A.3). Two SLR wells will monitor the injection zone beyond the east and west ends of the horizontal CO_2-injection laterals. One of the SLR wells (SLR2; reconfigured stratigraphic well) will be located to the east-northeast of the injection well pad between the projected 10- to 20-year plume boundaries and the other well (SLR1) will be located to the west of the injection well pad within the projected 2-year plume boundary. An additional SLR well will be constructed within 5 years from the start of injection. The location will be informed by any observed asymmetry in pressure front development and will be located outside the CO2 plume extent. The distance from the plume boundary will be based on the monitoring objective of providing information that will be useful for both leakage detection and model calibration within the early years of operation. It is estimated that the well will be located less than 5 miles from the projected plume extent in order to provide an intermediate-field pressure monitoring capability that would benefit leak detection capabilities and meet the EPA requirement for pressure monitoring outside the CO_2 plume.

Three RAT wells will be installed within the boundaries of the projected 1- to 3-year CO_2 plume. The RAT well locations were selected to provide information about CO_2 arrival at different distances from the injection wells and at multiple lobes of the CO_2 plume. The RATs will be completed with nonperforated, cemented casings and will be used to monitor CO_2 arrival and quantify saturation levels via downhole PNC (geophysical logging across the reservoir and confining zone).

The reservoir-monitoring network will address transport uncertainties by using an "adaptive" or "observational" approach to monitoring (i.e., the monitoring approach will be adjusted as needed based on observed monitoring and updated modeling results). It is recognized that additional contingency wells may be required in out-years to monitor evolution of the CO_2 plume and fully account for the injected CO_2 mass.

Direct Pressure Monitoring

Continuous monitoring of P/T/SpC will be conducted in the SLR monitoring wells to track the pressure front and inform the monitoring and modeling programs.

Instruments will be installed at each SLR monitoring well to facilitate near-continuous monitoring of indicator parameters of CO_2 arrival and/or changes in brine composition. (Tables A.3 and A.8 list the parameters and instrumentation that will be used in the SLR wells.)

Fluid P/T/SpC are the most important parameters to be measured in real time within the monitoring interval of each well. These are the primary parameters that will indicate the presence of CO_2 or CO_2-induced brine migration into the monitored interval. In addition, pH and Eh (oxidation potential) measurements may be useful for detecting dissolved CO_2 and assessing water chemistry changes in the monitored interval. An initial evaluation of probes that are capable of measuring the desired parameters will assess the measurement accuracy, resolution, and stability for each parameter prior to selection and procurement of sensors for the full monitoring well network.

Pressure is expected to increase at the SLR monitoring wells installed within the injection reservoir soon after the start of injection and before the arrival of CO_2 because of the pressurization of the reservoir. Pressure will also be monitored to ensure that pressure within the injection interval does not exceed design specifications and to determine whether any observed pressure changes above the primary confining zone could be associated with a leakage response. Changes in other parameters are expected to occur later in time than the initial increase of pressure.

Direct Geochemical Plume Monitoring

Fluid samples will be collected from the SLR monitoring wells before, during, and after CO_2 injection. The samples will be analyzed for chemical parameter changes that are indicators of the presence of CO_2 and/or reactions caused by the presence of CO_2. Baseline monitoring will involve collection and analysis of a minimum of three rounds of aqueous samples from each well completed in the targeted injection zone prior to initiation of CO_2 injection. A comprehensive suite of geochemical and isotopic analyses will be performed on fluid samples collected from the reservoir. These analytical results will be used to characterize baseline geochemistry and provide a metric for comparison during operational phases. Aqueous sampling will not be used to assess CO_2 saturation levels. Once $scCO_2$ arrives, these wells can no longer provide representative fluid samples because of the two-phase fluid characteristics and buoyancy of $scCO_2$.

B.7.2 Sampling Methods

Direct Pressure Monitoring

A single probe incorporating electronic sensors that will monitor indicator parameters (P/T/SpC) will be placed at reservoir depth in each monitored well. Each parameter will be measured at a 10-minute sampling interval and will be transmitted to the surface via the wireline cable. Additional sensors may be installed at the wellhead for measuring parameters such as wellhead pressure, barometric pressure, and ambient surface temperature. A data-acquisition system will be located at the surface to store the data from all sensors at the well site and will periodically transmit the stored data to the MVA data center in the control building.

Direct Geochemical Plume Monitoring

Fluid samples will be collected at monitored formation depths and maintained at formation pressures within a closed pressurized sample container to prevent the escape of dissolved gases. Access to the monitored interval at the SLR wells will be through an inner 2-7/8-in. tubing string extending to the monitoring interval and packed-off just above the screen.

Fluid samples will be collected within the open interval of each monitoring well using a flow-through sampler with a 950-cc (or larger) sample chamber. The samples will be maintained at formation pressure within a closed sample container to prevent the escape of dissolved gases. Prior to sampling, the P/T/SpC probe will be monitored as the well is purged (up to three times the volume of the well-screen section will be discharged from the well before collecting the sample). The probe will then be removed from the well and the sampler will be run into the borehole on the same wireline cable to collect the pressurized fluid sample. Additional purging may be conducted just prior to collection of the pressurized fluid sample if mixing between the fluid column and sampling interval during insertion of the sampler is a concern.

B.7.3 Sample Handling and Custody

Direct Pressure Monitoring

P/T/SpC measurements will be recorded by a data logger at each well site and also transmitted to data-acquisition systems located in the MVA data center.

Electronic data and field records will be transferred to laptop and/or desktop computers and/or backed-up on secured servers at least quarterly, as well as scanned copies of all pertinent hardcopy field records/notes.

Direct Geochemical Plume Monitoring

After removing the aqueous sampler from the well, the closed and pressurized sample container(s) will be transported to the MVA laboratory space in the control building for processing using standard chain-of-custody procedures.

B.7.4 Analytical Methods

Table A.7 summarizes the analytical methods for groundwater quality monitoring in the SLR wells. Where possible, methods are based on standard protocols from the EPA or Standard Methods for the Examination of Water and Wastewater (American Public Health Association, American Water Works Association, Water Environment Federation, 19th ed. or later, Washington, D.C.). Laboratories shall be required to have standard operating procedures for the analytical methods performed.

B.7.5 Quality Control

Direct P/T/SpC and other continuous monitoring equipment will be calibrated according to manufacturers' recommendations. If trends or other unexplained variability in the data are observed that might indicate a suspect response, instruments will be evaluated and, if required, recalibrated, or replaced.

The QC practices for groundwater monitoring of the geochemical plume are the same as those specified for groundwater monitoring above the confining zone (Section B.4.5). Field QC samples include field blanks and field duplicates; a minimum of one of each type of sample shall be collected at each sampling event. Laboratory QC samples include method blanks, laboratory duplicates, matrix spikes, matrix spike duplicates, and laboratory control samples. The frequencies of these samples will be determined by the laboratory contract and standard method protocols. Typically, method blanks and laboratory control samples are analyzed with every analytical batch, while the remaining QC samples are run at a frequency of 1 per 10 samples. Table A.8 lists additional, method-specific requirements.

B.7.6 Instrument/Equipment Testing, Inspection, and Maintenance

High-quality (high-accuracy, high-resolution) gauges with low drift characteristics will be used.

- Gauge components (gauge, cable head, cable) will be manufactured of materials designed to provide a long life expectancy for the anticipated downhole conditions.
- Upon acquisition, a calibration certificate will be obtained for every pressure gauge. The calibration certificate will provide the manufacturer's specifications for range, accuracy (% full scale), resolution (% full scale), and drift (< psi per year), and calibration results for each parameter. The calibration certificate will also provide the date that the gauge was calibrated, the methods and standards used, and the date calibration will expire.
- Gauges will be installed above any packers so they can be removed if necessary for recalibration by removing the tubing string. Redundant gauges may be run on the same cable to provide confirmation of downhole pressure and temperature.
- Upon installation, all gauges will be tested to verify that they are functioning (reading/transmitting) correctly.

For groundwater sampling, field equipment will be maintained, factory serviced, and factory calibrated according to the manufacturers' recommendations. Spare parts that may be needed during sampling will be included in supplies on-hand during field sampling.

For all laboratory equipment, testing, inspection, and maintenance will be the responsibility of the analytical laboratory per method-specific protocols and the laboratory's QA program. The laboratory's QA program will be reviewed by the Alliance prior to submission of samples for analysis.

B.7.7 Instrument/Equipment Calibration and Frequency

Pressure gauges that are used for direct pressure monitoring will be calibrated according to manufacturers' recommendations, and current calibration certificates will be kept on file with the monitoring data.

B.8 Pulsed-Neutron Capture Logging

PNC wireline logs will be used to quantify CO_2 saturation relative to depth in each of three monitoring RAT wells. These indirect measurements of CO_2 saturation will be used to detect and quantify CO_2 levels over the entire logged interval. The PNC logging data will be used for calibration of reservoir models and to identify any unforeseen occurrences of CO_2 leakage across the primary confining zone. Numerical modeling will be used to predict the CO_2 plume growth and migration over time by integrating the calculated CO_2 saturations in the three RAT wells with the geologic model and other monitoring data.

B.8.1 Sampling Process Design (Experimental Design)

PNC logs operate by generating a pulse of high-energy neutrons and subsequently measuring the neutron decay over time and across a wide energy spectrum. PNC logs can measure specific energy bins or a composite of energies, the latter of which is termed the thermal capture cross-section (sigma) operational mode. In sigma mode, all elements that capture and slow neutrons contribute to the measurement rather than just the characteristic energy levels associated with specific elements. Both measurement modes are useful for determining CO_2 saturation from PNC logs and will be simultaneously acquired.

PNC logging has been successfully implemented at a number carbon sequestration sites and while the PNC method has been shown to work quite well, problems associated with CO_2 flooding the casing and perforation zones have been identified. PNC logs are only sensitive to a localized region surrounding the borehole (15−30 cm) and are therefore susceptible to interference from features very near the borehole, such as changing borehole fluids, poor cement, or invaded drilling fluids. The monitoring RAT wells are designed with small-diameter, nonperforated casings to minimize near-borehole interference effects. Borehole effects will also be accounted for by analyzing response times from multiple detectors in the tool. Porosities within the reservoir at the FutureGen 2.0 storage site are moderate and the PNC logs are expected to adequately quantify CO_2 saturation along the RAT boreholes in order to calibrate reservoir models as well as identify possible leakage through the sealing layers.

B.8.2 Sampling Methods

Quarterly PNC logging will be conducted in RAT wells 1, 2, and 3. The locations of the RAT wells was chosen to sample various stages of the CO_2 plume migration, with the emphasis on the areas with large expected changes in the first five (5) years. Downhole repeatability of the tool performance will be verified by conducting a "repeat section" of the logging run. Repeatability is used to validate the

measurement acquired during the main logging pass, as well as to identify anomalies that may arise during the survey for re-logging. Measurement depth is of critical importance in all borehole logs. Depth will be measured with respect to a fixed reference throughout the lifetime of the project. Verification of proper tool operation will be performed prior to each logging event following the manufacturer's recommended procedure. Elastic cable stretch and slippage will be automatically compensated. Repeatability of logging depths will also be checked by repeat gamma-ray depth location of key strata or drill collar locators and can be used to correct depth measurements after logging is complete.

B.8.3 Sample Handling and Custody

No specialized sample-/data-handling procedures are required. PNC tool readings will be recorded on a computer located in the wireline logging truck. All electronic data and field records will be transferred to laptop and/or desktop computers and backed-up, on secure servers at the conclusion of each logging event, as will scanned copies of all pertinent hardcopy field records/notes.

B.8.4 Analytical Methods

PNC log data will be processed following industry best practices and coordinated with the borehole-logging operator to optimize data-collection parameters. Modeling can be done to simulate near-borehole interferences and remove their effects from the signal. Modeling is a recommended procedure and requires knowledge of the target formations and fluids that must be obtained from cores and additional logging data. Each logging result will be compared for each RAT well to the baseline or previous survey, as applicable, to determine changes in saturation.

B.8.5 Quality Control

Verification of vendor processing software and results will ensure that the acquired data are acceptable and that calculations of CO_2 saturations are reproducible. Third-party PNC logging and processing for a subset of boreholes and logging events can be used as part of the validation procedure. Failure of tool performance in the field or unreproducible "repeat sections" will result in non-acceptance of the data and may trigger a return of the PNC tool to the manufacturer for recalibration or replacement. Off-normal CO_2 saturation calculations will trigger additional evaluation and possible new logging runs.

B.8.6 Instrument/Equipment Testing, Inspection, and Maintenance

Examples of industry-published guidelines for calibration and field operation of the PNC wireline log hardware and data-collection software are provided in Appendix B.

B.8.7 Instrument/Equipment Calibration and Frequency

To ensure data-acquisition quality, the logging tool will be calibrated for accuracy, checked to be in good working order, and verified by the manufacturer. All tools and field operation software will be provided by the manufacturer with an auditable verification record to ensure traceability. In addition to the initial manufacturer calibration, PNC tool recalibration will be performed monthly and both prior to and after each logging event using an onsite calibration vessel following the manufacturer's guidelines. Examples of industry-published guidelines for calibration and field operation of the PNC wireline log hardware and data-collection software are provided in Appendix B.

B.9 Integrated Deformation Monitoring

B.9.1 Sampling Process Design (Experimental Design)

The deformation monitoring will include orbital DInSAR data (X-band TerraSAR-X, C-band Radarsat-2, X-Band Cosmo-Skymed, or any other satellite data that will be available at the time of data collection) and a field survey validation using permanent Global Positioning System (GPS) stations, permanent tiltmeters, and annual Differential Global Positioning System (DGPS) surveys. This approach will be used for the baseline before the injection and during the injection phase with modifications based on the experience gained during the two-year baseline-monitoring period.

Differential Synthetic Aperture Radar (SAR) Interferometry (DInSAR) is a method of generating surface displacement maps from two images acquired by radar aboard a satellite at distinct times. Specific and complex processing is applied to obtain time series of displacements of the ground surface. All DInSAR deformation measurements are corrupted by spatiotemporal variations in the atmosphere and surface scattering properties. Advanced DInSAR time-series analyses exploit a subset of pixels in a stack of many SAR images to reduce atmospheric artifacts and decorrelation effects. These pixels exhibit high phase stability through time. The output products from these advanced techniques include a pixel average velocity accurate to 1−2 mm/yr and a pixel time series showing cumulative deformation accurate to 5−10 mm for each of the SAR acquisition times. It should be noted that accuracy improves with time as the time series becomes larger.

B.9.2 Sampling Methods

Orbital SAR data will be systematically acquired and processed over the storage site with at least one scene per month to obtain an advanced DInSAR time series. These data will be obtained from the available orbital instruments available at the time of collection. It should be noted that the existing TerraSAR-X, Radarsat-2 and Cosmo-Skymed systems provide frequent systematic revisits of 11, 24, and 4 days, respectively.

Widespread overall temporal decorrelation is anticipated except in developed areas (e.g., roads, infrastructure at the site, and the neighboring towns) and for the six corner cube reflectors that will be deployed on site. These isolated coherent pixels will be exploited to measure deformation over time, and different algorithms (e.g., persistent scatters, small baseline subsets, etc.) will be used to determine the best approach for the site.

Data from five permanent tiltmeters and GPS stations will be collected continuously. In addition, annual geodetic surveys will be conducted using the Real-Time Kinematic (RTK) technique where a single reference station gives the real-time corrections, providing centimeter-level or better accuracy. Deformations will be measured at permanent locations chosen to measure the extent of the predicted deformation in the AoR and also used by the gravity surveys (see Section B.10).

B.9.3 Sample Handling and Custody

DInSAR data will be acquired, processed, and archived by the vendor. Displacement maps and deformation time series will be archived on digital media by the Alliance.

Permanent GPS and tiltmeter data will be collected in real time by the Alliance and stored on digital media on site. Differential GPS (DGPS) survey data will be archived on digital media by the Alliance.

B.9.4 Analytical Methods

To establish a more comprehensive geophysical and geomechanical understanding of the FutureGen 2.0 site, DInSAR and field deformation measurements will be integrated and processed with other monitoring data collected at the site: microseismicity, gravity, pressure, and temperature. This unique and complete geophysical data set will then be inverted to constrain the CO_2 plume shape, extension, and migration in the subsurface.

B.9.5 Quality Control

Verification of vendor processing software and results will ensure that the acquired data are acceptable and results reproducible.

B.9.6 Instrument/Equipment Testing, Inspection, and Maintenance

Testing of the whole DInSAR chain acquisition is routinely conducted by the space agencies.

Permanent tiltmeters and GPS instruments installed onsite will be checked annually.

The Trimble R8 receivers used for the annual DGPS surveys will be checked annually.

B.9.7 Instrument/Equipment Calibration and Frequency

Calibration of DInSAR chain acquisition is routinely conducted by the space agencies and the results will be compared to field measurements.

Tiltmeters and GPS instruments installed onsite will be calibrated for accuracy, checked to be in good working order, and verified by the manufacturer. The Trimble R8 receivers used for the annual DGPS surveys will also be calibrated and verified by the manufacturer.

All equipment and software will be provided by the manufacturer with an auditable verification record to ensure traceability.

B.10 Time-Lapse Gravity Monitoring

B.10.1 Sampling Process Design (Experimental Design)

Four-dimensional (4D or time-lapse) microgravimetry—the temporal change of gravity at the microGal scale (1 μGal = 10^{-6} m/s^2)—is a cost-effective and relatively rapid means of observing changes in density distribution in the subsurface, particularly those caused by the migration of fluids.

Time-lapse gravity monitoring is accomplished using repetitive annual surveys at a series of points located at the ground surface (permanent stations). Changes in gravity anomaly with time are determined and then interpreted in terms of changes in subsurface densities. These changes could be linked for example to replacement of water by CO_2. providing an indirect method of tracing the displacement of the CO_2 plume at depth. Due to the non-uniqueness of the solution, this monitoring method could rarely be used alone and gives the best results when used with other methods (deformation or seismic).

B.10.2 Sampling Methods

Permanent station locations were established in November 2011 for the purpose of future reoccupation surveys (Figure A.4). These stations are located on the roadways inside the survey area, the reference being the KC0540 station (Central Plaza Park monument, Jacksonville, Illinois). The emplacement of each permanent station on the roadway is designated by a marker. Markers are approximately half-inch-diameter nails with a three-quarter-inch heads to provide good visibility from the surface.

Because all the gravity measurements are relative, a tie to a gravity station outside the surveyed area must be made. This reference is station NGS# KC0540, a monument located in Central Plaza Park in Jacksonville, Illinois, which was tied to the absolute gravity station NGS# KC0319 located in Hannibal, Missouri.

To compensate for the instrumental drift, measurements are taken on a 2-hour cycle at a local reference station at the center of the surveyed area (station 137) and at an offsite location (station KC0540) twice a day.

B.10.3 Sample Handling and Custody

Data will be archived on a digital media by the Alliance.

B.10.4 Analytical Methods

Data reduction will be performed using the standardized methods to obtain Free Air and Bouguer anomalies. These anomalies will then be interpreted in terms of subsurface density anomalies by gravity direct or inverse modeling using the commercial software ENcom Model Vision™ 12.0.

B.10.5 Quality Control

Repeat measurements at the same field point is the only way to evaluate their quality. At least three measurements for each point will be recorded.

B.10.6 Instrument/Equipment Testing, Inspection, and Maintenance

The gravity meter used will be a LaCoste & Romberg Model D belonging to Pacific Northwest National Laboratory. It is a steel mechanism, "zero length" spring meter with a worldwide range that is less prone to drift than quartz meters. The instrument is thermostatically controlled to approximately 50°C during the duration of the surveys. A full maintenance and inspection of the instrument needs to be completed every 10 years at the LaCoste and Romberg factory; the next one is scheduled in 2021.

B.10.7 Instrument/Equipment Calibration and Frequency

No calibration of the instrument is required.

B.11 Microseismic Monitoring

Elevated pressures in the reservoir due to injection of CO_2 have the potential to induce seismic events. The objective of the microseismic monitoring network is to accurately determine the locations, magnitudes, and focal mechanisms of seismic events.

B.11.1 Sampling Process Design (Experimental Design)

A microseismic monitoring system must be able to detect a seismic event at a number of monitoring stations and use the signals to accurately determine the event location and understand the brittle failure mechanisms responsible for the event. The monitoring network consists of an array of seismic sensors placed either at the near-surface or within deeper monitoring boreholes. The accuracy of the network is dependent on both the geometry of the sensor array and the signal-to-noise ratio (SNR) at each of the sensor locations. The number and spatial distribution of sensors in a microseismic monitoring network must be designed to minimize the errors in estimating event location and origin times. The subsurface seismic velocity model also has a large influence on the predicted data and must be estimated as accurately as possible using borehole logs and data from vertical seismic profiling. Sensors need to have high sensitivity, flat response over the intended frequency range, a low noise floor, and stable performance over time.

External noise sources often occur at the surface or from nearby subsurface activities such as drilling. Surface noise attenuates with distance below the surface and it is therefore advantageous to emplace surface sensors within shallow boreholes in order to reduce external noise to an acceptable level. Surface or shallow borehole sensors provide multiple sensing azimuths and offsets, but surface sensors typically suffer from lower SNRs. Shallow borehole installations, however, can achieve a noise floor approaching that of sensors located in deep boreholes. Deep borehole monitoring can provide a higher SNR if the microseismic event occurs close enough to the array, but precise event location can be difficult due to geometric constraints on the array.

B.11.2 Sampling Methods

The microseismic network will consist of an array of near-surface shallow borehole sensors in addition two deep borehole sensor arrays installed within the ACZ wells. The network incorporates the benefits of both array types to improve the overall performance of the system and is expected to perform well for monitoring seismic events that occur in the AoR.

Commonly used sensors for seismic applications include moving coil geophones that that have frequency bandwidths from 5−400 Hz. These devices are often built with signal conditioning and digitizer circuitry located on the sensor to improve the electrical performance; however, because of the complexity of their assembly, their long-term deployment in a deep borehole environment results in reduced lifetimes. Permanent emplacement of standard moving coil geophones within a deep borehole would not be expected to last the lifetime of the FutureGen 2.0 project. Geophones will be placed in the shallow borehole stations and are expected to perform well in that environment, particularly for higher-frequency signals.

Surface sensors also require higher sensitivities and lower noise floors than sensors placed in deep boreholes because the distance from the event to the surface is often much greater. High-quality broadband seismometers exhibit much higher sensitivity and extremely low noise floors compared to standard geophones. These seismometers have long working lifetimes and an excellent frequency response from 1 mHz to 200Hz. Seismometers will also be installed in each shallow borehole along with a borehole geophone. To minimize signal attenuation and site noise, the boreholes will be drilled to at least the uppermost bedrock unit, and the casing will be sealed and pumped dry prior to sensor emplacement.

Fiber-optic-based seismic sensors use backscattered light from a laser pulse that has been introduced into an optical fiber to measure the movement of a sensing element. The fiber can be coupled to a device to mechanically amplify the strain on the fiber and produce a sensor with performance as good as, or better than, standard geophones. A key feature of these sensors is that because they have no electronics located within a borehole they are extremely robust; their lifetimes and performance stability are designed to last several decades. Due to their superior sensitivity and expected longevity, an array of fiber-optic accelerometers will be installed within two, deep ACZ wells. Optical cables will be extended from each of the wells back to a central control building that will house the data-acquisition and storage systems.

B.11.3 Sample Handling and Custody

No specialized sample/data handling procedures are required. Microseismic signals from the shallow boreholes will be continuously recorded on a data logger located at each of the stations. All electronic data will be continuously transferred to a data storage and processing system located at a central control building. Digital copies of all pertinent hardcopy field records/notes will also be transferred to the central data server.

B.11.4 Analytical Methods

Microseismic data will be processed and stored following industry best practices.

B.11.5 Quality Control

Verification of vendor processing software and results will ensure that the acquired data are acceptable and that determinations of event locations and focal mechanisms are accurate.

B.11.6 Instrument/Equipment Testing, Inspection, and Maintenance

Regular maintenance and testing of the seismic hardware and data-collection software are critical to ensuring high-quality results. All hardware will be maintained in accordance with manufacturer recommendations. Software updates will be incorporated as they are released by the manufacturer.

B.11.7 Instrument/Equipment Calibration and Frequency

All microseismic equipment will be calibrated for accuracy, checked to be in good working order, and verified by the manufacturer. All equipment and software will be provided by the manufacturer with an auditable verification record to ensure traceability. In addition to the initial manufacturer calibration, seismometers and geophones will be periodically recalibrated following the manufacturers' guidelines. In the event that damage is identified, it will be immediately reported and the equipment removed and replaced.

B.12 Inspection/Acceptance of Supplies and Consumables

Testing and monitoring supplies and consumables that may affect the quality of the results will be procured, inspected, and accepted in accordance with the Alliance representative's administrative procedures (e.g., Pacific Northwest National Laboratory's HDI Workflows and Work Controls).

Critical items and responsible personnel will be identified in task-specific sampling and analysis plans, as appropriate.

B.13 Non-direct Measurements (e.g., existing data)

Existing data, including literature files and historic data from surrounding areas and previous onsite characterization, testing, and monitoring activities, have been used to guide the design of the testing and monitoring program. However, these data are only ancillary to the well testing and monitoring program described here. These existing data will be used primarily for qualitative comparison to newly collected data.

All data will continue to be evaluated for their acceptability to meet project needs, that is, that the results, interpretation, and reports provide reasonable assurance that the project is operating as permitted and is not endangering any USDWs.

B.14 Data Management

All project data, record keeping, and reporting will be conducted to meet the requirements of 40 CFR 146.91(f).

B.14.1 Data Management Process

Project data will be managed in accordance with the Project Data Management Plan (Bryce et al. 2013). Management of all monitoring data is controlled by the subtier Monitoring Data Management Plan (Vermeul et al. 2014; not publicly available). Management of well MIT data is controlled by the subtier Well Construction Data Management Plan (Lanigan et al. 2013; not publicly available). All data will be managed by Alliance representatives throughout the duration of the project plus at least 10 years.

B.14.2 Recordkeeping Procedures

Project records will be managed according to project record management requirements and Alliance representatives' internal records management procedures.

B.14.3 Data Handling Equipment and Procedures

All data will be managed in a centralized electronic data management system. The underlying electronic servers will be routinely maintained, updated, and backed-up to ensure the long-term preservation of the data and records.

The centralized data-management system acts as a "data hub" to support collaborative analyses, enabling a diverse spectrum of experts—including geologists, hydrologists, numerical modelers, model developers, and others—to share data, tools, expertise, and computational models. This data-management system also acts as a "turn-key" data-management system that can be transferred to any future Alliance representatives or storage site operators.

B.14.4 Configuration Management and Change Control

The project's Configuration Management Plan (Alliance 2013b) identifies configuration-management requirements and establishes the methodology for configuration identification and control of releases and changes to configuration items. Each Alliance contractor is required to use configuration management to establish document control and to implement, account for, and record changes to various components of the project under its responsibility. The project's data configuration process is detailed in the Project Data Management Plan (Bryce et al. 2013) and its subsequent subtier data management plans. This data

configuration process controls how changes are made should errors or loss of data be detected during the course of routine data quality and readiness review checks and/or peer reviews.

QC mechanisms, checklists, forms, etc. used to detect errors are highly data-specific, but generally rely on spot-checks against field and laboratory records, as well as manual calculations to validate electronic manipulation of the data.

C. Assessment and Oversight

C.1 Assessments and Response Actions

As described in Section A.6 and detailed in Table A.2, the Monitoring, Verification, and Accounting (MVA) program for the FutureGen 2.0 CO_2 Pipeline and Storage Project includes numerous categories, methods, and frequencies of monitoring the performance of the CO_2 storage site. FutureGen staff responsible for the associated technical element or discipline will analyze the monitoring data and initiate any needed responses or corrective actions. Management will have ready access to performance data and will receive monitoring and performance reports on a regular basis.

In addition to the activities covered by the MVA program, data quality assessments will be performed to evaluate the state of configuration-controlled technical information in the FutureGen technical data repository to ensure that the appropriate data, analyses, and supporting information are collected, maintained, and protected from damage, deterioration, harm, or loss. These data quality assessments will be performed by a team consisting of the FutureGen 2.0 Data Manager, Project Quality Engineer, Subject Matter Experts, and additional knowledgeable and trained staff as appropriate for the scope and nature of the assessment. Assessments will be scheduled to occur at logical points in the project lifecycle, such as after completion and submission of a major deliverable that incorporates controlled technical information. Assessment results will be reported to management; deficiencies, weaknesses, opportunities for improvement, and noteworthy practices will be identified in the assessment reports. Assessment results will also be communicated to affected parties. Management will assign responsible staff to correct deficiencies and other nonconforming conditions and will ensure that corrective actions are implemented and verified in a timely manner. The Project Quality Engineer and FutureGen Data Manager will conduct follow-up surveillances to verify and document completion of corrective actions and to evaluate effectiveness.

C.2 Reports to Management

Management will be informed of the project status via the regular monitoring and performance reports generated by the MVA program, as well as reports of assessments conducted to verify data quality and surveillances performed to verify completed corrective actions. These reports are described in Section C.1; additional periodic reporting is not anticipated at this time. However, as directed by FutureGen management, targeted assessments by the Data Manager, Project Quality Engineer, or others will be conducted and reported to apprise management of project performance in areas of particular interest or concern.

D. Data Validation and Usability

D.1 Data Review, Verification, and Validation

The FutureGen 2.0 CO_2 Pipeline and Storage Support Project has established a Project Data Management Plan (PDMP) (Bryce et al. 2013) to identify how information and data collected or generated for the project will be stored, organized, and accessed to support all phases of the project. The PDMP describes the institutional responsibilities and requirements for managing all relevant data, including the intended uses and level of quality assurance needed for the data, the types of data to be acquired, and how the data will be managed and made available to prospective users. In addition to the PDMP, the FutureGen 2.0 project has issued discipline-specific subtier Technical Data Management Plans (TDMPs) to tailor data management processes to the needs of specific technical elements (e.g., computational modeling, geophysical, monitoring, site characterization). The PDMP and each TDMP define several categories of data, or Data Levels (consistent among all of the Data Management Plans), with corresponding data management, review, verification, validation, and configuration control requirements. The PDMP and TDMPs establish roles (e.g., Data Manager, Data Steward, Data Reviewer, Subject Matter Expert) and responsibilities for key participants in the data management process; project management assigns appropriate staff members to each role. Project staff who generate, review, verify, validate, or manage data are trained to the requirements of one or more Data Management Plans. Raw data (resulting from the use of a procedure or technology), defined as Level 1, are put under configuration control in the data management system at the time of upload to the system. Data defined at other Data Levels are put under configuration control when the data become reportable or decision-affecting. The procedures used to verify, validate, process, transform, interpret, and report data at each Data Level are documented and captured as part of the data management process.

D.2 Verification and Validation Methods

The Data Management Plans described in Section D.1 require that data packages undergo rigorous peer reviews. These reviews both *validate* the data—confirm that the appropriate types of data were collected using appropriate instruments and methods—and *verify* that the collected data are reasonable, were processed and analyzed correctly, and are free of errors. Data that have not undergone the peer-review process and are not yet under configuration control can be provided as preliminary information when accompanied by a disclaimer that clearly states that data are 1) preliminary and have not been reviewed in accordance with FutureGen's quality assurance practices, 2) considered "For Information Only", and 3) not to be used for reporting purposes nor as the basis for project management decisions. Once data are placed under configuration control, any changes must be approved using robust configuration-management processes described in the Data Management Plans. The peer-review and configuration-management processes include methods for tracking chain-of-custody for data, ensuring that custody is managed and control is maintained throughout the life of the project.

If issues are identified during a peer review, they are addressed and corrected by the data owner and peer reviewer (involving others, as necessary) as part of the peer-review process. These unreviewed data will not have been used in any formal work product nor as the basis for project management decisions, so the impacts of data errors will be minimal. If an error is identified in data under configuration control, in addition to correcting the error, affected work products and management decisions will be identified, affected users will be notified, and corrective actions will be coordinated to ensure that the extent of the error's impact is fully addressed.

D.3 Reconciliation with User Requirements

During the course of a long-duration project such as the FutureGen 2.0 CO_2 Pipeline and Storage Project, personnel changes over time can result in loss of institutional memory about the organization's data, thereby reducing the value of the data. New project staff may have little understanding of the content, intended uses, and pedigree of existing data sets. Metadata can help protect the organization's investment in data by providing context and pedigree, as well as describing interrelationships between various data sets. The Data Management Plans described in Section D.1 provide for Subject Matter Experts (SMEs) to establish and document metadata requirements for the data sets created by the FutureGen 2.0 project. Complete metadata will support data interpretation, provide confidence in the data, and encourage appropriate use of the data. To establish meaningful metadata requirements, SMEs must understand how data users and decision-makers will use the data. By adhering to metadata requirements when loading data into the project data repository, project staff ensure that user requirements addressed by the metadata are satisfied.

Data reviews, identification and resolution of data issues, and limitations on data use are discussed in Section D.2.

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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 13/16 in [4.60 cm] With flask: 2 1/4 in [5.72 cm]	2 7/8 in [7.30 cm]
Borehole size—max.	9 5/8 in [24.45 cm] With flask: 9 5/8 in [24.45 cm]	9 5/8 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.

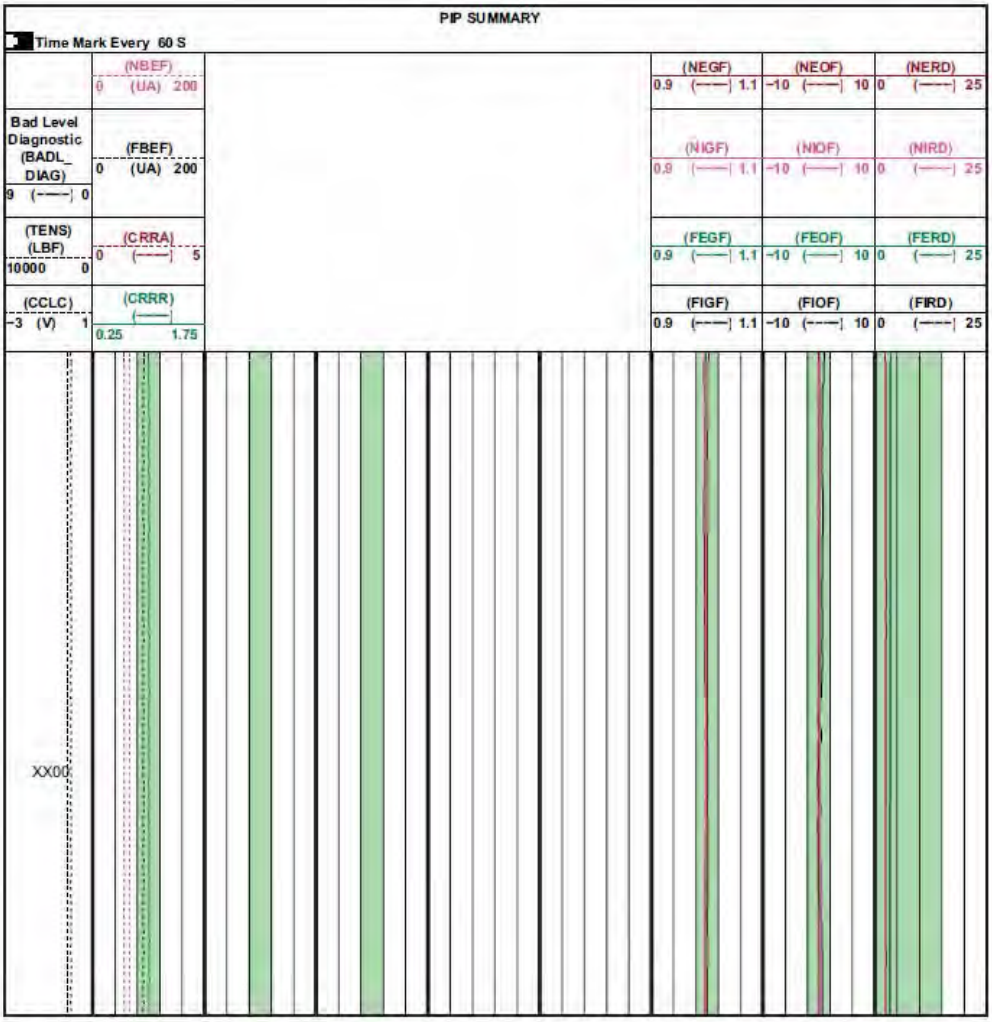


Figure 1. RST and RSTPro hardware format.

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.

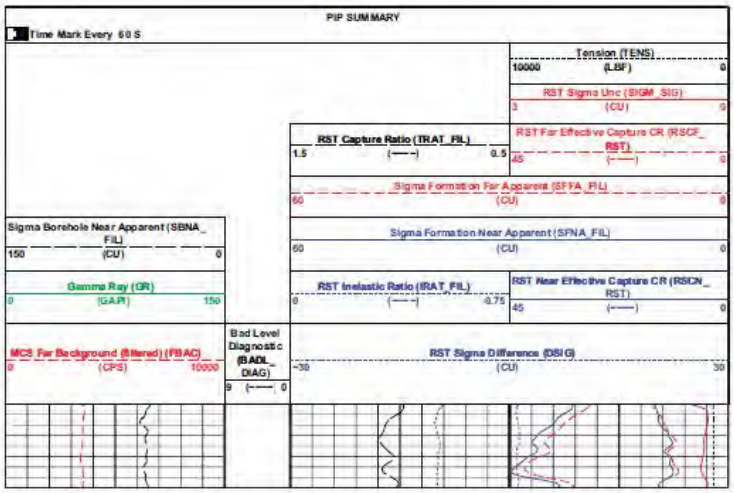


Figure 2. RST and RSTPro sigma standard format.

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]

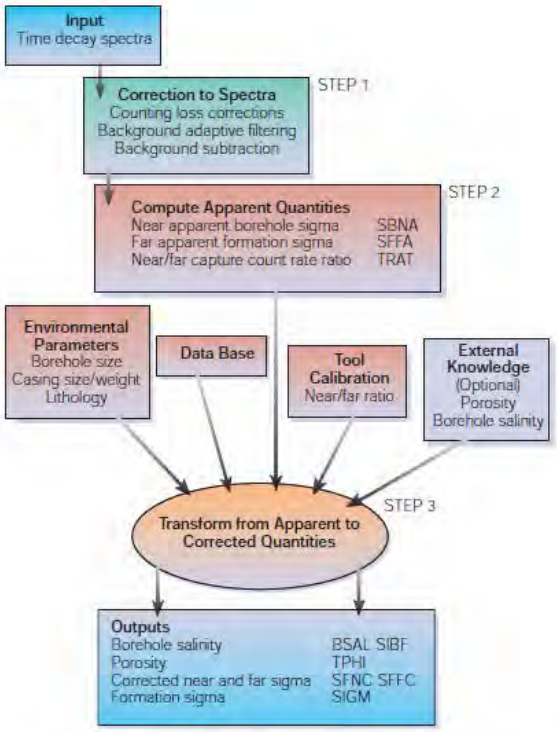
Water salinity was determined by a calibrated titration procedure and then converted into fluid sigma again using SNUPAR cross-section tables.

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-

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.

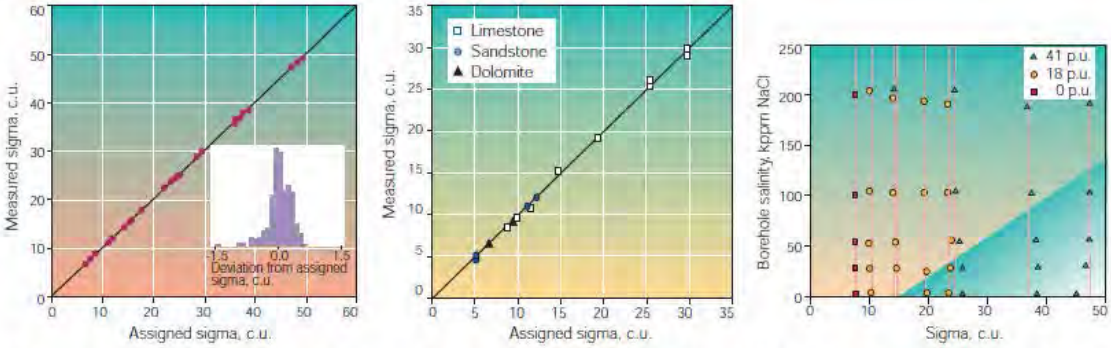
The next step is to generate the apparent quantities from the spectra, such as near and far apparent formation sigmas. These quantities are not environmentally corrected.

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.

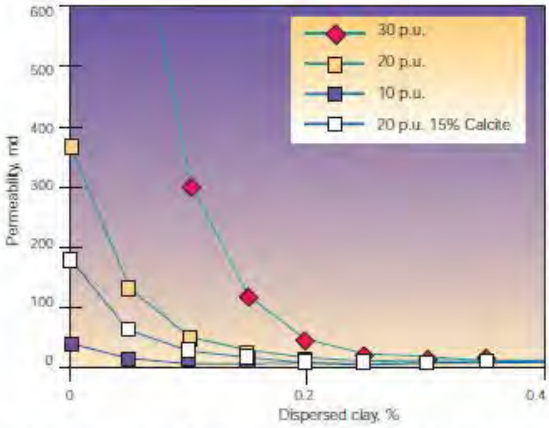
The EUROPA facility is an independent sigma calibration facility partially funded by the UK Atomic Energy Authority with major support from a consortium of 15 oil companies and government agencies. The RST-A tool was run in all the openhole formations and several cased-hole formations. A smaller number 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]

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.

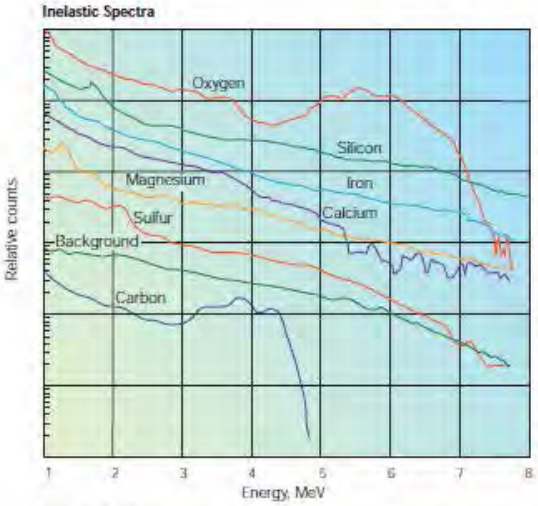
As neutrons slow to thermal energy levels, capture interactions dominate. Some elements are more likely to capture neutrons than others and so contribute more to the capture gamma ray spectrum.

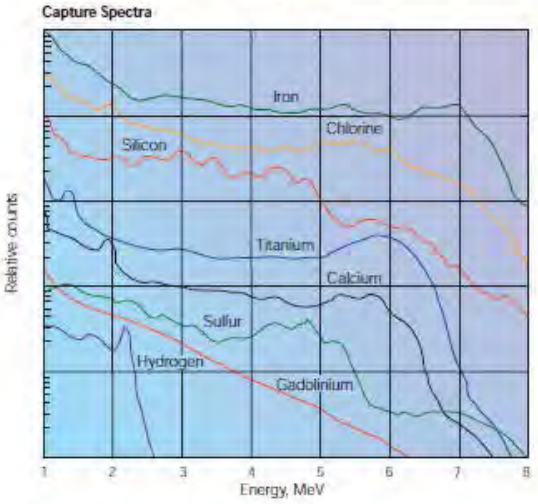
Inelastic and capture gamma ray spectra are recorded by opening counting windows at the appropriate time after a neutron burst from the RST neutron generator. Tool design allows not only for much higher gamma ray count rates than previous generation tools, but also for gain stabilization that enables 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

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
FSOO	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.

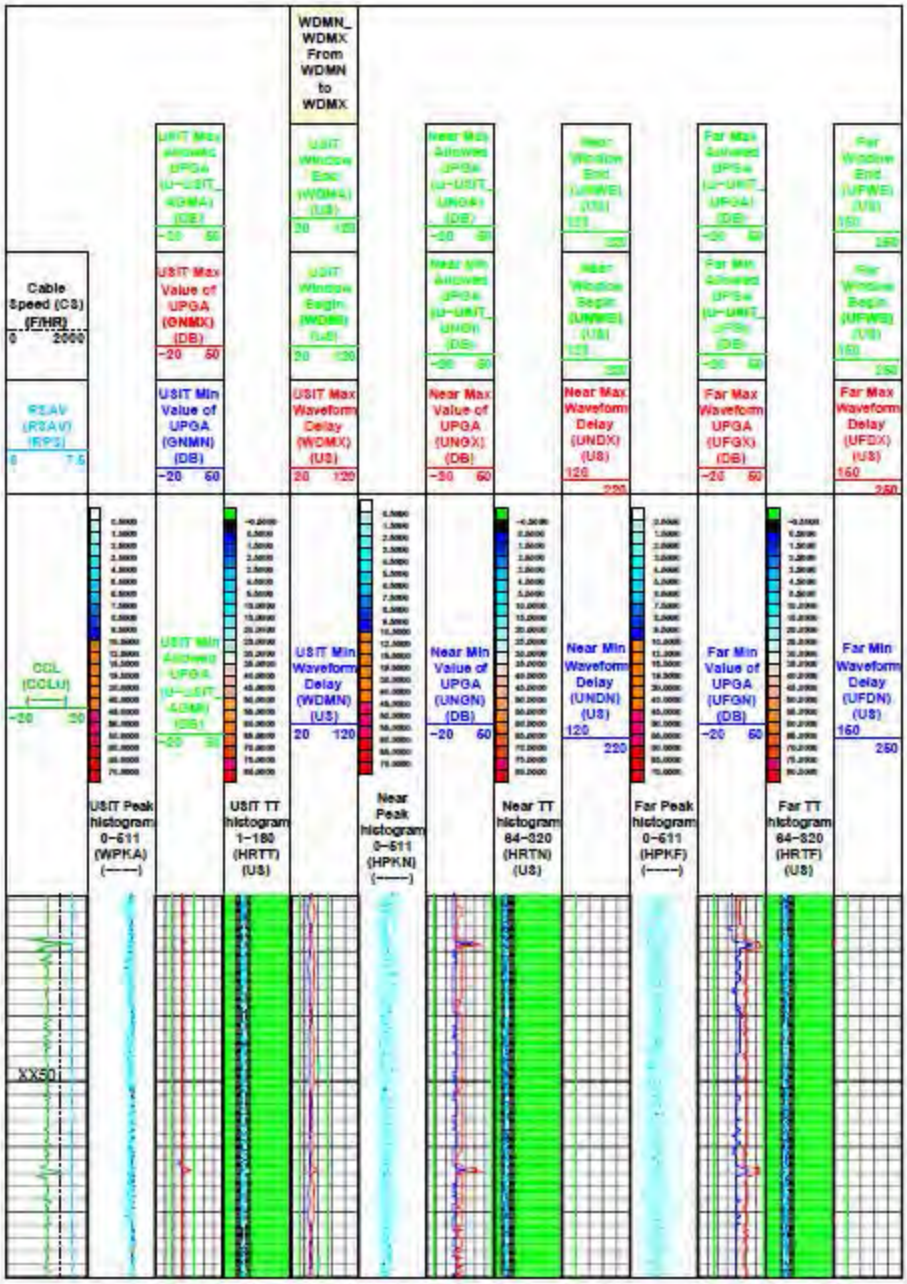


Figure 1. Isolation Scanner signal and waveforms quality control format.

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.

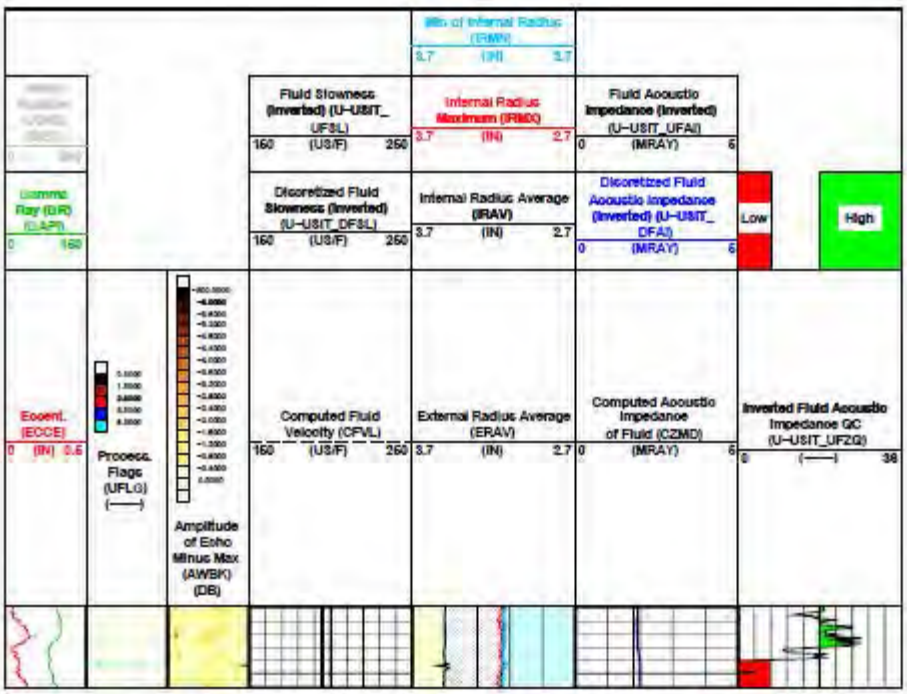


Figure 3. Isolation Scanner fluid property measurement quality control format.

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.

Schlumberger

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][1]
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

[1] 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[1]
SBI	Short bond index[1]
SCBL	Short synthetic CBL[1]
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

[1] 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 micro-annulus 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.

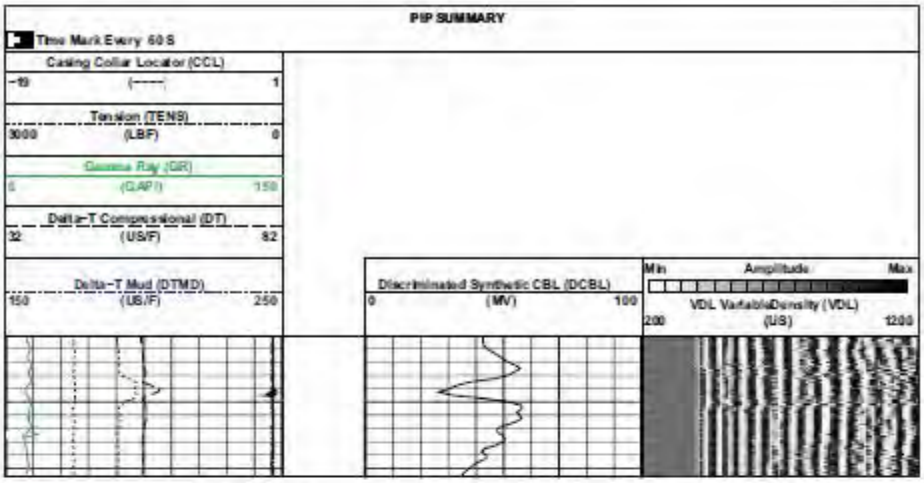


Figure 1. CBT standard format for CBL and VDL.

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.

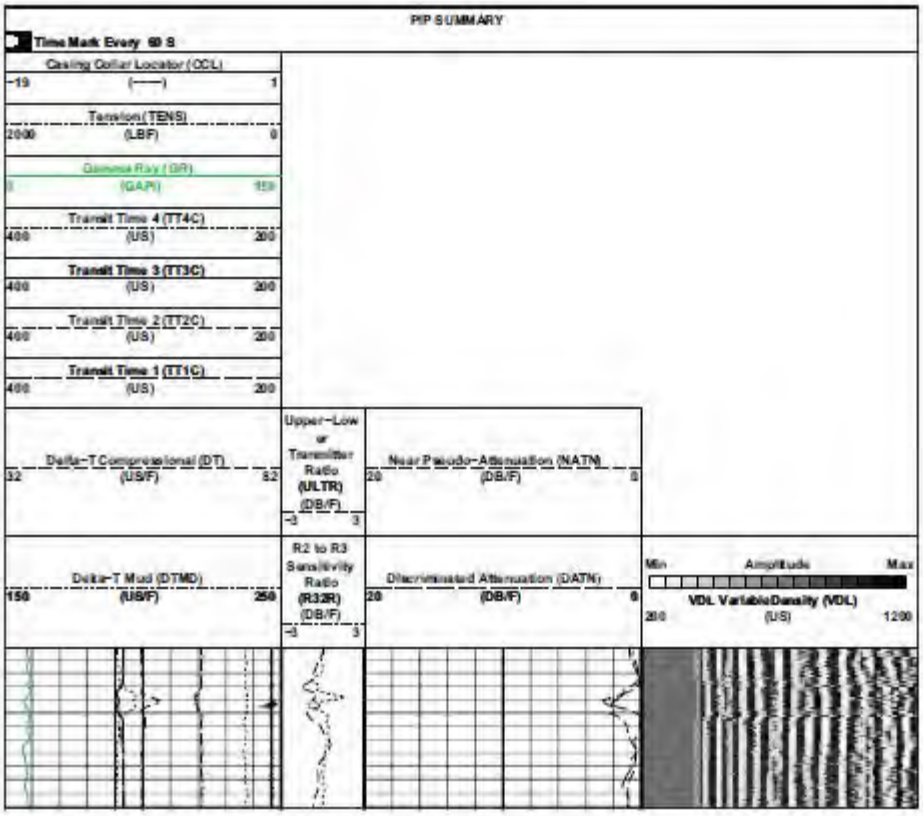


Figure 2. Additional CBT standard format for CBL and VDL.

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[1]	52 ± 5	329	272	NM[2]

[1] Although the CBT operates in up to 13⅜-in casing, the VDL presentation mainly shows casing arrivals within casings of 9⅝ in and larger are logged.
[2] NM = not meaningful

Schlumberger

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[1] 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

[1] 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 micro-annulus 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).

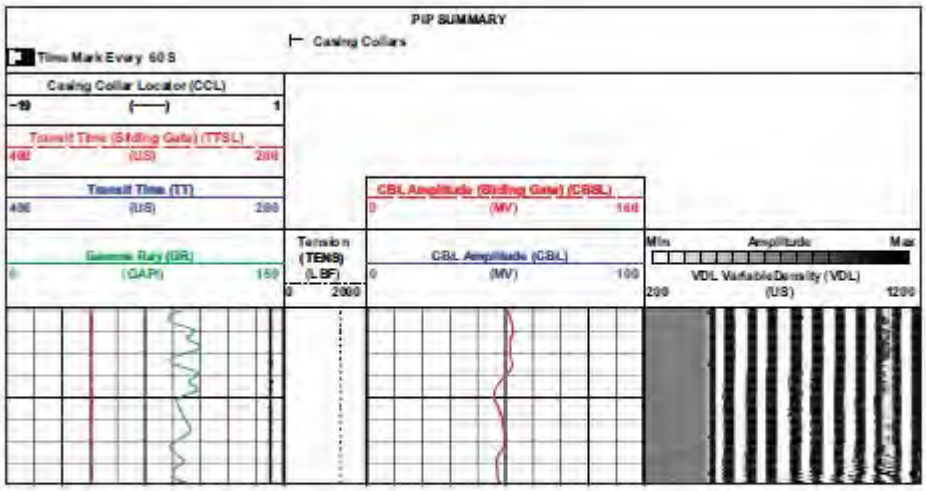


Figure 1. DSLT standard format.

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.

Cased Hole Gamma-Ray Logging

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.

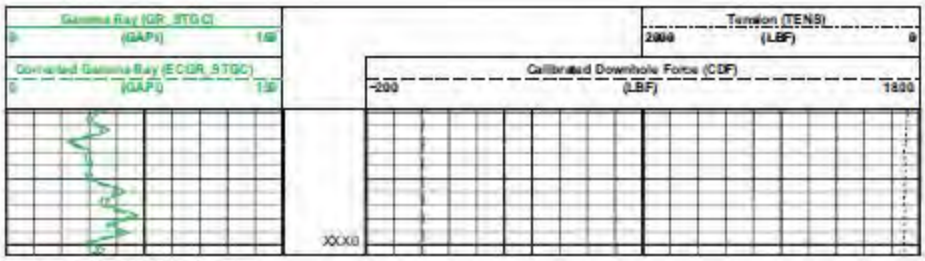


Figure 1. Gamma ray standard format

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.