

An Introduction to Logging While Drilling

Seminar in Marine Geophysics

14 February 2008

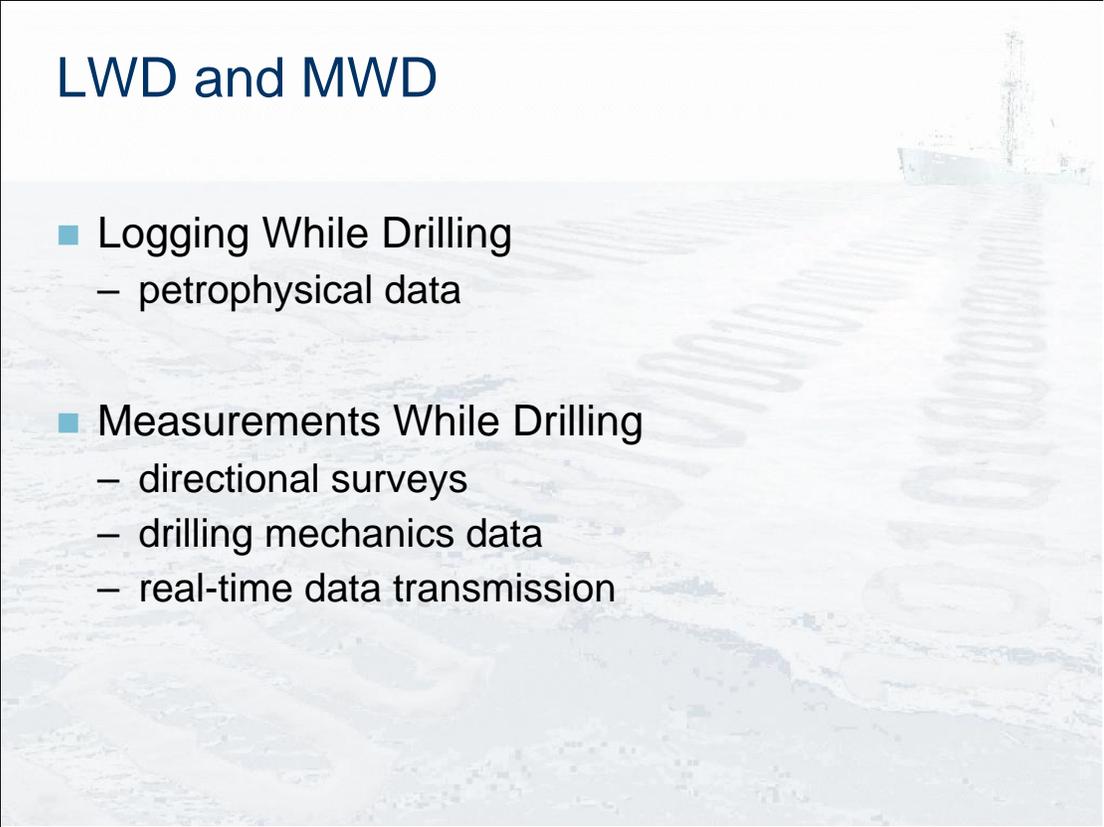


The next hour will serve as a primer to Logging While Drilling or LWD.

We will:

- describe the fundamentals (what it is and why we do it) and then get a little deeper into how it all works
- learn about drilling and real-time data
- highlight some differences between LWD and Wireline logging
- examine some particular issues with LWD that scientists might face.

LWD and MWD



- Logging While Drilling
 - petrophysical data
- Measurements While Drilling
 - directional surveys
 - drilling mechanics data
 - real-time data transmission

Logging While Drilling or LWD is the general term we use to describe the systems and techniques for gathering downhole data while drilling a well.

A more specific definition is the acquisition of petrophysical data.

Generally, LWD offers the *same measurements* as wireline, with some differences in quality, resolution and/or coverage.

I will also mention Measurements While Drilling or MWD. Specifically MWD refers to

- the acquisition and collection of wellbore deviation directional surveys
- the acquisition and collection of drilling mechanics data, like downhole torque, pressure, or vibration
- the process of sending the data uphole in real-time

Wireline vs LWD

■ Wireline

- small, light and delicate
- since the 30s
- high data speeds
- easy communication
- good borehole contact
- powered through cable

- takes time
- after-the-fact
- specific coverage
- problem at high deviation
- susceptible to hole condition

■ LWD

- big, heavy and tough
- since the 70s
- slow telemetry
- limited control
- subject to drilling
- batteries and mud turbine

- transparent to drilling
- real-time
- azimuthal
- can log in any direction
- more capable in tough env.

Here are a few main differences between conventional wireline logging and LWD.

LWD tools are really large instrumented *drill collars*, part of the Bottom Hole Assembly or BHA. The sensors are arranged so that they can make relatively unimpeded measurements of the formation. The electronics and batteries are housed so that drilling fluid can flow at high flow rates through the tool.

The real differentiators are:

- time (especially in the oilfield, where rig rates are half a million dollars per day)
- real-time (LWD is enabling decisions that are putting wells in the right place, and making them safer and more efficient to drill)

In scientific applications, unfortunately, time isn't as big of an issue.

I say unfortunately because the lack of financial incentive to drill and log (and core, etc.) efficiently tends to breed a culture of stagnation, rather than improvement.

As for real-time decisions, with the JOIDES Resolution that hasn't been a huge issue, as the holes we drill tend to be shallow and relatively simple.

That said, there are real-time applications, even in relatively simple wells.

But platforms like the Chikyu that will drill more challenging wells, or in projects like SAFOD, real-time control will become very important.

Finally, LWD tools go where Wireline tools fear to read: deviated wells, unstable boreholes.

Wireline vs LWD

Measurement	Wireline	LWD
Gamma Ray	many	many
Induction Resistivity	DIT, AIT	ARC, EcoScope
3D Induction Resistivity	ARI, Rt Scanner	PeriScope
Laterolog Resistivity, Imaging	FMS, FMI, DLL	GVR, RAB
Density	HLDT, IPL	ADN, EcoScope
Neutron Porosity	APS, CNL	ADN, EcoScope
Spectroscopy	ECS	EcoScope
Acoustic Velocity	DSI, Sonic Scanner	sonicVISION
VSP	CSI, VSI	seismicVISION
NMR	CMR, MR Scanner	proVISION
Pressure Sampling	MDT, PressureXpress	StethoScope
Fluid Sampling	MDT	n/a
Sidewall Coring	MSCT	n/a
Ultrasonic Imaging	UBI	n/a

I won't spend much time on this.

The takeaway is that for virtually every measurement and wireline tool, there is an equivalent LWD tool.

Notable exceptions are Fluid Sampling and Sidewall Coring.

The advanced wireline tools are too large to fit in drillpipe-conveyed logging like on the JR, so measurements like

NMR and Pressure Sampling can only be offered in LWD.

All these tool names are from Schlumberger, my old company.

But they are presented here (and Alberto has mentioned them before and future lectures will discuss them as well)

because Schlumberger does the wireline and LWD logging for both the US and Japanese IODP programs,

and is the sole corporate sponsor for the ICDP (for example, was the driller and logger on SAFOD).

The other main logging vendors (Baker Hughes and Halliburton) have comparable wireline and LWD offerings.

Wireline vs LWD



The size difference might seem intuitive, but has real implications on ease of use and deck space.

Notwithstanding the cable and winch infrastructure needed for wireline logging, LWD takes more planning.

Size Might Matter



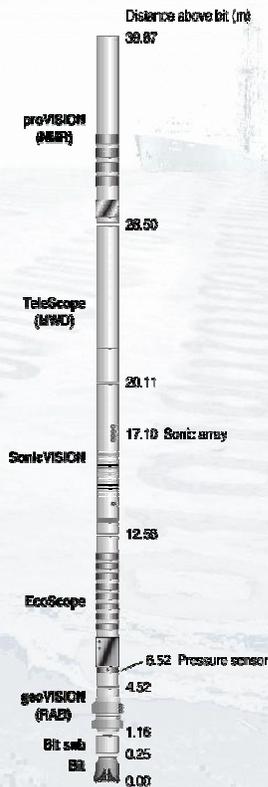
Consider a small scientific vessel. Can it accommodate these large LWD collars and backup tools?

This case is extreme: it's a *heptacomb* featuring more LWD tools than standard oil or science wells.

And in this case the operator and drilling contractor demand that tubulars be shipped in boxes (a practice becoming more and more common in the drilling industry).

Bottom Hole Assembly

- 20 to 50 metres long
- 6-7/5 inches in OD
- Stabilizers
- Key measurements near bit



Alberto showed you this slide a couple times over the last few weeks. It's a more or less typical BHA used in scientific ocean drilling.

Wireline tools often have centralizers to keep the tools/sensors in the center of the borehole. Or they have eccentralizers to force tools/sensors against the borehole wall.

Most BHAs, with or without LWD tools, use centralizers as well: stabilizers. Generally they are slightly undergauge, which means in a 9-7/8 inch borehole they will might be 9-1/2 in OD, with flow channels.

Stabilizers are useful for LWD tools like the sonic and induction resistivity tools because their measurements are best centralized. Stabilizers are also useful for "focused" LWD measurements like density or laterolog resistivity, because the sensor *button* or *window* can be at the surface of the stabilizer, and thus pressed against the borehole wall. Sometimes, though, stabilizers can pose a risk for sticking in the hole: they close off more of the borehole and can be the site of a blockage if formations start sloughing in.

Generally the most important measurements are near the bit, like the basic resistivity and GR sensors, followed by annular pressure, density and porosity. Observe here that the NMR measurement is over 30m above the bit. If scientists want full NMR coverage over a specific interval, then we'll have to drill at least 30m of *rat hole* past that zone.

Historical Background



Back in the day, oil wells were drilled straight down.

And it was easy, because it was flat and dry and well frankly there was no other way.

Look at this satellite view near Hobbs, NM (close to Midland, TX, the heart of West Texas oil country).

The images covers roughly 6.5 x 4.5 km, or 36 km sq. And there are over 600 wells here.

You can see the delineation of the reservoir: people would drill new wells until no more oil gushed up, meaning they'd reached the end.

So, pretty easy, but pretty inefficient and probably relatively inexpensive.

Now look at a field near Bakersfield, CA, in the foothills. The image is twice the magnification.

You can see it's harder to place the wellsites and access roads in the hills. Terrain is playing a part.

What if the oilfield is under the ocean? Or near a city?

Historical Background



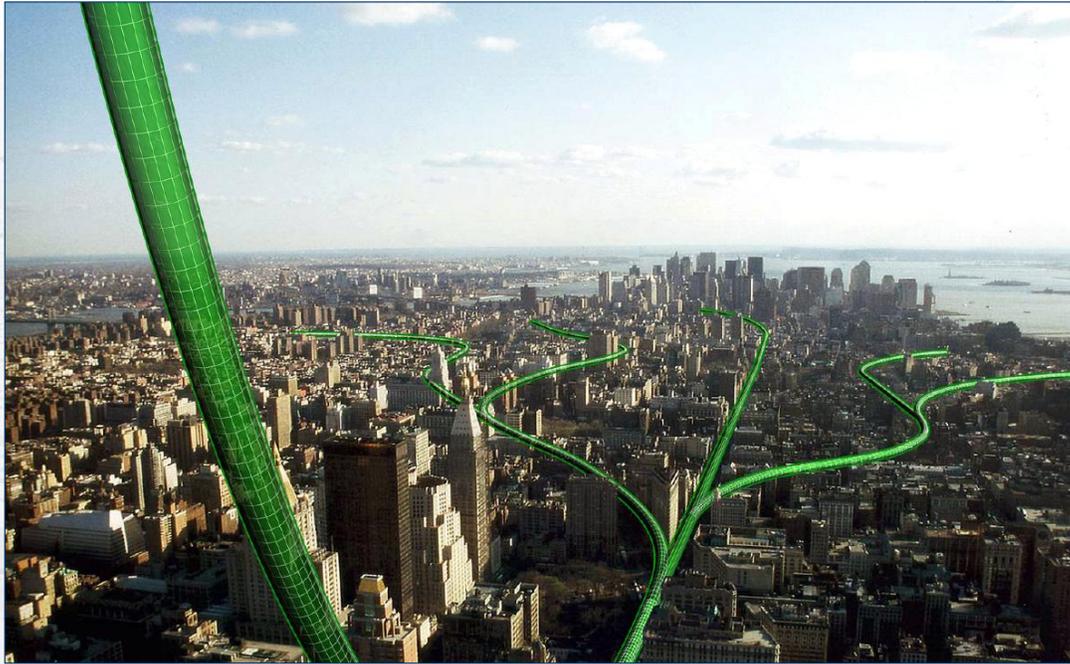
Huntington Beach, CA. 1928. What an eyesore.

And probably not that safe, healthy or environmentally friendly.

BTW, there are dozens of oil fields in and around the Los Angeles basin.

The Wilmington reservoir under Long Beach is the 3rd largest ever discovered in the US.

Directional Drilling



Because it's not practical, attractive or efficient to drill a huge number of vertical wells (especially offshore), the industry found ways of steering wells.

As Alberto pointed out, a horizontal well can tap a reservoir very efficiently. But even moderately deviated wells and *sidetracks* can exploit a large reservoir.

Or they can tap many smaller reservoirs or lenses in from a single well.

And so *directional drilling* was born.

Drillers used *whipstocks* (giant wedges at the bottom of the hole) and then *mud motors* to steer wells.

Mud motors are components of the bottom hole assembly or BHA, right above the bit.

They have mud turbine that turn the bit at high RPM even when the drillstring isn't rotating.

The housing or collar of the motor is bent, and so bit/drillstring/well goes in the direction of the bend.

The state-of-art is to use a *rotary steerable system*.

That is, a tool at the base of the BHA that points the bit in a certain direction by pushing pads against one spot in the borehole wall, or sometimes the bit itself gimbals in the desired direction.

In any case, the essential here is that in order to steer the well you have to know where it *is* and where it's *pointing*.

Originally, drillers dropped plumb-bob devices then gyroscopes to determine the angle (or inclination) and azimuth (or direction) of the well.

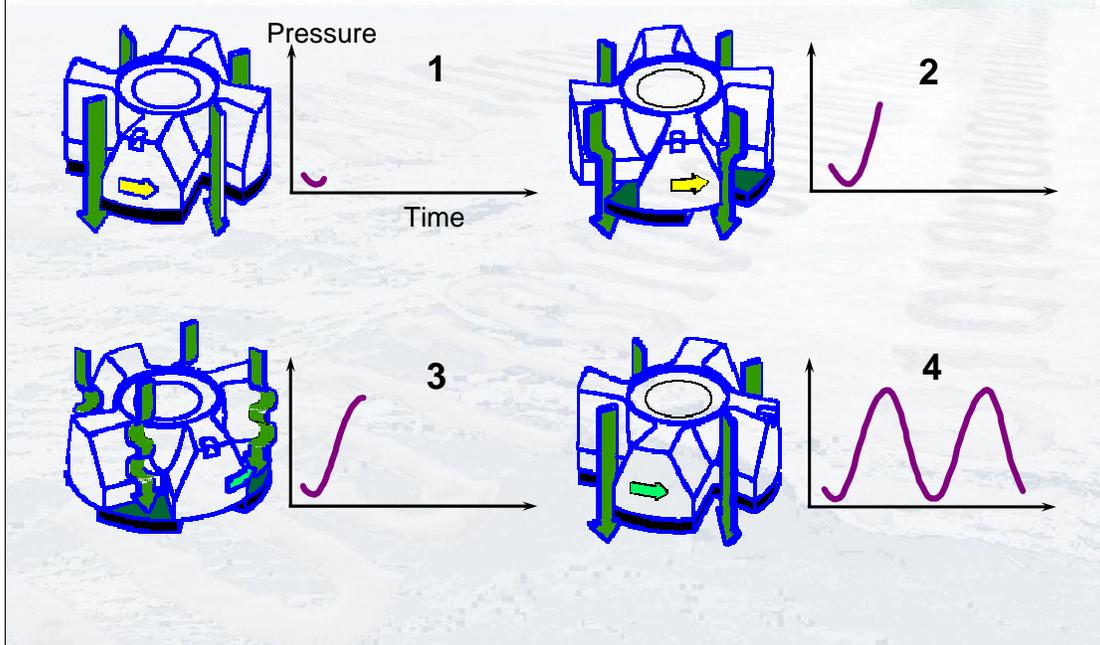
Engineers could plot a sequence of these *survey stations* and estimate the position and orientation of the well.

These survey stations took a long time and weren't always accurate.

So they developed a sensor package (3 accelerometers and 3 magnetometers) to reference the tool vs the earth gravity and magnetic fields.

And, importantly, they figured out a way to send that data *uphole in real-time*.

Real-Time Mud Pulse Telemetry



The most common way to send data uphole is by generating pressure pulses in the mud column that is being pumped down the drillstring.

Remember that the drill string - including the bit, LWD tools and rest of the BHA – is rotating at 60 RPM and being shocked at hundreds of Gs

while hundreds of gallons of erosive drilling fluid are being pumped down it. It's impossible to have a conventional wireline cable connected to the LWD tools.

So the MWD has a pulsing assembly or *modulator* for sending up data.

There are a few ways of generating the mud pulse, the most primitive of which use either a stopper to plug a hole, or have a valve that exhausts drilling mud to the annulus.

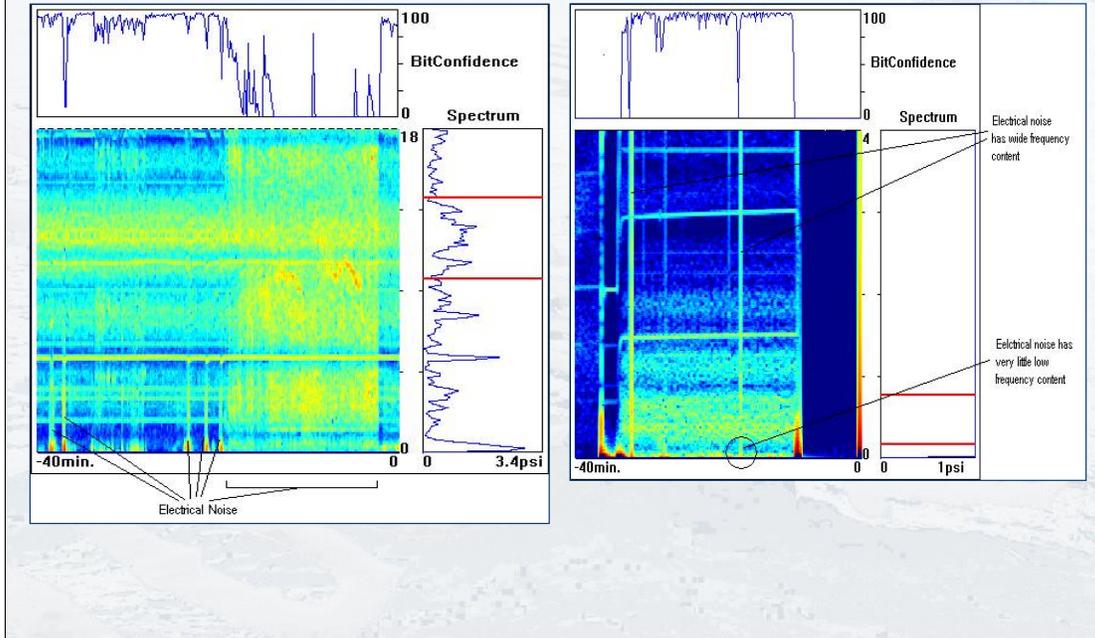
The most advanced uses what some call a mud siren, where a rotator spins and alternately blocks/releases mud flow over a stator.

This generates a continuous wave. The rotator spin rate can change or stutter which causes a phase shift in the sinusoidal wave.

That phase shift is measured and decoded into bits. Telemetry rates with continuous wave pulsing can reach 24 bps (commonly 6 bps).

The other two methods usually max out at 1 or 2 bits per second.

Signal Acquisition and Noise



These images of the raw mud pulse signal highlight some of its advantages and pitfalls.

A significant problem with mud pulse telemetry is that its susceptible to downhole and uphole noise.

Downhole noise can be drilling and bit noise, shocks, pulser jams.

Uphole noise can be from the mud pumps, electronic equipment on the rig.

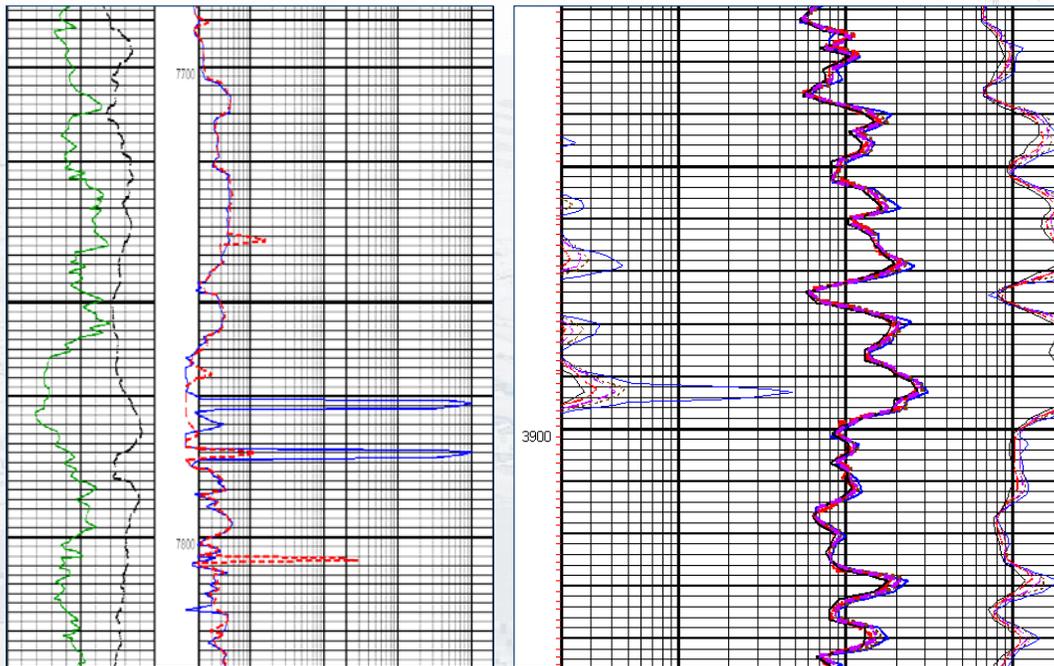
The image on the left is partially mislabelled: the lower indicator should read “drilling noise”, not “electrical noise”.

At the same time, engineers can examine the smoothness of drilling, the effects of mud erosion on the pulser, and even detect washouts (where leaks develop between connections of drill pipe or collars, and threaten to sever the entire drillstring).

The engineer can also observe what the driller is doing: drilling on bottom, reaming the hole, pumping at different rates, etc.

Analysing these kinds of raw signals let the alert engineer determine which downhole data are accurate or spurious.

Real-Time Logs



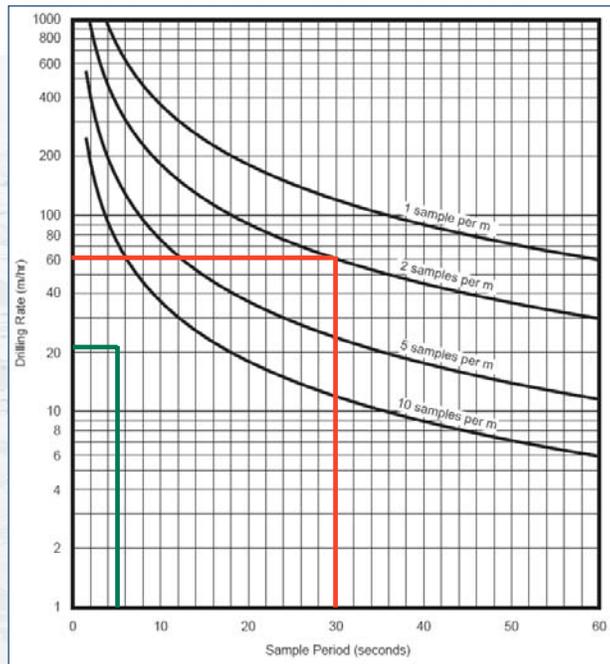
Here are two examples of real-time petrophysics logs, one being pretty typical, the other of higher quality.

Remember, petrophysics is just one part of what we can send uphole and, especially in scientific drilling, we want to focus more on drilling mechanics data: we can get the high-resolution petrophysical data from the tools' memory.

On the left, you can see that data is fairly sporadic and we're only sending up a few curves. There are also prominent spikes. Those relate to the sources of noise we discussed on the previous slide. On the right, we're sending up more resistivity curves. This is essentially a wireline-quality log (LWD always had a bit of an inferiority complex from its Wireline big brother). The spike near 3900 ft is real.

Generally gamma ray curves are in green and in the left-most track. The dashed black line is the Rate of Penetration or ROP. Resistivity curves are usually in a logarithmic track to the right of a depth track, in blue and red, and then other colors like pink, brown, and black. Not shown here are the density curve (usually red) and porosity curve (usually blue). Knowing standard colors and curve placements can help you understand a log at a glance without having to look at a header.

Drilling and Data Rates



The drilling rate or Rate of Penetration affects the quality of real-time logs (and, at very high rates, recorded logs as well).

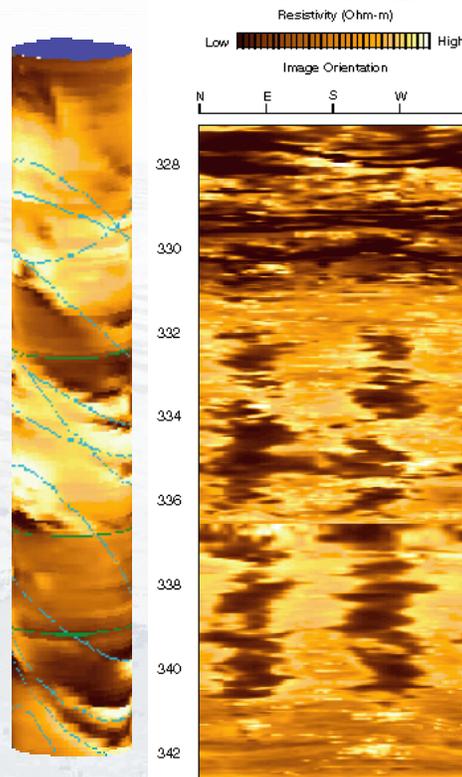
For example, when drilling at 60 m/hr (which is typical in the oilfield but perhaps a little fast in scientific drilling), sending up real-time data points every 30 seconds gives only 2 samples per metre.

Recorded data is often captured every 5 seconds. You can see that we'd be able to drill at 400 m/hr and capture the same data density.

Realistically, we want to keep ROPs in the 40 to 60 m/hr range for conventional "curve" data like GR, density, etc., and we want to drill as slowly as 20 m/hr in order to capture high-resolution image data (one data point every 3 cm).

Resistivity Images

- geoVISION Resistivity (6-3/4)
- Resistivity-at-the-Bit (8-1/4)
- Laterolog, like FMS/FMI



Speaking of image data, let's talk a bit about the common LWD resistivity image tools: the GVR and RAB.

Essentially they are the same tool, though the GVR is slightly more advanced in terms of measurement resolution, recording speed, etc. Commonly, the RAB only refers to the larger 8-1/4 inch collar.

These tools are analogous to the Wireline FMS and FMI tools.

As Alberto described, the tool images the borehole surface and can be presented as a cylinder or unwrapped.

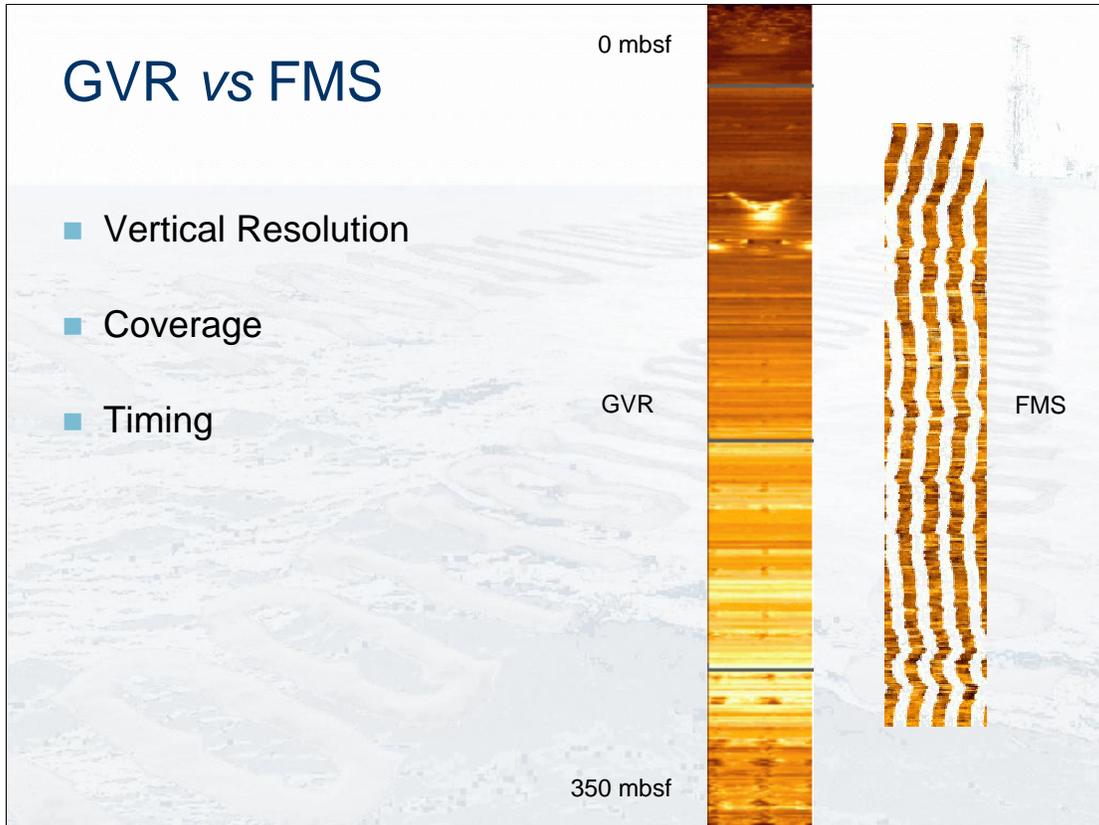
Sinusoids appear as As or Vs.

I won't elaborate too much since Trevor will offer a lecture on Image and Fracture Analysis later in the term.

Observe the drilling-induced borehole breakout railroad tracks.

The tool orients itself versus the earth's magnetic field, so the local stress orientations can be determined.

Later in the term, Dave will present a lecture on Stress Determination.



The FMS/FMI has much better vertical and horizontal resolution (on the order of mm, versus an inch for GVR).

But owing to the pad configuration Alberto explained in week 2, FMS coverage is poorer.

Especially in the large boreholes that can be drilled in scientific drilling. In enlarged borehole (>10 inches),

coverage might be less than 30% of the borehole wall.

Also, in pipe-conveyed logging, we will lose the top 50m of the hole.

And we risk losing tens of metres at the bottom of the hole due to sloughing and in-fill.

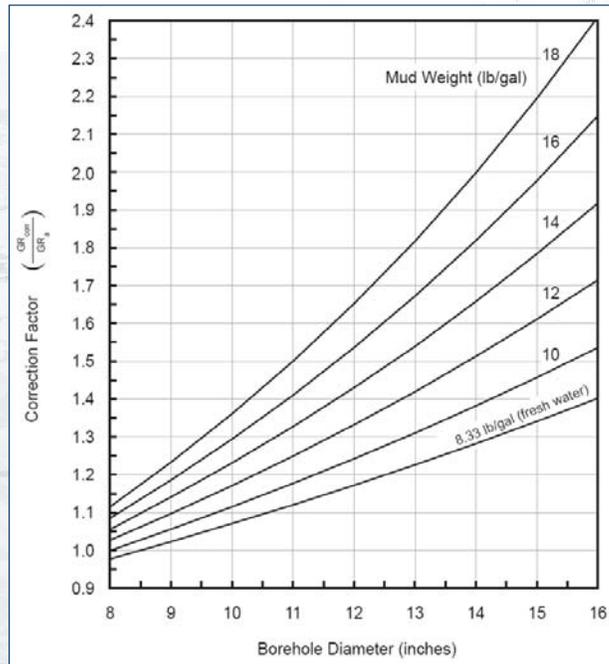
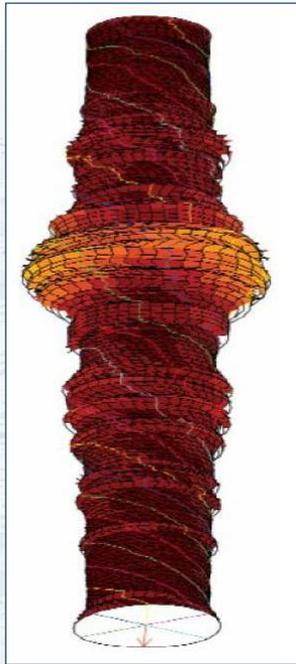
Another thing to consider is that GVR images are acquired over an interval within a few minutes of the bit opening up the hole.

FMS images might be acquired days later, and at least 6 to 12 hours later.

This is only a negative when you consider that the borehole wall might have deteriorated by then. But when run in the same borehole

(or comparable adjacent boreholes), the *time lapse* can tell you interesting things about wellbore stresses and even permeability.

Hole Condition



Wireline tools like the FMS use a mechanical caliper to determine hole condition.

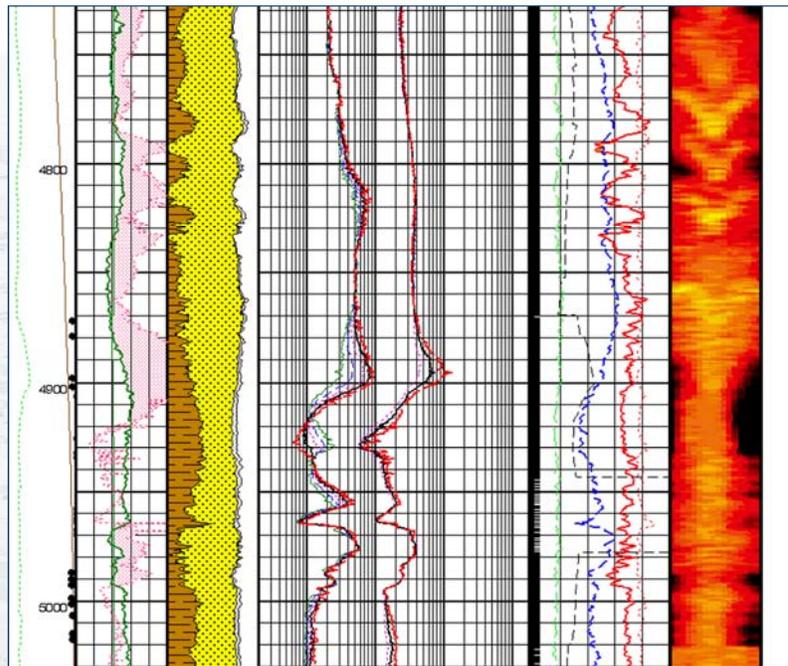
LWD tools can also provide calipers, the most robust ones being made from the density measurements, and others made from ultrasonic and resistivity measurements.

Because the tools rotate in the borehole and bin data, we can construct 3D images of the borehole (image on the left). Note: this is not necessarily a quick or automatic process.

These types of images are valuable from an operations perspective because they help us understand where we might hang up when lowering casing, or where we might have to cement the casing more thoroughly.

From a scientific perspective, it's important to recognize these washouts because of their effect on the data. Notice how the correction factor for GR (on the right) increases with increased borehole diameter. On the JR we drill with seawater (low slope curve), but on the Chikyu they will ultimately drill with very heavy muds. GR, for example, is affected by heavy mud because the weighting agent is barite which attenuates gamma rays.

Hole Condition



Even without taking the time to process a quantitative borehole caliper from LWD data, a first-look at the data will reveal hole condition.

Observe the image track on the left. That's a PEF (photoelectric factor) image of the borehole made with a density tool.

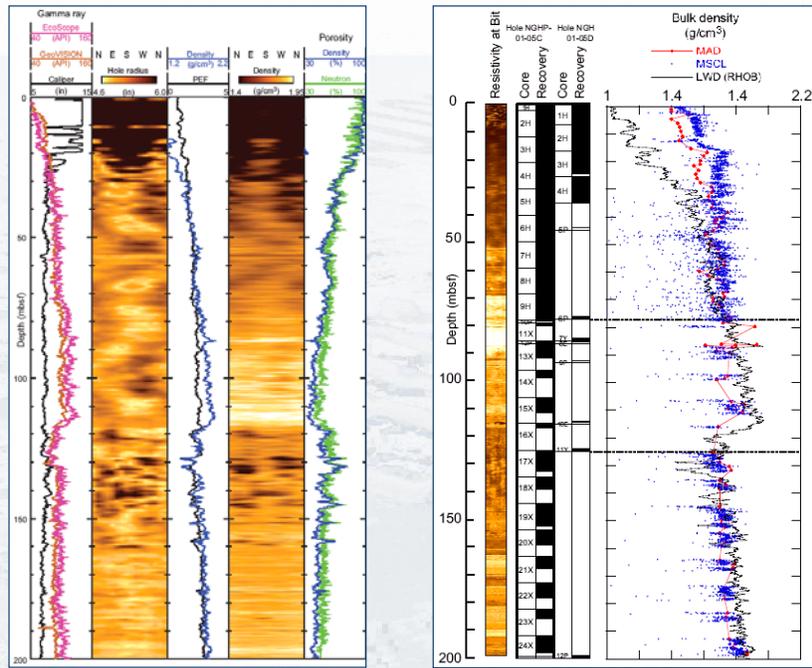
The PEF measurement is highly affected by standoff when using weighted muds. The black spots indicate washed out zones.

Note the black spots are restricted to the sides of the image: that's because the center of the image is equivalent to the bottom of the borehole.

The LWD BHA is resting on the bottom of this deviated borehole, and so the density/PEF sensors are pressed up as close as they can be to the borehole wall, mitigating the washout's effect on PEF.

Notice the Vs near 4800 ft. That indicates we're steering updip, as the top of the tool "sees" new formation first.

Hole Condition



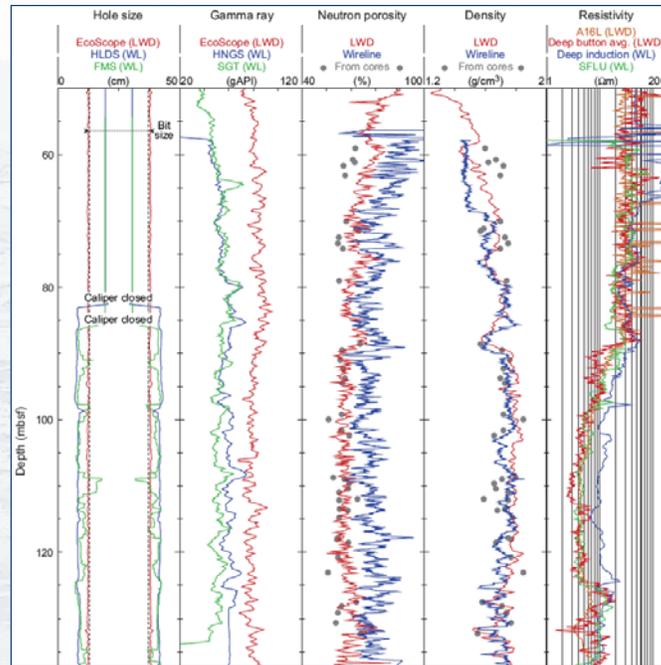
Here is some LWD, wireline and core data from a recent gas hydrate drilling cruise in India.

Notice the black spots in the “hole radius” (i.e. caliper) and density images indicate severe washouts. That’s typical of drilling in the ultra-soft sediments near the seafloor. The rotating action of the BHA and the mud flow through the bit washout the top few meters. In this case roughly 30 m are severely washed out. We can try to mitigate this by circulating or pumping at very low flow rates near the seafloor (but it doesn’t always help that much). Another way to mitigate it is to penetrate the interval very quickly (at the risk of sacrificing data density as seen before).

On the left, notice the deterioration of the LWD density quality (black curve), compared to the core data (blue curve) from APC cores.

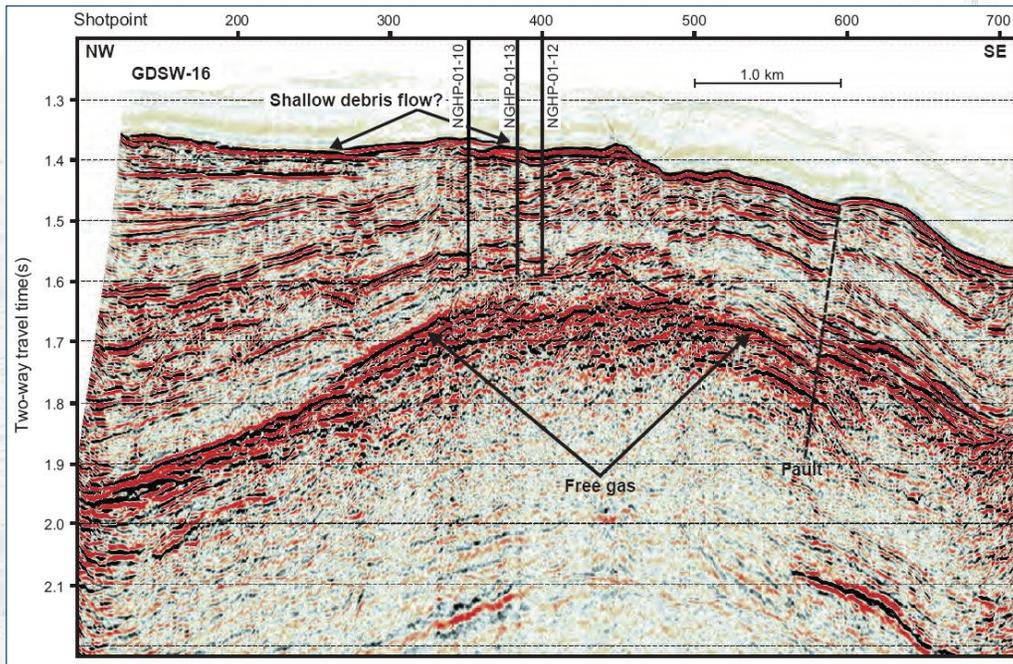
Notwithstanding the good APC core data at surface, this image at-a-glance just be able to justify logging (whether wireline or LWD) on any cruise: look at the core recovery from 80m on down.

Time Lapse



Also from India, but a different site. Observe the changes in hole size (caliper) and porosity between the LWD data (which was acquired immediately after the bit opened new hole) and the wireline data (collected perhaps 8 to 18 hours later). The hole is noticeably more enlarged. That visibly affects the wireline porosity data (which now reads artificially high).

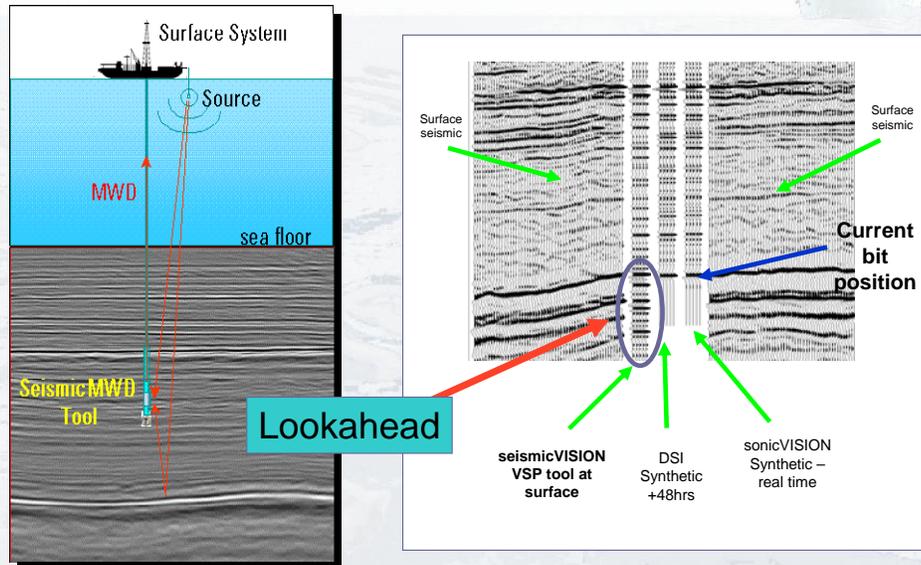
Drilling Hazards



Also from India, this seismic section highlight some drilling hazards that will warrant particular attention to real-time LWD data.

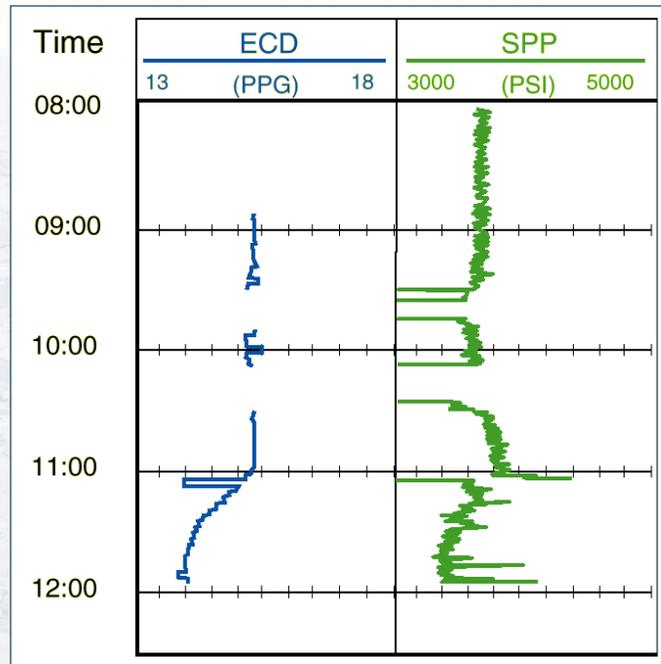
- gas
- disturbed formations (sloughing)
- faults (making correlating markers potentially unreliable and irrelevant)

Drilling Hazards: Seismic While Drilling



When drilling in faulted environments, or areas of uncertain time-depth ties, especially where there is a no-go horizon we can't afford to penetrate (such as the free gas zone from the previous slide), it might be useful to run a seismic-while-drilling tool. A series of hydrophones and geophones in the downhole tool (which is at a known depth) pick up direct arrivals (for a check-shot) and reflections (for look-ahead), helping drillers/scientists/engineers know *where* they are on the seismic map, and what's coming up. It's also possible to get a virtual check-shot (though not look-ahead), by processing acoustic LWD data.

Drilling Hazards: Gas Influx

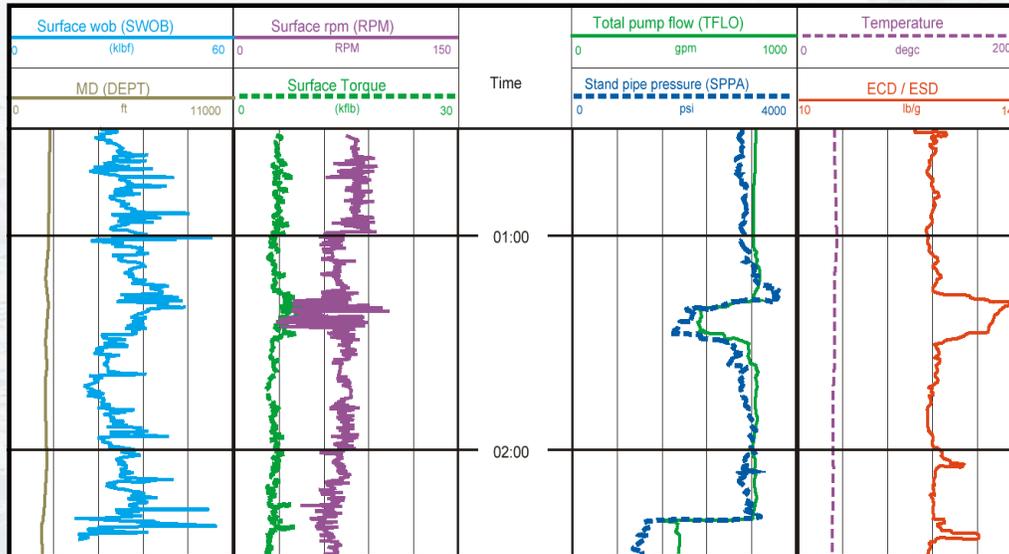


We'll now look at just a few of the things we might look for in real-time while drilling a well.

Here we look at the ECD or Equivalent Circulating Density. It's derived from the annular pressure sensor, and corrected for depth to give an equivalent mud density. Here, the ECD drops over time indicate an influx of less dense gas into the borehole. This is bad news and it's time to circulate out that gas and weight up the mud and prevent any more gas from entering the borehole. Otherwise, if the mud column becomes too light, the gas will flow even quicker, leading to a kick and perhaps even a blowout. That's basically the worst thing that can happen when drilling and the entire oilwell drilling process is geared to prevent that from happening (despite the fact that it was celebrated in the movie Armageddon).

We should also note that we're looking at this log on a time scale, which is the preferred scale for examining drilling mechanics data. What is this influx occurs while we are circulating at bottom without drilling? We'd never see this on a depth log.

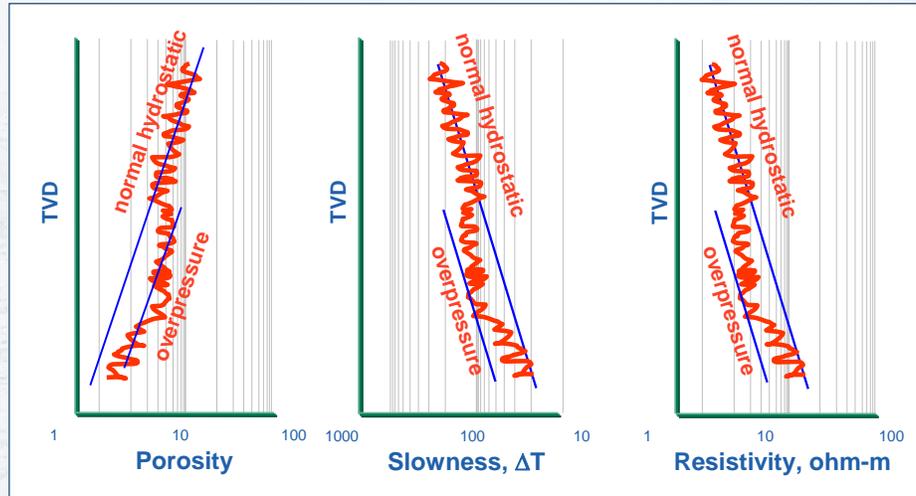
Drilling Hazards: Pack-Off



Here again we look at ECD, but also at some surface parameters like RPM, torque and standpipe pressure (the pressure at surface on the mud being circulated into the hole). Here the ECD starts creeping up and so does the standpipe pressure: a potential problem. At the same time, the RPM becomes erratic and the torque increase. We might be sticking as the hole packs off. That is, material might be sloughing and falling in on the tool. That material is increasing the pressure in the mud column leading to an increase in ECD.

It won't be the job of a scientist to monitor these parameters (the Schlumberger engineer, driller, and drilling engineer will be doing that), but this should help you understand some reasons why sending up drilling mechanics data is important, even at the expense of petrophysical data.

Drilling Hazards: Abnormal Pressure



Here are some basic ways you can recognize overpressure: changes in the trends of porosity, acoustic velocity (or slowness), and resistivity.

Generally, as depth increases so does compaction, leading to a reduction in porosity and acoustic slowness, and an increase in resistivity.

When those trends change, *in shales*, it can indicate an abnormal increase in pore pressure. By watching this in real-time, the driller and engineers can know to increase the mud weight to counter in potential gas or fluid influxes once they drill into an underlying sand formation.

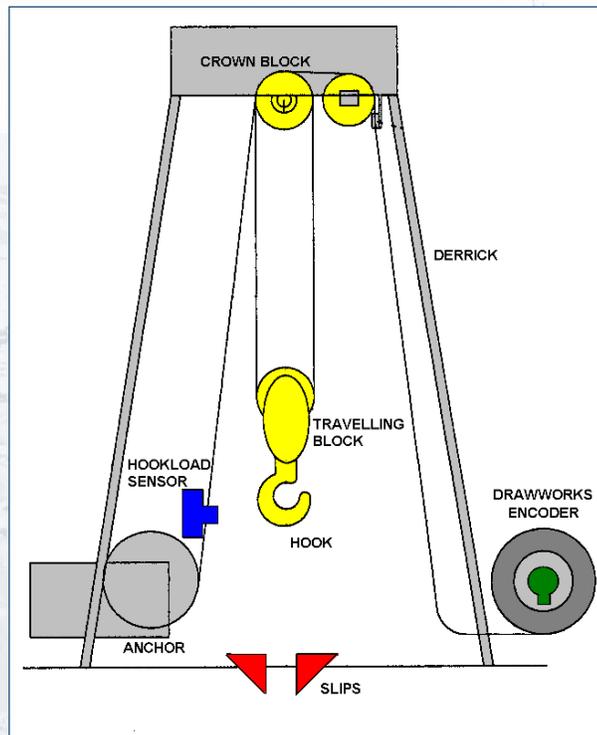
StethoScope: Formation Pressure



These are 6 slides that show the sequence of formation pressure measurement by the StethoScope tool.

This tool has not yet been used in scientific drilling (it's super expensive) but it's an excellent one for determining actual pore pressure, taking the guesswork out of estimating it using the basic methods listed above.

Depth Control



Changing gears now, let's discuss how Depth Control is a particular issue for LWD.

With Wireline it's relatively straightforward. If you remember this image from Dave's talk last week, an encoder precisely measures the cable that spools off the winch. Mature algorithms then account for temperature, tension, etc. and correct downhole tool position.

With LWD it's a more convoluted process, since there's no continuous string.

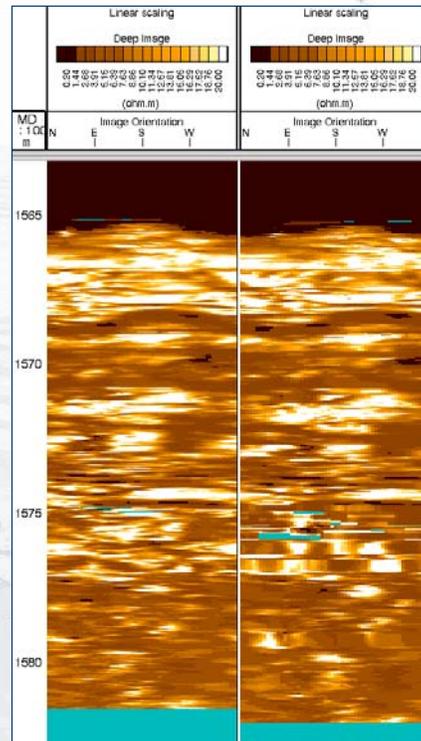
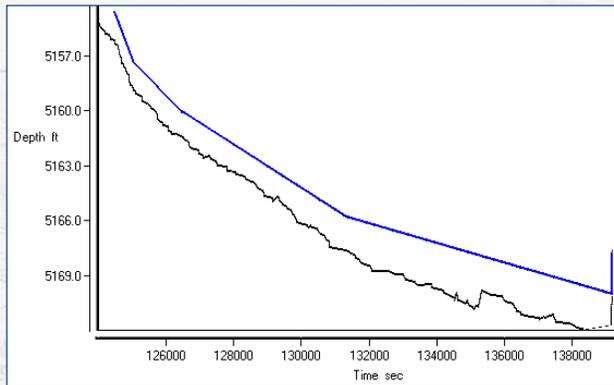
The hook is attached to a travelling that runs up and down in the derrick as drill line is spooled on or off the drawworks. The hook hangs onto lengths of drillpipe and lowers them into grips called slips that hold the string in place as the hook rises to get more pipe. To measure depth, an encoder on the drawworks measures how the drum rotates. That in turn is calibrated to how much drill line is spooled on or off, depending on the wrap diameter. A hookload sensor indicates whether or not the hook is attached to the heavy drillstring.

Major sources of error:

- the hookload sensor doesn't precisely when the string is in or out of slips
- the drawworks encoder is not calibrated precisely to the wraps on the drawworks spool
- as the cable spools out and the travelling block/hook lowers, some distance is taken in compression/bending of the drill string
- finally, the driller's behavior is important: he must drill by spooling drill line, not by letting out stroke in the heave compensator, or by *stuttering* the drilling penetration

So the surface encoder sometimes thinks the downhole tool is moving, but in reality it's stationary. And vice versa.

Depth Control



The LWD depth control problems express themselves on the logs and most strikingly in images.

On the left you can see a plot that's supposed to be LWD depth versus time.

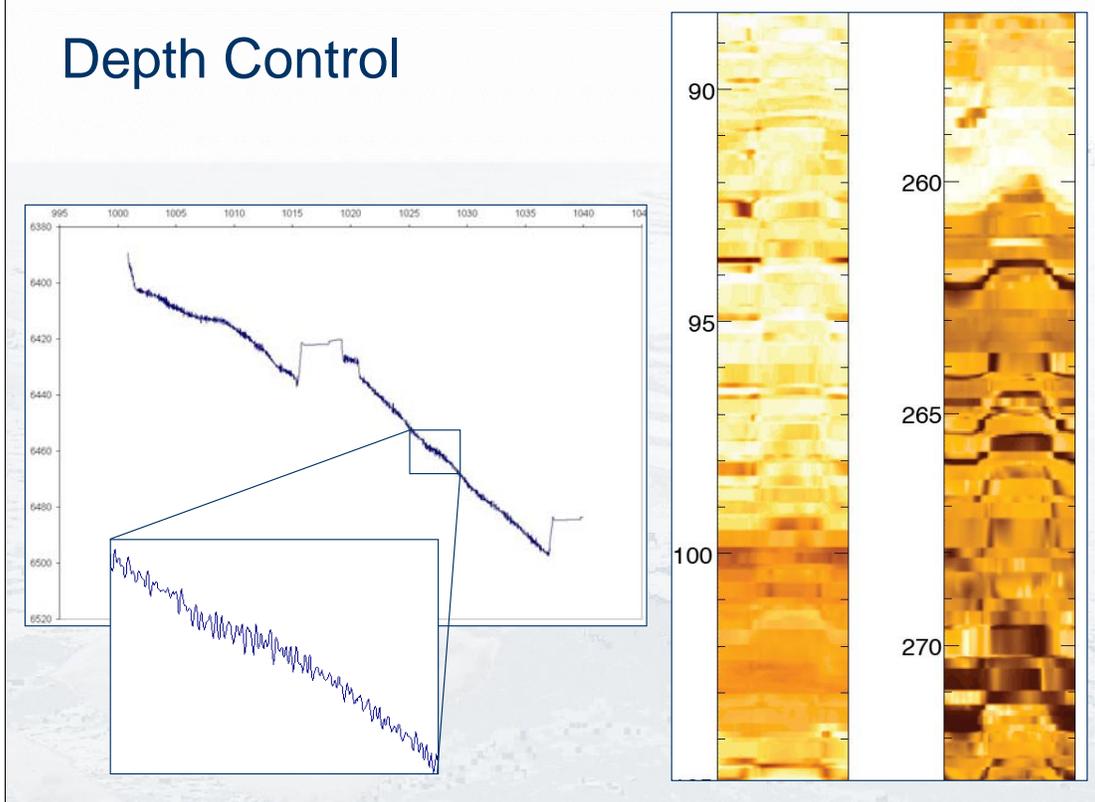
The black curve is derived from the encoder system described in the last slide. You can see it's very jagged. Except we know from looking at weight-on-bit and other data that the tool was actually constantly going down, like in the blue curve (offset in depth for clarity).

The error on the black curve came from drawworks motion not relating to downhole motion because of heave and pipe compression, and because the behavior of the driller in drilling sometimes with the heave compensator.

This is a problem because of the way downhole time-stamped LWD data are merged with uphole depth-time data. Once the tool "sees" new depth, that corresponding data is written to the database and then the system waits for new deeper depths.

On the right you see two image logs. The far right log is processed from the "bad" depth-time curve. You can see banding and smearing. A smoother images is generated from the artificial blue curve which in reality better approximates true downhole motion.

Depth Control



In these images we see a similar problem. Observe the banding and smearing.

We know right away something is wrong with the depth-time file and LWD depth control.

It seems there's a regular noise, with a period around 8s, similar to that of heave.

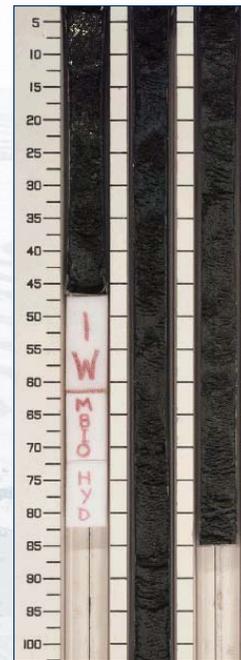
Further investigation reveals that the a different kind of encoder, called a geolograph, was used. That's fine, except it was hooked up in the wrong place and overprinted the heave signature onto the LWD depth.

It's important to be aware of these things: the Schlumberger engineers didn't catch it since the oilfield logging they are accustomed to doesn't suffer from the problems particular to riserless drilling on the JR and other platforms.

BTW, the plateaus on the curve are *connections* when the drillstring is in slips and a new joint of pipe is added.

Logging While Coring

- Correlation
- Mitigate poor core recovery
- Drastic lateral variation



I'll quickly present a slide on something we've developed here at the Borehole Research Group, in conjunction with Schlumberger and Texas A&M.

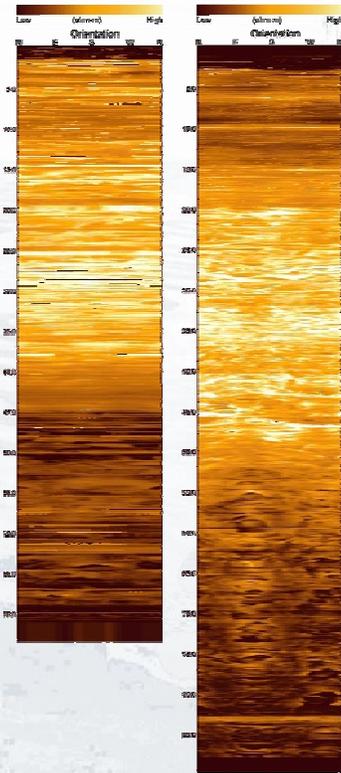
Alberto mentioned it but I will described it a little further.

Dr. Goldberg and his team essentially convinced Schlumberger to adapt a GVR tool by hollow it out, and allowing IODP rotary core barrels to pass through it.

This is important for core-log correlation/integration (consider that IODP rotary core recovery is often in the 20 to 60% range).

Logging While Coring

- Correlation
- Mitigate poor core recover
- Drastic lateral variation

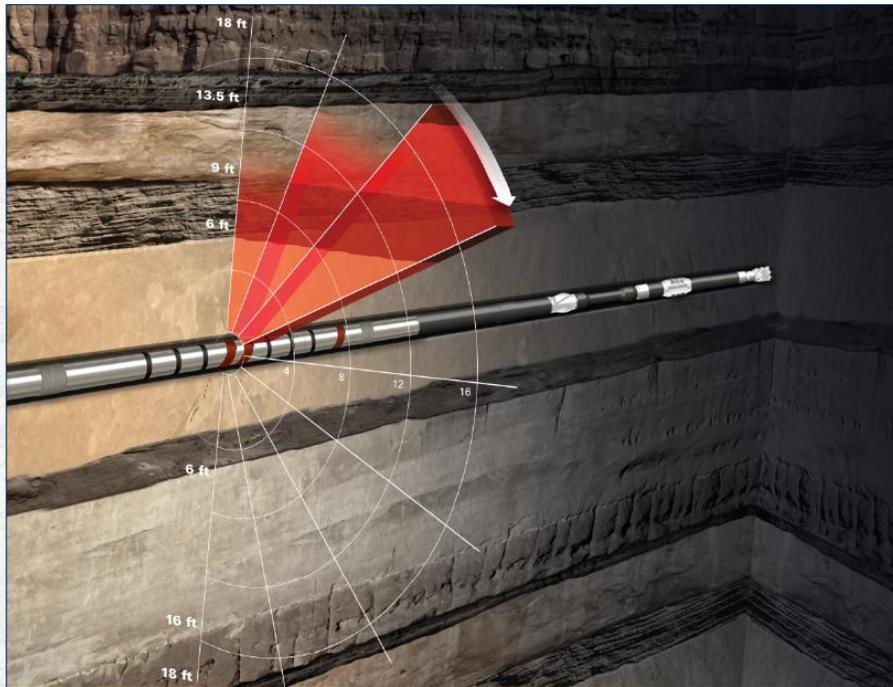


It's also particularly useful in gas hydrate cruises.

Hydrate deposits/expressions can exhibit significant lateral variations, even over a few meters.

In these cases it's particularly important to collect logging and core data from the same borehole.

PeriScope Geosteering



I just want to say a few words about the next greatest thing in LWD: directional deep-reading resistivity. Halliburton calls theirs the ADR, Schlumberger calls their the PeriScope.

It doesn't have much application in scientific drilling (yet!), though it might be very useful in SAFOD-type projects.

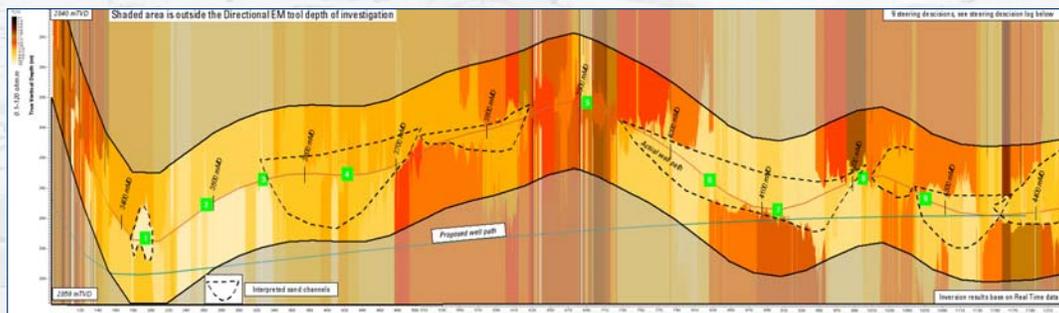
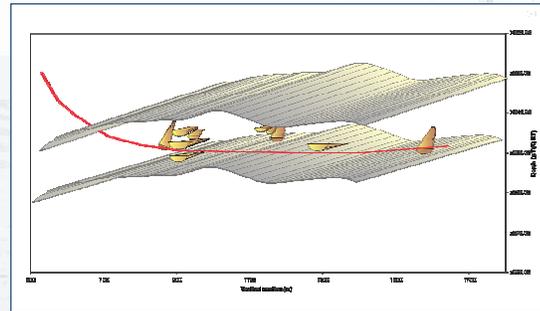
It's a technology designed for geosteering. That is, well placement and navigation through geological horizons.

As it rotates, the tool scans resistivities at different depths (different sensor spacings achieve different depth readings). The scanning part is conceptually similar to radar, though there is no "reflection" of a signal per se.

In this image, you can imagine that the different layers have different resistivities, especially the hydrocarbon-bearing sands as opposed to the shales or underlying water contact.

PeriScope Geosteering

- Channel Sands
- Horizontal and Vertical Variability



The tool's output gives geologists and engineers a pretty deep-reading look at what they are steering through, allowing them to adjust accordingly.