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Full Field Array Electromagnetics: Advanced EM from the surface to the borehole, exploration to reservoir monitoring.

K. Strack[1,2] & A.A. Aziz[1,2]*

Summary

Increasing production efficiency and monitoring water/steam/CO2 movements are key issues for hydrocarbon production and geothermal reservoirmonitoring.Similar technical issues exist for CO2 storage applications. They can be addressed with borehole and surface electromagnetic measurements, which are sensitive to fluid variations in the pore space. At the same time linking the electromagnetic (EM)information to 3D surface and borehole seismic data yields extrapolation to the inter-well space. Evaluating several reservoir dynamic monitoring methods and technologies leads to a practical concept of Full Field Fluid Monitoring with electromagnetics. Our implementation includes marine and land sources and receivers, surface-to-borehole arrays and single well system that can look tens or even 100 m around the wellbore and ahead of the drill bit.

On land we distinguish between exploration and production applications. For exploration it is essential to distinguish resistive and conductive targets equally well. To do this we can use natural field magnetotellurics for the conductive target like sediment thickness or geothermal targets. For resistive targets such as hydrocarbon reservoirs, we add Controlled Source ElectroMagnetics (CSEM) with a dipole transmitter. For ease of operation it is thus easiest to measure all EM components. If you want to use frequency domain and time domain in the same receiver deployment, you need to either cross calibrate the receiver or have a receiver with switchable response function.

In the marine environment, we include our receiver into seismic spreads and use fluxgate sensors for the low frequency magnetotelluric field and search coils for the high frequency component. CSEM is only needed when the resistive strata are thin. Multi- component acquisition and dense station spacing is essential to measure anisotropy and get lateral structural changes and to extend the application from exploration to production.

For borehole use we are combining our EM sensor packages with borehole seismic acquisition system or build special purpose LWD sub-assemblies. So far, we have been 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 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 issues associated with the inherent averaging nature of EM methods.

Introduction

Electromagnetic 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 only 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 much lower levels than expected.This is unusual, as in the borehole environment electromagnetic (EM) logging tools are the most important

[1]: KMS Technologies – KJT Enterprises, Inc., USA
[2]: University of Houston, USA
kurt@kmstechnologies.com

of all and in most cases used for reserve estimates.

The issue clearly lies in the loss of sensitivity with distance from the object of investigation and thus with increasing depth, the volume of investigation becomes larger and more fuzzy. While in the mining industry the targets are relatively shallow and mostly conductive, hydrocarbon target are normally resistive and electric fields are required. (Passalacqua, 1983; Eadie, 1980; Strack et al., 1988; Eidesmo et al., 2002) Unfortunately, electric field source and receiver systems are only customary in the marine environment as high power systems are dangerous to operate. In addition cost of a high power system goes up quadratic (power = current*current*ground resistance) as generator cost goes mostly linear with output current. While in the 1980s megawatt sources were used for geothermal exploration (Keller et al., 1984) in addition to superconducting receivers, we can today achieve the same or better results but more electronic control of the source waveform, improved signal-to-noise receivers and data processing (Strack and Vozoff, 1996; Strack, 1992). New version of these concepts using today's low power, low drift electronics and exclusively digital filters are refining this even further.

In addition to the bias towards conductive or resistive targets, anisotropy has been an ongoing issue.The electrical anisotropy of the subsurface has only been recently understood with the event of 3 component induction logs (Kriegshaeuser et al., 2000). We can now integrate sub-surface and surface EM measurements by calibrating horizontal and vertical resistivities correctly.

From the hardware side, electromagnetic systems always had a high cost per channel and bulky equipment. While a significant instrumentation downsizing effort would require funds beyond thebusiness value of the technology, there is sufficient room for improvements by linking seismic concepts and experience.This addresses the cost reduction from operational side. It means that multiple measurements are being carried out together and the logistics cost, which is usually the biggest part is covered by seismic operations. Thus incremental cost of the EM measurements is small. This is a must for larger scale field operations.

As long as only small amount of data are being acquired on land, the value of EM will be limited as the lateral resolution of EM is not as good as seismics. In the offshore environment where the business models are completely different this is not the case. Here, any additional information that can contribute to de-risking a drilling decision will help. The success of marine electromagnetics to the exploration portfolio has shown this (Eidesmo et al., 2002). The real value lies in the extending the technology use to additional parts of the reservoir life cycle, namely production.

The success of marine development has fueled improvements in the land development. Our new array acquisition system is a 24-bit version of our 32 bit marine node, our land transmitter design benefits from our marine transition zone transmitter.

Full Field Array EM

The 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 1 shows an artist rendition of such a cube. Her we can see several high value problems of the oil industry:

- Geosteering – placing the borehole in the right location in the subsurface
- Monitoring - observing fluid movement with permanent & semi-permanent sensors
- Defining attic reserves – exploring&monitoring from the surface (onshore & offshore) and linking the information to the 3D data cube.

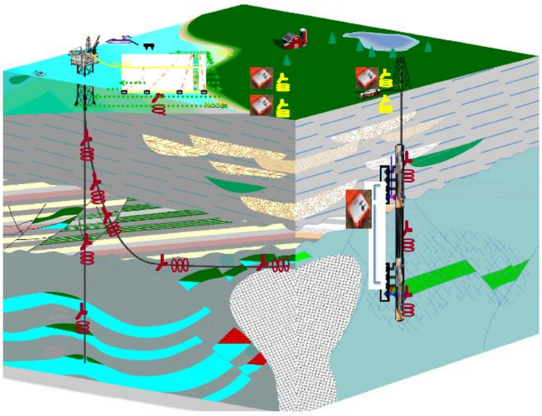

Figure 1: Artists rendition of Full Field Electromagnetics components. Sensors placed inside the borehole as well as on the surface (onshore and offshore) are shown.

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.

The problem with populating this 3D cube is cost of data acquisition, resolution of the electromagnetic methods and information value. 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) of reducing 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. Here, the issue remaining is the change of business model of the service companies as assets are owned by the oil field owner and only limited services are required. As the marine exploration cost is already very high, electromagnetics had a chance to break into a high-risk market with limited (compared to other geophysical methods) but unique risk mitigation value.

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. 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 acquire with fairly broadband system that are at the same time long-term-stable, have low noise and are significantly cheaper than electromagnetic system were 20 years ago. Issues such as synchronization, data formats, and data storage are well in the past. Figure 2 looks more like a seismic layout of a regular gridded surface and irregular lines linked with rough terrain carried nodes, but is the rendition of an electromagnetic survey. Second, borehole anisotropy measurements are now available everywhere as the two largest service companies provide them. In addition, borehole seismic system are today often manufactured by 3rd party vendors which allows us to easier integrate electromagnetics add-ons.

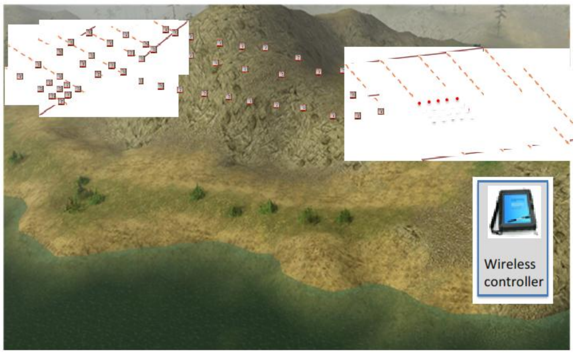

Figure 2: Seismic-style layout example of an electromagnetic survey using wireless nodes in a regular grid layout and also in irregular lines.

Technology components

Figure 3 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 being trapped in thin laminations between conductive shales. Standard induction logs only yield horizontal resistivities, which is dominated by the shales (Yu et al., 2002) resulting in significantly underestimated hydrocarbon reserves. Obviously, this tools does not only apply to thin laminations but also 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 3 we have a natural gamma ray log on the left, indicating shale content. To its right are 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 petrophysical equation oil saturation is calculated. Note, the oil saturation is significantly higher from the vertical resistivities. When we are carrying 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 hereto not reliably possible.

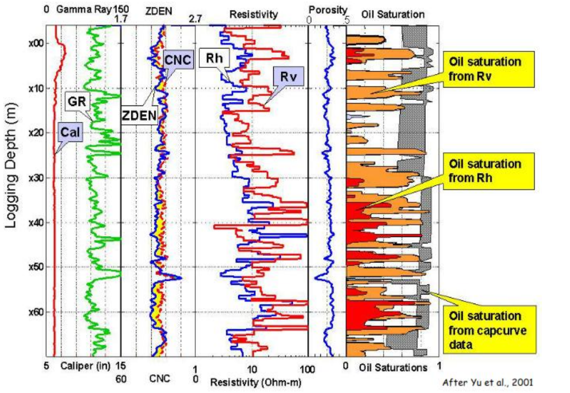

Figure 3: Example of an interpretation of a 3D induction logs interpretation (Yu et al., 2001). The tracks from left to right show: natural gamma ray for shale content, gamma-gamma density and neutron density for gas zone indicators, 2D inverted vertical and horizontal resistivities, interpreted porosity and interpreted oil saturation.

Given that most sedimentary basinsshow 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 already recognized in the 1960 by Keller who developed simple rules of log reduction to deal with the common anisotropy in the oil field environment (Keller and Frischknecht, 1967). 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 4 show 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 calibrated our logs for the purposed of linking them to magnetotelluric data (horizontal resistivities) and grounded dipole CSEM data (vertical resistivities).

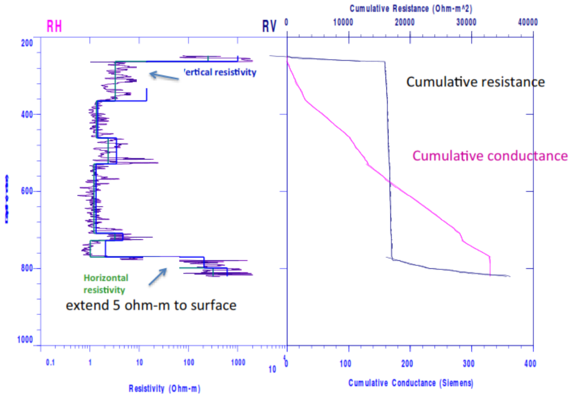

Figure 4: Example of deriving vertical and horizontal resistivity from an induction log shown on the left. The equivalent values superimposed on the log are derived from the cumulative conductance and cumulative transverse resistance on the right by fitting lines between layer boundaries. The layer boundaries 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. 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 5 from the troll field , Norway (Johnstad et al., 2005). We can see in the top pat of the figure a normalized amplitude plot, which is the measured amplitude over a 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.

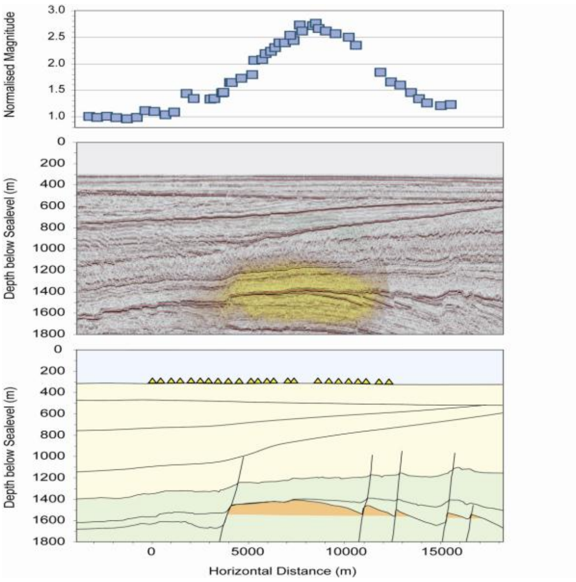

Figure 5: Example of a marine CSEM interpretation for the Troll field, Norway (after Johnstad et al., 2005). The top shows a magnitude versus offset curve , which exhibits an anomaly directly over the reservoir.

The next step in the marine environment is – as on land – to reduce acquisition hardware cost and to acquire denser data. Automatically, one would try to image the data directly as raw data as shown in Figure 6. The figure is for synthetic data and these concepts were confirmed in several proprietary data sets (Thomsen et al., 2007). The figure shows a common-source gather, where the curves are at increasing offsets from the left. In the top of the figure we have the UNPROCESSED data displayed with automatic gain control. The vertical axis is diffusion time after current turn OFF. You can clearly see first the ocean wave arriving, which is the initial strong response part that does not spread out that much with time. Following is the subsurface response, which includes the target and the rest of the subsurface. It clearly smears over larger time with increasing offset. As the target is resistive its contribution arrives early then the rest of the response at larger offsets. The bottom of the figure shows the target response only (automatic gain controlled displayed). The target move-out response behaves like a refracted seismic wave. This is a key feature requesting to use closer spacing and more data as well as time domain processing with marine data. It will allow direct imaging of the data and thus more operational decision can be made and the technology will move further in the reservoir life cycle.

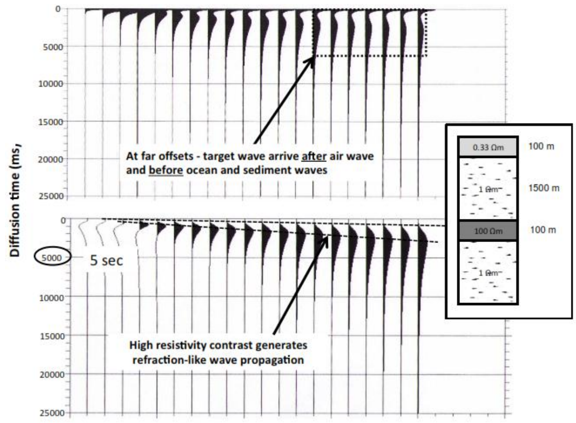

Figure 6: Common-source gathers for the impulse response of an inline electric field marine tCSEM™ setup. The normalized traces represent different offsets between source and receiver; displayed are measured voltages. The Earth model has an oil reservoir at 1,500 m depth below the seafloor. The top gather contains all wave components (air wave, ocean wave, sediment wave and target wave). The bottom gather only contains the reservoir response after removal of all other components.(after Allegar et al., 2008)

Technology examples

After seeing the needs for more denser or array data from the technology component side, we now look at two examples of difficult, but typical exploration problems where much denser data is beneficial. The first example is a sub-salt exploration problem where an additional drilling location around a salt dome was to be determined (Buehnemann etal., 2002; Zerilli et al., 2002). The issue was that reflection seismic data could not determine top of salt of the salt flanks or the structure below the salt. No electrical logs were available except for water well. The producing well site was to be used to used to drill a deviated well through the salt into a target area sub-salt (for environmental reasons). The survey location was near several major German cities and thus extremely electromagnetically noisy. Over the past several hundred years the near surface was many times re-cultivated and understanding the near surface from just surface expressions was not possible. This resulted of lengthy operation workflow derivation to determine operationally reliable electrode contact procedures. Over a period of 2 months over 300 sites were acquired, some of them 50 m spaced to control cultural noise (near rail road and through villages). This time included 2 weeks of survey operational parameter testing. A remote reference site was located several hundred km away.

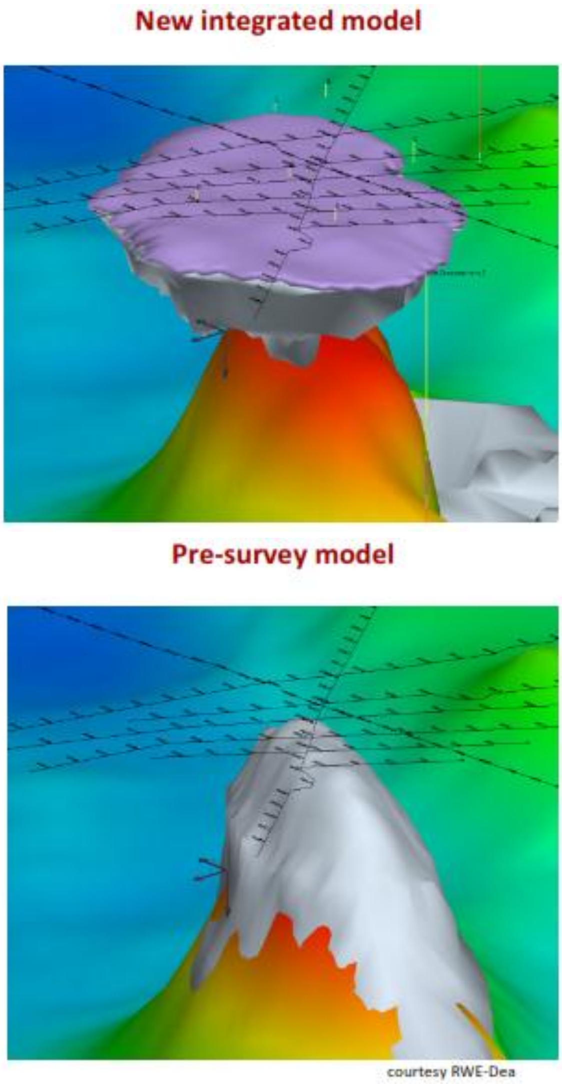

Figure 7: Interpreted images of the sub-salt exploration survey in Northern Germany. The interpretation integrates magnetotellurics with gravity and seismics(Buehneman et al., 2002). On the left is the interpretation AFTER acquiring and integrating the MT data and on the right the interpretation before the survey.

More detailed description can be found in Buehnemann et al. (2002) and Zerilli et al., (2002). Here, we are only showing a summery slide of the pre-survey and post- survey interpretation in Figure 7. The survey lines are indicated on the figure and the cross lines are the line with 50 m spacing with the other lines using 100 m spacing. Clearly, this would not have been possible with wider spacing, which is again a supporting argument for larger channel counts and array measurements.

The next example is from a success story from a reconnaissance geothermal exploration survey in Hungary. Here, magnetotellurics and gravity combined with vintage seismics was used to define early drilling locations (Yu et al., 2009). Magnetotelluric was done in low frequency and high frequency (Audio magnetotelluric) mode. 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 8. Subsequent drilling produced a 4 MW geothermal well with sufficient temperatures at approximately 1700 m depth.

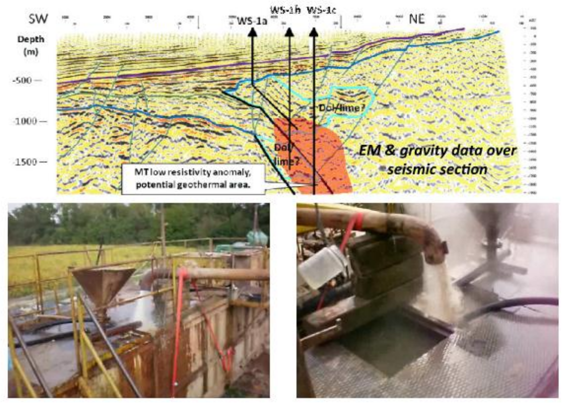

Figure 8: Integrated interpretation results from the integrated geothermal exploration in Hungary (Yu et al., 2009) The top of the figure shows the seismic section (vintage) with structural interpretation and resistivity anomaly superimposed. The bottom 2 pictures are from the initial flow test of the 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 plantis 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.

Reservoir monitoring

Over the past 15 years the need for permanent sensors has become clear to the industry. Unfortunately, due to the existing business model, it has been difficult to adapt new business models and make permanent sensors a viable business. Only recently have the large service companies been able to have profitable sensor division mostly in temperature and pressure measurements and completion hardware. Feed forward geophysical sensors are still in the beginning though the need is getting obvious. (First Break, Sept. 2011, report on reservoir monitoring). Among the sensors are seismic, gravity and electromagnetic sensors. Here, we focus on electromagnetic sensors and assume that automatically seismic sensors will be included as the data needs to be integrated into the 3D seismic cube. Gravity sensors are less important as the density is intrinsically included in the seismic impedance(Strack, 2010).

Our original concept included starting with natural field and then adding as needed controlled source and borehole measurements (Strack, 2004). We have since deviated from this concept as it we have learned from feasibilities that surface EM measurements in general has low resolution to deeper reservoir changes. Natural field will have even lower sensitivity than controlled sources. In addition the time-lapse changes in a reservoir are mostly three-dimensional and thus the corresponding anomaly is even about one decade smaller.

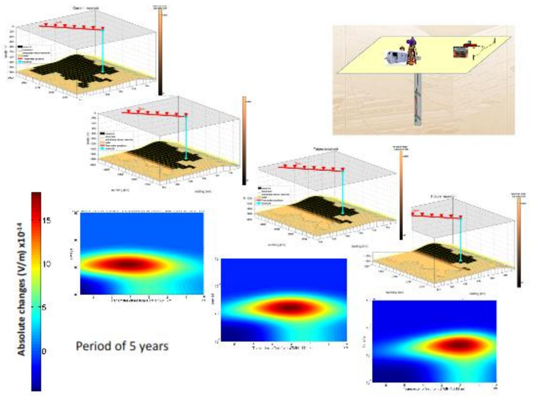

Figure 9: Simulated response of surface-to-borehole EM for 4 time steps over a period of 5 years (Colombo et al., 2010). For 3 of them the surface-to-borehole anomalous response is shown.

Figure 9 shows an example from a 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.

In the figure we see on the top right the survey layout. 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.

Conclusion

We started out with stating that the real value of electromagnetic methods lie in reservoir monitoring and explored why this has not made ore progress in the past 20 years. The reason of not taking EM methods closer to production operational decisions lies in:

- Technical deficiencies of the methods and the commercial demonstration of the solutions, hardware cost and standardization closer to seismic. For surface measurements this has been shown onshore as well as offshore.
- Lack of integrating the various measurements with calibration data such as well logs. This has been technically solved with the commercialization the 3D induction log that now allows proper up scaling as is customary during field studies.
- Last but not least cost reduction in hardware thus allowing more and denser measurements and imaging techniques with faster turn-around time. This has been solved with the event of new array acquisitions systems.

Several feasibilities have shown that of these solutions together with proper reservoir analysis and sensor technology allow to take this integrated technology (combine with seismic!) to a real field trial. However, while surface data will give us the integration in the 3D cube and interwell space, it will have low resolution and surface-to-borehole measurements are required.

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