Appendix A

Quality Assurance for Logging and Vendor Processing of Pulsed-Neutron Capture (PNC) Logs

This appendix contains wireline logging, indirect geophysical methods, and some non-routine sampling data processing and analysis industry standards.

Example of Vendor QA for Pulsed-Neutron Capture Logging: Schlumberger registered brand name RST

Reference: Schlumberger Wireline Log Quality Reference Manual accessed January 2014 http://www.slb.com/resources/publications/books/lqcrm.aspx.

The sigma mode of PNC logs will also be used both for monitoring carbon dioxide transport and for mechanical integrity tests.

Schlumberger

RST and RSTPro

Overview

The dual-detector spectrometry system of the through-tubing RST* and RSTPro* reservoir saturation tools enables the recording of carbon and oxygen and Dual-Burst* thermal decay time measurements during the same trip in the well.

The carbon/oxygen (C/O) ratio is used to determine the formation oil saturation independent of the formation water salinity. This calculation is particularly helpful if the water salinity is low or unknown. If the salinity of the formation water is high, the Dual-Burst measurement is used. A combination of both measurements can be used to detect and quantify the presence of injection water of a different salinity from that of the connate water.

Calibration

The master calibration of the RST and RSTPro tools is conducted annually to eliminate tool-to-tool variation. The tool is positioned within a polypropylene sleeve in a horizontally positioned calibration tank filled with chlorides-free water.

The sigma, WFL* water flow log, and PVL* phase velocity log modes of the RST and RSTPro detectors do not require calibration. The gamma ray detector does not require calibration either.

Specifications

Measurement Specifications

	RST and RSTPro Tools
Output	Inelastic and capture yields of various elements, carbon/oxygen ratio, formation capture cross section (sigma), porosity, borehole holdup, water velocity, phase velocity, SpectroLith* processing
Logging speed[†]	Inelastic mode: 100 ft/h [30 m/h] (formation dependent) Capture mode: 600 ft/h [183 m/h] (formation and salinity dependent) RST sigma mode: 1,800 ft/h [549 m/h] RSTPro sigma mode: 2,800 ft/h [850 m/h]
Range of measurement	Porosity: 0 to 60 V/V
Vertical resolution	15 in [38.10 cm]
Accuracy	Based on hydrogen index of formation
Depth of investigation[‡]	Sigma mode: 10 to 16 in [20.5 to 40.6 cm] Inelastic capture (IC) mode: 4 to 6 in [10.2 to 15.2 cm]
Mud type or weight limitations	None
Combinability	RST tool: Combinable with the PL Flagship* system and CPLT* combinable production logging tool RSTPro tool: Combinable with tools that use the PS Platform* telemetry system and Platform Basic Measurement Sonde (PBMS)

[†] See Tool Planner application for advice on logging speed.

[‡] Depth of investigation is formation and environment dependent.

Mechanical Specifications

	RST-A and RST-C	RST-B and RST-D
Temperature rating	302 degF [150 degC] With flask: 400 degF [204 degC]	302 degF [150 degC]
Pressure rating	15,000 psi [103 MPa] With flask: 20,000 psi [138 MPa]	15,000 psi [103 MPa]
Borehole size—min.	$1\frac{13}{16}$ in [4.60 cm] With flask: 2¼ in [5.72 cm]	2⅞ in [7.30 cm]
Borehole size—max.	9⅝ in [24.45 cm] With flask: 9⅝ in [24.45 cm]	9⅝ in [24.45 cm]
Outside diameter	1.71 in [4.34 cm] With flask: 2.875 in [7.30 cm]	2.51 in [6.37 cm]
Length	23.0 ft [7.01 m] With flask: 33.6 ft [10.25 m]	22.2 ft [6.76 m]
Weight	101 lbm [46 kg] With flask: 243 lbm [110 kg]	208 lbm [94 kg]
Tension	10,000 lbf [44,480 N] With flask: 25,000 lbf [111,250 N]	10,000 lbf [44,480 N]
Compression	1,000 lbf [4,450 N] With flask: 1,800 lbf [8,010 N]	1,000 lbf [4,450 N]

Tool quality control

Standard curves

The RST and RSTPro standard curves are listed in Table 1.

Table 1. RST and RSTPro Standard Curves

Output Mnemonic	Output Name
BADL_DIAG	Bad level diagnostic
CCRA	RST near/far instantaneous count rate
COR	Carbon/oxygen ratio
CRRA	Near/far count rate ratio
CRRR	Count rate regulation ratio
DSIG	RST sigma difference
FBAC	Multichannel Scaler (MCS) far background
FBEF	Far beam effective current
FCOR	Far carbon/oxygen ratio
FEGF	Far capture gain correction factor
FEOF	Far capture offset correction factor
FERD	Far capture resolution degradation factor (RDF)
FIGF	Far inelastic gain correction
FIOF	Far inelastic offset correction factor
FIRD	Far inelastic RDF
IC	Inelastic capture
IRAT_FIL	RST near/far inelastic ratio
NBEF	Near beam effective current
NCOR	Near carbon/oxygen ratio
NEGF	Near capture gain correction factor
NEOF	Near capture offset correction factor
NERD	Near capture RDF
NIGF	Near inelastic gain correction
NIOF	Near inelastic offset correction factor
NIRD	Near inelastic RDF
RSCF_RST	RST selected far count rate
RSCN_RST	RST selected near count rate
SBNA	Sigma borehole near apparent
SFFA_FIL	Sigma formation far apparent
SFNA_FIL	Sigma formation near apparent
SIGM	Formation sigma
SIGM_SIG	Formation sigma uncertainty
TRAT_FIL	RST near/far capture ratio

Operation

The RST and RSTPro tools should be run eccentered. The main inelastic capture characterization database does not support a centered tool, thus it is important to ensure that the tool is run eccentered. However, for a WFL water flow log, a centered tool is recommended to better evaluate the entire wellbore region.

Formats

The format in Fig. 1 is used mainly as a hardware quality control.

- Depth track
  - Deflection of the BADL_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).
- Track 1
  - CRRA, CRRR, NBEF, and FBEF are shown; FBEF should track openhole porosity when properly scaled.
- Track 6
  - The IC mode gain correction factors measure the distortion of the energy inelastic and elastic spectrum in the near and far detectors relative to laboratory standards. They should read between 0.98 and 1.02.
- Track 7
  - The IC mode offset correction factors are described in terms of gain, offset, and resolution degradation of the inelastic and elastic spectrum in the near and far detectors. They should read between –2 and 2.
- Track 8
  - Distortion on these curves affects inelastic and capture spectra from the near and far detectors. They should be between 0 and 15. Anything above 15 indicates a tool problem or a tool that is too hot (above 302 degF [150 degC]), which affects yield processing.

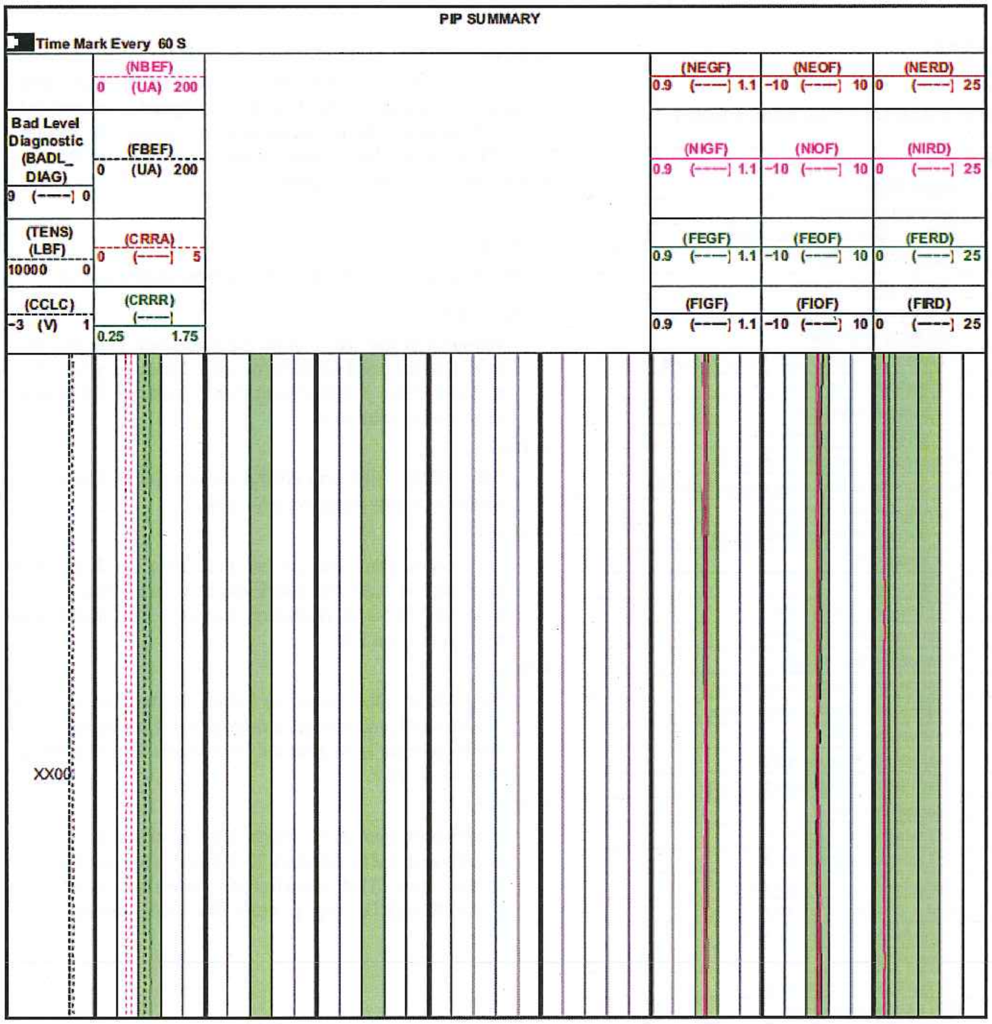


Figure 1. RST and RSTPro hardware format.

The format in Fig. 2 is used mainly for sigma quality control.

- Depth track
  - Deflection of the BADL_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).
- Tracks 2 and 3
  - The IRAT_FIL inelastic ratio increases in gas and decreases with porosity.
  - DSIG in a characterized completion should equal approximately zero. Departures from zero indicate either the environmental parameters are set incorrectly or environment is different from the characterization database (e.g., casing is not fully centered in the wellbore or the tool is not eccentered). Shales typically read 1 to 4 units from the baseline of zero because they are not characterized in the database.

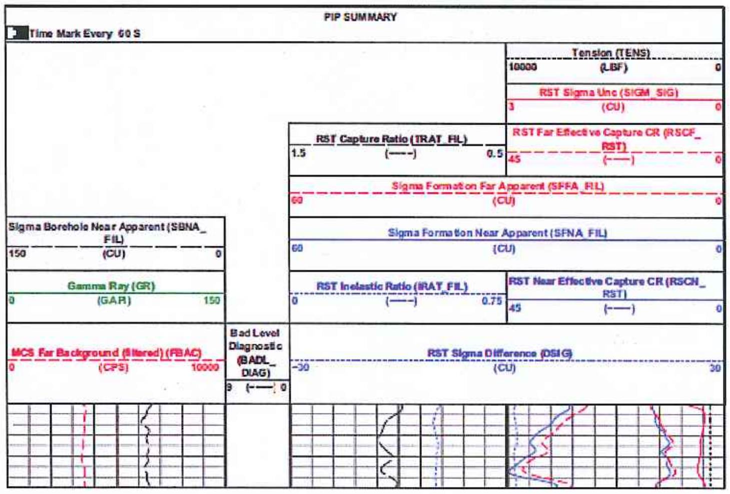


Figure 2. RST and RSTPro sigma standard format.

Response in known conditions

In front of a clean water zone, COR is smaller than the value logged across an oil zone. Oil in the borehole affects both the near and far COR, causing them to read higher than in a water-filled borehole. In front of shale, high COR is associated with organic content.

The computed yields indicate contributions from the materials being measured (Table 2).

Table 2. Contributing Materials to RST and RSTPro Yields

Element	Contributing Material
C and O	Matrix, borehole fluid, formation fluid
Si	Sandstone matrix, shale, cement behind casing
Ca	Carbonates, cement
Fe	Casing, tool housing

Bad cement quality affects readings (Table 3). A water-filled gap in the cement behind the casing appears as water to the IC measurement. Conversely, an oil-filled gap behind the casing appears as oil to the IC measurement.

Table 3. RST and RSTPro Capture and Sigma Modes

Medium	Sigma, cu
Oil	18 to 22
Gas	0 to 12
Water, fresh	20 to 22
Water, saline	22 to 120
Matrix	8 to 12
Shale	35 to 55

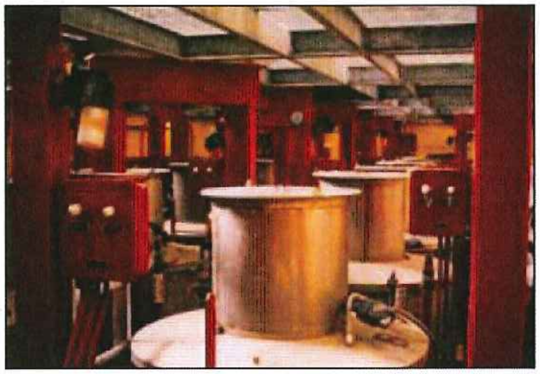
Quality Control in Processing Pulsed-Neutron Capture Logs

The following is an example from one vendor.

Reference: Albertin, I. et al., 1996, Many Facets of Pulsed Neutron Cased Hole Logging: Schlumberger Oilfield Review Summer 1996. Available at:
http://www.slb.com/~/media/Files/resources/oilfield_review/ors96/sum96/06962841.pdf

Additional information about the PNC tool is available at:
http://www.slb.com/~/media/PremiumContent/evaluation/petrophysics/porosity/rst_client_book.pdf

The Sigma Data Base

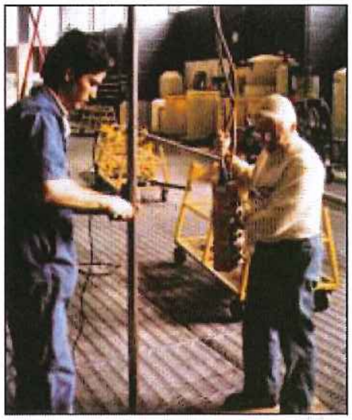


□The Schlumberger Environmental Effects Calibration Facility, Houston, Texas, USA. Over 4000 measurements were made in more than thirty formations of differing lithology and porosity, with different combinations of formation salinities, borehole salinities, and completions to produce the sigma data base.

□EUROPA facility, Aberdeen, Scotland.

Diffusion, borehole and lithology effects must be considered when transforming raw pulsed neutron capture measurements to actual physical quantities. These effects are difficult to account for in direct analytical approaches across the entire range of oilfield conditions. Therefore, an extensive data base of laboratory measurements is used to correct for these effects in real time.[1]

Over several years, the data base was acquired for the RST-A, RST-B and TDT-P logging tools at the Schlumberger Environmental Effects Calibration Facility (EECF), Houston, Texas *(above and right)*. This enables raw tool measurements to be referenced to calibrated values of formation sigma, borehole salinity and formation porosity for a variety of environmental conditions. Each tool was run in over 30 formations of different lithologies and porosities. Formation and borehole fluid salinities were varied and different completions were introduced into the borehole representing different casing sizes and cement thicknesses.



Altogether more than 1000 formation-borehole combinations were measured for each tool. Modeling was used to extend the range of available sandstone formations. To date, the data base contains over 4000 points.

The sigma values of the database formations are calculated classically

$$\Sigma = (1-\Phi)\,\Sigma_{ma} + \Phi\, S_{fl}\Sigma_{fl}$$

where Φ is the formation porosity, Σ_{ma} is matrix sigma, S_{fl} is the formation fluid saturation and Σ_{fl} is fluid sigma.

Porosity of the EECF tank formations was determined by carefully measuring all weights and volumes of the rocks, fluids and tanks used. CNL Compensated Neutron Log measurements verified the porosity values and the homogeneity of the formations.

Matrix sigma values were determined by gross macroscopic cross-section measurements provided by commercial reactor facilities and by processing complete elemental analyses through Schlumberger Nuclear Parameter (SNUPAR) cross-section tables.[2]

Water salinity was determined by a calibrated titration procedure and then converted into fluid sigma again using SNUPAR cross-section tables.

Algorithm—RST Sigma Processing

A three-step sequence is performed to translate raw log measurements into borehole salinity, porosity, corrected near and far sigma and formation sigma *(next page, top)*.

The first step is to correct the near and far detector time-decay spectra for losses in the detection and counting system, and for back-

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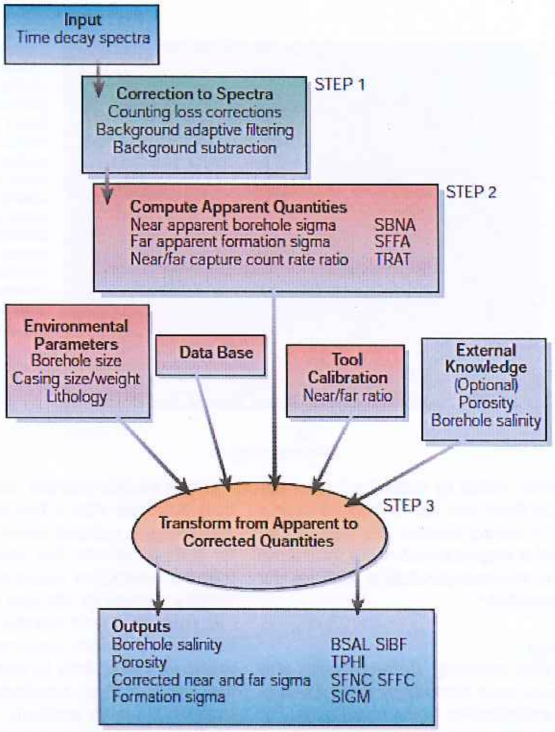
[1] Plasek RE et al, reference 3, main text.

[2] McKeon DC and Scott HD: "SNUPAR—A Nuclear Parameter Code for Nuclear Geophysics Applications," *Nuclear Physics* 2, no. 4 (1988): 215-230.



□Simplified RST sigma processing.

ground radiation. Typically the background is averaged to improve statistics.

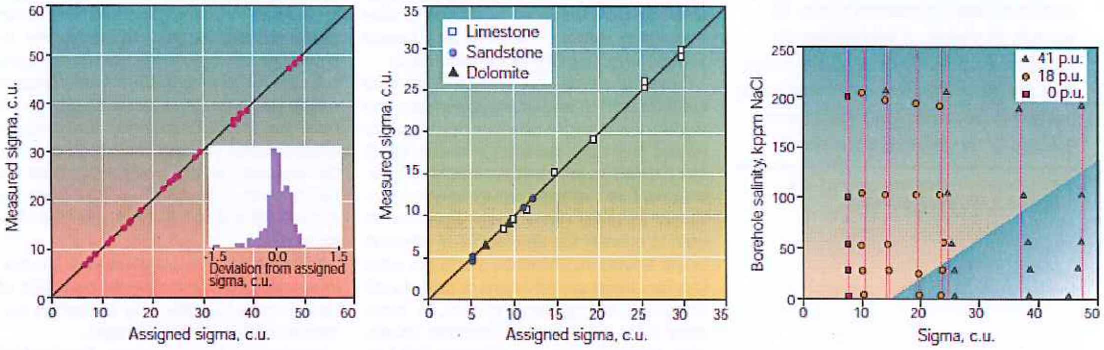
The next step is to generate the apparent quantities from the spectra, such as near and far apparent formation sigmas. These quantities are not environmentally corrected.

The third step is to apply transforms and environmental corrections to the apparent tool quantities to arrive at borehole salinity, porosity and formation sigma. The technique uses dynamic database parameterization that handles both the transformation and environmental corrections.

Accuracy

A series of benchmark measurements has been made to assess the accuracy of the algorithm used with the data base to compute borehole salinity, porosity and formation sigma *(below)*. These benchmark measurements include reprocessing the entire data base as well as logging in industry standard facilities such as the EUROPA sigma facility in Aberdeen, Scotland *(previous page, top right)* and the API porosity test pit, at the University of Houston, in Texas.

Database points were reprocessed with the dynamic parameterization algorithm and the results were compared with the assigned values.



□Processing accuracy. Benchmark measurements were made to assess the accuracy of the algorithm in computing formation and borehole sigma, porosity and borehole salinity. Sigma measured with the RST-A tool versus assigned database sigma *(left)* shows average errors are small—0.22 c.u. Sigma measured at the EUROPA facility in Aberdeen *(middle)* again shows excellent agreement with the assigned values. Comparison of RST-A tool sigma *(right)* versus borehole salinity shows that corrected sigma is independent of borehole salinity—vital for time-lapse surveys or log-inject-log operations. In the crossover region *(shaded area)*, formation sigma approaches or even exceeds borehole sigma. Historically, pulsed neutron capture tools erroneously identify the borehole decay as formation sigma and formation decay as borehole sigma in this region. However, the RST dynamic parameterization method solves this long-standing problem, correctly distinguishing between formation and borehole sigma components.

The algorithm does exceptionally well in matching the assigned values. For example, the average errors for formation sigma were 0.22 capture units (c.u.) for the RST-A tool and 0.20 c.u. for the RST-B tool.

The EUROPA facility is an independent sigma calibration facility partially funded by the UK Atomic Energy Authority with major support from a consortium of 15 oil companies and government agencies. The RST-A tool was run in all the openhole formations and several cased-hole formations. A smaller number of measurements were made with the RST-B tool. Both tools read the true formation sigma over a wide range of lithologies, porosities, formation and borehole fluids, borehole sizes and completions. Even in the difficult crossover region, where formation sigma approaches or exceeds borehole sigma, the errors are small and the tool does not lock on to the wrong sigma component.

Both EUROPA and the University of Houston API pits were used to check porosity readings. The agreement between the two sets of porosities was excellent.

Precision

Key to time-lapse monitoring techniques is repeatability or precision. Time-lapse uses differences in measured quantities to monitor, for example, the progress of waterflooding, the expansion of gas caps and the depletion of reservoirs. The RST tool has been benchmarked to log nearly three times faster than previous generation tools for the same level of precision.[3]

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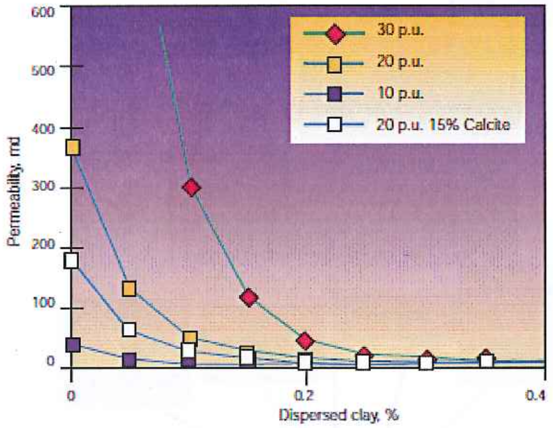
[3] For examples of repeatability—precision—see: Plasek et al, reference 3, main text.



□*Effect of clay and calcite on permeability. A small percentage of clay has a dramatic effect on permeability. Calcite also reduces permeability. So to determine a well's producibility or the cause of any formation damage, it is important to understand the mineralogy.*

techniques, which by definition look at differences from one log to another over a period of several months. RST data can be gathered at logging speeds nearly three times those of previous-generation tools for the same precision.[4]

Lithology

Assessing reservoir deliverability and enhancing zone productivity rely on a thorough understanding of the rock matrix. For example, clay content dramatically affects permeability (*above*).[5] Elemental yields derived from RST spectroscopy measurements provide the input to determine clay and other mineral content and hence improve understanding of the rock matrix.

Elemental yields—Neutrons interact with the formation in several ways. Inelastic and capture interactions produce spontaneous release of gamma radiation at energy levels that depend on the elements involved. Measurement of the gamma ray spectra produced by these interactions can then be used to quantify the abundance of elements in the formation. Elemental yields are often used in various combinations or ratios to aid complex lithology interpretation, to determine shale volume or to augment incomplete openhole data (see "Making Full Use of RST Data in China," *page 36*).

At high neutron energies, inelastic interactions dominate. After a few collisions, neutron energy is reduced below the threshold for inelastic events. The probability of an inelastic interaction occurring is also reasonably constant for all major elements.

As neutrons slow to thermal energy levels, capture interactions dominate. Some elements are more likely to capture neutrons than others and so contribute more to the capture gamma ray spectrum.

Inelastic and capture gamma ray spectra are recorded by opening counting windows at the appropriate time after a neutron burst from the RST neutron generator. Tool design allows not only for much higher gamma ray count rates than previous generation tools, but also for gain stabilization that enables lower gamma ray energy levels to be recorded for both inelastic and capture measurements. A major advantage of this is the inclusion of the inelastic gamma ray peaks on the spectrum at 1.37 MeV for magnesium and at 1.24 MeV and 1.33 MeV for iron.[6]

A library of standard elemental spectra, measured in the laboratory for each type of tool, is used to determine individual elemental contributions (*next page*).

SpectroLith interpretation—SpectroLith processing is a quantitative mineral-based

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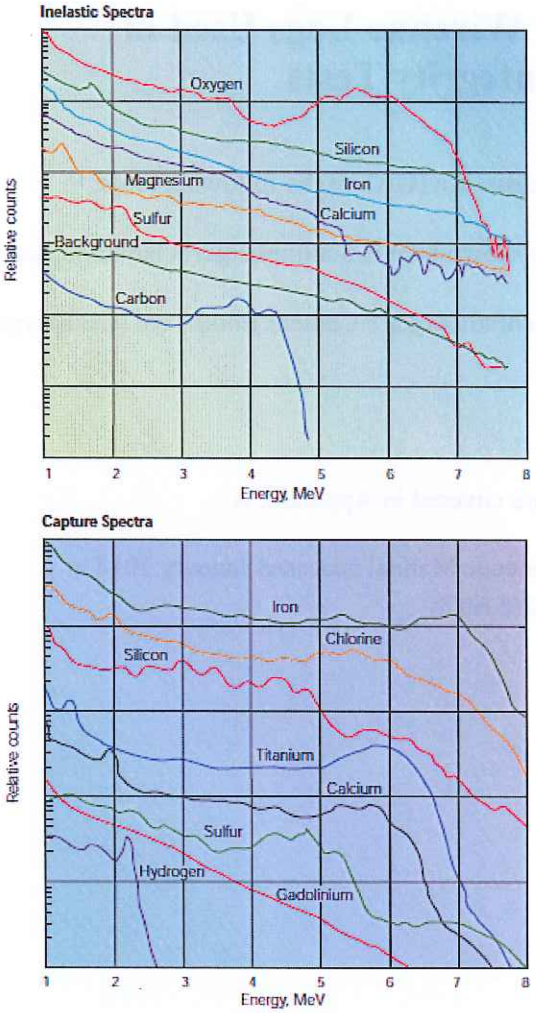
[4] For more details on time-lapse monitoring see sections on precision and auxiliary measurements: Plasek RE et al, reference 3.

[5] Herron M: "Estimating the Intrinsic Permeability of Clastic Sediments from Geochemical Data," *Transactions of the SPWLA 28th Annual Logging Symposium*, London, England, June 29-July 2, 1987, paper HH.

[6] Roscoe B, Grau J, Cao Minh C and Freeman D: "Non-Conventional Applications of Through-Tubing Carbon-Oxygen Logging Tools," *Transactions of the SPWLA 36th Annual Logging Symposium*, Paris, France, June 26-29, 1995, paper QQ.

[7] Herron SL and Herron MM: "Quantitative Lithology: An Application for Open and Cased Hole Spectroscopy," *Transactions of the SPWLA 37th Annual Logging Symposium*, New Orleans, Louisiana, USA, June 16-19, 1996, paper E.

[8] See Roscoe B et al, reference 6.



□Elemental standards for the RST-A tool. Lower gamma ray energy levels are recorded by the RST tools than by previous generation pulsed neutron tools. This allows measurement of elemental contributions from elements such as magnesium and iron. Elemental yields are processed from standard spectra obtained using laboratory measurements. Shown are the standards for inelastic (top) and capture (bottom) spectra for the 1 11/16-in. RST-A tool.

lithology interpretation derived from elemental yields. Traditional lithology interpretation relied on measurements of elements such as aluminum and potassium to determine clay content. Aluminum, especially, is difficult to measure and requires a combination of logging tools; the interpretation is also complex.

A recent detailed study of cores showed that a linear relationship exists between aluminum and total clay concentration. Of more importance, it also showed that silicon, calcium and iron can be used to produce an accurate estimation of clay without knowledge of the aluminum concentration.[7] The concentrations of these three elements can be obtained from RST spectroscopy measurements.

In addition, carbonate concentrations—defined as calcite plus dolomite—can be determined from the calcium concentration alone with the remainder of the formation being composed of quartz, feldspar and mica minerals.

SpectroLith interpretation involves three steps:

- production of elemental yields from gamma ray spectra
- transformation of yields into concentration logs
- conversion of concentration logs into fractions of clay, carbonate and framework minerals.

Borehole Fluid

The producing wellbore environment may include a combination of oil, water and gas phases in the borehole as well as flow behind casing. Borehole fluid interpretation is primarily based on fluid velocities and borehole holdup. The RST equipment makes these measurements using several independent methods, with enough redundancy to provide a quality control cross check:

- The WFL Water Flow Log measures water velocity and water flow rate using the principle of oxygen activation. This method detects water flowing inside and outside pipe, and in up and down flow.
- The Phase Velocity Log (PVL) measures oil and water velocities separately by injecting a marker fluid, which mixes and travels with the specified phase. This method may be applied to up and down flow, but only fluids in the pipe are marked and therefore detected.
- Two-phase—oil and water—borehole holdup may be measured in continuous logging mode with the RST-B tool.[8]
- Three-phase—oil, water and gas—borehole holdup is currently an RST-A station measurement based on a combination of C/O and inelastic count rate ratio data.
- Borehole salinity is one of the computations made as part of the sigma and porosity log and may be used to compute a borehole water holdup with either the RST-A or the RST-B tool.

(continued on page 39)

Appendix B

Quality Assurance for Wireline Logs Used in Mechanical Integrity Tests

This appendix contains examples of vendor quality assurance (QA) on the following tools:

- Ultrasonic Cement Evaluation tool: Example shown here is Schlumberger's Isolation Scanner (registered trademark)
- Cement Bond Log tool: Example shown is Schlumberger's Cement Bond Tool (CBT) registered trademark
- Cement Bond Logging QA
- Cased hole temperature log
- Cased hole gamma log
- NOTE: Pulsed-neutron capture (PNC) logs are covered in Appendix A

Reference: Schlumberger Wireline Log Quality Reference Manual accessed January 2014 at http://www.slb.com/resources/publications/books/lqcrm.aspx.

Schlumberger

Isolation Scanner

Overview

Isolation Scanner* cement evaluation service combines the classic pulse-echo technology of the USI* ultrasonic imager with a new ultrasonic technique—flexural wave imaging—to accurately evaluate any type of cement, from traditional slurries and heavy cements to lightweight cements.

In addition to confirming the effectiveness of a cement job for zonal isolation, Isolation Scanner service pinpoints any channels in the cement. The tool's azimuthal and radial coverage readily differentiates low-density solids from liquids to distinguish lightweight cements from contaminated cement and liquids. The service also provides detailed images of casing centralization and identifies corrosion or drilling-induced wear through measurement of the inside diameter and thickness of the casing.

Flexural wave imaging is used by Isolation Scanner service as a significant complement to pulse-echo acoustic impedance measurement. It relies on the pulsed excitation and propagation of a casing flexural mode, which leaks deep-penetrating acoustic bulk waves into the annulus. Attenuation of the first casing arrival, estimated at two receivers, is used to unambiguously determine the state of the material coupled to the casing as solid, liquid, or gas (SLG). Third-interface reflection echoes arising from the annulus/formation interface yield additional characterization of the cased hole environment:

- acoustic velocity (P or S) of the annulus material
- position of the casing within the borehole or a second casing string
- geometrical shape of the wellbore.

Because acoustic impedance and flexural attenuation are independent measurements, their combined analysis provides borehole fluid properties without requiring a separate fluid-property measurement.

Specifications

Measurement Specifications	
Output[†]	Solid-liquid-gas map of annulus material, hydraulic communication map, acoustic impedance, flexural attenuation, rugosity image, casing thickness image, internal radius image
Logging speed	Standard resolution: 2,700 ft/h [823 m/h] High resolution: 563 ft/h [172 m/h]
Range of measurement	Min. casing thickness: 0.15 in [0.38 cm] Max. casing thickness: 0.79 in [2.01 cm]
Vertical resolution	High resolution: 0.6 in [1.52 cm] High speed: 6 in [15.24 cm]
Accuracy	Acoustic impedance:[‡] 0 to 10 Mrayl (range); 0.2 Mrayl (resolution); 0 to 3.3 Mrayl = ±0.5 Mrayl, >3.3 Mrayl = ±15% (accuracy) Flexural attenuation:[§] 0 to 2 dB/cm (range), 0.05 dB/cm (resolution), ±0.01 dB/cm (accuracy)
Depth of investigation	Casing and annulus up to 3 in [7.62 cm]
Mud type or weight limitations[††]	Conditions simulated before logging

[†] Investigation of annulus width depends on the presence of third interface echoes. Analysis and processing beyond cement evaluation can yield additional answers through additional outputs, including a Variable Density* log of the annulus waveform and polar movies in AVI format.

[‡] Differentiation of materials by acoustic impedance alone requires a minimum gap of 0.5 Mrayl between the fluid behind the casing and a solid.

[§] For 0.3-in [8-mm] casing thickness

[††] Max. mud weight depends on the mud formulation, sub used, and casing size and weight, which are simulated before logging.

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Casing size—min.[†]	4½ in (min. pass-through restriction: 4 in [10.16 cm])
Casing size—max.[†]	9⅝ in
Outside diameter	IBCS-A: 3.375 in [8.57 cm] IBCS-B: 4.472 in [11.36] IBCS-C: 6.657 in [16.91 cm]
Length	Without sub: 19.73 ft [6.01 m] IBCS-A sub: 2.01 ft [0.61 m] IBCS-B sub: 1.98 ft [0.60 m] IBCS-C sub: 1.98 ft [0.60 m]
Weight	Without sub: 333 lbm [151 kg] IBCS-A sub: 16.75 lbm [7.59 kg] IBCS-B sub: 20.64 lbm [9.36 kg] IBCS-C sub: 23.66 lbm [10.73 kg]
Sub max. tension	2,250 lbf [10,000 N]
Sub max. compression	12,250 lbf [50,000 N]

[†] Limits for casing size depend on the sub used. Data can be acquired in casing larger than 9⅝ in with low-attenuation mud (e.g., water, brine).

Calibration

A master calibration of the near and far flexural transducers to identical sensitivities is required to avoid introducing a bias in the attenuation measurements. Within a pressurized sleeve filled with de-aired water, the tool is calibrated to an accurately machined stainless-steel target mounted relative to it to minimize any eccentering effects.

Tool quality control

Standard curves

Isolation Scanner standard curves are listed in Table 1.

Operation

The Isolation Scanner tool must be run centralized in the borehole. It is highly recommended to run the GPIT* general purpose inclinometry tool in combination for image orientation in a nonvertical well.

The Isolation Scanner tool planner must be run before the job with the following inputs: casing diameter, casing weight, logging fluid, and bit size. This is necessarily to obtain the transducer angle and job set-up parameters.

Table 1. Isolation Scanner Standard Curves

Output Mnemonic	Output Name	Output Mnemonic	Output Name
AGMA	Maximum allowed USI ultrasonic imager electronic programmable gain	THAV	Average thickness
AWAV	Average amplitude	THMN	Minimum thickness
AWBK	Amplitude of echo minus maximum	THMX	Maximum thickness
AWMN	Minimum amplitude	UFAI	USI fluid acoustic impedance (inverted)
AWMX	Maximum amplitude	UFDX	USI far maximum waveform delay
AZEC	Azimuth of eccentering	UFGA	USI far maximum allowed UPGA
CCLU	Casing collar locator from ultrasonic	UFGI	USI far minimum allowed UPGA
CFVL	Computed fluid velocity	UFGN	USI far minimum value of UPGA
CS	Cable speed	UFGX	USI far maximum value of UPGA
CZMD	Computed acoustic impedance of fluid	UFLG	USI processing flag
DFAI	USI discretized fluid acoustic impedance (inverted)	UFSL	USI fluid slowness (inverted)
ECCE	Eccentralization	UFWB	USI far window begin
ERAV	External radius average	UFWE	USI far window end
ERMN	Minimum external radius	UFZQ	USI inverted fluid acoustic impedance quality control
ERMX	Maximum external radius	UNDX	USI near window maximum delay
FSOD	Fluid slowness fitting casing outside diameter (parameter: 0 = off, 2 = use feedback on velocity and acoustic impedance, 5 = use feedback on velocity only, fixed or zoned impedance)	UNGA	USI near maximum allowed UPGA
GNMN	USI minimum value of programmable gain amplitude of waves (UPGA)	UNGI	USI near minimum allowed UPGA
GNMX	USI maximum value of UPGA	UNGN	USI near minimum value of UPGA
HPKF	USI histogram of far peaks	UNGX	USI near maximum value of UPGA
HPKN	USI histogram of near peaks	UNWB	USI near window begin
HRTF	USI histogram of far transit time	UNWE	USI near window end
HRTN	USI histogram of near transit time	UPGA	USI programmable gain amplitude of waves
HRTT	USI histogram of raw transit time	WDMA	USI waveform delay window end
IRAV	Internal radius average	WDMI	USI waveform delay window begin
IRMN	Internal radius minimum	WDMN	USI minimum waveform delay
IRMX	Internal radius maximum	WDMX	USI maximum waveform delay
RSAV	Motor resolution sub average velocity	WPKA	USI peak histogram

Formats

The format in Fig. 1 is used mainly for quality control of Isolation Scanner signals, enabling a quick view of the component USI, near, and far waveforms and arrival peak detection with histograms.

- Track 1
  - CS is the speed at which the cable is moving.
  - RSAV is the motor rotational velocity. It is important for confirming motor rotation during acquisition.
  - CCLU spikes in front of casing collars and is used for correlation.
- Track 2
  - The WPKA histogram is a distribution of the amplitude of the waveform measured by the USI transducer. The image scale and color represent the number of samples and their corresponding peak amplitude in binary bits.
- Track 3
  - GNMX and GNMN represent the minimum and maximum gains, respectively, of the amplifier responsible for image acquisition. The gain should be kept between 0 and 10 dB. If the gain is above 10 dB, the signal from the transducer is too small and the power should be increased by the engineer. If the gain is below 0 dB, the situation is reversed.
- Track 4
  - HRTT should be centered as shown in Fig. 2.
- Track 5
  - WDMN and WDMX should be close to each other. Depending on the sensor-to-casing standoff, the window in which the tool may locate the peak of the echo has to be set.
- Tracks 6 through 13
  - The log quality control concepts listed for Tracks 2 through 5 also apply in these tracks for the near and far transducers.

The purpose of the format in Fig. 3 is to check the quality of the fluid properties measurement (velocity and acoustic impedance) inversion.

- Track 1
  - ECCE decreases the signal-to-noise ratio of the ultrasonic measurements, resulting in the appearance of dark vertical bands on the amplitude map. ECCE should remain low throughout the logging interval represented in this figure.
- Track 2
  - The UFLG flags represent a diagnostic for processing. In normal cases, this track should be free of flags except at collars, which interrupt the model fitting by flagging.
- Track 3
  - The AWBK image track presents the reflectivity of the internal face of the casing. It corresponds to internal casing roughness and is also a good indicator of excessive eccentering. The color scale is in decibels, with black meaning low signal and white meaning high signal.
- Track 4
  - U-USIT_UFSL is the fluid slowness calculated assuming that the averaged outer casing OD is constant.
  - U-USIT_DFSL is the quantized value of UFSL. It compares the slowness between the current and previous depths and selects which will be used for processing.
  - CSVL is the actual fluid velocity input for processing. It may be equal to the discretized fluid slowness (DFSL) or the default fluid velocity (DFVL) depending on the software parameter setting of FSOD.
- Track 5
  - ERAV, IRAV, IRMX, and IRMN provide a view of the pipe.
- Track 6
  - U-USIT_UFAI is inverted from the flexural attenuation (UFAK) and the raw acoustic impedance (AIBK).
  - U-USIT_DFAI is a quantized value from the inverted fluid acoustic impedance.
  - CZMD is the acoustic impedance used in the processing. Its value depends on the software parameter setting of FSOD.
- Track 6
  - U-USIT_UFZQ is proportional to the number of points below the critical impedance that are considered liquid. Below a low threshold of 20%, it is flagged with red, and above a high threshold of 50%, it is flagged as green.

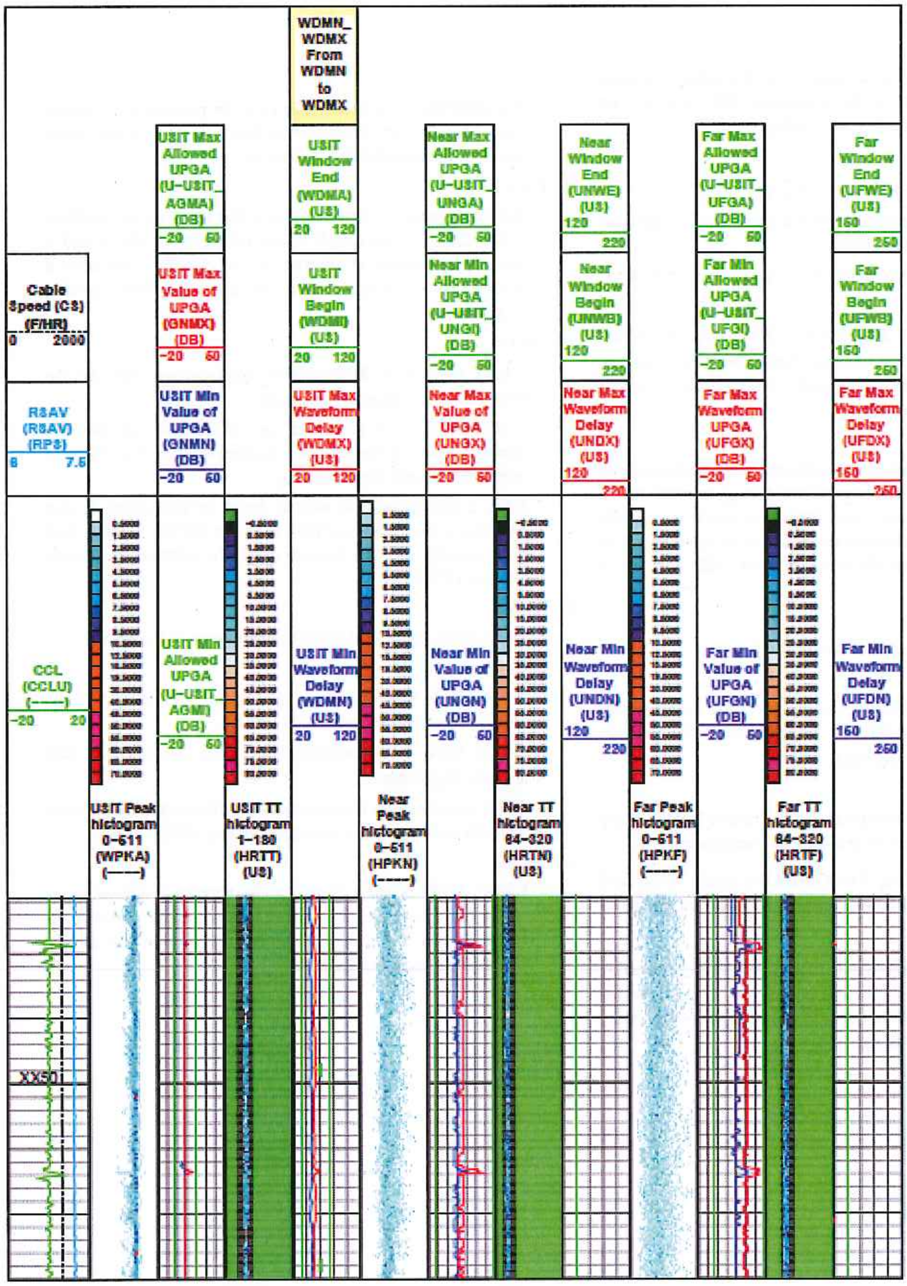
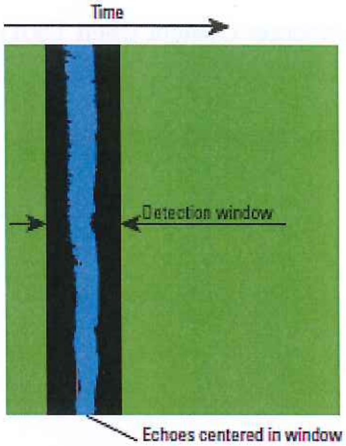


Figure 1. Isolation Scanner signal and waveforms quality control format.



Echoes centered in window

Figure 2. The USI transit-time histogram should be centered in the detection window.

Response in known conditions

The fluid slowness (DFSL) is checked for consistency with expected values in Table 2.

Table 2. Typical Isolation Scanner Fluid Slowness Ranges in Known Conditions

Fluid	DFSL, us/ft	Velocity, mm/us
Oil, oil-base, or heavy water-base mud	218 to 254	1.2 to 1.4
Water, light brine, or light water-base mud	184 to 218	1.4 to 1.65
Brine	160 to 184	1.65 to 1.9

The median internal radius is checked that it is reasonably close to what is expected from the casing size (±0.07 in [±2 mm]) to the casing inside diameter in noncorroded casing.

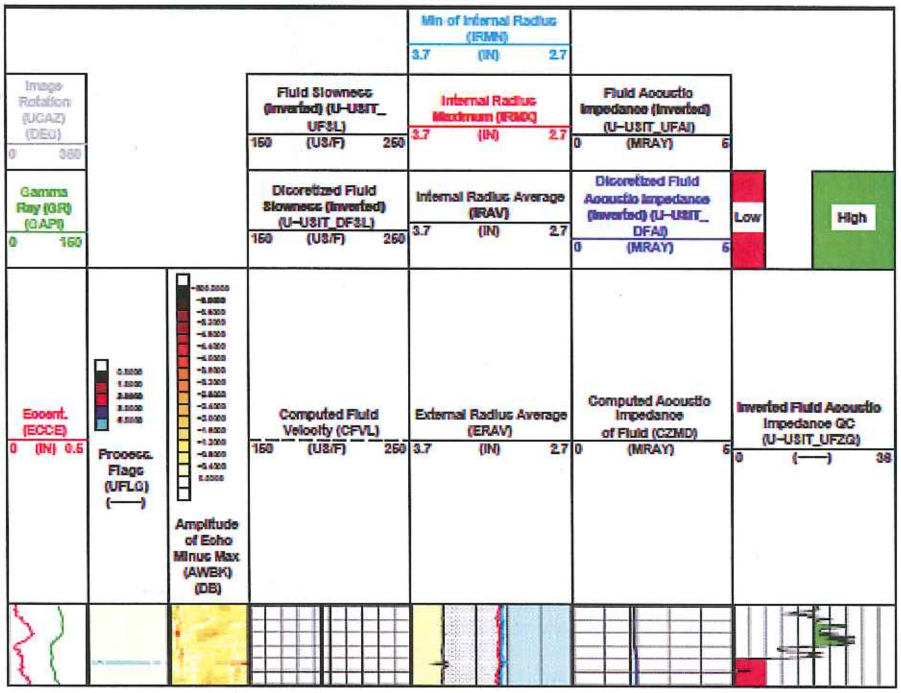


Figure 3. Isolation Scanner fluid property measurement quality control format.

Cement Bond

The example shown below is the QA for the sonic-based Schlumberger Cement Bond Tool (CBT) registered trademark.

Reference : Schlumberger Wireline Log Quality Reference Manual accessed January 2014 http://www.slb.com/resources/publications/books/lqcrm.aspx.

Cement Bond Tool

Overview

The cement bond log (CBL) made with the Cement Bond Tool (CBT) provides continuous measurement of the attenuation of sound pulses, independent of casing fluid and transducer sensitivity. The tool is self-calibrating and less sensitive to eccentering and sonde tilt than the traditional single-spacing CBL tools. The CBT additionally gives the attenuation of sound pulses from a receiver spaced 0.8 ft [0.24 m] from the transmitter, which is used to aid interpretation in fast formations.

A CBL curve computed from the three attenuations available enables comparison with CBLs based on the typical 3-ft [0.91-m] spacing. This computed CBL continuously discriminates between the three attenuations to choose the one best suited to the well conditions. An interval transit-time curve for the casing is also recorded for interpretation and quality control.

A Variable Density* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. This display provides information on the cement/formation bond and other factors that are important to the interpretation of cement quality.

Specifications

Measurement Specifications	
Output	Attenuation measurement, CBL, VDL image, transit times
Logging speed	1,800 ft/h [549 m/h][†]
Range of measurement	Formation and casing dependent
Vertical resolution	CBL: 3 ft [0.91 m] VDL: 5 ft [1.52 m] Cement map: 2 ft [0.61 m]
Accuracy	Formation and casing dependent
Depth of investigation	CBL: casing and cement interface VDL: depends on bonding and formation
Mud type or weight limitations	None

[†] Speed can be reduced depending on data quality.

Measurement Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	3.375 in [8.57cm]
Borehole size—max.	13.375 in [33.97 cm]
Outside diameter	2.75 in [6.985 cm]
Weight	309 lbm [140 kg]

Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

Tool quality control

Standard curves

CBT standard curves are listed in Table 1.

Table 1. CBT Standard Curves

Output Mnemonic	Output Name
CCL	Casing collar locator amplitude
DATN	Discriminated BHC attenuation
DBI	Discriminated bond index
DCBL	Discriminated synthetic CBL
DT	Interval transit time of casing (delta-*t*)
DTMD	Delta-*t* mud (mud slowness)
GR	Gamma ray
NATN	Near 2.4-ft attenuation
NBI	Near bond index
NCBL	Near synthetic CBL
R32R	Ratio of receiver 3 sensitivity to receiver 2 sensitivity, dB
SATN	Short 0.8-ft attenuation[†]
SBI	Short bond index[†]
SCBL	Short synthetic CBL[†]
TT1	Transit time for mode 1 (upper transmitter, receiver 3 [UT-R3])
TT2	Transit time for mode 2 (UT-R2)
TT3	Transit time for mode 3 (lower transmitter, receiver 2 [LT-R2])
TT4	Transit time for mode 4 (LT-R3)
TT6	Transit time for mode 6 (UT-R1)
ULTR	Ratio of upper transmitter output strength to the lower transmitter output strength
VDL	Variable Density log

[†] In fast formations only

Operation

The tool should be run centralized.

A log should be made in a free-pipe zone (if available). Where a microannulus is suspected, a repeat section should be made with pressure applied to the casing.

Formats

The format in Fig. 1 is used both as an acquisition and quality control format.

- Track 1
  - DT and DTMD are derived from the transit-time measurements from all transmitter-receiver pairs. They respond to eccentralization of any of the six measurements modes and are a sensitive indicator of wellbore conditions. In a low-quality cement bond or free pipe, both readings are correct. In well-bonded sections, the transit time may cycle skip, affecting the DT and DTMD values.
  - CCL deflects in front of casing collars.
  - GR is used for correlation purposes.
- Track 2
  - DCBL is related to casing size, casing weight, and mud. As a quality control DCBL should be checked against the expected responses in known conditions (see the following section). Also, DCBL should match the VDL image readings.
- Track 3
  - VDL is a map of the waveform amplitude versus depth and it should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings. For example, in a free-pipe section, the DCBL amplitude reads high and VDL shows strong casing arrivals with no formation arrivals. In a zone of good bond for the casing to the formation, the CBL amplitude reads low and the VDL has weak casing arrivals and clear formation arrivals.

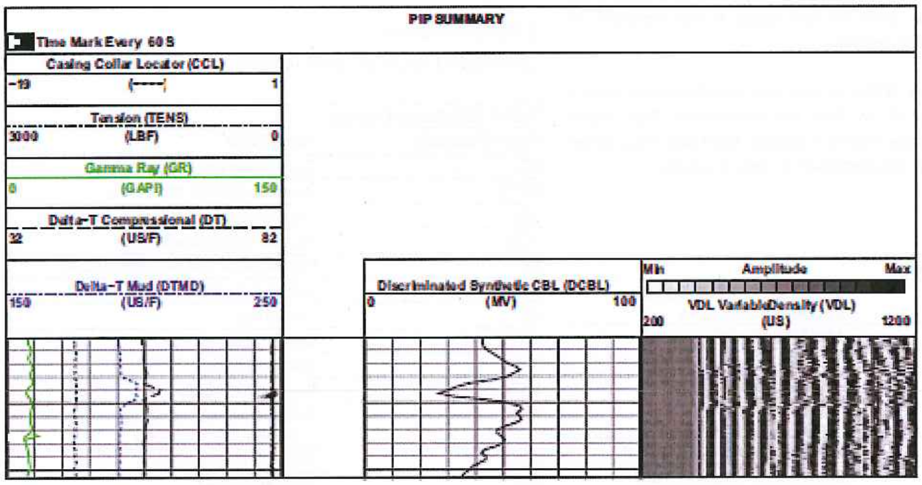


Figure 1. CBT standard format for CBL and VDL.

The format in Fig. 2 is also used both as an acquisition and quality control format.

- Track 1
  - The transit time pairs should overlay (TT1C overlays TT3C, and TT2C overlays TT4C) because these pairs are derived from equivalent transmitter-receiver spacings. In very good cement sections, the transit-time curve may be affected by cycle skipping. DT and DTMD may be also affected.
- Track 2
  - The ULTR and R32R ratios are quality indicators of the transmitter or receiver strengths. They should be 0 dB ± 3 dB, unless one of the transmitters or receivers is weak. Both curves should be checked for consistency and stability.
- Track 3
  - DATN should equal NATN in free-pipe sections. In the presence of cement behind casing and in normal conditions, NATN reads higher than DATN.
- Track 4
  - VDL is a map of the waveform amplitude versus depth that should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings.

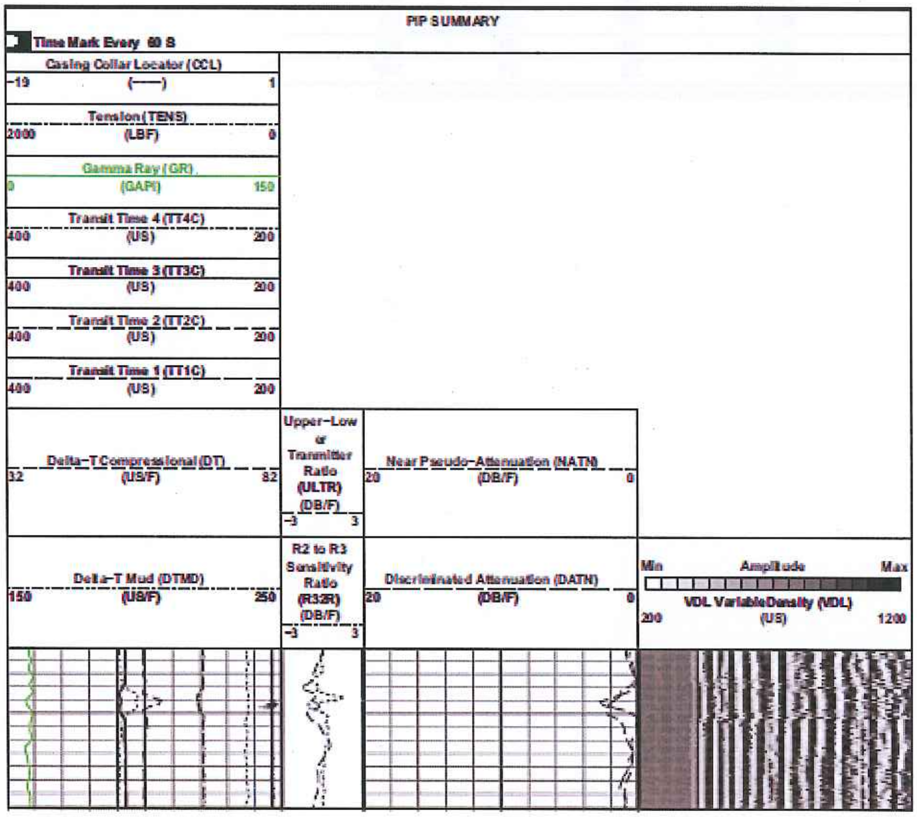


Figure 2. Additional CBT standard format for CBL and VDL.

Response in known conditions

- DT in casing should read the value for steel (57 us/ft ± 2 us/ft [187 us/m ± 6.6 us/m]).
- DTMD should be compared with known velocities (water-base mud: 180–200 us/ft [590–656 us/m], oil-base mud: 210–280 us/ft [689–919 us/m]).
- Typical responses for different casing sizes and weights are listed in Table 2.

Table 2. Typical CBT Response in Known Conditions

Casing Size, in	Casing Weight, lbm/ft	DCBL in Free Pipe, mV	TT1, us	TT2, us	TT5, us
4.5	11.6	84 ± 8	252	195	104
5	13	77 ± 7	259	203	112
5.5	17	71 ± 7	267	210	120
7	24	61 ± 6	290	233	140
8.625	38	55 ± 6	314	257	166
9.625	40[†]	52 ± 5	329	272	NM[‡]

[†] Although the CBT operates in up to 13⅜-in casing, the VDL presentation mainly shows casing arrivals where casings of 9⅝ in and larger are logged.

[‡] NM = not meaningful

Cement Bond Logging

Overview

Cement bond tools measure the bond between the casing and the cement placed in the annulus between the casing and the wellbore. The measurement is made by using acoustic sonic and ultrasonic tools. In the case of sonic tools, the measurement is usually displayed on a cement bond log (CBL) in millivolt units, decibel attenuation, or both. Reduction of the reading in millivolts or increase of the decibel attenuation is an indication of better-quality bonding of the cement behind the casing to the casing wall. Factors that affect the quality of the cement bonding are

- cement job design and execution as well as effective mud removal
- compressive strength of the cement in place
- temperature and pressure changes applied to the casing after cementing
- epoxy resin applied to the outer wall of the casing.

The recorded CBL provides a continuous measurement of the amplitude of sound pulses produced by a transmitter-receiver pair spaced 3-ft [0.91-m] apart. This amplitude is at a maximum in uncemented free pipe and minimized in well-cemented casing. A transit-time (TT) curve of the waveform first arrival is also recorded for interpretation and quality control.

A Variable Density* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. The VDL display provides information on the cement quality and cement/formation bond.

Specifications

Measurement Specifications

	Digital Sonic Logging Tool (DSLT) and Hostile Environment Sonic Logging Tool (HSLT) with Borehole-Compensated (BHC)	Slim Array Sonic Tool (SSLT) and SlimXtreme* Sonic Logging Tool (QSLT)
Output	SLS-C, SLS-D, SLS-W, and SLS-E[†] 3-ft [0.91-m] CBL Variable Density waveforms	3-ft [0.91-m] CBL and attenuation 1-ft [0.30-m] attenuation 5-ft [1.52-m] Variable Density waveforms
Logging speed	3,600 ft/h [1,097 m/h]	3,600 ft/h [1,097 m/h]
Range of measurement	40 to 200 us/ft [131 to 656 us/m]	40 to 400 us/ft [131 to 1,312 us/m]
Vertical resolution	Amplitude (mV): 3 ft [0.91 m] VDL: 5 ft [1.52 m]	Near attenuation: 1 ft [0.30 m] Amplitude (mV): 3 ft [0.91 m] VDL: 5 ft [1.52 m]
Depth of investigation	Synthetic CBL from discriminated attenuation (DCBL): Casing and cement interface VDL: Depends on cement bonding and formation properties	DCBL: Casing and cement interface VDL: Depends on cement bonding and formation properties
Mud type or weight limitations	None	None
Special applications		Conveyed on wireline, drillpipe, or coiled tubing Logging through drillpipe and tubing, in small casings, fast formations

[†] The DSLT uses the Sonic Logging Sonde (SLS) to measure cement bond amplitude and VDL evaluation.

Mechanical Specifications

	DSLT	HSLT	SSLT	QSLT
Temperature rating	302 degF (150 degC)	500 degF (260 degC)	302 degF (150 degC)	500 degF (260 degC)
Pressure rating	20,000 psi (138 MPa)	25,000 psi (172 MPa)	14,000 psi (97 MPa)	30,000 psi (207 MPa)
Casing ID—min.	5 in (12.70 cm)	5 in (12.70 cm)	3½ in (8.89 cm)	4 in (10.16 cm)
Casing ID—max.	18 in (45.72 cm)	18 in (45.72 cm)	8 in (20.32 cm)	8 in (20.32 cm)
Outside diameter	3⅝ in (9.21 cm)	3¾ in (9.53 cm)	2½ in (6.35 cm)	3 in (7.62 cm)
Length	SLS-C and SLS-D: 18.7 ft (5.71 m) SLS-E and SLS-W: 20.6 ft (6.23 m)	With HSLS-W sonde: 25.5 ft (7.77 m)	23.1 ft (7.04 m) With inline centralizers: 29.6 ft (9.02 m)	23 ft (7.01 m) With inline centralizers: 29.9 ft (9.11 m)
Weight	SLS-C and SLS-D: 273 lbm (124 kg) SLS-E and SLS-W: 313 lbm (142 kg)	With HSLS-W sonde: 440 lbm (199 kg)	232 lbm (105 kg) With inline centralizers: 300 lbm (136 kg)	295 lbm (134 kg) With inline centralizers: 407 lbm (185 kg)
Tension	29,700 lbf (132,110 N)	29,700 lbf (132,110 N)	13,000 lbf (57,830 N)	13,000 lbf (57,830 N)
Compression	SLS-C and SLS-D: 1,700 lbf (7,560 N) SLS-E and SLS-W: 2,870 lbf (12,770 N)	With HSLS-W sonde: 2,870 lbf (12,770 N)	4,400 lbf (19,570 N)	4,400 lbf (19,570 N)

Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Scheduled frequency of Q-checks varies for each tool. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

Tool quality control

Standard curves

CBL standard curves are listed in Table 1.

Table 1. CBL Standard Curves

Output Mnemonic	Output Name
BI	Bond index
CBL	Cement bond log (fixed gate)
CBLF	Fluid-compensated cement bond log
CBSL	Cement bond log (sliding gate)
CCL	Casing collar log
GR	Gamma ray
TT	Transit time (fixed gate)
TTSL	Transit time (sliding gate)
VDL	Variable Density log

Operation

The tool must be run centralized.

A log should be made in a free-pipe zone (if available). Where a microannulus is suspected, a repeat section should be made with pressure applied to the casing.

Formats

The format in Fig. 1 is used for both acquisition and quality control.

- Track 1
    - TT and TTSL should be constant through the log interval and should overlay. These curves deflect near casing collars. In sections of very good cement, the signal amplitude is low; detection may be affected by cycle skipping. GR is used for correlation purposes, and CCL serves as a reference for future cased hole correlations..
- Track 2
    - CBL measured in millivolts from the fixed gate should be equal to CBSL measured from the sliding gate, except in cases of cycle skipping or detection on noise.
- Track 3
    - VDL is a presentation of the acoustic waveform at a receiver of a sonic measurement. The amplitude is presented in shades of a gray scale. The VDL should show good contrast. In free pipe, it should be straight lines with chevron patterns at the casing collars. In a good bond, it should be gray (low amplitudes) or show strong formation signals (wavy lines).

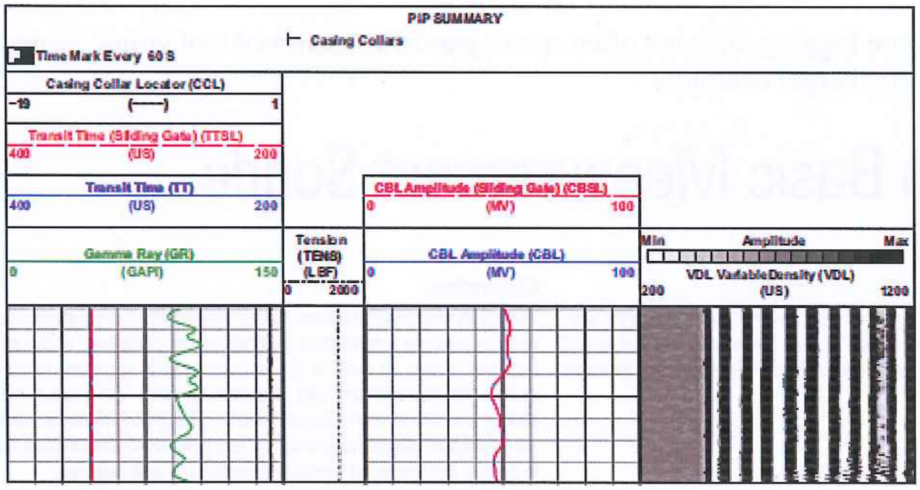


Figure 1. DSLT standard format.

Response in known conditions

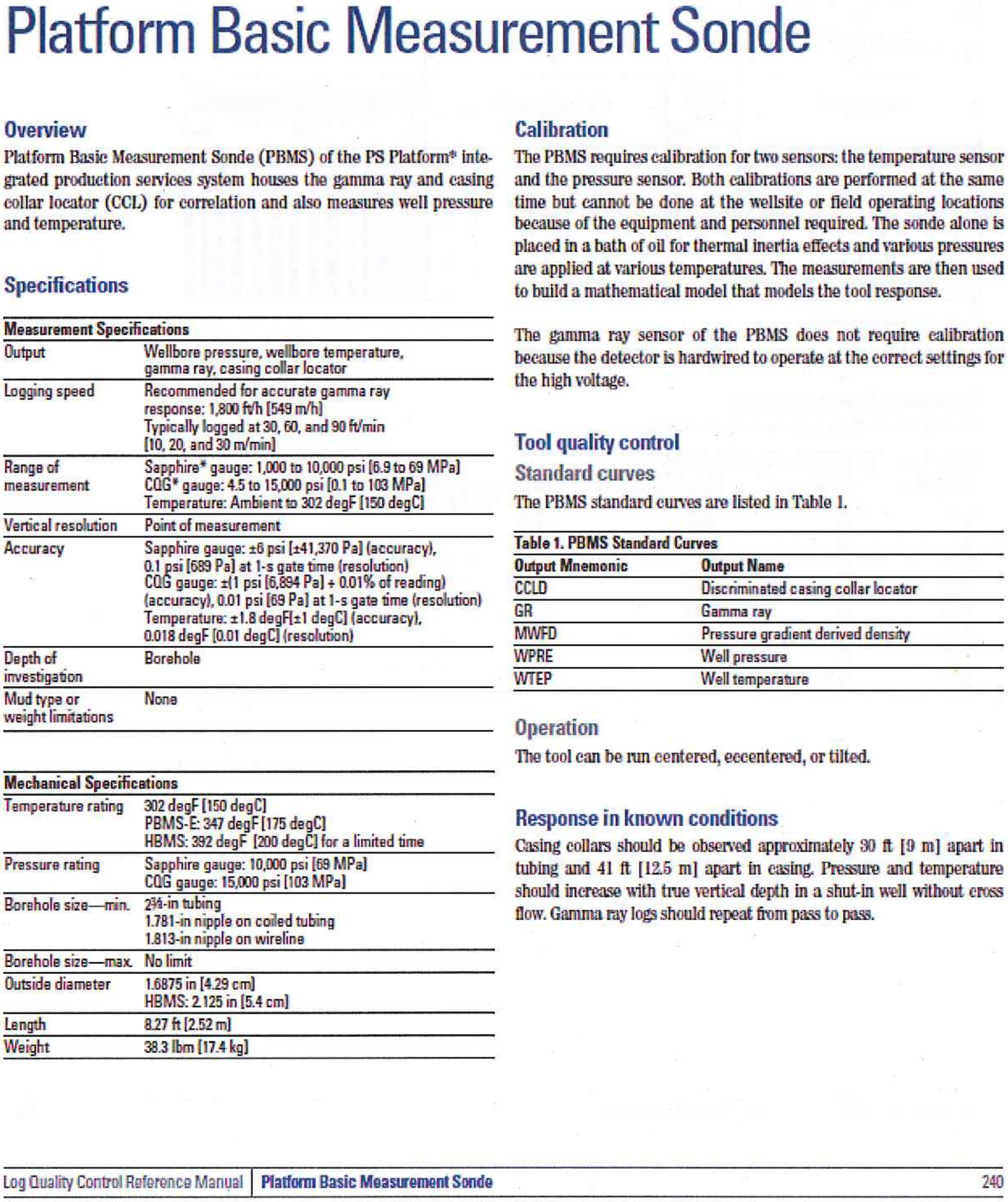
The responses in Table 2 are for clean, free casing.

Table 2. Typical CBL Response in Known Conditions

Casing OD, in	Weight, lbm/ft	Nominal Casing ID, in	CBL Amplitude Response in Free Pipe, mV
5	13	4.494	77 ± 8
5.5	17	4.892	71 ± 7
7	23	6.366	62 ± 6
8.625	36	7.825	55 ± 6
9.625	47	8.681	52 ± 5
10.75	51	9.850	49 ± 5
13.375	61	12.515	43 ± 4
18.625	87.5	17.755	35 ± 4

Cased Hole Temperature Logging

Cased hole temperature logging tools are often run as part of a multi-tool tool string, as described in the following Schlumberger example.



Platform Basic Measurement Sonde

Overview

Platform Basic Measurement Sonde (PBMS) of the PS Platform* integrated production services system houses the gamma ray and casing collar locator (CCL) for correlation and also measures well pressure and temperature.

Specifications

Measurement Specifications	
Output	Wellbore pressure, wellbore temperature, gamma ray, casing collar locator
Logging speed	Recommended for accurate gamma ray response: 1,800 ft/h [549 m/h] Typically logged at 30, 60, and 90 ft/min [10, 20, and 30 m/min]
Range of measurement	Sapphire* gauge: 1,000 to 10,000 psi [6.9 to 69 MPa] CQG* gauge: 4.5 to 15,000 psi [0.1 to 103 MPa] Temperature: Ambient to 302 degF [150 degC]
Vertical resolution	Point of measurement
Accuracy	Sapphire gauge: ±6 psi [±41,370 Pa] (accuracy), 0.1 psi [689 Pa] at 1-s gate time (resolution) CQG gauge: ±(1 psi [6,894 Pa] + 0.01% of reading) (accuracy), 0.01 psi [69 Pa] at 1-s gate time (resolution) Temperature: ±1.8 degF[±1 degC] (accuracy), 0.018 degF [0.01 degC] (resolution)
Depth of investigation	Borehole
Mud type or weight limitations	None

Mechanical Specifications	
Temperature rating	302 degF [150 degC] PBMS-E: 347 degF [175 degC] HBMS: 392 degF [200 degC] for a limited time
Pressure rating	Sapphire gauge: 10,000 psi [69 MPa] CQG gauge: 15,000 psi [103 MPa]
Borehole size—min.	2⅜-in tubing 1.781-in nipple on coiled tubing 1.813-in nipple on wireline
Borehole size—max.	No limit
Outside diameter	1.6875 in [4.29 cm] HBMS: 2.125 in [5.4 cm]
Length	8.27 ft [2.52 m]
Weight	38.3 lbm [17.4 kg]

Calibration

The PBMS requires calibration for two sensors: the temperature sensor and the pressure sensor. Both calibrations are performed at the same time but cannot be done at the wellsite or field operating locations because of the equipment and personnel required. The sonde alone is placed in a bath of oil for thermal inertia effects and various pressures are applied at various temperatures. The measurements are then used to build a mathematical model that models the tool response.

The gamma ray sensor of the PBMS does not require calibration because the detector is hardwired to operate at the correct settings for the high voltage.

Tool quality control

Standard curves

The PBMS standard curves are listed in Table 1.

Table 1. PBMS Standard Curves

Output Mnemonic	Output Name
CCLD	Discriminated casing collar locator
GR	Gamma ray
MWFD	Pressure gradient derived density
WPRE	Well pressure
WTEP	Well temperature

Operation

The tool can be run centered, eccentered, or tilted.

Response in known conditions

Casing collars should be observed approximately 30 ft [9 m] apart in tubing and 41 ft [12.5 m] apart in casing. Pressure and temperature should increase with true vertical depth in a shut-in well without cross flow. Gamma ray logs should repeat from pass to pass.

Schlumberger

Gamma Ray Tools

Overview

Gamma ray tools record naturally occurring gamma rays in the formations adjacent to the wellbore. This nuclear measurement indicates the radioactive content of the formations. Effective in any environment, gamma ray tools are the standard devices used for the correlation of logs in cased and open holes.

Calibration

The calibration area for gamma ray tools must be free from outside nuclear interference. Background and plus calibrations are typically performed at the wellsite with the radioactive sources removed from the area so that no contribution is made to the signal. The background measurement is made first, and then a plus measurement is made by wrapping the calibration jig around the tool housing and positioning the jig on the knurled section of the gamma ray tool.

Specifications

Measurement Specifications

	Highly Integrated Gamma Neutron Sonde (HGNS)	Hostile Environment Telemetry and Gamma Ray Cartridge (HTGC)	Scintillation Gamma Ray Tool (SGT)	Slim Telemetry and Gamma Ray Cartridge (STGC)	SlimXtreme* Telemetry and Gamma Ray Cartridge (QTGC)	Combinable Gamma Ray Sonde (CGRS)
Output	Formation gamma ray	Formation gamma ray	Formation gamma ray	Formation gamma ray	Formation gamma ray	Gamma ray activity
Logging speed	3,600 ft/h [1,097 m/h]	1,800 ft/h [549 m/h] High resolution: 900 ft/h [274 m/h] Correlation logging: 3,600 ft/h [1,097 m/h]	3,600 ft/h [1,097 m/h]	1,800 ft/h [549 m/h] High resolution: 900 ft/h [274 m/h] Correlation logging: 3,600 ft/h [1,097 m/h]	1,800 ft/h [549 m/h] High resolution: 900 ft/h [274 m/h] Correlation logging: 3,600 ft/h [1,097 m/h]	Up to 3,600 ft/h [1,097 m/h]
Range of measurement	0 to 1,000 gAPI	0 to 2,000 gAPI	0 to 2,000 gAPI	0 to 2,000 gAPI	0 to 2,000 gAPI	0 to 2,000 gAPI
Vertical resolution	12 in [30.48 cm]	12 in [30.48 cm]	12 in [30.48 cm]	12 in [30.48 cm]	12 in [30.48 cm]	12 in [30.48 cm]
Accuracy	±5%	±7%	±7%	±7%	±7%	±5%
Depth of investigation	24 in [60.96 cm]	24 in [60.96 cm]	24 in [60.96 cm]	24 in [60.96 cm]	24 in [60.96 cm]	24 in [60.96 cm]
Mud type or weight limitations	None	None	None	None	None	None
Combinability	Part of Platform Express* integrated system	Combinable with most tools	Combinable with most tools	Combinable with most tools	Combinable with most tools	Combinable with most tools
Special applications						H_2S service

Mechanical Specifications

	HNGS	HTGC	SGT	STGC	QTGC	CGRS
Temperature rating	302 degF [150 degC]	500 degF [260 degC]	350 degF [177 degC]	302 degF [150 degC]	500 degF [260 degC]	350 degF [177 degC]
Pressure rating	15,000 psi [103 MPa]	25,000 psi [172 MPa]	20,000 psi [138 MPa]	14,000 psi [97 MPa]	30,000 psi [207 MPa]	20,000 psi [138 MPa]
Borehole size—min.	4½ in [11.43 cm]	4⅞ in [12.38 cm]	4⅞ in [12.38 cm]	3⅜ in [8.57 cm]	3⅞ in [9.84 cm]	1 13/16-in [4.61-cm] seating nipple
Borehole size—max.	No limit	No limit	No limit	No limit	No limit	No limit
Outside diameter	3.375 in [8.57 cm]	3.75 in [9.53 cm]	3.375 in [8.57 cm]	2.5 in [6.35 cm]	3.0 in [7.62 cm]	1.6875 in [4.29 cm]
Length	10.85 ft [3.31 m]	10.7 ft [3.26 m]	5.5 ft [1.68 m]	7.70 ft [2.34 m]	10.67 ft [3.25 m]	3.2 ft [0.97 m]
Weight	171.7 lbm [78 kg]	312 lbm [142 kg]	83 lbm [38 kg]	68 lbm [31kg]	180 lbm [82 kg]	16 lbm [7 kg]
Tension	50,000 lbf [222,410 N]	120,000 lbf [533,790 N]	50,000 lbf [222,410 N]	50,000 lbf [222,410 N]	120,000 lbf [533,790 N]	10,000 lbf [44,480 N]
Compression	37,000 lbf [164,580 N]	28,000 lbf [124,550 N]	23,000 lbf [103,210 N]	17,000 lbf [75,620 N]	13,000 lbf [57,830 N]	1,000 lbf [4,450 N]

Tool quality control

Standard curves

The gamma ray tool standard curves are listed in Table 1.

Table 1. Gamma Ray Tool Standard Curves

Output Mnemonic	Output Name
ECGR	Gamma ray environmentally corrected
GR	Gamma ray

Operation

The tool can be run centered or eccentered.

Formats

The format in Fig. 1 is used for both acquisition and quality control.

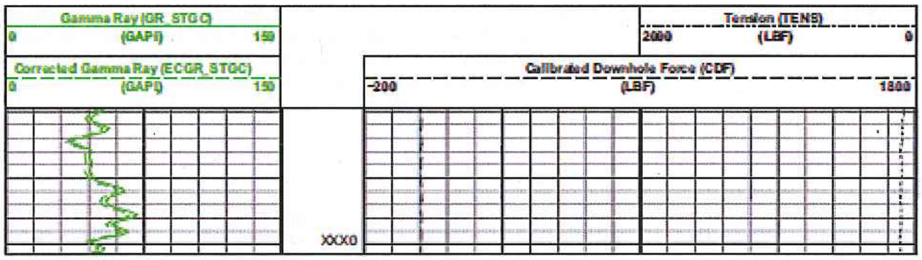


Figure 1. Gamma ray standard format.

Response in known conditions

- In shales, the gamma ray reading tends to be relatively high.
- In sands, the gamma ray reading tends to be relatively low.
- Gamma ray logs recorded in wells that have been on production may exhibit very high readings in the producing interval compared with the original logs recorded when the well was drilled. Mud additives such as potassium chloride and loss-control material can affect log readings.

ATTACHMENT D: INJECTION WELL PLUGGING PLAN

Facility Name: FutureGen 2.0 Morgan County CO_2 Storage Site
IL-137-6A-0001 (Well #1)

Facility Contacts: Kenneth Humphreys, Chief Executive Officer,
FutureGen Industrial Alliance, Inc., Morgan County Office,
73 Central Park Plaza East, Jacksonville, IL 62650, 217-243-8215

Location of Injection Well: Morgan County, IL; 26−16N−9W; 39.80111°N and 90.07491°W

The FutureGen Alliance shall comply with the reporting and notification provisions in 40 CFR 146.92.

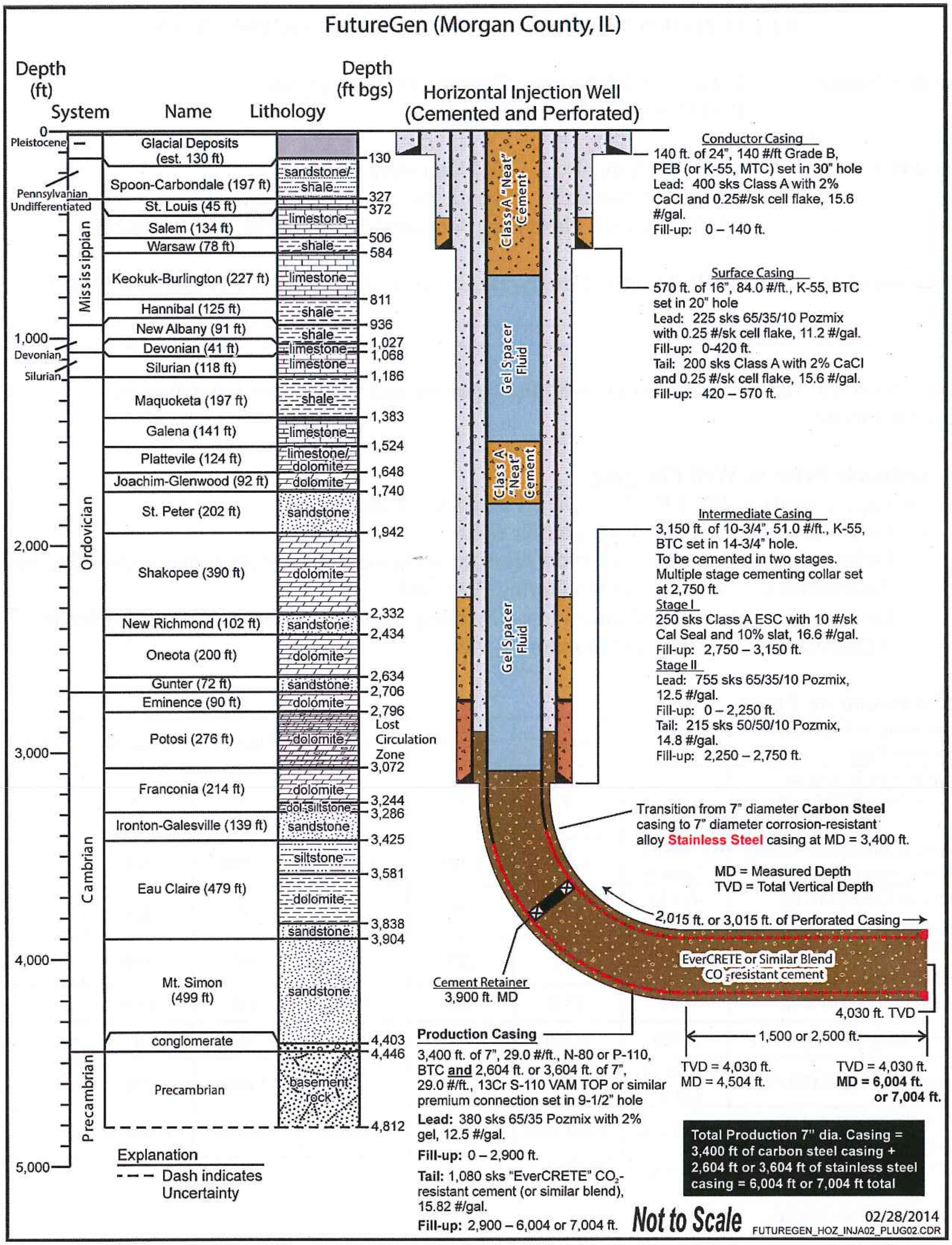
Immediately Prior to Well Plugging:
Per the requirements at 40 CFR 146.92, The FutureGen Alliance must:

1. Flush each injection well with a buffer fluid;
2. Determine the bottomhole reservoir pressure using methods and procedures identified in Attachment C – Testing and Monitoring Plan; and
3. Demonstrate external mechanical integrity using methods and procedures identified in Attachment C – Testing and Monitoring Plan.

Information on Plugs:

Cementing to Plug and Abandon Data	Plug #1	Plug #2	Plug #3	Plug #4	Plug #5	Plug #6	Plug #7
Diameter of Boring in Which Plug Will Be Placed (in)	7	7	7	7	7	7	
Depth to Bottom of Tubing or Drill Pipe (MD) (ft)	6,004 or 7,004(a)	3,900	3,100	1,800	1,500	700	
Sacks of Cement to Be Used (each plug) (sks)	451 or 665(a)	149	0	53	0	124	
Slurry Volume to Be Pumped (ft^3)	505 or 745(a)	167	271	63	167	146	
Slurry Weight (lb/ft^3)	15.8	15.8	8.6	15.6	8.6	15.6	
Top of Plug (MD) (ft)	3,900	3,100	1,800	1,500	700	0	
Bottom of Plug (MD) (ft)	6,004 or 7,004(a)	3,900	3,100	1,800	1,500	700	
Type of Cement or Other Material	EverCrete	EverCrete	6% Gel	Class A	6% Gel	Class A	
Method of Emplacement (e.g., balance method, retainer method, or two-plug method)	Balance Method						

(a) This value applies to injection wells completed with a 2,500 ft lateral.
MD = measured depth.



Conductor Casing
140 ft. of 24", 140 #/ft Grade B, PEB (or K-55, MTC) set in 30" hole
Lead: 400 sks Class A with 2% CaCl and 0.25#/sk cell flake, 15.6 #/gal.
Fill-up: 0 – 140 ft.

Surface Casing
570 ft. of 16", 84.0 #/ft., K-55, BTC set in 20" hole
Lead: 225 sks 65/35/10 Pozmix with 0.25 #/sk cell flake, 11.2 #/gal.
Fill-up: 0-420 ft.
Tail: 200 sks Class A with 2% CaCl and 0.25 #/sk cell flake, 15.6 #/gal.
Fill-up: 420 – 570 ft.

Intermediate Casing
3,150 ft. of 10-3/4", 51.0 #/ft., K-55, BTC set in 14-3/4" hole.
To be cemented in two stages. Multiple stage cementing collar set at 2,750 ft.
Stage I
250 sks Class A ESC with 10 #/sk Cal Seal and 10% slat, 16.6 #/gal.
Fill-up: 2,750 – 3,150 ft.
Stage II
Lead: 755 sks 65/35/10 Pozmix, 12.5 #/gal.
Fill-up: 0 – 2,250 ft.
Tail: 215 sks 50/50/10 Pozmix, 14.8 #/gal.
Fill-up: 2,250 – 2,750 ft.

Transition from 7" diameter **Carbon Steel** casing to 7" diameter corrosion-resistant alloy **Stainless Steel** casing at MD = 3,400 ft.

Cement Retainer
3,900 ft. MD

Production Casing
3,400 ft. of 7", 29.0 #/ft., N-80 or P-110, BTC **and** 2,604 ft. or 3,604 ft. of 7", 29.0 #/ft., 13Cr S-110 VAM TOP or similar premium connection set in 9-1/2" hole
Lead: 380 sks 65/35 Pozmix with 2% gel, 12.5 #/gal.
Fill-up: 0 – 2,900 ft.
Tail: 1,080 sks "EverCRETE" CO$_2$-resistant cement (or similar blend), 15.82 #/gal.
Fill-up: 2,900 – 6,004 or 7,004 ft.

TVD = 4,030 ft.
MD = 4,504 ft.

TVD = 4,030 ft.
MD = 6,004 ft. or 7,004 ft.

Total Production 7" dia. Casing = 3,400 ft of carbon steel casing + 2,604 ft or 3,604 ft of stainless steel casing = 6,004 ft or 7,004 ft total

Figure 1. Diagram of Injection Well after Plugging and Abandonment (geology and depths shown in this diagram are based on site-specific characterization data obtained from the FutureGen 2.0 Stratigraphic Well).

OMB No. 2040-0042 Approval Expires 11/30/2014

EPA

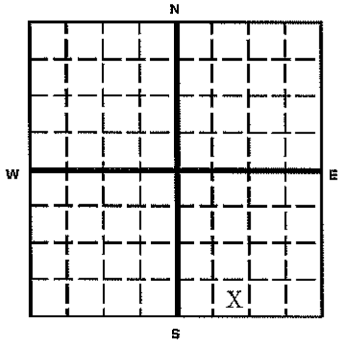
United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility
Morgan County Class VI UIC Well #1
(cased well completion, 1,500 ft lateral) [address not yet available]

Name and Address of Owner/Operator
FutureGen Alliance, Inc.
73 Central Park Plaza East, Jacksonville, IL 62650

Locate Well and Outline Unit on Section Plat - 640 Acres



State Illinois

County Morgan

Permit Number not yet issued

Surface Location Description
SE 1/4 of SE 1/4 of SW 1/4 of SE 1/4 of Section 26 Township 16N Range 9W

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location ___ ft. frm (N/S) ___ Line of quarter section
and ___ ft. from (E/W) ___ Line of quarter section.

TYPE OF AUTHORIZATION

☑ Individual Permit
☐ Area Permit
☐ Rule

Number of Wells 1

WELL ACTIVITY

☐ CLASS I
☐ CLASS II
  ☐ Brine Disposal
  ☐ Enhanced Recovery
  ☐ Hydrocarbon Storage
☐ CLASS III

Lease Name

Well Number

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
24"	140.0	140'	140'	30"
16"	84.0	570'	570'	20"
10 3/4"	51.0	3,150'	3150'	14 3/4"
7"	29.0	6,004'	6,004'	9 1/2"

METHOD OF EMPLACEMENT OF CEMENT PLUGS

☑ The Balance Method
☐ The Dump Bailer Method
☐ The Two-Plug Method
☐ Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	7"	7"	7"	7"	7"	7"	
Depth to Bottom of Tubing or Drill Pipe (ft	6,004	3,900	3,100	1,800	1,500	700	
Sacks of Cement To Be Used (each plug)	451	149	0	53	0	124	
Slurry Volume To Be Pumped (cu. ft.)	505	167	271	63	167	146	
Calculated Top of Plug (ft.)	3,900	3,100	1,800	1,500	700	0 (GL)	
Measured Top of Plug (if tagged ft.)	3,900	3,100	1,800	1,500	700	0 (GL)	
Slurry Wt. (Lb./Gal.)	15.82	15.82	8.6	15.6	8.6	15.6	
Type Cement or Other Material (Class III)	EverCrete	EverCrete	6% Gel	Class A	6% Gel	Class A	

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
(7" perforated casing) 3,950 ft MD	6,004 ft MD		

Estimated Cost to Plug Wells
Plug #1 Set through a cement retainer set at 3,900 ft MD
$600,000.00

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*
Kenneth K. Humphreys, Chief Executive Officer

Signature
Kenneth K. Humphreys

Date Signed
03/03/2014

EPA Form 7520-14 (Rev. 12-11)

ATTACHMENT E: POST-INJECTION SITE CARE (PISC) AND SITE CLOSURE PLAN

Facility Information

Facility Name: FutureGen 2.0 Morgan County CO_2 Storage Site
IL-137-6A-0001 (Well #1)

Facility Contacts: Kenneth Humphreys, Chief Executive Officer,
FutureGen Industrial Alliance, Inc., Morgan County Office,
73 Central Park Plaza East, Jacksonville, IL 62650, 217-243-8215

Location of Injection Well: Morgan County, IL; 26–16N–9W; 39.80111°N and 90.07491°W

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that the FutureGen Alliance will perform to meet the requirements of 40 CFR 146.93. The FutureGen Alliance will monitor ground water quality and track the position of the carbon dioxide plume and pressure front for fifty years of post-injection site care and may not cease post-injection monitoring and site care until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, the FutureGen Alliance will plug all monitoring wells, restore the site to its original condition, and submit a Site Closure report and associated documentation.

Pre- and Post-Injection Pressure Differential

The information regarding pre- and post-injection pressure differentials, as required by 40 CFR 146.93(a)(2)(i) is presented below.

The maximum injection pressure differential is 479 psi at the injection well when injection stops. The magnitude and area of elevated pressure gradually decreases over time after injection stops; as further detailed in Table 1.

Figure 1 shows the pressure differential versus time for monitoring well locations in the Area of Review (AoR) and at the geometric centroid of the four horizontal injection wells. Simulated pressures at the injection "point" increase during the 20-year injection period from 1,779 psi to a maximum of 2,258 psi. The highest pressures are in the immediate vicinity of each injection well. As shown, pressures at the injection and monitoring well locations decline over time after injection ceases. Despite the modeled pressure of 2,258 psi, current permit limitations will require the pressure in the injection well not to exceed 2,252 psi.

Figure 2 presents aqueous pressure differentials from baseline at the top of the injection zone and the extent of the carbon dioxide plume at 20 years after the start of injection (i.e., the end of injection) and 70 years after the start of injection (i.e., at site closure).

Table 1. Pressure differential to baseline conditions at well locations near the base of the Ironton Formation for Above Confining Zone Well 1 (ACZ1) and ACZ2 and at the middle of the Mount Simon 11 layer in the injection zone for the rest of the wells during and after.

	Pressure Differential (psi)				
Year	SLR1	SLR2	ACZ1	ACZ2	Injection Well
Distance from Injection Well (ft)	3740	6555	1010	3740	0
Elevation (ft)	-3371	-3414	-2763	-2751	-3390
0 (Start injection)	0	0	0	0	0
1	223	125	0	0	350
2	277	165	0	0	394
3	311	192	0	0	417
4	333	211	0	0	431
5	348	225	0	0	441
10	393	274	0	0	466
15	413	313	1	1	475
20 (Stop injection at year end)	425	338	2	2	479
21	255	235	2	2	259
22 (Approximate maximum extent of CO_2 Plume)	199	186	2	2	200
23	167	157	2	2	167
24	145	137	3	3	145
25	129	121	3	3	128
30	85	81	4	4	84
35	64	61	4	4	63
40	51	49	5	5	50
45	42	40	5	5	41
50	36	34	5	5	35
60	27	26	5	5	26
70	22	21	5	5	21
80	18	17	5	5	17
90	15	14	5	5	14
100	13	12	4	4	12

SLR1	Single-Level in-Reservoir #1
SLR2	Single-Level in-Reservoir #2
ACZ1	Above Confining Zone #1
ACZ2	Above Confining Zone #2
Injection Well	Geometric centroid of four horizontal laterals

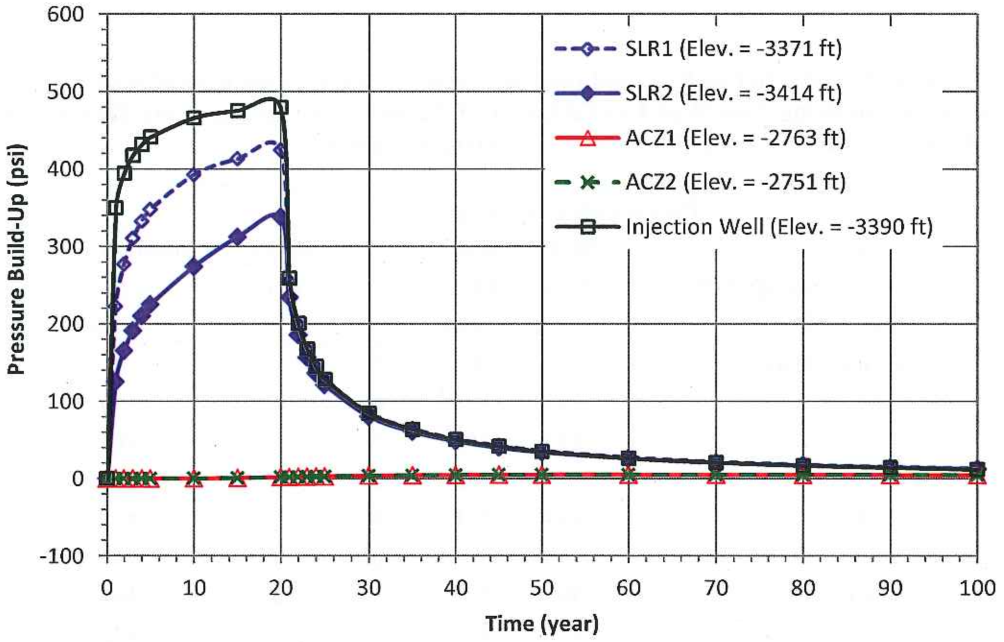


Figure 1. Simulated aqueous pressure differential versus time at monitoring well locations near the base of the Ironton Formation for ACZ1 and ACZ2 and at the middle of the Mount Simon 11 layer in the injection zone for the rest of the wells.

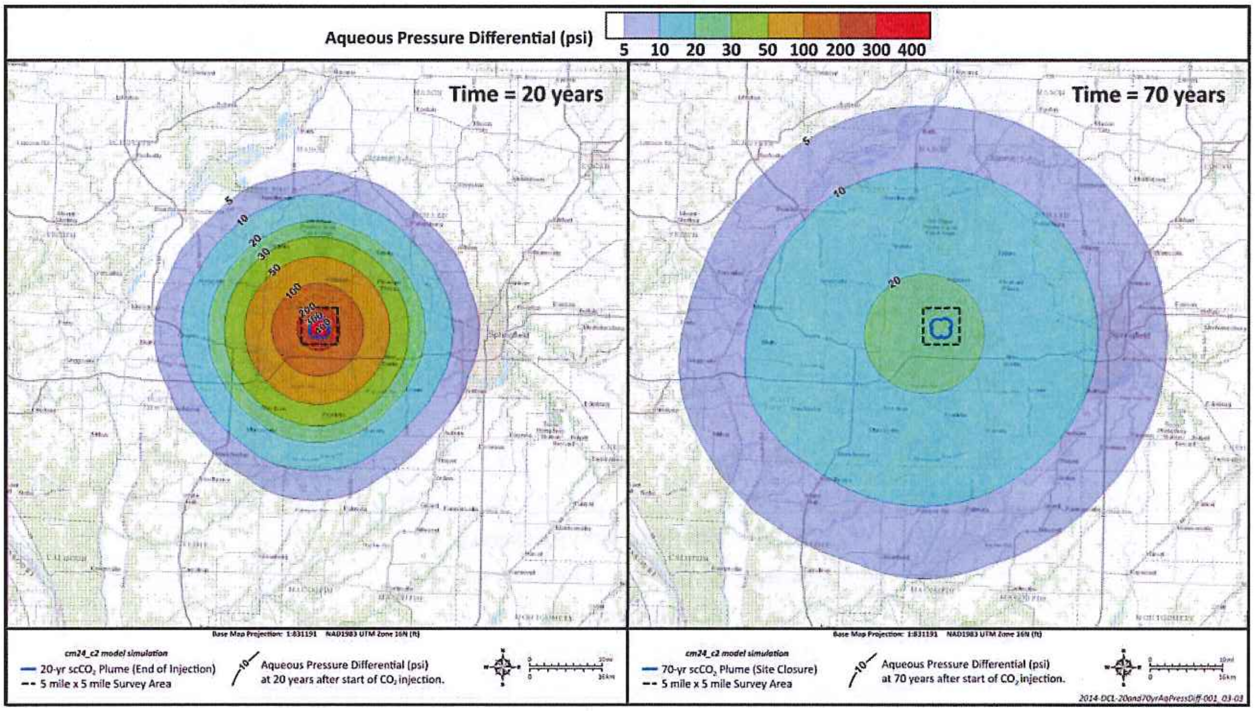


Figure 2. Aqueous pressure differentials from baseline condition at the top of the injection zone and CO_2 plume extents at 20 years (end of injection) and 70 years (site closure) after start of injection.

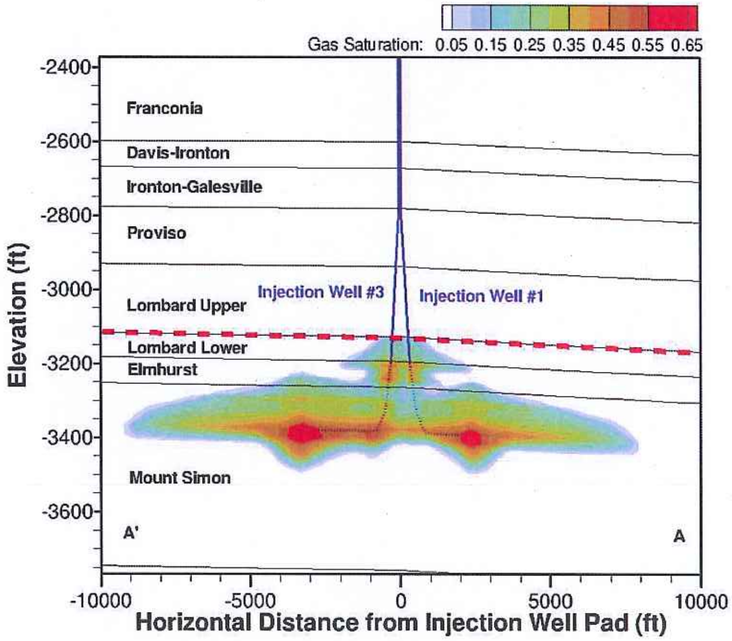
Predicted Position of the CO_2 Plume and Associated Pressure Front Upon Cessation of Injection and at Site Closure

The information regarding the predicted position of the carbon dioxide plume and associated pressure front at site closure, as required by 40 CFR 146.93(a)(2)(ii) is presented below.

The areal extent of the CO_2 plume increases during injection and for 2 years post-injection. As the areal extent decreases (at year 22), the plume migrates predominately upward. The computational modeling results indicate that the sequestered CO_2 will migrate above the Mount Simon Sandstone, into the Elmhurst as well as the lower part of the Lombard.

Figure 3 and Figure 4 show the upward migration of the CO_2 plume near the injection wells at 20 and 70 years. These two-dimensional images demonstrate various levels of gas saturation or upward migration into the injection zone (Mount Simon Formation, Elmhurst Sandstone, and the lower part of the Lombard). The computational model results indicate that the Model Layer "Lombard 5" is the top unit containing a fraction of injected CO_2 during the 100-year simulation. The top of the injection zone is set at 3,153 ft (below MSL) at the FutureGen stratigraphic well, corresponding to the top of the Lombard 5 layer of the numerical model.

The computational model estimates that the CO_2 plume forms a cloverleaf pattern as a result of the four lateral-injection-well design. The plume grows both laterally and vertically as injection continues. Most of the CO_2 resides in the Mount Simon Sandstone. A small amount of CO_2 enters into the Elmhurst and the lower part of the Lombard Formation. When injection ceases at 20 years, the lateral growth becomes negligible but the plume continues to move slowly primarily upward. Once CO_2 reaches the low-permeability zone in the upper Mount Simon it begins to move laterally.



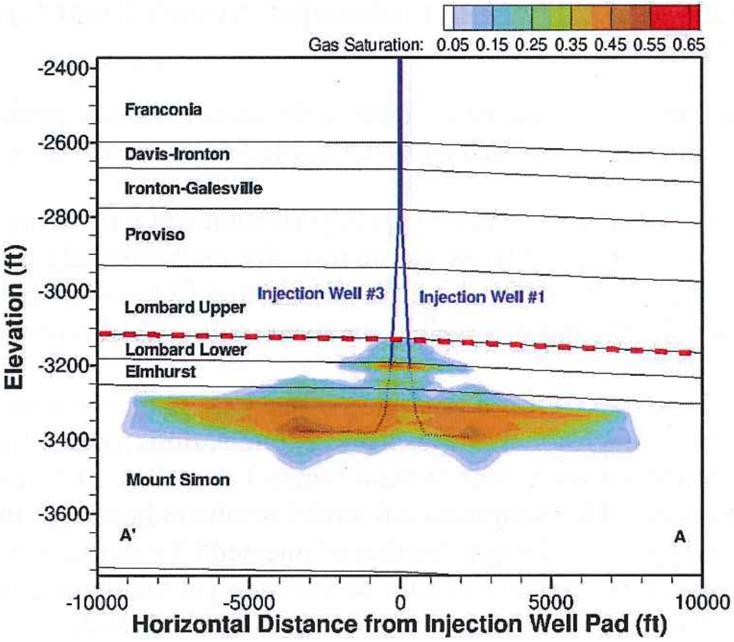


Figure 3. Cutaway view of CO_2-rich phase saturation along A-A' (Injection Wells 1 and 3) at 20 and 70 years. The red dashed line indicates the top of the injection zone.