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Standard Guide for Using the Seismic-Reflection Method for Shallow Subsurface Investigation[1]

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1. Scope

1.1 *Purpose and Application:*

1.1.1 This guide summarizes the technique, equipment, field procedures, data processing, and interpretation methods for the assessment of shallow subsurface conditions using the seismic-reflection method.

1.1.2 Seismic reflection measurements as described in this guide are applicable in mapping shallow subsurface conditions for various uses including geologic (**1**), geotechnical, hydrogeologic (**2**), and environmental (**3**).[2] The seismic-reflection method is used to map, detect, and delineate geologic conditions including the bedrock surface, confining layers (aquitards), faults, lithologic stratigraphy, voids, water table, fracture systems, and layer geometry (folds). The primary application of the seismic-reflection method is the mapping of lateral continuity of lithologic units and, in general, detection of change in acoustic properties in the subsurface.

1.1.3 This guide will focus on the seismic-reflection method as it is applied to the near surface. Near-surface seismic reflection applications are based on the same principles as those used for deeper seismic reflection surveying, but accepted practices can differ in several respects. Near-surface seismic-reflection data are generally high-resolution (dominant frequency above 80 Hz) and image depths from around 6 m to as much as several hundred meters. Investigations shallower than 6 m have occasionally been undertaken, but these should be considered experimental.

1.2 *Limitations:*

1.2.1 This guide provides an overview of the shallow seismic-reflection method, but it does not address the details of seismic theory, field procedures, data processing, or interpretation of the data. Numerous references are included for that purpose and are considered an essential part of this guide. It is recommended that the user of the seismic-reflection method be familiar with the relevant material in this guide, the references cited in the text, and Guides D420, D653, D2845, D4428/D4428M, Practice D5088, Guides D5608, D5730, D5753, D6235, and D6429.

1.2.2 This guide is limited to two-dimensional (2-D) shallow seismic-reflection measurements made on land. The seismic-reflection method can be adapted for a wide variety of special uses: on land, within a borehole, on water, and in three dimensions (3-D). However, a discussion of these specialized adaptations of reflection measurements is not included in this guide.

1.2.3 This guide provides information to help understand the concepts and application of the seismic-reflection method to a wide range of geotechnical, engineering, and groundwater problems.

1.2.4 The approaches suggested in this guide for the seismic-reflection method are commonly used, widely accepted, and proven; however, other approaches or modifications to the seismic-reflection method that are technically sound may be equally suited.

1.2.5 Technical limitations of the seismic-reflection method are discussed in 5.4.

1.2.6 This guide discusses both compressional (P) and shear (S) wave reflection methods. Where applicable, the distinctions between the two methods will be pointed out in this guide.

1.3 *This guide offers an organized collection of information or a series of options and does not recommend a specific course of action. This document cannot replace education or experience and should be used in conjunction with professional judgment. Not all aspects of this guide may be applicable in all circumstances. This guide is not intended to represent or replace the standard of care by which the adequacy of a given professional service must be judged, nor should this document be applied without consideration for a project's many unique aspects. The word "Standard" in the title of this guide means only that the document has been approved through the ASTM consensus process.*

1.4 The values stated in SI units are regarded as standard. The values given in parentheses are inch-pound units, which are provided for information only and are not considered standard.

1.5 *Precautions:*

[1] This guide is under the jurisdiction of ASTM Committee D18 on Soil and Rock and is the direct responsibility of Subcommittee D18.01 on Surface and Subsurface Characterization.

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[2] The boldface numbers in parentheses refer to the list of references at the end of this standard.

1.5.1 *It is the responsibility of the user of this guide to follow any precautions within the equipment manufacturer's recommendations, establish appropriate health and safety practices, and consider the safety and regulatory implications when explosives or any high-energy (mechanical or chemical) sources are used.*

1.5.2 *If the method is applied at sites with hazardous materials, operations, or equipment, it is the responsibility of the user of this guide to establish appropriate safety and health practices and determine the applicability of any regulations prior to use.*

1.5.3 *This standard does not purport to address all of the safety concerns, if any, associated with its use. It is the responsibility of the user of this standard to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to use.*

2. Referenced Documents

2.1 *ASTM Standards:*[3]

D420 Guide to Site Characterization for Engineering Design and Construction Purposes (Withdrawn 2011)[4]

D653 Terminology Relating to Soil, Rock, and Contained Fluids

D2845 Test Method for Laboratory Determination of Pulse Velocities and Ultrasonic Elastic Constants of Rock

D3740 Practice for Minimum Requirements for Agencies Engaged in Testing and/or Inspection of Soil and Rock as Used in Engineering Design and Construction

D4428/D4428M Test Methods for Crosshole Seismic Testing

D5088 Practice for Decontamination of Field Equipment Used at Waste Sites

D5608 Practices for Decontamination of Field Equipment Used at Low Level Radioactive Waste Sites

D5730 Guide for Site Characterization for Environmental Purposes With Emphasis on Soil, Rock, the Vadose Zone and Groundwater (Withdrawn 2013)[4]

D5753 Guide for Planning and Conducting Borehole Geophysical Logging

D5777 Guide for Using the Seismic Refraction Method for Subsurface Investigation

D6235 Practice for Expedited Site Characterization of Vadose Zone and Groundwater Contamination at Hazardous Waste Contaminated Sites

D6429 Guide for Selecting Surface Geophysical Methods

D6432 Guide for Using the Surface Ground Penetrating Radar Method for Subsurface Investigation

3. Terminology

3.1 *Definitions*—For general terms, See Terminology D653. Additional technical terms used in this guide are defined in Refs (**4**) and (**5**) .

3.2 *Definitions Specific to This Guide*

3.2.1 *acoustic impedance*—product of seismic compressional wave velocity and density. Compressional wave velocity of a material is dictated by its bulk modulus, shear modulus, and density. Seismic impedance is the more general term for the product of seismic velocity and density.

3.2.2 *automatic gain control (AGC)*—trace amplitude adjustment that varies as a function of time and the amplitude of adjacent data points. Amplitude adjustment changing the output amplitude so that at least one sample is at full scale deflection within a selected moving window (moving in time).

3.2.3 *body waves—P*- and *S*-waves that travel through the body of a medium, as opposed to surface waves which travel along the surface of a half-space.

3.2.4 *bulk modulus (elastic constant)*—the resistance of a material to change its volume in response to the hydrostatic load. Bulk modulus (K) is also known as the modulus of compression.

3.2.5 *check shot survey*—direct measurement of traveltime between the surface and a given depth. Usually sources on the surface are recorded by a seismic receiver in a well to determine the time-to-depth relationships at a specified location. Also referred to as downhole survey.

3.2.6 *coded source*—a seismic energy-producing device that delivers energy throughout a given time in a predetermined or predicted fashion.

3.2.7 *common mid-point (CMP) or common depth point (CDP) method*—a recording-processing method in which each source is recorded at a number of geophone locations and each geophone location is used to record from a number of source locations. After corrections, these data traces are combined (stacked) to provide a common-midpoint section approximating a coincident source and receiver at each location. The objective is to attenuate random effects and events whose dependence on offset is different from that of primary reflections.

3.2.8 *compressional wave velocity*—also known as *P*-wave velocity. In seismic usage, velocity refers to the propagation rate of a seismic wave without implying any direction, that is, velocity is a property of the medium. Particle displacement of a compressional wave is in the direction of propagation.

3.2.9 *dynamic range*—the ratio of the maximum reading to the minimum reading which can be recorded by and read from an instrument without change of scale. It is also referred to as the ability of a system to record very large and very small amplitude signals and subsequently recover them. Integral to the concept of dynamic range is the systems Analog to Digital converter (A/D). A systems A/D is rated according to the number of bits the analog signal is segmented into to form the digital word. A/D converters in modern seismographs usually range from 16 to 24 bits.

3.2.10 *fold (or redundancy)*—the multiplicity of common-midpoint data or the number of midpoints per bin. Where the midpoint is the same for 12 source/receiver pairs, the stack is referred to as "12-fold" or 1200 percent.

[3] For referenced ASTM standards, visit the ASTM website, www.astm.org, or contact ASTM Customer Service at service@astm.org. For *Annual Book of ASTM Standards* volume information, refer to the standard's Document Summary page on the ASTM website.

[4] The last approved version of this historical standard is referenced on www.astm.org.

3.2.11 *G-force*—measure of acceleration relative to the gravitational force of the earth.

3.2.12 *impedance contrast*—ratio of the seismic impedance across a boundary. Seismic impedance of the lower layer divided by the seismic impedance of the upper layer. A value of 1 implies total transmittance. Values increase or decrease from 1 as the contrast increases, that is, more energy reflection from a boundary. Values less than 1 are indicative of a negative reflectivity or reversed reflection wavelet polarity.

3.2.13 *normal moveout (NMO)*—the difference in reflection-arrival time as a function of shot-to-geophone distance because the geophone is not located at the source point. It is the additional traveltime required because of offset, assuming that the reflecting bed is not dipping and that raypaths are straight lines. This leads to a hyperbolic shape for a reflection.

3.2.14 *normal moveout velocity (stacking velocity)*—velocity to a given reflector calculated from normal-moveout measurements, assuming a constant-velocity model. Because the raypath actually curves as the velocity changes, fitting a hyperbola assumes that the actual velocity distribution is equivalent to a constant NMO velocity, but the NMO velocity changes with the offset. However, the assumption often provides an adequate solution for offsets less than the reflector depth. Used to calculate NMO corrections to common-midpoint gathers prior to stacking.

3.2.15 *Nyquist frequency*—also known as the aliasing or folding frequency, is equal to half the sampling frequency or rate. Any frequency arriving at the recording instrument greater than the Nyquist will be aliased to a lower frequency and cannot be recovered.

3.2.16 *optimum window*—range of offsets between source and receiver that provide reflections with the best signal-to-noise ratio.

3.2.17 *Poisson's ratio*—the ratio of the transverse contraction to the fractional longitudinal extension when a rod is stretched. If density is known, specifying Poisson's ratio is equivalent to specifying the ratio of V_s/V_p, where V_s and V_p are *S* - and *P*-wave velocities. Values ordinarily range from 0.5 (no shear strength, for example, fluid) to 0, but theoretically they range from 0.5 to −1.0; $\{\mu = \sqrt{1-0.5(V_p/V_s)^2} / 1-(V_p/V_s)^2\}$.

3.2.18 *raypath*—a line everywhere perpendicular to wavefronts (in isotropic media). A raypath is characterized by its direction at the surface. While seismic energy does not travel only along raypaths, raypaths constitute a useful method of determining arrival time by ray tracing.

3.2.19 *reflection*—the energy or wave from a seismic source that has been reflected (returned) from an acoustic-impedance contrast (reflector) or series of contrasts within the earth.

3.2.20 *reflector*—an interface having a contrast in physical properties (elasticity and/or density) that reflects seismic energy.

3.2.21 *roll-along switch*—a switch that connects different geophone groups to the recording instruments, used in common-midpoint recording.

3.2.22 *seismic impedance*—product of seismic wave velocity and density. Different from acoustic impedance as it includes shear waves and surface waves where acoustic impedance, by strict definition, includes only compressional waves.

3.2.23 *seismic sensor*—receivers designed to couple to the earth and record vibrations (for example, geophones, accelerometers, hydrophones).

3.2.24 *seismic sensor group (spread)*—multiple receivers connected to a single recording channel, generally deployed in an array designed to enhance or attenuate specific energy.

3.2.25 *seismogram*—a seismic record or section.

3.2.26 *shear modulus (G) (elastic constant)*—the ratio of shear stress to shear strain of a material as a result of loading and is also known as the rigidity modulus, equivalent to the second Lamé constant m mentioned in books on continuum theory. For small deformations, Hooke's law holds and strain is proportional to stress.

3.2.27 *shear wave velocity (S-wave velocity)*—speed of energy traveling with particle motion perpendicular to its direction of propagation (see Eq 2).

3.2.28 *shot gather*—a side-by-side display of seismic traces that have a common source location. Also referred to as "field files."

3.2.29 *source to seismic sensor offset*—the distance from the source-point to the seismic sensor or to the center of a seismic sensor (group) spread.

3.2.30 *takeout*—a connection point on a multiconductor cable where seismic sensors can be connected. Takeouts are usually physically polarized to reduce the likelihood of making the connection backwards.

3.2.31 *tap test*—gently touching a receiver while monitoring on real-time display, to qualitatively appraise sensor response.

3.2.32 *twist test*—light rotational pressure applied to each seismic sensor to ensure no motion and, therefore, a solid ground coupling point.

3.2.33 *wavetrain (wavefield)—(1)* spatial perturbations at a given time that result from passage of a wave; and *(2)* all components of seismic energy traveling through the earth as the result of a single impact.

3.2.34 *wide-angle reflections*—reflections with an angle of incidence near or greater than the critical angle. The critical angle is defined as the unique angle of incidence at which rays incident to a boundary (boundary defined as an abrupt vertical increase in velocity) "refract" and travel in the lower, higher velocity media parallel to the boundary. Wide-angle reflections become asymptotic to refractions at increasing offset and can possess exceptionally large amplitudes. If they are included in CMP stacked sections they can disproportionately contribute to the stacked wavelet.

3.2.35 *wiggle trace*—a single line display of seismic sensor output as a function of time.

4. Summary of Guide

4.1 *Summary of the Method*—The seismic-reflection method utilizes seismic energy that propagates through the earth, reflects off subsurface features, and returns to the surface. The seismic waves travel from a source to seismic sensors deployed in a known geometry. Sound waves traveling downward will reflect back to the surface wherever the velocity or density of subsurface materials increases or decreases abruptly (for example, water table, alluvium/bedrock contact, limestone/shale contact).

4.1.1 Images of reflectors (velocity or density contrast) are used to interpret subsurface conditions and materials. Reflections returning from reflectors to seismic sensors will follow travel paths determined by the velocities of the materials through which they propagate. Reflection arrivals on seismic data recorded with multiple seismic sensors at different offsets (distance between source and seismic sensor) from the source can be collectively used to estimate the velocity (approximately average) of the material between the reflection point and seismic sensor. Reflections can be used to characterize properties of the subsurface such as continuity, thickness, and depth of layers and changes in velocity and material type.

4.1.2 The seismic-reflection method depends on the presence of discrete seismic-velocity or mass-density changes in the subsurface that represent acoustical impedance changes. Mathematically, acoustic impedance is proportional to the product of mass density and acoustic wave velocity. Reflection may or may not occur at natural boundaries between geologic layers or at manmade boundaries such as tunnels and mines. The classic use of the seismic reflection method is to identify boundaries of layered geologic units. However, the technique can also be used to search for localized anomalies such as sand or clay lenses and faults.

4.1.3 Seismic energy in the earth travels in the form of body waves and surface waves. Body waves propagating through the earth behave similarly to sound waves propagating in air. When sound waves traveling in air from voices, explosions, horns, etc., come in contact with a wall, cliff, or building (all acoustic contrasts), it is common to hear an echo, which is reflected sound. When a body wave propagating in the subsurface comes in contact with a volume of material with a different acoustical impedance in the subsurface, reflections (echoes) are also generated. In the subsurface, the situation is complex because some of the body wave energy arriving at an acoustic interface can be transmitted, refracted, or converted to other types of seismic waves at the interface. Surface waves are the dominant (in total energy) part of a seismic energy pulse and propagate along the free surface of the earth much like a wave on the ocean moves toward shore. Surface waves penetrate into the earth to a depth that is a function of their wavelength.

4.1.4 The seismic-reflection method requires contrasts in the physical properties of earth materials, much like ground penetrating radar (GPR) (see Guide D6432). The measurable physical parameters (seismic velocity and density) upon which the seismic-reflection method depends are quite different from the physical parameters (conductivity and dielectric constant) on which GPR depends, but the concept of reflected energy is analogous. The similarities between seismic reflection and electrical methods (resistivity, spontaneous potential), electromagnetic (EM), or potential fields (gravity or magnetics) are substantially less.

4.2 *Complementary Data*—Geologic and hydrogeologic data obtained from borehole logs, geologic maps, data from outcrops, or other surface and borehole geophysical methods are generally necessary to uniquely interpret subsurface conditions from seismic-reflection data. The seismic-reflection method provides a non-unique representation of the subsurface that, without supporting or complementary data, cannot be definitively interpreted.

5. Significance and Use

5.1 *Concepts:*

5.1.1 This guide summarizes the basic equipment, field procedures, and interpretation methods used for detecting, delineating, or mapping shallow subsurface features and relative changes in layer geometry or stratigraphy using the seismic-reflection method. Common applications of the method include mapping the top of bedrock, delineating bed or layer geometries, identifying changes in subsurface material properties, detecting voids or fracture zones, mapping faults, defining the top of the water table, mapping confining layers, and estimating of elastic-wave velocity in subsurface materials. Personnel requirements are as discussed in Practice D3740.

5.1.2 Subsurface measurements using the seismic-reflection method require a seismic source, multiple seismic sensors, multi-channel seismograph, and appropriate connections (radio or hardwire) between each (Fig. 1, also showing optional roll-along switch).

5.1.3 Seismic waves generated by a controlled seismic energy source propagate in the form of mechanical energy (particle motion) from the source through the ground or air to seismic sensors where the particle (ground) motion is converted to electrical voltage and transmitted to the seismograph.

5.1.3.1 Seismic energy travels away from the source both through the ground and air. In the ground, the energy travels as an elastic wave, with compressional waves (Eq 1) and shear waves (Eq 2) moving away from the source in a hemispherical pattern, and surface waves propagating away in a circular pattern on the ground surface.

$$V_p = \sqrt{[(K+4G/3)/\rho]} \tag{1}$$

$$V_s = (G/\rho)^{1/2} = \{E/[2\rho\,(1+\mu)]\}^{1/2} \tag{2}$$

where:

V_p = compressional wave velocity,
K = bulk modulus,
G = shear modulus,
ρ = density,
E = Young's modulus,
μ = Poisson's ratio, and
V_s = shear wave velocity.

Seismic energy propagation time between seismic sensors depends on wave type, travel path, and seismic velocity of the material. The travel path of reflected body waves (compressional (P) and shear (S) waves) is controlled by subsurface material velocity and geometry of interfaces defined by acoustic impedance (product of velocity and density) changes. A

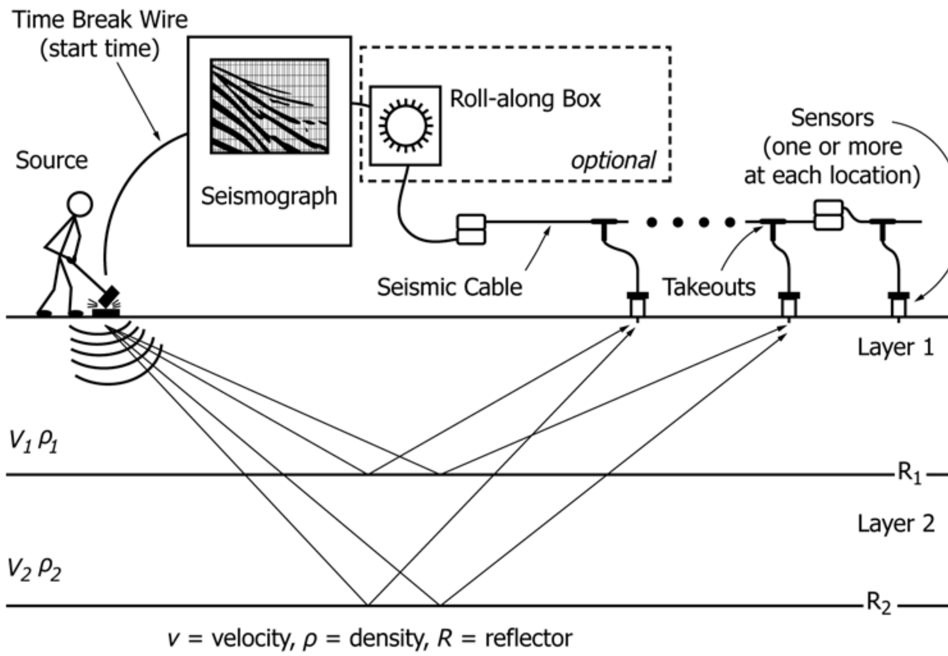


FIG. 1 Schematic of Equipment and Deployment of Equipment for a Seismic Reflection Survey

difference in acoustic impedance between two layers results in an impedance contrast across the boundary separating the layers and determines the reflectivity (reflection coefficient) of the boundary; for example, how much energy is reflected versus how much is transmitted (Eq 3). At normal incidence:

$$R = \frac{\rho_2 V_2 - \rho_1 V_1}{\rho_2 V_2 + \rho_1 V_1} \quad \text{and} \quad A = \frac{\rho_2 V_2}{\rho_1 V_1} \tag{3}$$

where:

R = reflectivity = reflection coefficient,
$V_1 V_2$ = velocity of layers 1 and 2,
$\rho_1 \rho_2$ = density of layers 1 and 2,
$V\rho$ = acoustic impedance, and
A = impedance contrast.

Snell's law (Eq 4) describes the relationship between incident, refracted, and reflected seismic waves:

$$\frac{V_1}{\sin i} = \frac{V_1}{\sin r} = \frac{V_1}{\sin t} \tag{4}$$

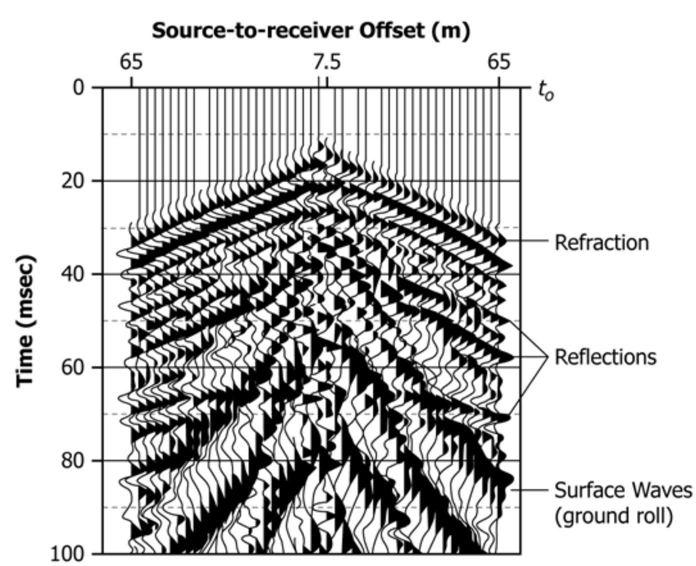
where:

i = incident angle,
r = reflected angle, and
t = refracted angle.

At each boundary represented by a change in the product of velocity and density (acoustic impedance), the incident seismic wave generates a reflected P, reflected S, transmitted P, and transmitted S wave. This process is described by the Zoeppritz equations (for example, Telford et al. (**6**)).

5.1.3.2 Analysis and recognition of seismic energy arrival patterns at different seismic sensors allows estimation of depths to reflection coefficients (reflectors) and average velocity between the reflection coefficient and the earth's surface. Analog display of the seismic waves recorded by each seismic sensor is generally in wiggle trace format on the seismogram (Fig. 2) and represents the particle motion (velocity or acceleration) consistent with the orientation and type of the seismic sensor (geophone or accelerometer) and source.

5.1.4 A multichannel seismograph simultaneously records the wave field at a number of seismic sensors as a function of time (Fig. 2). Multichannel seismic data are typically displayed as a time and source-to-seismic sensor distance representation of the source-induced particle motion propagating in the earth. This particle motion, also known as the elastic wave field, can be complex and is modified in a predictable way by the seismic sensors and instrumentation used for recording the seismic



NOTE 1—Shows the entire wavefield.

NOTE 2—Acquired with vertical geophones.

FIG. 2 48-Channel Seismograph Record Acquired with a Seismic Source 7.5 m Away from the Nearest Seismic Sensors

signal. A wave field is generally displayed in wiggle trace format, with the vertical (time) axis of the display typically referenced to the instant the seismic energy was released (t_0) and the horizontal axis showing the linear source-to-seismic-sensor distance (Fig. 2). The arrivals of the wavefield at each seismic sensor are synchronized in time based on the selected digital sampling rate of the seismograph. Each seismic event of the wavefield represents different travel paths, particle motions, and velocities of the energy spreading outward from the seismic source. Fig. 2 shows data acquired from a shot in the center of a line of seismic sensors

5.2 *Parameters Measured and Representative Values*—Tables 1 and 2 provide generalized material properties related to the seismic-reflection method.

5.2.1 The seismic-reflection method images changes in the acoustic (seismic) impedance of subsurface layers and features, which represent changes in subsurface material properties. While the seismic reflection technique depends on the existence of non-zero reflection coefficients, it is the interpreter who, based on knowledge of the local conditions and other data, must interpret the seismic-reflection data and arrive at a geologically feasible solution. Changes in reflected waveform can be indicative of changes in the subsurface such as lithology (rock or soil type), rock consistency (that is, fractured, weathered, competent), saturation (fluid or gas content), porosity, geologic structure (geometric distortion), or density (compaction).

5.2.2 *Reflection Coefficient or Reflectivity*—Reflectivity is a measure of energy expected to return from a boundary (interface) between materials with different acoustic impedance values. Materials with larger acoustic impedances overlying materials with smaller acoustic impedances will result in a negative reflectivity and an associated phase reversal of the reflected wavelet. Intuitively, wavelet polarity follows reflection coefficients that are negative when faster or denser layers overlie slower or less dense (for example, clay over dry sand) layers and positive when slower or less dense layers overlie faster or denser (for example, gravel over limestone) layers. A reflectivity of one means all energy will be reflected at the interface.

5.3 *Equipment*—Geophysical equipment used for surface seismic measurement can be divided into three general categories: source, seismic sensors, and seismograph. Sources generate seismic waves that propagate through the ground as either an impulsive or a coded wavetrain. Seismic sensors can measure changes in acceleration, velocity, displacement, or pressure. Seismographs measure, convert, and save the electric signal from the seismic sensors by conditioning the analog signal and then converting the analog signal to a digital format (A/D). These digital data are stored in a predetermined standardized format. A wide variety of seismic surveying equipment is available and the choice of equipment for a seismic reflection survey should be made to meet the objectives of the survey.

5.3.1 *Sources*—Seismic sources come in two basic types: impulsive and coded. Impulsive sources transfer all their energy (potential, kinetic, chemical, or some combination) to the earth instantaneously (that is, usually in less than a few milliseconds). Impulsive source types include explosives, weight drops, and projectiles. Coded sources deliver their energy over a given time interval in a predetermined fashion (swept frequency or impulse modulated as a function of time). Source energy characteristics are highly dependent on near-surface conditions and source type (**8-11**). Consistent, broad bandwidth source energy performance is important in seismic reflection surveying. The primary measure of source effectiveness is the measure of signal-to-noise ratio and resolution potential as estimated from the recorded signal.

5.3.1.1 Selection of the seismic source should be based upon the objectives of the survey, site surface and geologic conditions and limitations, survey economics, source repeatability, previous source performance, total energy and bandwidth possible at survey site (based on previous studies or site specific experiments), and safety.

5.3.1.2 Coded seismic sources will generally not disturb the environment as much as impulsive sources for a given total amount of seismic energy. Variable amplitude background noise (such as passing cars, airplanes, pedestrian traffic, etc.) affects the quality of data collected with coded sources less than for impulsive sources. Coded sources require an extra

TABLE 1 Approximate Material Properties

Material	*P*-Wave[A] Velocity (m/s)	*S*-Wave[A] Velocity (m/s)	Density (kg/m^3)	Acoustic Impedance[B]
Dry sand/gravel	750[C]	200	1800	1.35×10^6
Clay	900	300	2000	1.80×10^6
Saturated sand	1500	350	2100	3.15×10^6
Saturated clay	1800	400	2200	3.96×10^6
Shale	3500	1500	2500	8.75×10^6
Sandstone	2850	1400	2100	5.99×10^6
Limestone	4000	2200	2600	10.4×10^6
Granite	6000	3500	2600	15.6×10^6

[A] Velocities are mean for a range appropriate for the material (**7**).
[B] Acoustic impedance is velocity multiplied by density, specifically for compressional waves; the equivalent for shear waves is referred to as seismic impedance (units of kg/s·m ^{2}).
[C] Subsonic velocities have been reported by researchers studying the ultra-shallow near surface .

TABLE 2 Approximate Reflectivity of Interfaces Between Common Materials

Material Middle Layer[A]	Material Bottom Layer[B]	Approximate Reflectivity[C]
Dry Sand	Dry Sand	0.0
Dry Sand	Dry Clay / Saturated Clay	0.14 / 0.5
Dry Sand	Gravel	–0.08
Dry Sand	Saturated Sand	0.43
Dry Sand	Limestone	0.75
Dry Sand	Shale	0.72
Dry Sand	Sandstone	0.63
Dry Sand	Granite	0.84
Saturated Sand	Granite	0.66
Clay	Dry Sand	–0.14
Clay	Clay	0.0
Clay	Gravel	–0.17
Clay	Saturated Sand	–0.27
Clay	Limestone	0.71
Clay	Shale	0.66
Clay	Sandstone	0.54

[A] Layer 1 on Fig. 1.
[B] Layer 2 on Fig. 1.
[C] *R* in Eq 3, Absolute value *R* = 1 total reflectance.

processing step to compress the time-variable signal wavetrain down to a more readily interpretable pulse equivalent. This is generally done using correlation or shift and stack techniques.

5.3.1.3 In most settings, buried small explosive charges will result in higher frequency and broader bandwidth data, in comparison to surface sources. However, explosive sources generally come with use restrictions, regulations, and more safety considerations than other sources. Most explosive and projectile sources are designed to be invasive, while weight drop and most coded sources are generally in direct contact with the ground surface and therefore are non-invasive.

5.3.1.4 Sources that shake, impact, or drive the ground so that the dominant particle motion is horizontal to the surface of the ground are shear-wave sources. Sources that shake, impact, or drive the ground so that the dominant particle motion is vertical to the surface of the ground are compressional sources. Many sources can be used for generating both shear and compressional wave energy.

5.3.2 *Seismic Sensors*—Seismic sensors convert mechanical particle motion to electric signals. There are three different types of seismic sensors: accelerometers, geophones (occasionally referred to as seismometers), and hydrophones.

5.3.2.1 Accelerometers are devices that measure particle acceleration. Accelerometers generally require pre-amplifiers to condition signal prior to transmission to the seismograph. Accelerometers generally have a broader bandwidth of sensitivity and a greater tolerance for high G-forces than geophones or hydrophones. Accelerometers have a preferred direction of sensitivity.

5.3.2.2 Geophones consist of a stationary cylindrical magnet surrounded by a coil of wire that is attached to springs and free to move relative to the magnet. Geophones measure particle velocity and therefore produce a signal that is the derivative of the acceleration measured by accelerometers. Geophones are generally robust, durable, and have unique response characteristics proportional to their natural frequency and coil impedance. The natural frequency is related to the spring constant and the coil impedance is a function of the number of wire windings in the coil.

5.3.2.3 Hydrophones are used when measuring seismic signals propagating in liquids. Because shear waves are not transmitted through water, hydrophones only respond to compressional waves. However, shear waves can be converted to compressional waves at the water/earth interface and provide an indirect measurement of shear waves. Hydrophones are pressure-sensitive devices that are usually constructed of one or more piezoelectric elements that distort with pressure.

5.3.2.4 Geophones and accelerometers can be used for compressional or shear wave surveys on land. Orientation of the seismic sensor determines the seismic sensor response and sensitivity to different particle motion. Some seismic sensors are omnidirectional and are sensitive to particle motion parallel to the motion axis of the sensor, regardless of the sensor's spatial orientation direction. Others seismic sensors are designed to be used in one orientation or the other (*P* or *S*). Shear wave seismic sensors are sensitive to particle motion perpendicular to the direction of propagation (line between source and seismic sensors) and are sensitive to vertical (*SV*) or horizontal (*SH*) transverse wave motion. Compressional wave seismic sensors are sensitive to particle motion parallel to the direction of propagation (line between source and seismic sensor) and thus the motion axis of the seismic sensor needs to be in a vertical position.

5.3.3 *Seismographs*—Seismographs measure the voltages generated by seismic sensors as a function of time and synchronize them with the seismic source. Seismographs have differing numbers of channels and a range of electronic specifications. The choice of an appropriate seismograph should be based on survey objectives. Modern multichannel seismographs are computer based and require minimal fine-tuning to adjust for differences or changes in site characteristics. Adjustable seismograph acquisition settings that will affect the accuracy or quality of recorded data are generally limited to sampling rate, record length, analog filter settings, pre-amplifier gains, and number of recording channels. There is limited need for selectable analog filters and gain adjustments with modern, large dynamic range (>16 bits) seismographs. Seismographs store digital data in standard formats (for example, SEGY, SEGD, SEG2) that are generally dependent on the type of storage medium and the primary design application of the system. Seismographs can be single units (centralized), with all recording channels (specifically analog circuitry and A/D converters) at a single location, or several autonomous seismographs can be distributed around the survey area. Distributed seismographs are characterized by several small decentralized digitizing modules (1–24 channels each) located close to the geophones to reduce signal loss over long-cable seismic sensors. Digital data from each distributed module are transmitted to a central system where data from multiple distributed units are collected, cataloged, and stored.

5.3.4 *Source and Seismic Sensor Coupling*—The seismic sensors and sources must be coupled to the ground. Depending on ground conditions and source and seismic sensor configuration, this coupling can range from simply resting on the ground surface (for example, land streamers, weight drop, vibrator) to invasive ground penetration or burial (for example, spike, buried explosives, projectile delivery at bottom of a hole). Hydrophones couple to the ground through submersion in water in a lake, stream, borehole, ditch, etc.

5.3.5 *Supporting Components*—Additional equipment includes a roll-along switch, cables, time-break system (radio or hardwire telemetry between seismograph and source), quality control (QC) and troubleshooting equipment (seismic sensor continuity, earth leakage, cable leakage, seismograph distortion and noise thresholds, cable and seismic sensor shorting plug), and land surveying equipment.

5.4 *Limitations and Interferences:*

5.4.1 *General Limitations Inherent to Geophysical Methods:*

5.4.1.1 A fundamental limitation of all geophysical methods is that a given set of data does not uniquely represent a set of subsurface conditions. Geophysical measurements alone cannot uniquely resolve all ambiguities, and some additional information, such as borehole measurements, is required. Because of this inherent limitation in geophysical methods, a seismic-reflection survey will not completely represent subsurface geological conditions. Properly integrated with other geologic information, seismic-reflection surveying can be an effective, accurate, and cost-effective method of obtaining detailed subsurface information. All geophysical surveys measure physical properties of the earth (for example, velocity, conductivity, density, susceptibility) but require correlation to the geology and hydrology of a site. Reflection surveys do not directly measure material-specific characteristics (such as color, texture, and grain size), or lithologies (such as limestone, shale, sandstone, basalt, or schist), except to the extent that these lithologies may have different velocities and densities.

5.4.1.2 All surface geophysical methods are inherently limited by signal attenuation and decreasing resolution with depth.

5.4.2 *Limitations Specific to the Seismic-Reflection Method:*

5.4.2.1 Theoretical limitations of the seismic-reflection method are related to the presence of a non-zero reflection coefficient, seismic energy characteristics, seismic properties (velocity and attenuation), and layer geometries relative to recording geometries. In a homogenous earth, no reflections are produced and therefore none can be recorded. When reflection measurements are made at the surface of the earth, reflections can only be returned from within the earth if layers with non-zero reflection coefficients are present within the earth. Layers, for example, defined by changes in lithology without measurable changes in either velocity or density cannot be imaged with the seismic reflection method. Theoretical limits on bed or object-resolving capabilities of a seismic data set are related to frequency content of the reflected energy (see 8.4).

5.4.2.2 Successful imaging of geologic layers dipping at greater than 45 degrees may require non-standard deployments of sources and seismic sensors.

5.4.2.3 Resolution (discussed in 8.4) and signal-to-noise ratios are critical factors in determining the practical limitations of the seismic-reflection method. Source configuration, source and seismic sensor coupling, near-surface materials, specification of the recording systems, relative amplitude of seismic events, and arrival geometry of coherent source-generated seismic noise are all factors in defining the practical limitations of seismic-reflection method.

(1) Highly attenuative near-surface materials such as dry sand and gravel, can adversely affect the resolution potential and signal strength with depth of seismic energy **(12)**. Attenuation is rapid reduction of seismic energy as it propagates through an earth material, usually most pronounced at high frequencies. Attenuative materials can prevent survey objectives from being met.

(2) While it is possible to enhance signal not visible on raw field data, it is safest to track all coherent events on processed seismic reflection sections from raw field data through all processing steps to CMP stack. Noise can be processed to appear coherent on CMP stacked sections.

(3) Differences in water quality do not appear to change the velocity and density sufficiently that they can be detected by the seismic-reflection method **(13)**.

5.4.3 *Interferences Caused by Natural and by Cultural Conditions:*

5.4.3.1 The seismic-reflection method is sensitive to mechanical and electrical noise from a variety of sources. Biologic, geologic, atmospheric, and cultural factors can all produce noise.

(1) Biologic Sources—Biologic sources of noise include vibrations from animals both on the ground surface and underground in burrows as well as trees, weeds, and grasses shaking from wind. Examples of animals that can cause noise include mice, lizards, cattle, horses, dogs, and birds. Animals, especially livestock, can produce seismic vibrations several orders of magnitude greater than seismic signals at longer offset traces on high-resolution data.

(2) Geologic Sources—Geologic sources of noise include rockslides, earthquakes, scattered energy from fractures, faults or other discontinuities, and moving water (for example, water falls, river rapids, water cascading in wells).

(3) Atmospheric Sources—Atmospheric sources of noise include wind shaking seismic sensors or cables, lightning, rain falling on seismic sensors, snow accumulations melting and falling from trees and roofs, and wind shaking surface structures (for example, buildings, poles, signs).

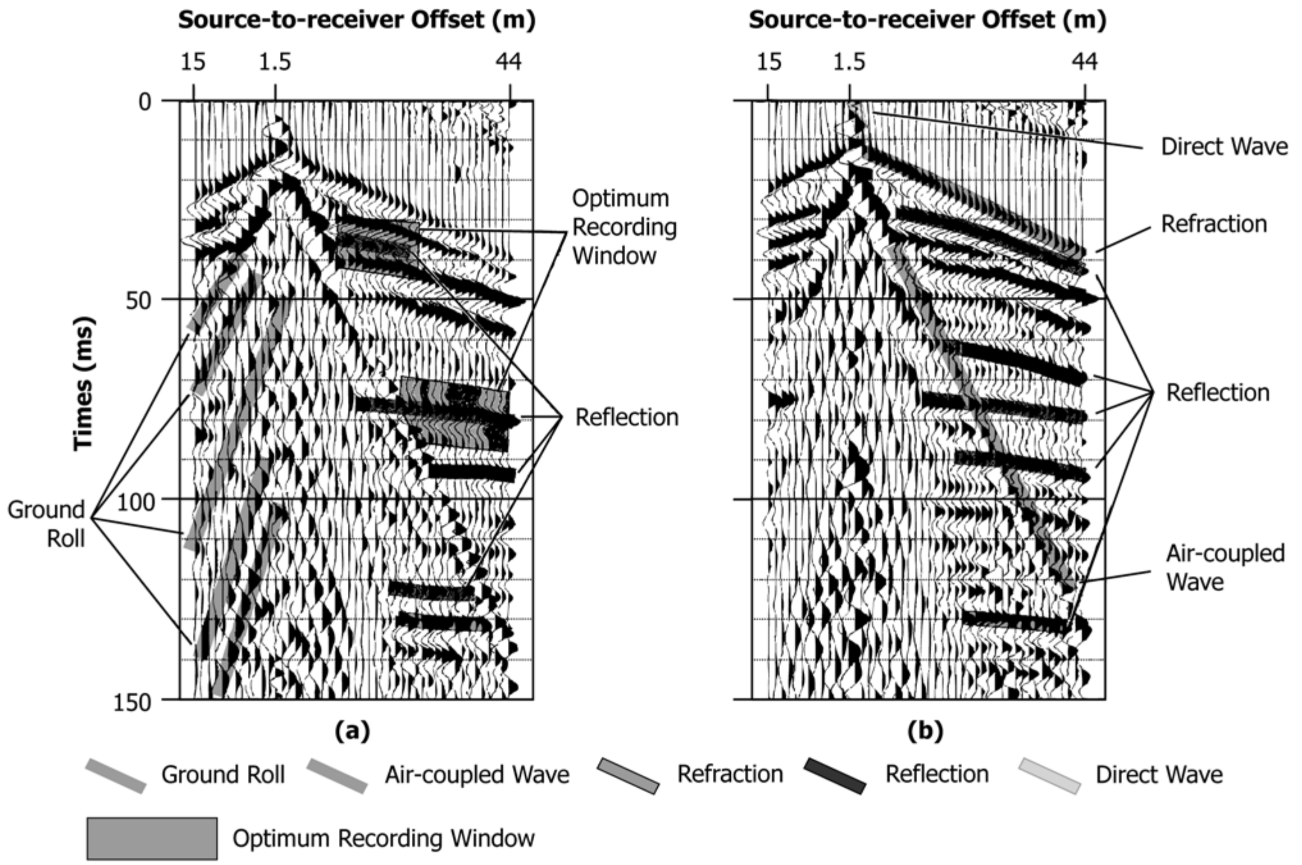
(4) Cultural Sources—Cultural sources of noise include power lines (that is, 50 Hz, 60 Hz, and related harmonics), vehicles (for example, cars, motorcycles, trains, planes, helicopters, ATVs), air conditioners, lawn mowers, small engine-powered tools, construction equipment, and people—both crew members and pedestrians—moving in proximity to the seismic line. Radio Frequency (RF) and other electromagnetic (EM) signals transmitted from radar installations, radio transmitters, or beacons can appear on seismic data at amplitudes several times larger than source-generated seismic signals.

5.4.3.2 During the design and operation of a seismic reflection survey, sources of biologic, geologic, atmospheric, and cultural noise and their proximity to the survey area should be considered, especially the characteristic of the noise and size of the area affected by the noise. The interference of each is not always predictable because of unknowns associated with earth coupling and energy attenuation.

5.4.4 *Interference Caused by Source-Generated Noise:*

5.4.4.1 Seismic sources generate both signal and noise. Signal is any energy that is to be used to interpret subsurface conditions. Noise is any recorded energy that is not used to interpret subsurface conditions or diminishes the interpretability of signal. Ground roll (surface waves), direct waves, refractions, diffractions, air-coupled waves, and reflection multiples are all common types of source-generated noise observed on a seismogram recorded during seismic reflection profiling (Fig. 3).

(1) Ground Roll—Ground roll is a type of surface wave that appears on a reflection seismogram (see Figs. 2 and 3). Ground roll is generated by the source and propagates along the ground surface as a lower velocity, higher amplitude, dispersive wave. Ground roll can dominate near-offset seismic sensors, making separation of reflections at close offsets difficult. Ground roll can be misinterpreted as reflection arrivals, especially if the incorrect offsets or geophone interval are used.



NOTE 1—The reflection arrivals are shown on both records.

FIG. 3 Gained Field Records from Two Different Positions on One Seismic Line

(2) Direct Waves—The seismic energy arriving first in time at the sensors closest to the source is known as the direct wave. Direct waves are body waves that travel directly from the source seismic sensor through the uppermost layer of the earth.

(3) Refractions—Refracted seismic energy travels along a velocity contrast (contact separating two different materials) returning to the surface at an angle related to the velocity above and below the contrast and with a linear phase velocity equal to the seismic velocity of the material below the velocity contrast. Refractions are generally the first (in time) coherent seismic energy to arrive at a sensor, beginning a source-to-sensor offset beyond those where direct wave energy arrives first. For a more detailed discussion of refractions and their use as a geophysical imaging tool, see Guide D5777.

(4) Diffraction—Diffractions are energy scattered from discontinuous subsurface layers (faults, fractures) or points where subsurface layers or objects terminate (lens, channel, boulder). Diffractions are generally considered seismic noise when undertaking a reflection survey.

(5) Air-coupled Waves—Air-coupled waves are sound waves traveling through the air, exciting the ground near the seismic sensor and then recorded by the seismic sensor. Air waves generated by the source arrive on seismograms with a linear velocity (distance from sourcȩ arrival time) of ~330 m/s (velocity of sound in air). Cultural noise generated by aircraft is a form of air-coupled wave. Air-coupled waves can reflect from surface objects and in some cases appear very similar to reflections from layers within the earth on seismograms. Air-coupled waves can alias to produce false trace-to-trace coherency and be misinterpreted as reflections.

(6) Reflection Multiples—Reflection multiples are reflections that reverberate between several layers in the subsurface. Multiple reflections or reverberations between layers are reflections and therefore appear on seismograms with all the characteristics of reflections. Multiples can best be distinguished by their arrival pattern and cyclic nature on seismograms and their lower than expected normal move-out velocity.

5.5 *Alternative Methods*—Limitations discussed above may preclude the use of the seismic-reflection method. Other geophysical (see Guide D6429) or non-geophysical methods may be required to investigate subsurface conditions when signal-to-noise ratio is too low or the resolution potential is insufficient for the survey objectives.

6. Procedure

6.1 This section includes a discussion of personnel qualifications, planning and implementing the seismic reflection survey, processing seismic-reflection data, and interpretation of seismic-reflection data.

6.1.1 *Qualification of Personnel*—The success of a seismic reflection survey, as with most geophysical techniques, is dependent upon many factors. One of the most important factors is the competence and experience of the person(s) responsible for planning, carrying out the survey, processing the data, and interpreting the data. An understanding of the theory, field procedures, data processing steps and parameters, interpretation of seismic-reflection data, potential artifacts and pitfalls of seismic data processing and interpretation, and the site geology is necessary to complete a seismic reflection survey. Personnel not having specialized training and experience should be cautious about using this technique and solicit assistance from qualified practitioners.

6.2 *Planning the Survey*—Successful use of the surface seismic-reflection method depends to a great extent on careful and detailed planning that considers geology, program objectives, and limitations (economic and methodology). The survey should be divided into unique phases or stages to allow the survey to be halted if the objectives cannot be met.

6.2.1 *Objective(s) of the Seismic Reflection Survey:*

6.2.1.1 Planning and design of a seismic reflection survey should consider the objectives of the survey, practical limitations of the technique, cost limitations, and the characteristics of the site. These factors determine the survey design, the equipment used, expertise required, reasonable level of effort, data processing needs, interpretation approach, and budget necessary to achieve the desired results. Important considerations include site geology, site conditions, ambient noise, depth range of investigation, resolution requirements (vertical and horizontal), topography, and site access. It is good practice to obtain as much relevant information as possible about the site (for example, geophysical data from any previous work at or near the site, geologic and geophysical logs in the study area, topographic maps, aerial photos) prior to designing a survey and mobilization to the field.

6.2.1.2 A geologic/hydrologic model of subsurface conditions at the site should be developed early in the design phase using all boring information and other geophysical and geologic data available for the site being investigated and any additional information for adjacent areas as well. This model should include and try to incorporate the thickness and type of soil cover, depth and type of rock, depth to water table, continuity of target layers, contrast between target layers, and a stratigraphic section with all potential horizons, both at the target depths and any potential surrounding (above and below) reflectors, that might be imaged with the seismic-reflection method.

6.2.1.3 A computer model of the seismic response using the geologic/hydrologic model and survey design parameters provides a useful guide to the potential of discriminating target reflections from coherent noise events and therefore options for upgrading or modifying survey objectives (**14**). Studying the approximate and relative locations of model reflections and their apparent curvature within the seismic sensor spread recorded for each shot station provides preliminary feedback on survey designs and their potential effectiveness in meeting the survey objectives.

6.2.1.4 Meeting the objective(s) of the survey, in particular the depth range of interest and resolution requirements, is strongly influenced by the seismograph, source, and seismic sensors selected as well as the relative recording geometry (spread) and relative location of survey lines (with respect to target, surface, or near-surface features), and resolution characteristics of the data. For survey objectives to be met, it is necessary to consider the optimum recording window length and number of seismic sensors within the optimum recording window necessary to maximize the signal-to-noise ratio of the data. The optimum recording window is the range of offsets and recording times where the signal-to-noise ratio for a given reflection is greatest (Fig. 3). When shallow layers are the target of the seismic reflection survey, seismic sensor and shot spacing must be small and line separations short, the source must be low energy and generate a source wavelet with a high usable seismic frequency (**15**). Reflection surveys targeting deep layers will usually have wider shot and seismic sensor station spacing and lines separated by greater distances resulting in reduced horizontal resolution but appropriate to meet the objectives of the survey (**16**). Sources used for deep surveys are typically high energy and possess a lower usable seismic frequency source signature. It is usually difficult to image both deep and shallow reflectors using a single seismic survey configuration. Imaging requirements of the survey must be balanced with cost, equipment limitations, and earth characteristics.

6.2.2 *Assess Feasibility of the Seismic-Reflection Method to Image Target:*

6.2.2.1 To assess the applicability and potential success of a seismic reflection survey, one must first determine whether the targets are sufficiently large and whether large enough reflection coefficients exist for the technique to meet the survey objectives. Several characteristics must be considered: reflection coefficient, resolution requirements, cost, and site characteristics.

6.2.2.2 Valuable insight into the likelihood that program objective(s) can be successfully accomplished and the level of resources is adequate to meet those objectives can be ascertained by studying data from previous seismic reflection and refraction surveys in the area, understanding the geology (particularly the near-surface), and reviewing published case histories containing results and descriptions of previous surveys that successfully imaged similar targets in similar geologic settings.

6.2.2.3 Forward computer modeling using known seismic properties and layer/target geometries can help define appropriate objectives and also can assist during the design of both the testing and production portions of the survey. If possible, a short seismic profile, called a walkaway, with close seismic sensor spacing and a wide range of source-to-seismic sensor offsets is extremely valuable in determining seismic properties of the site and for initial estimations of the resolution and signal-to-noise potential of seismic data. Ideally, several of these walkaway tests should be conducted around the survey area. A borehole with known stratigraphy, combined with downhole velocity measurements, is desirable to constrain both the forward modeling and interpretations of test spread data.

6.2.3 *Selection of the Approach:*

6.2.3.1 Choices related to specific techniques as well as the multitude of acquisition, processing, and interpretation parameters selected during a seismic reflection survey must be guided by data characteristics, confident identification of signal, and experience.

6.2.4 *Seismic-Reflection Methods:*

6.2.4.1 Reflections as displayed on seismograms will normally have a unique pattern (hyperbolic curvature for linear seismic sensor spreads), whose shape is a function of reflector depth and average velocity between the ground surface and reflector. This curved shape allows the reflection to be uniquely identified and separated from other seismic events of the wavefield (Fig. 3). The apex of the hyperbola will be coincident with the source location when the reflector has no dip. Reflections can be present at any offset and any time after the first arrival wavelet has completely dissipated. The first arrival is generally either a direct or refracted wave. Reflections within the optimum offset and time portion of the seismogram possess the highest signal-to-noise ratio and most generally can be uniquely identified as reflections (Fig. 3). Identification of surface waves, air-coupled waves, refractions, direct waves, guided waves, diffractions, and reflections—both primary and multiples—should be possible on shot gathers and common mid-point (CMP) gathers.

6.2.4.2 *Spot Correlation or Single Point*—Reflector depth and geometry can be estimated for a particular geographic location from seismograms generated from several source locations (including source locations on either end of the sensors' positions) and a line of multiple seismic sensor locations appropriate to record coherent reflections within the optimum offset window for a particular target. In the special case of flat-lying subsurface reflectors, information on reflector depth can be estimated from a single seismogram. Reflector depth for each multi-seismic sensor spread can be calculated using normal move-out (NMO) velocity or borehole velocity surveys and two-way travel time from the seismograms. If depth information is required over a larger area, several spot-correlation surveys can be performed. Depth estimates for a particular reflector are typically contoured to represent the topography of the reflector surface. Successful use of the spot-correlation method requires excellent data quality and generally a high amplitude reflection with a consistent geometry. This high amplitude reflection is used for correcting static and other near-surface differences from one shot location to the next.

6.2.4.3 *Optimum Offset or Common Offset*—Single channel data acquired from a single source-sensor pair with a fixed separation at each equally spaced source location is gathered according to surface location and displayed as a continuous gather (**17**). Each single point trace is then displayed sequentially with all other traces from along a survey line according to the location of the mid-point between source and seismic sensor. These common-offset sections, or common-offset gathers, form a 2-D time cross-section consisting of traces with uniform spatial separation and depth displayed as two-way travel time. Traces are single fold and can be considered analogous to a 2-D geologic cross-section. Determining the optimum offset (ideal single offset between source and seismic sensor to record the reflection of primary interest) for the target interval or reflector and associated measurement of velocity requires the acquisition of a multi-seismic sensor seismogram that includes a range of offsets both significantly shorter and longer than the calculated single optimum offset used for production data recording. Because non-reflected seismic energy can generate patterns on the seismogram that look like reflected events, all coherent patterns on single-fold common-offset sections should be identified, interpreted, and ground truth verified (preferably correlated to borehole data). The determinations of velocity and subsequent estimations of depth must be done independently from the common offset data. Corrections for near-surface static irregularities, non-vertical incidence, time-to-depth, and source zero time variations are recommended to best correlate reflections with reflectors. While the optimum offset method is a valid approach when the signal-to-noise ratio is high, advances in equipment and computational power have made the common mid-point technique the more widely accepted and used reflection profiling method (see 6.2.4.4).

6.2.4.4 *Common Mid-Point (CMP) or Common Depth Point (CDP)*—CMP is a signal enhancement technique involving the stacking of traces with different shot and seismic sensor locations but a common reflecting point in the subsurface (Fig. 4). Multi-channel or multi-trace shot gathers (usually >12, normally 24 to 96 for near-surface applications) are recorded at discrete, equally spaced locations across a range of source-to-seismic sensor offset distances. The spacing of seismic within this range of source-to-seismic sensor offsets must be appropriate for the target characteristics and resolution potential of the data. These multi-channel shot gathers sample the entire wavefield with coherent signal and noise arriving at unique times on each trace of the shot gather. The objective of processing these multi-trace gathers is to increase the signal-to-noise ratio and improve the resolution of events in the data. Routine CMP seismic data processing includes: *(1)* NMO corrections to adjust each trace for non-vertical incident raypaths between source and seismic sensor; *(2)* gathering of each trace according to consistent mid-points between source and seismic sensor; *(3)* removal of noise through muting; *(4)* suppression of noise through filtering (frequency and slope/velocity); *(5)* correction for trace-to-trace lateral, near-surface irregularities in material velocity or layer topography (static); *(6)* stacking or summing all traces with a common mid-point between source and seismic sensor after corrections for non-vertical incidence and reduction/suppression of noise; and *(7)* correction for changes in surface elevation. Once all traces with a common mid-point are gathered and stacked into a multifold (fold is the number of traces summed per CMP) reflection section, events that are coherent from trace to trace are correlated with reflections interpreted on shot gathers. Conversion from time to depth, using measured or estimated velocity, results in a cross-section analogous to a 2-D geologic cross-section.

6.2.5 *Survey Design:*

6.2.5.1 *Location of Survey Lines*—Preliminary location of survey lines should take into consideration the survey target, geologic and hydrologic characteristics of the site, topography

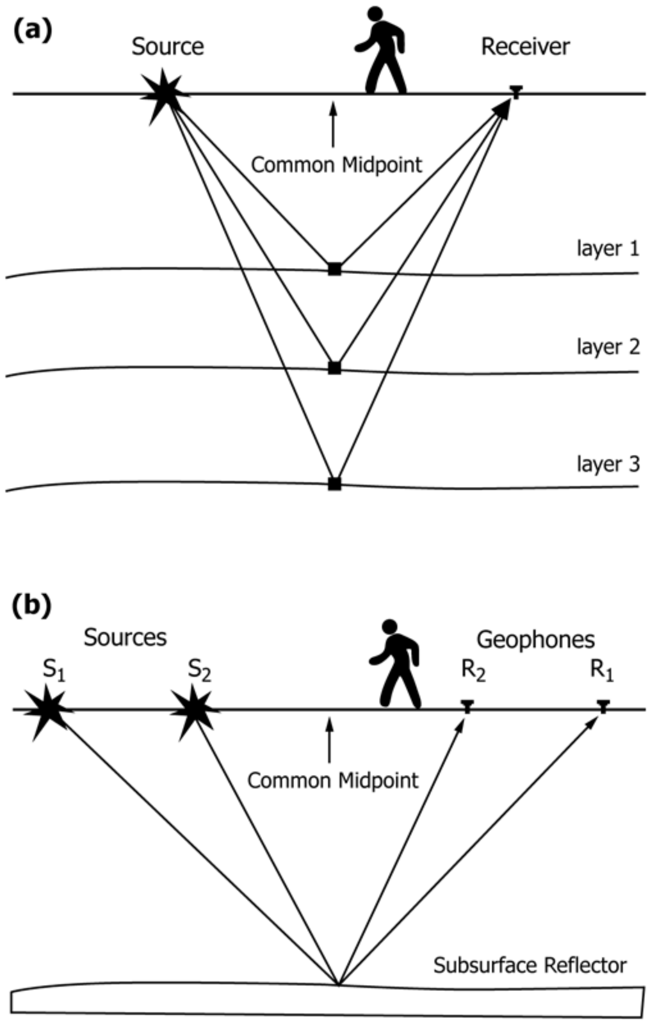


FIG. 4 (a) Common midpoint imaging with rays reflecting from several layers and same midpoint between source and receivers. (b) Common midpoint imaging with two source and receivers with a single reflecting point.

FIG. 4 *(a)* Common Midpoint Imaging with Rays Reflecting from Several Layers and Same Midpoint between Source and Receivers; *(b)* Common Midpoint Imaging with Two Source and Receivers with a Single Reflecting Point

and near-surface conditions, noise sources, cultural features, overall survey objectives, and resolution and subsurface sampling requirements. Location of survey lines is usually done with the aid of topographic maps, aerial photos, previous seismic data, and an on-site visit, if possible. Consideration should be given to the need for data at a given location; the accessibility of the area; the proximity of wells or test holes for control data; the extent and location of surface obstacles (for field operations and air wave echo problems), buried structures, and utilities; sources of cultural noise that will prevent acquisition of useful measurements or introduce noise into the data (see 5.4.3); and adequate space for a consistent and optimum set of source-to-seismic sensor offsets to be acquired that fully traverse the target area.

6.2.5.2 *Source and Seismic Sensor Station Geometry*—The spacing of the seismic source and sensors should be based on the following issues: stacking fold or redundancy, resolution potential, trace-to-trace coherence, number of traces needed within the optimum reflection offset and two-way reflection time range, arrival pattern of all coherent seismic energy, economics, available number of seismograph recording channels, likely geometry and variability of subsurface rock layers, aliasing of coherent noise, and reflection raypaths. In general, seismic sensor spacing should provide for the recording of several (>4) adjacent seismic traces within the optimum window that fully and coherently sample the target reflection wavelet. Over a normal range of possible signal-to-noise ratios, both source and seismic sensor spacing could change by a factor of two or more depending on the geologic setting and associated set of seismic characteristics. In most cases, signal-to-noise is difficult to predetermine; thus, the spacing of the source and seismic sensor station might require adjustments after, and based on, initial field testing.

(1) Source and seismic sensor orientation is important for both compressional and shear wave reflection profiling. Seismic energy generally has a dominant direction of particle motion and is therefore polarized. Sources and seismic sensors should be most sensitive to the dominant direction of particle motion as specified in the survey design. Compressional wave profiling using geophones or accelerometers requires the axis of the magnet/coil to be nearly vertical (<10° from vertical). Explosive sources used for compressional wave surveys require no alignment; however, compressional wave sources that produce directional energy (force can be described with a single vector) should have a dominant vertical force vector. Shear wave seismic sensors should be oriented perpendicular (*SH*) or parallel (*SV*) to the survey line, but in both cases the axis of the coil/magnet sensor should be parallel to the ground surface. Shear wave seismic sensors have a first motion sensitivity that requires consistent deployment relative to one pole of the seismic sensor's magnet. Leveling is often necessary for shear wave geophones. Shear wave sources are directional (polarized) and require consistent alignment between source and seismic sensors relative to first motion. Shear sources can be aligned to generate particle motion perpendicular (*SH*) or parallel (*SV*) to the survey 2-D profile. In addition, first motion relative to the survey line can be left to right or right to left (*SH*) or front to back or back to front (*SV*); however, it is critical that the first motion direction is consistent and documented.

(2) Source orientation relative to geologic structure can be important in optimizing recorded reflections. If possible, it is important to orient the source down dip (dip of the reflection horizon of interest relative to the ground surface) from the seismic sensor spread. Meeting the survey objectives often requires knowledge and consideration of reflector geometry relative to source and seismic sensor geometry. For multichannel acquisition, split spread geometries are generally conducive to dipping reflector environments, whereas for a given number of recording channels, end-on source to seismic

sensor orientations (especially when dip changes along a profile line) provide the best velocity and therefore depth control for relatively flat-lying reflectors.

6.2.5.3 *Spread Geometry*—For reflection profiling, source-to-seismic sensor offset is one of the most critical field parameters. For common-offset shooting, only one offset distance is recorded. Therefore, there is no room for error, and all interpreted events must be correlated to a multi-channel seismogram for event identification and confirmation. For CMP or spot correlation style recording, the seismic sensor spread geometry must include a range of offsets ideal for the targets of interest. In general, the maximum offset should be approximately equal to the maximum depth of interest, while the closest offset should be no more than one-fourth the minimum depth of interest to avoid phase and amplitude distortion from inclusion of wide angle reflections in the CMP stack. Optimum resolution (highest frequency) can be obtained by recording traces as near vertically incident (source and seismic sensor at same location) as possible, thereby avoiding wide-angle distortion and wavelet stretch during correction for non vertical incidence. Care must be taken to avoid data deterioration by including near-source effects and interference with surface waves and air-coupled waves.

6.2.5.4 *Line Spacing and Orientation and Subsurface Coverage*—Since the 2-D seismic-reflection method described here assumes that all reflection energy recorded along a profile line is returning from the slice of earth directly beneath the profile line, obtaining a realistic 3-D image of the subsurface will generally require at least two lines. Survey coverage and orientation of reflection profiles should be designed to be consistent with the survey objectives. The total area surveyed should be significantly larger than the area of interest. It is important to sample areas outside the primary target area so as to obtain an understanding of local "background" conditions in relation to the target area and to provide some separation between the survey target and potential edge effects. If migration (correction for raypath distortion) is necessary, the size of the fully sampled subsurface must be increased beyond the target area to allow for the migration aperture. For CMP data specifically, this enlarged subsurface sampled area ensures that the area of interest will have full-fold coverage and offset distribution sufficient for complete migration of the target area. Line orientation can be critical and should be carefully considered with respect to geologic features of interest, such as buried channels, faults, or fractures. For example, when mapping a buried channel, the reflection survey lines should cross over the channel so that its boundaries can be determined and so that the reflection profiles are as near orthogonal to the axis of the channel as possible.

6.2.5.5 *Subsurface Coverage*—Due to the CMP geometry of multiple equally spaced seismic sensors and source locations moving uniformly down the survey line, the subsurface sampling interval for most survey designs will be one-half the seismic sensor spacing.

6.2.5.6 *Equipment Requirements*—Recording equipment should be selected based primarily on project objectives, with cost and on-hand availability considered secondary. State-of-the-practice equipment should be considered an important criterion for maximizing the potential of successfully meeting the objectives of a reflection survey. This equipment would include seismographs capable of recording the seismic wavefield, with dynamic ranges greater than 100 dB and sampling rates well above the Nyquist frequency.

(1) Spread Cables and Seismic Sensors—Spread cables should have sufficient seismic sensor connecting points (take-outs) to allow a reasonable range of seismic sensor spacings necessary to meet the objectives of the survey. Final selection of seismic sensor station spacing should come from in-field walkaway testing (see 6.3.1.2). Excessive cable between take-outs increases the signal loss, makes the cable more susceptible to transmitting wind noise, and results in noticeable increases in impedance with distance from the seismograph. Cable heads or connectors need to mate fully and lock tightly. Cable to earth leakage, cable cross talk, and poor connections can result in increased noise levels and should be avoided. Geophones are the most commonly used type of seismic sensor (see 5.3.2). Geophones measure velocity and are classified according to natural frequency and coil impedance. The natural frequency of geophones used on a seismic reflection survey should be appropriate for the source energy, attenuation characteristics of the site, resolution requirements of the survey, and dynamic range of the seismograph. Accelerometers are also used for seismic sensors and provide a measure of particle acceleration. Accelerometers require amplification of the signal at the seismic sensor. This amplification increases the signal amplitude before it is transmitted down the seismic cable and can also increase the noise threshold. With modern seismographs (and for most near-surface targets), rarely is there a need for seismic sensors with natural frequencies that exceed 50 Hz. With the higher frequency nature of reflected energy and the limited penetration depths of near-surface applications discussed here, geophones with a natural frequency less than 10 Hz are rarely used for compressional wave surveys (or less than 8 Hz for shear wave surveys). It should be recognized that the high frequency (>100 Hz) of low frequency phones (<20 Hz) may not be linear. A single seismic sensor configuration is commonly used; however, some advantage can be gained by adding more seismic sensors (in series or parallel) at each station (**15**). Seismic sensors are generally coupled to the ground with spikes, and, historically, spikes have provided optimum coupling. In some situations where penetration of the ground is not possible, gravity coupling using plates instead of spikes might produce an acceptable signal-to-noise ratio. Gravity coupling of seismic sensors in a towed spread can be a reasonable compromise to spike-coupled seismic sensor geophones in some near-surface settings. Comparisons of seismic sensor coupling styles should be part of the pre-survey testing to verify that gravity coupling is an acceptable substitute for traditional spike coupling. Standard geophone spikes are typically about 7 cm in length; however, for some applications, an advantage can be gained by increasing the length of the seismic sensor spikes to as much as 14 cm.

(2) Sources—It is always good to have at least two uniquely different types of sources available for testing at any new site. These sources should deliver energy to the ground in distinctly different fashions and have the ability to vary the

amount of energy. For example, if attempting to image a 30-m-deep target in an alluvial valley with a 10-m-deep water table, it would be reasonable to test a small downhole explosive (that is, downhole shotgun with 8 or 12 gauge loads) and an impact source (that is, 7 or 9 kg hammer and striker plate). Sources available for testing should be selected based on environmental limitations, resolution requirements, amount of seismic energy, adaptability to setting, economics, permitting, previous experience, and signal strength relative to noise.

(3) Seismograph—The more seismograph channels available, the greater the potential flexibility in optimizing the recording spread and, in some situations, the wider the depth range of targets imageable with a single survey. The number of traces available should be sufficient to allow each reflection event of interest to be recorded on several (>4) traces or channels within the optimum window. For most near-surface applications, this level of sampling will require seismographs having at least 24 channels, but more likely 48 to 96, and in some cases as many as 240 channels.

(a) Typically the optimum set of seismic sensors for a target reflector or subsurface interval is a subset of the total number of seismic sensors deployed at one time on the ground. This subset of seismic sensors can be selected either mechanically by a roll-along switch (when there are more sensors than recording channels) or electronically (when each sensor is connected to a dedicated recording channel). This optimum range of seismic sensors (relative to the source location) is advanced along the survey line as the source advances.

(b) Increasing the number of active recording channels can substitute for a roll switch (mechanical or digital) in recording sufficient and appropriate traces necessary to minimally sample the target reflections. A fixed-spread geometry (stationary spread requires no roll-along switch) generally requires up to twice as many recording channels to maintain sufficient and appropriate offset seismic sensors as the source moves down the survey line.

(c) Operation of seismic equipment for near-surface investigations should rely on a low noise power source, if possible (for example, battery power). Data should be recorded digitally on a reliable medium, robust enough to handle the rigors of the field environment. It is good practice to routinely test seismograph performance to ensure operation is within manufacturer's specifications. Data should be transferred to a reliable, long-term, non-volatile digital medium as soon as possible after recording with the seismograph.

(4) Supporting Equipment—Recording seismic-reflection data may require use of a roll box (switch). A roll box allows different groups of seismic sensors to be selected such that all recording channels of the seismograph maintain the optimum geometry with respect to the source. Test equipment (for example, cable and takeout shorting plugs, seismograph test oscillator, seismic noise monitor, seismic sensor impedance monitor, cable to earth leakage meter) can be key in troubleshooting equipment to optimize data quality and active recording channels. Any component located between the seismic sensors and seismograph's A/D converters represents a potential source of electronic noise. Minimizing the use of jumper cables, roll box, adapters, or any other connecting point reduces background noise.

6.2.6 *Data Formats*—Digital data formats can be divided into two major categories: acquisition and processing. Acquisition formats are well documented and conform to rigid guidelines (most published and endorsed by the Society of Exploration Geophysicists—SEG). Data processing formats vary significantly between the many software developers. Common terminology for many processing formats is "modified SEG-Y," which indicates the general header formats are consistent with the published SEG-Y format (**18**), but some liberty has been taken with respect to specific header locations and floating point designations.

6.2.6.1 *Data Acquisition Format*—Digital data formats for seismic-reflection data are generally an SEG format. Engineering seismographs have begun using SEG-2 format as described by Pullan et al. (**19**). SEG2 is the first string-oriented format with no fixed length. Seismic formats routinely used for storing raw seismic data include SEG-2, SEG-Y, SEG-D, and SEG-B. With the exception of SEG2, these formats are fixed length headers. SEG-B is a multiplexed format. Other formats are occasionally used but only rarely. Reference to all recognized formats can be found in the Society of Exploration Geophysics publications.

6.2.6.2 *Data Processing Format*—Digital formats used for processing seismic-reflection data are generally characterized by fixed length headers and traces and therefore lend themselves to the use of magnetic tape storage media. Most processing software uses SEG-Y format for data, but very few processing formats are strictly the SEG-Y format published by Barry et al. (**18**). Instead most are some modification of SEG-Y that the software programmer has devised to make data handling easier during data processing. Transfer of data from one processing company to another or from one software package to another has routinely been done in the recognized SEG-Y format.

6.3 *Implementation of Survey:*

6.3.1 *On-site Check of Survey Plan:*

6.3.1.1 A systematic visual inspection of the site should be made upon arrival to determine if the initial survey plan is feasible. Modifications to the survey plan may be required to maximize the potential for successfully meeting the objectives of the reflection program.

6.3.1.2 A feasibility test should be the first operation to be undertaken once the survey plan has been appropriately modified based on the site inspection. These tests, termed "walkaway" tests, allow seismic sensor spacing, source offsets, source types, seismic sensor types, record length, sampling interval, and seismograph parameters to be compared with the planned configuration and the optimum set of recording parameters selected. Walkaway tests also provide the first look at the reflection potential of the site. This includes analysis of resolution potential, signal-to-noise ratio, and the feasibility that the targets of interest can be effectively imaged. Results from these experiments not only highlight needed changes to the planned survey design, but they also represent one of the first opportunities to evaluate the effectiveness of the technique and therefore the likelihood for success. The walkaway tests should provide sufficient information to determine if continuing to the production portion of the reflection program is warranted.

(1) Walkaway testing should include: *(1)* traces recorded with source-to-seismic sensor offsets at least 1½ times the maximum depth of interest, *(2)* seismic sensor spacing that allows at least ten traces within the optimum window for the shallowest reflection of interest (normally, seismic sensor spacing for walkaways should be about half what modeling and experience suggests is optimum for site and target), *(3)* comparisons of individual versus vertically stacked shot gathers, *(4)* comparison of dominant reflection frequencies of sources tested, *(5)* comparison of signal-to-noise with different sources and signal stacking, *(6)* evaluation of environmental impact of sources, *(7)* hyperbolic curve fitting to estimate normal moveout (NMO) velocity and the feasibility that interpretable coherent events are reflections, *(8)* estimation of imageable depth range, *(9)* estimates of resolution potential (vertical and horizontal), *(10)* selection of sampling interval based on highest usable frequency and record length to ensure deepest reflections of interest are recorded, *(11)* selection of source-seismic sensor geometry appropriate for apparent reflection arrival patterns (that is, split-spread or end-on, seismic sensor spacing, source interval), and *(12)* evaluation of time break accuracy and performance of various sources and source configurations. Some digital processing of the walkaway data might be necessary to fully appraise the characteristics of the data. This can be done onsite or locally and should include: frequency filtering, amplitude scaling (automatic gain control or AGC), NMO curve fitting, increasing the number of apparent channels of the recording system to improve apparent event coherency by gathering traces from several source offset into source-seismic sensor offset sequential order, and correlation of calculated velocities to borehole measured average velocities.

(2) Verify station-to-station consistency in source performance and apparent reflection characteristics by recording at least two shot gathers from two different source locations/offsets for each source type tested. This allows comparison of wavefield changes and consistencies in reflected energy. A lack of consistency in event curvature, wavelet characteristics, coherent noise, or reflection amplitude with offset effects could indicate spatial aliasing or misidentification of reflection.

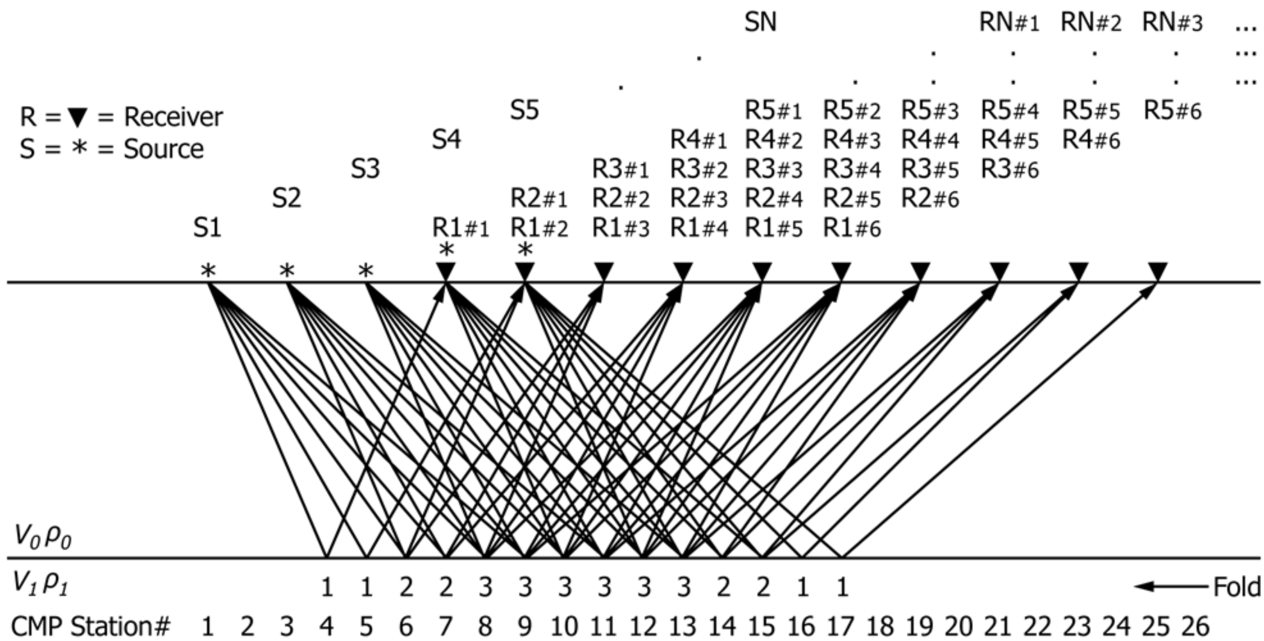
6.3.2 *Lay Out the Survey Lines*—Locate the best position for the seismic lines based on the survey design (see 6.2.4) and the on-site visit (see 6.3.1). Care should be taken to ensure that line placement balances survey objectives with optimum seismic recording environment. If possible, lines should tie (cross in high fold portion of the lines or at least a spread length away from the end of lines) with each other and with any borehole (ground truth) available on-site. Survey lines should be laid out to maximize any overlap with other geophysical or geologic data.

6.3.3 *Conducting the Survey:*

6.3.3.1 Spot correlation or single point profiling requires the deployment of a single seismic spread and as many source locations for that spread as necessary to record the appropriate range of offsets for a given seismic sensor spacing and number of recording channels. It is critical to fully capture the target reflections within the optimum window as defined by the spread geometry. Once the depth to the reflectors of interest has been estimated from velocity and two-way reflection time, the spread is re-deployed at a new location within a grid designed to sample the reflector at the desired spatial interval. This method is not routinely employed for near-surface applications due to the high likelihood of spatial undersampling. The spot-correlation technique also requires unusually high data quality with several, consistent reflections to be correlated across a relatively large area. Procedures described for conducting a CMP survey (see 6.3.3.3) are generally applicable to spot correlation profiling.

6.3.3.2 Common offset or optimum offset profiling is a continuous profiling technique that uses a series of single seismic sensor-source pairs separated by some predetermined optimum distance to best image a given target. Data are recorded at each equally separated source-seismic sensor pair along the profile line at increments appropriate for data resolution and event continuity. Retaining a consistent separation between source and seismic sensor (constant reflecting angle between all source-seismic sensor pairs) is critical for constructing a reflection cross-section. Coherent events identified on common offset cross-sections should correlate to reflections on multi-trace shot gathers. Independent determination of velocity is necessary to convert the common offset time section to a depth section. To be successful, the offset profiling technique requires excellent data quality and frequent acquisition of multi-channel seismograms to be used for quality control (QC) (correlating reflection events on single fold cross-sections with multi-channel seismograms ensures that interpreted coherent events are reflections and not coherent noise). Details of acquisition, data processing, and interpretation of the common offset method are not included here because this method has been for the most part replaced by the CMP technique.

6.3.3.3 Common mid-point (CMP) reflection profiling is a continuous profiling technique using multiple seismic sensors to record seismic data generated by each source along a profile line (Fig. 5). Sources and seismic sensors are generally equally spaced appropriately for the target. Seismic sensors should be separated from each other so that the spatial subsurface sampling interval is appropriate for the survey objectives. Source spacing should normally be a whole number increment of the seismic sensor spacing and is the basis for calculating CMP-stacked data fold or redundancy. Source spacing should be selected so that signal-to-noise ratio and lateral resolution requirements of the survey are met. Each source location should be separated from the selected set or spread of seismic sensors so that the optimum range of source-to-seismic sensor offsets is recorded. Each progressive move of the source station along the line should be accompanied by a seismic sensor spread move of equal distance so that the source and seismic-sensor geometry remains fixed. These incremental source-location advancements along the profile line should produce a seismogram for each source location. The seismogram has data collected from a spread of seismic sensors whose offsets have



NOTE 1—All of seismic sensor spread one (R1) records shot number one (S1), seismic sensor spread two (R2) records shot number two (S2), and so on. Fold indicates the number of unique shot-seismic sensor pairs that image or sample that point. CMP station #8, for example, is the common midpoint for three shot-seismic sensor pairs (S1-R1#5, S2-R2#3, and S3-R3#1) and, once processed, will have a single trace that has contributions from those three traces and 3-fold redundancy, or 300 percent coverage. Seismic reflection surveys commonly include seismographs with 24 and more channels and therefore folds in excess of 12, however only a 6-channel system and 3-fold sampling is shown here for display simplicity.

FIG. 5 Reflection Raypaths between Source and Seismic Sensor and Progression of Source and Seismic Sensors along a Standard 2-D CMP Seismic Reflection Profile

been optimized for site conditions and survey objectives determined from walkaway testing. By rolling the spread and source along the profile line, each subsurface sample point (usually separated by one-half the surface seismic sensor spacing) should be imaged multiple times by different source-seismic sensor pairs. The number of times a particular subsurface point is sampled (fold) is a function of seismic sensor spacing, source spacing, and number of seismic sensors. This redundancy in subsurface sampling is key to the signal enhancement potential of the CMP technique. CMP stacked sections are analogous to cross-sections of the earth (that is, road cut, outcrop, trench) with trace-to-trace coherent wave forms representing layers in the earth. CMP time sections should be converted to depth using an appropriate measured (for example, borehole, NMO) average velocity function for the site. Since a stacked reflection wavelet has a variety of attributes that can be related to earth material properties, a wealth of information besides just layer structure can be extracted from CMP-stacked sections when the signal-to-noise is high.

(1) Acquisition—CMP data require a seismograph with multiple recording channels. Critical to all reflection surveying is the incremental progression of source and optimum seismic sensor offset(s) along the target transect or profile to be imaged. The process of incrementally moving the shot and seismic sensor spread along the profile in a fixed configuration as described in 6.3.3.3 is referred to as rolling along. When using the CMP method, this progression of the source and seismic sensor spread along the survey line usually involves physical movement of the source from station to station and the manual, mechanical, electronic, or digital movement of the seismic sensor spread. Manually moving the geophone spread can be done by hand in such a way as to maintain a constant source to spread offset but this approach may not be the most efficient. Mechanical or electronic movement of the seismic sensor spread is usually accomplished by incorporating CMP or spread cables and an electronic or mechanical roll along switch. For mechanical rolling, a multi-contact roll along switch is utilized. The number of contacts on seismograph side of the switch is equal to number of seismograph recording channels while number of contacts on the cable/seismic sensor side is equal to total transmission lines in the cable. The ratio of contacts on the seismograph side to contacts on the cable/seismic sensor side should be equal to or greater than 1:2. CMP or spread cables (cables with at least as many transmission lines in each cable as channels in the seismograph) are used to select a specific set of seismic sensors that are passed to the seismograph and recorded. When rolling along electronically, information from all seismic sensors connected to the spread cables is passed to the seismograph where software selects only the recording channels within the optimum offset range to be digitally saved in the seismograph. Electronic rolling of the spread requires a seismograph with a significantly larger number of recording channels (greater than 50 %) than necessary to accomplish the objectives of the survey, connected to a group of seismic sensors that span a distance significantly longer than the optimum offset range. All seismic sensors connected to the seismograph outside the optimum spread range are then eliminated, either by the seismograph or during subsequent digital data processing.

(a) Production data should undergo continuous QC (6.3.6). If the seismograph used does not have a real-time screen display, then hard copy should be routinely generated during acquisition. Display parameters should be set to optimize viewing of reflections interpreted during walkaway analysis. Parameter design for the production portion of the survey should be based on: *(1)* modeling and test data, *(2)* balancing the need for high spatial sampling and subsurface redundancy with survey economics, *(3)* maximizing the number of traces within the "optimum window" of all target reflections, *(4)* considerations for expected dip, *(5)* environmental limitations or interferences, *(6)* optimizing fold and offset distributions, and *(7)* concerns for uniformity in source and seismic sensor coupling. As many seismic sensors as possible should be responding to seismic energy through good ground coupling and without ground leakage. Optimally 100 % of recording traces are live, but realistically 85 % should be responding cleanly to seismic energy. Geometries and recording parameters should take into account survey economics, data quality, signal-to-noise ratio, and resolution. Care should be taken to avoid underground facilities, utilities, and overhead electrical power lines. General guidelines for acquisition parameters include the following: *(1)* active (that is, recorded) spread length should be approximately equal to the maximum depth of interest; *(2)* source offset to the nearest seismic sensor of optimum spread should be chosen so as to avoid overdriving the nearest seismic sensors but allow incidence reflections to be recorded as near vertical as possible; *(3)* care should be taken not to include too many wide-angle events within the optimum spread; *(4)* vertical stacking should be used with care (1 good shot is better than 10 bad ones); *(5)* "bad shots" for whatever reason—cultural noise, source coupling, time zero break, or source location—should be re-acquired (every good data trace and shot gather is important); *(6)* reflections coherent across multiple traces possessing similar characteristics should be interpretable on approximately 20 % of all raw or minimal in-field processed (spectral filtered and scaled) shot gathers recorded along the survey profile; *(7)* advanced processing should not be necessary to see consistent reflections on shot gathers (processing is to enhance, not produce); *(8)* consistency in acquisition procedures is critical (especially for CMP data processing and interpretation of stratigraphic features) and changes should be noted (elevation, ground condition or covering, and equipment—even slight variations in these can resemble geologic changes, especially structural); *(9)* observers' notes should be complete and contain more information about crew activities, data characteristics, noise sources, and landmarks than seems necessary at the time; and *(10)* data should be digitally saved on a medium separate from the seismograph every day.

(2) Data Processing—Data processing should enhance coherent reflection events, not produce artificial reflections. CMP data processing flows should be reasonably consistent from one high-resolution seismic reflection processor or processing company to another. The difference will be in the detail—both attention to detail and the specific parameter selections. Many times "special" or "designer" processes or proprietary processing techniques or parameters unique to individual data processors or processing companies will be used to optimize a data set. However, regardless of the processes or parameters used to enhance seismic-reflection data, coherent events enhanced throughout processing and presented as reflections on the final stacked sections should correlate to reflections interpreted on shot or CMP gathers. It is important to distinguish signal enhancement from processing artifacts.

(a) CMP data require digital processing. Basic or "brute" processing should include assignment of source and seismic sensor geometries to each trace, adjustment for elevation, removal or suppression of coherent and random noise, correction for non-vertical incidence (using reflection velocity estimations of normal move out—NMO), spectral (frequency and phase relative to amplitude) analysis and filtering or shaping, sorting into CMP gathers, scaling of amplitudes (for example, automatic gain control—AGC normalize), and CMP stacking. Depending on the data, enhancements to the quality of the final CMP stacked section can come with more "advanced" processing, which includes additional statics routines (for example, refraction, surface consistent, residual), filtering of various types (for example, frequency, fk, τp), true amplitude adjustments (for example, spherical divergence correction), migration, velocity analysis (for example, semblance, constant velocity panels, curve fitting to gathers), or other more sophisticated processing routines. The need for migration should be determined by site characteristics and the data, being ever mindful that migration is not as critical for shallow, lower velocity data as deeper, conventional data sets and often reduces resolution. Care should be taken in assignment of all parameters, but for high resolution near-surface data, it is critical that special care be taken in using and selecting parameters for some operations to avoid processing artifacts on CMP stacked sections. This special care includes maximum allowable static correction during automatic routines, fan size for fk filtering, first arrival muting, coherency processing, any kind of mixing process, and taper length of mutes, to name a few. Reflections that can be interpreted on shot or CMP gathers prior to "advanced" processing techniques should be present, with generally the same characteristics, after application of the techniques.

(b) The specific processing flow and parameters and emphasis placed on each operation should vary to some degree with the characteristics of each individual data set. In general, the techniques used to process CMP data should generally follow a consistent flow (Fig. 6). CMP data processing of seismic-reflection data should focus on increasing the signal-to-noise ratio and resolution potential of CMP stacked sections. Pre-stack processing should attempt to tune the spectral properties, remove or at least reduce contributions from noise, adjust all time arrival reflection wavelets for source-to-receiver offset to emulate vertical incidence, compensate for statics (due to variations in near-surface topography and velocity), and minimize artifacts associated with source offset, residual noise, and pre-stack processes. Post-stack processing should be designed to enhance coherent reflection events and their unique properties or attributes while retaining the tie with equivalent coherent reflection events interpreted on pre-stack gathers. There is no standardized processing flow. Each processing flow

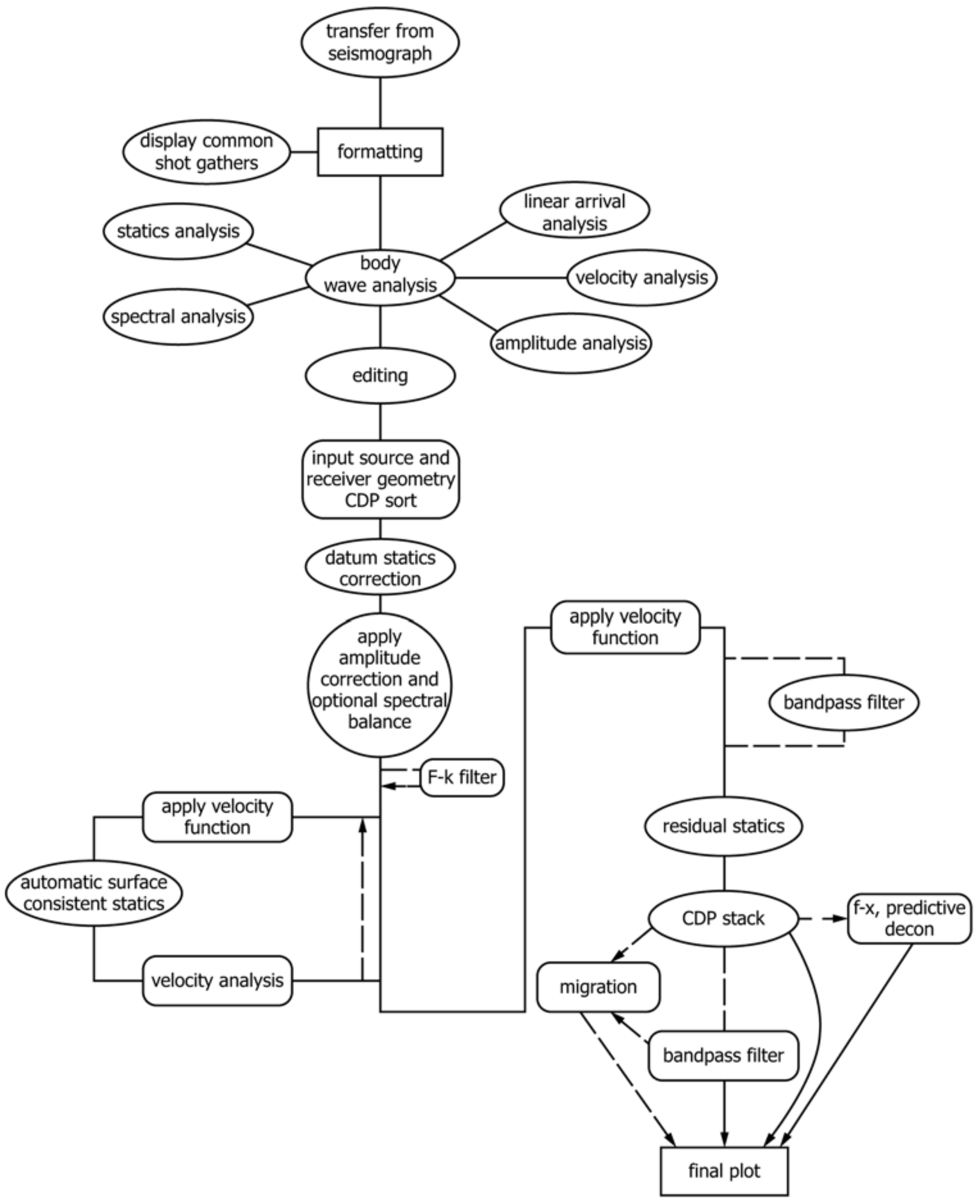


FIG. 6 A Flow-Chart Showing One Possible Generic Sequence for Processing CMP Data

should be customized to the data from a given area. The sequence and types of basic processing operations performed on CMP reflection data should be relatively consistent throughout the data set.

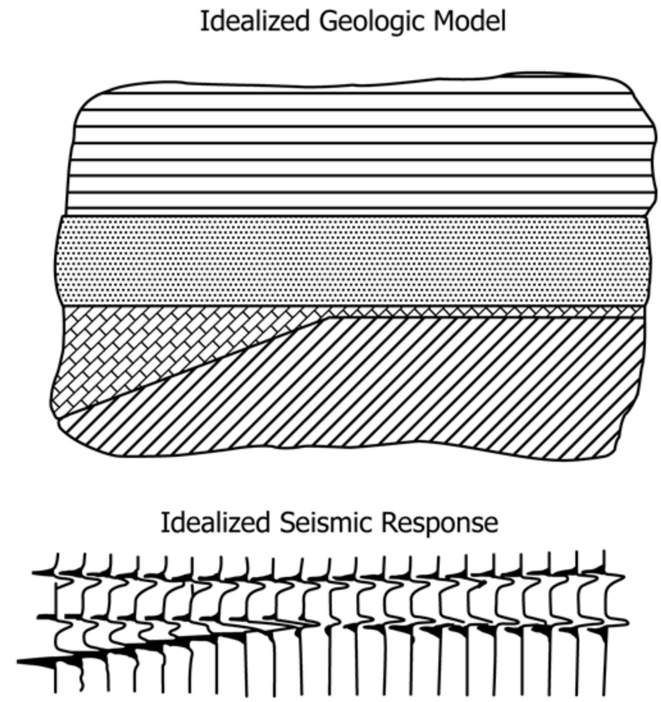
(3) Preliminary Interpretation—Preliminary interpretation of field data should be labeled as draft or preliminary and treated with caution because, in some cases, data having only gone through preliminary analysis and processing can yield erroneous initial interpretations. Field analysis and brute processing should be done primarily as a QC measure and should accomplish the following primary objectives: a preliminary evaluation of data quality and characteristics, in-field determination of data quality and its potential to meet the objectives of the survey, a very preliminary interpretation of geology, and to assist in determining the appropriate final processing flow.

(4) Interpretation—Interpretation of seismic data should be appropriate for the resolution, signal-to-noise ratio, and processing flow of the seismic cross-sections. Techniques to interpret seismic data can be digital or analog. A variety of software is available for interpretations based on seismic attributes or simply reflection wavelet correlations from trace to trace. Attributes most routinely used to interpret subsurface characteristics include frequency, amplitude, phase, and coherency. Analog techniques are the most commonly used methods of interpreting near-surface seismic-reflection data. Interpreting shot gathers, common offset sections, CMP gathers, or CMP stacked sections should incorporate ground truth (borehole data in particular), all geologic (local and regional) and geophysical (seismic as well as other methods) data and

associated interpretations, as well as other pertinent information about the area or site investigated. Interpretations should consider wavelet characteristics and consistency, resolution potential, processing parameters, acquisition parameters, geometry of coherent events, viability of apparent vertical variability in interpreted structure and stratigraphy, and, most of all, reflections interpreted on shot or CMP gathers. Wavelet analysis should consider the source wavelet and the effects of various processing operations on the final reflection wavelet. No geophysical data allow for unique interpretations. Interpretations should therefore always incorporate as much supplemental information as possible, such as drilling logs, other geophysical surveys, regional and local geologic setting, and any borehole analysis in the area.

(a) If possible, it is good practice to correlate borehole data (if available, especially if an uphole/downhole survey has been conducted) with reflections that have been tracked from the shot gather, through CMP data processing, and onto the CMP stacked sections to establish a link between the time-seismic sections and subsurface conditions. This correlation provides confidence and some measure of the accuracy and resolution of the CMP data as it relates to a geologic cross-section. An important operation to confirm the velocity function and to assist with geologic mapping using the seismic data is the conversion of the CMP-stacked section from two-way travel time to depth. An accurate velocity function (used to correct for non-vertical incident seismic raypaths) should provide a meaningful depth section for structural interpretations. If the velocity function is not representative of the true seismic properties, a time to depth conversion will create reflection geometries inconsistent with true geologic structure.

(b) Reflection wavelets have a shape indicative of the source used, material properties of the earth, each processing step, and display parameters. Considerations must be made for interference between reflection wavelets returning from reflectors separated by less than the wavelength of the dominant frequency (wavelength = velocity / dominant frequency; $\lambda = V/f$) (Fig. 7). Depending on the dominant frequency of the seismic signal and the velocity of the subsurface materials, the wavelength of reflection signals can vary from meters to tens of meters in length (Table 5). Interpretation of seismic reflection sections requires an assessment of the signal wavelength and an understanding of the constraints this places on vertical resolution (see 8.4.2). Seismic traces are displayed in two-way travel times and should be converted to depth before correlating reflections to reflectors corresponding geologic interfaces or hydrologic features. Velocity information from borehole surveys or from reflection curve analysis should allow conversion from two-way travel time to depth. Correlation of reflection wavelets to geologic interfaces requires consideration of resolution potential of the stacked data, CMP data processing parameters, and signal-to-noise ratio. Due to the potentially complex nature of stacked reflection waveforms, when reflectors are separated by less than a wavelength (but more than one-quarter wavelength), caution should be exercised not to over interpret CMP stacked sections (Fig. 8). Common seismic attributes (for example, phase, amplitude, frequency, coherency, velocity) of stacked data can be used to deduce physical properties of rocks. CMP stacked sections are analogous to road cuts, outcrops, or trenches, but on the scale of tens to hundreds of meters rather than the meter scale generally observed at these features.



NOTE 1—Vertical resolution is one-quarter wavelength. Many times, practical limits of one-half wavelength are more appropriate for near-surface reflection data, which inherently have a lower signal-to-noise ratio than more conventional surveys.

FIG. 7 Resolution Potential of Seismic-Reflection Data

(c) The level of effort involved in the interpretation of CMP seismic reflection sections will depend upon the objectives of the survey, the desired detail of the interpretation, the quantity and quality of supporting and complementary information from the site, and how much information is really present in the seismic data. The appropriate method and focus of the interpretation should be consistent with how the results are to be incorporated into other studies and findings and with the acquisition and processing history of the seismic reflection sections.

6.3.4 *Verification of Seismic Reflection Interpretation*—Interpretations of seismic reflections should be verified by comparison with existing drill data or other subsurface information or new drill information that has been acquired based on the seismic interpretations and time-to-depth conversions using measured seismic velocity. If currently available subsurface data are not sufficient to verify the interpretations or if no data are available at all, this fact should be mentioned in the report. Interpretations made without the aid of ground truth rely on wavelet characteristics, relative geometries of reflections, knowledge of the processing flow, and experience in similar geologic settings to make the necessary identifications, correlations, and judgments. Verification relies on ground truth necessitating time to depth ties. Borehole correlations with reflections based on logs, cores, or cuttings alone provide only limited confirmation of interpretations. In

TABLE 3 Lateral Resolution[A] Limits for z = 10 m

Material Type	Representative *P*-Wave Velocity (m/s)	Dominant Frequency (Hz or 1/s)	Radius Fresnel Zone (m)
Dry Sand	500	50	7.1
		100	5.0
		200	3.5
		300	2.9
	1000	50	10.0
		100	7.1
		200	5.0
		300	4.1
Wet Sand/Dry Clay	1500	50	12.2
		100	8.7
		250	5.5
		500	3.9
Tight, Wet Clay/Shale	2000	50	14.1
		100	10.0
		250	6.3
		500	4.5
Shale	2500	50	15.8
		100	11.2
		250	7.1
		500	5.0
Shale/Sandstone	3000	50	17.3
		100	12.2
		250	7.7
		500	5.5
Sandstone/Limestone	3500	50	18.8
		100	13.2
		250	8.4
		500	5.9
Limestone	4000	50	20.0
		100	14.1
		250	8.9
		500	6.3
Granite	6000	50	24.5
		100	17.3
		250	11.0
		500	7.7

[A] Lateral resolution is a measure of horizontal (map view) size necessary to distinguish object or layer uniqueness or separation.

TABLE 4 Lateral Resolution[A] Limits for z = 50 m

Material Type	Representative *P*-Wave Velocity (m/s)	Dominant Frequency (Hz or 1/s)	Radius Fresnel Zone (m)
Dry Sand	500	50	15.8
		100	11.2
		200	7.9
		300	6.5
	1000	50	22.4
		100	15.8
		200	11.2
		300	9.1
Wet Sand/Dry Clay	1500	50	27.4
		100	19.4
		250	12.2
		500	8.7
Tight, Wet Clay/Shale	2000	50	31.6
		100	22.4
		250	14.1
		500	10.0
Shale	2500	50	35.4
		100	25.0
		250	15.8
		500	11.2
Shale/Sandstone	3000	50	38.7
		100	27.4
		250	17.3
		500	12.2
Sandstone/Limestone	3500	50	41.8
		100	29.6
		250	18.7
		500	13.2
Limestone	4000	50	44.7
		100	31.6
		250	20.0
		500	14.1
Granite	6000	50	54.8
		100	38.7
		250	24.5
		500	17.3

[A] Lateral resolution is a measure of horizontal (map view) size necessary to distinguish object or layer uniqueness or separation.

some cases, average velocity functions based on NMO curve fitting can be used to approximate time to depth conversions that are reasonable for the objectives and desired accuracy of the survey. Verification should include a seismic check shot survey (uphole/downhole), and boreholes designed to encounter areas identified on seismic data as unique or anomalous.

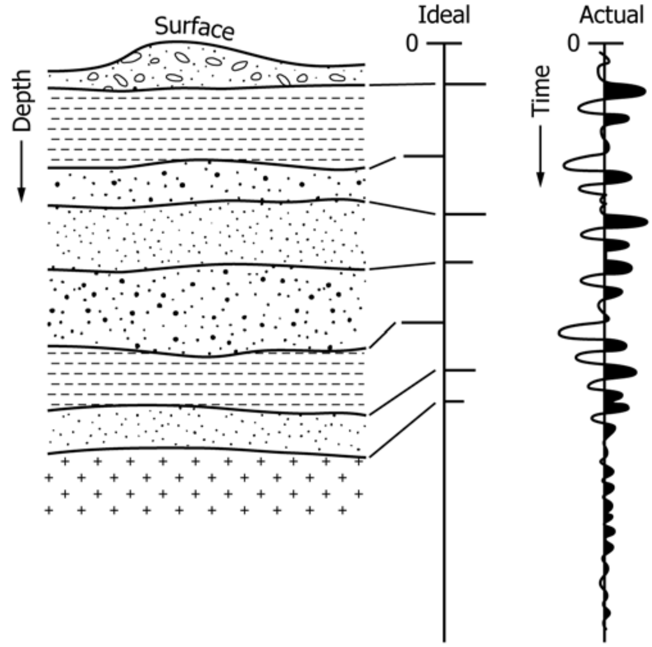
6.3.5 *Quality Control (QC)*—A good QC program should be used to ensure data are optimally acquired in the field, artifacts are not produced during processing, and only reflections are interpreted and correlated to geologic or hydrologic features. QC is critical and should be continuous throughout the acquisition, processing, and interpretation phases. Appropriate QC requires documentation of acquisition, processing, and interpretation procedures and should generally include discussion of testing and analysis steps, parameters tested and selected, rationale or reason for non-standard approaches or parameters, basis for and other data supporting interpretations, optional interpretations (ranked from most to least reasonable), equipment and instrumentation tests and frequency of tests, operational thresholds, environmental conditions affecting data quality, and representative shot gathers for each major acquisition and processing step. This documentation should be sufficient for a near-surface seismologist competent in high-resolution the seismic reflection method to reasonably reproduce the final CMP stacked section. As part of that overall Q/C program, the following should also be addressed: equipment performance relative to manufacturer's specifications, method used for field monitoring of equipment performance and routine operating limits, and requirements and methods for tracking of reflection events from shot gathers through processed sections and interpretations.

6.3.5.1 Near-surface inconsistencies in materials (and therefore seismic velocity), variable topography, an extremely wide and changing optimum recording window, and poor source/seismic sensor coupling conditions necessitate following a good set of QC guidelines and careful monitoring of shot to shot data quality. The seismograph should be set up with the appropriate QC options selected (which might include wiggle trace display, nearly real-time digital filtering, and real-time graphical display of noise levels) to monitor cultural, air traffic, vehicle traffic noise, cable-to-ground leakage, and geophone connection and quality of ground contact. If the seismograph does not have these capabilities, an external mechanism (supporting equipment) or procedure should be established to maintain optimum recording conditions. The seismograph should be routinely checked electronically to verify that it is

TABLE 5 Vertical Layer[A] Resolution Limits

Material Type	Representative P-Wave Velocity (m/s)	Frequency (Hz or 1/s)	Theoretical ¼ λ (m)	Practical ½ λ (m)
Dry Sand	500	50	2.5	5.0
		100	1.25	2.5
		200	0.62	1.25
		300	0.41	0.82
	1000	50	5.0	10.0
		100	2.5	5.0
		200	1.25	2.5
		300	0.8	1.6
Wet Sand/Dry Clay	1500	50	7.5	15.0
		100	3.75	7.5
		250	1.5	3.0
		500	0.75	1.5
Tight, Wet Clay/ Shale	2000	50	10.0	20.0
		100	5.0	10.0
		250	2.0	4.0
		500	1.0	2.0
Shale	2500	50	12.5	25.0
		100	6.25	12.5
		250	2.5	5.0
		500	1.25	2.5
Shale/Sandstone	3000	50	15.0	30.0
		100	7.5	15.0
		250	3.0	6.0
		500	1.5	3.0
Sandstone/Limestone	3500	50	17.5	35.0
		100	8.75	17.5
		250	3.5	7.0
		500	1.75	3.5
Limestone	4000	50	20.0	40.0
		100	10.0	20.0
		250	4.0	8.0
		500	2.0	4.0
Granite	6000	50	30.0	60.0
		100	15.0	30.0
		250	6.0	3.0
		500	3.0	1.5

[A] Geologic layers are represented by changes in material; seismic layers are defined by detectable changes in acoustic impedance.



NOTE 1—The spike or ideal trace represents the reflection coefficients at each interface. If every "wiggle" on the actual trace were interpreted as a layer, the interpretation of seismic data would not accurately represent the subsurface.

FIG. 8 Actual Seismic Trace (with Simulated Noise) that Would Result from a Reflection Survey over the Geologic Model

operating within manufacturer's specifications. On-site procedures should be established and followed to ensure all equipment operates at performance levels consistent with manufacturer's operating guidelines. The cable-to-ground resistance of each seismic sensor group should be high enough to avoid excessive signal leakage to the ground. Each geophone string should have a continuity check once connected to the spread cables confirming that string continuities are within a reasonable percentage of nominal string impedance, considering cable loss. Some kind of a geophone test (for example, tap test and twist test) can help identify problems with geophone coupling, system response, cabling to seismograph, noise at cable and geophone connections, and excessive overall background noise levels relative to signal. Shots should not be recorded if background noise levels on active (live) geophones are greater than a predetermined threshold. This threshold may vary from site to site and from one survey objective to another.

6.3.5.2 For many sites, distinguishing and separating signal from noise is challenging for high-resolution shallow seismic-reflection data. This is true for shot gathers and more so for common offset gathers and CMP-stacked data. High-amplitude coherent noise events routinely arrive in the same time window as smaller-amplitude, near-surface reflections. Once seismic traces are digitally processed, and especially once CMP stacked, contributions from coherent noise are often not easy to separate from the signal. It is therefore critical that reflections observed on multi-trace shot gathers be tracked through signal enhancement processing and correlated to reflection events interpreted on common offset and CMP-stacked sections. It is beneficial for appraising data quality and validity to have several representative data samples from across the profile available for each of the following sequence of gathers: raw multi-trace shot record, optimally filtered and scaled multi-channel shot record, CMP gather of filtered and scaled data, and NMO-corrected CMP gather of filtered and scaled data. These pre-stacked data should be compared and contrasted with the stacked sections. This process is critical for confident matching of each coherent event on the CMP stacks with the appropriate geologic interface.

6.3.5.3 Documentation of the procedures followed, testing and analysis done, and rationale for parameters selected during the acquisition, data processing, and interpretation of seismic-reflection data are necessary to ensure the quality of the output and evaluate the effectiveness of the method. The method used and objectives of the survey will generally dictate field and processing procedures and emphasis. The effectiveness of the method can be limited by site conditions and parameter selections.

6.3.5.4 Field logs should be completed and methodically maintained to document field operations (especially consistency and accuracy checks between source operator actual location, logged source location, and record number of file), data quality appraisals, equipment type and function, parameters and settings, site specific features and anomalies, productivity, QC procedures, and overall field activities.

6.3.5.5 Changes to the planned field procedures should be documented, along with rationale for changes and compromises, if any, that changes represent. Results of walk-away noise testing used to determine the production parameters, equipment, and procedures should be thoroughly documented, with samples and annotations of test data retained for inclusion in report.

6.3.5.6 Any conditions or changes in conditions that could reduce or vary the quality of the data (weather conditions, sources of natural and cultural noise, equipment changes, etc.) should be documented.

6.3.5.7 Data being recorded (by a computer or digital-acquisition system) with no means of visibly observing the data should be reviewed as soon as possible to check data quality and measure how effectively the data will meet the program objectives. Hard copy analog plots of shot records used for QC in the field should be saved until digital data can be processed. Any annotations or observations about or concerning the data made by field staff should be archived with the field logs.

6.3.5.8 Finally, the seismic-reflection data should be routinely checked to determine if the recorded signal makes geologic sense. Phase velocities of coherent events should be calculated and verified to be within a range appropriate for the site and seismic energy type.

6.3.6 *Calibration and Standardization*—In general, the manufacturer's recommendations should be followed for calibration and standardization of equipment within operational ranges. If no such recommendations are provided, periodic checks of equipment should be made to confirm operational fitness. Common industry practice is to use equipment that has self testing abilities. Common measurements for seismographs include noise levels, harmonic distortion, crossfeed, timing accuracy, and phase and amplitude distortion. A check should also be made after each equipment problem has been diagnosed and repaired. An extensive and thorough operational check of equipment should be carried out before each project with an abbreviated version completed before starting each day's fieldwork.

6.3.7 *Presentation of Data:*

6.3.7.1 Processed and interpreted seismic-reflection data lends itself to presentation with time/depth on the vertical axis and station location or CMP location on the horizontal axis. The data presentation format is analogous to geologic cross-sections derived from correlations between drill holes or renderings from rock outcrops. Data are generally presented in wiggle trace format with positive amplitudes shaded dark and represented by a right kick or deflection. Color display of any of the seismic attributes can enhance the interpretability of the information by improving the detail viewable in the presentation. The most common display format is a single wiggle trace for each surface station with north and west to the left of the display and south and east on the right of the display. Wiggle traces on CMP or common offset sections represent the amplitude of the reflected energy (Eq 1) returning from each layer after adjustment (generally not true for common offset displays) for the non-vertical incident raypaths between source and seismic sensor.

6.3.7.2 Final interpretations of seismic reflection sections are used to refine or confirm the third dimension of a geologic or hydrologic site model. Such a model is a simplified characterization of a site that attempts to incorporate all the essential features of the physical system under study. This model is usually represented as a cross-section, a contour map, or other drawings that illustrate the general geologic and hydrogeologic conditions and any anomalous conditions at a site.

6.3.7.3 Scaling of the seismic section (traces/cm and cm/s) should optimize the information in the section and match existing geologic cross-sections. This scale matching enhances the usefulness of the seismic data and minimizes transcription errors.

6.3.7.4 Seismic sections should be annotated with line directions, borehole locations, ties with other seismic lines, road crossings, and any other correlation points with other data. Plotting should follow map conventions with west and north on left side of plot unless the client specifies differently.

6.3.7.5 Seismic sections should be accompanied by a site map identifying the locations of all the seismic sections, tie locations (by CMP or shot station number), scale, significant surface features, anomalies and obstacles, and acquisition directions (beginning and ending of line as acquired).

7. Report

7.1 *Components of the Report*—The following are a list of the key items that should be contained within most reports. In some cases, there is no need for an extensive formal report.

7.1.1 The report should include a discussion of:

7.1.1.1 The purpose, objectives, and scope of the reflection survey.

7.1.1.2 The geologic/hydrologic setting;

7.1.1.3 Description of the method, including limitations of the reflection method and historical perspective on application of technique to similar problems;

7.1.1.4 Assumptions made;

7.1.1.5 The field approach, including a description of the equipment and the data acquisition parameters used, testing, samples of various test seismogram and in-field processing, quality control measures, operational statistics;

7.1.1.6 The location of the seismic line(s) on a site map that includes landmarks, well locations, known geologic features, and surface features;

7.1.1.7 Data processing flow, methods, and parameters with justifications for their use, assumptions made during processing and parameter selections, and data characteristics based on data analysis, appendices with sufficient details of the processing flow and parameters to allow a reasonable reproduction of the stacked sections by a competent near-surface seismic reflection professional;

7.1.1.8 Software used to process data, including name and version number;

7.1.1.9 Event identifications on shot gathers from samples along the profiles and walkaway gathers collected during testing, including abnormal seismic energy and interpretations made from shot gathers enhanced later after processing;

7.1.1.10 Interpretation description and highlighting of individual features of interest on final seismic sections;

(1) Name of any interpretation software used.

7.1.1.11 Presentation and discussion of interpreted and uninterpreted sections with discussion of any enhancements or unusual processing or interpretation techniques;

7.1.1.12 Correlations between interpretations and ground truth with scales matched as closely as possible;

7.1.1.13 The format of all recorded digital data (for example, SEGY, SEG2) and supporting analog information (for example, notebook, hardcopy analog recorder);

(1) All available GPS data and coordinates for beginning and ending of each seismic line.

(2) All survey information available, including coordinates of each station.

7.1.1.14 Performance information, which should include source, seismograph, processing flow (with sufficient detail to allow an experienced shallow seismic reflection processor to reasonably re-create the seismic sections), field logs, and safety plans;

7.1.1.15 If conditions occurred where a variance from this ASTM guide is necessary, the reason for the variance should be given and appropriate documentation and citation to support it;

7.1.1.16 Appropriate references for any supporting data used in the interpretation; and

7.1.1.17 Identification of the person(s) responsible for the acquisition, processing, and interpretation of the seismic reflection survey.

7.1.1.18 Conclusions and recommendations should include overall summary and listing of any follow-up work that might complement and extend the seismic survey.

8. Precision and Bias

8.1 *Bias*—For the purpose of this guide, bias is defined as a measure of the closeness to the truth.

8.1.1 The bias with which geology or anomalies can be determined by seismic-reflection methods depends on many factors. Some of these factors are:

8.1.1.1 Human errors in field procedures, record keeping, corrections to data, processing, and interpretation;

8.1.1.2 Instrument errors in measuring or recording;

8.1.1.3 Geometry limitations related to line location and topography;

8.1.1.4 Noise;

8.1.1.5 Variation of the earth from simplifying assumptions used in the field and interpretation procedure (that is, suitability of the target for the geophysical methods being used to delineate it);

8.1.1.6 Site-specific geologic limitations, such as roads, creeks, rivers, extreme topography, severely dipping subsurface layers; and

8.1.1.7 Ability and experience of the field crew and interpreter.

8.2 *Differences Between Depths Determined Using Seismic-Reflection Data and Those Determined by Drilling:*

8.2.1 The bias of a seismic reflection survey is commonly thought of as how well the geologic interpretations agree with borehole data. In many cases, the depth and apparent geometries of reflectors agree reasonably well with cross-sections derived from borehole data. In other cases, there will be considerable disagreement between the reflection results and boring data. While in some situations, apparent reflector depths and geometries may be quite accurate, the interpreted results may disagree with a depth obtained from drilling for the reasons discussed in 8.2.2 through 8.2.4. It is important that the user of geologic information interpreted from reflection data be aware of these concepts and understands that geologic information interpreted from seismic reflection survey will not always agree 100 % with drilling data.

8.2.2 *The Fundamental Differences Between Seismic-Reflection Interpretations and Drilling Interpreted Geology (that is, Depths and Geometries):*

8.2.2.1 The seismic-reflection method is based upon the measurement of particle motion as a function of two-way travel time from the source down to the reflector and back up to the seismic sensors. To image a reflector, it is necessary for a significant change in acoustic impedance to exist between the two layers that represent the reflecting interface.

8.2.2.2 When the top of the rock surface is defined by drilling, it is often based upon refusal of the drill bit to continue to penetrate, the number of blow counts with a split-spoon sampler, or the first evidence of rock fragments. These methods may produce different interpretations of the top of the rock surface and may not agree with the top of the rock surface as interpreted by the seismic-reflection method. The differences between two-way travel times and depths determined by drilling can yield as much as 15 % or more difference in the two depth determinations, even when the top of rock is relatively flat.

8.2.2.3 Layers geologically defined as differences in the lithology of consolidated or unconsolidated sediments or drilling changes in borehole logs don't always have a sufficient change in the acoustic impedance to generate a discernable reflection on a seismogram. Changes in saturation or the nature of pore fluids can also produce a high amplitude reflection event that may not have been observed in borehole core samples.

8.2.2.4 Depth estimates of reflections interpreted on reflection data require time-to-depth conversion. Seismic data are measured in time and must be converted to depth for correlation to drill or other ground truth. Converting time of seismic reflections to depth of reflectors requires knowledge of the average velocity from ground surface to the reflector. Normal moveout (NMO) velocities are estimated from geometric analysis and are inherently uncertain. Borehole velocity surveys (uphole, checkshot, downhole) provide time-to-depth functions with much less uncertainty than NMO analysis. Expectations of as much as 10 % difference between NMO-calculated velocity and average velocity measured in boreholes is reasonable.

8.2.3 *Lateral Geologic Variability*—Agreement between seismic reflection sections and boring measurements may vary considerably along the profile line, depending upon lateral geologic changes, such as dip as well as the degree of weathering and fracturing in the rock. Seismic reflection measurements may not account for small lateral geologic changes and may only provide an average depth over them. In addition, the presence of a water table near the bedrock surface can, in some cases, lead to an error in interpretation. Therefore, it is not always possible to have exact agreement between seismic sections and boring data along a survey line.

8.2.4 *Positioning Differences*—The drilling location and the feature or layer interpreted on the seismic reflection section may not correspond to exactly the same point surface location. It is common to find that the boreholes are located on the basis of drill-rig access and may not be located along the line of the seismic profile. Differences in position can easily account for as much as 10 % difference in depth where top of rock is highly variable (for example, karst) or where velocity structures are very complex.

8.3 *Precision*—For the purposes of this guide, precision is the repeatability between measurements: that is, the degree to which the depth or wavelet representation of a reflector from two identical measurements in the same location with the same equipment match one another. Precision of a seismic reflection section will be affected by variability of source coupling, zero time signal, changes in near-surface data processing parameters, and properties or attributes emphasized during interpretation. If a seismic reflection survey were repeated under identical conditions (including processing flows and interpretation philosophies), the measurements would be expected to have a high level of precision.

8.4 *Resolution:*

8.4.1 *Lateral Resolution*—Lateral resolution of a seismic reflection survey is a function of seismic reflection wavelength and velocity with inherent dependence on CMP spacing, generally described as related to the broadband Fresnel radius. An object one-quarter the Fresnel zone appears on reflection data as a diffraction and is considered a point source rather than a reflecting point. Resolving horizontal variations in geometry and/or stratigraphy is more challenging and estimating the resolving potential of reflection data is not nearly as straightforward in the horizontal dimension as in the vertical. Horizontal resolution has recently been described for broadband, zero phase seismic data as a zone of influence (**20**) with Rayleigh's criteria used to quantify the minimum distance two objects can be separated and still be distinguishable (**21**). This distance can be calculated using the relationship:

$$r = \sqrt{VZ/2f} \tag{5}$$

where:

r = broadband Fresnel radius,
f = dominant frequency,
V = velocity, and
Z = depth to the reflector (**22**).

Decreasing receiver spacing improves the apparent coherency of reflection events, but mathematically does not improve lateral resolution. A minimum receiver spacing approximate one-eighth the radius of the Fresnel zone should be maintained to insure proper sampling and optimize the interpretability of small objects on CMP stacked sections (Fig. 9).

8.4.1.1 Lateral resolution can be thought of as the designation of the closest two objects can be that a particular seismic reflection section can distinguish each. Increasing the dominant frequency is the only way to improve lateral resolution for a particular material (Table 3). Depth of the target does affect the resolution (Table 4).

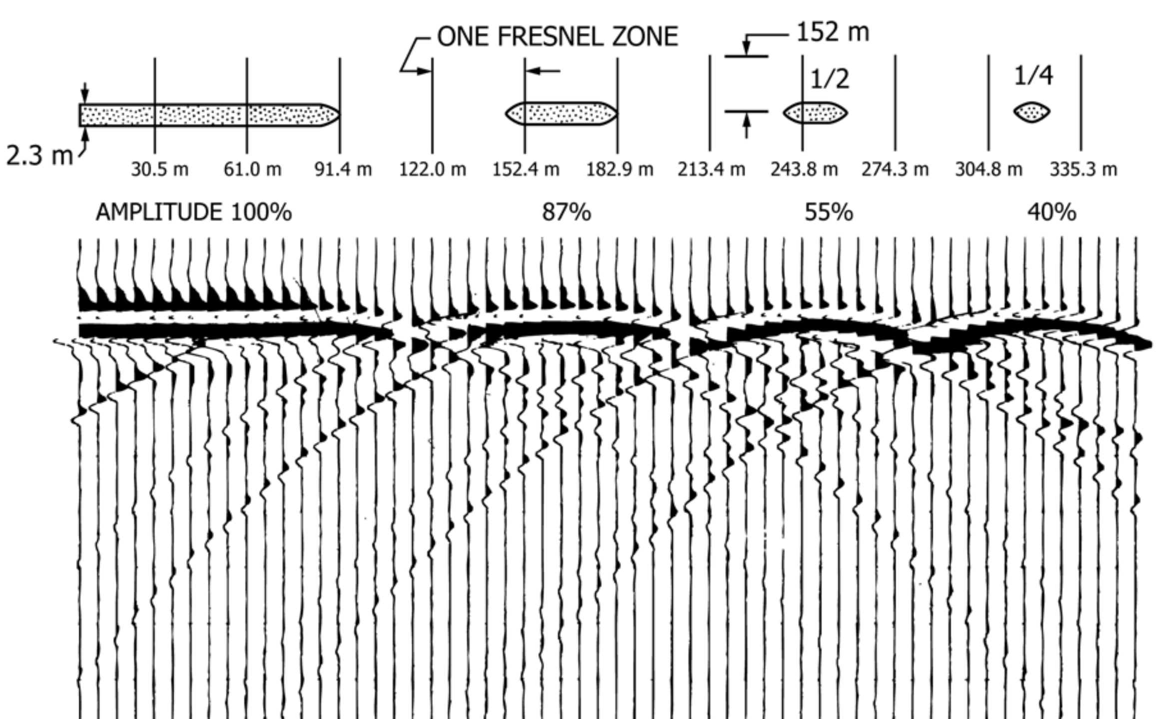


FIG. 9 Model Response for Sand Lenses of Varying Lateral Extent Illustrating Significance of Fresnel Zone Size

8.4.2 *Vertical Resolution*—Vertical resolution is generally expressed in terms of bed resolution. Bed resolution is the thickness of a bed that can be detected or resolved. As top and bottom layers of a bed approach each other (as the bed gets thinner) and eventually become separated by a distance less than the wavelength of the seismic energy, reflections from the top and bottom begin to interfere. Theory suggests that beds separated by less than one-quarter the dominant wavelength cannot be detected or resolved (**23**). In practice, due to noise and generally less than ideal spectral characteristics, it is more reasonable to assume that bed thickness needs to be half the dominant wavelength for the bed to be resolvable (**24**).

8.4.2.1 Vertical resolution can be thought of as the designation of the thinnest layer, the top and bottom of which can be detected by a particular seismic reflection section. For a given material type with a characteristic velocity, dominant frequency is the only variable that affects vertical resolution (Table 5). Theoretical limits have been estimated based on modeling of elastic media without noise and with uniform wavelet characteristics (Table 5). Practical limits represent reasonable expectations for "normal" data acquisition settings and equipment with noise and real variability in wavelet characteristics (Table 5).

9. Quality Assurance

9.1 It is generally good practice to have the entire seismic reflection work program, including the report, monitored and reviewed by a person knowledgeable with the seismic-reflection method and site geology but not directly involved with the project.

10. Keywords

10.1 geophysics; near-surface; seismic reflection; surface geophysics

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