THE LOG-DERIVED SW COMPARED TO SURFACE MEASUREMENT OF CORE SW: HOW THEY ARE RECONCILED

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ABSTRACT

The log derived total water saturation (Swt) is lower than a surface (laboratory) measurement of total water saturation remaining in the core, Core_Swt. Hydrocarbon fluids leak as the core is brought to the surface. Previous interpreters have noted this fact and either used preserved core or ignored the differences. Now we have a solution to reconcile both measurements. The maximum lost fluids are equivalent to the hydrocarbon-filled portion of the free porosity measured by a nuclear magnetic resonance log (NMR). The method for calculating the log-derived surface saturation, Sw_surface is to first determine the hydrocarbon pore volume, (HCPV). Then subtract the free hydrocarbon volume. Convert the net hydrocarbon volume to saturation using the total porosity. Why is this method important? There are very few preserved core measurements of Sw. This method provides a comparison of core and log Sw that does not require a preserved core. However, the method is not exact because the free hydrocarbon-filled porosity within the core pore space is not the same volume as the portion of that free hydrocarbon volume that bleeds from the core as the core is retrieved to surface. The measurements that we used are resistivity, spontaneous potential (SP), elements from nuclear spectroscopy, bulk density, neutron, NMR and, of course, Core_Swt to compare to.

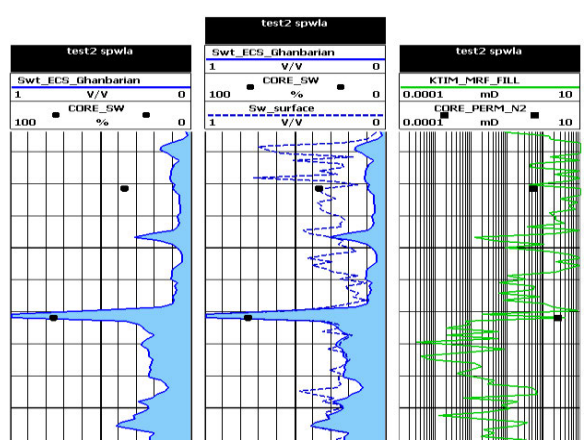
The plot at the end of the abstract shows our goal: compare core Sw to log derived Sw_surface so that one compares both log and core at the same surface conditions.

Core Sw can be used to confirm log Sw when there is a free fluid measurement to assist and complete mineral-based log interpretation is used.

We show several examples: Bitumen sands, as well as conventional and unconventional (Montney).

- An example is presented from a low porosity zone with high permeability. Core_Sw is higher than the log derived in situ Sw.
- Another example is very high free porosity so the core Sw initially looks like it is mis-scaled.
- In Bitumen oil sands, the NMR clearly shows there is free porosity in situ even though at the surface the bitumen is not mobile. In addition, our method to obtain Rw from the SP is innovative and provides a good variable Rw value to use in the Water Saturation Equation (Ref. 1) for the bitumen sands and shales. The Cation Exchange Capacity (CEC) is obtained by identifying the clay families and their associated CEC. The same methodology is followed for the all examples.
- An example is shown in the Unconventional Montney formation where the permeability is very low. As the permeability decreases, the fluid loss from the retrieved core also decreases.

The method shown is empirical, designed for the Petrophysicist who does not have a research laboratory available. There is some adjustment required when the NMR is unable to "see" certain hydrocarbons due to the nature of the measurement (such as dry gas). However, the results certainly show whether the log interpretation is validated by core, despite not having preserved core.



INTRODUCTION

The log derived Sw is always lower than surface measurements of core Sw due to lost fluids and core-handling methodology (Ref. 22). We calculate Sw_surface as a saturation equivalent to the saturation measured at the surface on the core, after fluids were lost as the core was retrieved to surface. The maximum amount of lost fluids is equivalent to the free porosity within the pores that is filled with hydrocarbons, oil and gas, or FREE_OIL [free oil/gas volume]. The core Sw is close to the calculated surface saturation as the core was not preserved.

Consider the pore illustration (Ref. 23). The crude oil shown is in nuclear magnetic space as "Free Porosity". As the core is retrieved to the surface, some of this oil will bleed out of the core, depending on the pore throat size (as well as permeability, viscosity, temperature, pressure etc.) Hence, if we measure and interpret the free porosity occupied by oil within the pore, we will have a maximum amount of free porosity that will drain. We convert the maximum free porosity to water saturation at surface conditions by subtracting the free porosity from the hydrocarbon pore volume and dividing by porosity. We call the result, Sw_surface, where,

Surface HCPV = Insitu HCPV Minus Free Oil, and

Sw at surface = 1 - Surface HCPV / Porosity

The resulting Sw_surface could be higher than the core water saturation since it is probable that not all the hydrocarbon-filled free porosity has drained. However, the envelope between Sw_surface and in situ log derived Sw provides the possible solutions for Core Sw. When Core Sw falls in this envelope we can consider the core and log Sw's are reconciled. There are, however, reasons why the core Sw does not fall in the envelope. Among these are the different vertical resolutions of the NMR tool and the sampling frequency of the core as well as the vertical resolution of the resistivity tool and the density log. We attempt to mitigate some of these resolution differences, in the examples shown.

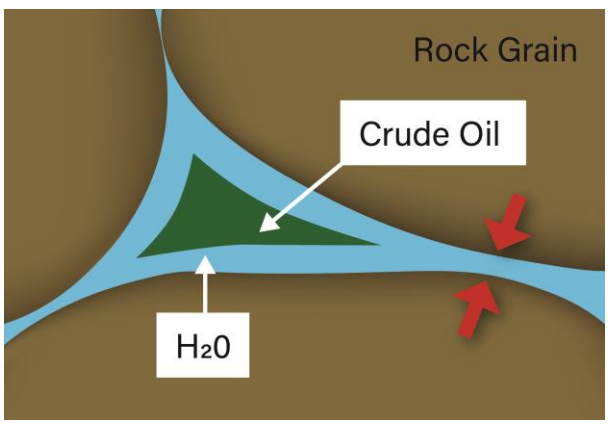


Figure 1:- Volume of free oil, shown as 'crude oil', that bleeds from the core is dependent on the pore throat size, viscosity, etc. (Ref. 23). Oil shown is in the pore space of a water-wet rock.

The result of the computation, before Sw_surface, is below (Figure 2). Incidentally, the Rw has been confirmed by a comparison of Rt and Ro in the shale when there is no organic carbon (see Appendix). In these shales, Ro should equal Rt, however, there are some thin zones where Ro is greater than Rt, but we assume this is caused by residual vertical resolution differences rather than Rw changes.

METHOD AND EXAMPLES

First a note about Core_Sw. All the measurements in this paper were made prior to the methods proposed in 2019, Ref. 22. Consequently, the Core Sw's presented are probably already higher than they should be if newer core handling procedures were used.

The input logs to the 'in situ' water saturation calculation are shown in the List of Acronyms. All examples have an elements-to-mineral-derived porosity, cation exchange capacity and Example 1 also has a pseudo thin-bed resistivity using the pad of the Formation micro imager tool superimposed on the deep laterolog array curve.

The first pass of the calculation for Example 1 uses the 33ms porosity from the NMR mandrel tool with less vertical resolution than pad-type tools. Our program, 'Petrophysics Designed to Honour Core' (PDHC), was used for all examples and was derived using Ref. 5, 6 & 9 to 20.

Note that when a curve name includes "_ECS" it means the curve was provided as an output from our PDHC program that was programmed to use the elemental capture spectrometry tool. Input to PDHC can come from any vendor's elemental tool or x-ray fluorescence measurements (XRF). The output is pre-programmed to use names that are common to Schlumberger curves. Output names are not constrained to any vendor's input or output names. We seek forgiveness if we have infringed on any trademarks.

EXAMPLE 1 HIGH FREE POROSITY COUPLED WITH MEDIUM PERMEABILITY

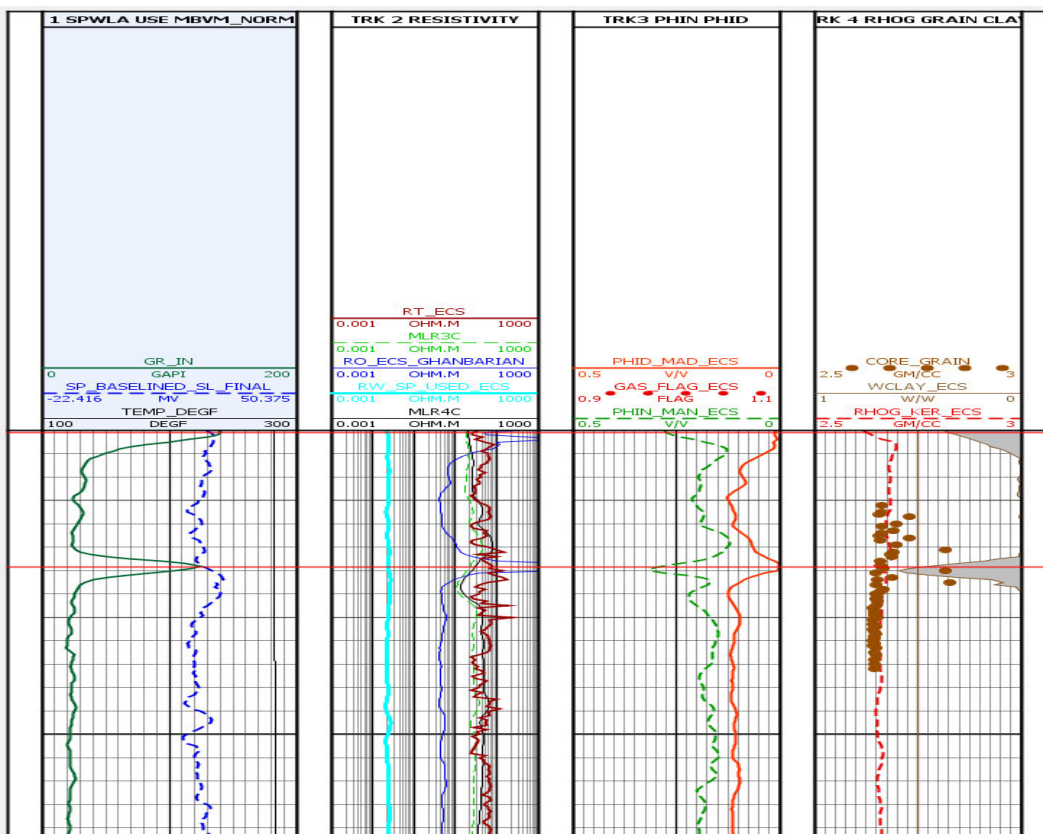


Figure 2: - High Free Porosity Example. The input and computation results are shown. Incidentally, the Rw has been confirmed (not shown) by a comparison of Rt and Ro in the shale (see Appendix) when there is no organic carbon. Of course, when porosity approaches zero, the Ro will be higher than "Rt" since the "Rt" is influenced by the side beds, even though the formation micro scanner pad-1 resistivity was used. Note the higher core grain density values. The curve RO_ECS_GHANBARIAN is the wet resistivity using a formation factor developed by B. Ghanbarian (Ref. 7).

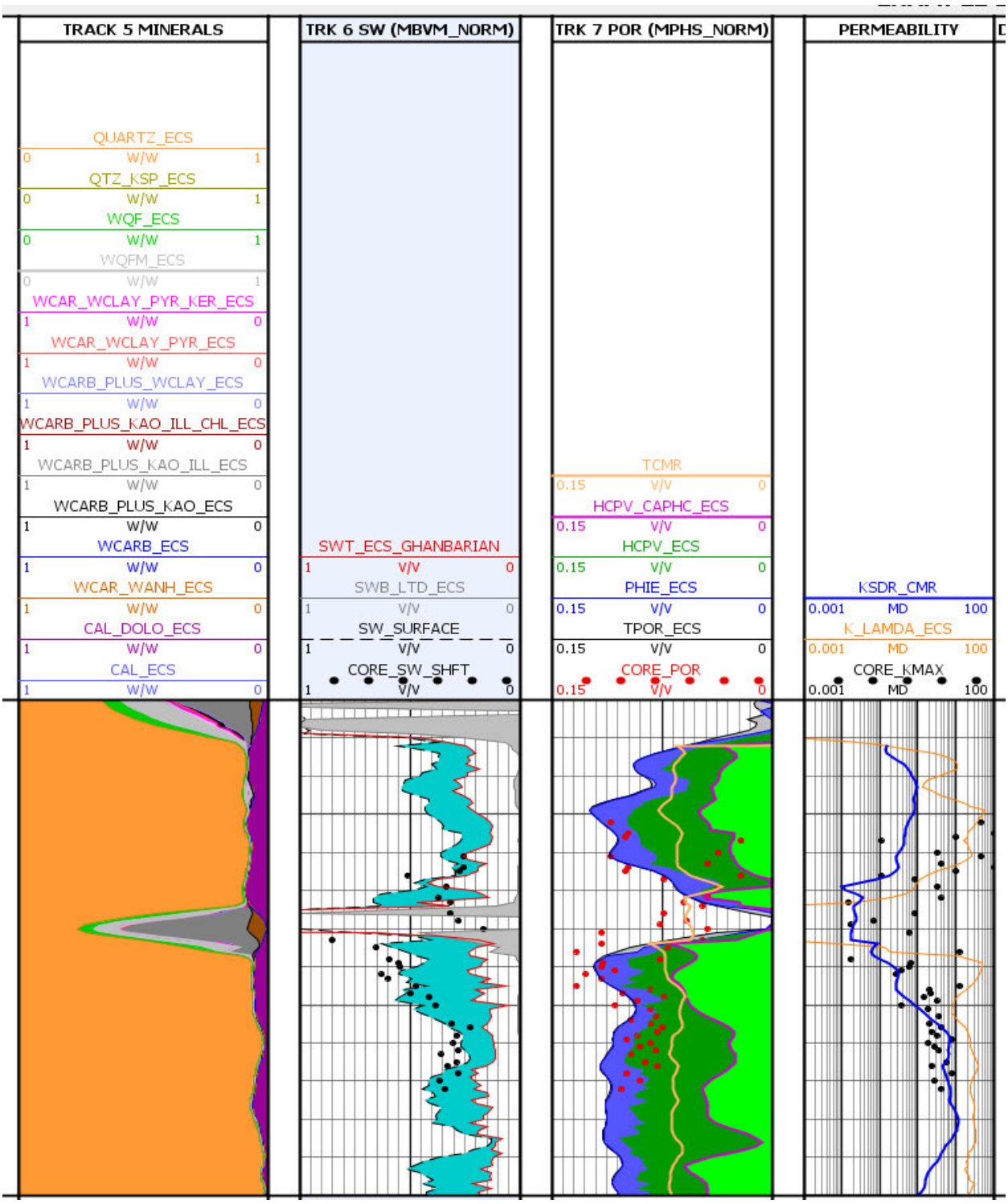


Figure 3: - High Free porosity with core Sw in the blue-coloured envelope shown in Track 6 above. Compensation for vertical resolution of the mandrel NMR has been made for the zone just under clay-zero porosity, using clustering when original recorded MPHS (Baker's total NMR porosity) was greater than density-derived porosity. In addition, subtraction from MBVM (Baker's 33 ms free porosity) is made. See note below in 'Comments' on NMR porosity. Note that we are reconciling the core_Sw, with the log Sw, not matching core Sw to derive the Rw. The depth between the grid lines is 1 metre. Effective porosity, (Phie), and total porosity, (Tpor), are usually the same since there is almost no clay in the main sand zones.

Review of revised values. Figures 2 and 3

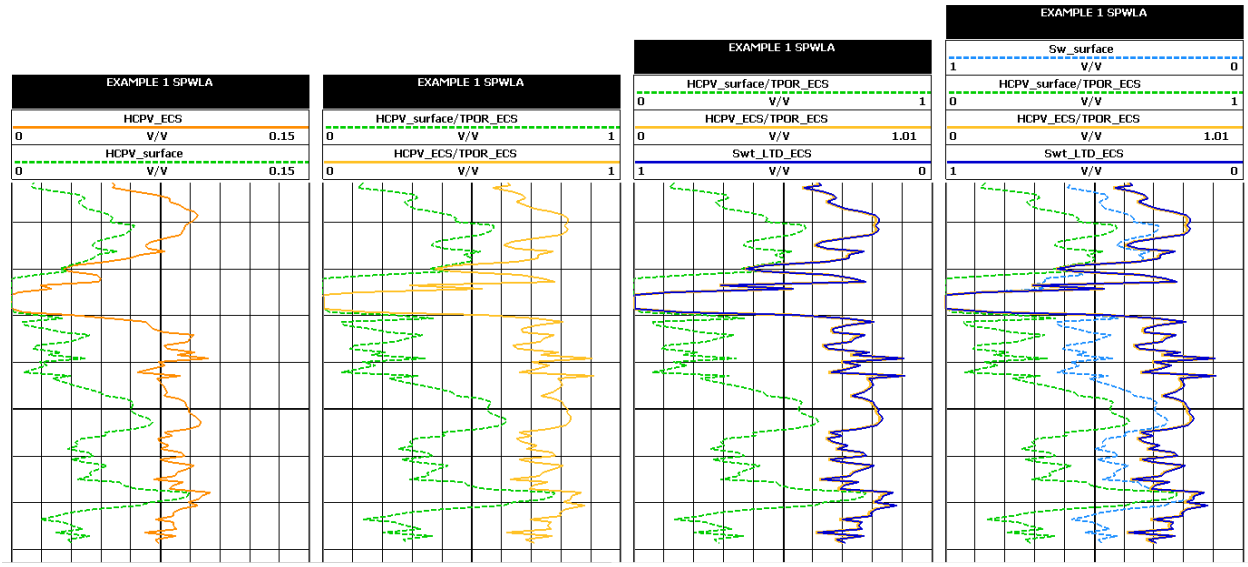


Figure 4: - High Free porosity with core Sw in the envelope. Summary of process: Left Track 1 shows the HCPV and HCPV_surface on a 0 to 0.15 scale. Track 2 is the same data but divided by porosity, resulting in a saturation curve. Track 3 is the same data again with Swt added. The HCPV/TPOR is slightly offset or the Swt would plot directly on top. Next is the same data with blue-dashed Sw_surface. One can see the result of normalization of MBVM before the Sw_surface calculation is made, by comparing the original green dashed HCPV_surface/TPOR_ECS to the final blue dashed Sw_surface which fits the core better (see Figure 5, right track).

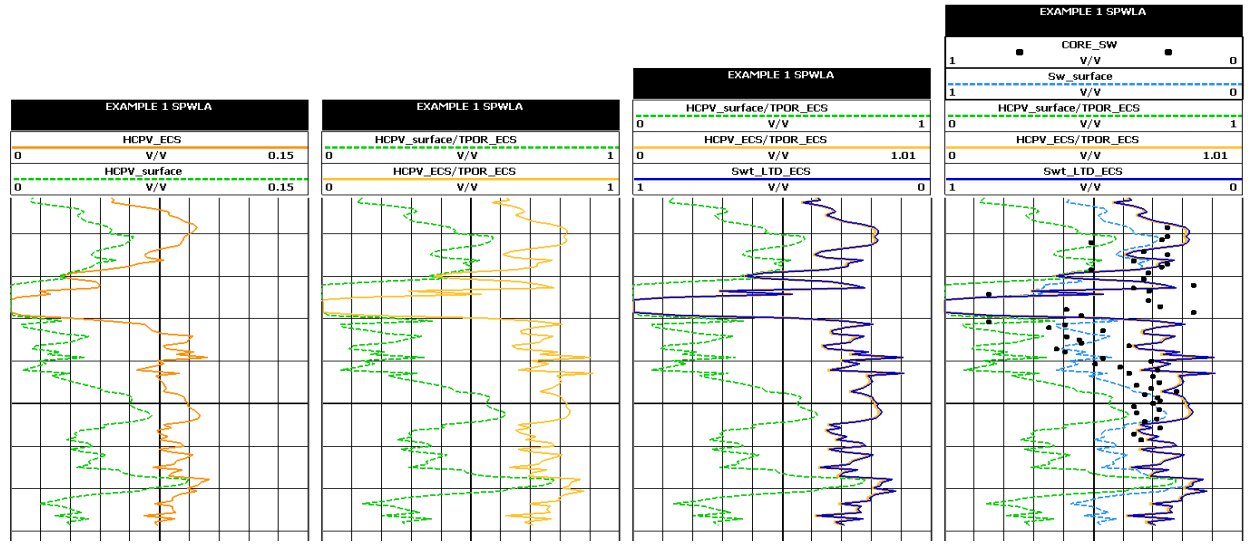


Figure 5: - High Free porosity with core Sw in the envelope. Summary of process: Next is the same data in tracks 1 to 3 but with both Sw_surface and core Sw added in the right-most track. One can see the result of normalization by comparing the original green dashed HCPV_surface/TPOR_ECS to the final blue dashed Sw_surface which fits the core better. The difference between the green-dash and the blue-dash curves is the free fluid porosity that has been reduced indicating that not all the pore free-fluid has bled from the core.

Explanation of Results of Revised Values. Figures 2 and 3

The tracks referred to below, are at the top banner of the Figures.

1. Track 3, Figure 2, PHID_MAD and PHIN_MAN are matrix-adjusted density and neutron curves derived from the elements (Ref. 12). Cross-over indicates light hydrocarbon such as gas. There is no cross-over on the section shown.

2. Track 4, Figure 2, RHOG & CLAY, shows vertical resolution differences of the log grain density (Ref. 16) and core grain density. The higher core values likely siderite since it is common in the area, although there is no core mineralogy on this well to confirm the presence of siderite.
3. Track 5, Figure 3 MINERALS show the main components of the sands are quartz and dolomite. Could the mineralogy be confirmed by the core? Yes, but we do not have core-mineral identification measurements (such as QemScan, x-ray diffraction (XRD), or Fourier Transformed Infrared Spectrometry (FTIR)). Note that if we did have sufficient core mineralogy, we could use a log model dependent on the core minerals, called 'Robust Elm', available in Geological Analysis using Maximum Likelihood [Bayesian] Systems (GAMLS), (Ref. 4).
4. Track 6 SW Figure 3 shows Sw_surface and core SW. When the Core_Sw is within the blue envelope we consider the core and log to be 'reconciled'. Also, note the existence of Core_Sw in the envelope but higher than Swt indicates that some hydrocarbon has been lost and, therefore, the zone has producible hydrocarbons. Use caution about predicting *moveable fluids* (i.e. flushing beyond the pore throat) when Sw is higher than 45% as there may be water block and nothing is moveable A 45% Sw may result in a low permeability of 0.04 mD (In absolute values, Krw = Swe^4 mD). (Ref. 2 & 24).
5. Track 7 POROSITY Figure 3 shows the result of total NMR porosity (output by our program as yellow "TCMR" (from the name, TCMR^{TM_SLB}, even though it is MPHS^{TM_Baker}), and HCPV_CAPHC. Note that hydrocarbon pore volume minus capillary hydrocarbon (HCPV_CAPHC) is equivalent to 33ms free porosity and is output by our program as the light-green shading).
6. Track 8 PERMEABILITY Figure 3, shows the intrinsic permeability, K_Lamda (Ref.13, 14) and the lower blue permeability using the formula from Schlumberger-Doll-Research originally developed for the combinable magnetic resonance tool, KSDR_CMR. Note that KSDR_CMR appears to correlate with Pressure Decay permeability and K_Lamda appears to correlate with the Pulse Decay permeability (Figure 3) K_Lamda is derived from the mineralogy surface area, grain density, pore throat size and porosity (Ref. 13, 14, 17). The Core Sw falls in the coloured envelope between Sw_LTD_ECS and Sw_surface.

Comments: Density and core Porosity differences:

a. Near the clay zone, the higher core grain density indicates siderite is [probably] present.
b. Siderite is not accounted for in the elements to mineral model that we used. If we had core-measured mineralogy we could include it.

- NMR porosity adjustments
  We have established that core Sw and log Swt are reconciled. Now we want to improve the reconciliation by more closely matching the envelope with Core_Sw. The vendor-supplied "thin-bed corrected" NMR curves, post logging. In addition, we clustered the two NMR curves, by nulling data when the original NMR total porosity was greater than the density total porosity above the clay streak. Also, we normalized the 33ms free porosity by subtracting 0.04 v/v above the clay streak and 0.02 v/v below the clay streak. The KSDR_CMR permeability was lower above than below the clay streak.

EXAMPLE 2 VERY HIGH FREE POROSITY COUPLED WITH MEDIUM PERMEABILITY

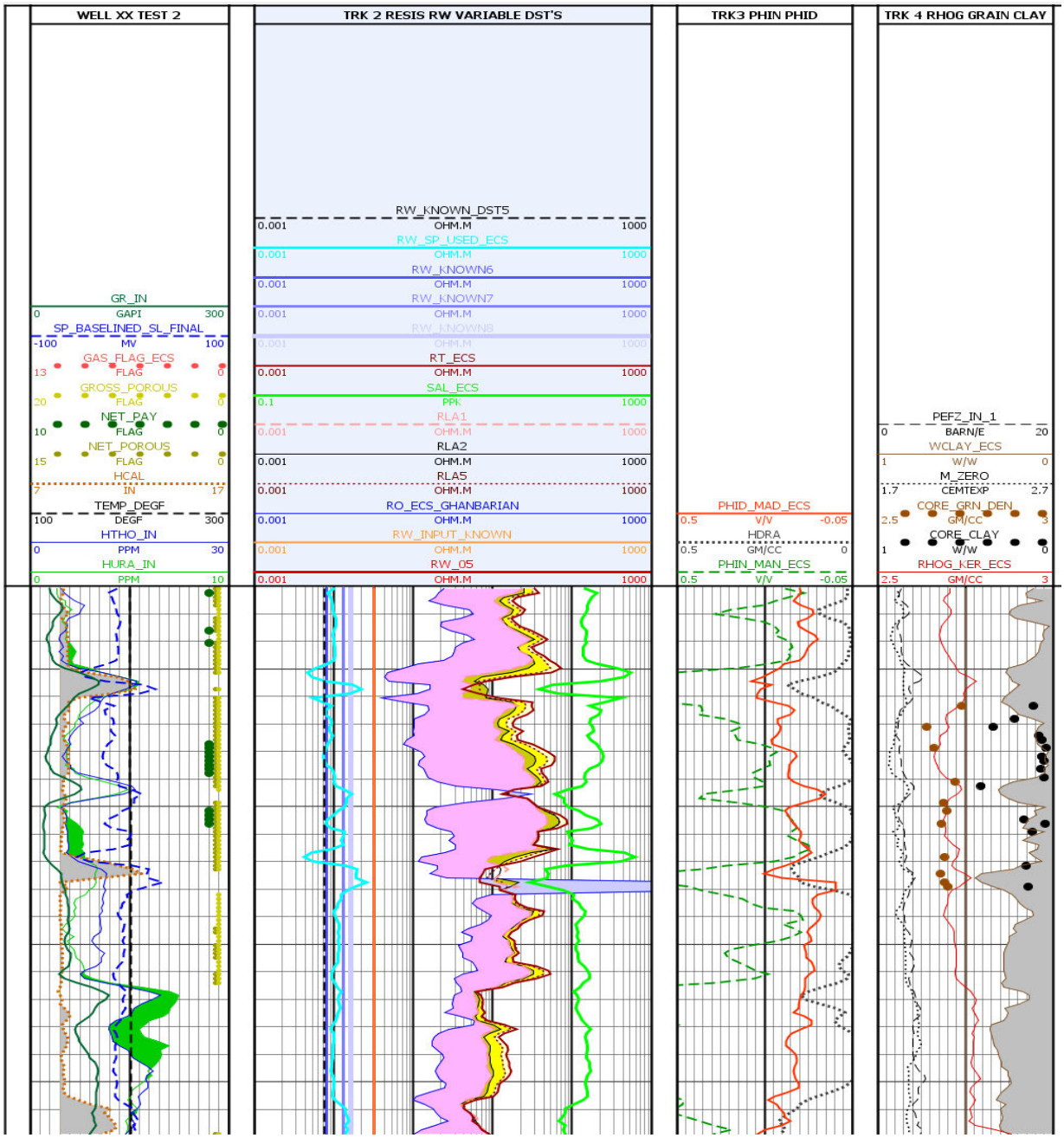


Figure 6: - Very high Free porosity with core Sw. Plot shows input resistivity, density and neutron as well as grain density. The SP is from the ratio of Rxo/Rt. There are 'sine-wave' effects at bed boundaries. The measured SP was not preferred to calculate Rw because the positive SP resulted in shales having low Ro and apparent hydrocarbon. However, over this short zone, there is little difference (see Appendix). Note the pay in the cleanest zone.

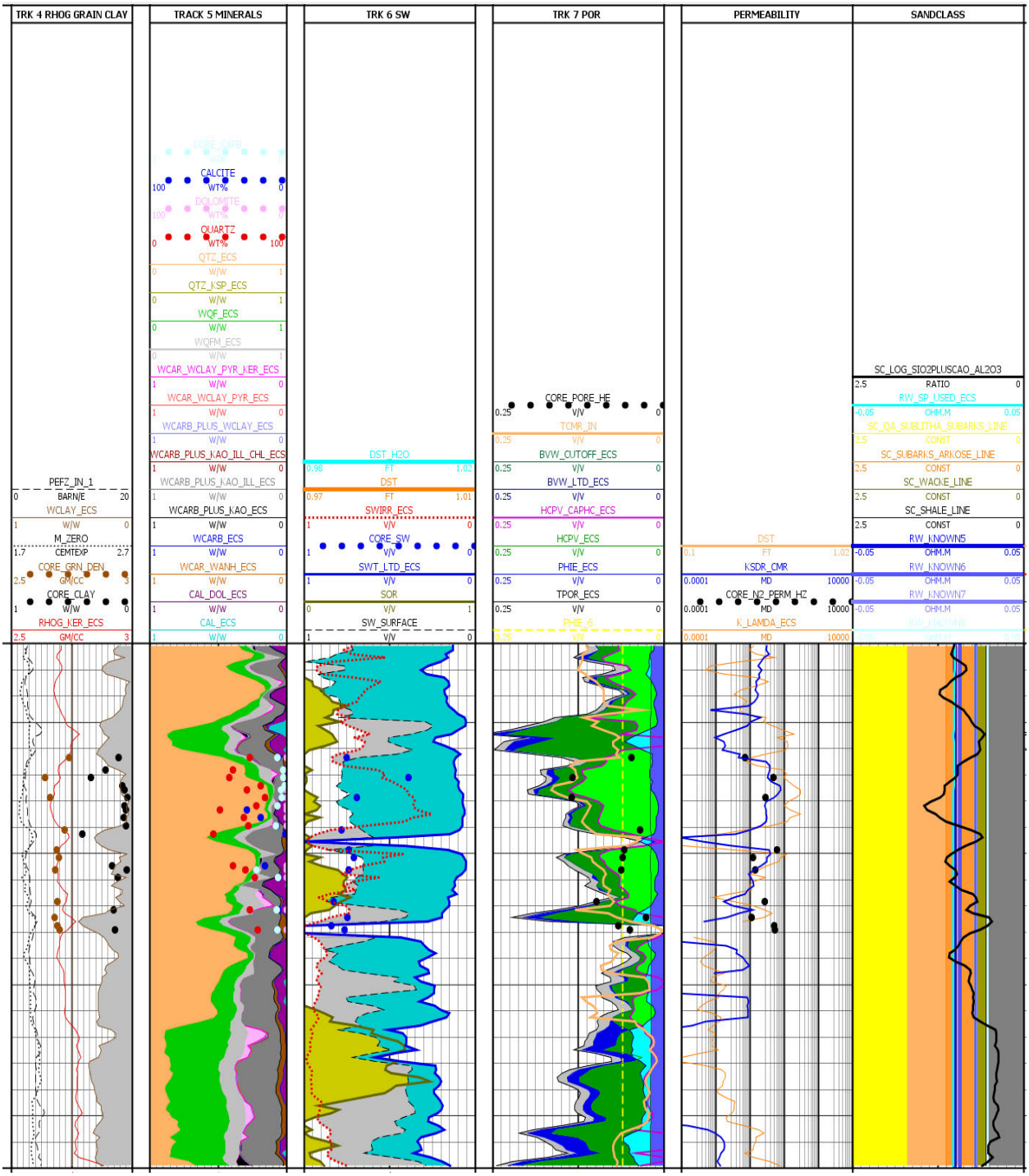


Figure 7: - Very high Free porosity with core Sw. Plot shows output mineralogy, Sw, porosity, permeability and sand class. The core Sw is close to being within the envelope. Note the TCMR-derived KSDR is quite close to the core nitrogen horizontal permeability. On the right-most track, the 'Sand Class' (Ref. 10) ratio of (log(SIO2+CAO)/AL2O3) (black curve) shows a mixture of litharenite (lighter orange colour) and arkose rock (darker orange colour) Yellow is arenite, light orange is litharenite, darker orange is arkose, olive is wacke and shale is grey. Of course, the higher permeability is in the litharenite. Also plotted are the Rw from the SP (light blue, little fluctuation) and the Rw's from the tests (dark to very light blues) to show the Rw used is 'calibrated'.

EXAMPLE 3 LOW FREE POROSITY COUPLED WITH A HIGH PERM (BITUMEN)

The computation provides the 'in situ' weight of tar, which is denoted as WTAR_BOB_QL (orange). The olive-green coding in track 2 and the light green in track 3, represent the free fluid portion of the heavy oil in the pore, some escaping during the core retrieval.

When the core is on the surface, the viscosity has increased dramatically so it appears that none of this thick oil could possibly have escaped. Hence, while core bitumen on the surface is a very low viscosity, "quasi-solid bitumen at 10 degC" heating to 25 C results in mobile bitumen (Ref. 8). Changes in Vp/Vs are used to observe "Mobile, heated bitumen seems to be indicated by significant increases of 30% or more in the Vp/Vs ratio between baseline and 4D monitor surveys". Hence, there is a free fluid signal from the NMR. To obtain more accurate Bitumen-in-Place, log interpretation with NMR can be used, as shown in Figure 8, rather than using the lower-bitumen value derived from the surface-measured core.

EXAMPLE 3 PLOT

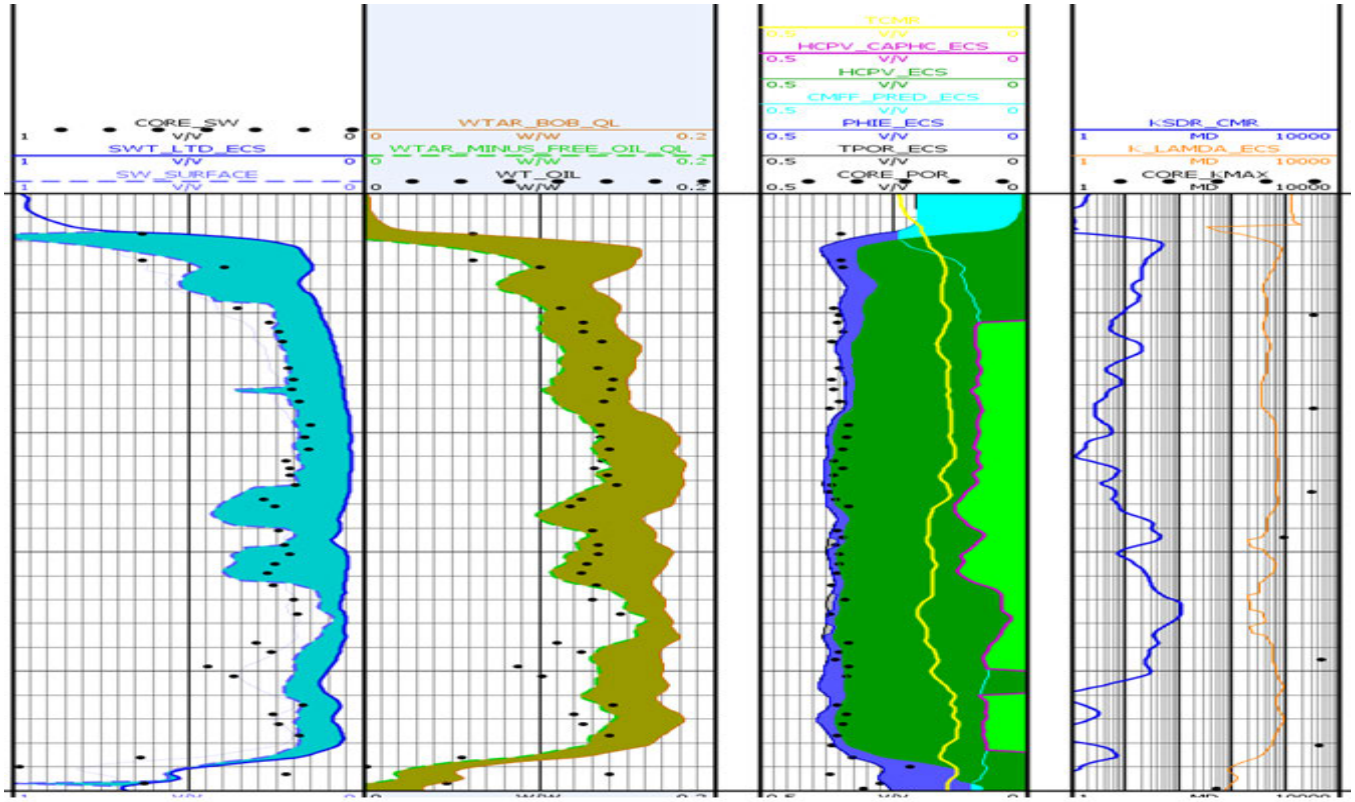


Figure 8: - Medium Free porosity example with core Sw at the left edge of the envelope. In Track 1, note the in situ SWT_LTD_ECS at the right edge of the envelope averages about 20 saturation units less than the core Sw. An interesting aside is the difference is approximately the same as quoted in Ref. 20 Abstract for crushed core Sw units in the Permian Basin, "…previous crushed-rock core analysis protocols underestimate water saturation by at least 30% or ~15 saturation units". Ref. 22 also notes that "…it is not possible to control the efficiency of water extraction using the Dean Stark method". The volumetric result is mirrored when the weight fractions are considered in Track 2. Hence, there is more oil in situ than recovered in the core (of course). The Rw is often considered 'unknown' in bitumen, according to some Petrophysicists who work in the area and '…furthermore, there is no consistent method to the determination of Rw because water filled sands have different Rw's than oil filled sands' (paraphrased). The solution to obtaining Rw is discussed later (see Appendix)

EXAMPLE 4 FREE POROSITY COUPLED WITH A LOW PERM (UNCONVENTIONAL, MONTNEY FORMATION, NORTHERN ALBERTA)

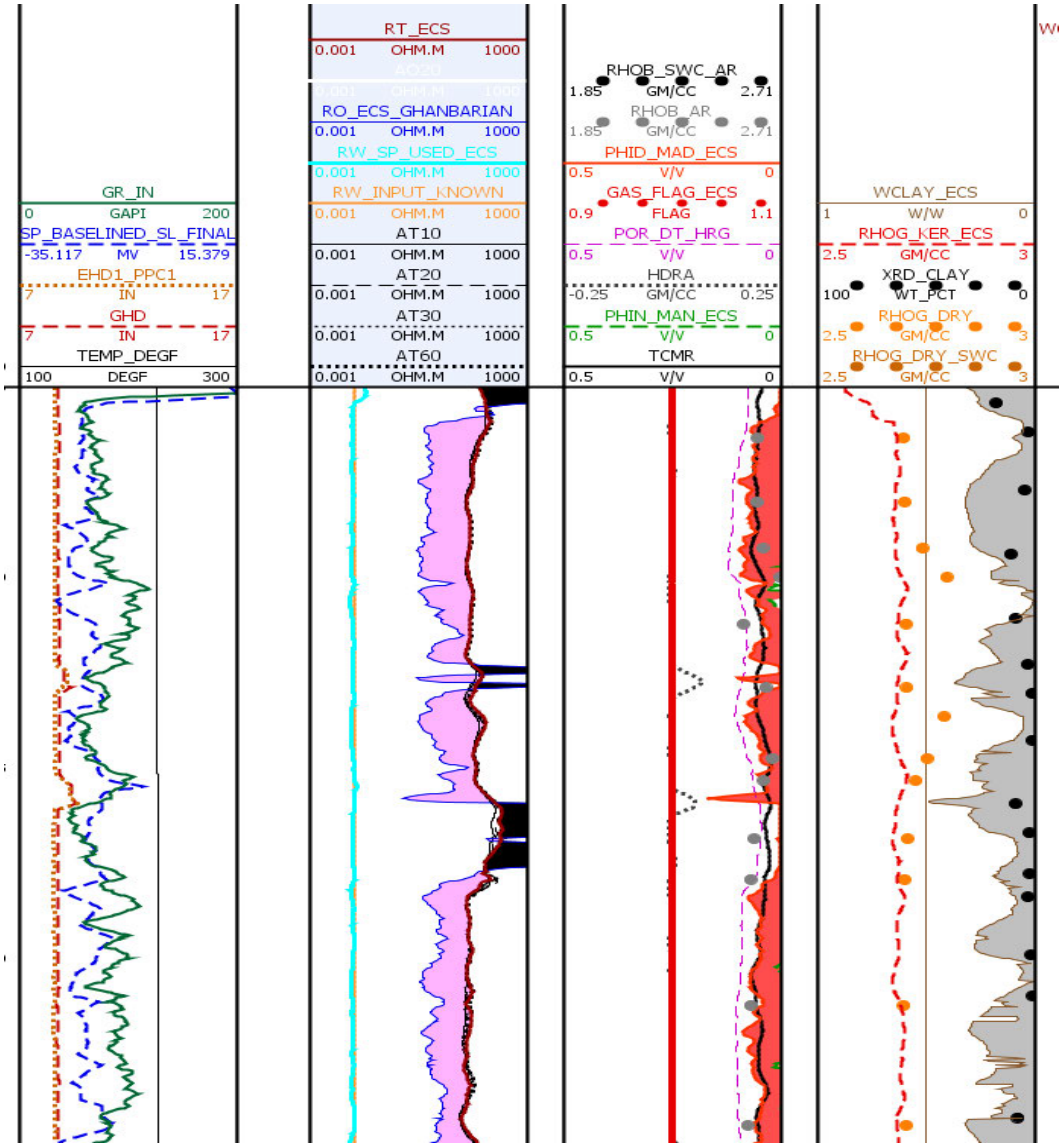


Figure 9: Montney input section on 0.0254-step, no grid. An unconventional.Montney well with a full log and core data set. The TCMR_MW^{TM_SLB} and CMFF^{TM_SLB} were used as recorded. Logs shown in the plot are calipers, HGR, and SP (predicted since mud is oil) & Temperature all in Track 1. In Track 2, RW_SP_USED, RW_KNOWN, Ro, and resistivity AT10 to AT60; Rt_ECS is AT90. In the second track, the pink coding between Ro and Rt is gas, the black coding is when the poorer vertical resolution of the array tool is less than the density-derived Ro. The third track shows a gas flag as well as the density correction, HDRA in the center of the track. On the right side is the porosity from the sonic porosity, the field neutron, HNPO_LIM and the TCMR_WT curve (black). Also, the red gas coding is between the matrix-adjusted density porosity and the matrix-adjusted neutron porosity. Note the difference between the higher field neutron on limestone and the much lower matrix-adjusted neutron. The fourth track shows the grain densities of core and log as well as the clay of core and log. Note that most of the clay core samples come from the lowest clay zones. The reason for this probably human bias to pick the lowest clay zones. Also the bedding of the rock is probably much thinner than seen by the elemental tool, so we do not 'see' the real bedding without formation micro scanner bed resolution.

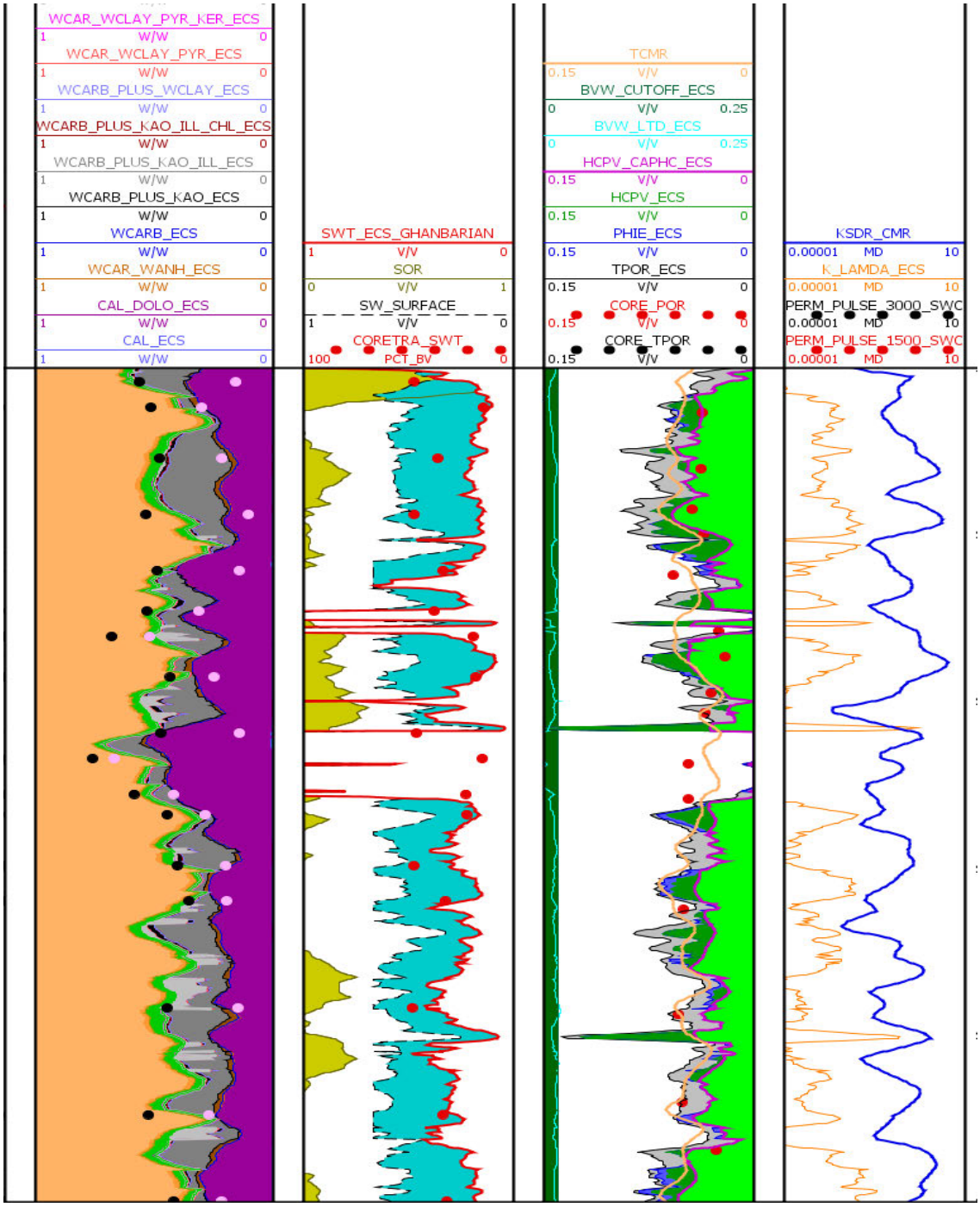


Figure 10: - No grid, same section as Figure 9 on 0.0254-step. Free porosity with core Sw in the envelope. The high free fluid is gas (shown in Figure 9). The envelope is based on the 33ms CMFF. Note there is a high loss in zones where Core_Sw is at the left of the envelope, as the core comes to the surface, even though permeability is low, as shown on the 0.00001 to 10 mD scale. On the other hand, there is almost zero loss when core_Sw is on the right side of the envelope. The zero loss zones correlate with low K_Lamda permeability, as expected. Since K_Lamda determines porosity from the high resolution density log, it has finer vertical resolution than the KSDR_CMR permeability. Our recommendation is to always use high resolution measurements, coupled with dipmeter bedding, *especially* when comparing to core. Although depth adjustments have been made with core and log, core appears to be slightly deep to the log, noticeable when low quartz does not line up exactly with low core quartz. Note this environment is different in terms of the relative values of KSDR_CMR and the lower K_Lamda.

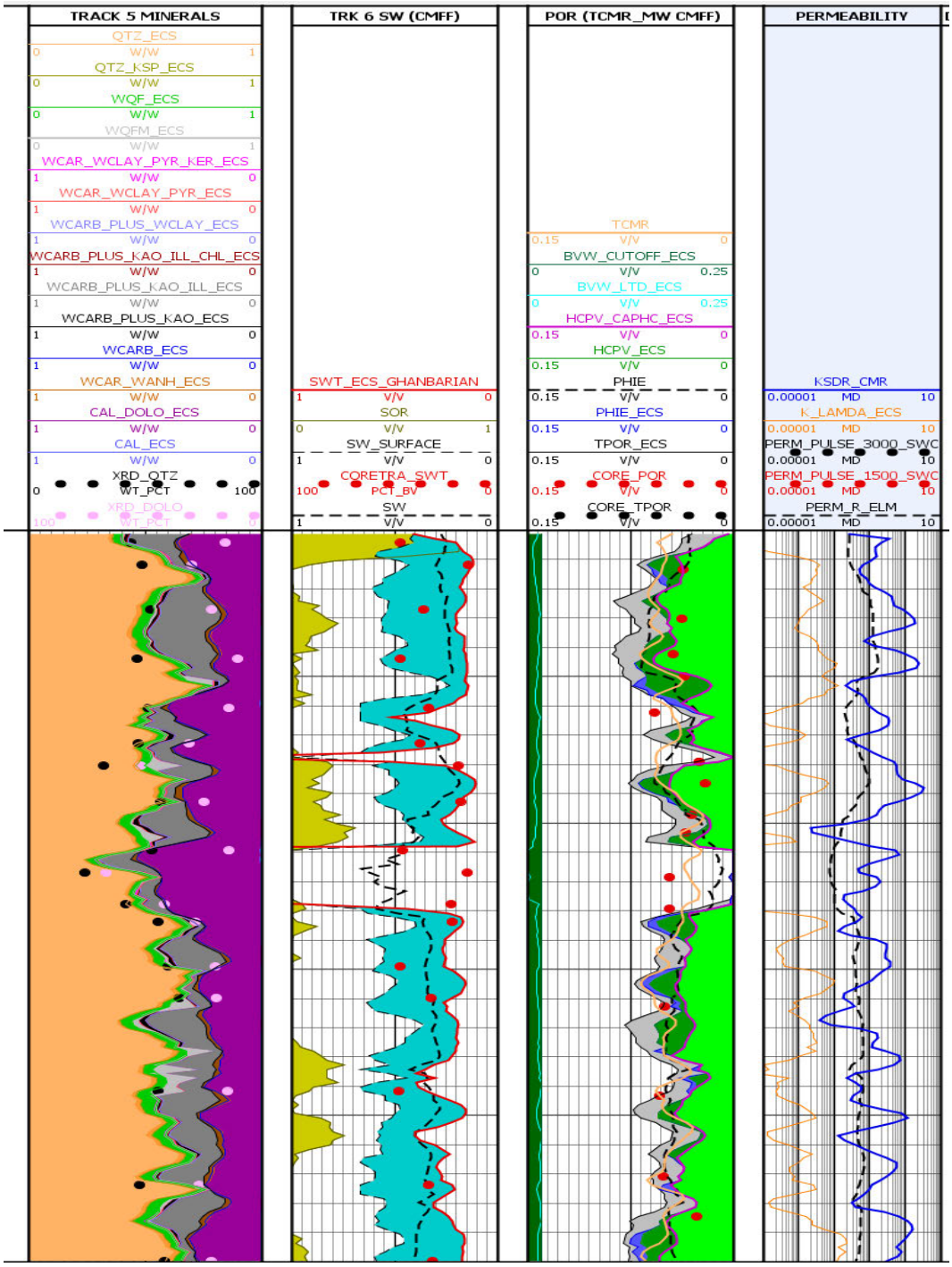


Figure 11: - Low Free porosity with core Sw in the envelope on 0.1524-step. Same section as Figures 9, 10 of Montney zone with another interpreter's Swe (labelled as SW, dashed black), Phie (dashed black) and PERM (dashed black). The SW appears to be flared to try to match Core Sw. If one does not have the possible core-Sw-variation provided by the NMR free-fluid, then the black dashed curve is reasonable. However, with the advantage of using this elements-mineral model plus the 33ms free porosity, we see the true Sw is lower than the dashed black curve. The lower resolution of 0.1524 step, compared to Figure 10's 0.0254 step seems to show less correlation with elemental-model-derived quartz and core quartz. This poorer correlation is the reason we prefer the higher resolution step of 0.0254m for all calculations.

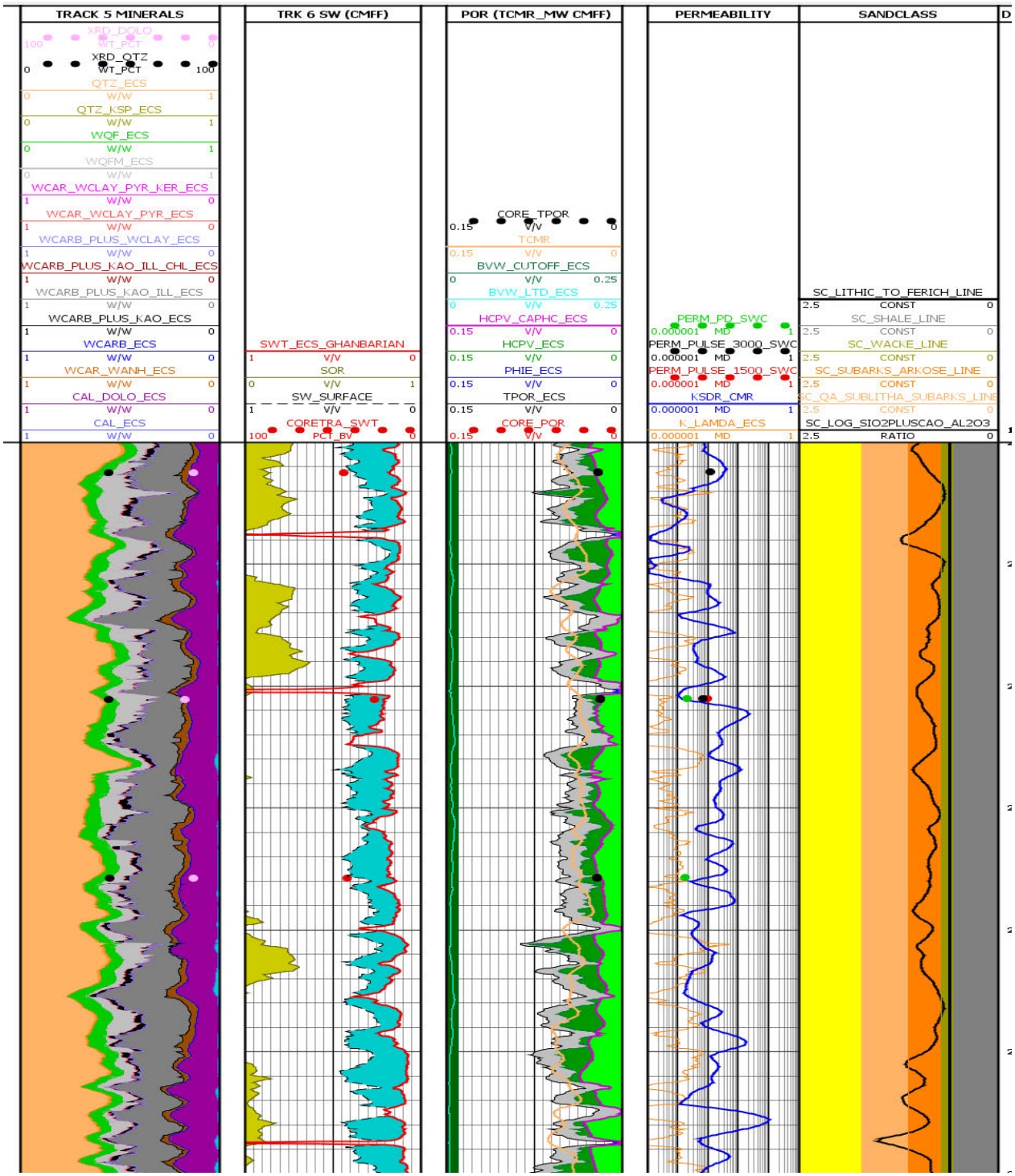


Figure 12:- Lower section on a 0.0254-step, where sidewall core permeabilities were measured. Note perm scale change to 0.000001 to 1mD; scale is changed one decade lower from the above sections to accommodate low core values. Same well as Figures 9 to 11 of Montney, but different zone. Core Pressure Decay measured on sidewall rotary cores ([core] PERM_PD_SWC) is the lowest perm (green dot) and appears to correlate with K_Lamda; [Core] Pressure Pulse permeabilities at 3000 psi overburden is next lowest (PERM_PULSE_3000, black dot) and [Core] Pressure pulse permeabilities at 1500 psi overburden (PERM_PULSE_1500, red dot), appear to correlate with KSDR. There is insufficient data to scientifically confirm core and log permeability correlations. The sand classification indicates mostly Arkose rock (Ref. 10)

CONCLUSION

The method to calculate an insitu log-derived-Sw comparable to a Sw measured on the core at the surface is a simple yet effective way to validate the log-derived in situ calculation of Swt. The results are inexact but create an envelope of possibility accounting for the unknown portion of the free fluid that bleeds from the core as it is retrieved. The method is designed for the Petrophysicist who does not have a lab available and who is often the recipient of field data without a closely relevant theoretical framework for explanation or implementation. As with almost all log interpretation, corrections to field data are often needed. The calculation is:

Sw_surface = (1- [HCPV minus Free-HC-filled porosity]/total porosity).

Where 'Free-HC-filled' porosity initially assumes all free porosity is drained from the pore. Subsequently, the 'Free_HC-filled' porosity is reduced so that Sw_surface more closely matches Core_Sw.

LIST OF ACRONYMS

Acronyms specific to usage in PDHC are listed as well as some core measurement terms used in "Tight Rock Analysis™ SLB, Terratek".

"_ECS": as an appended curve name means the calculation was made by PDHC and the elements are based on the Elementary Capture Spectroscopy model developed in the 1990s. Iron is influenced by 14% aluminum. (Ref. 12)

GAMLS: Geologic Analysis via Maximum Likelihood Analysis, developed by Dr. Eric Eslinger et al (Ref. 3)

HCPV: hydrocarbon pore volume, Porosity*(1-Sw).

HCPV_CAPHC: hydrocarbon pore volume minus capillary hydrocarbon is equal to free hydrocarbon volume.

k is a constant in the SP equation, that equals:

-1*(61+0.133*Temperature in DEG F.),

or

+1*(61+0.133*Temperature in DEG F.), if RXO/RT is used for the SP

MINERALS: The Mineral order presented is for siliciclastics to increase left to right and be coded from the curve to the left so the coding of each mineral group over laps the previous mineral group, leaving the last mineral in the group name as the colour shown. Powerlog™ has this methodology built in but the plot program we use does not so we have to cumulate curves to plot them. Clays and carbonates are increased to the left and code to the right so that coding overlaps. The resulting colour represents the last mineral in the name. For example quartz is just quartz and is coloured light orange. WCAR_WCLAY is the sum of the carbonates plus all the clays, kaolinite plus illite plus chlorite plus smectite; so smectite is the last in the list with smectite coded from curve to right with a light blue colour (if present). Similarly WQFM is the sum of the weight fractions of quartz plus feldspars plus mica (usually muscovite). Since mica is the last in the list, mica is coded from curve to left with a light grey colour

All mineral curves are weight fractions, not volume fractions, for direct comparisons to core weight fractions of minerals. The PDHC program also outputs volume fractions, since grain density of the mineral (RHOGi) and mineral group (RHOG), are known. Weight to volume fractions are:

V = W*(1-TPOR)*RHOG/RHOGi

The order is the curve group higher up the list codes (shades) over any curve lower in the list:

QTZ or QUARTZ: quartz coded from curve to left with a light orange colour; covers QTZ_KSP olive coding.

QTZ_KSP: quartz plus potassium feldspar; Potassium feldspar coded from curve to left with a dark olive green colour

WQF: weight of quartz plus feldspars, potassium and plagioclase sodium feldspars. Plagioclase feldspar coded from curve to left with a light green colour.

WQFM: weight of quartz plus feldspars plus mica. Mica coded from curve to left with a light grey colour. Usually the mica is muscovite, labeled as MSV output.

WCAR_WCLAY_PYR_KER: weight of carbonates plus clays plus pyrite plus kerogen; kerogen is coded from curve to right with a light pink colour.

WCAR_WCLAY_PYR: weight of carbonates plus clays plus pyrite; pyrite is coded from curve to right with a black colour.

WCAR_WCLAY: weight of carbonates plus kaolinite plus illite plus chlorite plus smectite; smectite is coded from curve to right with a light blue colour.

WCARB_PLUS_KAO_ILL_CHL: weight of carbonates plus kaolinite plus illite plus chlorite; chlorite is coded from curve to right with a dark burgundy colour.

WCARB_PLUS_KAO_ILL: weight of carbonates plus kaolinite plus illite; illite is coded from curve to right with a grey colour.

WCARB_PLUS_KAO: weight of carbonates plus kaolinite; kaolinite is coded from curve to right with a dark orange colour.

WCARB: sum of calcite plus dolomite plus anhydrite plus siderite; siderite is coded from curve to right with a brown-tan colour. Siderite is not explicitly solved for but is offered as an alternative to ankerite when 'excess iron' is available over that needed for illite and pyrite.

WCARB_WANH: carbonate minus anhydrite leaves anhydrite coded from curve to right with a rose colour.

CAL_DOLO: calcite plus dolomite; dolomite is coded from curve to right with a purple colour.

CAL: calcite is coded from curve to right with a cyan (bright blue) colour.

NPHI: neutron porosity in limestone units. Used in the calculation as a pseudo clay element, 'WMIN'. WMIN is a function of the water in the minerals, proportional to hydrogen, as the difference between neutron and density on a limestone scale. Each clay has a portion of the total WMIN, changeable by the analyst. In addition, NPHI is used for constructing a matrix-adjusted neutron, **PHIN_MAN**; this is used with the matrix-adjusted density, **PHID_MAD**, as a gas flag.

PDHC: Petrophysics Designed to Honour Core. Equation coding was developed in Excel by Bob Everett, coded by Jamie Everett in Java and is available from Robert V. Everett Petrophysics, Inc (Ref. 3 & 12). We have included many input parameters to allow the interpreter to match core mineralogy. Methods used were encoded in the year 2000 and are similar to those described in Ref. 17 (2002) with several exceptions. Drs. Michael and Susan Herron who invented the ideas and I worked on the same methodology so we have a similar approach albeit sometimes different methods to solve for and use minerals from elements.

Pressure-Decay Permeability: "Matrix permeability measured on crushed grains of shale or mudstone. The crushed material is orders of magnitude larger than pore structures. Crushing of shales/mudstones allows for access to pore space and for the removal of artifacts or non-natural features from the rock in order to obtain more accurate data. Pressure decay is only partly valid for silty laminated shales and not valid for sandstones or tight gas sandstones". (Paraphrased and Courtesy Tight Rock Analysis, Terratek.)

Pulse-Decay Permeability: Plug Permeability. "Often misinterpreted as an accurate measure of reservoir permeability in shales. Laminated shales are first of all extremely difficult to plug, secondly in plug form, samples contain non-natural artifacts/microfractures from the coring and processing stage of the core analysis which enhance or artificially increase permeability values and sometimes porosity values". (Paraphrased and Courtesy Tight Rock Analysis, Terratek.)

RHOB: bulk density in g/c3; may be modified or normalized when other wells are also considered or when a rugose hole or heavy mud affects its validity. Our recommendation is to use a tandem density "…two density tools in orthogonal orientation" when formation

stress creates hole rugosity (Ref. 21)

RHOG_KER or RHOG_ECS: Grain density in g/c3; the RHOG_ECS is from Ref. 12 and 17; the addition of KER means it has also been corrected for kerogen in PDHC.

Ro_ECS_Ghanbarian or Ro_ECS: The output wet resistivity curve from the PDHC model. If the term Ghanbarian is included in the name, the curve includes a formation factor modelled by Ghanbarian (Ref. 7).

RMF is used in the SP equation for SP_ZERO: (RMF*(Temp_RMF+6.77)/(TEMP_DEGF+6.77))

RT: the deep reading resistivity curve; may be modified by super-imposing the pad resistivity from a dipmeter or formation micro scanner to improve vertical resolution. Example 1 used this method with significant improvement of Core Sw and Swt_ECS_Ghanbarian. The term 'Ghanbarian' refers to the formation factor used (Ref. 7) in the Swt calculation.

Rt_ECS: The output name from the PDHC program for whatever curve was input to represent true resistivity, such as Rt_HLRT, RLA5, etc.

RW_05 is used in the SP equation for SP_ZERO: (0.05*(308+6.77)/(TEMP_DEGF+6.77))

RW_SP: the first estimate of Rw using the SP, where SP_ZERO, SP_SHIFT and SP_BASELINE are calculated. Not corrected for SP drift. RW_SP_USED is corrected for drift in the PDHC program, by the analyst.

RW_SP_USED_SL_FINAL or RW_SP_USED: the final estimate of Rw using the SP, where SP_ZERO, SP_SHIFT and SP_BASELINE are calculated. SL means straight-lined corrected for SP drift. in the PDHC program, by the analyst.

"_SHFT": means a curve has been depth shifted to match depth of other curves. Usually core has been depth shifted whether SHFT is appended or not.

SP_ZERO is -k(log(RMF/RW_05))

SP_SHIFT is (SP +add), or(+ k*(log Rxo/Rt) + add)

SP_BASELINE is SP_SHIFT – SP_ZERO.

SWB_LTD: bound water saturation limited to Swt.

SWIRR: the irreducible water saturation using the Coates-Timur model involving porosity and could be modified with K_Lamda permeability (Ref. 17).

TEMP_DEGF: temperature in degrees Fahrenheit from a straight line equation, such as 0.0198*DEPTHFT+42.805; modified to fit whatever bottom hole temperature data is available.

TCMR: total NMR porosity from whatever nuclear spectroscopy tool was used. Used in the calculation of SDR permeability and NMR total porosity. It can be used instead of density porosity or in density-NMR porosity (**DMRP**) in PDHC. Also, "**MPHS_SPWLA**" or "**TCMR_SPWLA**" means the recorded value has been normalized in some way.

TRA: Tight Rock Analysis™ SLB by Terratek on Example 4 Montney example showing pressure pulse and pressure decay results for permeability Units are mD in the 0.000001 to 1.0 range.

WTAR_BOB_QL: weight fraction of bitumen or heavy oil using equations modified by Bob in the quick-look or post processing section of PDHC.

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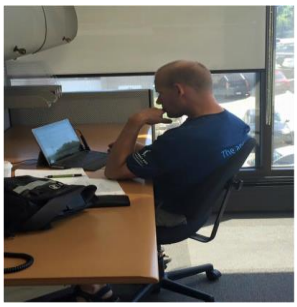

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APPENDIX

UTILITY OF SP AND RXO/RT & ZERO FOR SP

While the utility of using the SP and Rxo/Rt to derive Rw has been around for years, the method of deriving a zero to measure SP deflection from has not been commonly used. Using a zero value is the key to deriving a valid continuous Rw, as opposed to using a GR shale baseline or a fixed Rw whether temperature corrected or not. The value for a variable formation water resistivity, Rw is a crucial part of the calculation of water saturation. In turn, water saturation influences the value of Sw_surface. A continuous value Rw , through sands and shales is preferable to a fixed value as the value can be confirmed at any depth from known values, shales or water tests. Either the SP or Rxo/Rt can provide the continuous Rw.

Example of Rw from SP and Rw from Rxo/Rt for Example 2 well.

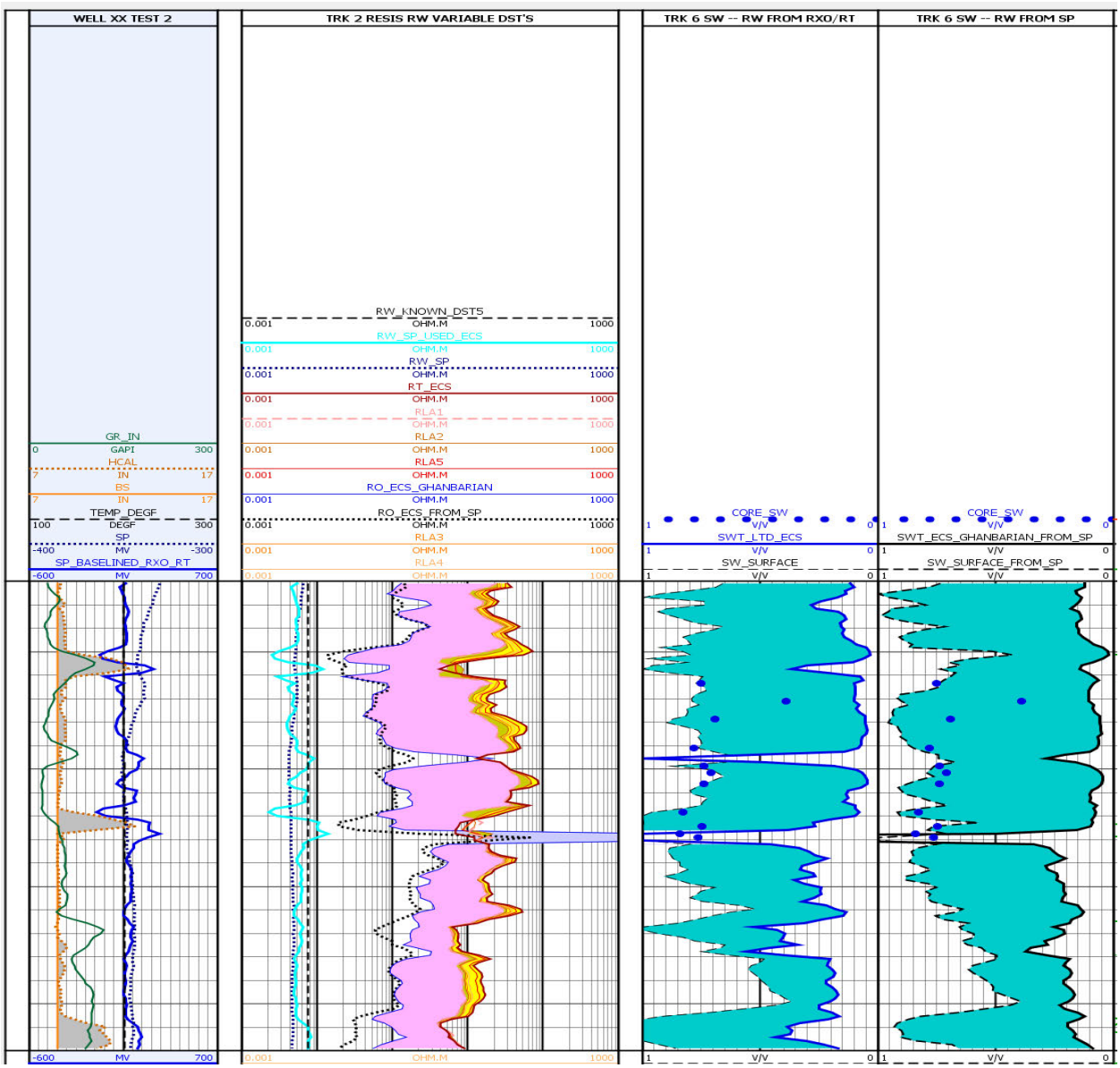

Figure A1: comparison of Rw derived from Rxo/Rt and Rw derived from SP. Track 1 shows two SP's; the smooth SP (dotted) is recorded and the jagged SP (solid blue) is from RXO/RT. Track 2 shows the two Rw's and Ro's derived (again dotted and solid). Track 3 is the Sw_surface and Swt using Rxo/Rt for Rw. Track 4 has Sw_surface and Swt using the recorded SP. Both are similar but influenced by the shape of the Rw. The conclusion is the same: the Core_Sw is in the range of probability.

Can Core Sw Be Used To Verify Rw?

The short answer is no. In low perm with very small pore throats, the lowest Core_Sw *may* equal log Sw as no hydrocarbons have escaped. In higher perm, core measured at the surface will have lost hydrocarbons as the core is retrieved to surface. Therefore, the core Sw represents an upper limit for Rw but not always a lower limit. To find the lower limit of Rw, one needs a wet zone, either a shale, since we solve for cation exchange capacity (CEC), or a clean wet zone where no clay correction to resistivity is required. Be aware that a clean wet zone may have water influx with a different salinity than the virgin hydrocarbon zones. The elements-to-mineral interpretation method provides CEC derived from the clay families with their

associated CEC. The average CEC has been measured at the Schlumberger-Doll Research Lab (Ref. 9 to 20). The reference papers cited offer the methods used but do not list the CEC derived. The values we used are Chlorite 2, Illite 25, Smectite 100 and Kaolinite 6 meq/100g. One can also calculate an "m and n" from the elements to mineral method (Ref. 17). The SP is used to connect the Rw in the wet zone to Rw in the hydrocarbon zone assuming no hydrocarbon SP-reduction. Wet shale is preferable as it is less likely to have been flushed by external water influx. Using the SP necessitates the use of a zero deflection for the SP. An old method was to draw a 'shale baseline' but this method is now improved. Our improved method is to calculate the zero from the equation

SP_zero= [(-k*logRMF/RW_05)+offset].

The offset is added so that the result over the depth interval analyzed, has an average of zero. The equation provides a zero that changes with temperature, since RMF and RW_05 are temperature corrected. The RW_05 is 0.05@308F (0.187@25C), corrected for temperature. This value is used as an approximation of an average value for Rw. One can use a different Rw, in the SP_zero equation, if one is known.

On the other hand, when permeability is very low as in some tight gas sands, there may be little to no loss of hydrocarbons as the core is retrieved to surface so the lowest values of Core Sw can be used to confirm Rw.

We illustrate using Example 3, in a shaly zone that does not have organic carbon.

The zone below, Figure A2 has Rw too high. Note the Ro>Rt in the shale zone at the top. Also note the core Sw is below the log Sw, an incorrect relationship (blue shading). Note the matrix-adjusted density and neutron porosities are plotted, rather than plotting the logged density and neutron. The matrix-adjusted values provide a better cross-over for the gas flag.

Does Rw From The Sp Always Work In Both Sands And Shales?

No. When the SP has positive deflection, the sands will have a higher Rw than the shales. However, the Rw in the shales may be so low when calculated using the SP that Ro is very low and it appears there are hydrocarbons in the shales. In this case, as in Example 2, a better method is to calculate a new SP from the ratio of Rxo/Rt, making the deflection negative in the sands and positive in the shales. Of course, if a pad tool has been used for Rxo, the Rxo measurement may be invalidated by rough hole in the shales. On newer array laterolog the measurement is not affected by the borehole, as in Example 2 allowing the Rxo/Rt method to work. However, if one is simply concerned with the sands and not shaly sands, the positive-deflection SP works OK, as the relative deflection from sand to sand provides a valid Rw. This was validated on Example 2 where the numerous water tests provided a measured Rw that corresponded exactly to the Rw derived from the SP in the tested sands. Note the tested sands were not 100% water saturated but the relative permeability to water provided producible water. The Corey equations from Ref. 2 provide a reasonable permeability to water as Swe^4 = ~ KRW mD. When KRW is greater than 0.001 mD, water is produced from this gas reservoir. .

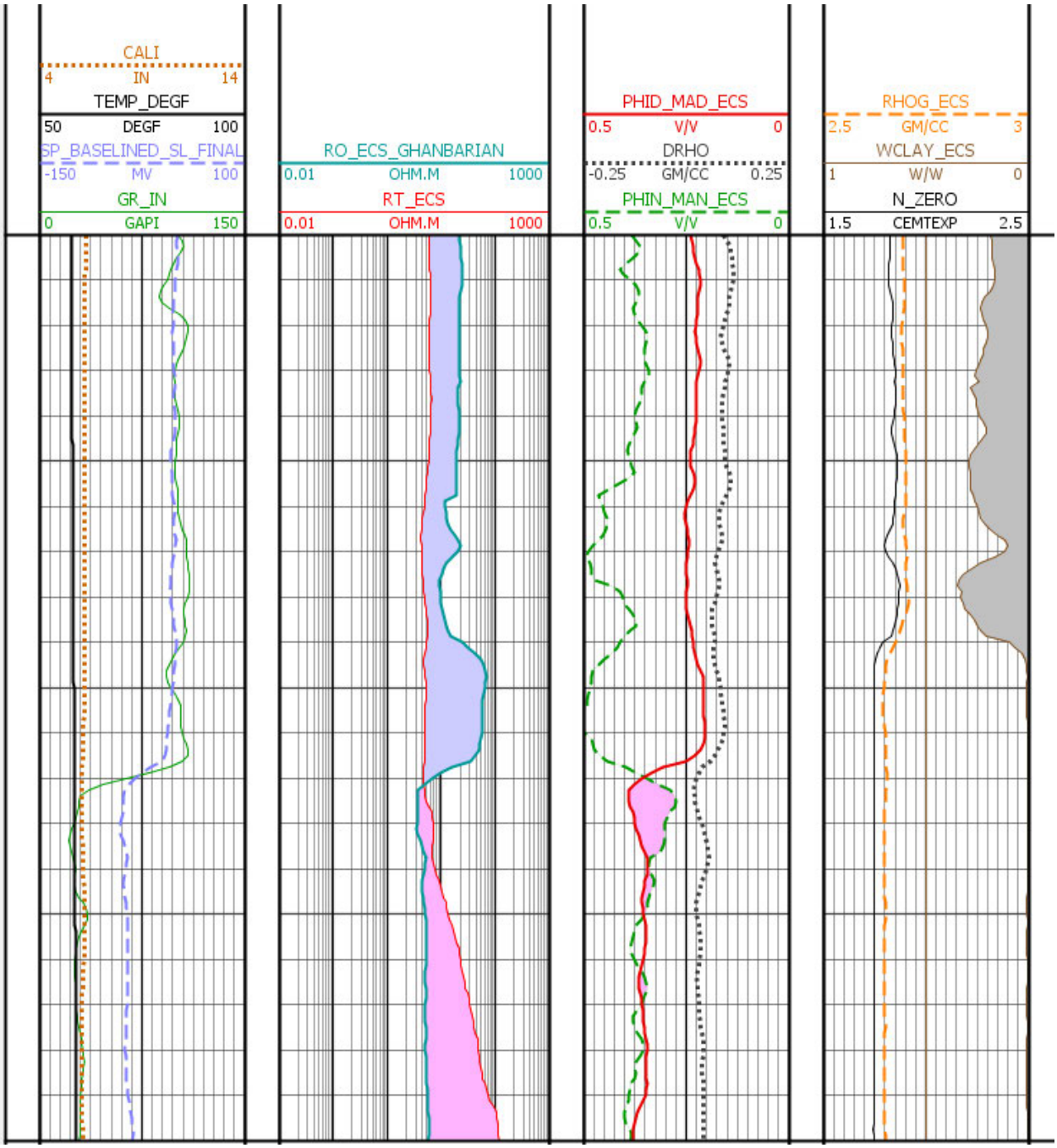

Figure A2: - Rw is too high as Ro is greater than Rt in wet shales (blue shading when Ro>Rt)

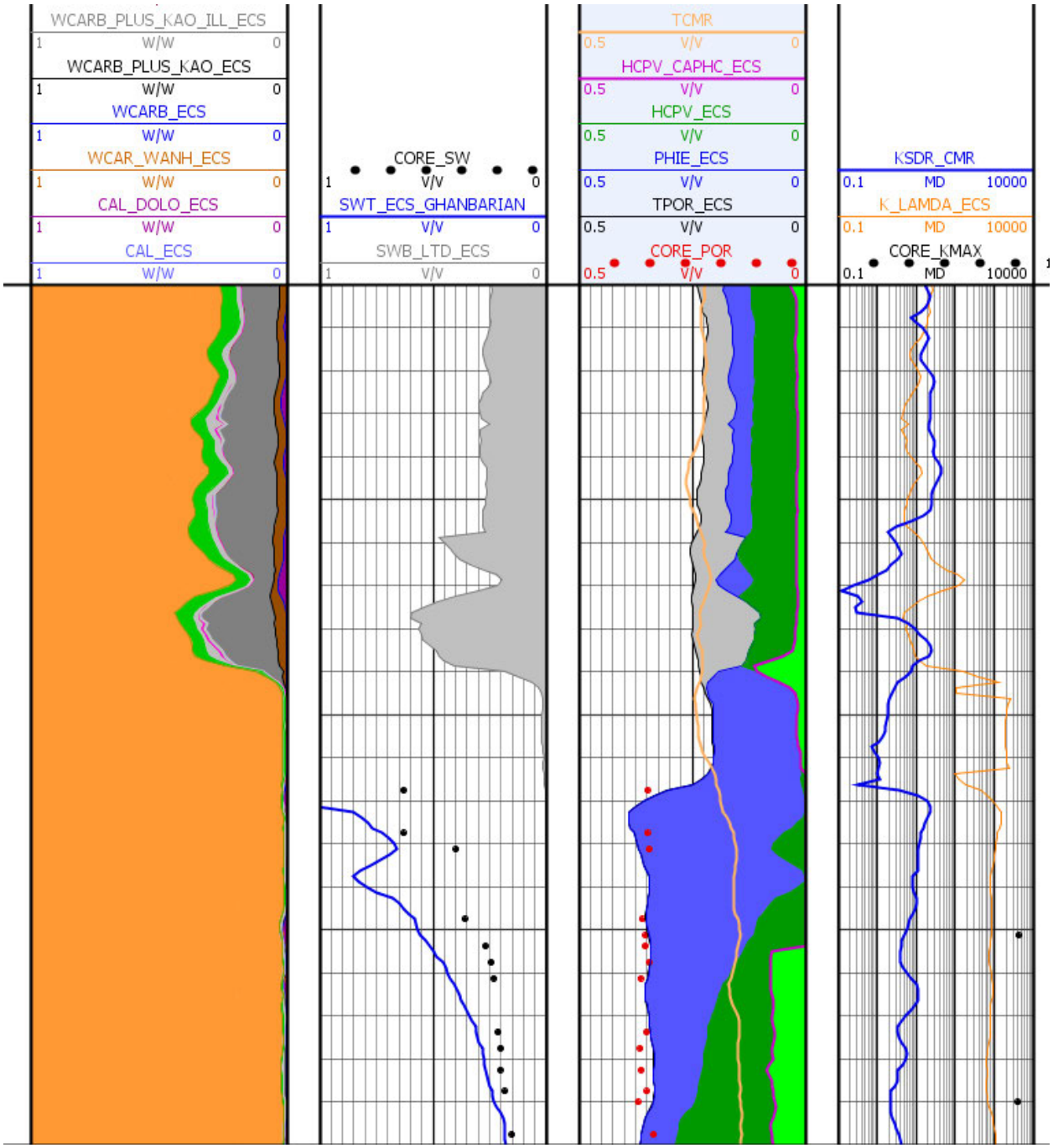

Figure A3: Rw is too high as Ro is greater than Rt in wet shales; the result is core Sw less than log Sw, an incorrect relationship. To correct the Rw, decrease the Rw until Ro = Rt in the shale, as in Figure A5.

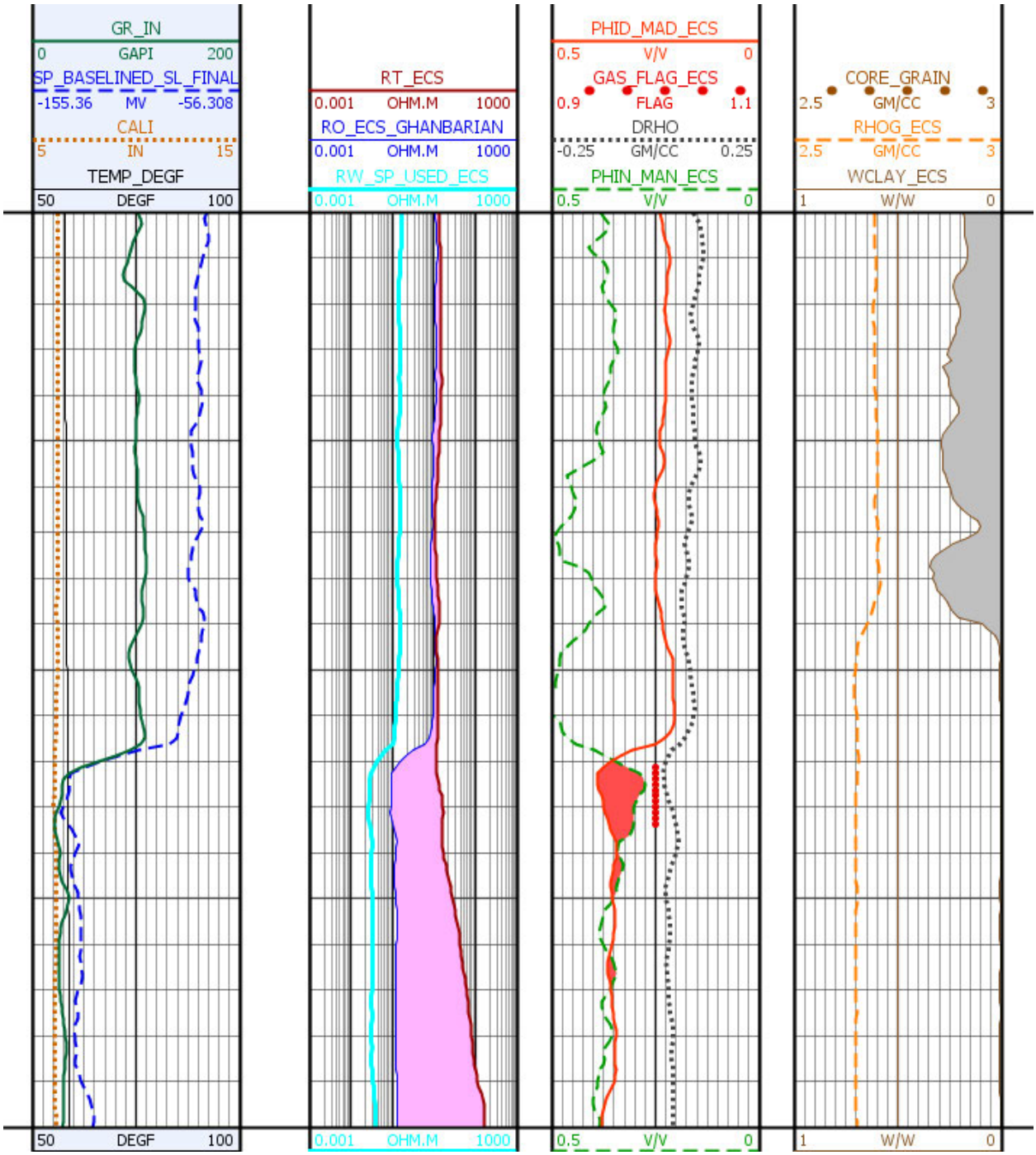

Figure A4: - Rw is close as Ro is equal to Rt in wet shales, above the pink hydrocarbon zone. Also, note the SP is different in the shale and in the sand (not surprising). Hence, the Rw is different in the shale (~1.1 ohmm at 62F) and in the sand ~0.25 ohmm at 62F). The changing Rw is the reason why a fixed, constant Rw does not work. Note the accumulation of gas at the top of the bitumen: a common occurrence.

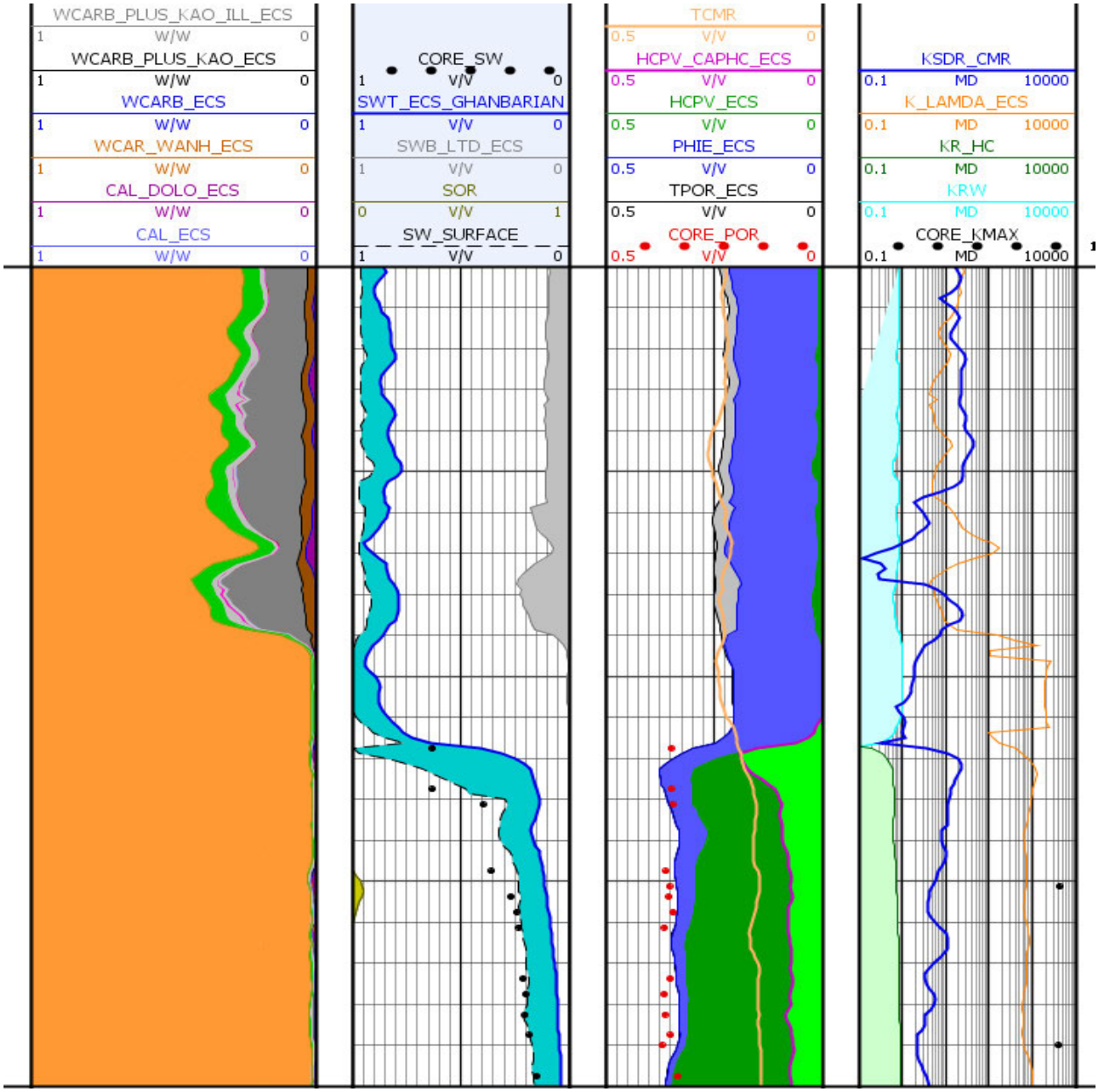

Figure A5: Rw is close to being correct as Ro was equal to Rt in wet shales; note log Sw lower than core Sw, as it should be. The perm track on the right shows the relative perm of water (light blue shading) and oil (light green shading) from the Corey equations. Next, we calculate the Sw_surface. There is a close agreement with the Sw_surface and Core_Sw. Hence, we have a correct Rw and a modified 33ms NMR porosity that provides the envelope for core Sw to be reconciled. Rw is OK as Ro is equal to Rt in wet shales. The 33 ms free porosity has been adjusted from the original measurement so that the core_Sw is at the edge of the Sw_surface envelope. If one adjusted the Rw to make the insitu log Sw match core Sw, then the log Sw would be too high. This Rw adjustment to make log and core agree is a common practice and incorrect. The blue shading indicates the magnitude of the error if log Sw was matched to core Sw.