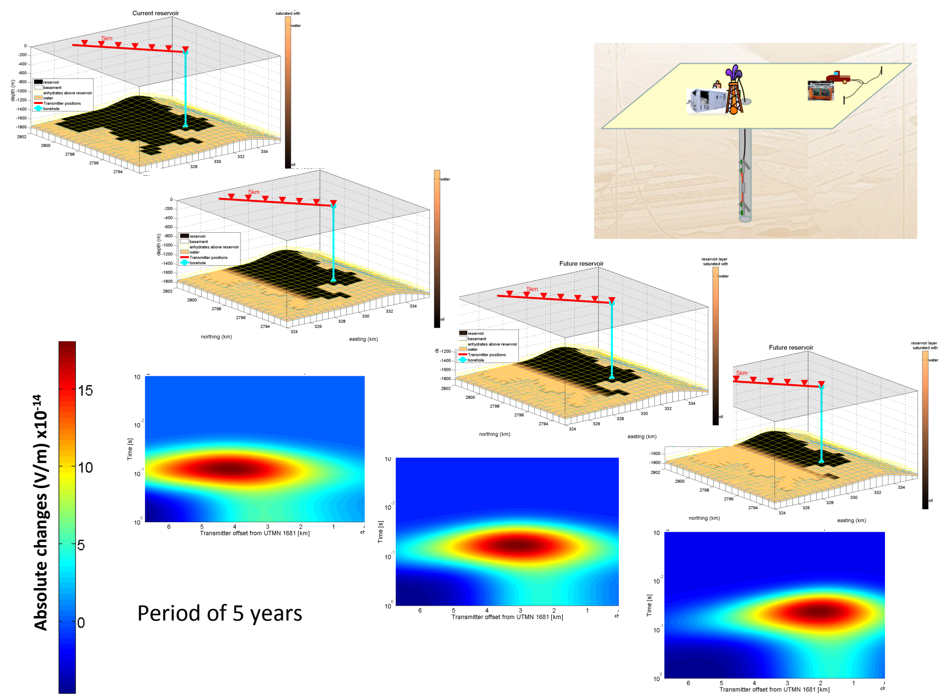

Figure 9: Simulated response of surface-to-borehole EM for 4 time steps over a period of 5 years (Colombo et al., 2010). For three of them the surface-to-borehole anomalous response is shown.

On the more pure technical aspects anisotropy, directionality and thin resistive layer detection are the most important aspects. Directionality is address by tensor measurements. This is aided by using multiple transmitter dipoles in perpendicular direction. Further inline and broadside arrangements can be used, but in the context of 3D array measurements this is not so important. Following, we will expand on the anisotropy and resistive layer detection. In addition fracture detection from induction logs is becoming more common (Hu et al., 2010).

For the anisotropy illustration, Figure 10 shows an example of a 3D induction log interpretation. The 3D induction-logging tool was developed by Baker Atlas under mentorship and funding of Shell (Kriegshaeuser et al., 2000, Strack et al., 2000). It allows the measurement of horizontal and vertical resistivities in vertical borehole, specifically, and in general, the determination of the tensor resistivity. The motivation lies in a large amount of resistive oil trapped in thin laminations between conductive shales. Standard induction logs only yield horizontal resistivities, which are dominated by the shales (Yu et al., 2002), resulting in significantly underestimated hydrocarbon reserves. Obviously, this tool does not only apply to thin laminations but also to any dispersed shales and with the appropriate petrophysical analysis yields tensor saturation. Higher transverse isotropic resistivities (resistivities are the same on horizontal direction and different in vertical direction) result in most cases in higher vertical resistivities and thus higher hydrocarbon saturation or more oil. This justified the development of this tool. In Figure 10 we have a natural gamma ray log on the left, indicating shale content. To its right is gamma-gamma density and neutron density curves followed by 2D inverted resistivities (vertical, Rv, and horizontal, Rh). Together with the porosity track that follows and the appropriate petro-physical equation, oil saturation is calculated. Note the oil saturation is significantly higher from the vertical resistivities. When we carry out controlled source EM (CSEM) measurements with a grounded dipole, we measure predominantly the vertical resistivity. This means calibration of surface dipole CSEM measurements can now be done as it was previously not reliably possible.

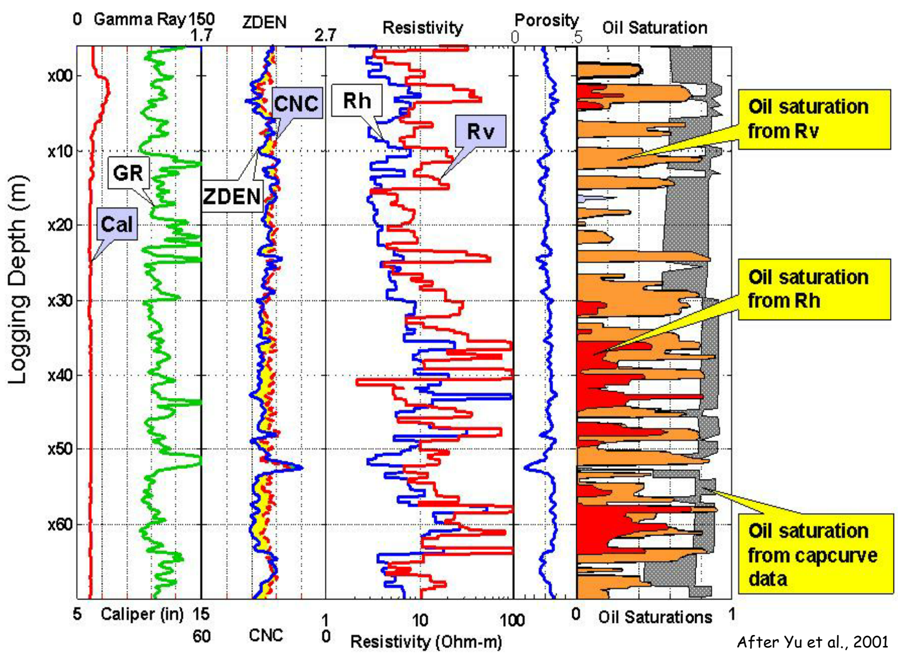

Figure 10: Example of an

Given that most sedimentary basins show electrical anisotropy as do fractured carbonates, one could assume that most of our prior log calibrations are inadequate and many of our interpretations should be revisited. Fortunately, this was recognized in the1960 by Keller who developed simple rules of log reduction to deal with the common anisotropy in the oil field environment (Keller and Frischknecht, 1967; Harthill, 1968). He studied systematically the effect of electrical anisotropy on logs. In summary, he derived limiting equivalent resistivity rules using the fact that inductive methods are biased towards conductors and galvanic methods are biased towards resistors. In the 1960s, the group around Keller used resistivity logs for vertical resistivities and induction logs for the horizontal one and also inverted them (in 1960s with great difficulty!). From a normal induction log we can obtain the limiting equivalent resistivities by using the cumulative conductance (thickness multiplied with resistivity) for the lower bound and the cumulative transverse resistance (resistivity multiplied with thickness) for the upper bound. Figure 11 shows a graphic display of a log with the cumulative conductances and transverse resistances on the right. Graphically you can point to the layer boundaries, calculate the cumulative values and fit a straight line between the boundaries to determine the horizontal and vertical resistivities for that layer. These values are then superimposed on the log on the left. In this way we can now calibrate our logs for the purposed of linking them to magnetotelluric data (horizontal resistivities) and grounded dipole CSEM data (vertical resistivities).

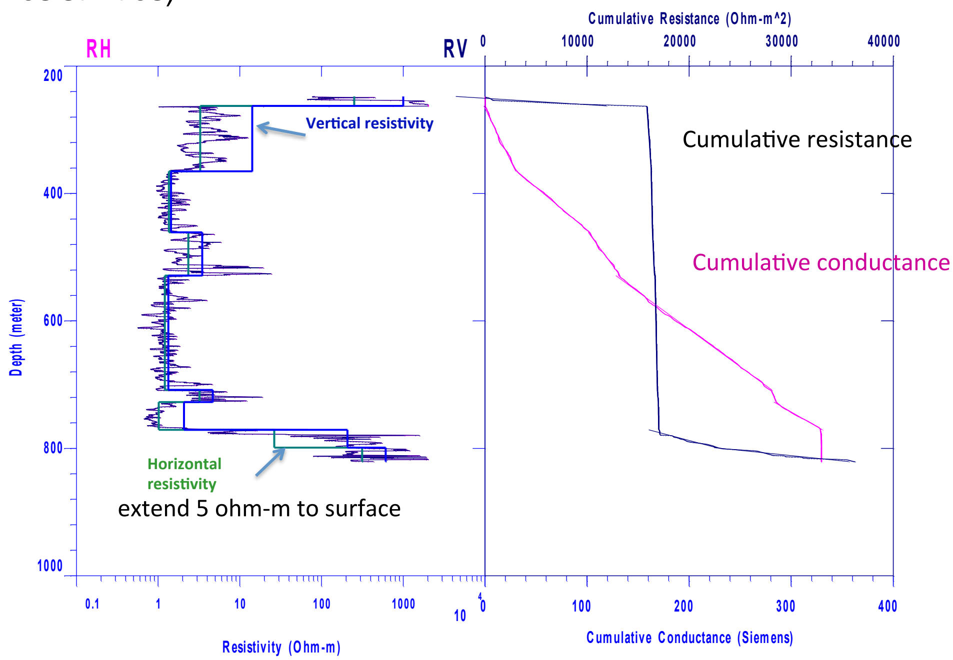

Figure 11: Example of deriving vertical and horizontal resistivity from an induction log shown on the left. The equivalent values superimposed on the log are derived from the cumulative conductance and cumulative transverse resistance on the right by fitting lines between layer boundaries. The layer boundaries are interactively picked by the user. The plot was generated with IX1D by Interpex Ltd. (www.interpex.com).

This technical progress did not provide sufficient business motivation until the fast growth, subsequent fall and now stabilization of the marine EM exploration industry (Eidesmo et al., 2002). Technically, this was caused by the thin resistive layer effect recognized first on land (Eadie, 1980; Passalacqua, 1988; Strack et al., 1988) and subsequently pioneered offshore by Eidesmo et al. (2002). An early example is shown in Figure 12 from the Troll field, Norway (Johnstad et al., 2005). We can see in the top part of the figure a normalized amplitude plot, which is the measured amplitude over reference background amplitude outside of the hydrocarbon reservoir. Clearly, an anomaly can be seen which coincides with the seismic image with superimposed interpreted anomaly in the middle as well as the interpreted structure of the reservoir shown at the bottom of the figure.

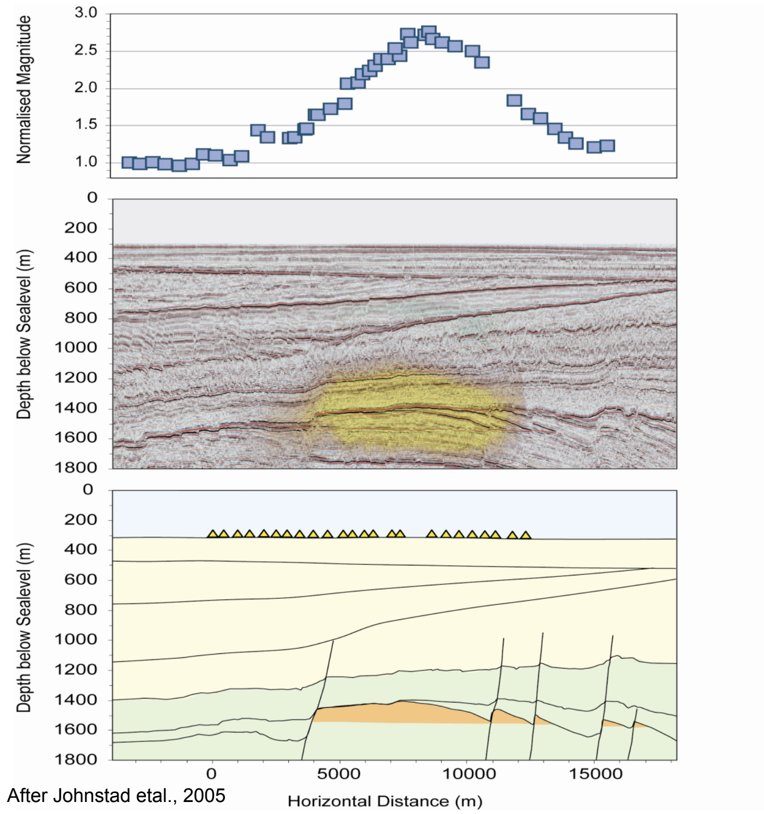

Figure 12: Example of a marine CSEM interpretation for the Troll field, Norway (after Johnstad et al., 2005). The top shows a magnitude versus offset curve , which exhibits an anomaly directly over the reservoir.

The most important aspect of applying electromagnetics is the integration with other methods. We have selected here a success story from a geothermal exploration in Hungary. Here, magnetotellurics (MT) and gravity combined with vintage seismics were used to define early drilling locations (Yu et al., 2009). MT was done at low frequency and high frequency (Audio MT) modes. The data was inverted first independently and then compared with the gravity inversion. Subsequent interpretation with the geology yielded a combined model where low resistivity and low-density anomaly coincided. For the entire survey throughout Hungary over 40 targets were defined in such a fashion. Next the vintage seismic data was integrated with the EM and gravity and the inversions were redone several times as the structural interpretation changed. This yielded finally the interpretation shown at the top of Figure 13. Subsequent drilling produced a 4 MW geothermal well with sufficient temperatures at approximately 1700 m depth.

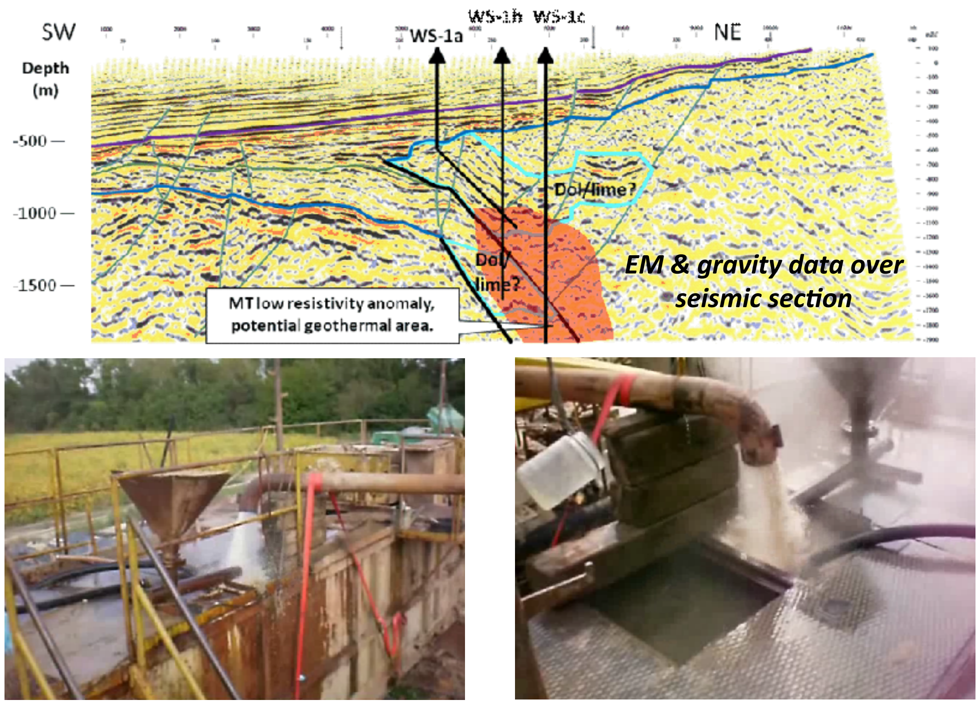

Figure 13: Integrated interpretation results from the integrated geothermal exploration in Hungary (Yu et al., 2009) The top of the figure shows the seismic section (vintage) with structural interpretation and resistivity anomaly superimposed. The bottom 2 pictures are from the initial flow test of the successful 3 MW geothermal well.

While this was done with vintage MT systems and larger spacing, the reruns of the interpretation and resulting lateral shifts of the anomaly clearly tell us that denser data or smaller array setups (like 9 or 25 sites patches) would have delivered the results faster. Now, when the power plant is being developed more wells will have to be drilled and denser measurements will be required as the resolution capabilities of sparse stations is not enough. In other hydrocarbon applications (Zerilli et al., 2002; Buehnemann et al. 2002) like for example sub-salt imaging dense EM measurements have already proven very useful. The dense spatial sampling allows better noise definition and thus better interpretation.

Conclusion

For unconventional resources electromagnetics can provide value in several technical areas and contribute added value:

- In placing the borehole inside the reservoir getting maximum reservoir contact deep reading geosteering technology that is based on electromagnetics helps by looking up to 50 m around and ahead of the drill bit. This gives the driller sufficient time to steer the drill in the optimum location..
- As shale is intrinsically anisotropic, considering anisotropy is essential to calibrate and integrate borehole and surface measurements. Anisotropy can also be used for fracture direction and location. In addition, multi-component EM can and be used as hydrocarbon indicator and further reduces the exploration risk.

- Integration of various measurements with calibration data such as well logs is essential in reducing the drilling risk. Using 3D inversion of 3D array measurements is a key element for this.
- Last but not least, the cost reduction in hardware allows more and denser measurements and imaging techniques with faster turn-around time. This has been solved with the advent of new array acquisitions systems.
- In order to take this technology to market several commercial field trials are required.

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