Methane Hydrate Production from Alaskan Permafrost

3D Vertical Seismic Profile Survey

Topical Report

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by

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Abstract

Natural-gas hydrates have been encountered beneath the permafrost and considered a drilling hazard by the oil and gas industry for years. Drilling engineers working in Russia, Canada and the USA have documented numerous problems, including drilling kicks and uncontrolled gas releases, in arctic regions. Information has been generated in laboratory studies pertaining to the extent, volume, chemistry and phase behavior of gas hydrates. Scientists studying hydrates as a potential energy source agree that the resource potential is great – on the North Slope of Alaska alone, it has been estimated at 590 TCF. However, little information has been obtained from physical samples taken from actual hydrate-bearing rocks.

This gas-hydrate project is a cost-shared partnership between Maurer Technology, Anadarko Petroleum, Noble Corporation, and the U.S. Department of Energy's Methane Hydrate R&D program. The purpose of the project is to build on previous and ongoing R&D in the area of onshore hydrate deposition to identify, quantify and predict production potential for hydrates located on the North Slope of Alaska.

The project team drilled and continuously cored the Hot Ice No. 1 well on Anadarko-leased acreage beginning in FY 2003 and completed in 2004. An on-site core analysis laboratory was built and used for determining physical characteristics of hydrates and surrounding rock.

After the well was logged, a 3D **vertical seismic profile (VSP)** was recorded to calibrate the shallow geologic section with seismic data and to investigate techniques to better resolve lateral subsurface variations of potential hydrate-bearing strata. Paulsson Geophysical Services, Inc. deployed their 80 level 3C clamped borehole seismic receiver array in the wellbore to record samples every 25 ft. Seismic vibrators were successively positioned at 1185 different surface positions in a circular pattern around the wellbore. This technique generated a 3D image of the subsurface. Correlations were generated of these seismic data with cores, logging, and other well data.

Unfortunately, the Hot Ice No. 1 well did not encounter hydrates in the reservoir sands, although brine-saturated sands containing minor amounts of methane were encountered within the hydrate stability zone (HSZ). Synthetic seismograms created from well log data were in agreement with reflectivity data measured by the 3D VSP survey. Modeled synthetic seismograms indicated a detectable seismic response would be expected in the presence of hydrate-bearing sands. Such a response was detected in the 3D VSP data at locations up-dip to the west of the Hot Ice No. 1 wellbore.

Results of this project suggest that the presence of hydrate-bearing strata may not be related as simply to HSZ thickness as previously thought. Geological complications of reservoir facies distribution within fluvial-deltaic environments will require sophisticated detection technologies to assess the locations of recoverable volumes of methane contained in hydrates. High-resolution surface seismic data and more rigorous well log data analysis offer the best near-term potential.

The hydrate resource potential is huge, but better tools are needed to accurately assess their location, distribution and economic recoverability.

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1. Introduction

Efforts described here are part of a large gas-hydrate project structured as a cost-shared partnership between Maurer Technology, Anadarko Petroleum, Noble Corporation, and the U.S. Department of Energy's Methane Hydrate R&D program. The overall purpose of the project is to plan, design and implement a program to safely and economically drill/core and produce natural gas from arctic hydrates. The project team has documented planning, operations and lessons learned to assist in future hydrate research and field operations to make an objective technical and economic assessment of this promising natural gas reservoir potential. Specifically described here are results from a special 3D **vertical seismic profile (VSP)** recorded to calibrate the shallow geologic section with seismic data and to investigate techniques to better resolve lateral subsurface variations of potential hydrate-bearing strata.

On February 7, 2004, the Hot Ice No. 1 hydrate well reached its planned depth of 2300 ft, about 300 ft below the zone where temperature and pressure conditions would theoretically permit hydrates to exist (i.e., the hydrate stability zone (HSZ)). Although significant gas shows were encountered in highly porous sandstones, no methane hydrates were found. The continuous coring rig used in the project proved to be a safe and efficient drilling system, with 93% of core recovered.

This project used a special purpose on-site core laboratory to help analyze hydrate cores. Live data and images were transmitted from the rig over the internet, which reduced the number of engineers and scientists required to oversee the project. Additionally, the well was drilled from a special purpose-built arctic platform designed for minimal environmental impact.

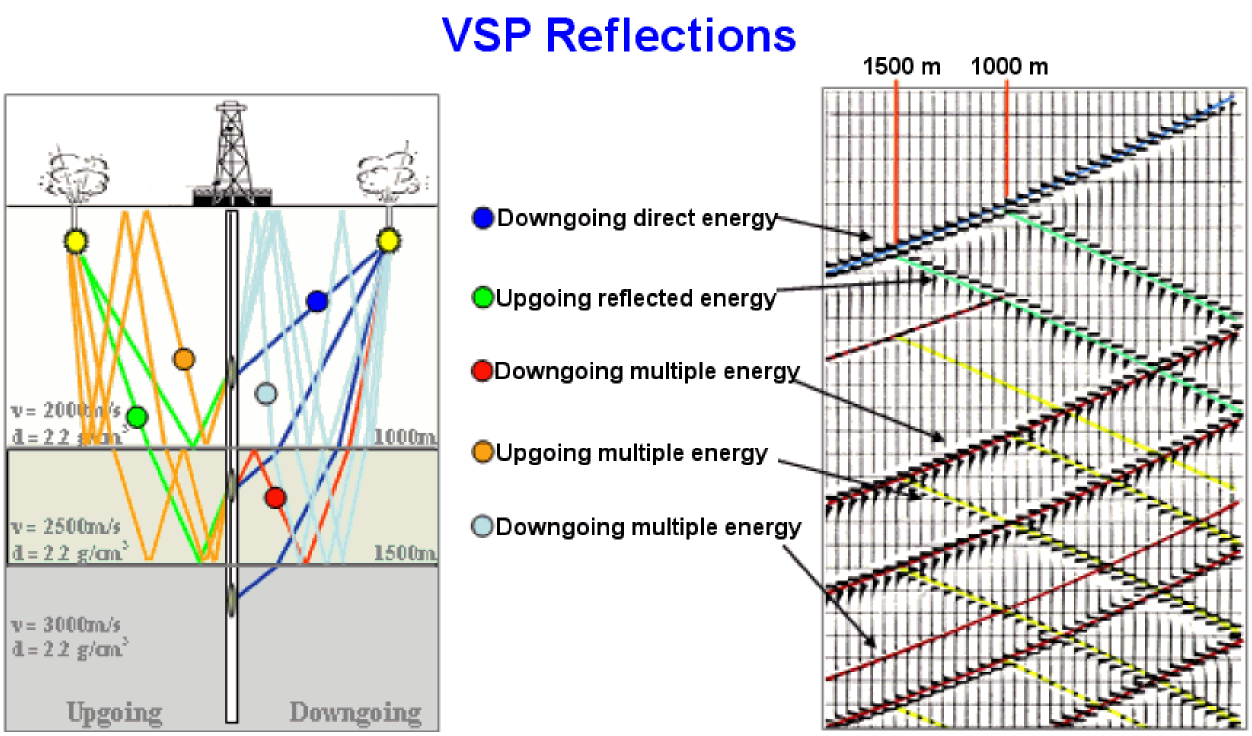


Figure 1. In a VSP, each borehole receiver records down-going and up-going energy from each surface shot-point location

A massive 3D VSP survey was conducted to investigate lateral variations of the potential hydrate reservoir. The VSP survey at Hot Ice No. 1 was designed to calibrate the shallow geologic section with seismic data and to investigate techniques to better resolve lateral subsurface variations of potential hydrate-bearing strata in the vicinity of the wellbore.

Basic operation of a VSP is to deploy seismic receivers in the well bore at regular intervals and record energy transmitted by seismic equipment on the surface. Receivers in the wellbore record not only energy that travels directly from the seismic sources, but also energy reflected by subsurface rock layer boundaries and energy that reflects between layers of rock (multiples) (**Figure 1**). Recorded data are processed by computer to extract reflected compressional wave data, resulting in a high-resolution, three-dimensional image of the subsurface seismic reflectors in a radius around the wellbore. Massive 3D VSP's significantly increase the resolution of 3D images compared to those obtained from surface seismic surveys. Use of downhole receivers usually results in doubling of useful seismic frequency bandwidth as compared to surface receivers. Bandwidth is doubled because seismic waves recorded on downhole receivers only travel once through the highly attenuating weathering layer.

The 3D VSP has a considerable advantage over traditional VSP methods which produce either a zero-offset, single-fold subsurface image or (in the case of a walk-away or offset VSP) a few traces in a single offset direction from the wellbore. A 3-D VSP can be economically feasible through the use of Paulsson Geophysical Services, Inc.'s (P/GSI) massive array that deploys 80 receivers in the wellbore (**Figure 2**) to sample the entire vertical section with respect to each surface shot point.

Figure 2. Deploying VSP Receiver Array into the Wellbore

This technique requires that each surface shot point be occupied only once by the seismic source (**Figure 3**), thereby greatly reducing time required to record a three-dimensional survey. Systems based on using fewer receivers require multiple deployments of the receivers in the wellbore and each deployment would necessitate reoccupying each surface shot-point location, greatly increasing the time and cost of a 3D VSP survey.

Figure 3. VSP “Thumper” Truck

2. Experimental

2.1 Task Statement

Task 12.0 – Shallow Seismic Survey(s)

As stated in the original Statement of Work, the project team was to conduct vertical seismic profiles (VSP) to characterize the hydrate-bearing strata and to calibrate the shallow stratigraphy to existing seismic data. Acquisition, processing, and interpretation were to be designed for optimum imaging of shallow stratigraphy (i.e, less than 3500 ft). The team was to correlate VSP data with core, log, other well data, existing non-proprietary seismic data, and other well data generated.

2.2 Survey Design

In the vicinity of the Hot Ice No. 1 location, the nearby ARCO Cirque #2 well in Sec.17 of T9N, R7E had encountered several hydrate-bearing sands within the zone of penetration of the Hot Ice No. 1 well. In the survey design phase, wireline logs from the Cirque #2 well were used to model expected seismic response at Hot Ice No. 1 to determine shot-point spacing and fold. As expected, modeling showed that the seismic fold would be highest near the wellbore and decrease away from the wellbore (**Figure 4**). Radius of the Fresnel zone would also increase with offset. For more details on the fold estimates for various offset angles and targets, see **Appendix A**.

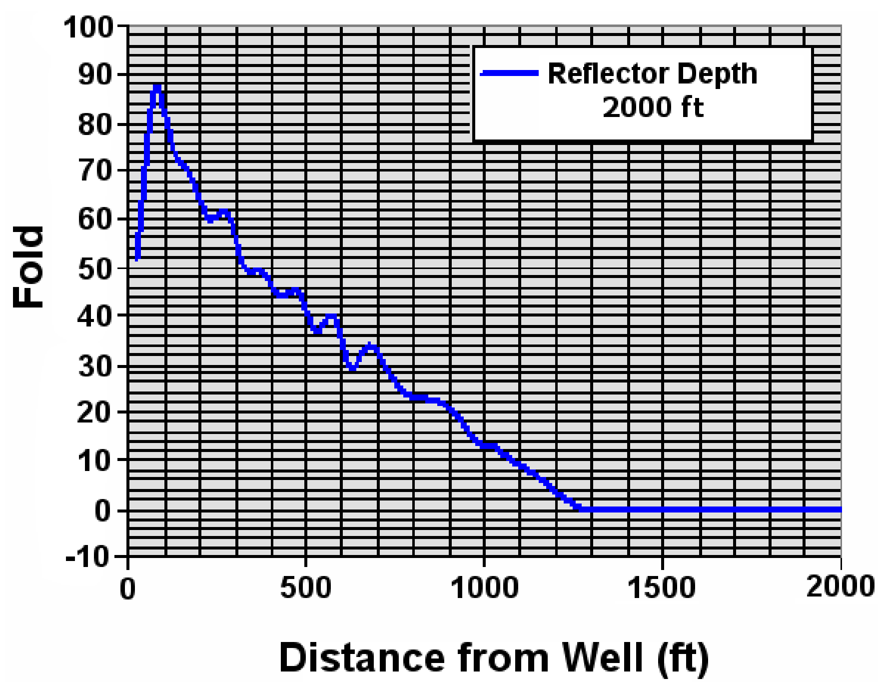


Figure 4. 2-D Fold Estimate for a Reflector at 2000 ft

Multiple surface shot-point grids were tested on the model to study effects of shot-point spacing and azimuthal coverage. The final surface shot-point design deployed 1185 shot points in a circular pattern with variable shot-point spacing ranging from 120 ft near the wellbore and increasing to 175 ft at the maximum offset of 2749 ft (**Figure 5**). This pattern of concentric rings was designed to concentrate more seismic energy near the wellbore where the fold would be highest and increase shot-point spacing to accommodate the increase in the Fresnel zone with offset. The maximum offset was chosen to ensure adequate coverage below the wellbore to image reflectors observed on surface 3-D seismic data. This provided a full azimuth survey with full offset coverage out to offsets equivalent to the depth of the wellbore. This design would provide a P-wave reflection image with a radius of 1000 ft at a depth of 2000 ft (approximate depth of the base of the hydrate stability zone (HSZ)), and a maximum radius of 1435 ft at 2870 ft and deeper.

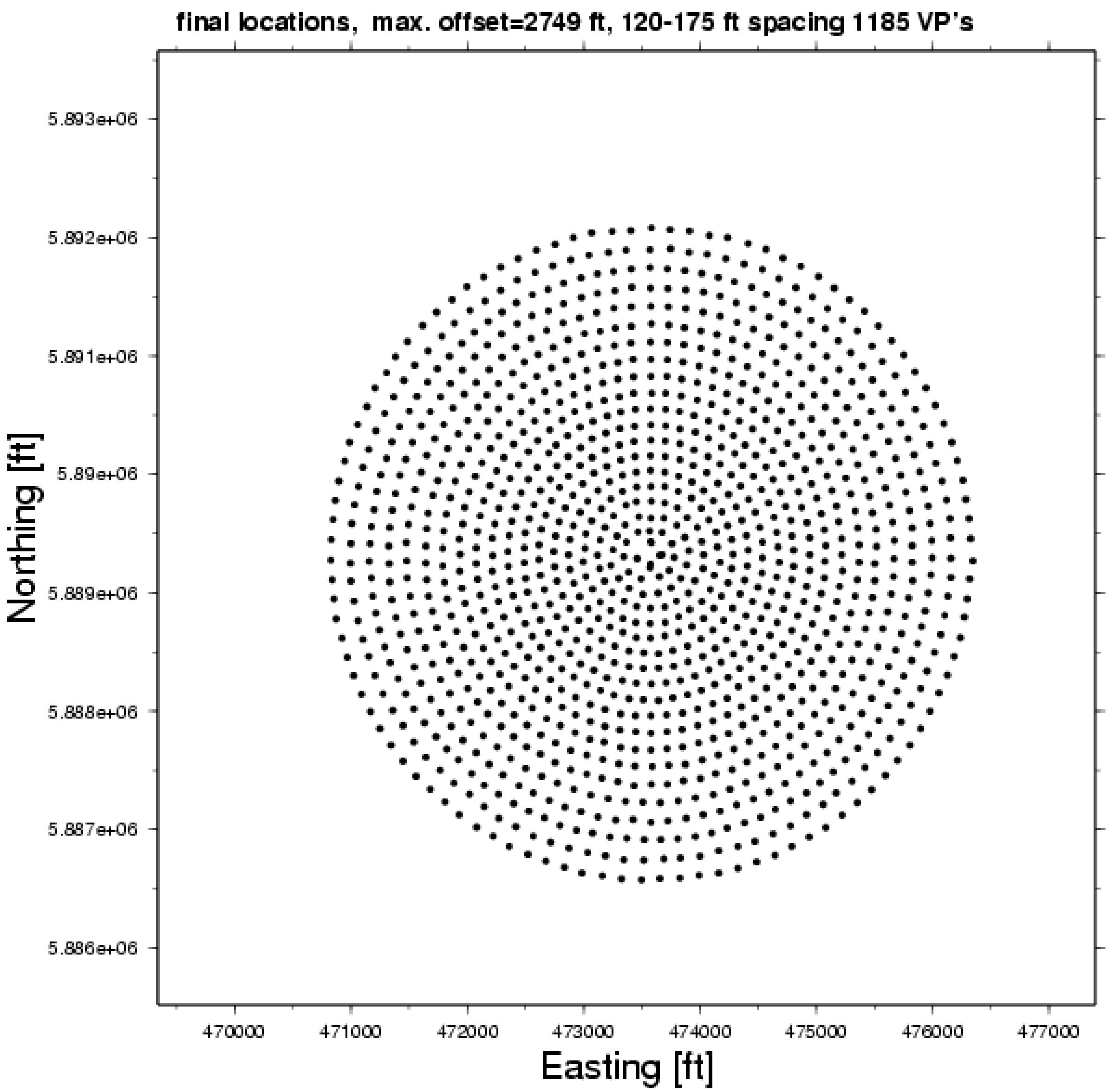


Figure 5. Map of Surface Shot-Point Locations

2.3 Survey Equipment

Paulsson Geophysical Services, Inc. (P/GSI) was retained as the primary contractor for acquisition and processing of the 3D VSP survey. P/GSI subcontracted PGS Onshore Inc. (PGS) to provide surface source and support equipment and personnel; and Geometrics to provide data-recording equipment and personnel.

P/GSI deployed their third-generation cable (80-006) with eighty 15-Hz OYO SMC1850 geophones arrayed in three-component pods (one vertical and two orthogonal horizontal axes) (**Figure 6**). The 80 3-C pods were deployed at 25-ft intervals on the cable from 294.35 ft to 2269.15 ft in the wellbore (see **Appendix B**).

Figure 6. Installing Receiver into Pod

P/GSI also provided a ProMax processing system for on-site, real-time processing and QC of recorded data (**Figures 7–9**). GeoMetrics provided an RX-132 seismograph recording system and required personnel to record the three-component VSP data (**Figure 8**).

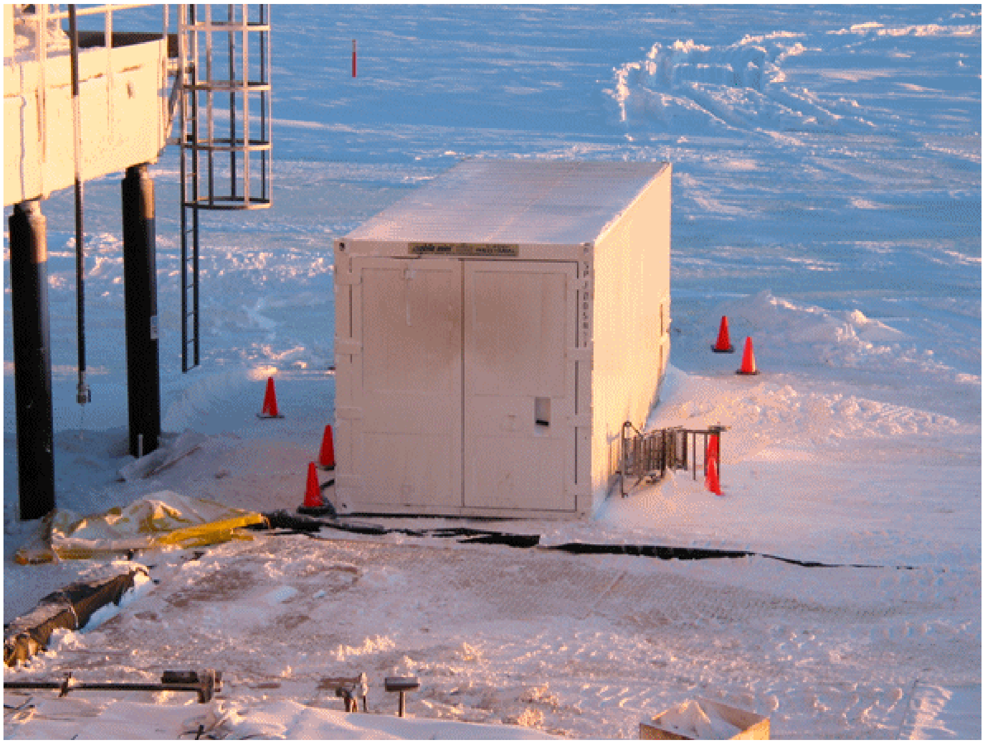


Figure 7. P/GSI Recording Hut near Hot Ice Platform

Figure 8. Recording Equipment inside Recording Hut

Figure 9. Data QC during Parameter Testing

PGS provided three AHV4 (62,000 lb) surface vibrator seismic source vehicles, plus support vehicles and personnel (**Figures 10 and 11**). Two vibrators were used for recording the survey and a third vibrator was on stand-by to minimize delays due to equipment problems. Parameters included:

- 2 x 8, 220 Hz, 10 sec linear sweeps, 0.2 sec cosine taper
- Adaptive circular pattern based on estimated Fresnel Zone size
- Source point interval: 120-175 ft, max. offset 2750 ft, for a total of 1185 shot points

Figure 10. PGS Vibrator during VSP Production Recording


Figure 11. PGS Vibrator near Hot Ice Platform

3. Results and Discussion

3.1 Field Operations

All equipment and personnel were on location at the Hot Ice No. 1 well on February 12, 2004. Parameter testing began that day and continued until 5 a.m. the next day. A parameter testing program was undertaken to determine optimal frequency range, record length, signal taper and number of sweeps to use for the production recording of the VSP (see Testing Program below) (see also **Appendix C**). As a result of these tests, the final sweep parameters were two sweeps per shot point, each sweep 10 seconds long, running from 8-220 Hz with a 0.3 cosine taper.

Testing Program for Hot Ice No. 1 VSP

Objective: Determine optimum signal parameters (sweep length, frequency range and number of sweeps) for a maximum offset of 2600 ft for the VSP

Critical Issues:

1. Vibrator frequency range capability
2. Ground roll effects
3. Tube waves
4. Move-up time between surface points

Testing Sequence:

1. Record a 32 sec 10-200 Hz sweeps for harmonics filtering analysis
2. Test sweep lengths with 10-200 Hz sweep frequency range at near offset (off ice pad)

16 sec x 1 sweep	0.3 cosine taper
12 sec x 1 sweep	0.3 cosine taper
10 sec x 2 sweeps	0.2 cosine taper
8 sec x 2 sweeps	0.2 cosine taper
6 sec x 2 sweeps	0.1 cosine taper

3. Test sweep frequency ranges using best sweep length

6-160 Hz	10-160 Hz	14-160 Hz
6-180 Hz	10-180 Hz	14-180 Hz
6-200 Hz	10-200 Hz	14-200 Hz
6-220 Hz	10-220 Hz	14-220 Hz
6-240 Hz	10-240 Hz	14-240 Hz

4. Test <u>number of sweeps</u> using best sweep length and frequency range

16 sec x 1	16 sec x 2	
12 sec x 1	12 sec x 2	
10 sec x 1	10 sec x 2	
8 sec x 1	8 sec x 2	8 sec x 4
6 sec x 1	6 sec x 2	6 sec x 4

5. Do walk-away using sweep parameters with 500 ft intervals

Production recording ran from 5:10 a.m. February 13 until 3:35 a.m. February 14 (**Figure 12**). Energy from a total of 1185 shot-point locations was recorded by 80 receiver positions containing three geophones each for a total of 284,400 traces.

Date	Time	Comments	PGS	P/GSI
10-Feb	16:00	Arrive at Hot Ice location w/ PGSI & PGS personnel.	Vibes ~14 mi out - stopped for poor visibility	
	17:30	Safety meeting.	Dicussed vib capabilities, testing program, etc.	Need to relocate recording shack
	18:30			Looked at logs & discussed program & hydrates w/PGSI personnel
	19:30	Went outside - blowing snow. Went to rig floor	Scripting up the testing program in Excursion.	Pods unpacked. Tight quarters for deployment
	20;15	Temp -10 w/wind (-50 WC).		Reported snow had blown into computer shack - door not fully latched (faulty latch). Should be tripping in soon & warming up computer shack. Expect ~6 hrs to trip in
11-Feb	6:00	Phase III travel advisory (wind & blowing snow)	Vibes may try moving.	No trip in - problems with slipd & bottom hole assembly
	8:00	Conference call to Houston on Hot Ice operations		
	10:00		Crew trying to move. Tucker abandoned - bad transmission	Tripping out tubing
	11:30		No contact with crew - not on site	
	12:30	Phase III travel advisory (wind & blowing snow)	Vibes stopped ~13 mi out. will wait until dark for wind to die down.	Tripped out all gear & circulating - probabilitof freezing up w/o circulating. Can't circulate w/PGSI equip in hole. Computers OK from snow
	21:00		Vibes moving	POOH & circulate. Should trip in ~midnight (5-6 hrs to trip)
12-Feb	5:00		Vibes 6 mi. out, 1.5 mph	10 pods in - running slow. Should be in hole when Vibes arrive
	8:00		Vibes at South end of pipeline & will cross to east side to avoid pipeline crossing & power line	20 pods in hole & pressure testing
	9:30		Tucker arr. on site. Waiting on vibes	
	11:00		Tucker went back to escort vibes	40 pods in hole & pressure testing
	13:15		Vibes on site	Should be in hole in 2-3 hrs
	17:00			Array in hole w/top pod @ surface. Need to set spool on ground near shack. Need to refuel drilling rig before moving spool
	20:40	Shut off some rig motors to reduce noise	Vibes need adjustment to reduce distortion at high frequencies	Pod clamping pressure 95 psi - will check hourly
		Will do test program with 1 vibe (not walkaway).	Will hard-wire production sweep parameters & then record walkaway w/ production sweeps	PGSI will record zero-offset VSPs w/vibes close to rig, then redeploy array to bottom
	21:30	Inner ring is Line 1, outer ring is Line 20	Vibe ready for testing	
	22:26	**Test 1** 32 sec sweep 10-200		
	22:36	**Test 2** 14 sec+2 sec listen (not enough disc for 16 sec)		
	22:59	10-200, 12 sec (+2), .3 taper		
	23:15	10-200, 10 sec (+2)		
	23:23	10-200, 8 sec (+2)		
	23:34	10-200, 6 sec (+2)		
	23:37	10-200, 8 sec x 2 (+2)		
	23:39	10-200, 6 sec x 2 (+2)		
		spectrum comparison for 10-220 Hz: 6, 10, 14 sec better than 8 & 12.		
		6 sec sweep too short (deeper notches) 10&14 look the same		
13-Feb	0:07	**Test 3** 10 sec (+2) 6-200 (0.2) - more distortion & baseplate warning		
	0:10	14 sec (+2) 6-200 (0.3)		
	0:17	14 sec (+2) 6-200 (0.3)		
	0:20	10 sec (+2) 14-200 (0.2)		
	0:25	14 sec (+2) 14-200 (0.3)		
		10 sec 14-200 looks lower frequency than 10-200		
	0:35	10 sec(+2) 8-200 (0.2) - better than 6 or 14 low end but not as good as 10 Hz		
	0:42	10 sec (+2) 8-160 (0.2) - baseplate warning		
	0:43	10 sec (+2) 8-180 (0.2) - baseplate warning		
	0:47	10 sec (+2) 8-220 (0.2)		
	0:48	10 sec (+2) 8-240 (0.2) - more distortion on vibe but better spectrum than 220 Hz		
	0:58	10 sec (+2) 8-220 (0.2)x2 (0 & 180 phase) correlate then stack - very little difference between single sweep & variphase		
	1:05	10 sec (+2) 8-220 (0.2)x2 - stacked traces better than single or variphase		
		Production sweep = 10 sec (+2) 8-220 (.2)	Will hard-wire production sweep parameters	Will trip in array to bottom
	4:35	Pulse test		
	4:40	**Walkaway test** with production sweep @ 500 ft.		
	4:46	1000 ft offset		
	4:49	1500 ft offset		
	4:53	2000 ft offset		
	4:56	2500 ft offset		
	5:10	**Production survey started** - Line 01 VP 001, & Line 20 VP001 working each vibe to center		
	12:00	Approx 1/3 survey recorded in 7 hrs - slower than expected. Expect survey completion by midnight. Have to manually start vibes. Geometrics unit adding delays		
	2030	Left location on fuel and water trucks		
14-Feb	3:35	Last shot recorded - **VSP completed**		

Figure 12. VSP Field Operations Log

3.2 Data Processing

Processing of the VSP data was designed to focus on the up-going P-P (primary to primary) reflection data. No additional processing for the P-S (primary to shear) or S-S (shear to shear) data was included.

The processing flow consisted of the following steps:

1. **Tape Input**
2. **Trace Editing**
3. **Geometry Assignment**

   Assign x, y, z location information to each receiver using the well deviation survey with 2D inversion of VSP data as a quality check.

   Receiver relocation is based on a 2D inversion in the vicinity of the respective receiver level. As such it is of limited accuracy (5-10 ft, depending on the accuracy of the first break picks) and usually cannot replace an accurate deviation survey. It is used for quality control of the deviation survey. As seen in **Figure 13** top view, both the inverted locations and the deviation survey locations show the same general trend, and are located close to each other. This confirms the accuracy of the deviation data.

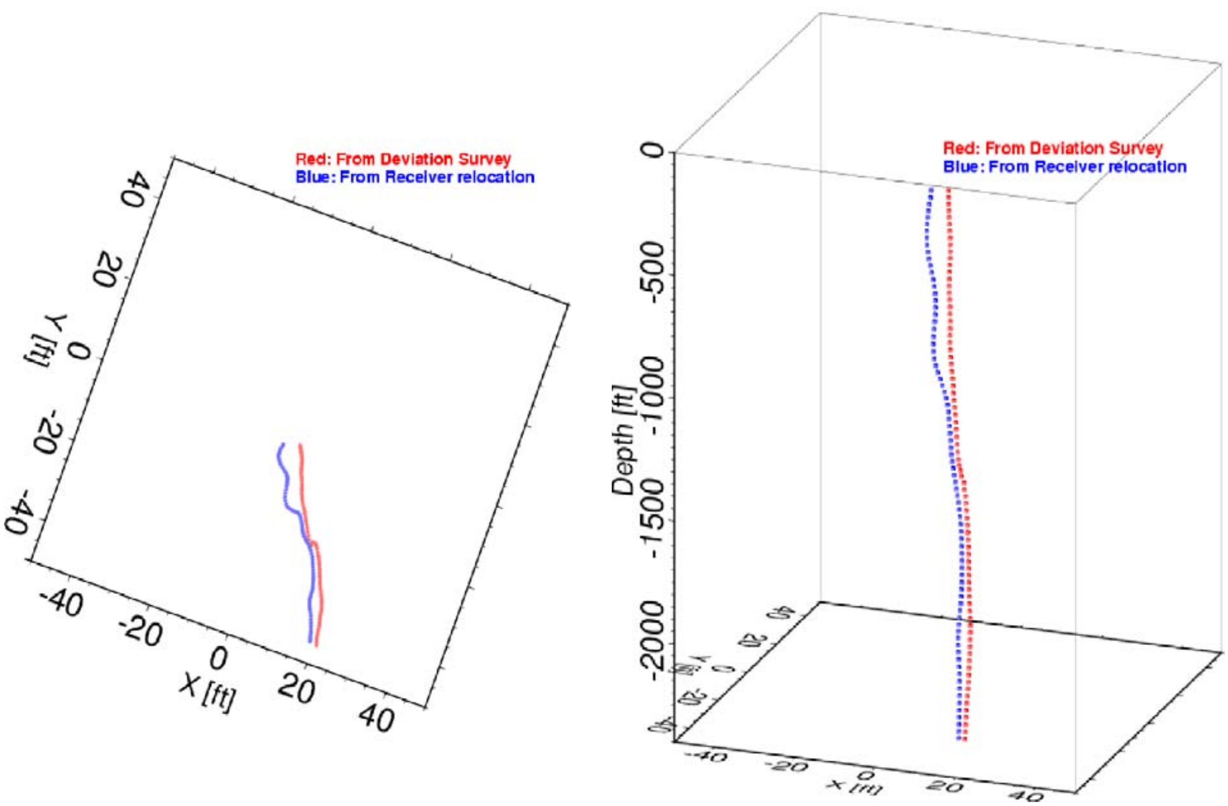


Figure 13. VSP Receiver Location and Borehole Deviation

4. 3-C Orientation

As receiver pods in the array are deployed, their directional orientation is random. It is critical to determine the receiver orientations to focus the energy in the direction of the source position. Hodogram analysis (see **Appendix D**) is used to determine the angle of maximum energy and, therefore, true receiver orientation. This is used to separate total recorded energy into the vertical and two orthogonal horizontal directions (see **Appendix E**).

5. Pick First Breaks on 3-C Oriented Data

After the three-component data have been properly oriented, the first break arrivals are picked on the P-component data for all of the shot points for use in developing the velocity model and for separating the three-component data into oriented volumes. (See **Appendix F**.)

6. Wavefield Separation using 3-C Oriented Data

Wavefield separation is performed by subtracting the (source-rotated) H1 component from the vertical component (this enhances up-going P energy). (See **Appendix G**.)

7. Statics

Shot statics are designed to correct travel-time undulations caused by local changes in the near surface which are unique to individual shot locations or a small patch of shots, i.e. short wavelength. Longer wavelength components are due to other causes (e.g., topography, lateral heterogeneity, anisotropy, etc.), and these corrections should not be included in the shot statics. (See **Appendix H**.)

8. Deconvolve 3-C Oriented Data

Deconvolution is designed to remove multiples and other undesirable components (noise) from the signal spectrum. A source-signature deconvolution (zero-phase wavelet inversion) method was chosen with a 500-ms operator length and notch filters to compensate for 60-Hz rig noise and harmonics. (See **Appendix I**.)

9. Amplitude Recovery

Amplitude recovery is used to compensate for a number of effects in the recorded data. This is used to compensate for decay of seismic energy strength with distance from the source, i.e., with offset from the wellbore or depth from the surface. Amplitude recovery can also reduce contamination from tube waves which result from energy traveling along the surface to the wellbore and propagating down the well casing to the receivers. Some methods can be too aggressive and negatively impact the desired signal, so care must be taken in testing and selection. After testing several methods of amplitude recovery, the team’s final choice was to use a 250-ms Automatic Gain Control (AGC) function. (See **Appendix J**.)

10. Migration Velocity Field Derivation

The first pass of migration was done with a single velocity function derived from well control and trend extraction for the deeper data. The 3-D migration velocity volume was generated by integrating the sonic well log with interpreted horizons from the VSP data and local surface seismic data. The shallow section within the radius of investigation of the Hot Ice No. 1 VSP is essentially planar with monoclinal dip to the east. Reflectors in the VSP volume were approximated by planes, and sonic log velocities were populated in the model with these horizon constraints (see **Appendix K**).

11. 3D Kirchhoff Prestack Depth Migration of P-P Data

The final stage of processing is to position the seismic reflectors at their proper locations subsurface. A 3D Kirchhoff prestack depth migration algorithm was used for this step. This algorithm is an integral form of the wave equation and is applied along a diffraction curve for each reflection point sampled in the subsurface. The algorithm operates in the pre-stack domain using the 3D migration velocity model, and converts the final processed data from time to depth.

12. Output to Tape and Preparation of Report on Results and Analysis

The final depth-migrated seismic data volume was adjusted to a datum of mean sea level. The final shot point interval was 15 ft with a vertical sample rate of 5 ft to a depth extent of 4500 ft (approximately 2200 ft below the well TD). The 3D migration velocity volume was used to convert depth data to a time volume with a datum of mean sea level and a vertical sample rate of 1 ms to a time extent of 1100 ms.

An “L-plot” was produced to document the correlation between VSP and log data (see **Appendix L**). This figure also shows the correlation between the VSP corridor stack and a synthetic seismogram from wireline log data.

3.3 Integration with Well Data

Wireline well logs from the surface to 1260 ft MD (approximate base of permafrost) were unreliable due to washouts in unconsolidated sediments (**Figure 14**).

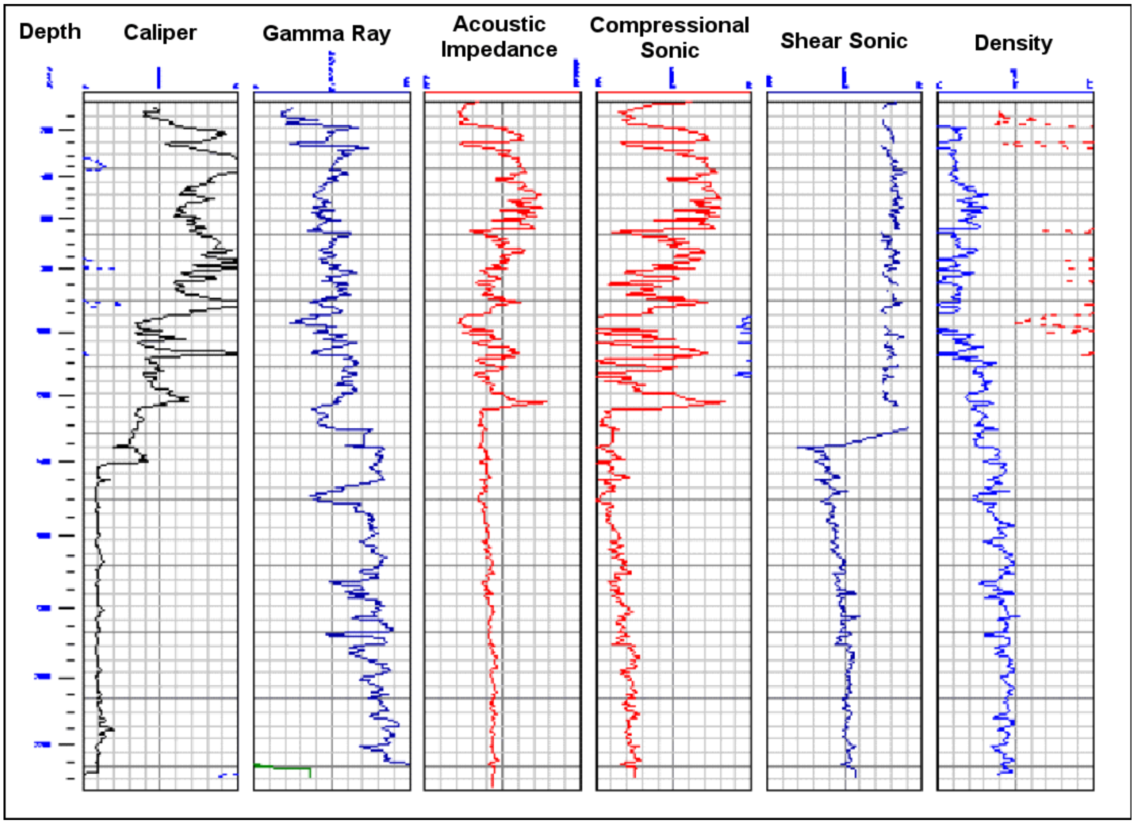


Figure 14. Hot Ice No. 1 Log Showing Washout Effects in Upper Wellbore

Washouts occurred during the drilling phase when the 5⅞-inch cored hole was enlarged to 8½ inches for logging and casing and the mud chiller was offline for mechanical problems. No potential reservoir sands were seen in this section and no hydrates were observed in the cores.

Below 1260 ft MD, there were several potential reservoir sands. The thickest sand is seen between 1480 ft and 1508 ft MD (Sand A). This sand is well within the HSZ and was determined to be brine-saturated with some gas in solution.

Sonic and density logs can be combined to create an acoustic impedance log, which can then be convolved with a seismic wavelet to create a synthetic seismogram. This creates an approximation of a seismic trace at the wellbore location. A synthetic seismogram can be used to correlate geologic formations and interfaces with the reflection seismic data recorded by a VSP or surface seismic survey. Accuracy of the correlation depends on the quality of the wireline log data and the seismic wavelet. For the Hot Ice No. 1 well, the quality of the upper 1260 ft of log data is very poor, resulting in unreasonable acoustic impedance values, which in turn create invalid synthetic seismic reflection events.

Compressional velocity, shear velocity and density logs from lowermost 900 ft of the Hot Ice No. 1 well were used to generate an offset-stacked synthetic seismogram to investigate the seismic character of the strata penetrated (**Figure 15**). Sand A (indicated by horizontal lines in Figure 5) is a fining-upward sandstone with very little acoustic impedance contrast with the overlying shale. This results in a very weak trough event (negative reflectivity) for the top of the sand. Sand A has a fairly sharp base with a good impedance contrast with the underlying shale. This combination results in a moderate peak event (positive reflectivity) at the base. Very little change is observed in the offset traces, other than the normal decrease in frequency content with offset distance.

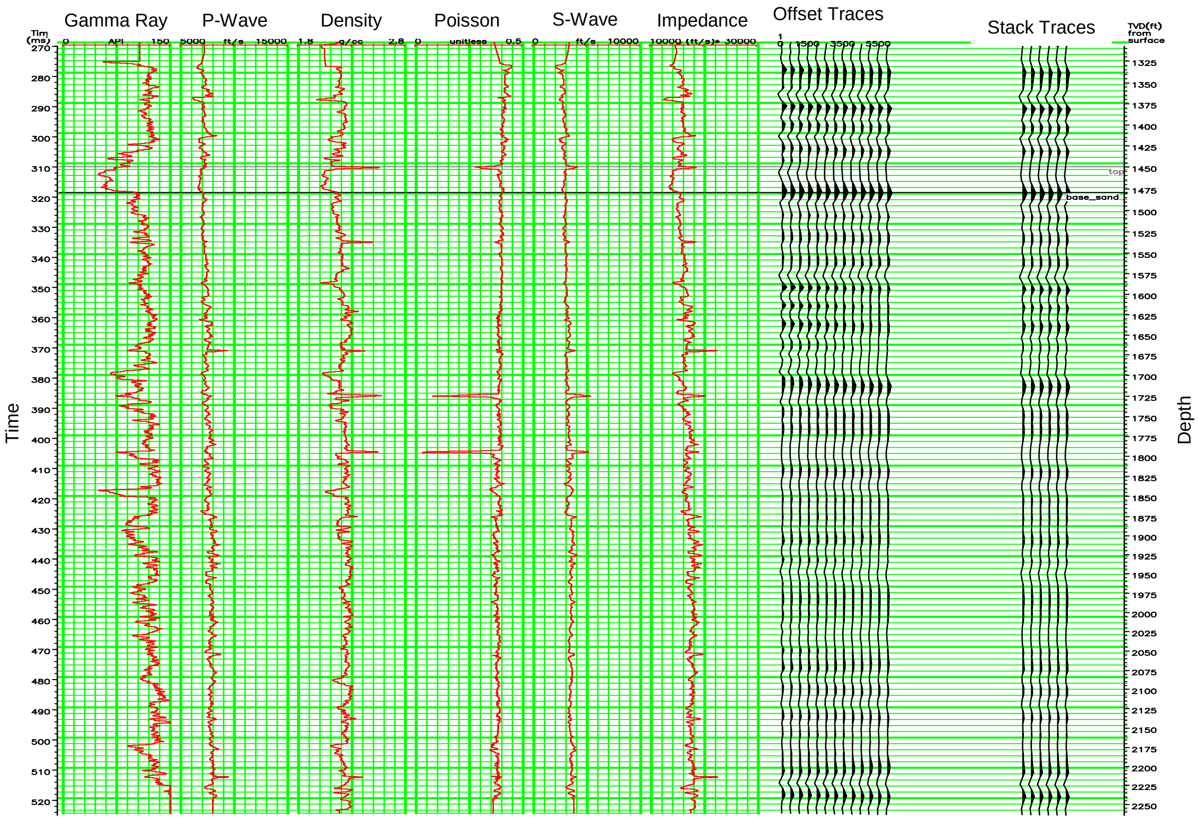


Figure 15. In-Situ Synthetic Seismogram (Sand A indicated by horizontal lines)

Offset traces in Figure 5 show computed seismic response for different offset distances away from the energy source. Shapes of the traces change, primarily because frequency content decreases with distance (higher frequencies are absorbed and scattered by the earth), and because elastic properties of the earth (especially shear impedance) are more influential for energy propagation and reflection with offset. The stack traces in the seismogram are the result of summing the offset traces into a single trace. In this display, there is one offset trace for each distance noted at the header plus six identical summed traces.

A second offset-stacked synthetic seismogram was constructed to investigate changes in seismic response due to the presence of methane hydrates in Sand A. Compressional velocity, shear velocity and density values were replaced with values for a hydrate saturation of approximately 70% (**Table 1**).

Table 1. Properties for Synthetic Seismograms

Condition	Vp	Vs	Density
Brine sand	7150 ft/sec	2850 ft/sec	2.03 g/cc
Hydrate sand	12464 ft/sec	7216 ft/sec	2.01 g/cc

The pseudo-hydrate-bearing sand would have a strong peak event at the top and a weak trough event at the base (**Figure 16**). There is a modest decrease in amplitude with offset as well as normal frequency decrease. For Sand A (gamma ray < 75), substituted hydrate values are Vp = 12,465 ft/sec, Vs = 7216 ft/sec, and density = 2.01 g/cc.

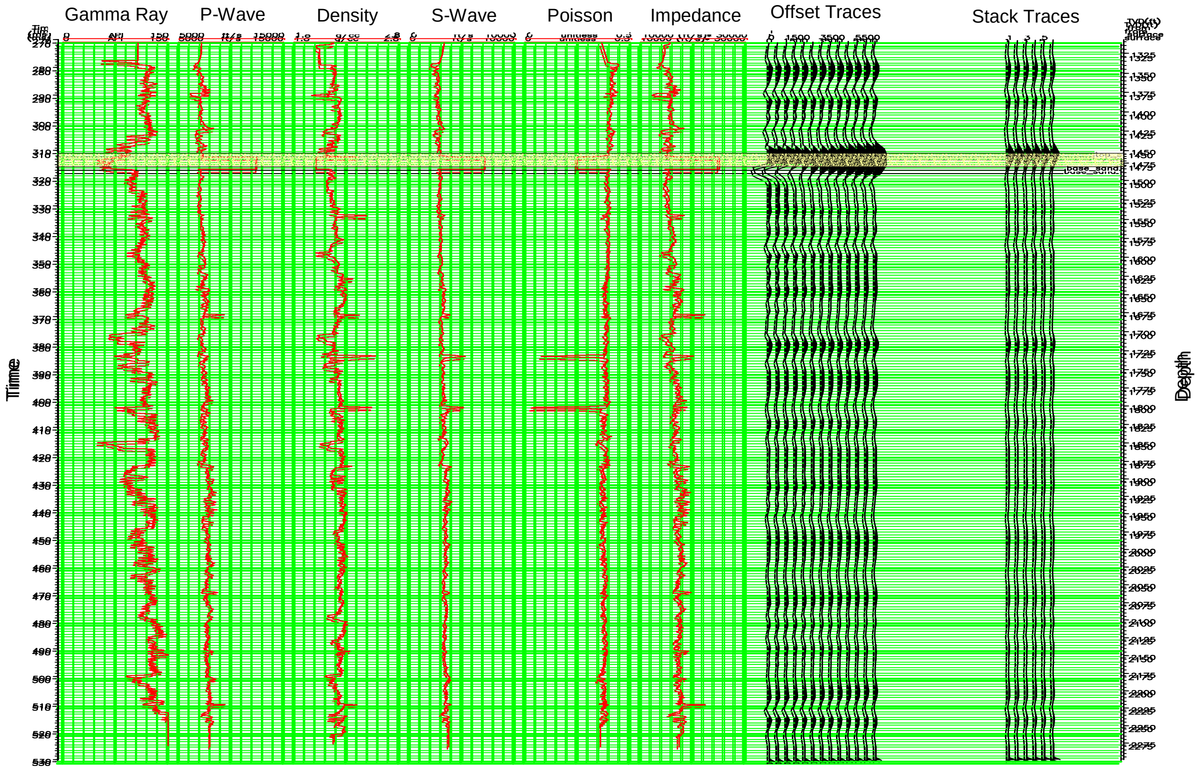


Figure 16. Hydrate Synthetic Seismogram (Sand A indicated by horizontal lines)

A comparison of these modeled seismograms (**Figure 17**) shows that the presence of methane hydrates within the reservoir sand would be seen as an observable reflection event with a different polarity at the top and base than that of the brine-saturated sand. (These traces have been reduced to emphasize the area surrounding Sand A.) The final migrated VSP data provide the vehicle to investigate the presence of polarity or other seismic character changes away from the wellbore that might indicate the presence of hydrates in the reservoir Sand A.

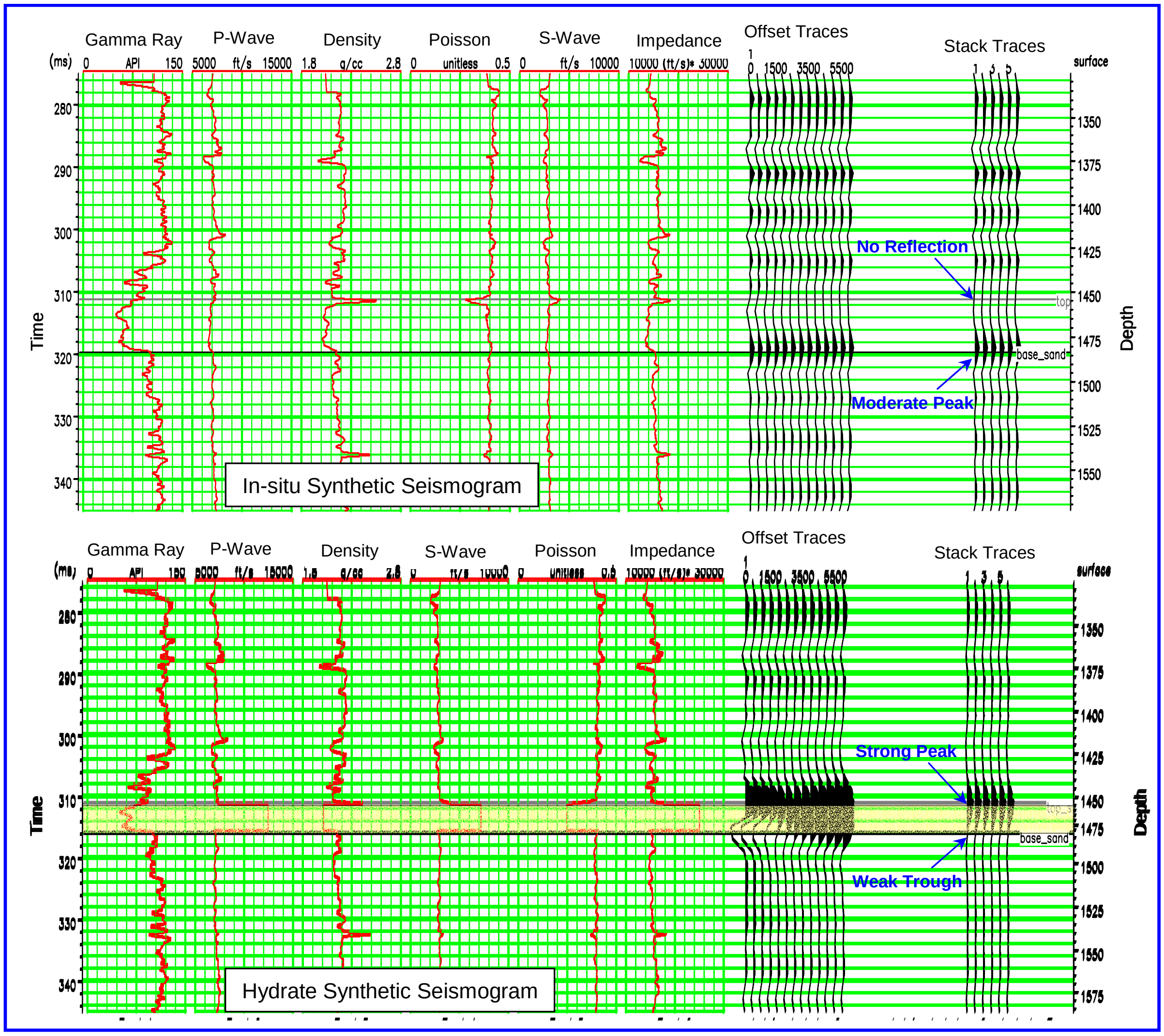
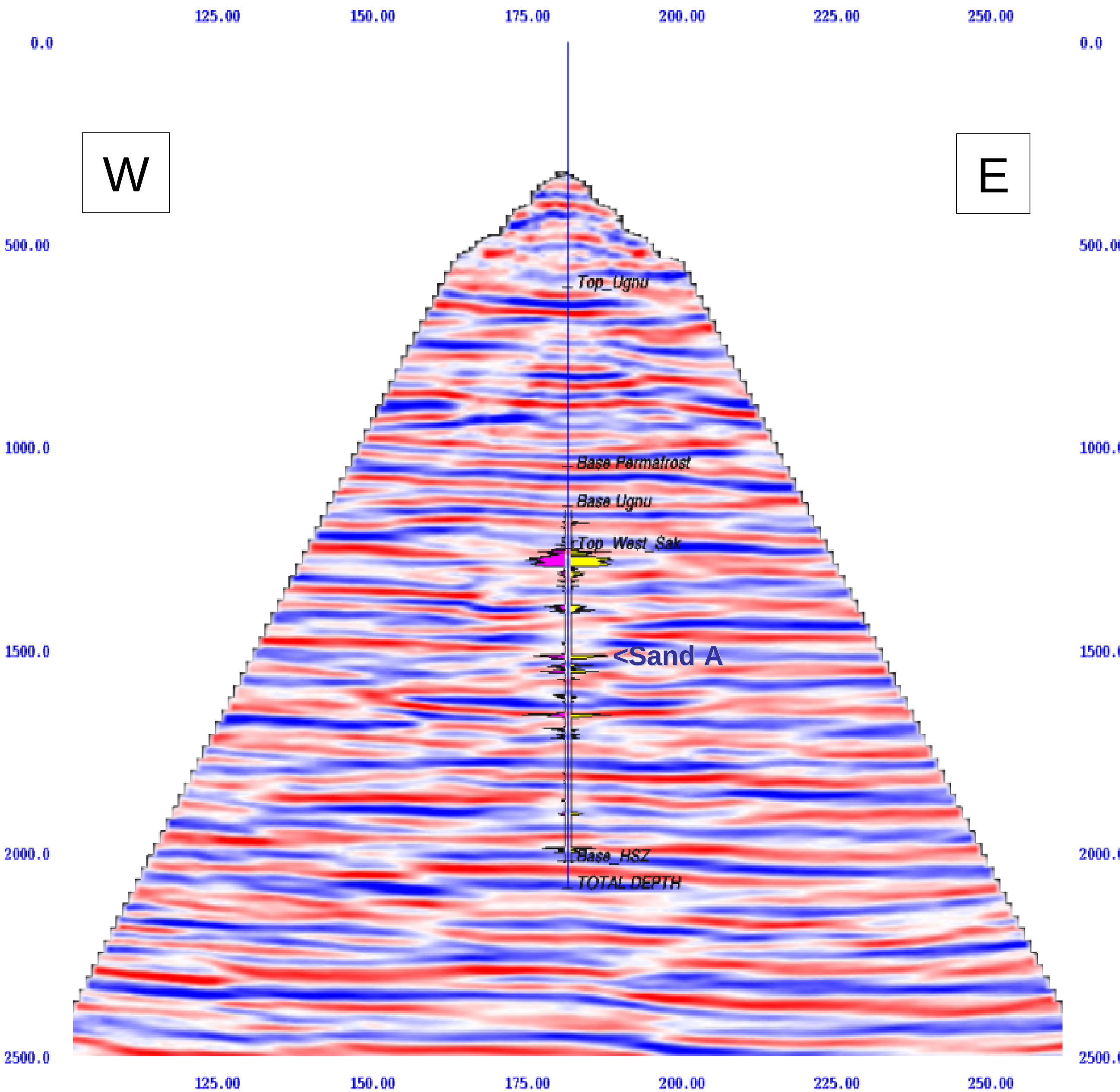
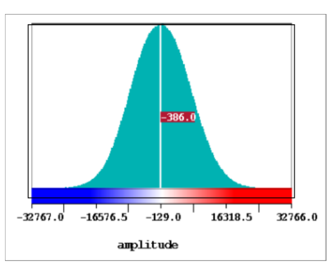


Figure 17. Comparison of Synthetic Seismic Responses from Well Log Data and Reservoir Sand if Methane Hydrates were Present

3.4 VSP Interpretation

The final depth-migrated VSP data and wireline log data from the well were loaded into an interpretation project for analysis using Paradigm's VoxelGeo interpretation software. The first step in interpreting the VSP data was integration of the well log data. Since both wireline data and VSP data were in the depth domain, this task was straightforward. Sand A can be seen by selectively color-filling the Vshale curve for values less than 50% and the porosity log for values greater than 15% (**Figure 18**). (In the figure, "Base HSZ" refers to the base of the hydrate stability zone.)





Well log color fill:
Left: Vshale < 50%
Right: Porosity > 15%

Figure 18. East-West profile of VSP Data Through Hot Ice No. 1.
(filled log curves identify Sand A, where Vshale <50% and porosity >15%)

One of the major challenges to interpreting the Hot Ice No. 1 VSP volume is the stratigraphic nature of the geology represented by the seismic reflectors. Since the Ugnu and West Sak are predominantly fluvial-deltaic deposits, rock layers may be expected to thin, thicken, pinch out, truncate, and change dip direction throughout the section. Small faults may exist in such an environment as well. Such stratigraphy should result in discontinuous and variable reflectors that may not be widely extensive.

A second interpretation challenge is identification of any polarity reversals in the Sand A reflection interval which might indicate the presence of methane hydrates in the sand. Interpretation techniques that track amplitudes will naturally follow a consistent polarity event (peak or trough) throughout a volume. The only hints of polarity changes in an amplitude-tracked reflection event would be dip changes, which also could be caused by reflector terminations at faults or facies boundaries, in addition to polarity shifts.

In light of the challenges in interpreting a stratigraphically variable reflection package with possible polarity changes, an interpretation technique was devised for the Hot Ice No. 1 VSP volume (see **Appendix M**). Several laterally continuous geologic markers were identified above and below Sand A and two of these were coarsely interpreted and gridded. Three dimensional planes were fit to these marker horizons to reduce the uncertainty due to edge effects of the transversely anisotropic velocities, as seen in Appendix H. Because of slight dip and azimuth differences in the two marker planes bracketing Sand A, an average marker plane was computed and then positioned at the Sand A level. Amplitude values were displayed on the geologic marker plane where it intersected the VSP volume.

As seen in **Figure 19**, the amplitude display on the geologic marker plane at the top of Sand A shows little or no amplitude strength at the well location (yellow). To the west, the amplitudes are strong peaks (blue). This amplitude variation is the same response seen in the synthetic seismograms when the in-situ case is substituted for a hydrate-bearing case. ***Therefore, the change in amplitude may indicate the presence of methane hydrates in Sand A only a few hundred feet west, and updip, of the wellbore.***

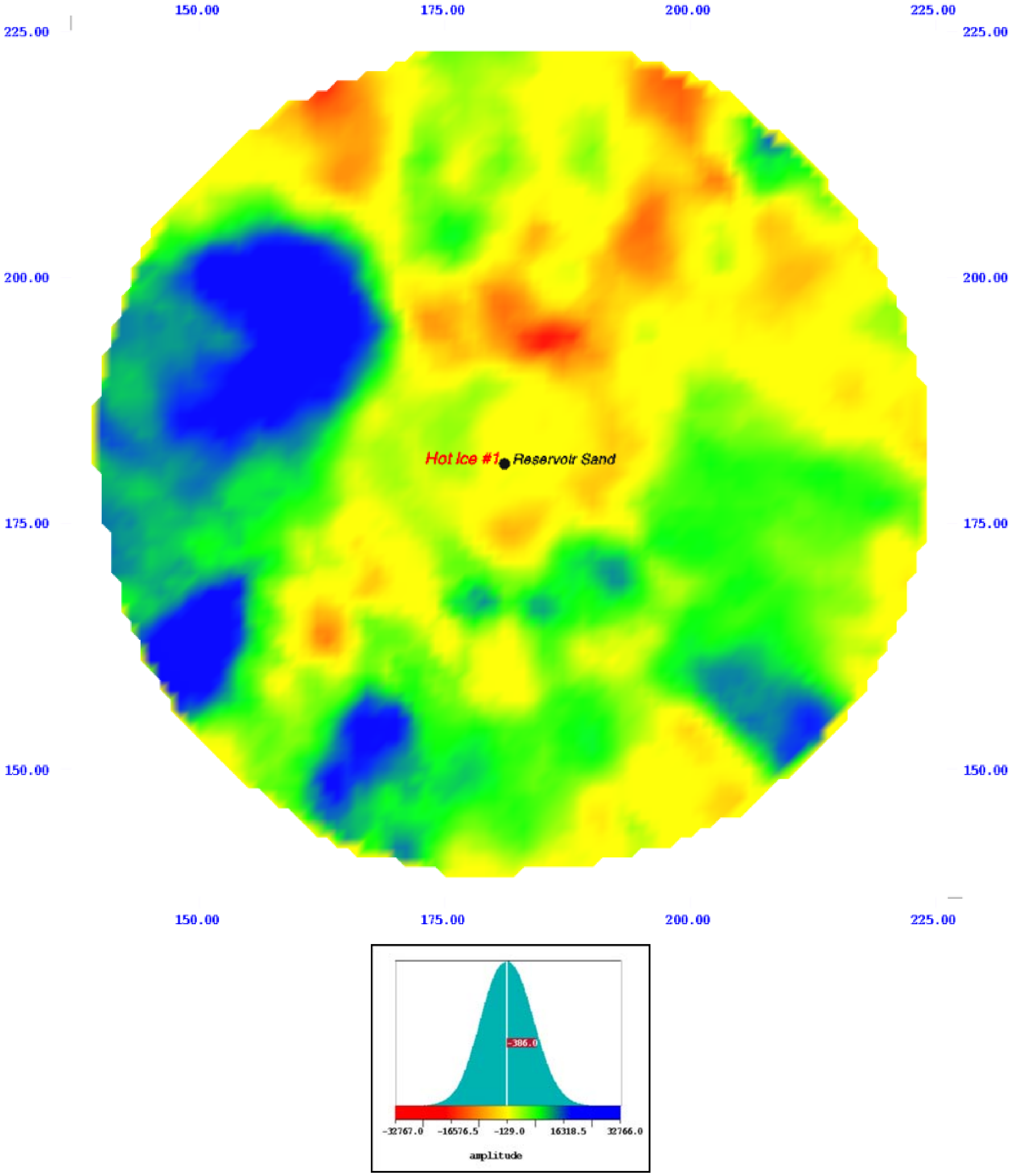


Figure 19. VSP Amplitude Data Displayed on a Seismic Marker at top of Sand A.
(Amplitude values at the well are approximately zero. To the west, amplitudes are strong peaks.)

The amplitude display on the geologic marker at the base of Sand A, however, does not show the response expected for a change from brine-saturated sand to hydrate-bearing sand. There is no peak reflector at the base of Sand A at the well location, although a weak to moderate trough, indicative of the base of a hydrate-bearing sand, is seen in the same area west of the well as the strong peak at the top of Sand A.

Finding Hydrates

As mentioned, we did not find hydrates in the Hot Ice well, much to the disappointment of the entire team. The question became, "What would hydrates look like if they are nearby?" Using the well logs below the washouts, we created a set of synthetic seismograms to investigate this question. The synthetic seismogram for the in-situ case is shown in the upper half of Figure 17. On offset gathers, the top and base of the in-situ brine sand should have little change in reflectivity with offset. On stacked, zero phase data, this sand should have little reflectivity at the top and a weak to moderate peak at the base.

We then performed a fluid substitution with rock properties calculated for this sand with a 70% saturation of hydrates.

Condition	Vp	Vs	Density
Brine Sand	7150 ft/sec	2850 ft/sec	2.03 g/cc
Hydrate Sand	12464 ft/sec	7216 ft/sec	2.01 g/cc

The resulting synthetic seismogram is shown in the lower half of Figure 17.

On offset gathers, the top of a hydrate-bearing sand should be represented by a strong peak and the base by a strong trough, both decreasing in amplitude with offset. On stacked, zero-phase data, this sand should have a strong peak at the top and little or no reflectivity at the base.

We then transferred this expectation to the VSP data to see if these differences could be discerned. Color-filled log data are shown in Figure 18. On the left is the V shale log with values less than 50% in magenta. On the right is the porosity log with values greater than 15% in yellow. These cutoffs were used to identify the most sand-prone units. There is one thicker sand at around 1400 ft and several thinner sands below it.

The primary challenge in interpreting the VSP volume is how to pick a horizon in a predominantly fluvial setting where sands and shales interfinger and where we are looking for a change in polarity if hydrates are present. Fortunately, there is a regional shale marker immediately above the main sand; the team created a plane to fit that shale. That shale plane was then moved down to the sand and used as a pseudo-sand horizon. The amplitudes from the 3D VSP were then draped onto the sand horizon.

In plan view, these amplitudes are shown in Figure 19. Recall from the synthetic seismograms that in-situ sand at the wellbore had very little amplitude information; it is shown in Figure 19 in yellow, according to the colorbar. Also recall that hydrates would have a strong peak at the top of the sand. The blue patch northwest of the wellbore fits that description and may indicate the presence of hydrates near the well.

4. Conclusions

The Hot Ice No. 1 massive 3D VSP was a highly innovative survey with several first-time applications of recently developed technology. It was the first survey recorded using Paulsson Geophysical Services (P/GSI) third-generation 80 level 3C downhole seismic array, and the first P/GSI survey using 25 ft spacing between the 3C pods. It was also P/GSI's first deployment in a partially uncased hole. P/GSI's processing system was first networked directly with the recording system for real-time field processing and data QC. The production sweep was the highest-frequency sweep (8-220 Hz) used thus far on a P/GSI survey. It was also the Industry's first acquisition geometry using circular pattern shooting with variable shot spacing for an onshore 3D VSP.

The 3D VSP successfully imaged the volume surrounding the Hot Ice No. 1 well consisting of a sequence of deltaic fluvial deposits. The anticipated resolution could be met with the average dominant frequency of the processed data to reach between 110-130 Hz.

Since Hot Ice No. 1 was dry (no producible volume of methane hydrates was found), one of the goals was to map a potential hydrate-bearing horizon into the surrounding volume and investigate the reflective properties for evidence of hydrates. This proved to be a difficult task, mainly because gas hydrates generally produce only weak AVO anomalies. This task could not be accomplished since AVO/AVA studies would have to be carried out in the depth domain for a 3D VSP survey and (although being developed) P/GSI does not currently have a suitable true-amplitude prestack migration algorithm for this purpose.

Recommendations for Future Work

Several areas of investigation can be undertaken to derive additional information from the 3D VSP survey. Other methods of separating up-going and down-going energy may give different images of the subsurface. Processing the shear energy may provide additional insights into rock properties of the potential reservoir sands and help identify any changes in the pore-filling materials within the VSP survey area.

5. Acknowledgements

This project could not have been completed without input from Dr. Alexander Goertz of P/GSI who did all data processing, including numerous parameter tests and evaluations; and Ms. Shari Houston of Anadarko who performed the synthetic seismogram modeling.

6. References

(No references were cited in this report)

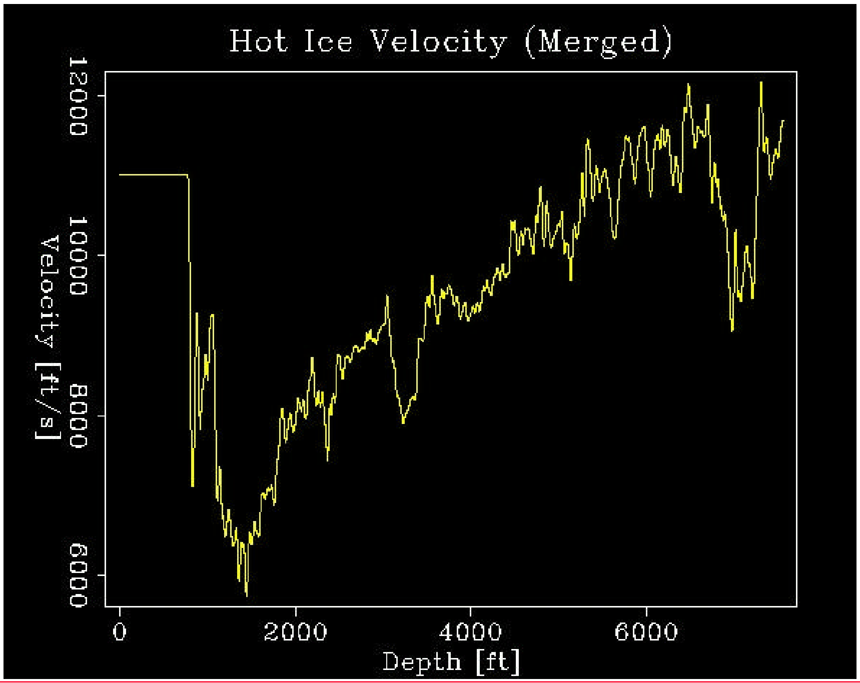
Appendix A

Subsurface Fold Coverage

Pre-Survey Modeling Steps

1. Generation of four different shot patterns based on a maximum source offset of 2,600 ft (220, 175,165 and 150 ft)
2. Construction of simple 1D model using Cirque 2 sonic log
3. Walk-away line fold estimation using ray tracing in layered media based on:
    1. Fresnel zone due to 100 Hz seismic signal
    2. Pure ray hit

Velocity Profile from Cirque 2 well



Extended Well log up shallow with 11,000 ft/sec constant velocity

Smoothing length in depth is 25 ft

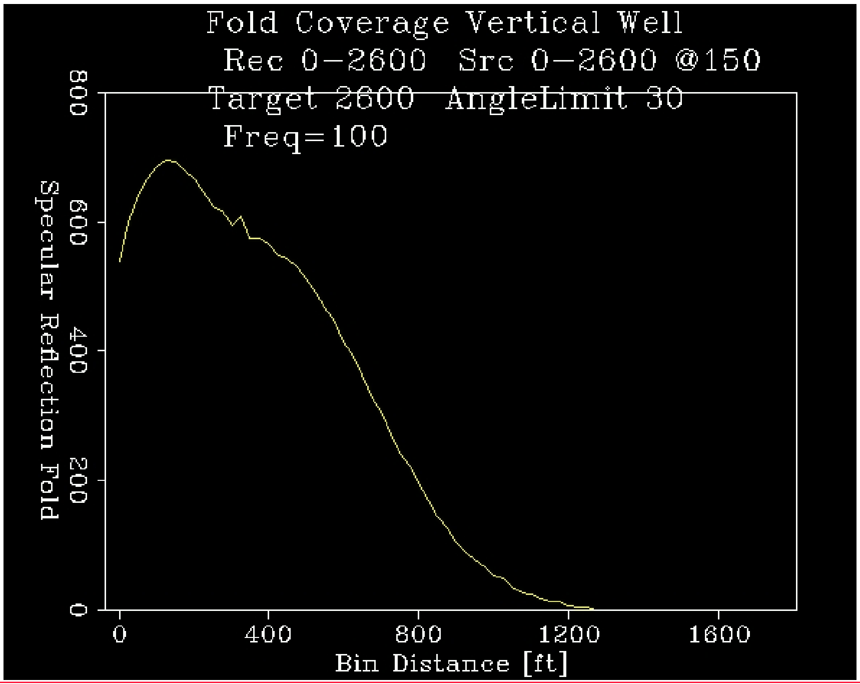
Data Displays:

- Velocity model at the well location
- Fold estimates for each source spacing (220, 175,165 and 150 ft) for target depths of 2,600 ft, 2,000 ft and 1,000 ft, each with 30 and 45° incident angles
- For the target depth of 2,000 ft, estimates are shown with and without the Fresnel zone width parameter in the fold computation

Walk-Away Line Fold Estimation

Target depth for the following estimates is 2,600 ft

Walk-Away Line Fold Estimation



Target 2,600 ft depth

Receivers from 0-2,600 ft depth

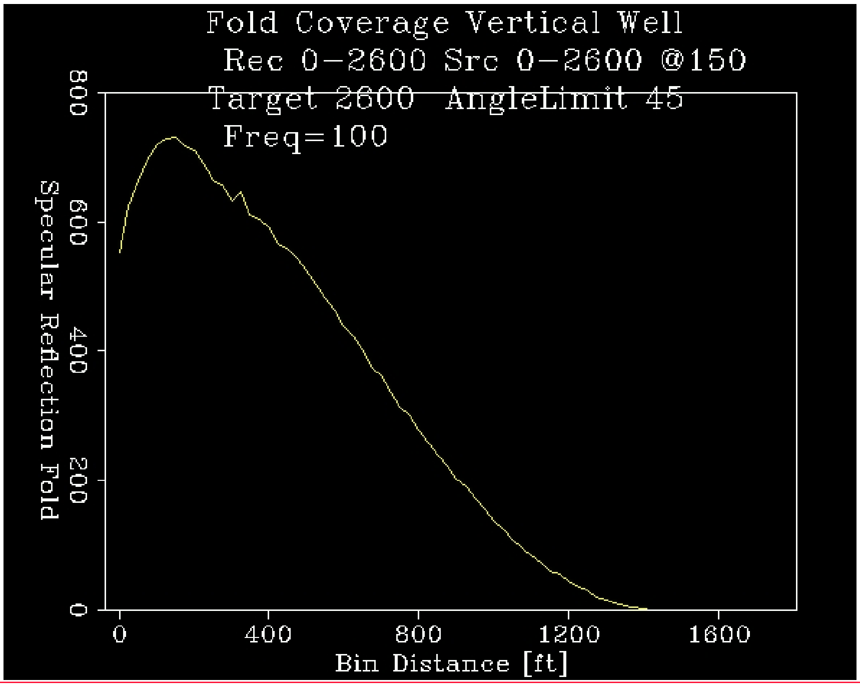
Sources from 0-2,600 ft depth

Source spacing 150 ft

Max incidence angle at target 30°

Fresnel zones for frequencies of 100 Hz

Walk-Away Line Fold Estimation



Target 2,600 ft depth

Receivers from 0-2,600 ft depth

Sources from 0-2,600 ft depth

Source spacing 150 ft

Max incidence angle at target 45°

Fresnel zones for frequencies of 100 Hz

This presentation contains P/GSI processing information. Version 12/11/02

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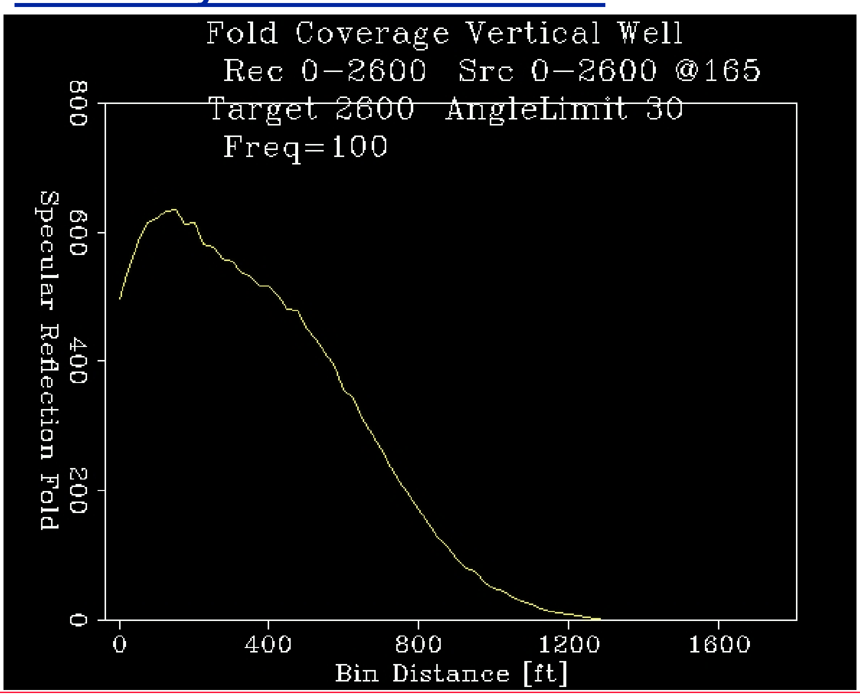
Walk-Away Line Fold Estimation



Target 2,600 ft depth

Receivers from 0-2,600 ft depth

Sources from 0-2,600 ft depth

Source spacing 165 ft

Max incidence angle at target 30°

Fresnel zones for frequencies of 100 Hz

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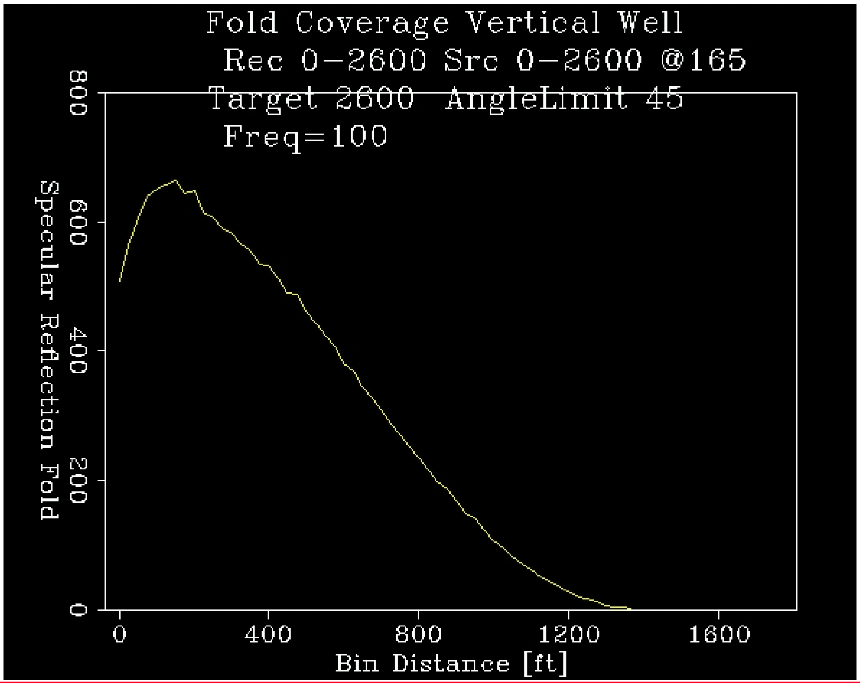
Walk-Away Line Fold Estimation



Target 2,600 ft depth

Receivers from 0-2,600 ft depth

Sources from 0-2,600 ft depth

Source spacing 165 ft

Max incidence angle at target 45°

Fresnel zones for frequencies of 100 Hz

This presentation contains P/GSI processing information. Version 12/11/02

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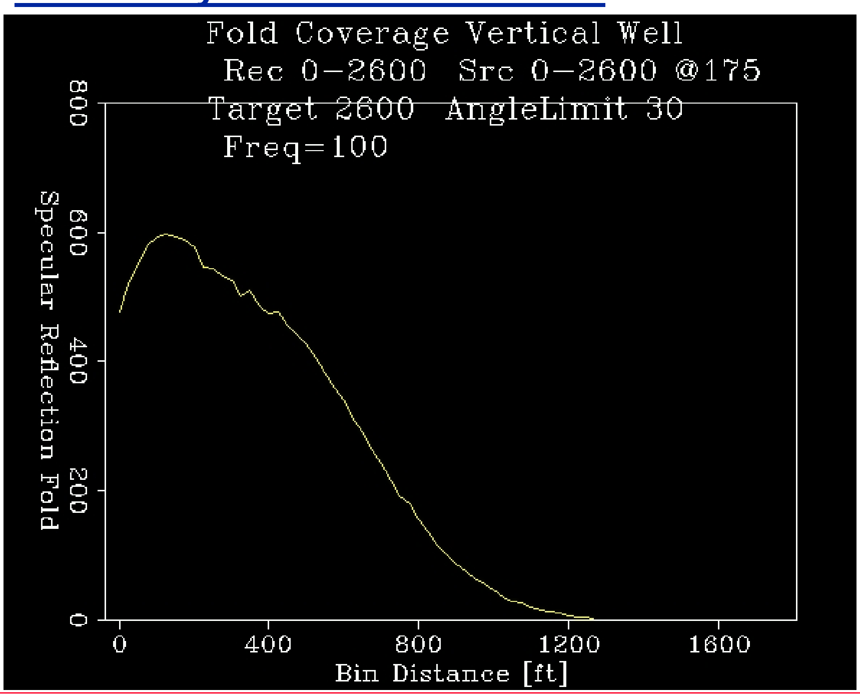
P/GSI™

Walk-Away Line Fold Estimation



Target 2,600 ft depth

Receivers from 0-2,600 ft depth

Sources from 0-2,600 ft depth

Source spacing 175 ft

Max incidence angle at target 30°

Fresnel zones for frequencies of 100 Hz

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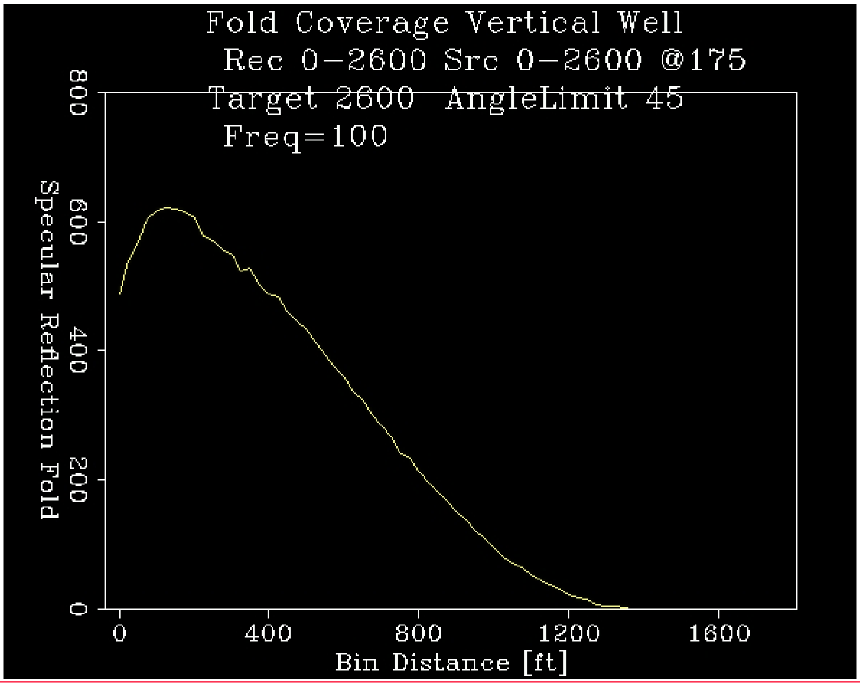
Walk-Away Line Fold Estimation



Target 2,600 ft depth

Receivers from 0-2,600 ft depth

Sources from 0-2,600 ft depth

Source spacing 175 ft

Max incidence angle at target 45°

Fresnel zones for frequencies of 100 Hz

This presentation contains P/GSI processing information. Version 12/11/02

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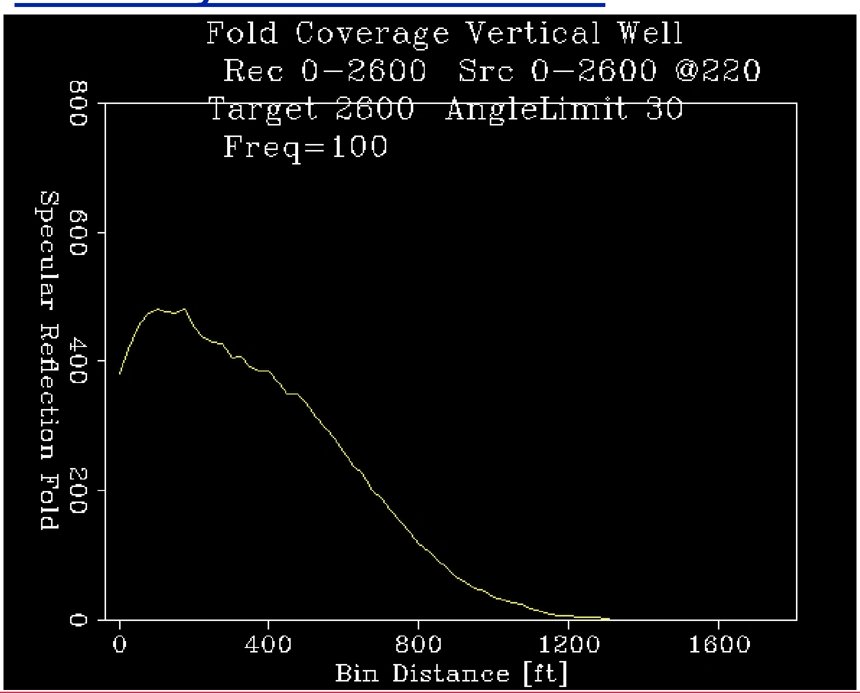
Walk-Away Line Fold Estimation



Target 2,600 ft depth

Receivers from 0-2,600 ft depth

Sources from 0-2,600 ft depth

Source spacing 220 ft

Max incidence angle at target 30°

Fresnel zones for frequencies of 100 Hz

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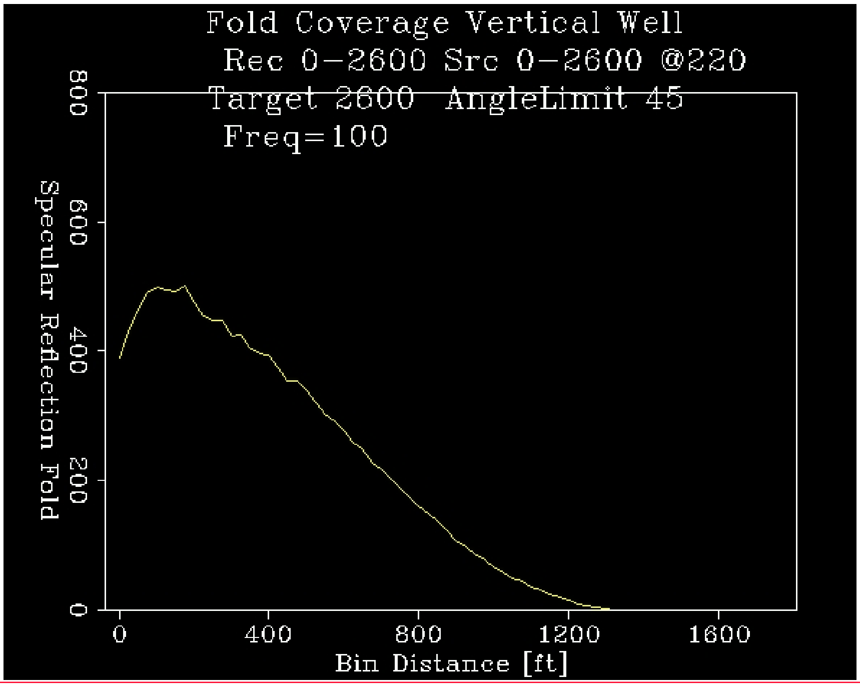
Walk-Away Line Fold Estimation



Target 2,600 ft depth

Receivers from 0-2,600 ft depth

Sources from 0-2,600 ft depth

Source spacing 220 ft

Max incidence angle at target 45°

Fresnel zones for frequencies of 100 Hz

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Walk-Away Line Fold Estimation

Target depth for the following estimates is 2,000 ft

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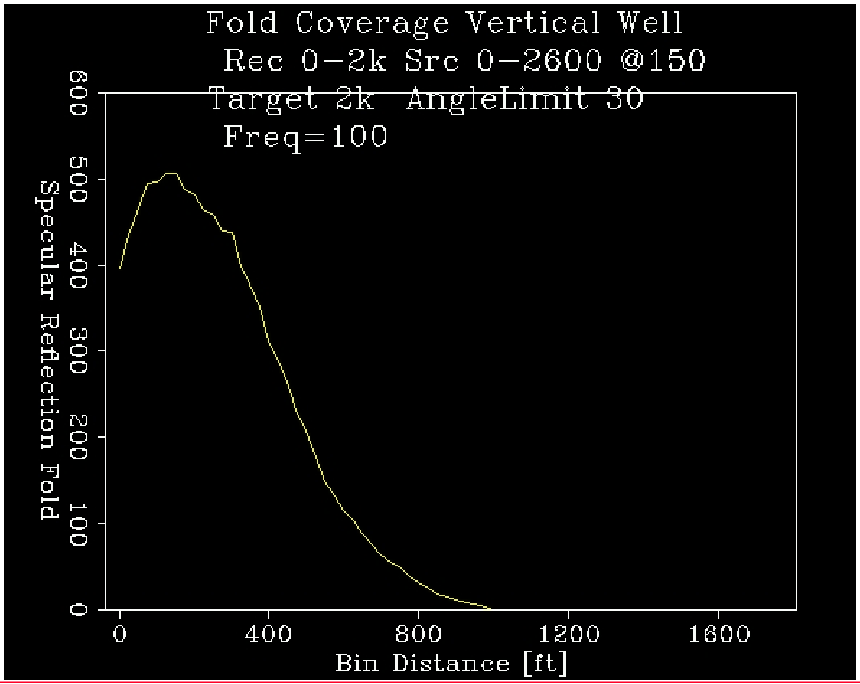
Walk-Away Line Fold Estimation



Target 2,000 ft depth

Receivers from 0-2,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 150 ft

Max incidence angle at target 30°

Fresnel zones for frequencies of 100 Hz

This presentation contains P/GSI processing information. Version 12/11/02

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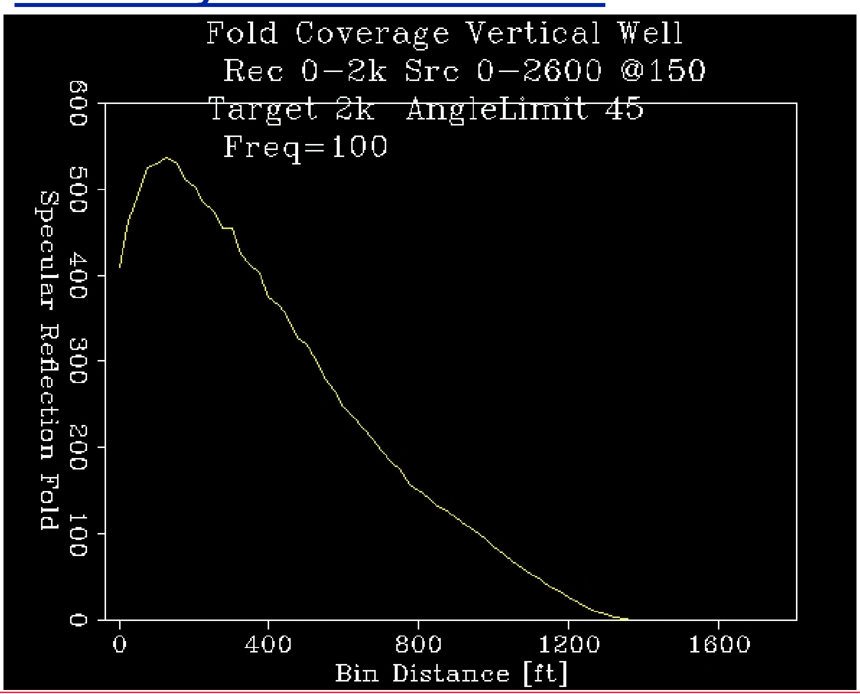
Walk-Away Line Fold Estimation



Target 2,000 ft depth

Receivers from 0-2,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 150 ft

Max incidence angle at target 45°

Fresnel zones for frequencies of 100 Hz

This presentation contains P/GSI processing information. Version 12/11/02

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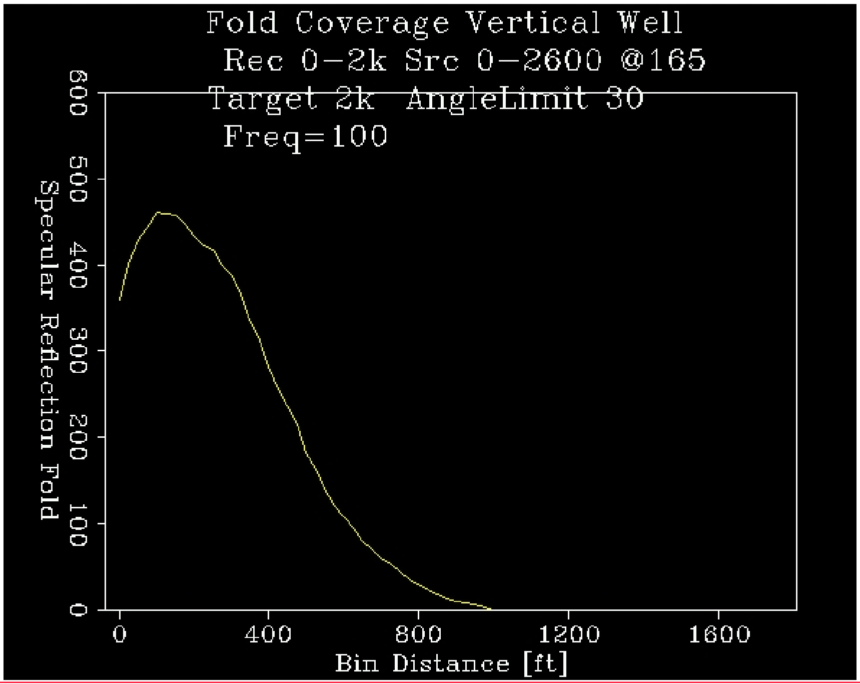
Walk-Away Line Fold Estimation



Target 2,000 ft depth

Receivers from 0-2,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 165 ft

Max incidence angle at target 30°

Fresnel zones for frequencies of 100 Hz

This presentation contains P/GSI processing information. Version 12/11/02

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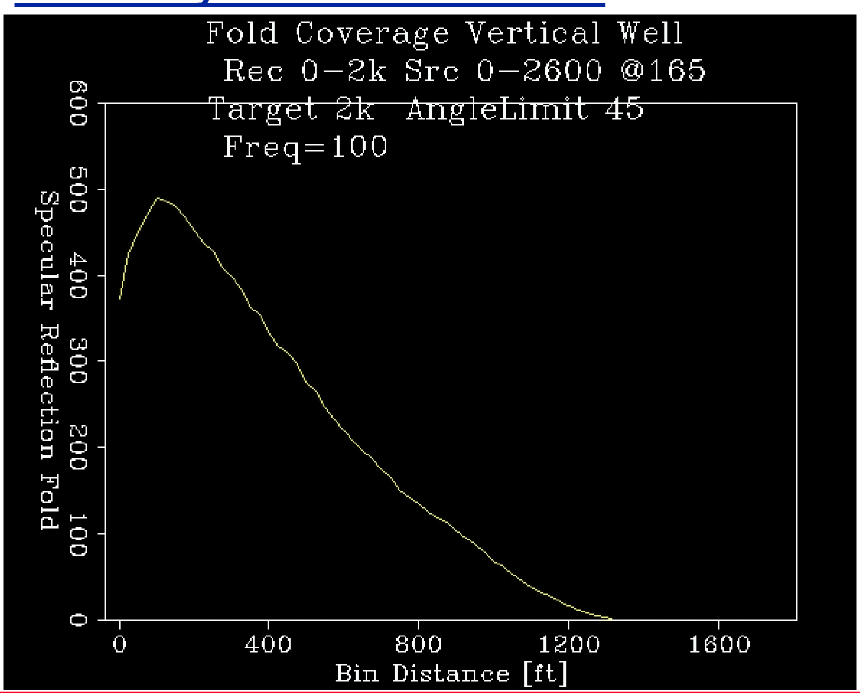
Walk-Away Line Fold Estimation



Target 2,000 ft depth

Receivers from 0-2,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 165 ft

Max incidence angle at target 45°

Fresnel zones for frequencies of 100 Hz

This presentation contains P/GSI processing information. Version 12/11/02

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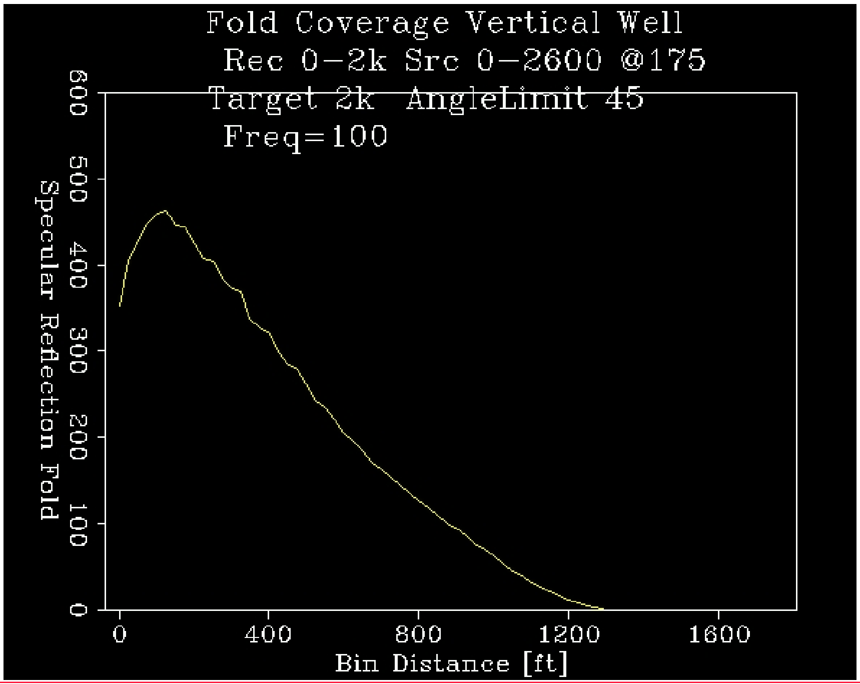
Walk-Away Line Fold Estimation



Target 2,000 ft depth

Receivers from 0-2,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 175 ft

Max incidence angle at target 45°

Fresnel zones for frequencies of 100 Hz

This presentation contains P/GSI processing information. Version 12/11/02

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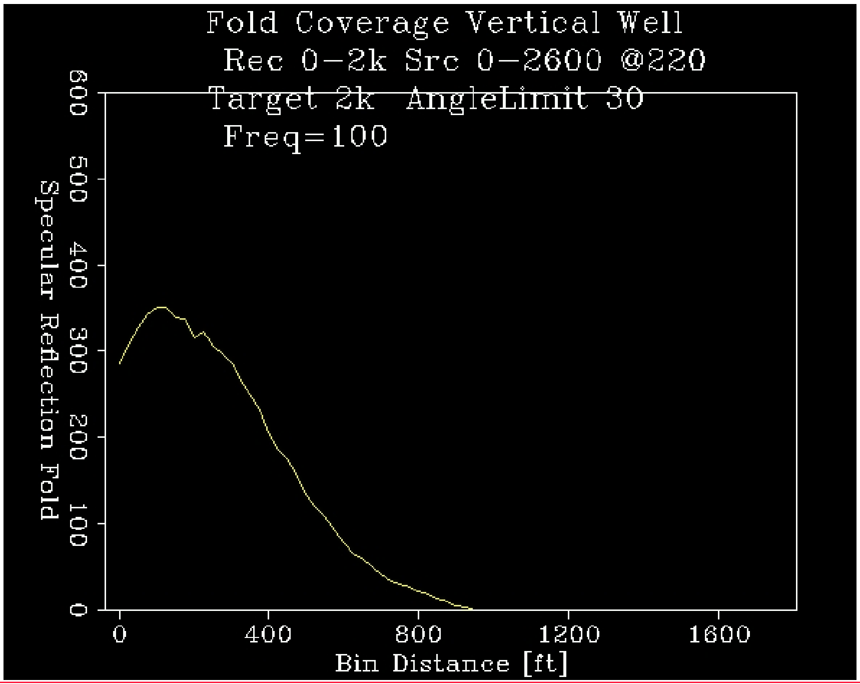
Walk-Away Line Fold Estimation



Target 2,000 ft depth

Receivers from 0-2,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 220 ft

Max incidence angle at target 30°

Fresnel zones for frequencies of 100 Hz

This presentation contains P/GSI processing information. Version 12/11/02

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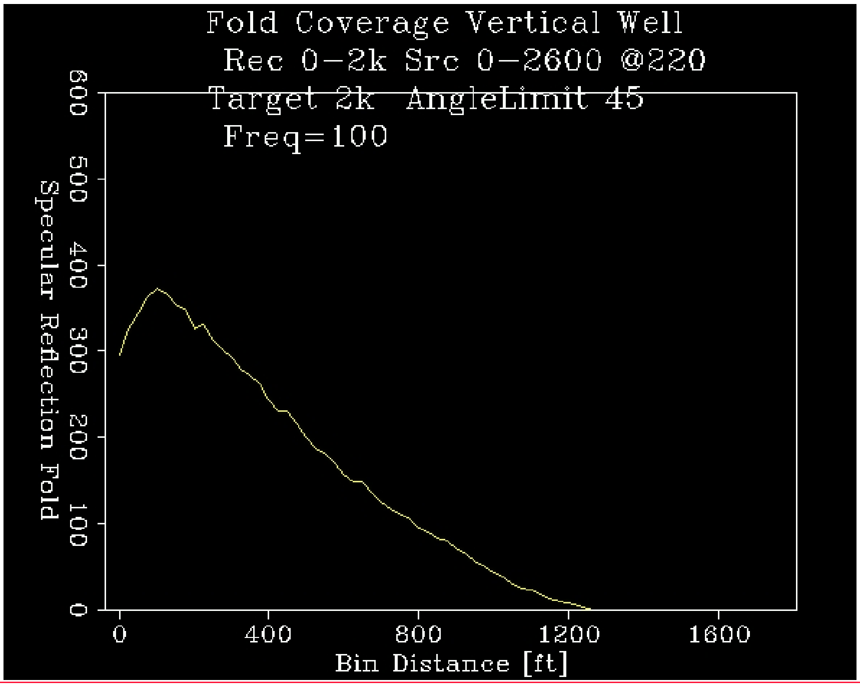
Walk-Away Line Fold Estimation



P/GSI™

Target 2,000 ft depth

Receivers from 0-2,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 220 ft

Max incidence angle at target 45°

Fresnel zones for frequencies of 100 Hz

This presentation contains P/GSI processing information. Version 12/11/02

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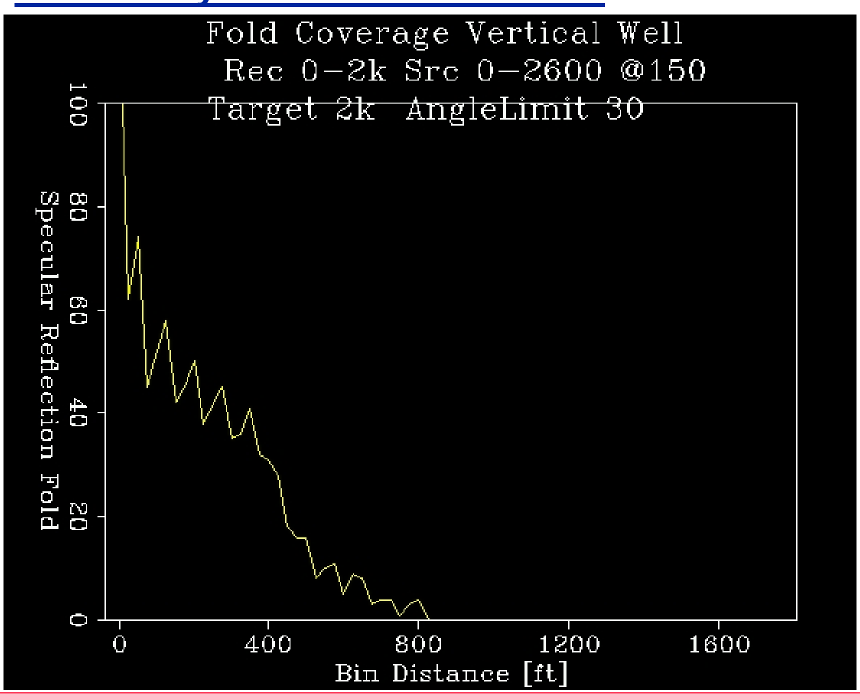
Walk-Away Line Fold Estimation



P/GSI™

Target 2,000 ft depth

Receivers from 0-2,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 150 ft

Max incidence angle at target 30°

Without Fresnel zones.

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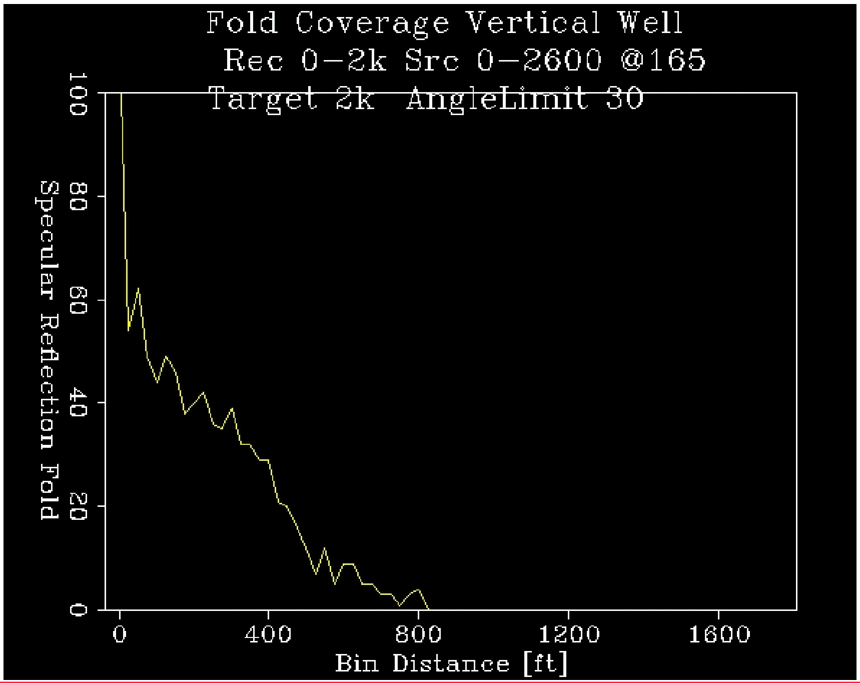
P/GSI™

Walk-Away Line Fold Estimation



Target 2,000 ft depth

Receivers from 0-2,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 165 ft

Max incidence angle at target 30°

Without Fresnel zones.

This presentation contains P/GSI processing information. Version 12/11/02

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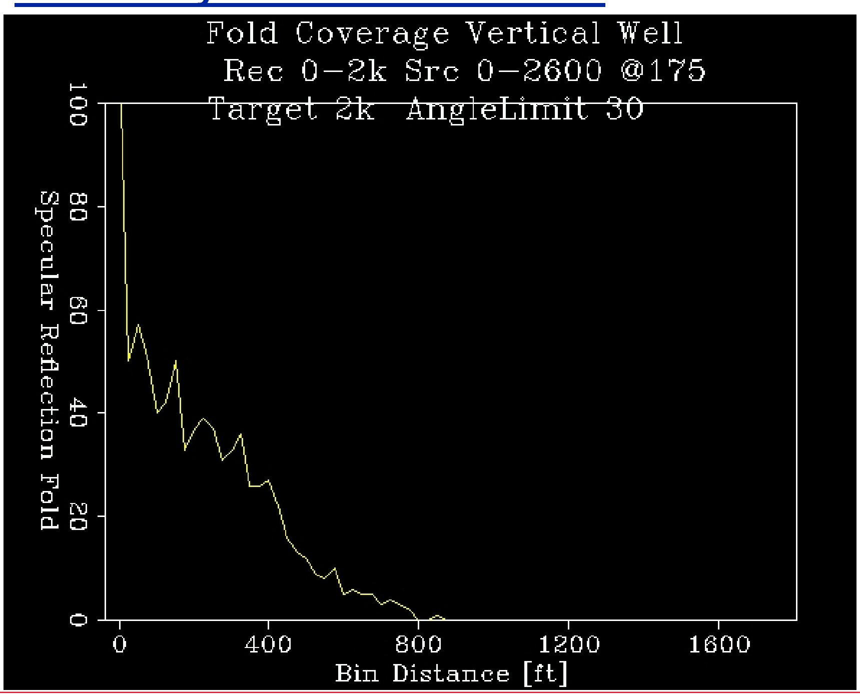
P/GSI™

Walk-Away Line Fold Estimation



Target 2,000 ft depth

Receivers from 0-2,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 175 ft

Max incidence angle at target 30°

Without Fresnel zones.

This presentation contains P/GSI processing information. Version 12/11/02

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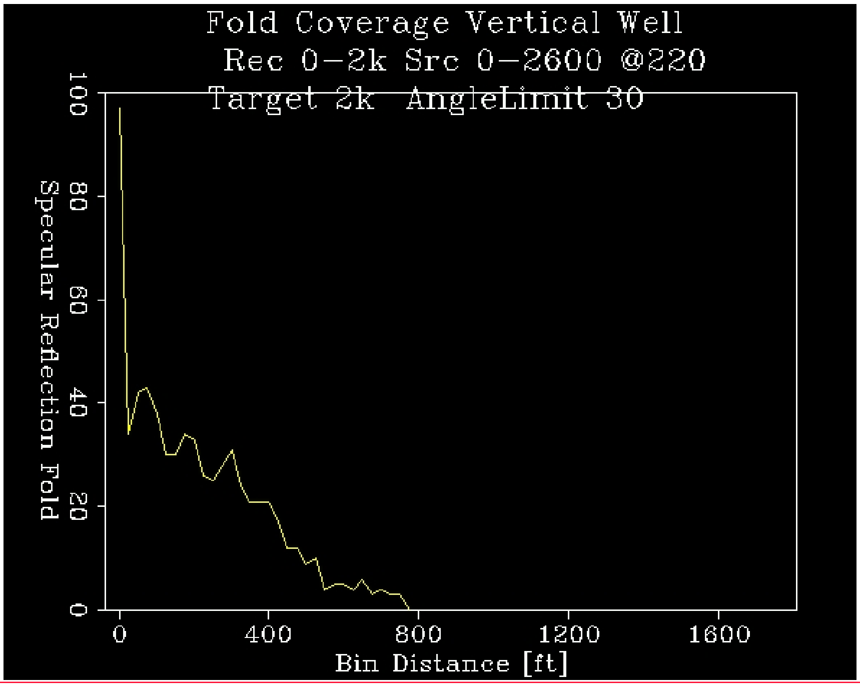
Walk-Away Line Fold Estimation



Target 2,000 ft depth

Receivers from 0-2,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 220 ft

Max incidence angle at target 30°

Without Fresnel zones.

This presentation contains P/GSI processing information. Version 12/11/02

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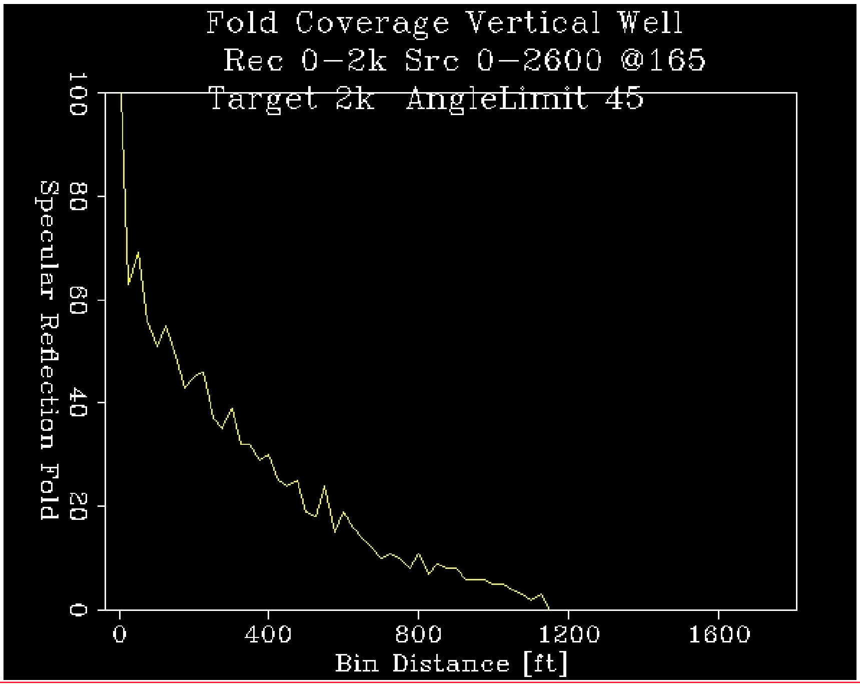
P/GSI™

Walk-Away Line Fold Estimation



Target 2,000 ft depth

Receivers from 0-2,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 165 ft

Max incidence angle at target 45°

Without Fresnel zones.

This presentation contains P/GSI processing information. Version 12/11/02

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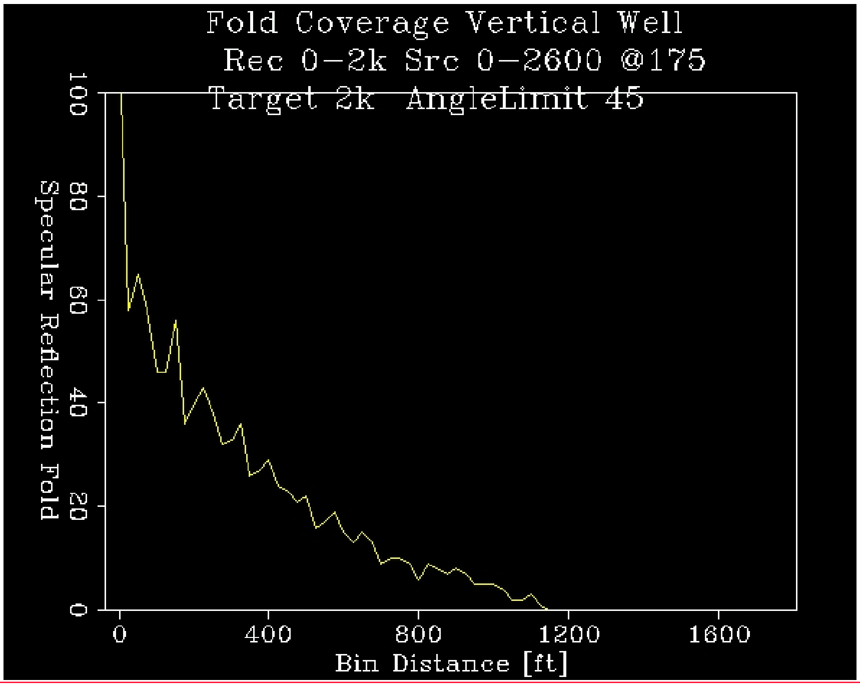
Walk-Away Line Fold Estimation



Target 2,000 ft depth

Receivers from 0-2,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 175 ft

Max incidence angle at target 45°

Without Fresnel zones.

This presentation contains P/GSI processing information. Version 12/11/02

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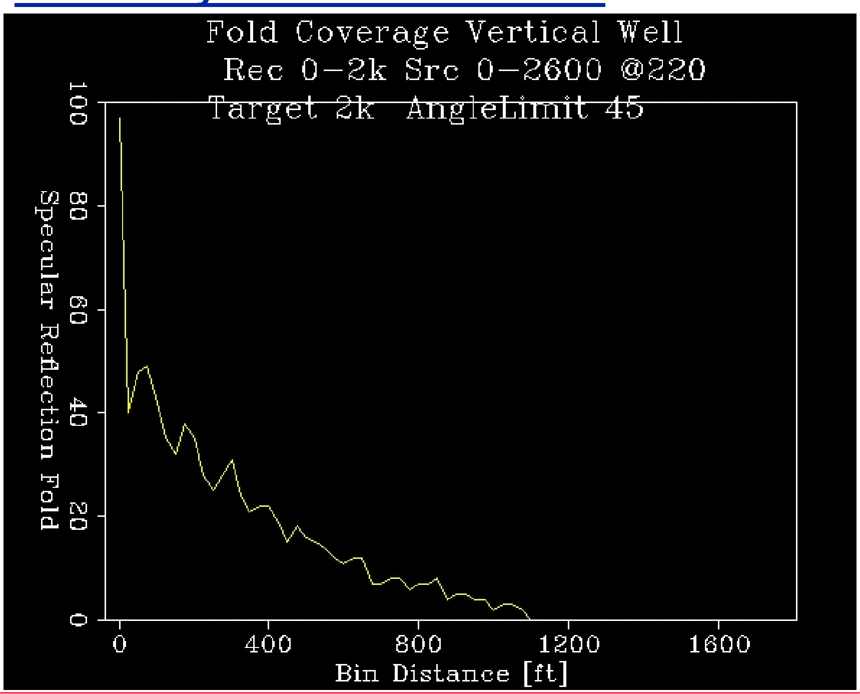
P/GSI™

Walk-Away Line Fold Estimation



Target 2,000 ft depth

Receivers from 0-2,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 220 ft

Max incidence angle at target 45°

Without Fresnel zones.

This presentation contains P/GSI processing information. Version 12/11/02

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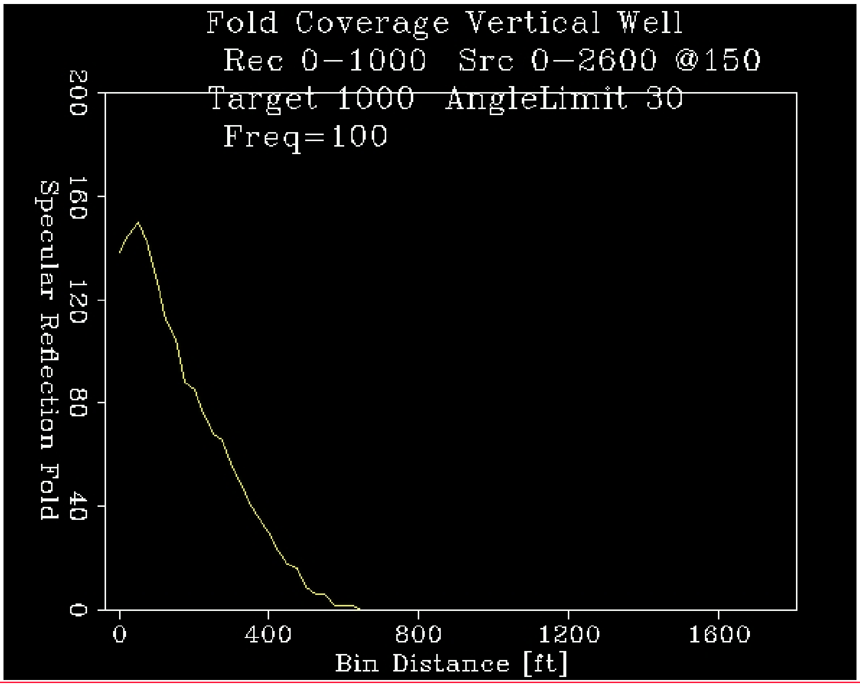
Walk-Away Line Fold Estimation

Target depth for the following estimates is 1,000 ft

Walk-Away Line Fold Estimation



Target 1,000 ft depth

Receivers from 0-1,000 ft depth

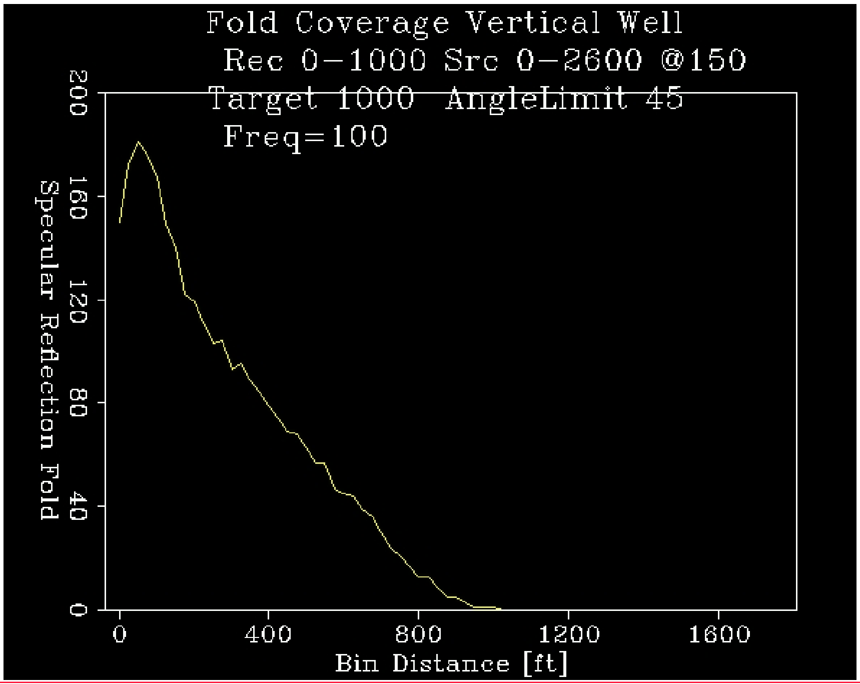
Sources from 0-2,600 ft depth

Source spacing 150 ft

Max incidence angle at target 30°

Fresnel zones for frequencies of 100 Hz

Walk-Away Line Fold Estimation



Target 1,000 ft depth

Receivers from 0-1,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 150 ft

Max incidence angle at target 45°

Fresnel zones for frequencies of 100 Hz

This presentation contains P/GSI processing information. Version 12/11/02

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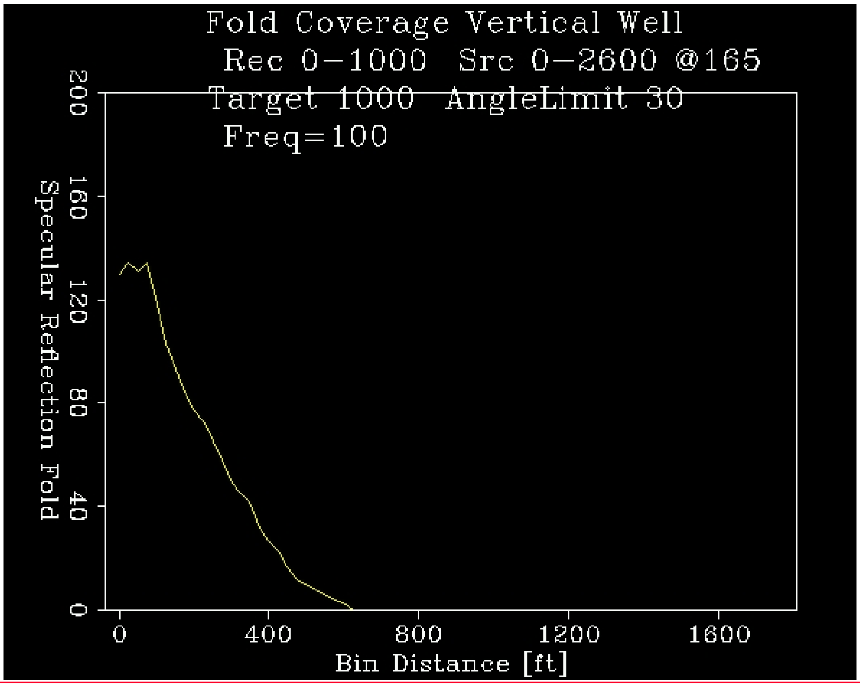
Walk-Away Line Fold Estimation



Target 1,000 ft depth

Receivers from 0-1,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 165 ft

Max incidence angle at target 30°

Fresnel zones for frequencies of 100 Hz

This presentation contains P/GSI processing information. Version 12/11/02

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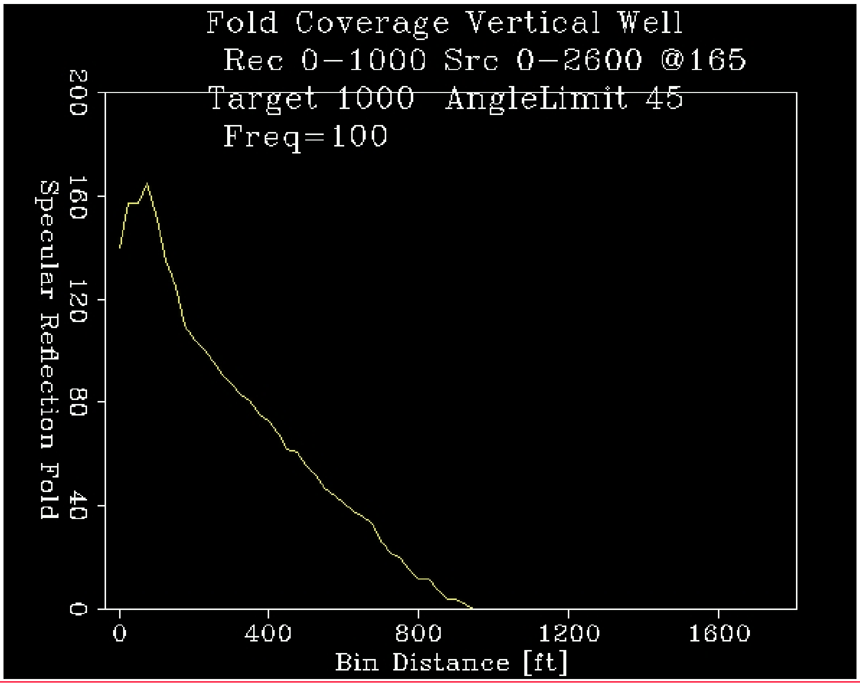
Walk-Away Line Fold Estimation



Target 1,000 ft depth

Receivers from 0-1,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 165 ft

Max incidence angle at target 45°

Fresnel zones for frequencies of 100 Hz

This presentation contains P/GSI processing information. Version 12/11/02

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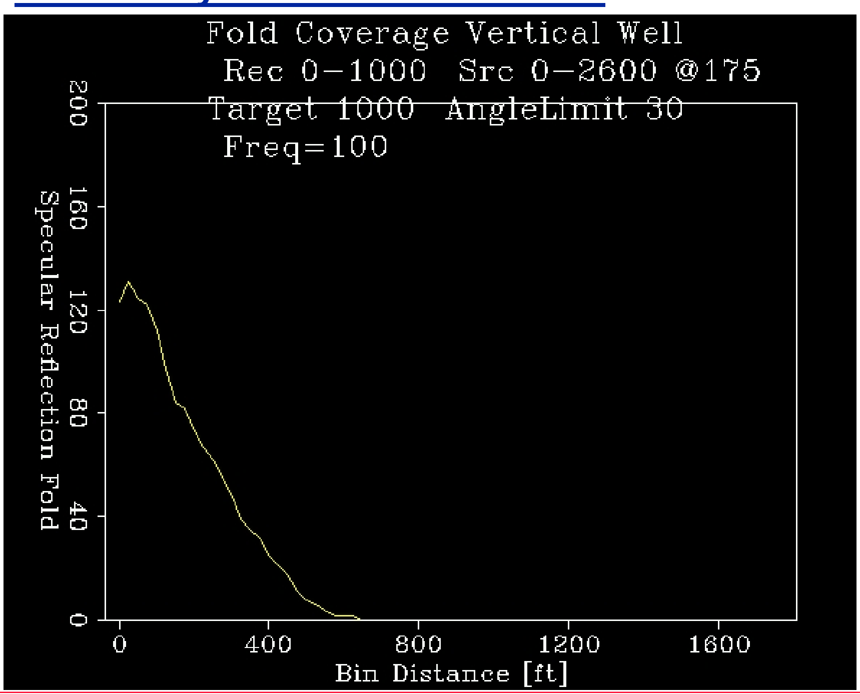
Walk-Away Line Fold Estimation



Target 1,000 ft depth

Receivers from 0-1,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 175 ft

Max incidence angle at target 30°

Fresnel zones for frequencies of 100 Hz

This presentation contains P/GSI processing information. Version 12/11/02

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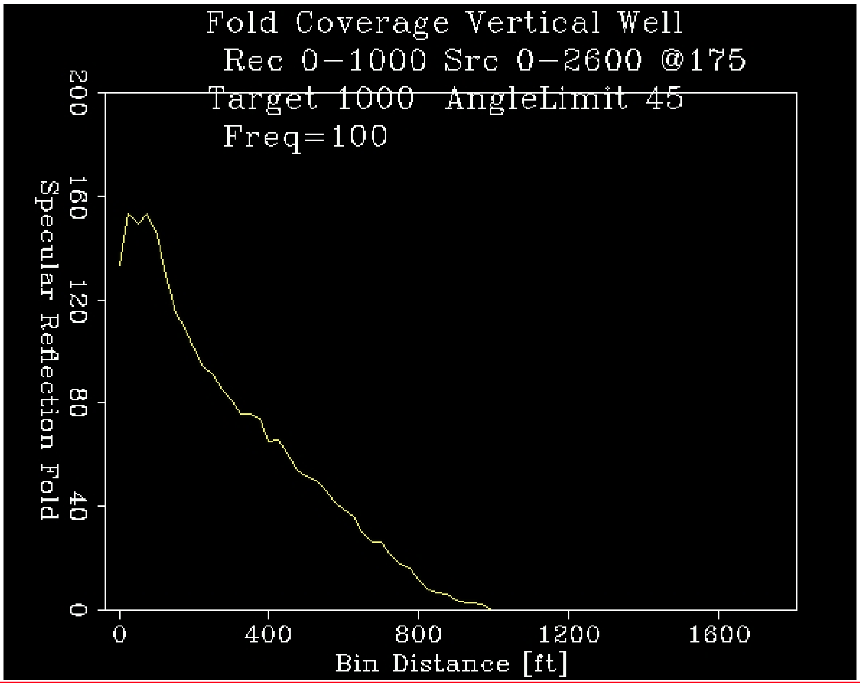
Walk-Away Line Fold Estimation



Target 1,000 ft depth

Receivers from 0-1,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 175 ft

Max incidence angle at target 45°

Fresnel zones for frequencies of 100 Hz

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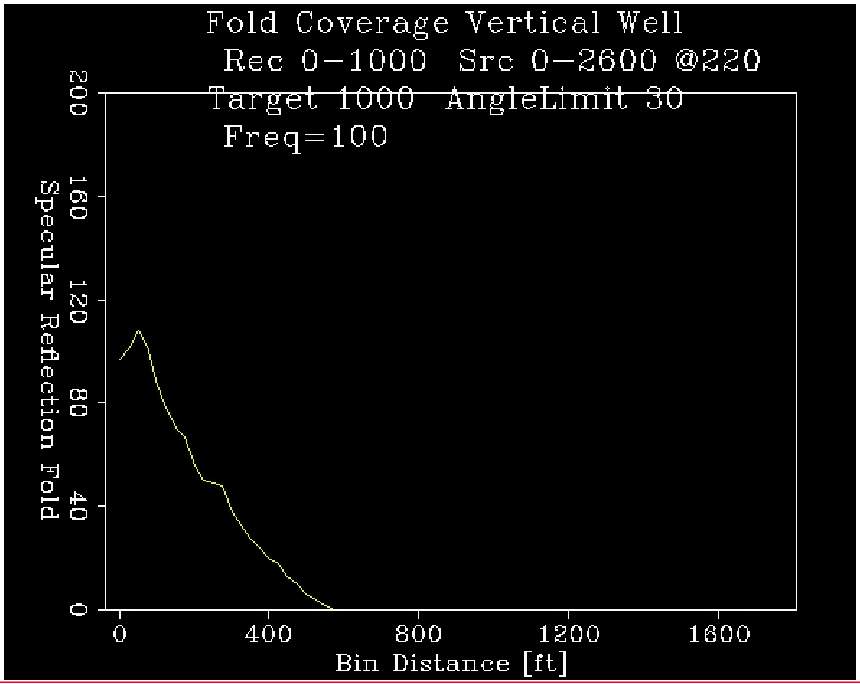
Walk-Away Line Fold Estimation



Target 1,000 ft depth

Receivers from 0-1,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 220 ft

Max incidence angle at target 30°

Fresnel zones for frequencies of 100 Hz

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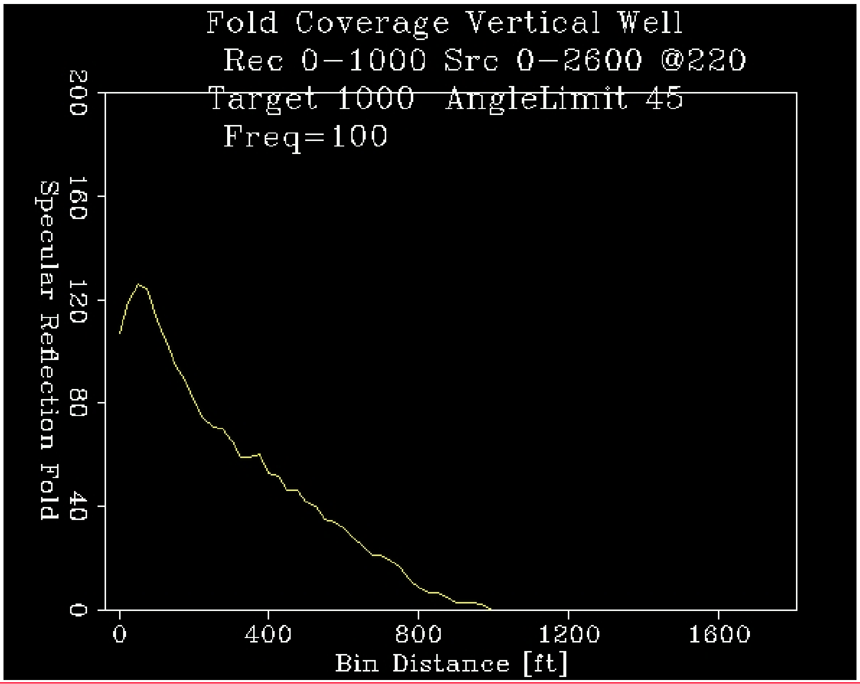
Walk-Away Line Fold Estimation



Target 1,000 ft depth

Receivers from 0-1,000 ft depth

Sources from 0-2,600 ft depth

Source spacing 220 ft

Max incidence angle at target 45°

Fresnel zones for frequencies of 100 Hz

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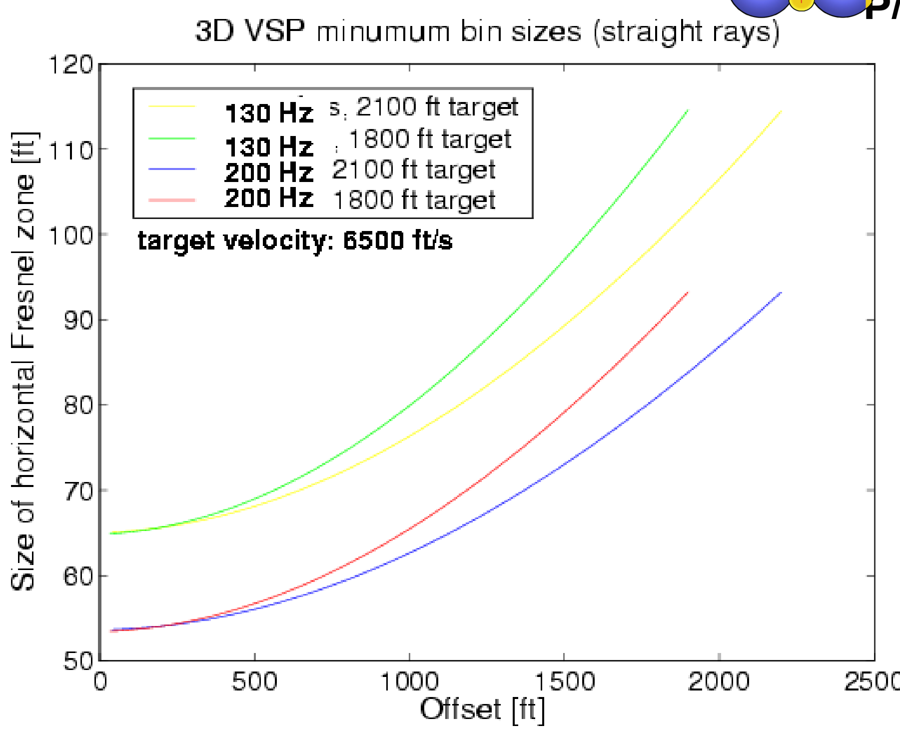

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Appendix B

P/GSI Equipment

Deployment and Retrieval

The Hot Ice 3D VSP - a ground breaking survey

- The first survey recorded using P/GSI's 3rd generation 80 level 3C downhole seismic array
- P/GSI's first 80 level cable with 25 ft spacing between the 3C pods
- P/GSI's first deployment in an open hole
- P/GSI's first survey with the processing system networked with the recording system for immediate processing of the data
- Industry first acquisition geometry using circular pattern shooting for an on shore 3D VSP
- Highest frequency sweeps, 8 – 220 Hz, used on a P/GSI survey
- First 3D VSP used to map methane hydrates

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Well Information

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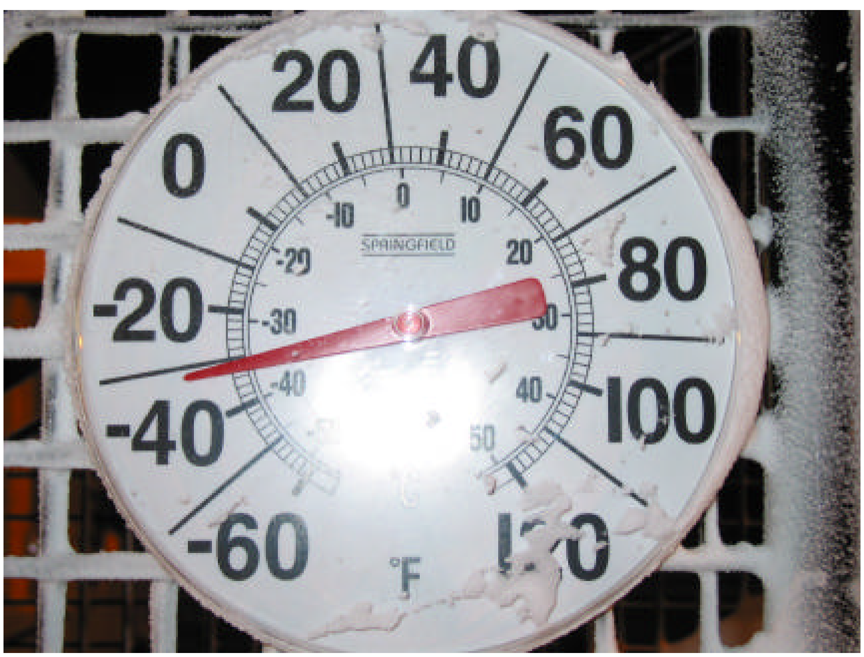
Outside air temperature during survey



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Deployment of P/GSI's 3rd Generation 80 Level 3C Downhole Seismic Array

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Receivers on the cable spool

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Deployment of cable spool into the drilling room

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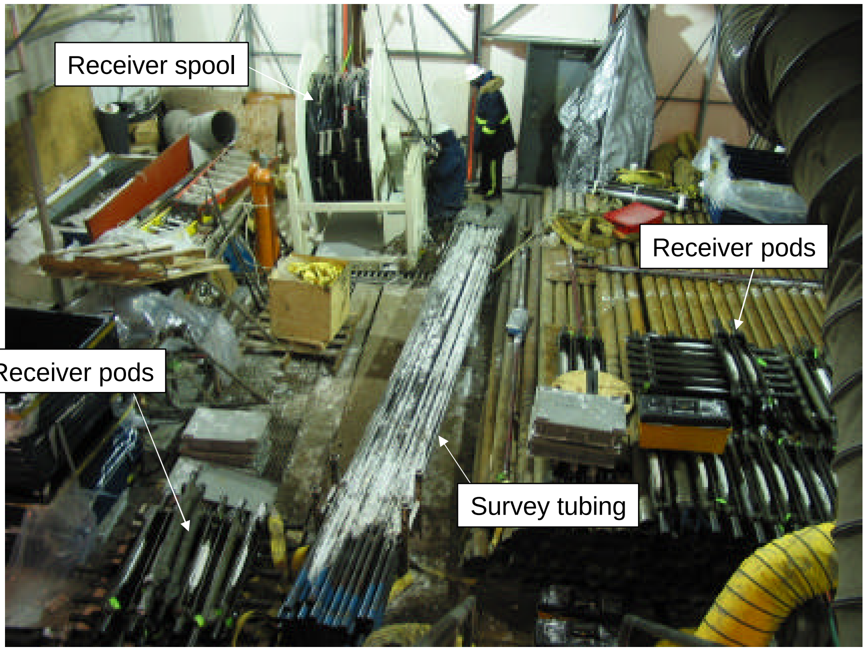
Survey equipment in the drilling room



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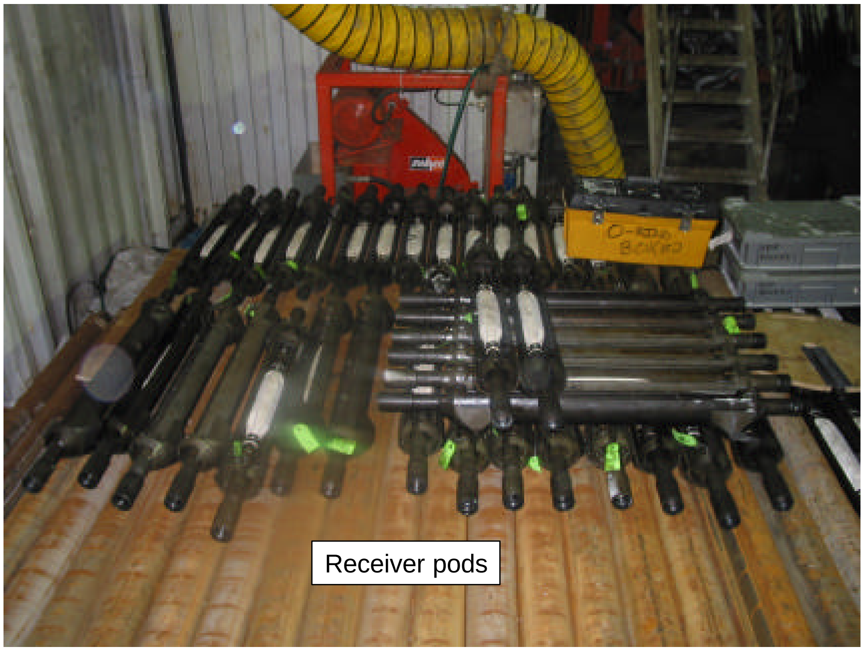
Survey equipment in the drilling room



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Survey equipment in the drilling room

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Pulley for cable deployment into the wellbore

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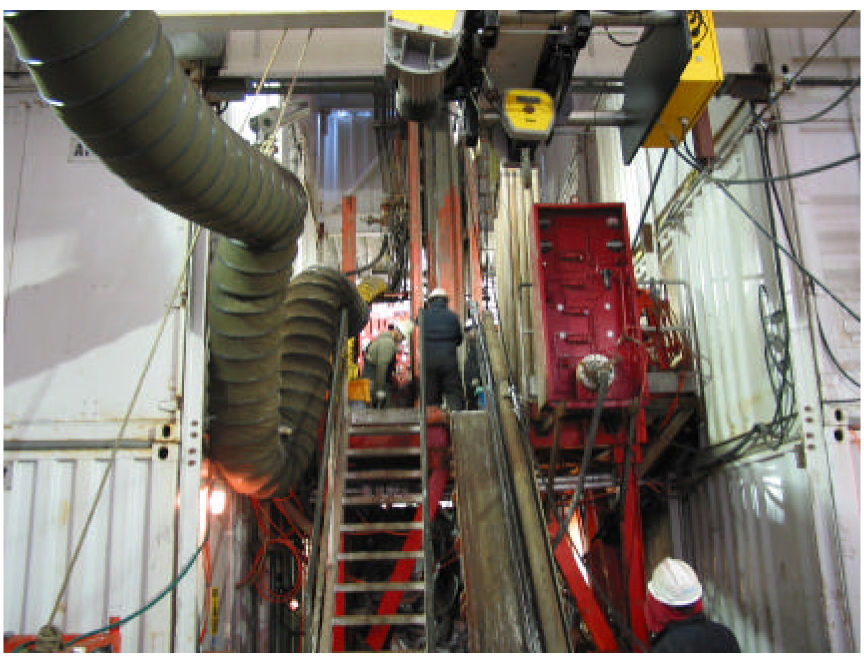
Deploying equipment into the wellbore



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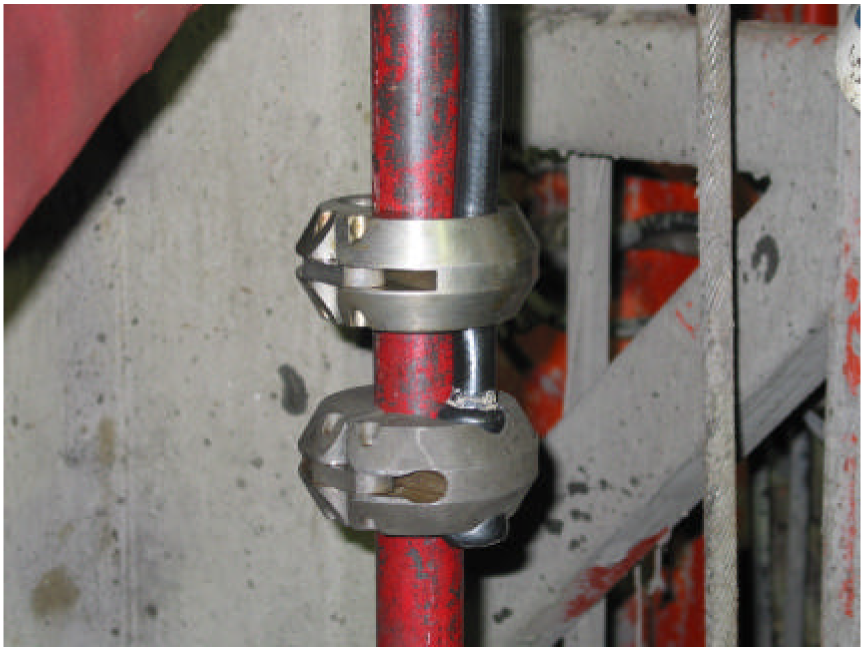
Cable and centralizers on production tubing



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Receiver and cable

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Deploying receiver array into the wellbore

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Installing a receiver into a pod

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Slide 16 of 32

Installing a receiver into a pod

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Slide 17 of 32

Installing a receiver into a pod

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Attaching production tubing to a receiver pod

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Complete pod assembly

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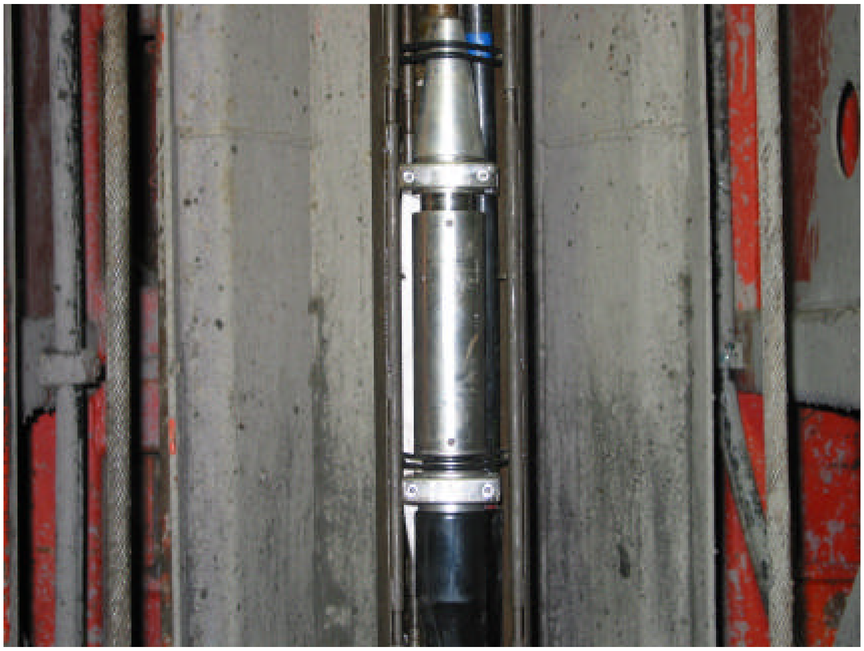
Complete pod assembly



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Expansion bladder inside a receiver pod

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BOP cable feedthrough assembly

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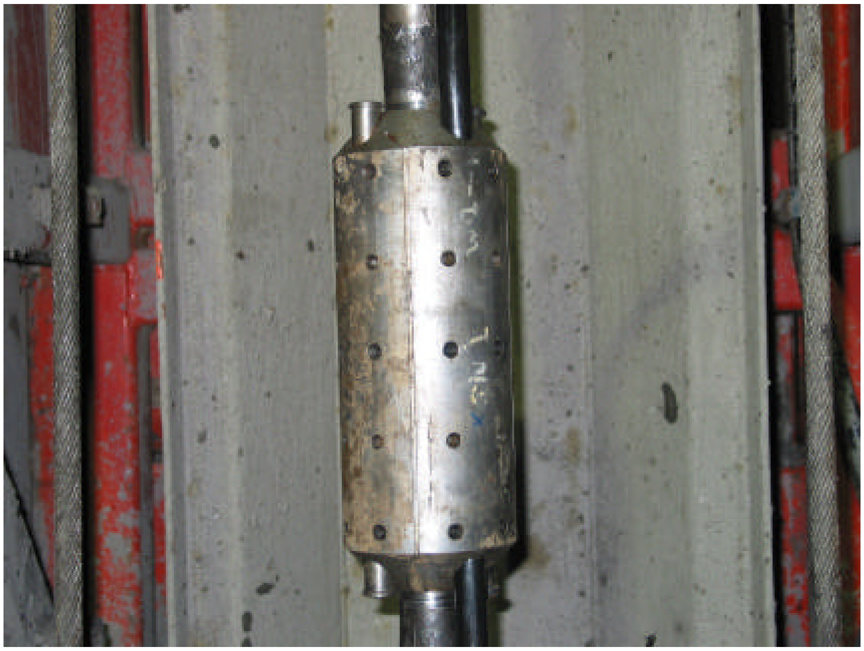
BOP cable feedthrough assembly completed



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Cable and tubing deploying into the wellbore

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Cable and tubing deploying into the wellbore

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Retrieval of P/GSI's 3rd Generation 80 Level 3C Downhole Seismic Array

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Pulling equipment out of the wellbore

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Pulling equipment out of the wellbore

This presentation contain P/GSI processing information

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Pulling equipment out of the wellbore

This presentation contain P/GSI processing information

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Pulling equipment out of the wellbore

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Pulling equipment out of the wellbore

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Appendix C

VSP Sweep Tests

Compilation of sweep parameter tests

- Test 1 – Uncorrelated 32 s sweep 10-200 Hz to check harmonics
- Test 2 – Sweep length
  - 14 s, 12 s, 10 s, 8 s, 6 s, all 10-200 Hz
- Test 3 – Sweep frequency range using 10 s
  - 6-200Hz, 8-200Hz, 14-200Hz
  - 8-160Hz, 8-180Hz, 8-220Hz, 8-240Hz
- Test 4 – Number of sweeps using 10s, 8-220 Hz
  - 2 sweeps 180 degree phase rotated (varisweep)
  - 2 sweeps in phase
- Walkaway test
  - 500 ft, 1000 ft, 1500 ft, 2000 ft, 2500 ft

Compilation of sweep parameter tests

- **Test 1 – Uncorrelated 32 s sweep 10-200 Hz to check harmonics**
- Test 2 – Sweep length
  - 14 s, 12 s, 10 s, 8 s, 6 s, all 10-200 Hz
- Test 3 – Sweep frequency range using 10 s
  - 6-200Hz, 8-200Hz, 14-200Hz
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- Test 4 – Number of sweeps using 10s, 8-220 Hz
  - 2 sweeps 180 degree phase rotated (varisweep)
  - 2 sweeps in phase
- Walkaway test
  - 500 ft, 1000 ft, 1500 ft, 2000 ft, 2500 ft

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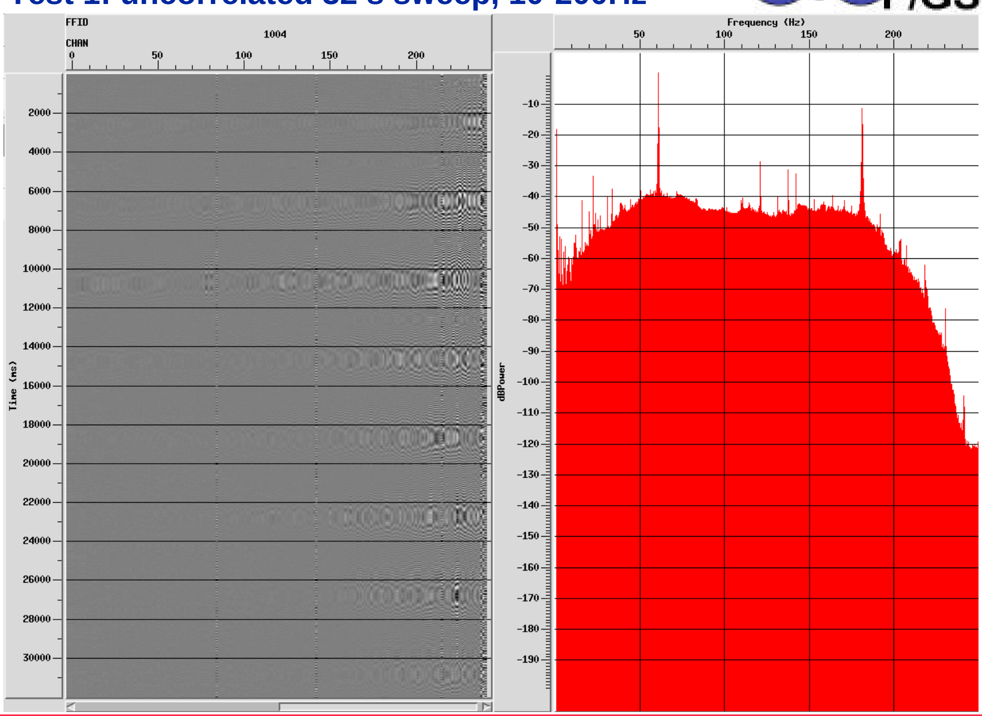
Test 1: uncorrelated 32 s sweep, 10-200Hz



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Compilation of sweep parameter tests

- Test 1 – Uncorrelated 32 s sweep 10-200 Hz to check harmonics
- **Test 2 – Sweep length**
  - **14 s, 12 s, 10 s, 8 s, 6 s, all 10-200 Hz**
- Test 3 – Sweep frequency range using 10 s
  - 6-200Hz, 8-200Hz, 14-200Hz
  - 8-160Hz, 8-180Hz, 8-220Hz, 8-240Hz
- Test 4 – Number of sweeps using 10s, 8-220 Hz
  - 2 sweeps 180 degree phase rotated (varisweep)
  - 2 sweeps in phase
- Walkaway test
  - 500 ft, 1000 ft, 1500 ft, 2000 ft, 2500 ft

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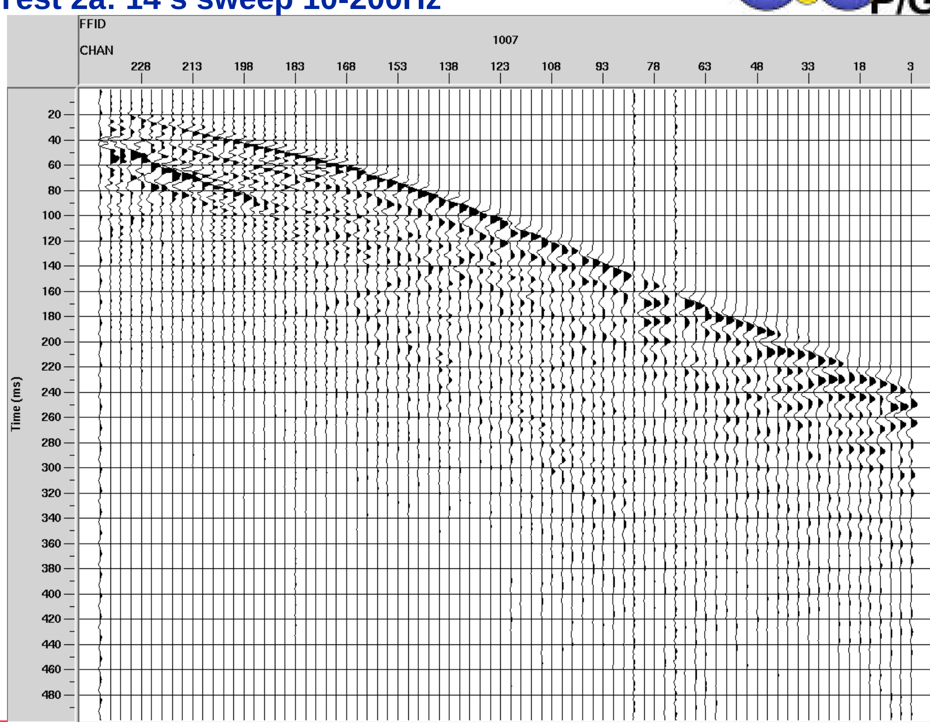
Test 2a: 14 s sweep 10-200Hz



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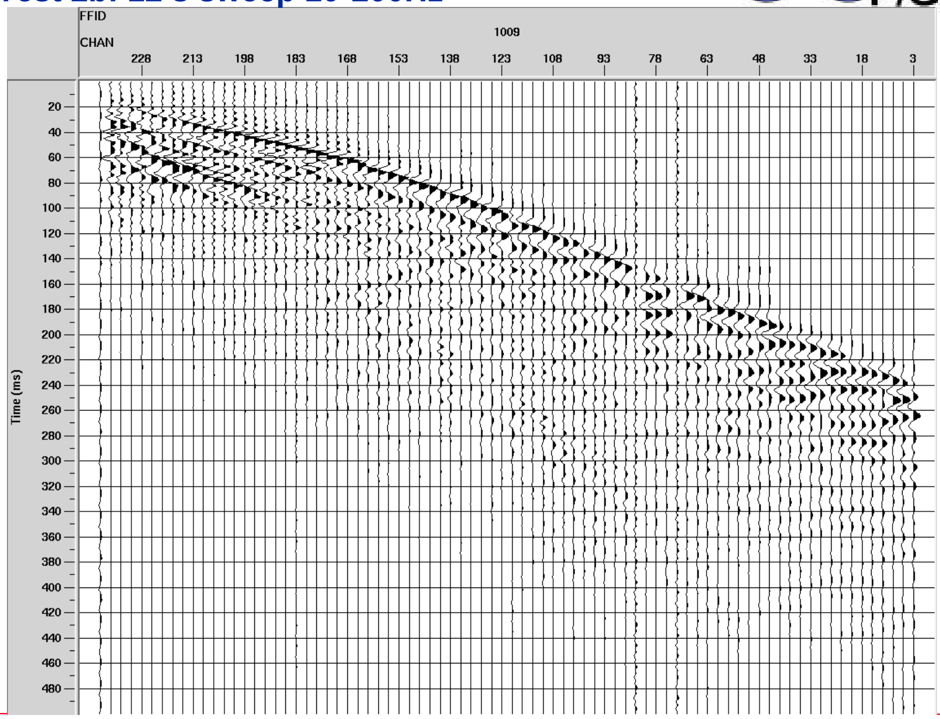
Test 2b: 12 s sweep 10-200Hz



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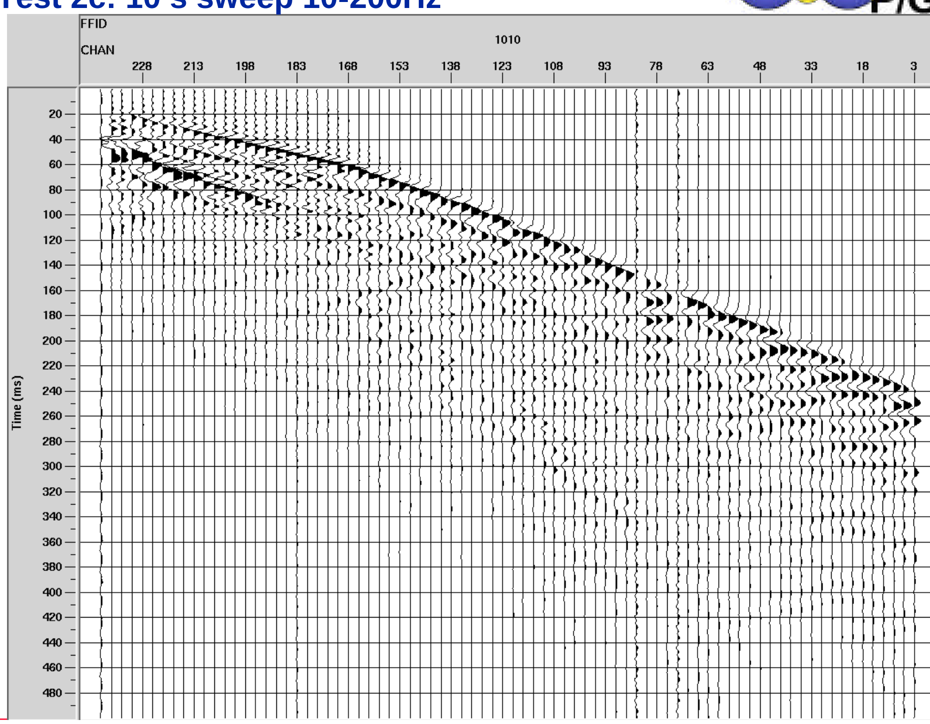
Test 2c: 10 s sweep 10-200Hz



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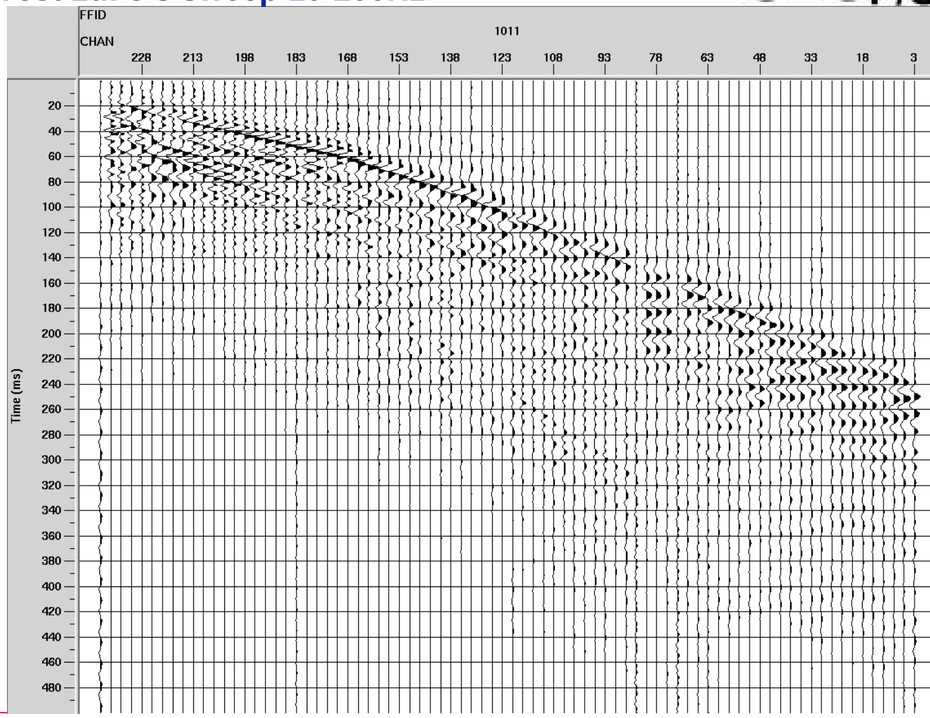
Test 2d: 8 s sweep 10-200Hz



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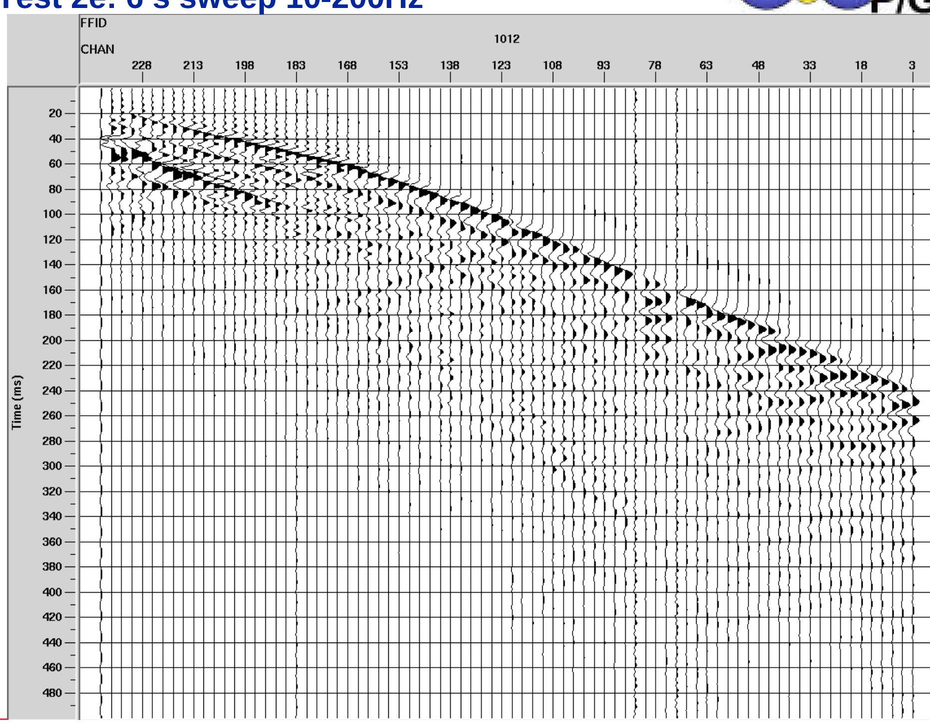
Test 2e: 6 s sweep 10-200Hz



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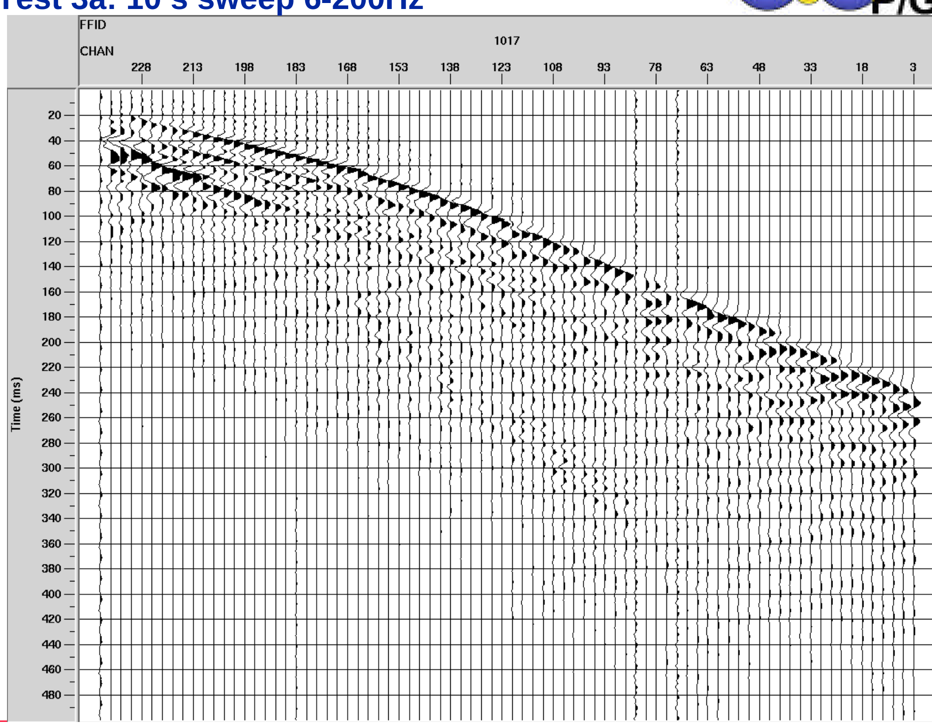
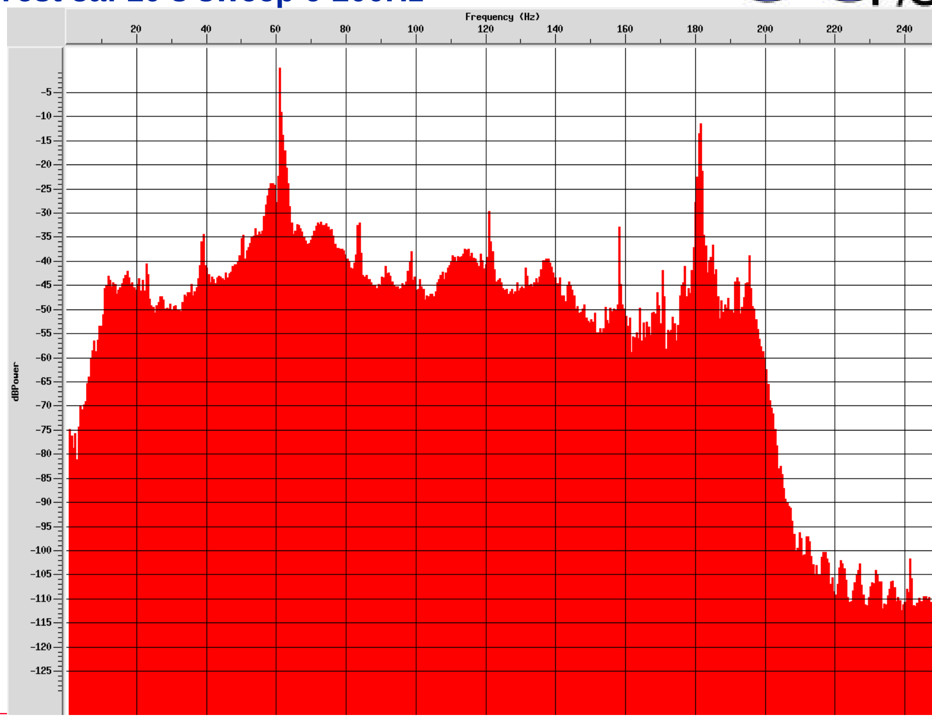
Compilation of sweep parameter tests

- Test 1 – Uncorrelated 32 s sweep 10-200 Hz to check harmonics
- Test 2 – Sweep length
  - 14 s, 12 s, 10 s, 8 s, 6 s, all 10-200 Hz
- **Test 3 – Sweep frequency range using 10 s**
  - **6-200Hz, 8-200Hz, 10-200Hz, 14-200Hz**
  - 8-160Hz, 8-180Hz, 8-220Hz, 8-240Hz
- Test 4 – Number of sweeps using 10s, 8-220 Hz
  - 2 sweeps 180 degree phase rotated (varisweep)
  - 2 sweeps in phase
- Walkaway test
  - 500 ft, 1000 ft, 1500 ft, 2000 ft, 2500 ft

Test 3a: 10 s sweep 6-200Hz



Test 3a: 10 s sweep 6-200Hz



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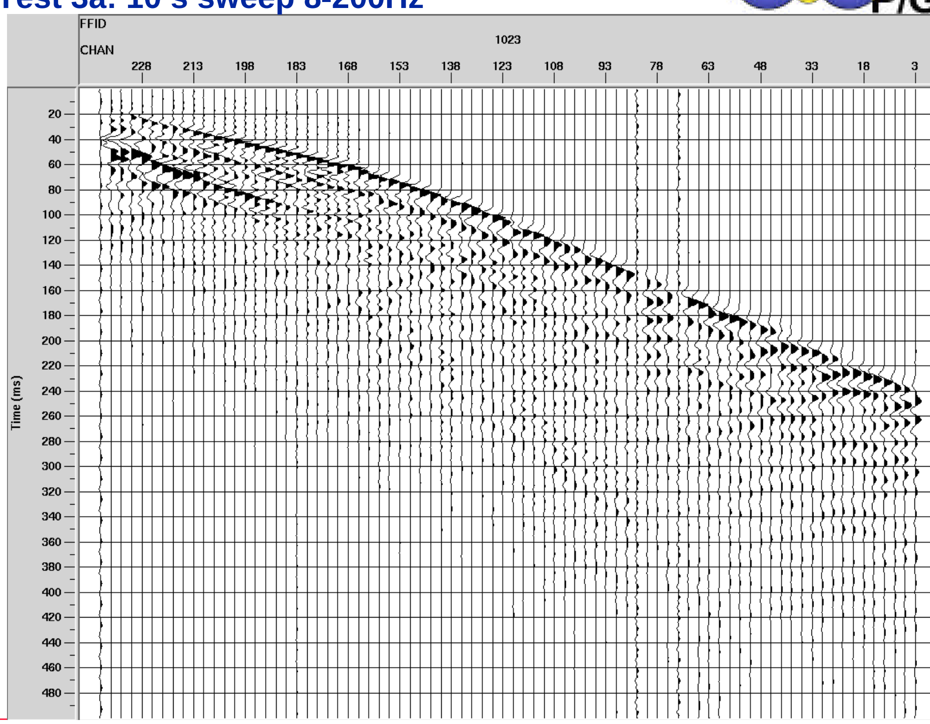
Test 3a: 10 s sweep 8-200Hz



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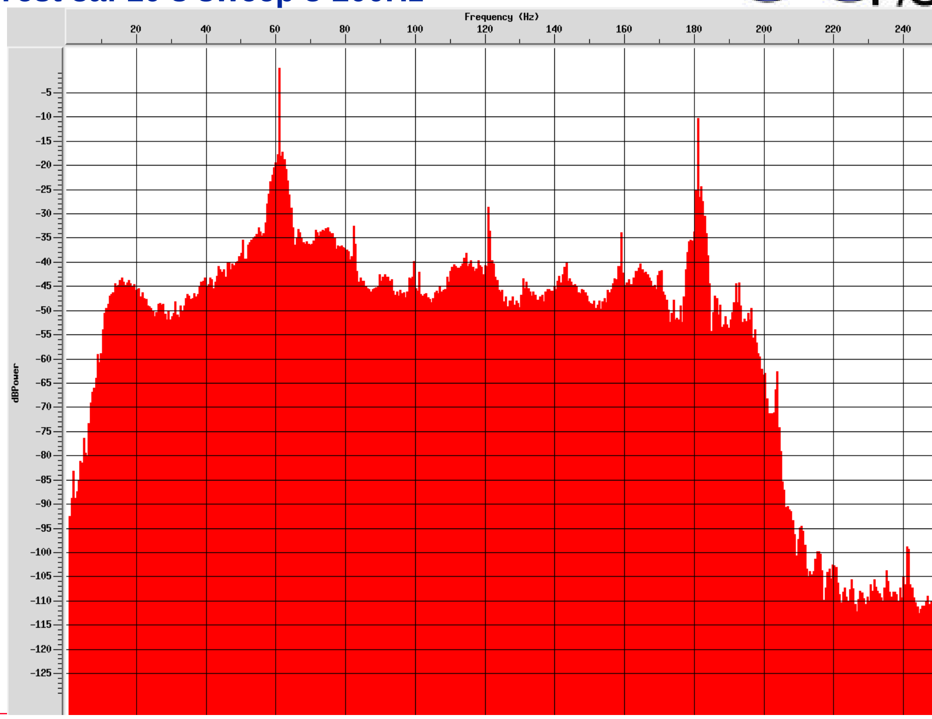
Test 3a: 10 s sweep 8-200Hz



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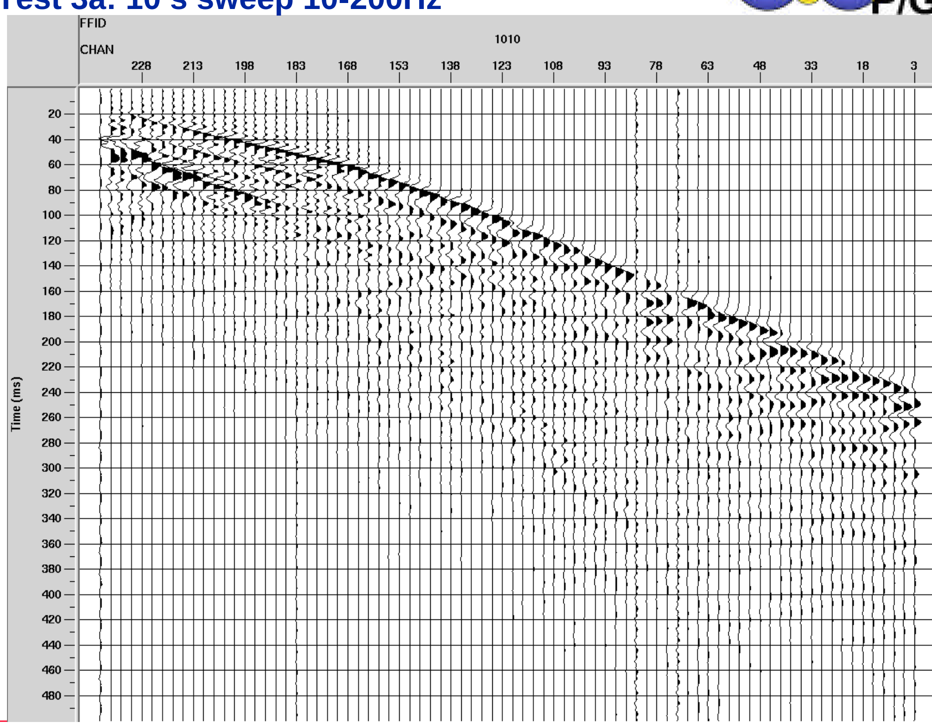
Test 3a: 10 s sweep 10-200Hz



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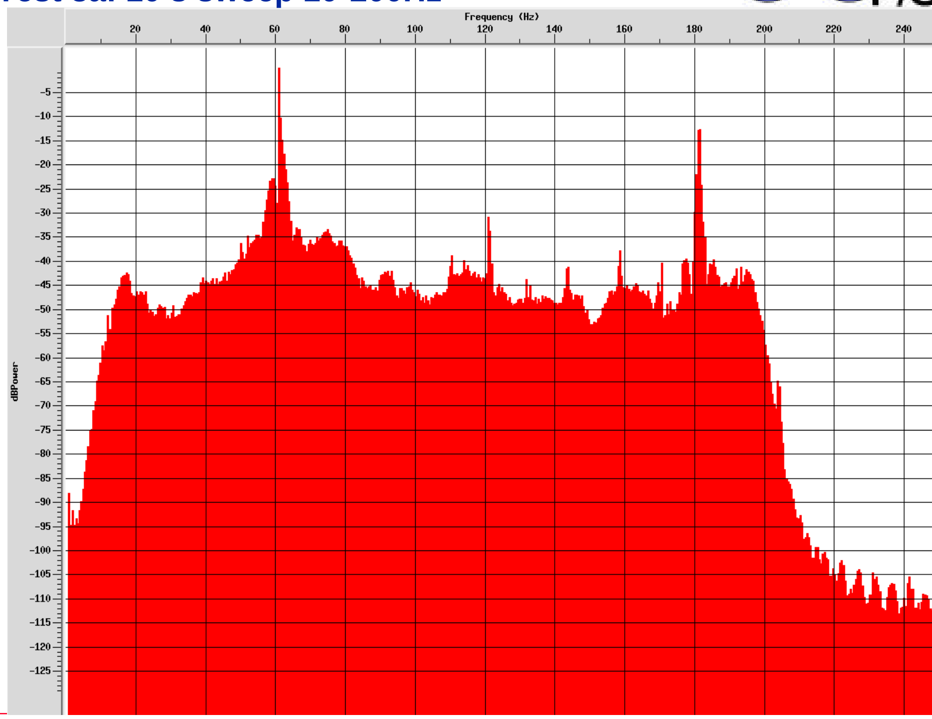
Test 3a: 10 s sweep 10-200Hz



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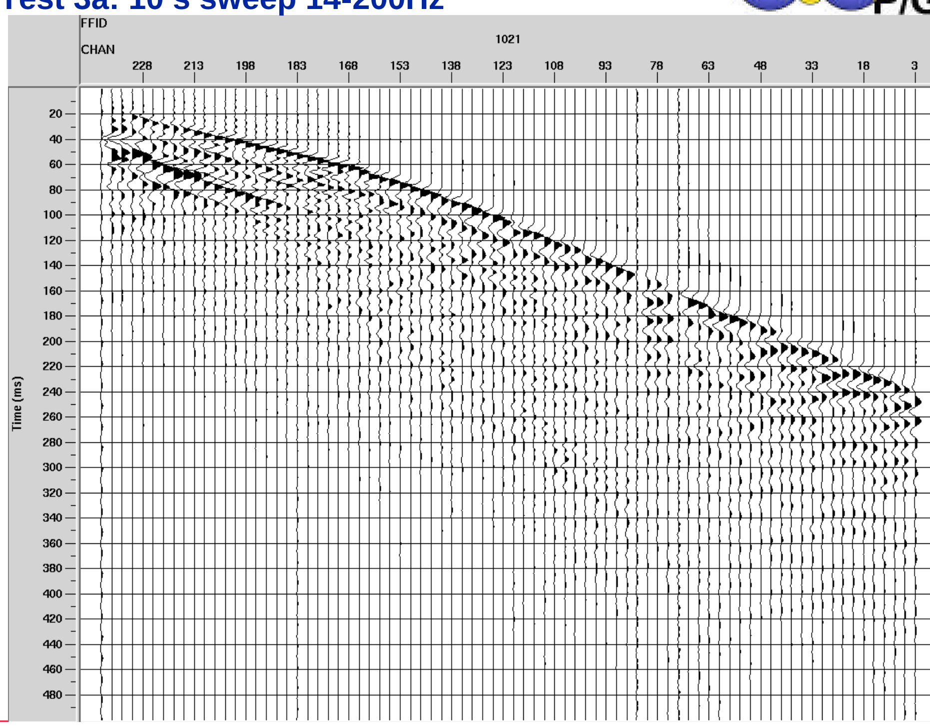
Test 3a: 10 s sweep 14-200Hz



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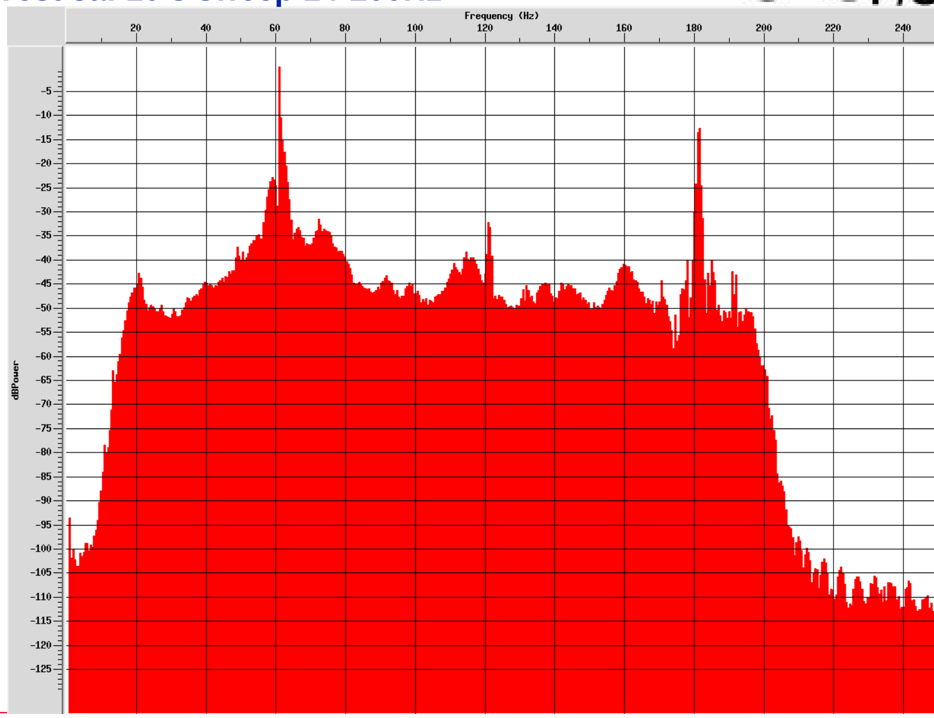
Test 3a: 10 s sweep 14-200Hz



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Compilation of sweep parameter tests

- Test 1 – Uncorrelated 32 s sweep 10-200 Hz to check harmonics
- Test 2 – Sweep length
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- **Test 3 – Sweep frequency range using 10 s**
  - 6-200Hz, 8-200Hz, 14-200Hz
  - **8-160Hz, 8-180Hz, 8-220Hz, 8-240Hz**
- Test 4 – Number of sweeps using 10s, 8-220 Hz
  - 2 sweeps 180 degree phase rotated (varisweep)
  - 2 sweeps in phase
- Walkaway test
  - 500 ft, 1000 ft, 1500 ft, 2000 ft, 2500 ft

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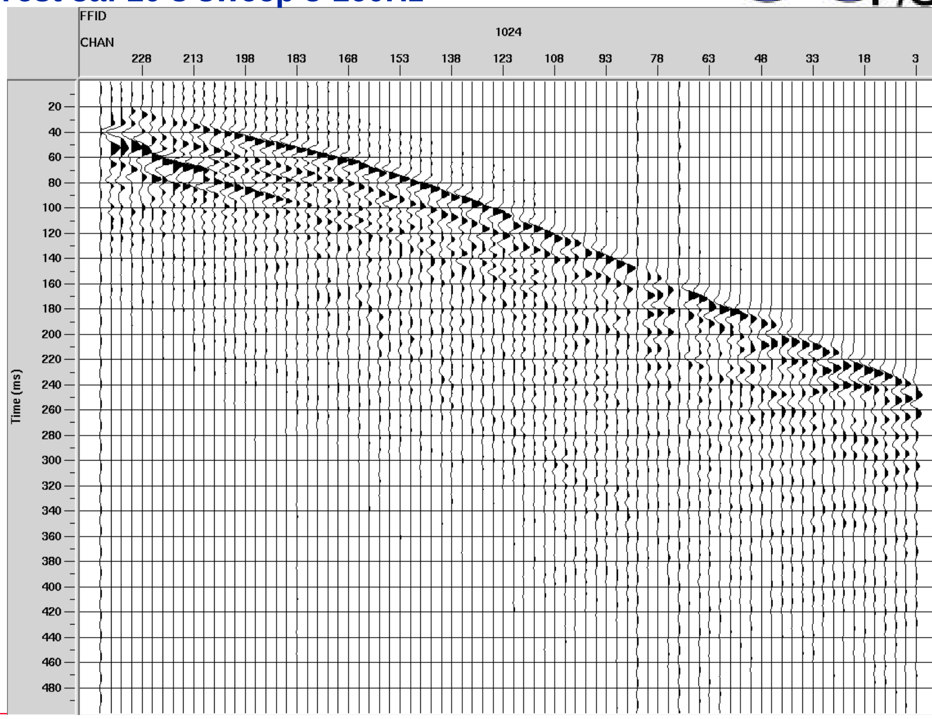
Test 3a: 10 s sweep 8-160Hz



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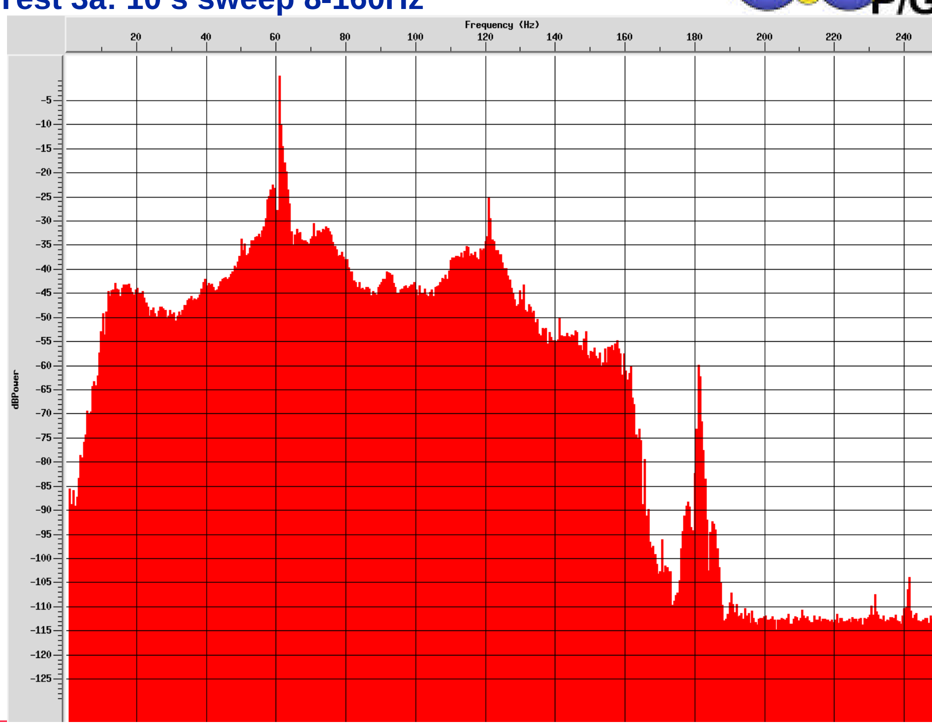
Test 3a: 10 s sweep 8-160Hz



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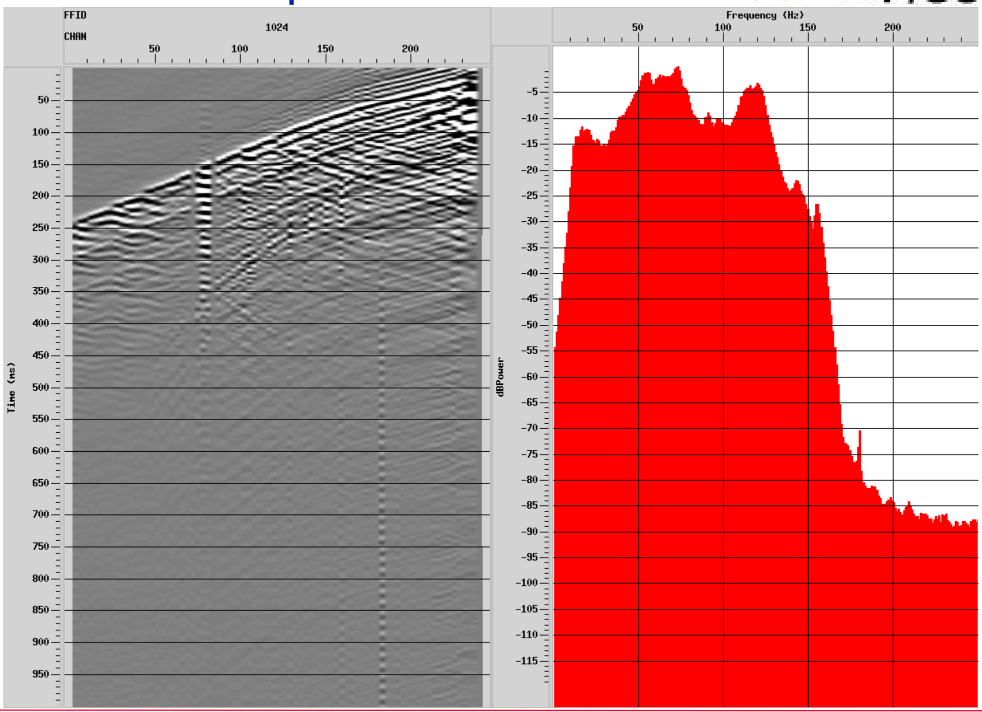
Test 3a: 10 s sweep 8-160Hz



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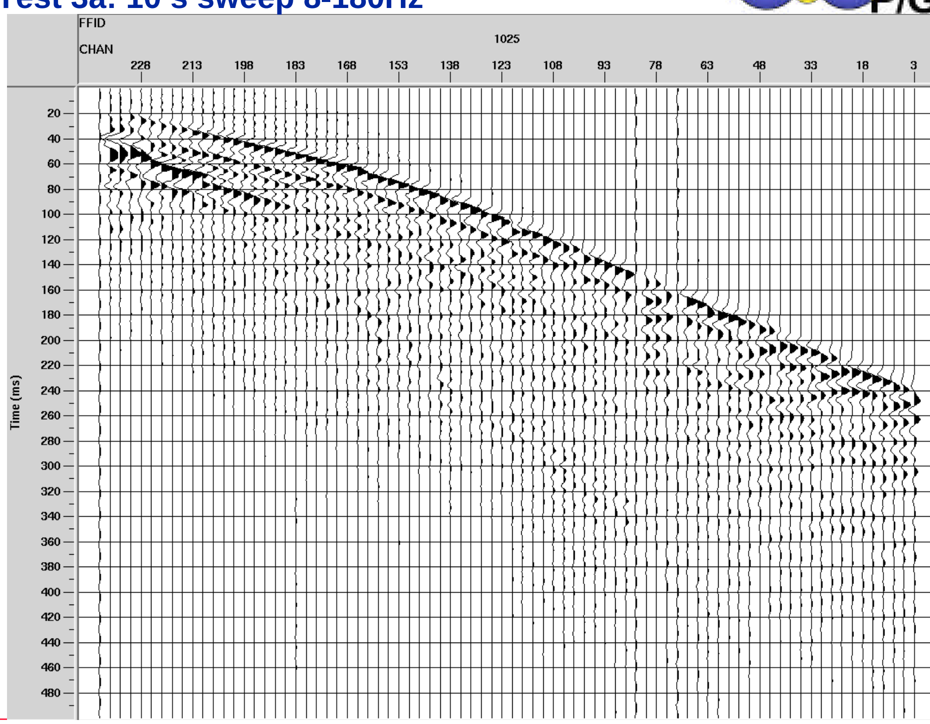
Test 3a: 10 s sweep 8-180Hz



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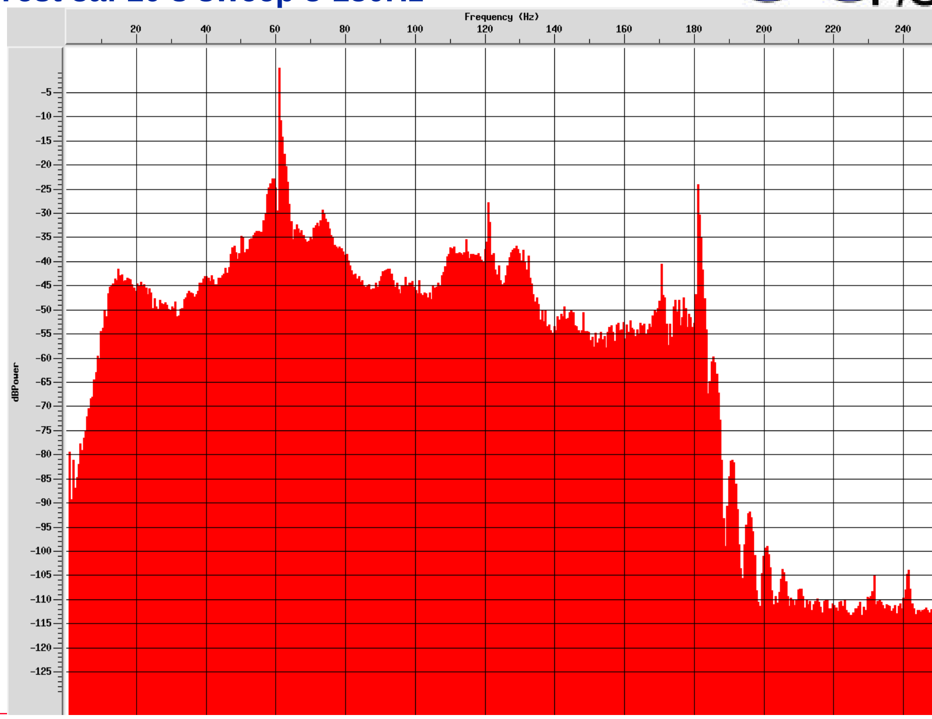
Test 3a: 10 s sweep 8-180Hz



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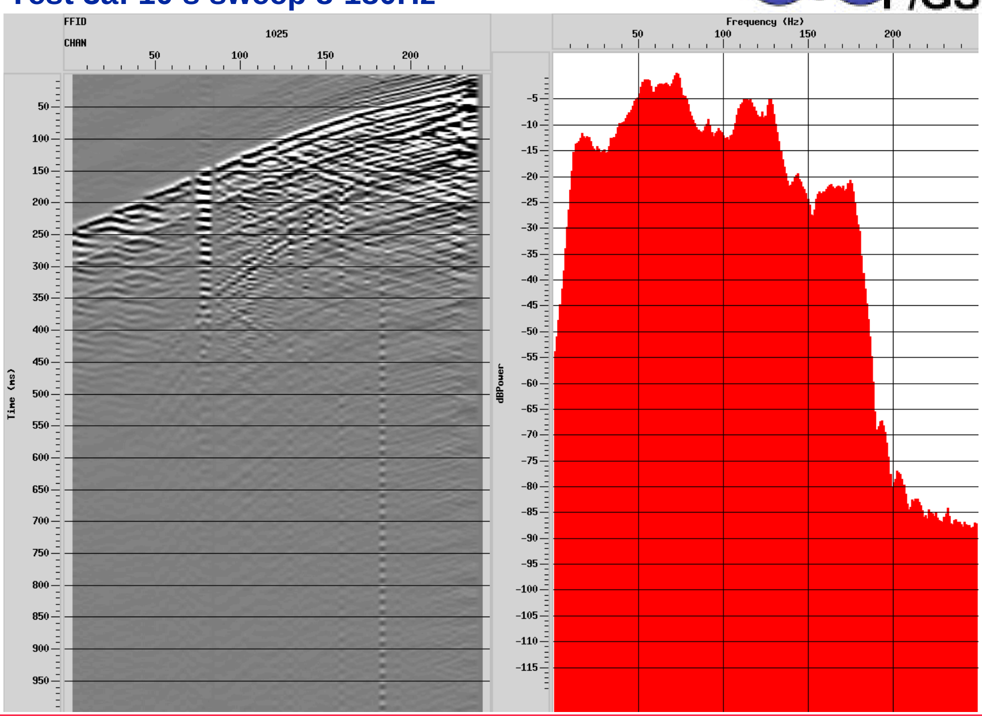
Test 3a: 10 s sweep 8-180Hz



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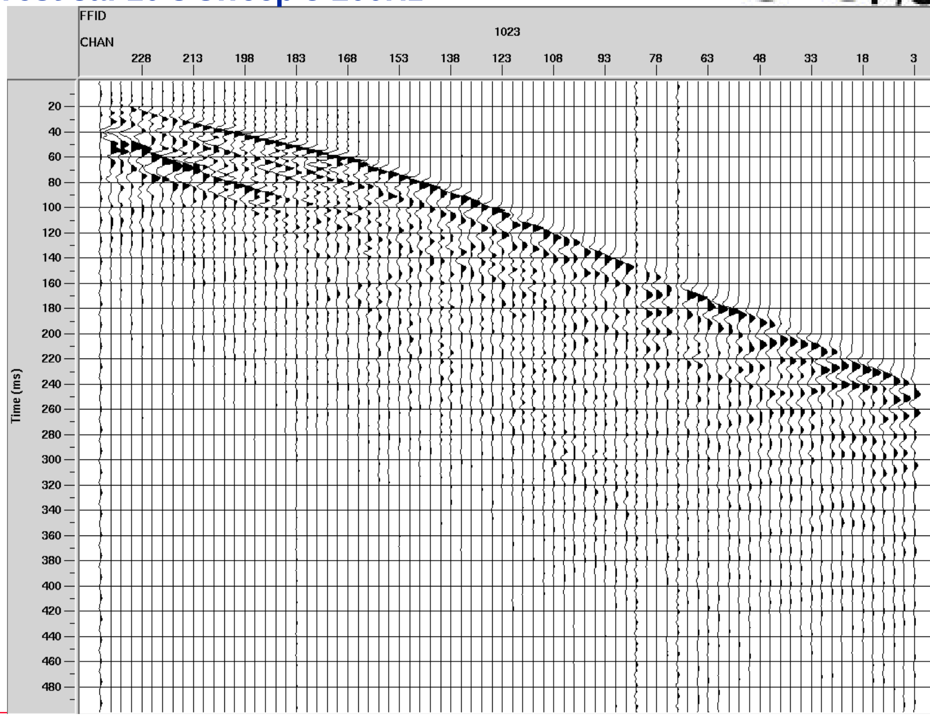
Test 3a: 10 s sweep 8-200Hz



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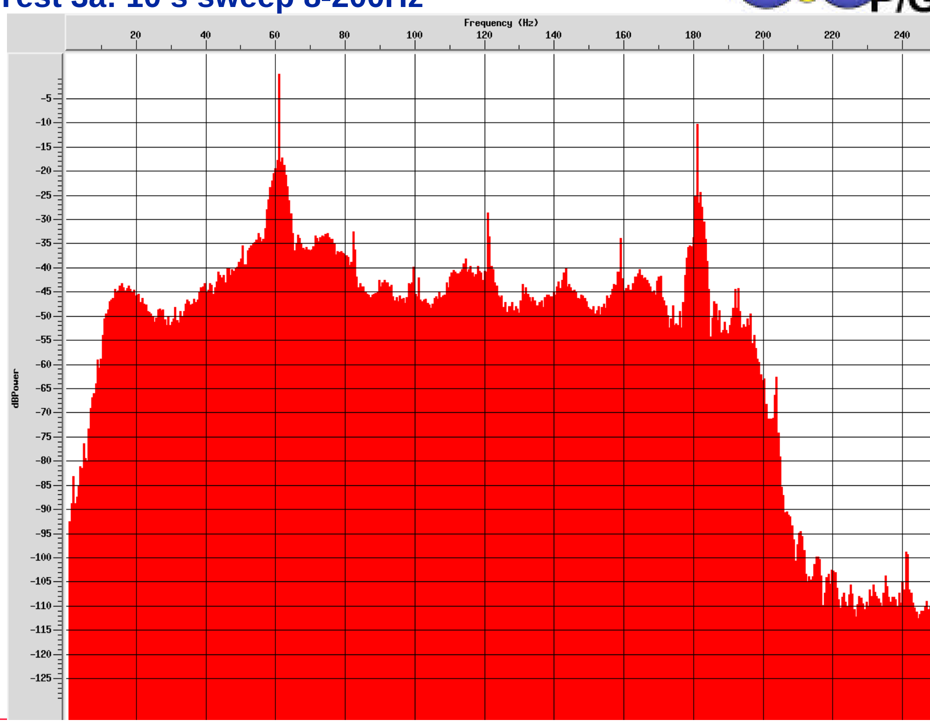
Test 3a: 10 s sweep 8-200Hz



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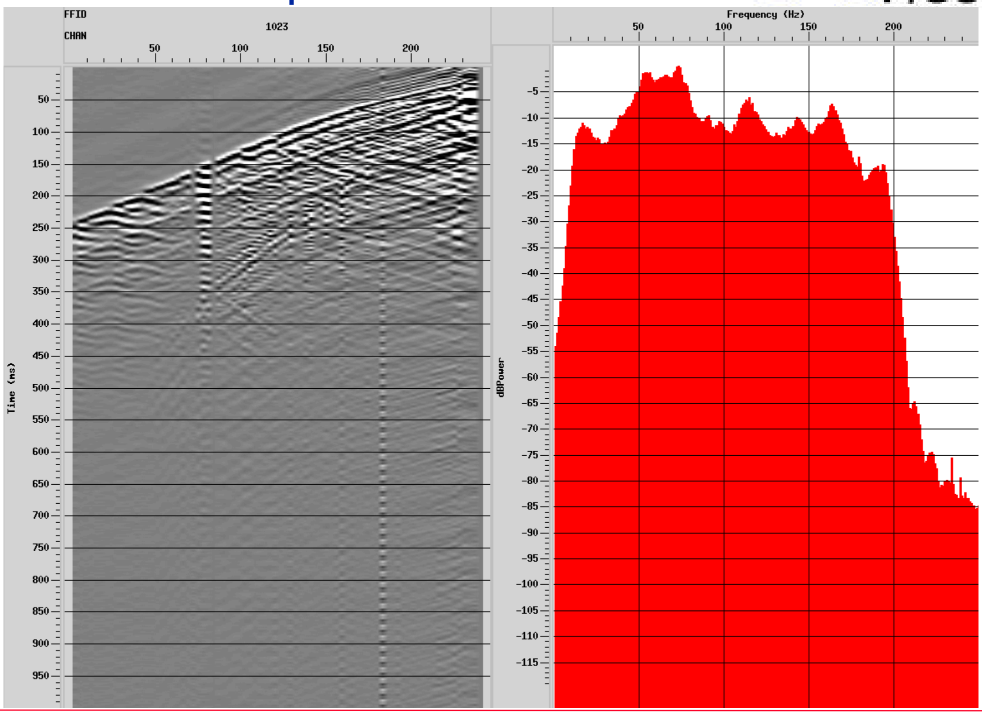
Test 3a: 10 s sweep 8-200Hz



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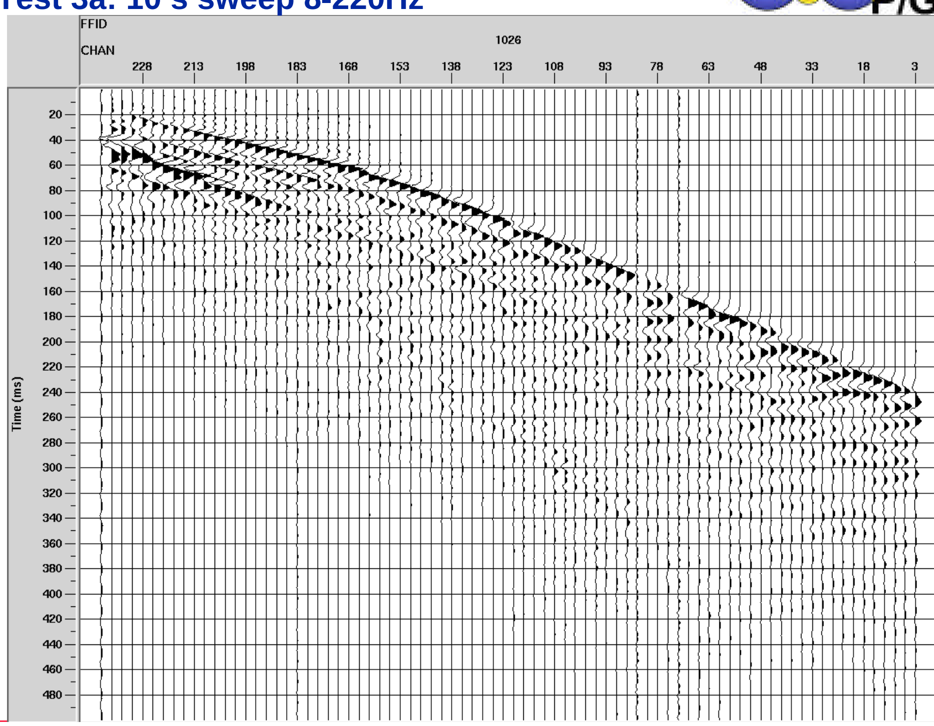
Test 3a: 10 s sweep 8-220Hz



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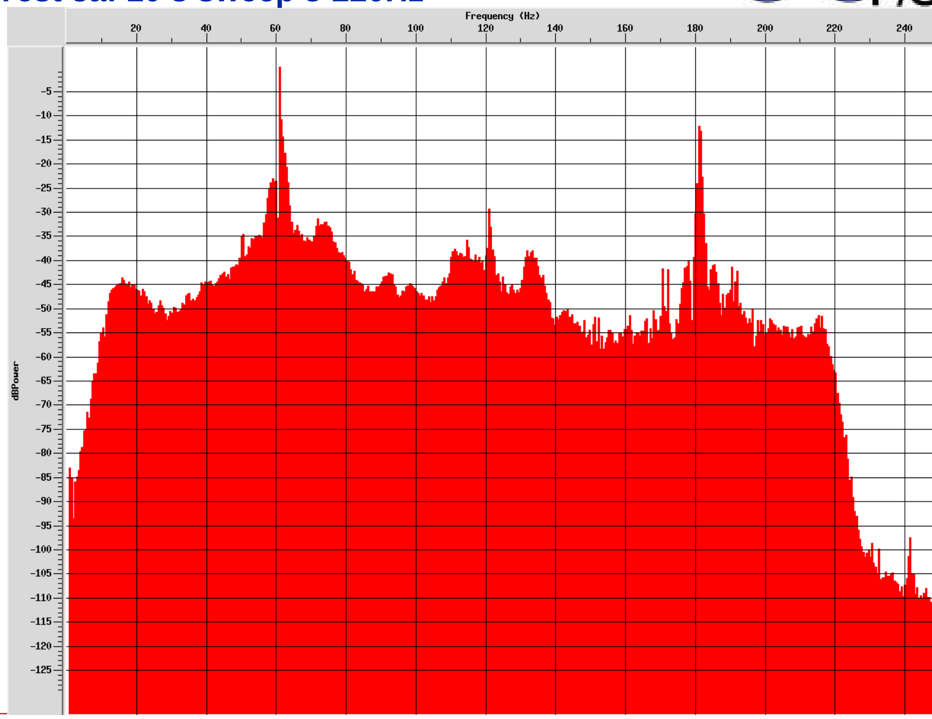
Test 3a: 10 s sweep 8-220Hz



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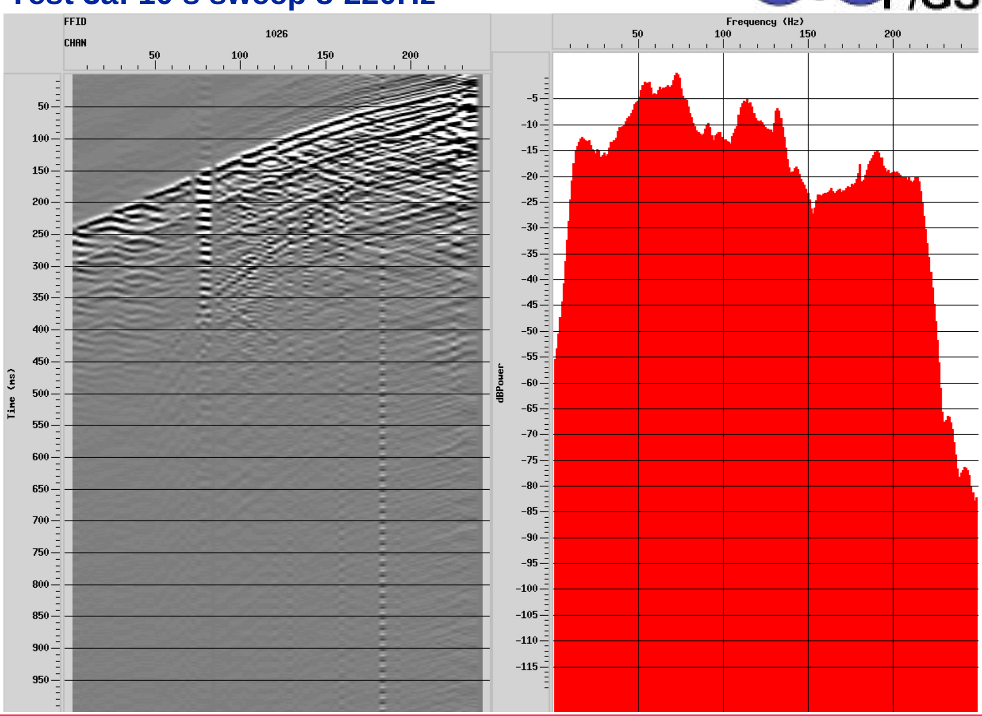
Test 3a: 10 s sweep 8-220Hz



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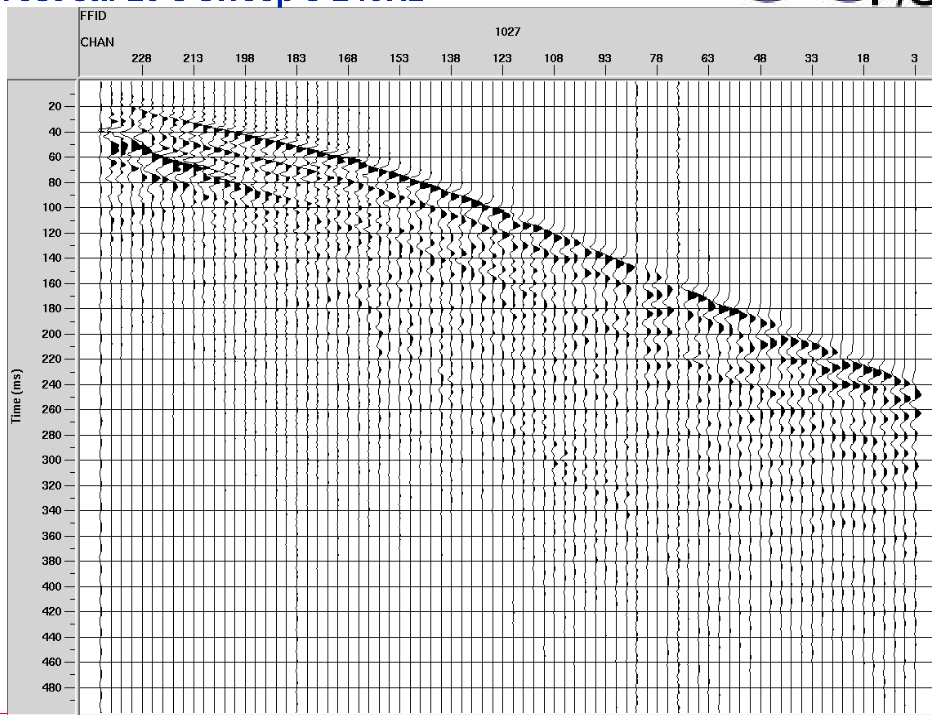
Test 3a: 10 s sweep 8-240Hz



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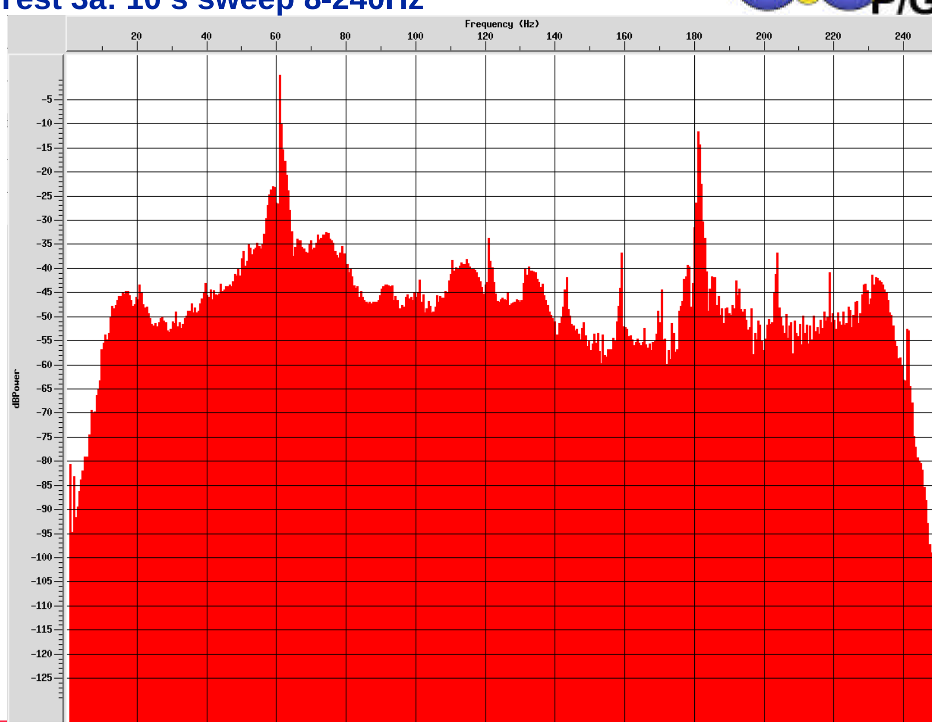
Test 3a: 10 s sweep 8-240Hz



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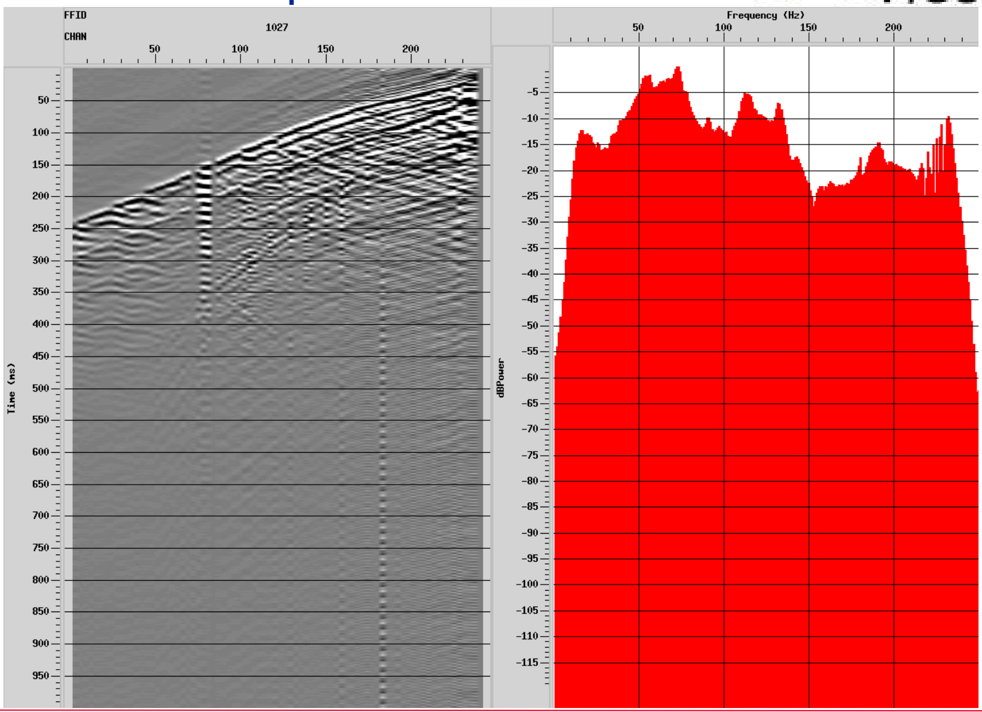
Test 3a: 10 s sweep 8-240Hz



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Compilation of sweep parameter tests

- Test 1 – Uncorrelated 32 s sweep 10-200 Hz to check harmonics
- Test 2 – Sweep length
  - 14 s, 12 s, 10 s, 8 s, 6 s, all 10-200 Hz
- Test 3 – Sweep frequency range using 10 s
  - 6-200Hz, 8-200Hz, 14-200Hz
  - 8-160Hz, 8-180Hz, 8-220Hz, 8-240Hz
- **Test 4 – Number of sweeps using 10s, 8-220 Hz**
  - **2 sweeps 180 degree phase rotated (varisweep)**
  - **2 sweeps in phase**
- Walkaway test
  - 500 ft, 1000 ft, 1500 ft, 2000 ft, 2500 ft

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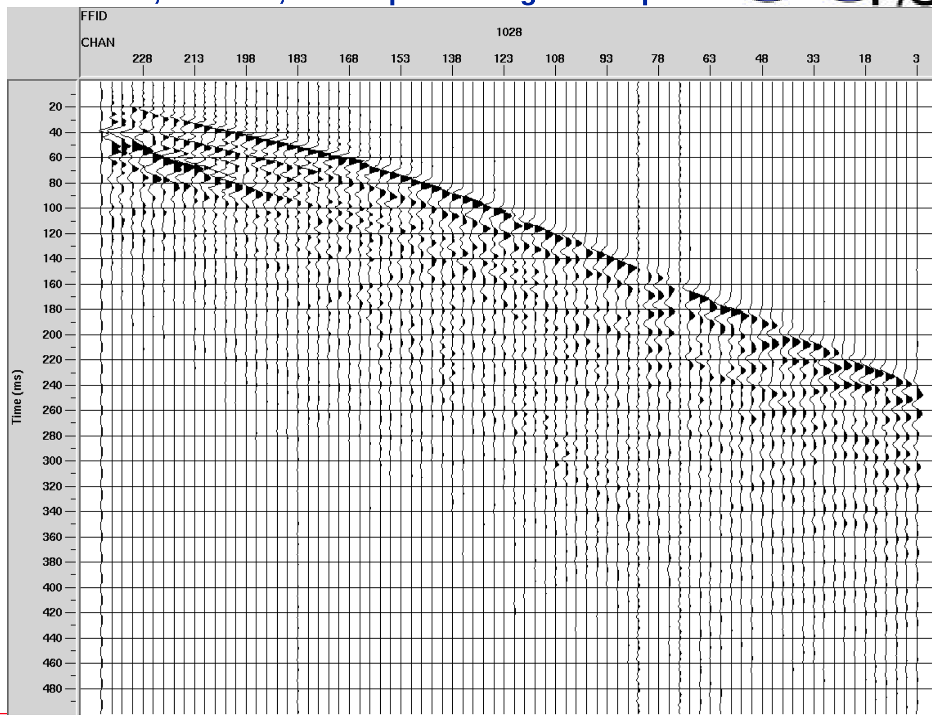
Test 4: 10 s, 8-220Hz, 2 sweeps 180 deg. out of phase



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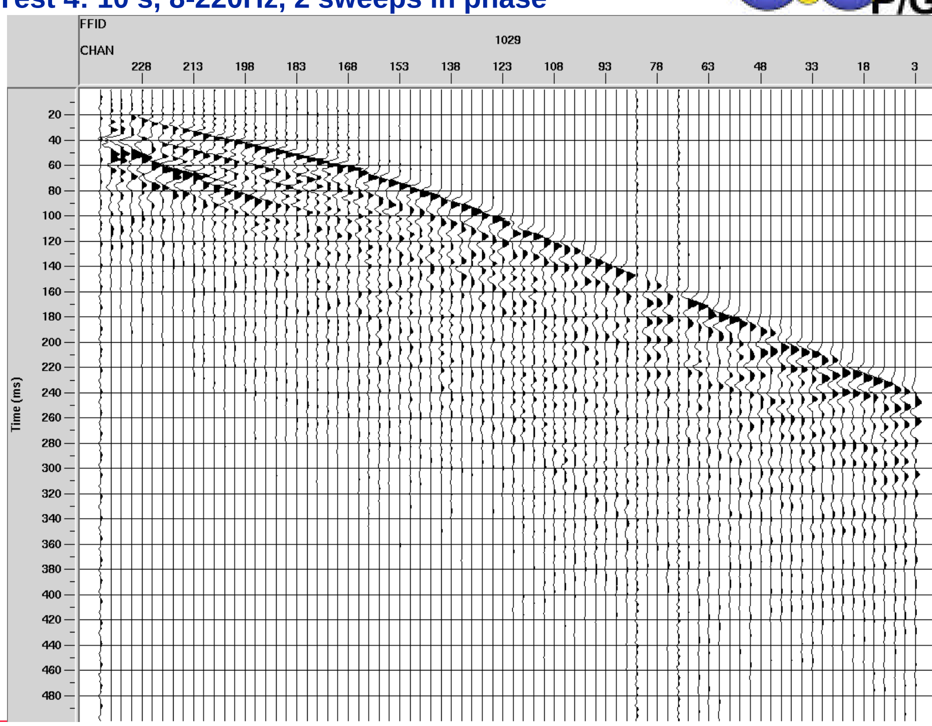
Test 4: 10 s, 8-220Hz, 2 sweeps in phase



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Compilation of sweep parameter tests

- Test 1 – Uncorrelated 32 s sweep 10-200 Hz to check harmonics
- Test 2 – Sweep length
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- Test 3 – Sweep frequency range using 10 s
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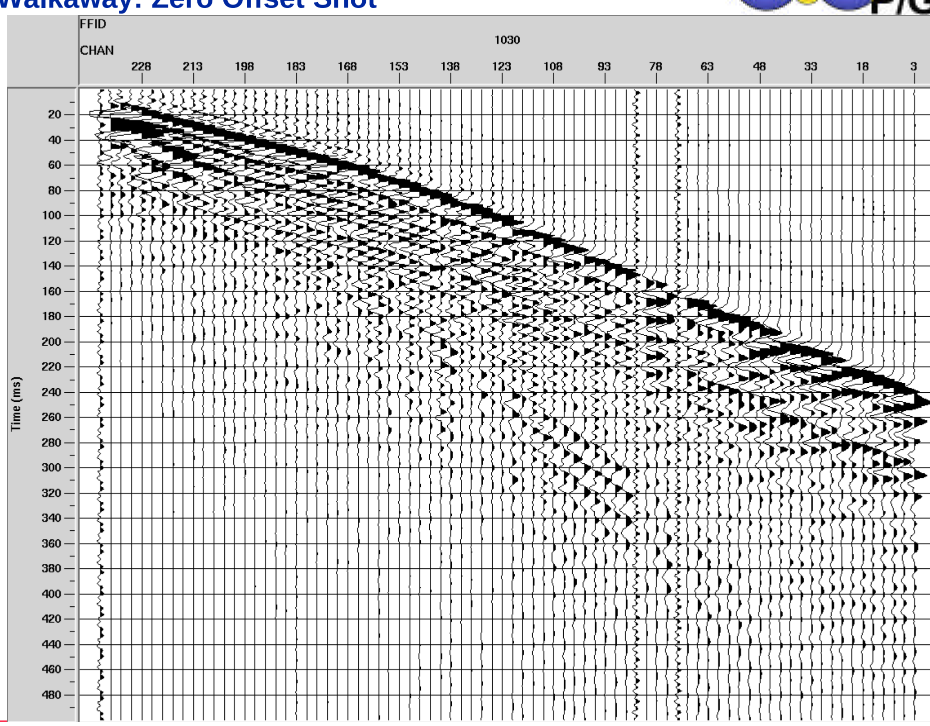
- Test 4 – Number of sweeps using 10s, 8-220 Hz
  - 2 sweeps 180 degree phase rotated (varisweep)
  - 2 sweeps in phase
- **Walkaway test**
  - **500 ft, 1000 ft, 1500 ft, 2000 ft, 2500 ft**

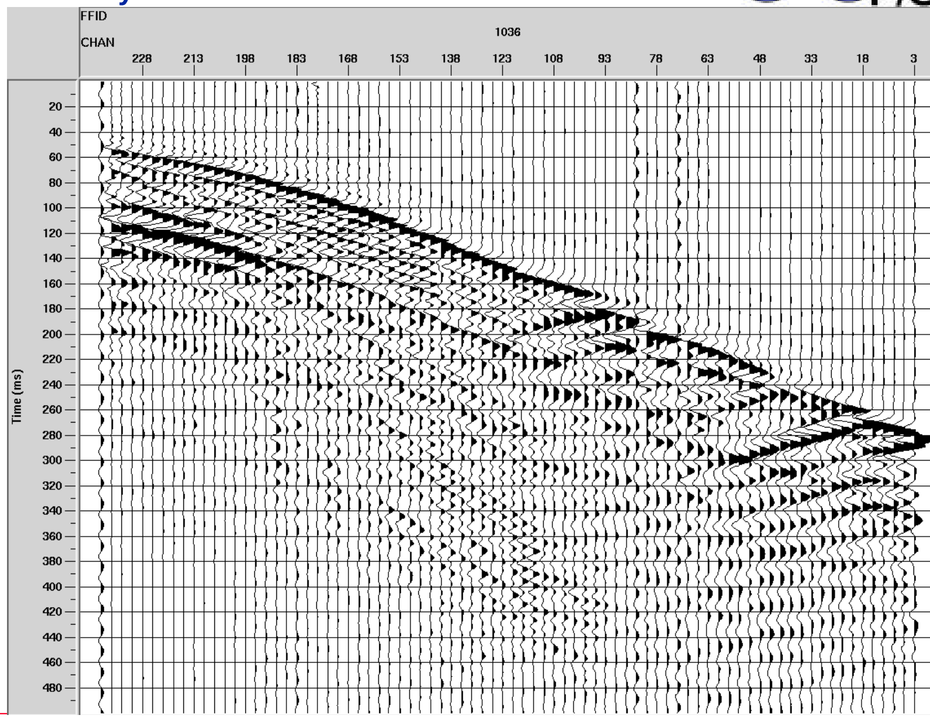
This presentation contains P/GSI processing information **Slide 39 of 62**

Walkaway: Zero Offset Shot



This presentation contains P/GSI processing information **Slide 40 of 62**

Walkaway: 500 ft due North



This presentation contains P/GSI processing information

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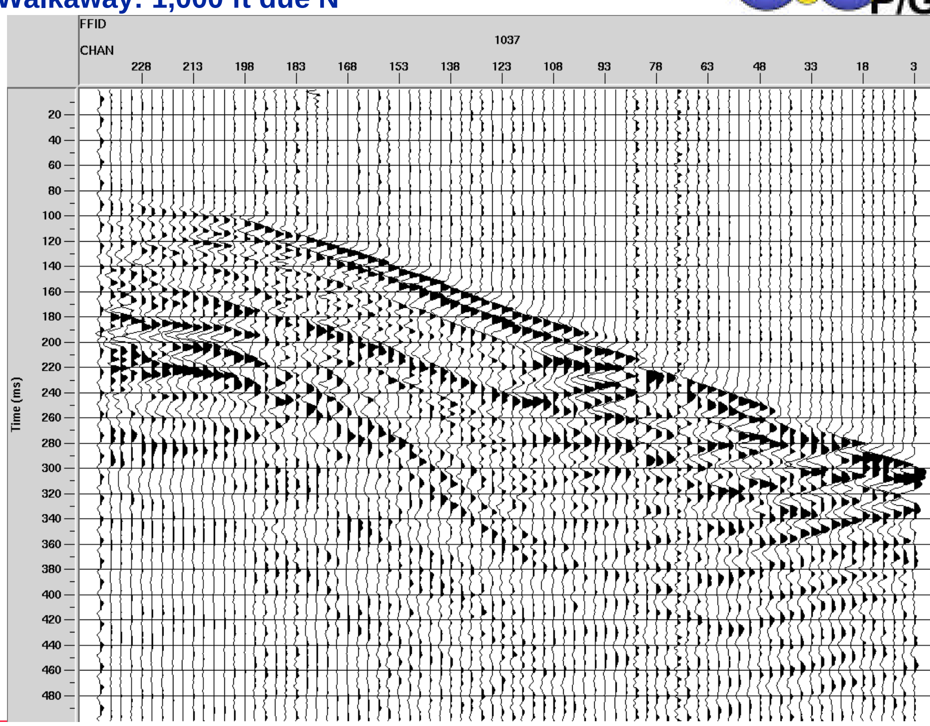
Walkaway: 1,000 ft due N



This presentation contains P/GSI processing information

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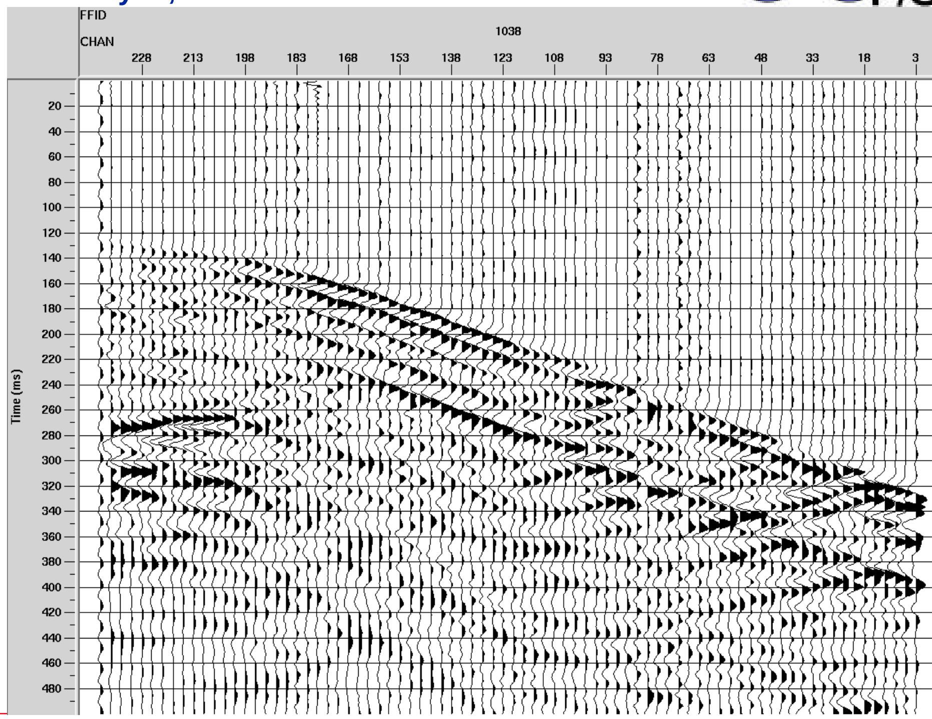
Walkaway: 1,500 ft due N

P/GSI™



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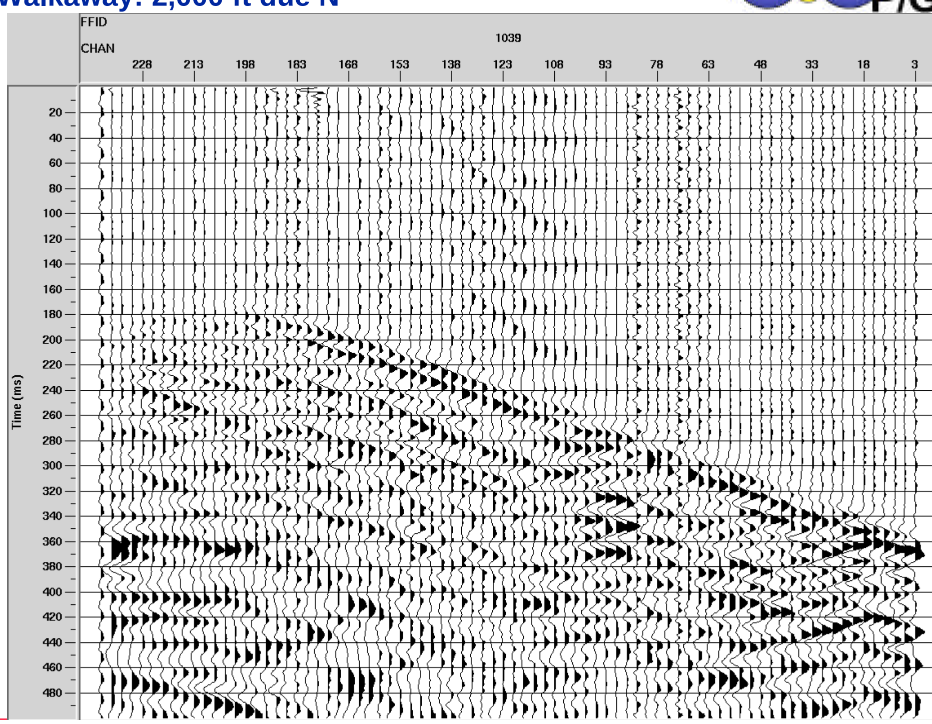
Walkaway: 2,000 ft due N

P/GSI™



This presentation contains P/GSI processing information

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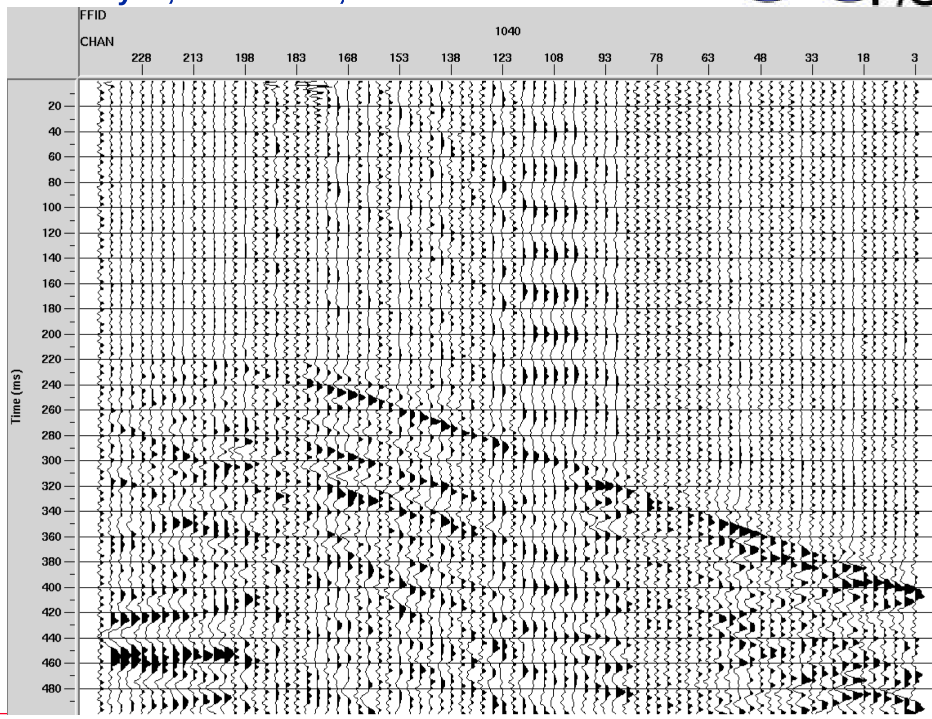
Walkaway: 2,500 ft due N, raw data



This presentation contains P/GSI processing information

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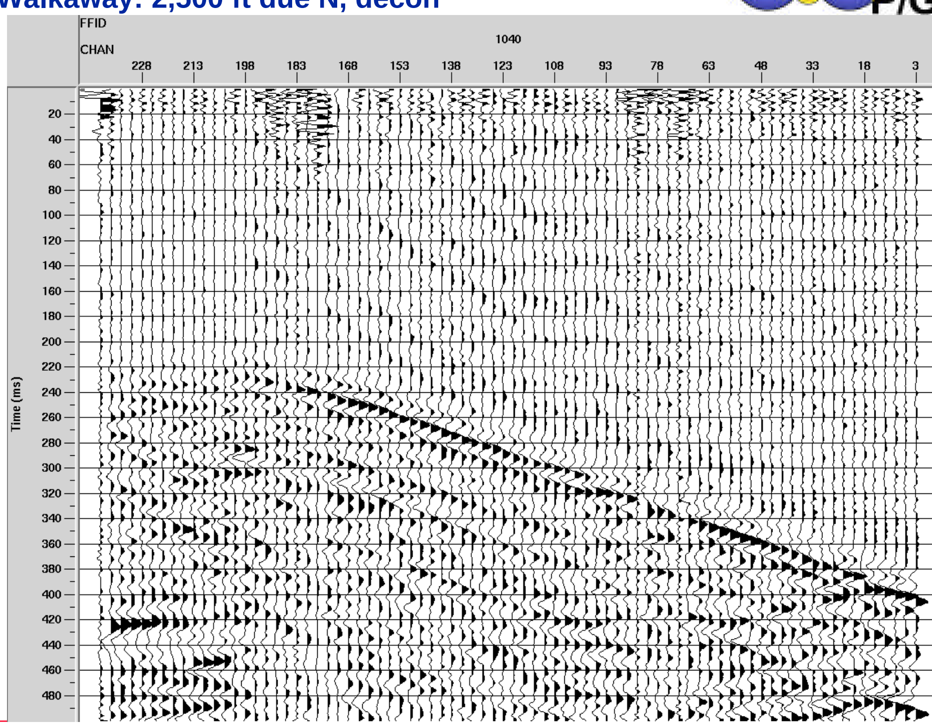
Walkaway: 2,500 ft due N, decon



This presentation contains P/GSI processing information

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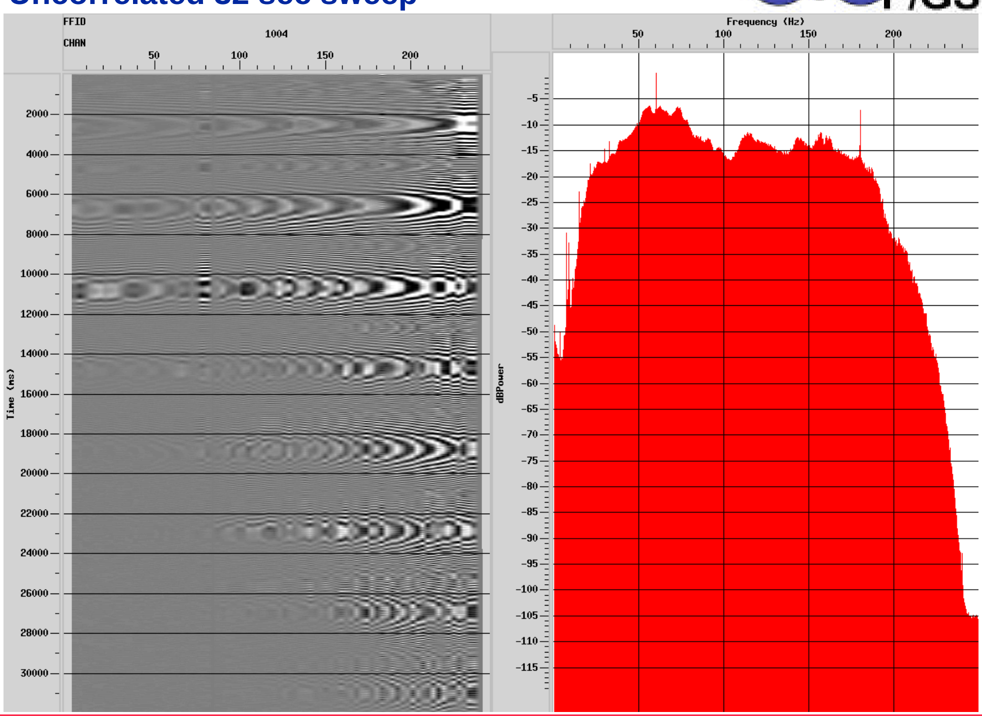
Additional Spectra and Data

Zero Offset shot, array deployed 0-2000 ft @ 25 ft spacing:

- **Spectra of time windows out of a uncorrelated record of a 32-sec sweep:**
  - **Whole record: 32 sec, 10-200 Hz**
  - Harmonics Analysis:
    - 0-4 s, 4-8s, 8-12 s, 12-16 s, 16-20 s, 20-24 s, 24-32 s
- Sonogram from PGS
- 8 – 220 Hz sweep
  - Upper half of array (0-1000 ft)
  - Lower half of array (1000-2000 ft)

Uncorrelated 32 sec sweep



Additional Spectra and Data

Zero Offset shot, array deployed 0-2000 ft @ 25 ft spacing:

- **Spectra of time windows out of a uncorrelated record of a 32-sec sweep:**
  - Whole record: 32 sec
  - **Harmonics Analysis:**
    - **0-4 s, 4-8s, 8-12 s, 12-16 s, 16-20 s, 20-24 s, 24-32 s**
- Sonogram from PGS
- 8 – 220 Hz sweep
  - Upper half of array (0-1000 ft)
  - Lower half of array (1000-2000 ft)

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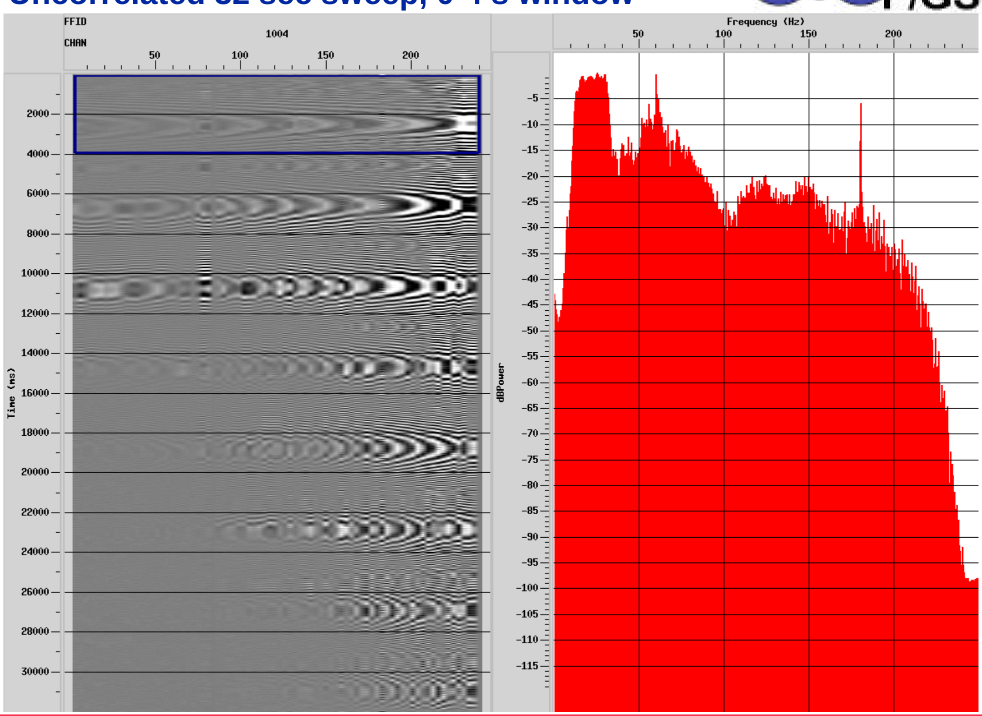
Uncorrelated 32 sec sweep, 0-4 s window



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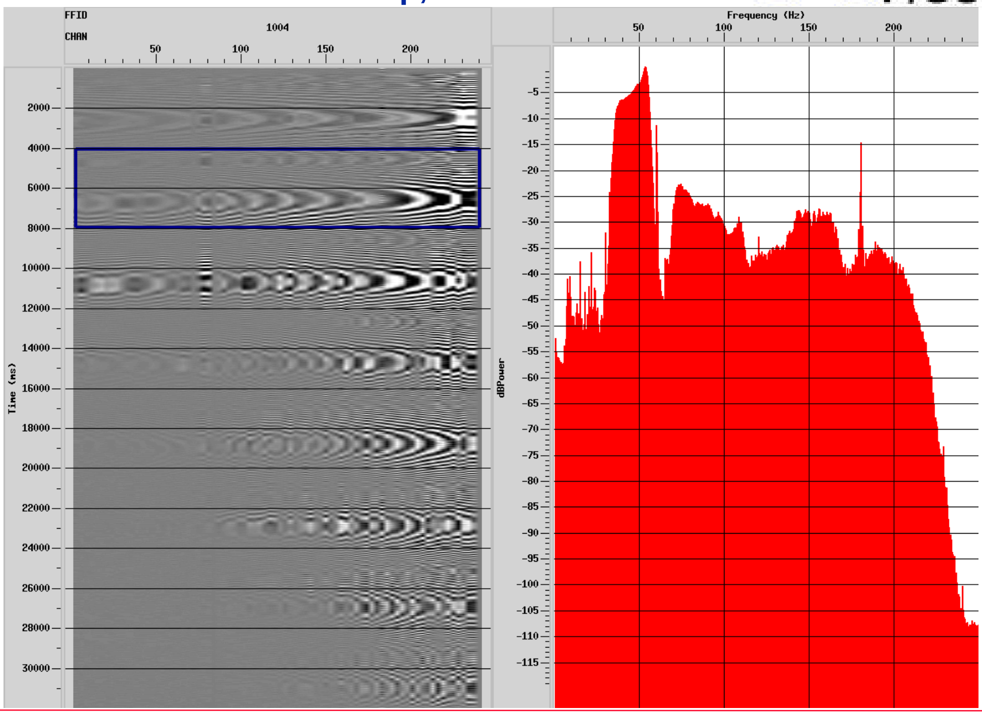
Uncorrelated 32 sec sweep, 4-8 s window



This presentation contains P/GSI processing information

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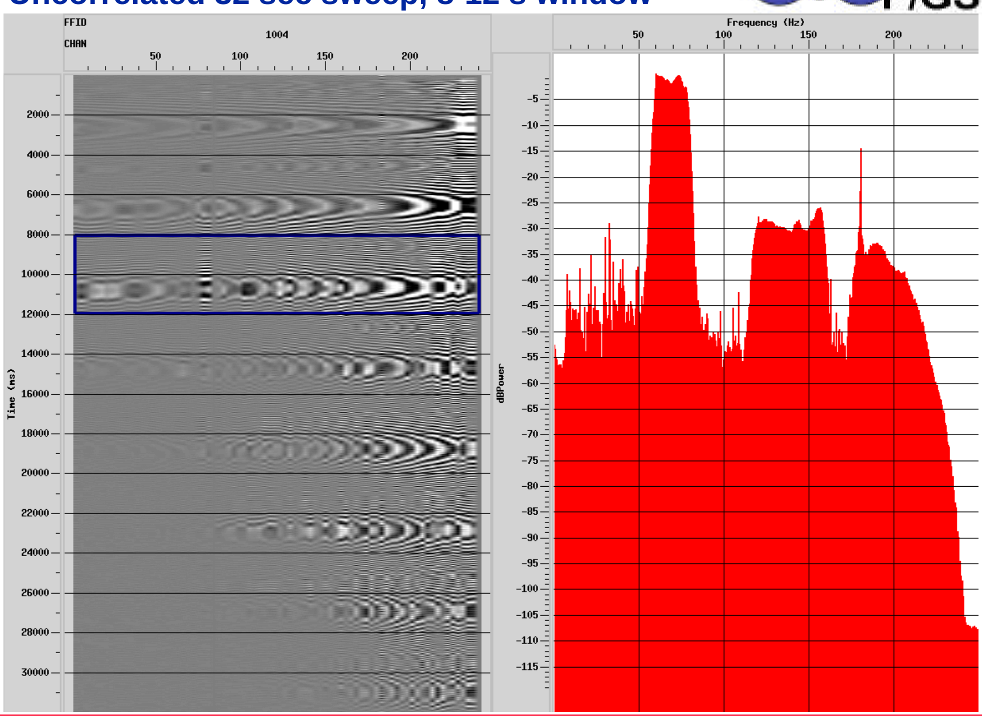
Uncorrelated 32 sec sweep, 8-12 s window



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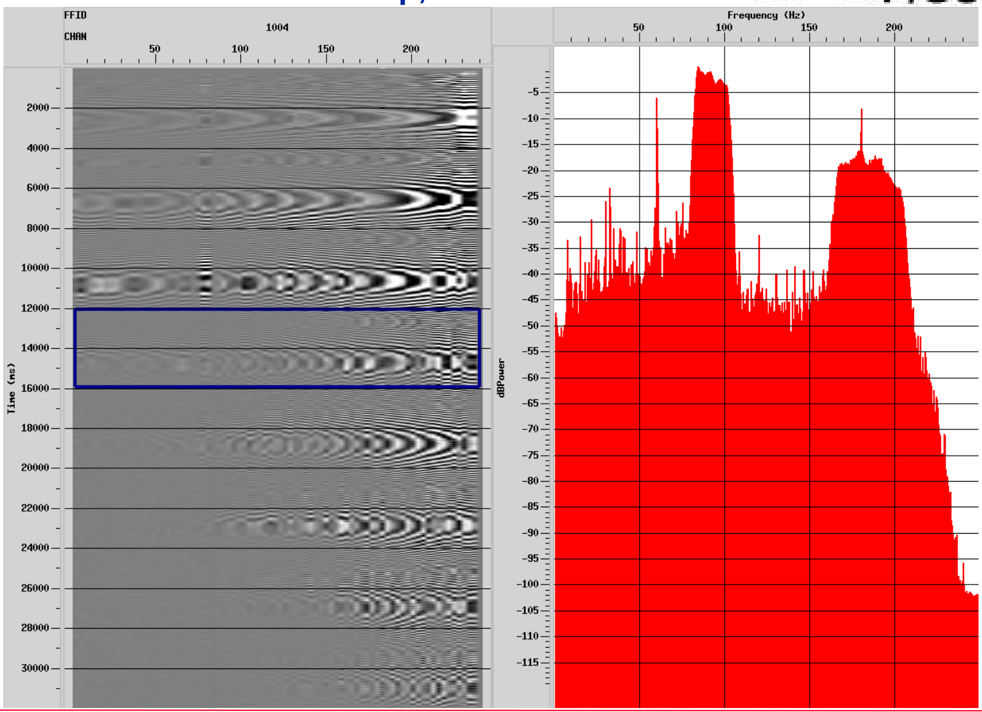
Uncorrelated 32 sec sweep, 12-16 s window



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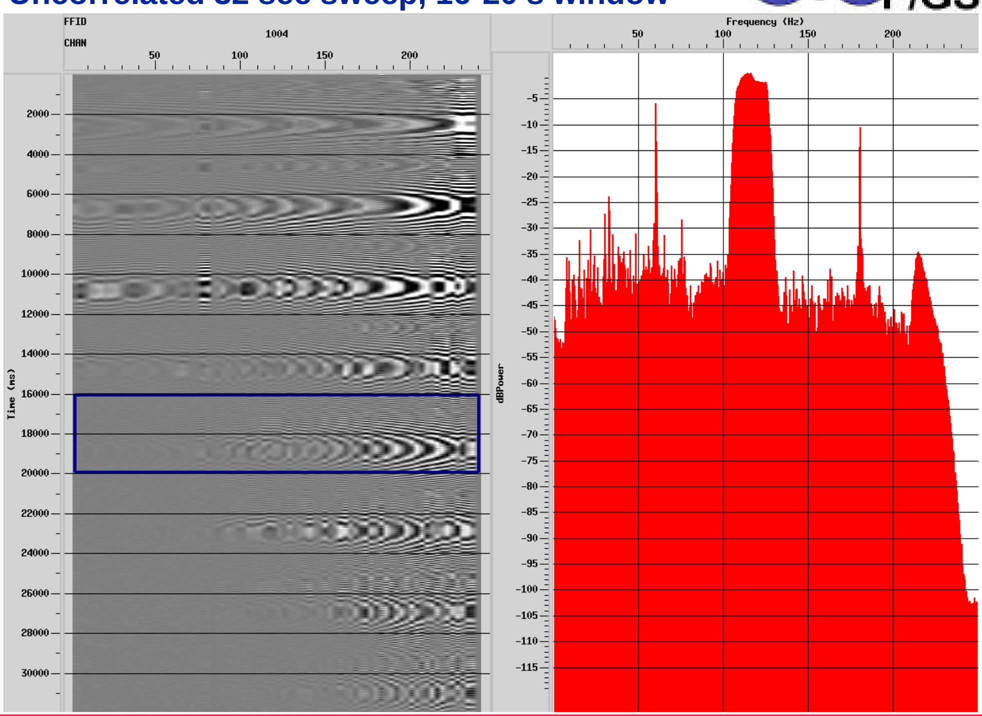
Uncorrelated 32 sec sweep, 16-20 s window



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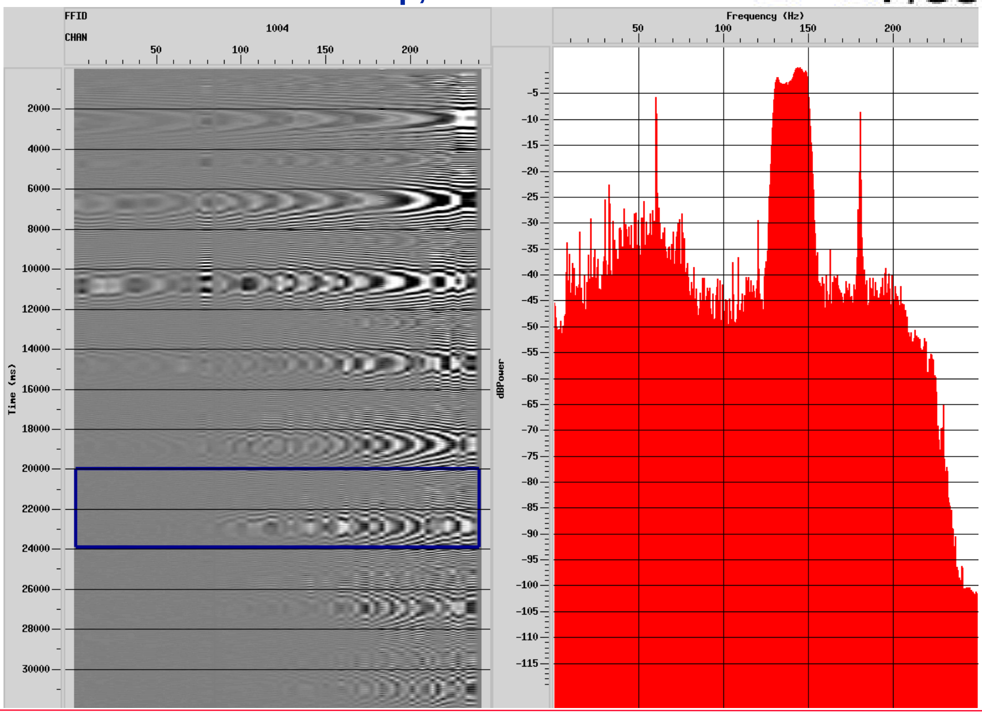
Uncorrelated 32 sec sweep, 20-24 s window



This presentation contains P/GSI processing information

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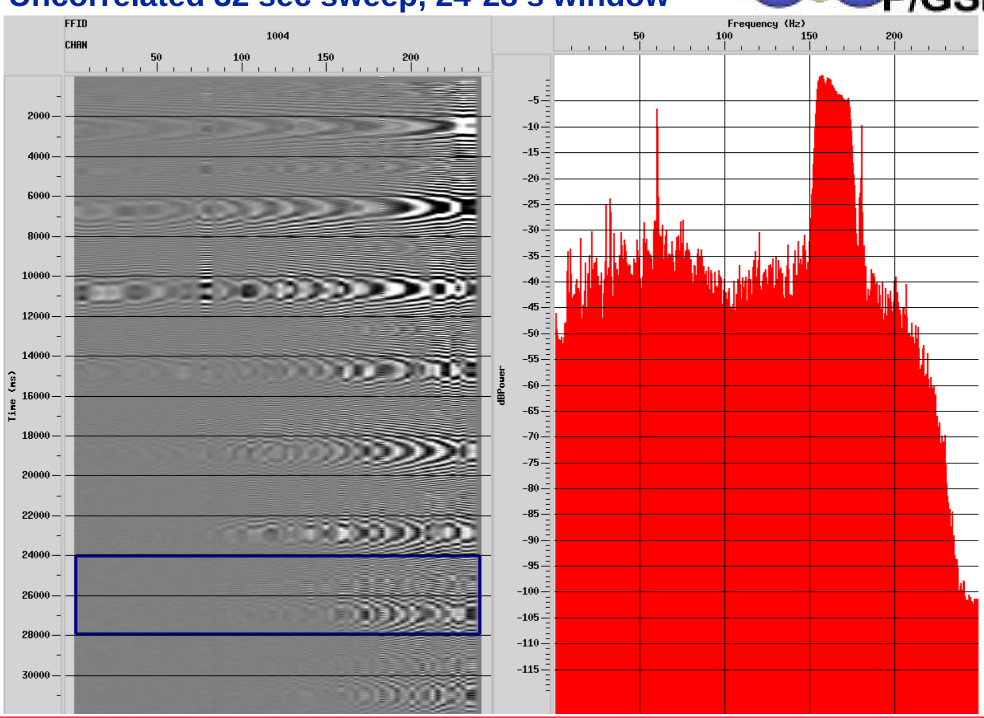
Uncorrelated 32 sec sweep, 24-28 s window



This presentation contains P/GSI processing information

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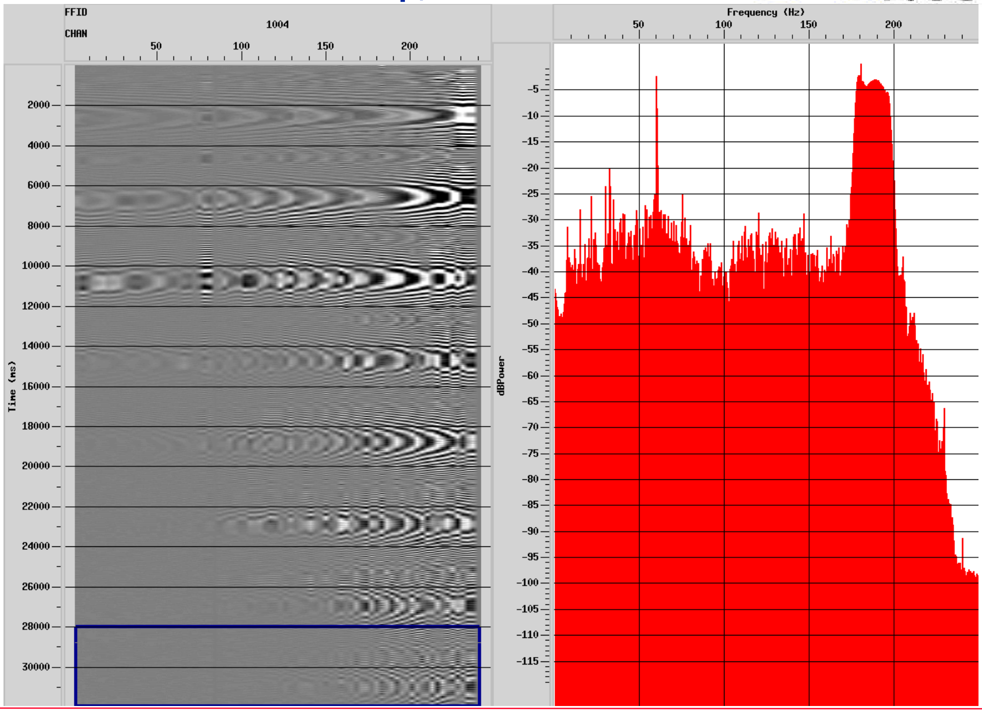
Uncorrelated 32 sec sweep, 28-32 s window

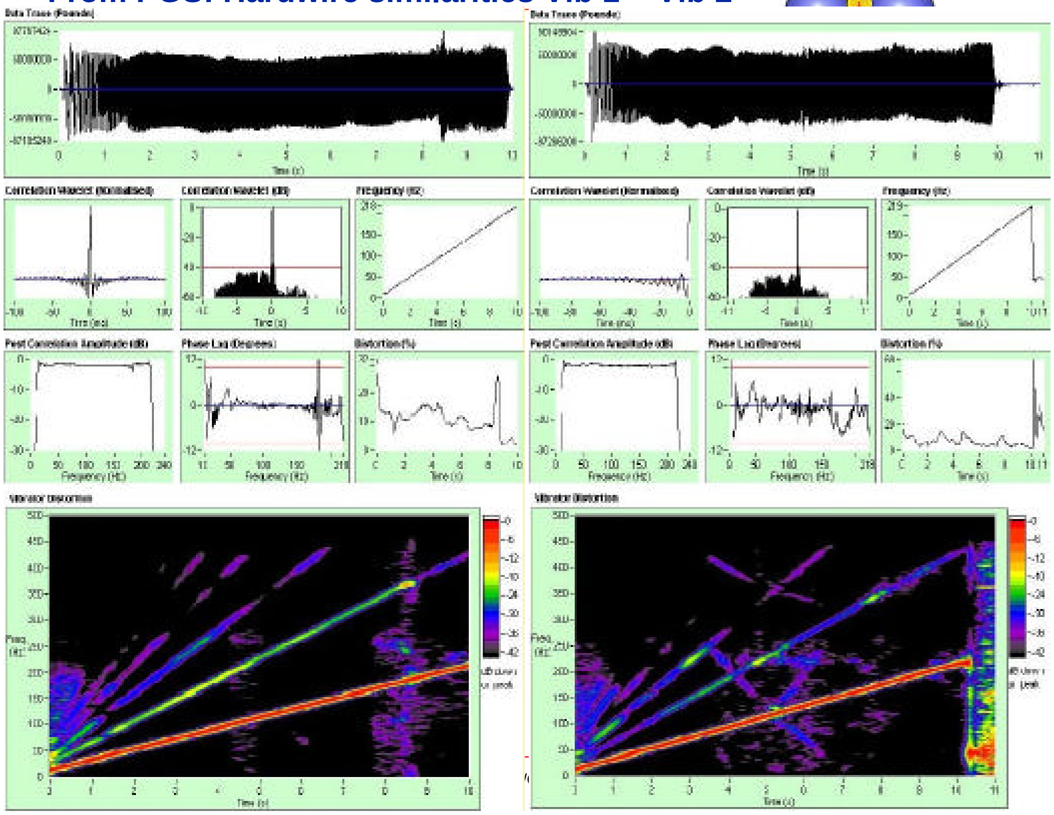


Additional Spectra and Data

Zero Offset shot, array deployed 0-2000 ft @ 25 ft spacing:

- Spectra of time windows out of a uncorrelated record of a 32-sec sweep:
  - Whole record: 32 sec
  - 0-4 s, 4-8s, 8-12 s, 12-16 s, 16-20 s, 20-24 s, 24-32 s
- **Sonogram from PGS**
- 8 – 220 Hz sweep
  - Upper half of array (0-1000 ft)
  - Lower half of array (1000-2000 ft)

From PGS: Hardwire similarities Vib 1 + Vib 2



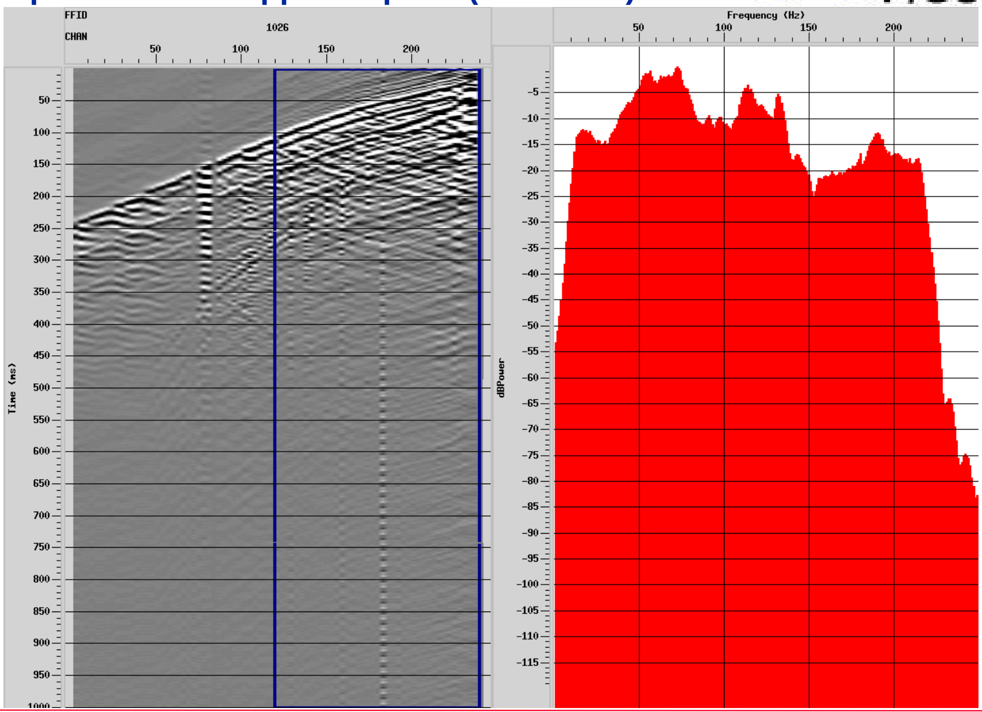
Additional Spectra and Data

Zero Offset shot, array deployed 0-2000 ft @ 25 ft spacing:

- Spectra of time windows out of a uncorrelated record of a 32-sec sweep:
  - Whole record: 32 sec
  - 0-4 s, 4-8s, 8-12 s, 12-16 s, 16-20 s, 20-24 s, 24-32 s
- Sonogram from PGS
- **8 – 220 Hz sweep**
  - **Upper half of array (0-1000 ft)**
  - **Lower half of array (1000-2000 ft)**

This presentation contains P/GSI processing information

Spectrum over upper 40 pods (0 - 1000 ft)



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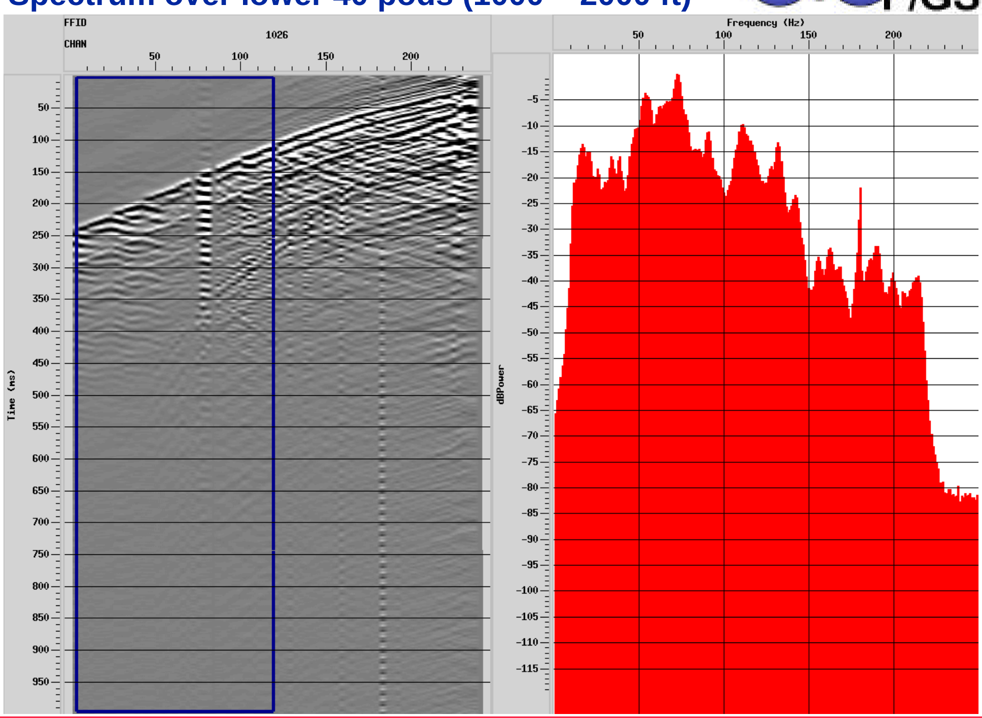
Spectrum over lower 40 pods (1000 – 2000 ft)



This presentation contains P/GSI processing information

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Appendix D

VSP Hodogram Analysis

Hodogram Analysis for Orientation Angles

- Determine H1: show which horizontal component is H1 / H2 (definition: H1 🕒 90 degrees to the right of H2)
- Hodogram Analysis: Example Hodograms
- Hodogram analysis: Histograms of resulting orientation angles for selected pods

Hodogram Analysis for Orientation Angles

- **Determine H1: show which horizontal component is H1 / H2 (definition: H1 ◷ 90 degrees to the right of H2)**
- Hodogram Analysis: Example Hodograms
- Hodogram analysis: Histograms of resulting orientation angles for selected pods

This presentation contains P/GSI processing information

Slide 3 of 20

Hodogram Analysis for Orientation Angles

- The next slide shows the vertical component of pod 28 for all shots around Ring No. 8, aligned on the first break.
- The Amplitude of the first break varies sinusoidally as the source goes around the ring.
- From the Variation of Amplitude the orientation of the components with respect to each other is observed.

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Slide 4 of 20

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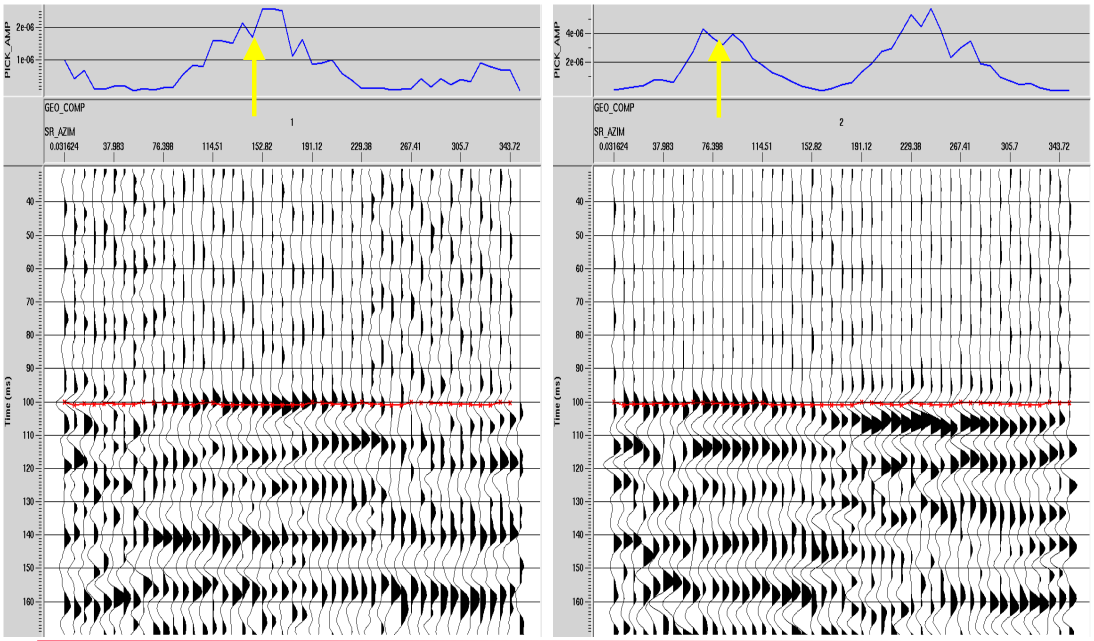
First break on Horizontals: Pod 26, around Ring 8

Geophone comp. 1 = H1 | **Geophone comp. 2 = H2**

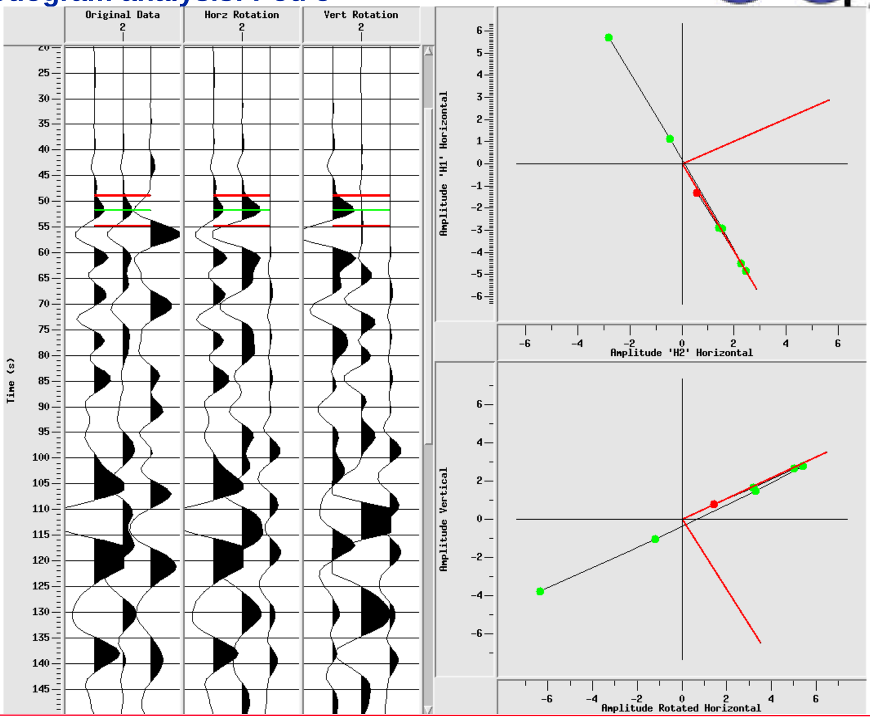


P/GSI™

Hodogram Analysis for Orientation Angles

- Determine H1: show which horizontal component is H1 / H2 (definition: H1 🕓 90 degrees to the right of H2)
- **Hodogram Analysis: Example Hodograms**
- Hodogram analysis: Histograms of resulting orientation angles for selected pods

Hodogram analysis: Pod 5



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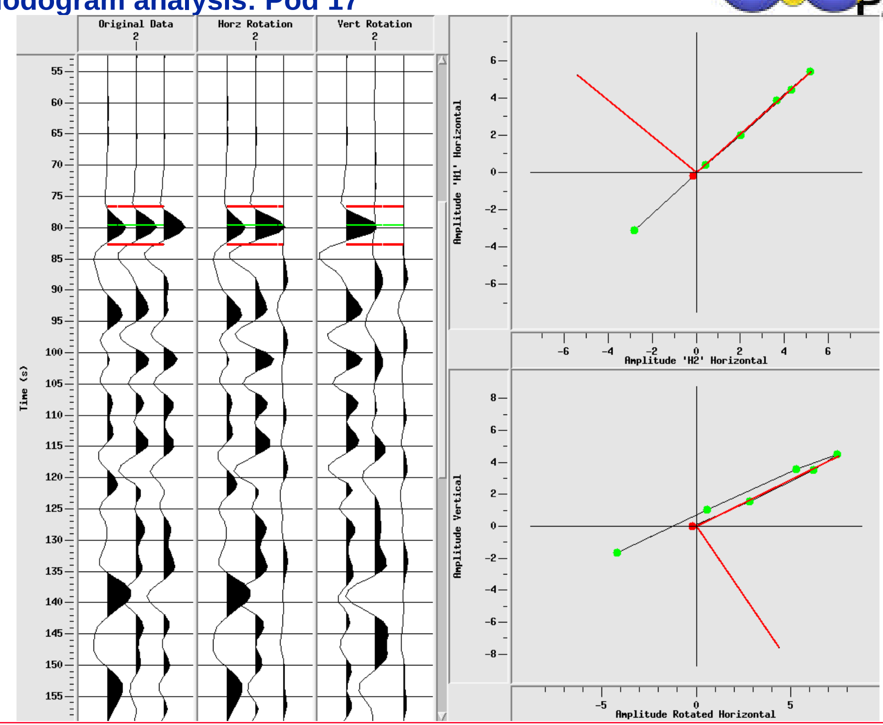
Hodogram analysis: Pod 17



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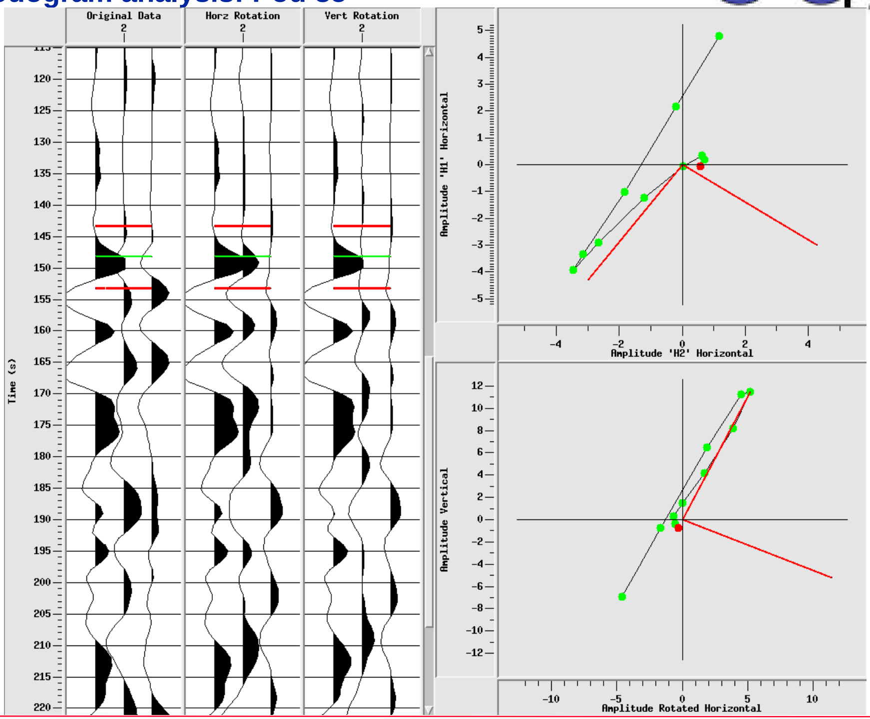
Hodogram analysis: Pod 35



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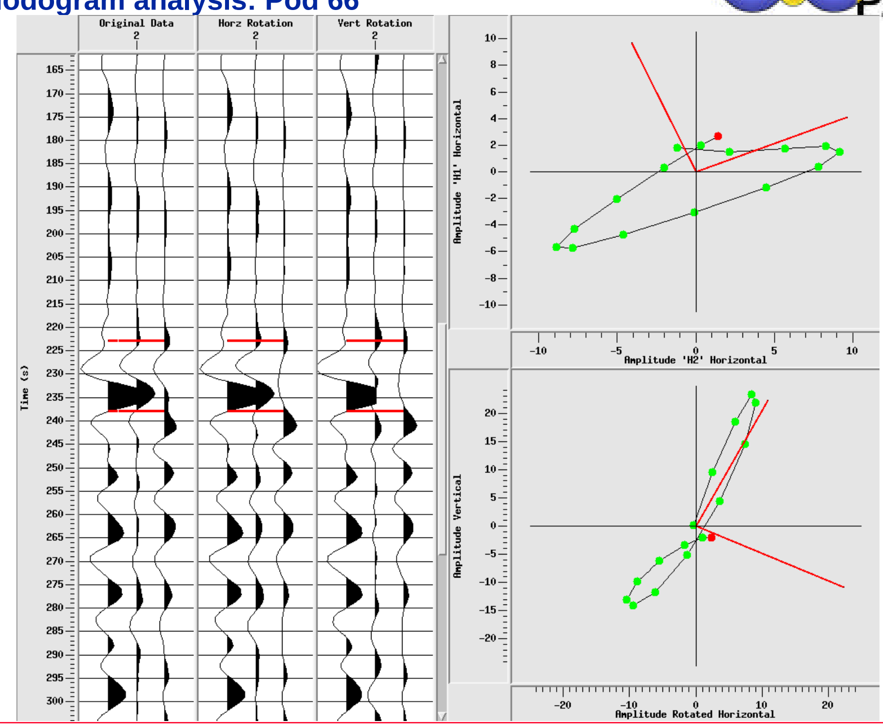
Hodogram analysis: Pod 66



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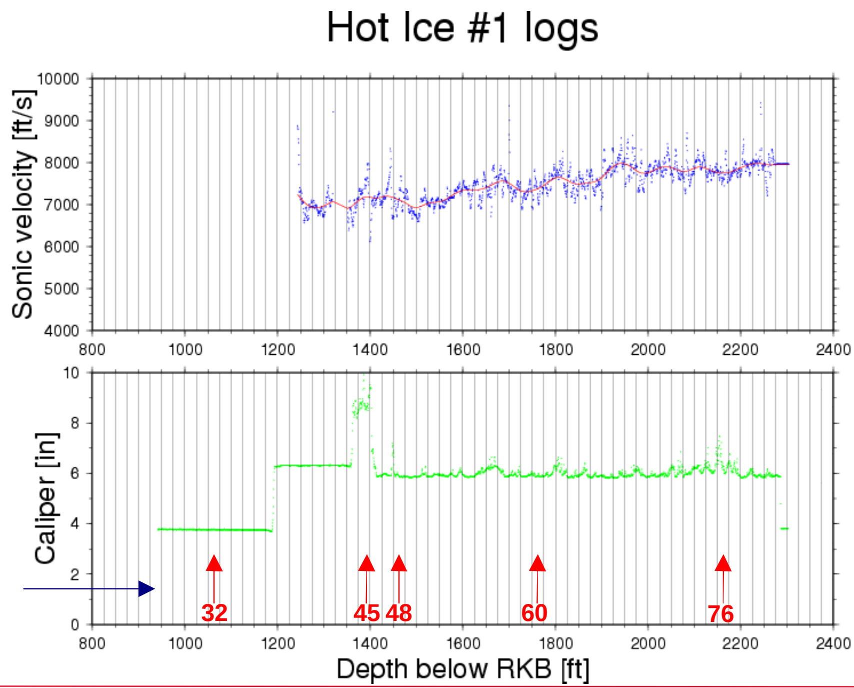
Hodogram Analysis for Orientation Angles

- Determine H1: show which horizontal component is H1 / H2 (definition: H1 ◷ 90 degrees to the right of H2)
- Hodogram Analysis: Example Hodograms
- **Hodogram analysis: Histograms of resulting orientation angles for selected pods**

Hodogram Analysis for Orientation Angles

- The orientation of the geophone pod (azimuth w/ respect to North) was determined automatically using a maximum number of sources. The resulting orientations from each source point were first edited for outliers, then averaged over all sources.
- On the following slides, the left side shows histograms of all pod orientations as determined for each source point. A sharp gaussian distribution should be seen around the true orientation angle whereas the width of the distribution should depend linearly on the signal-to-noise ratio. Therefore the peaks should widen with depth as the signal-to-noise ratio deteriorates. This is clearly visible. High noise levels also can be attributed to bad coupling due to widening of the hole (as indicated by the caliper log)
- The right hand side shows the deviations of the individual orientation angles from the mean value plotted at the respective shotpoint locations. Any strong colouring shows strong deviation from the mean. Recurring patterns would indicate biased results due to heterogeneity, interference, anisotropy etc.

Sonic and Caliper log below 800 ft



Location of pods shown in the following

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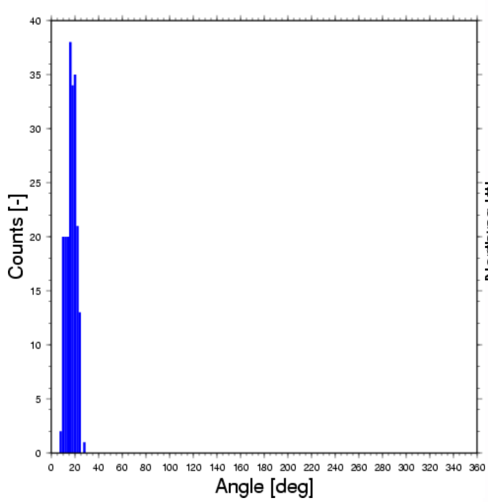
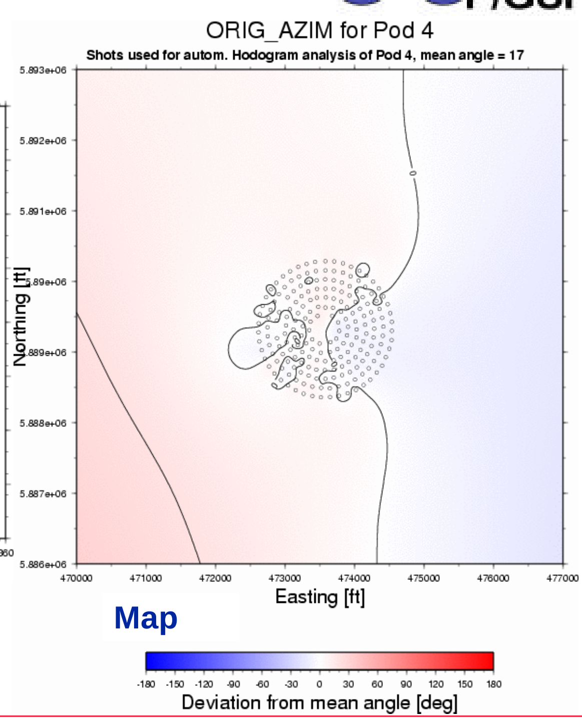
Pod 4: 369 ft below RKB

Histogram





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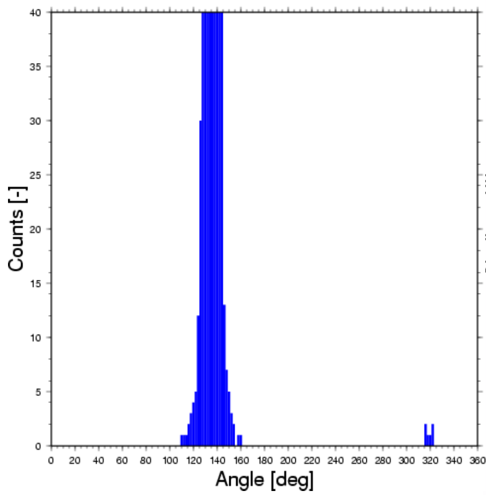
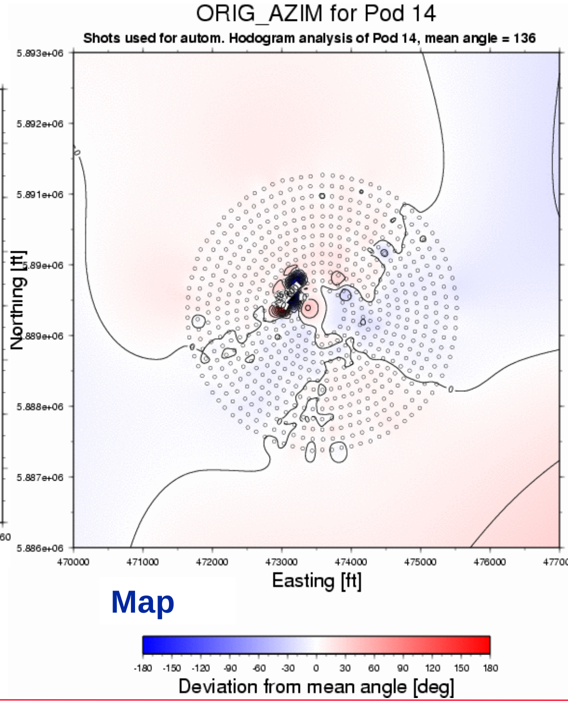
Pod 14: 619 ft below RKB

Histogram



Map



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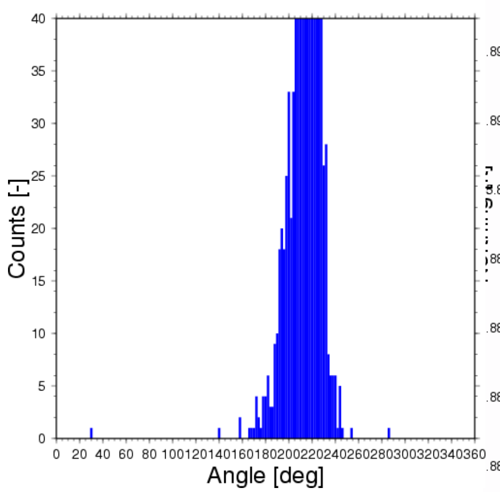
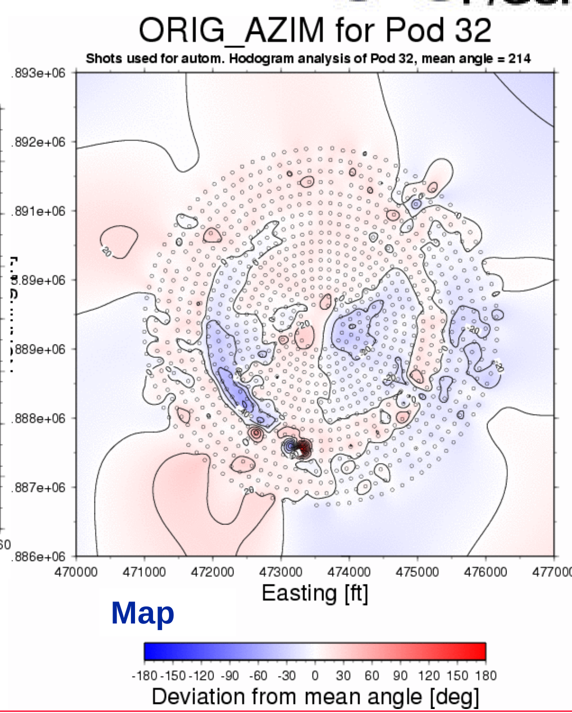
Pod 32: 1069 ft

Histogram



Map



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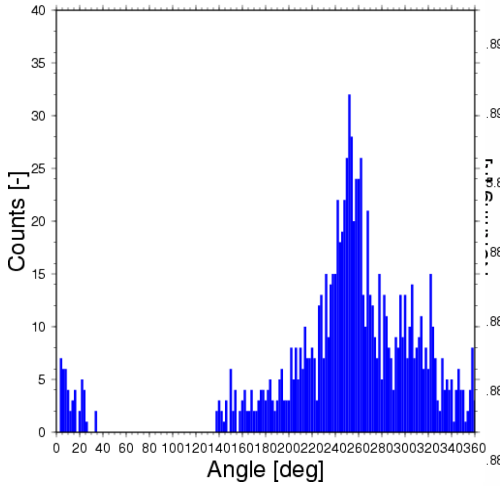
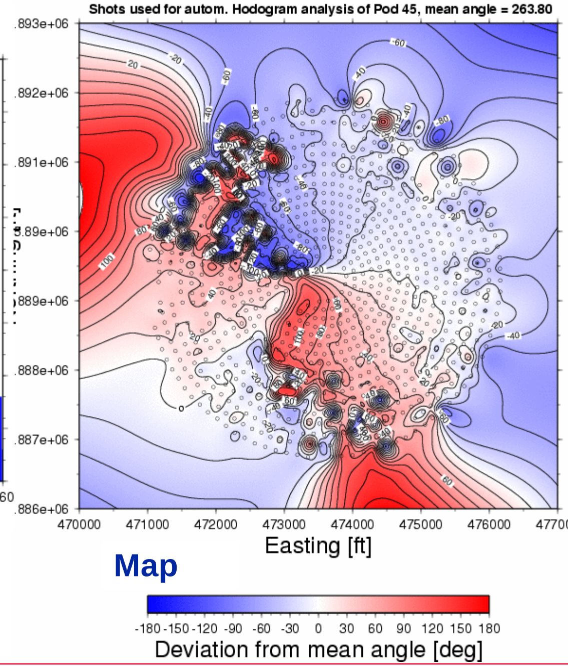
Pod 45: 1394 ft RKB

(widening in caliper log from hole washout)

Histogram

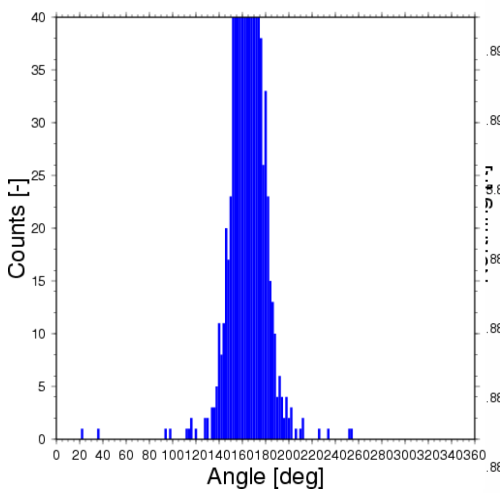


ORIG_AZIM for Pod 45

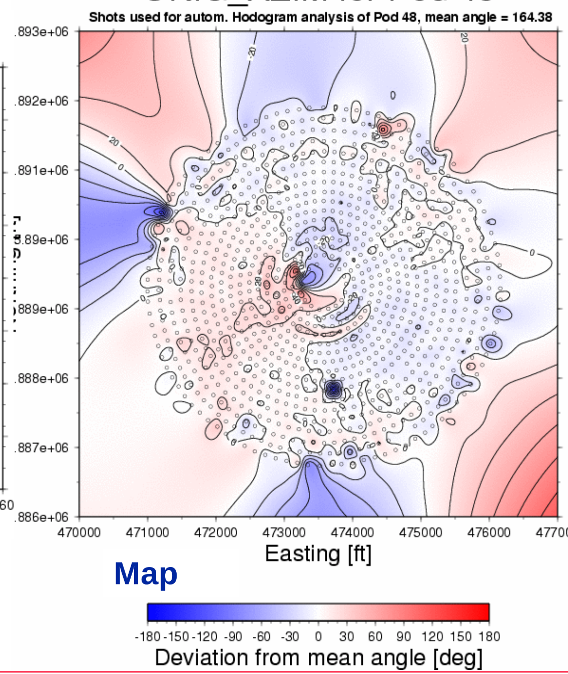


Pod 48: 1469 ft

Histogram



ORIG_AZIM for Pod 48



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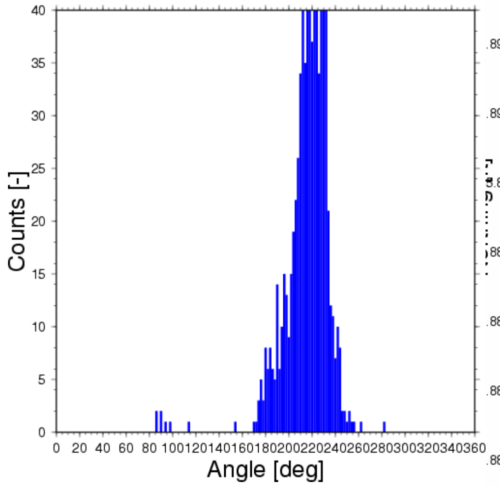
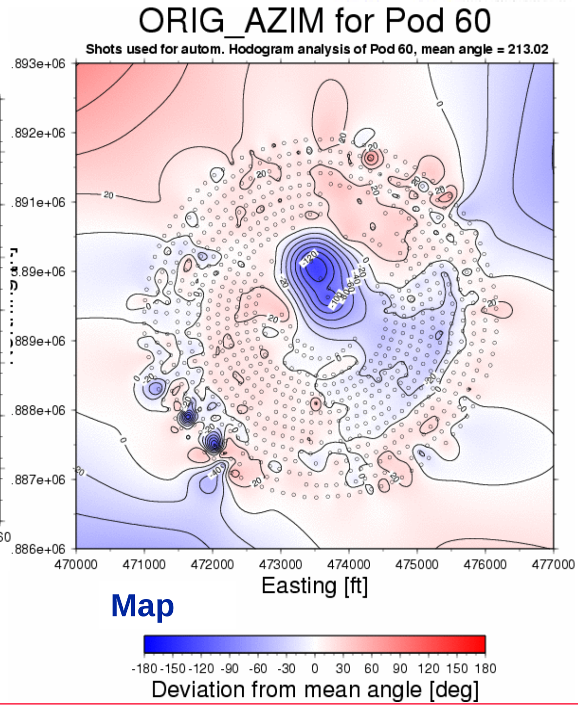
Pod 60: 1769 ft below RKB

Histogram





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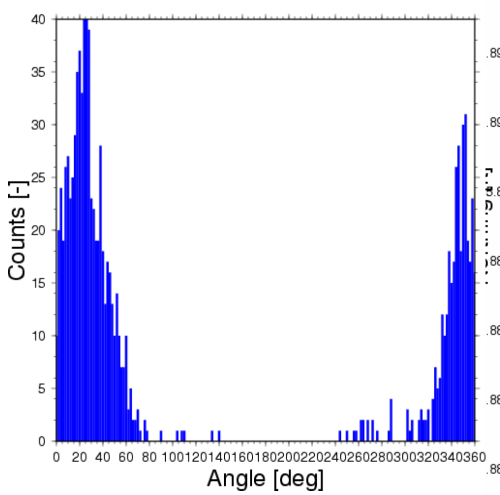
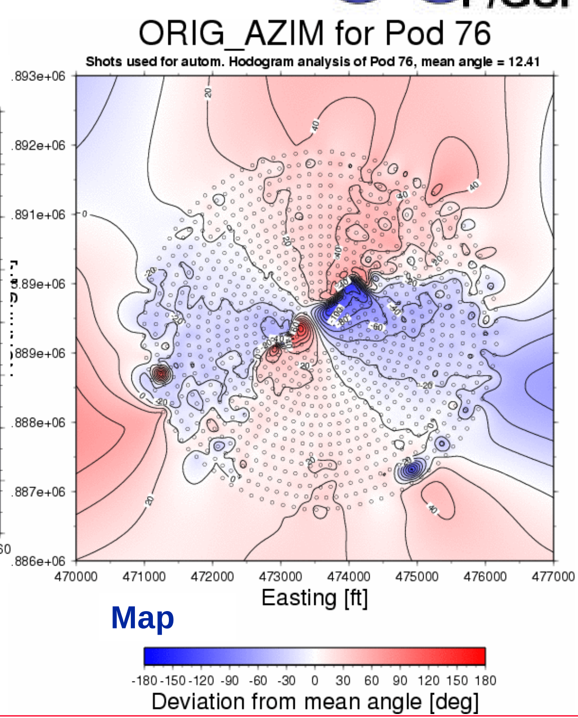
P/GSI™

Pod 76: 2169 ft below RKB

Histogram





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Appendix E

Three-Component Processing

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Slide 1 of 8

Three-Component Processing

- 3-Component Rotation to true XYZ:
  - **Shot point due N of well**
  - Shot point due E of well

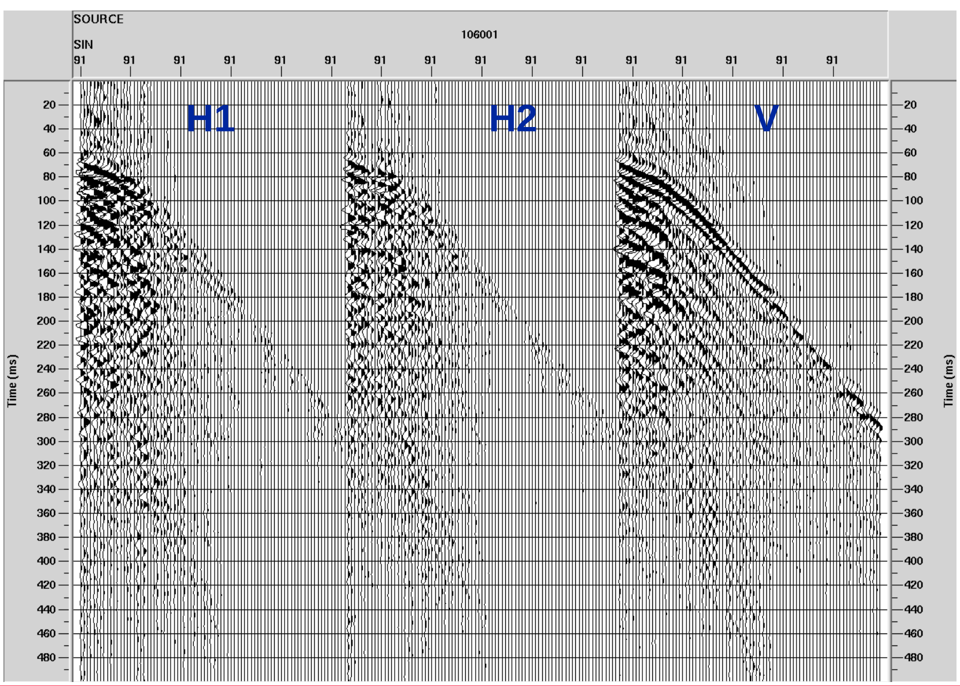
This presentation contains P/GSI processing information

Slide 2 of 8

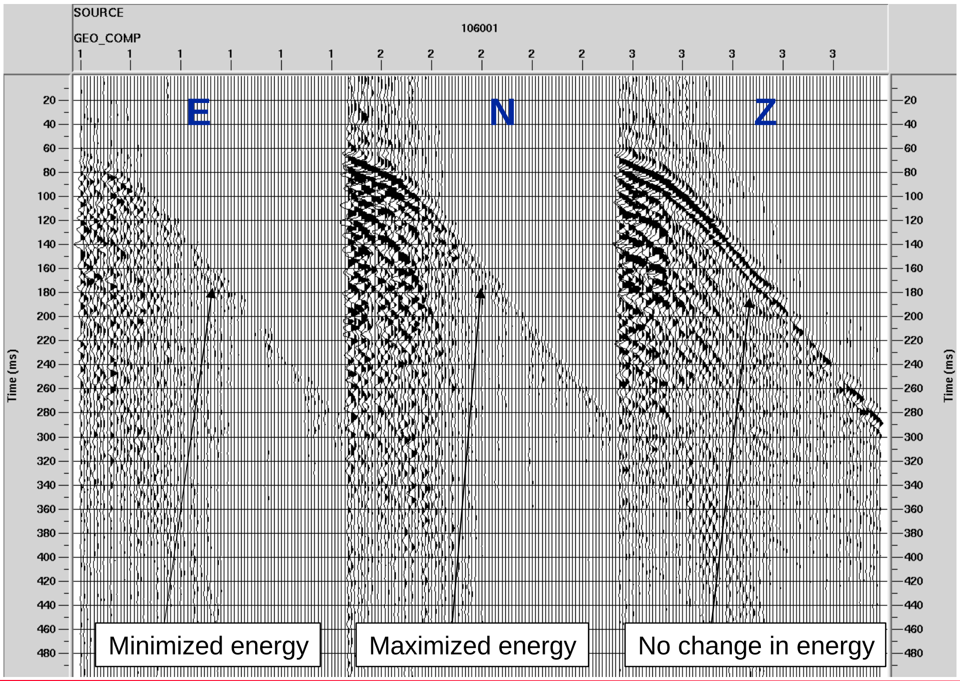
Three-Component Processing

- For a shot point due North, the energy of the horizontal components should be moved to the N (North) component.
  Any remaining energy on the E (East) component is due to either bad rotation or SH energy
- Likewise, if the shot point was due East, all horizontal energy should be moved to the E component

Before Rotation to XYZ: Shot point due North



After Rotation to XYZ: Shot point due North



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Slide 5 of 8

Three-Component Processing

- 3-Component Rotation to true XYZ:
  - Shot point due N of well
  - **Shot point due E of well**

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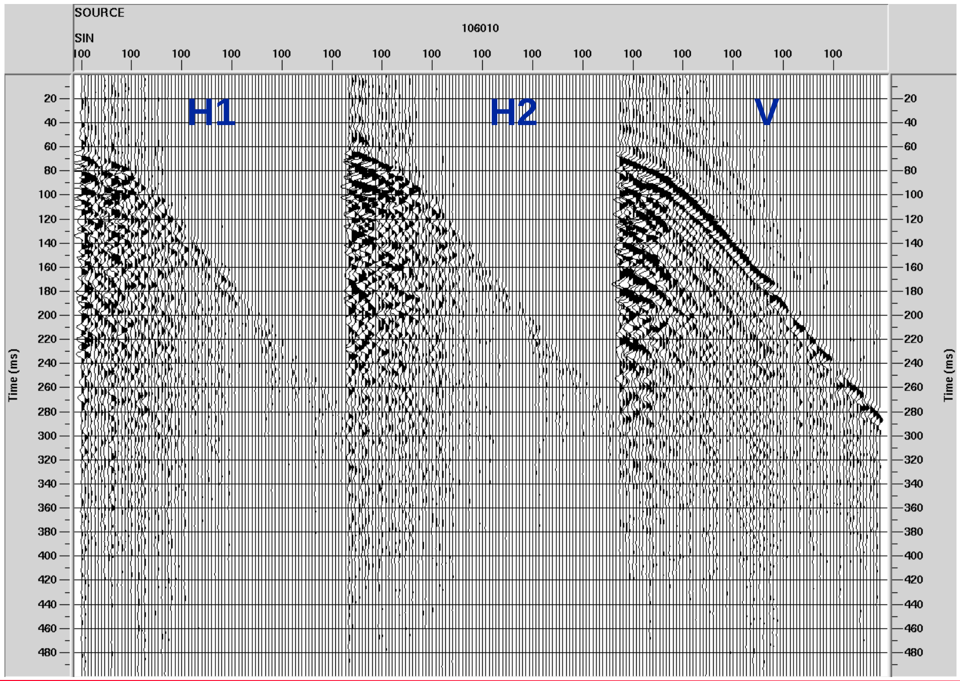
Slide 6 of 8

Before Rotation to XYZ: Shot point due East



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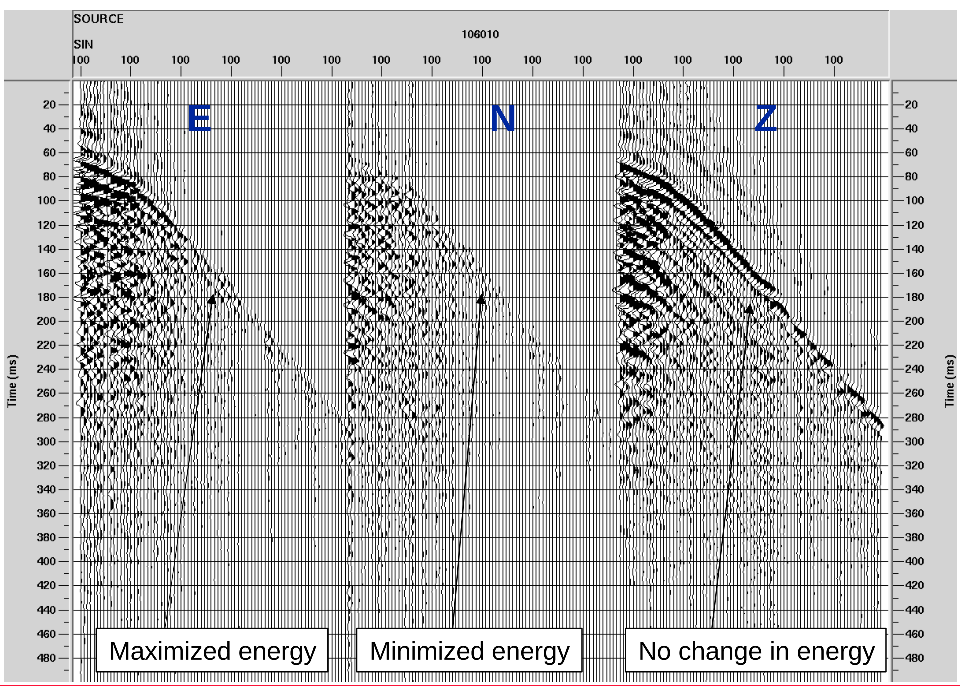
Rotated to XYZ: Shot point due East



This presentation contains P/GSI processing information

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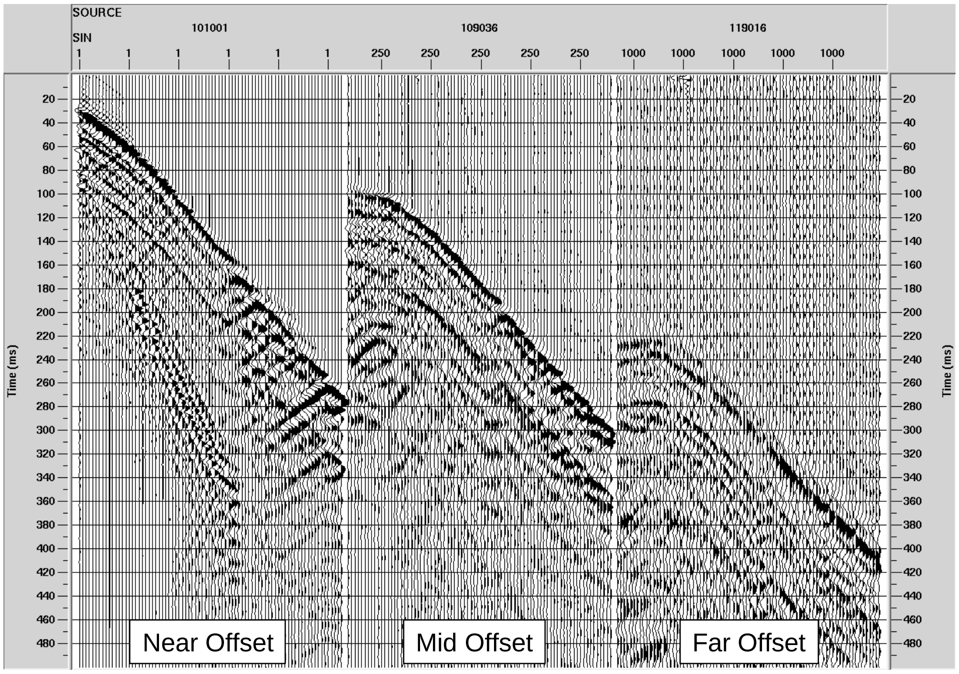
Appendix F

First Break Picks

First Break Picks

- Data rotated to source (downgoing P), unfiltered for near, mid and far offsets, FB picks displayed
- FB picks from near-offset shot at the beginning of survey compared to FB picks of same shot at the end of survey:
  - Note how high velocity precursors in the open-hole section diminish over time

P-component data (rotated and tilted towards source)



This presentation contains P/GSI processing information

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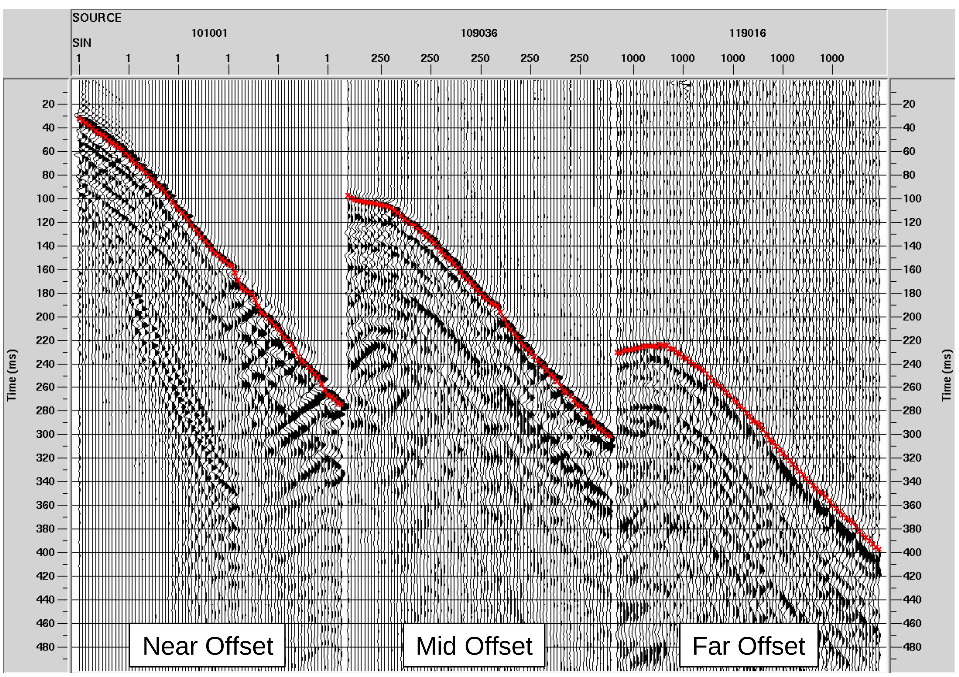
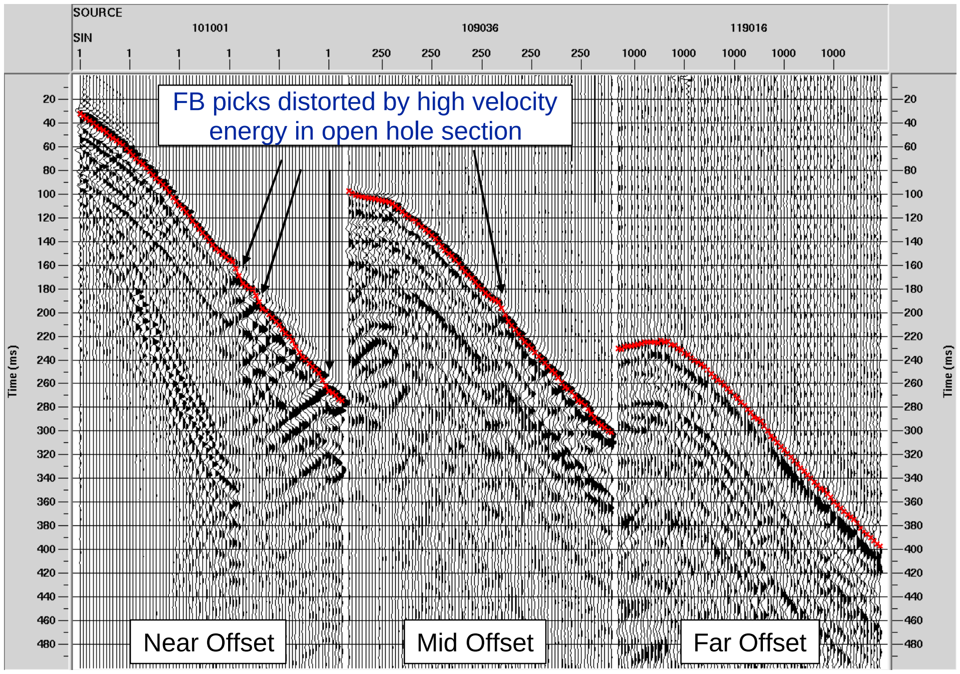
P-component data (rotated and tilted towards source)



This presentation contains P/GSI processing information

Slide 4 of 8

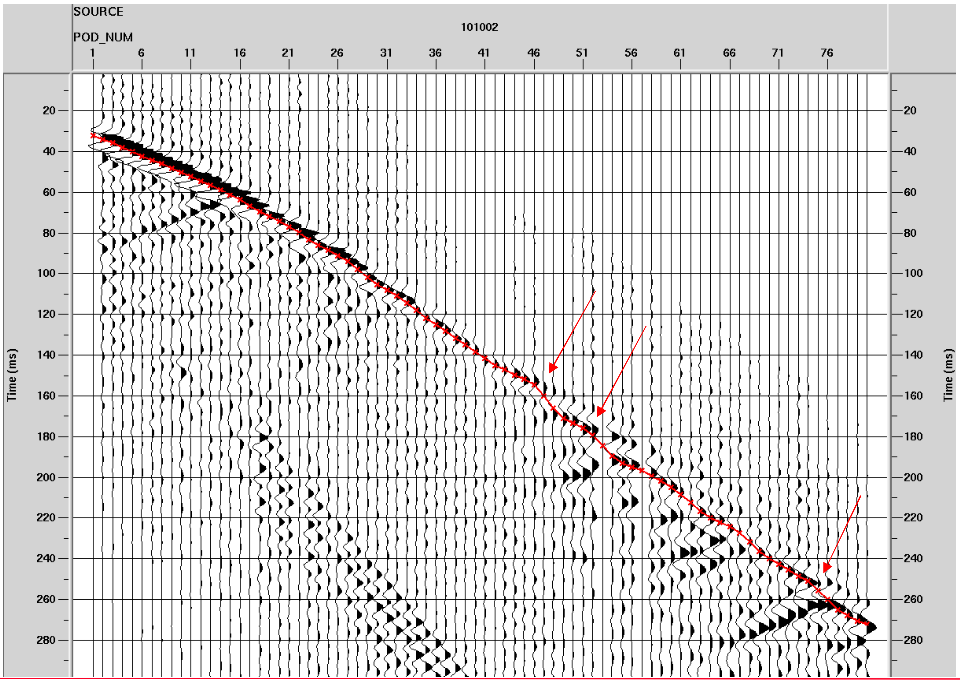
P-component data (rotated and tilted towards source)



First Break Picks

- Data rotated to source (downgoing P), unfiltered for near, mid and far offsets, FB picks displayed
- FB picks from near-offset shot at the beginning of survey compared to FB picks of same shot at the end of survey:
  - Note how high velocity precursors in the open-hole section diminish over time

Zero Offset shot on ice pad before production



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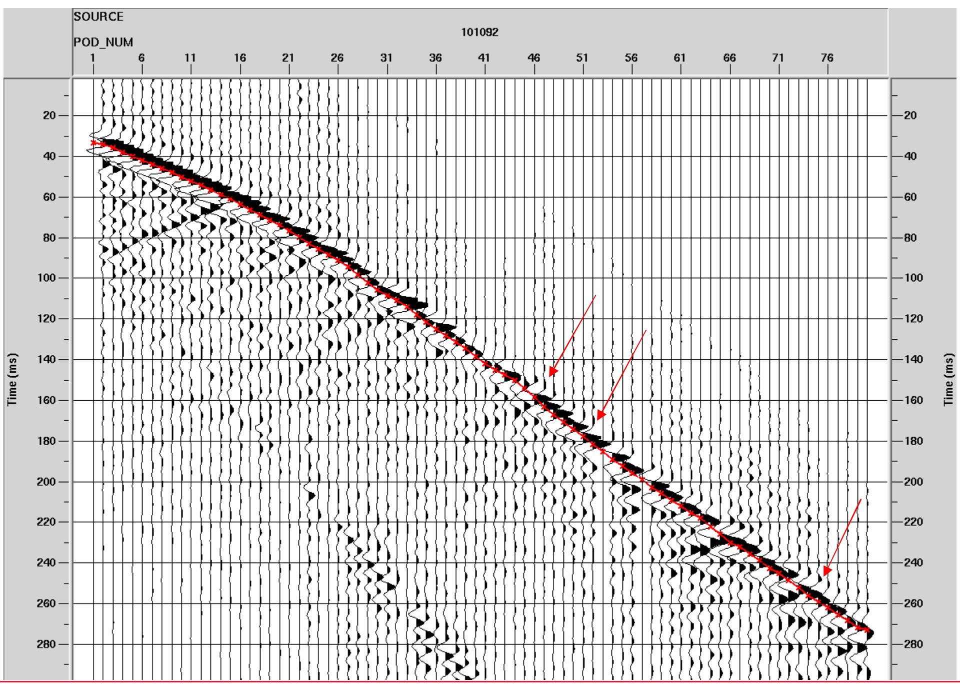
Slide 7 of 8

Zero Offset shot on ice pad after production (30 hr)



This presentation contains P/GSI processing information

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Appendix G

Three-Component Wavefield Separation

Three-Component Wavefield Separation

Wavefield separation is performed by:

- rotating H1 component towards the source
- reversing polarity of the V component
- subtracting (source-rotated) H1 component from vertical component (this enhances upgoing P)

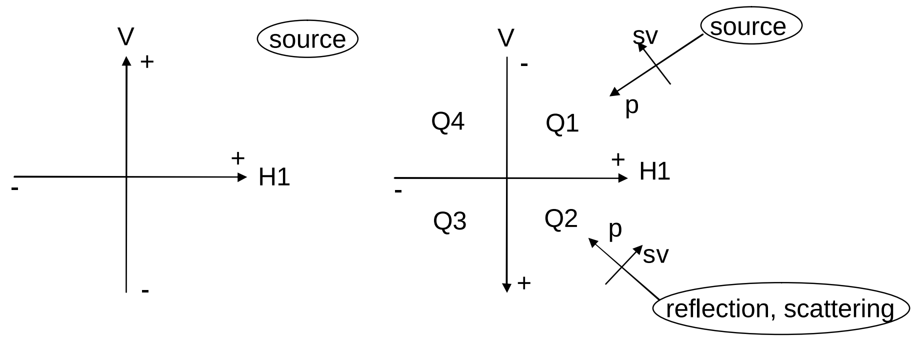
The following slides show the raw (AGC'd) wavefield and the upgoing wavefield for a near, mid and far offset shotpoint. Also shown is a FK spectrum of the upgoing wavefield for the near-offset shotpoint.

3-Component upgoing p-wave separation

1) Rotate H1 (azimuth only) towards source

2) Reverse V polarity

3) Sum: -V + H1

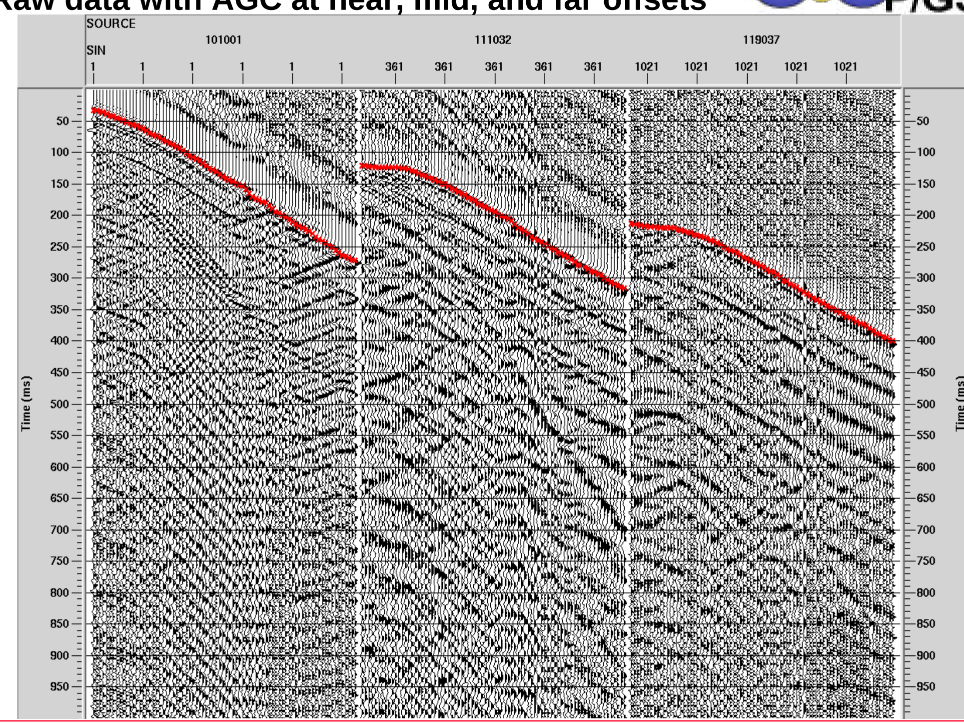


- •Downgoing p-waves are attenuated with a dipole response in the Q1 quadrant, with total attenuation at 45° inclination from the vertical.
- •Downgoing s-waves are amplified with a double-dipole response in the Q1 quadrant.
- •Upgoing p-waves are amplified with a double-dipole response in the Q2 quadrant.
- •Upgoing s-waves are attenuated with a dipole response in the Q2 quadrant.

This presentation contain P/GSI processing information

Slide 3 of 6

Raw data with AGC at near, mid, and far offsets



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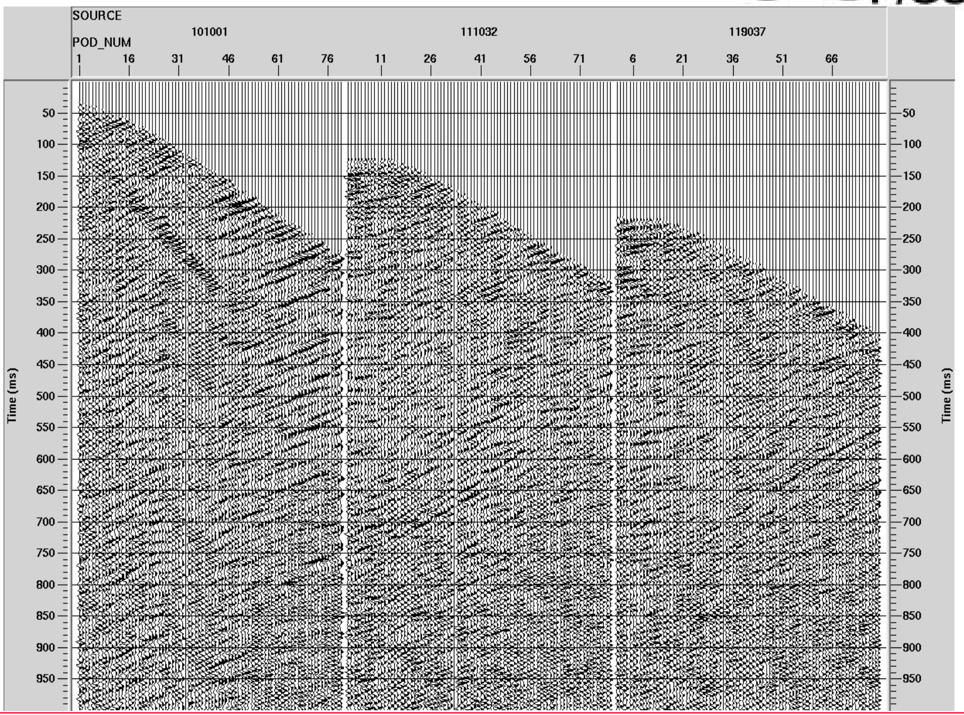
Slide 4 of 6

Upgoing wavefield with AGC



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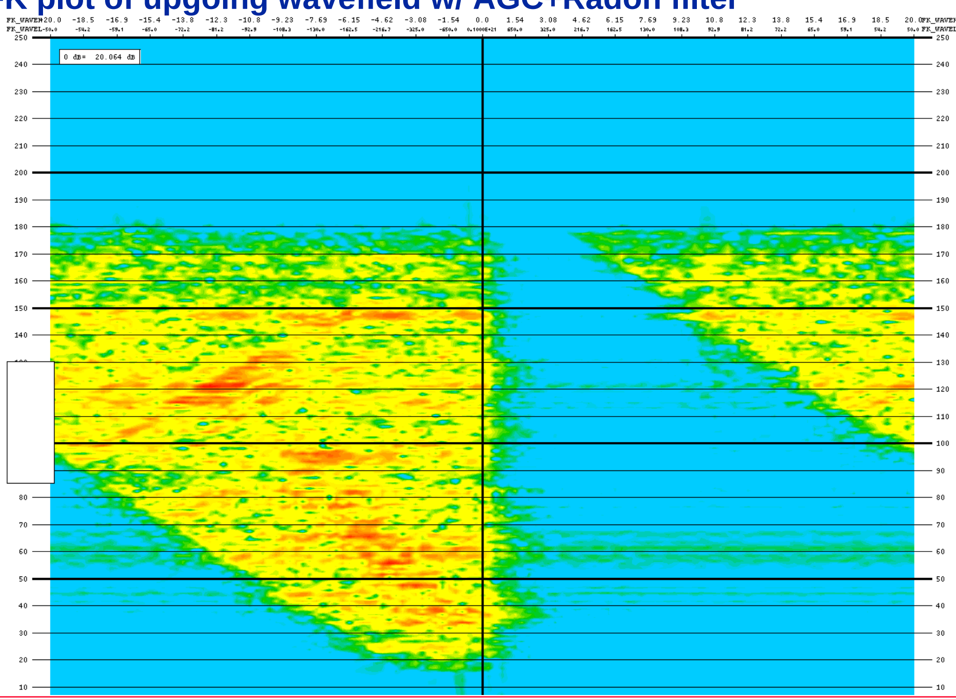
Slide 5 of 6

FK plot of upgoing wavefield w/ AGC+Radon filter



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Appendix H

VSP Statics

Shot statics

Shot statics are designed to correct local traveltime undulations caused in the near surface which are unique to one shot location or a small patch of shots. It is therefore necessary to retain the short (spatial) wavelength component of the raw shot statics. Longer wavelength components are due to other causes, e.g., topography, lateral heterogeneity, anisotropy, etc., and these corrections should not be included in the shot statics.

The empirical part of computing the shot statics is to attenuate the longer wavelength components in the raw statics by smoothing the raw statics and subtracting them from the original to obtain a low-cut filtered residual which is the shot static correction.

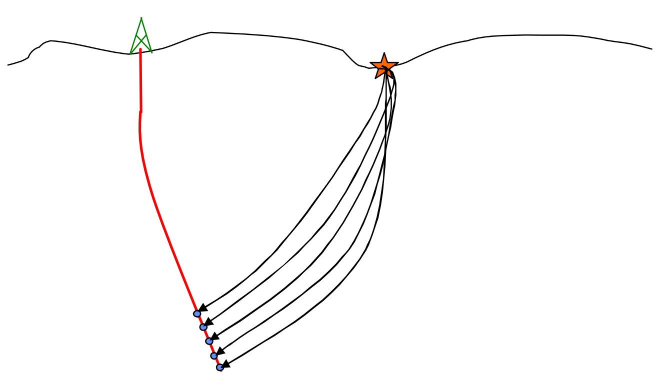
The shot statics calculation is partially model based and partially empirical:
The model based part is to raytrace the direct arrival times from all sources into all receivers. The first break picks are then subtracted from the computed arrival times. These traveltime differences are converted into surface consistent shot point statics by averaging over the lower 40 receiver levels for each shot.

The results are raw, or full bandwidth, shot statics. A variety of phenomena contribute to the traveltime differences over all (spatial) wavelengths. If the velocity model was exact then the full bandwidth statics could be applied without further modification.

Shot statics

- **Plots shown in the following:**
  - Topography: Shot statics should not mimic topographic features, since the topography is implicitly taken into account during a prestack depth migration.
  - Raw Difference between first-break picks and forward-computed first-break times: this plot shows
    - 1. the overall correctness of the (1D) velocity model
    - 2. The ring of positive residuals at the perimeter is a clear indication of TIV anisotropy. For now, we might get away with an isotropic model if we skip the outer 3 rings of data (where the picks are less accurate anyway due to higher S/N ratio)
  - Final Shot static values: The raw FB residuals are substracted from the smoothed values to yield the final (short-wavelength) shot statics. A smoothing length of 1000 ft was used. Most static values are within +/- 1 ms, exept the outer three rings
  - Receiver gathers for certain azimuths for QC purposes before and after application of the statics

3D Shot static computation



Use the average of several travel time differences between ray traced and picked first breaks, common to each shot, into a group of (n) lower receiver levels.

$$FBdiff = 1/n \bullet \Sigma(Fbcomputed - Fbpicked)$$

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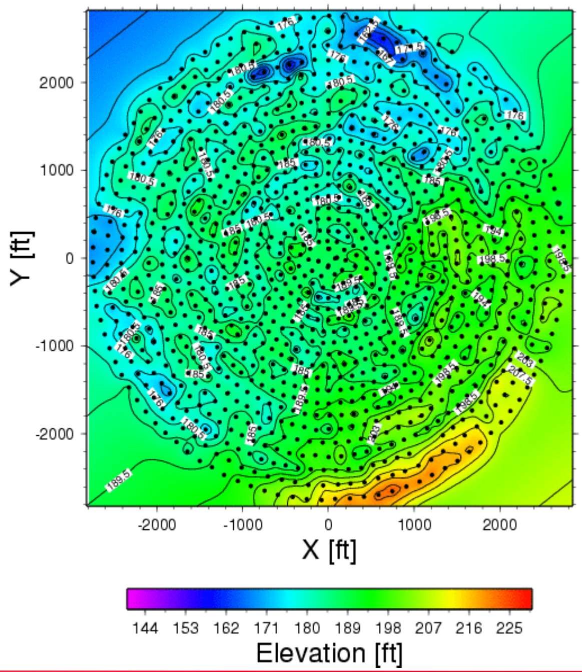
Topography from shot elevations



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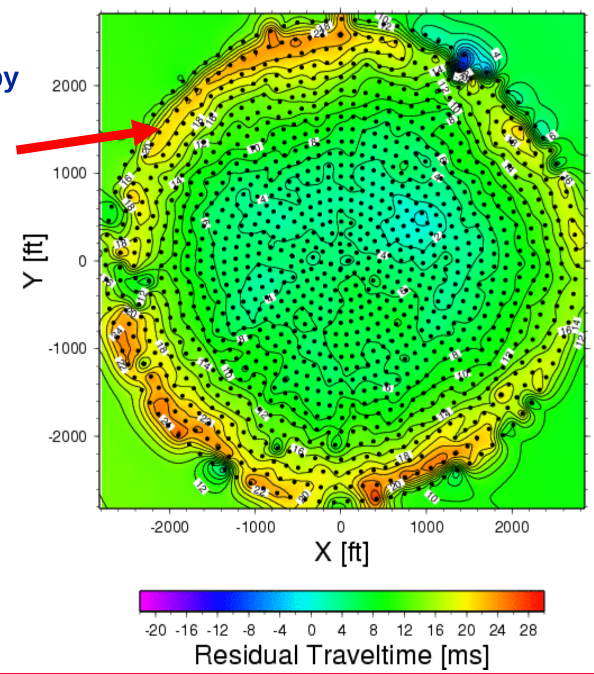
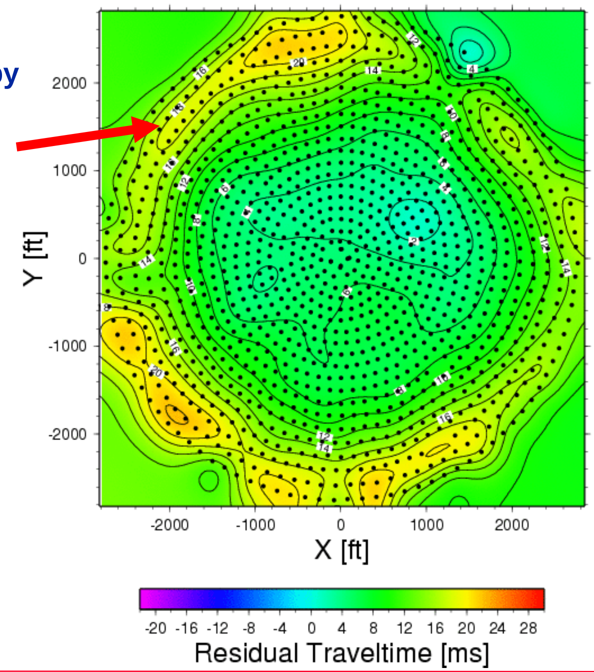
Raw traveltime residuals

TIV anisotropy causes this bulge of positive values

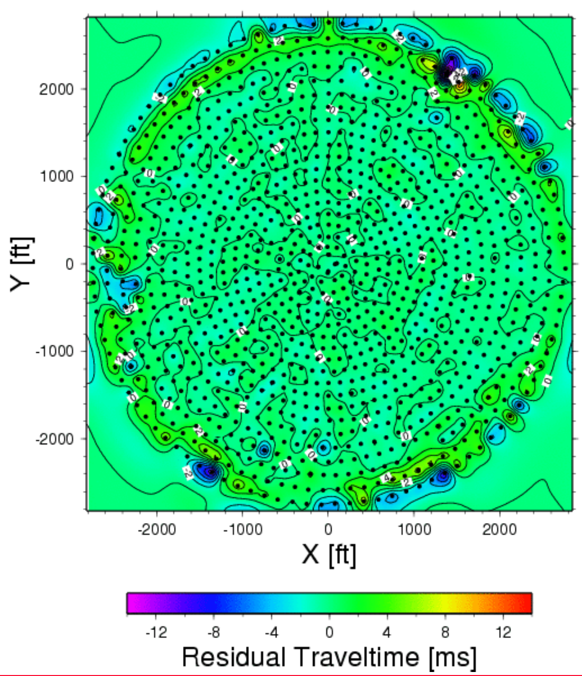


1000 ft Smoothed traveltime residuals

TIV anisotropy causes this bulge of positive values

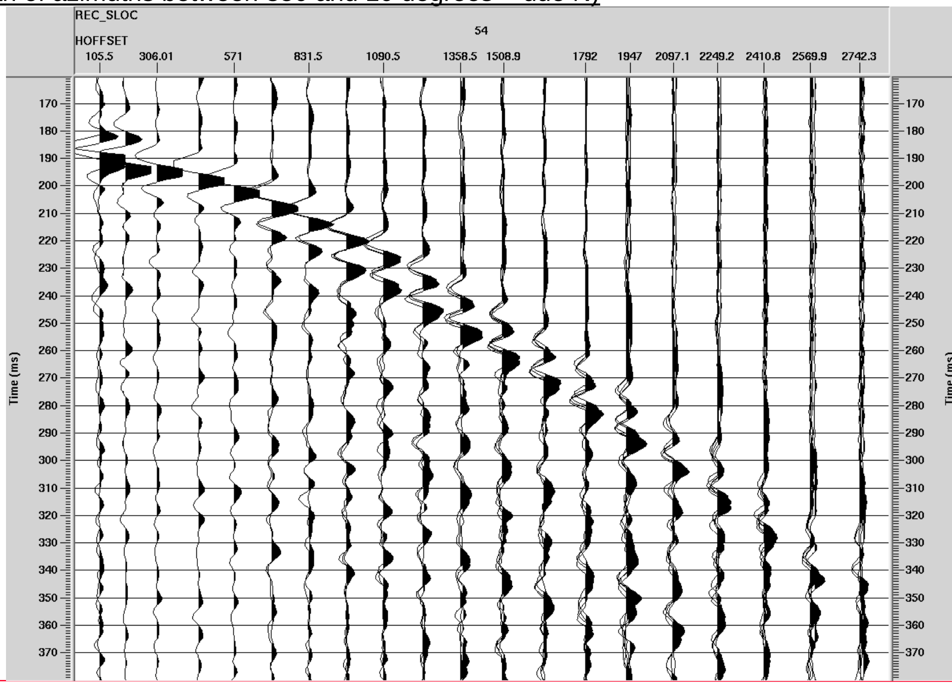


Final shot static values



Receiver gather before static application

(fan of azimuths between 350 and 10 degrees = due N)



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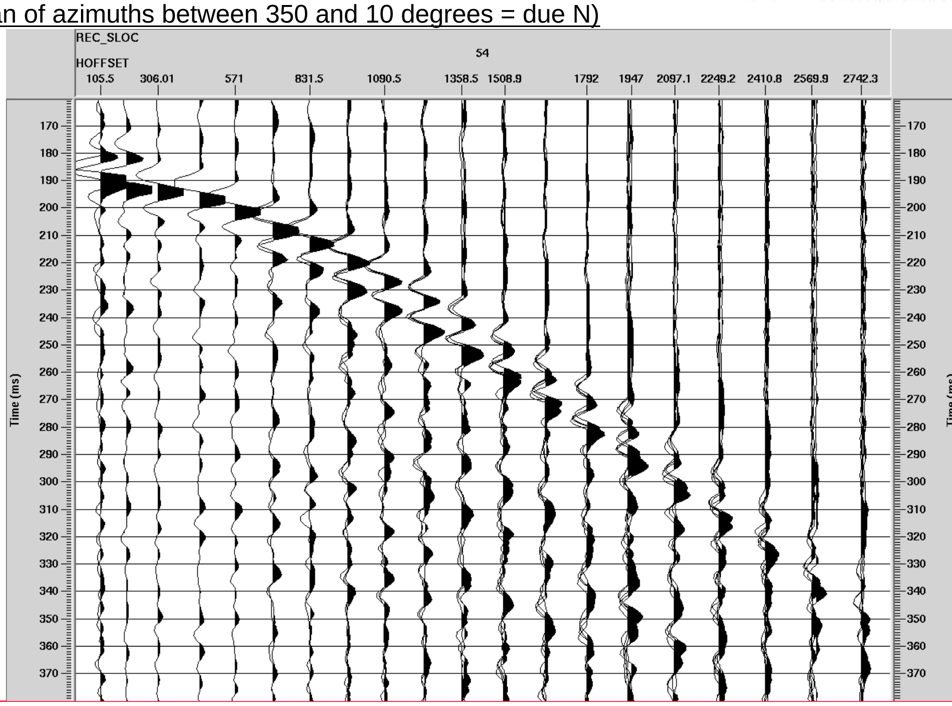
Receiver gather after static application

(fan of azimuths between 350 and 10 degrees = due N)



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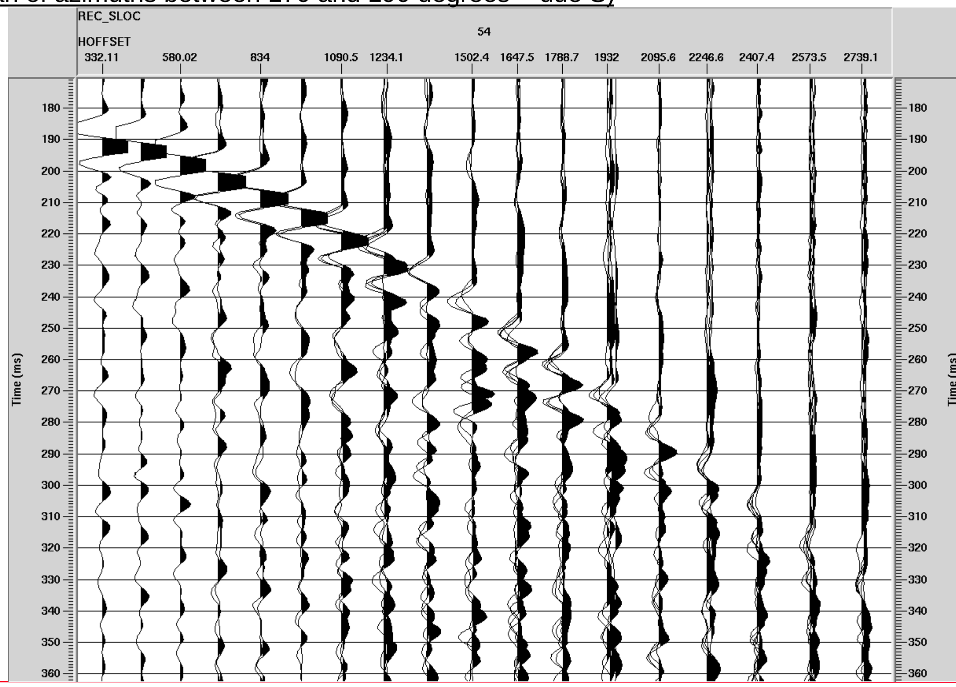
Receiver gather before static application

(fan of azimuths between 170 and 190 degrees = due S)

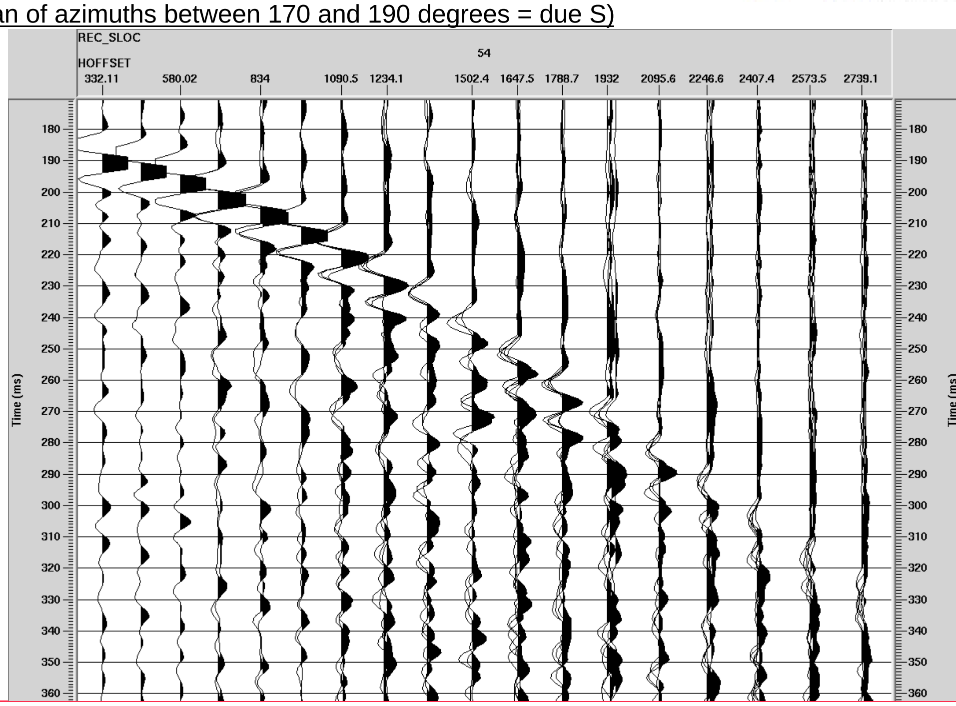


This presentation contains P/GSI processing information

Slide 11 of 12

Receiver gather after static application

(fan of azimuths between 170 and 190 degrees = due S)



This presentation contains P/GSI processing information

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Appendix I

Deconvolution

Deconvolution and spectral bandwidth

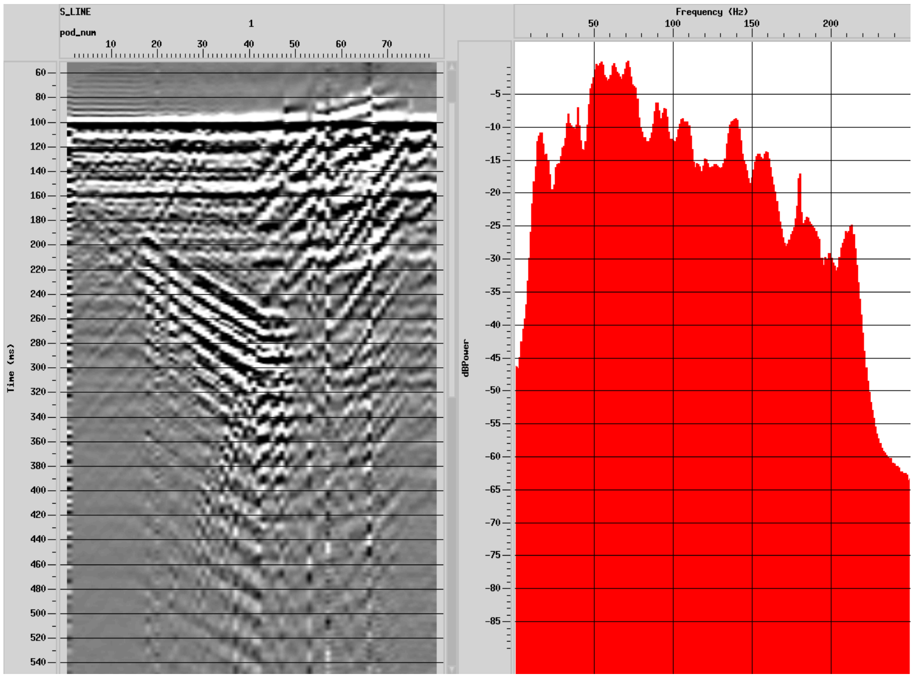
Two alternative methods of deconvolution are shown for sample shotgathers at near/mid/far offsets:

- Predictive Deconvolution (Wiener/Levinson)
  - 60-ms operator length
  - 11-ms prediction distance
  - Trailing Butterworth bandpass filter (15-4-180-20)
  - Three trailing notch filters at 30, 40 and 60 Hz
- Source-signature deconvolution (zero-phase wavelet inversion)
  - Leading Butterworth Bandpass filter (60-8-180-24)
  - Filter generation based on downgoing wavefield
  - 500-ms operator length
  - Trailing Butterworth bandpass filter (65-6-150-6)
  - Trailing notch filters at 30, 40, 60, 120 and 180 Hz

Source-signature deconvolution was chosen for the Hot Ice VSP

The following slides show shot gathers aligned on first breaks and average amplitude spectra over the time window shown.

Raw wavefield at zero offset



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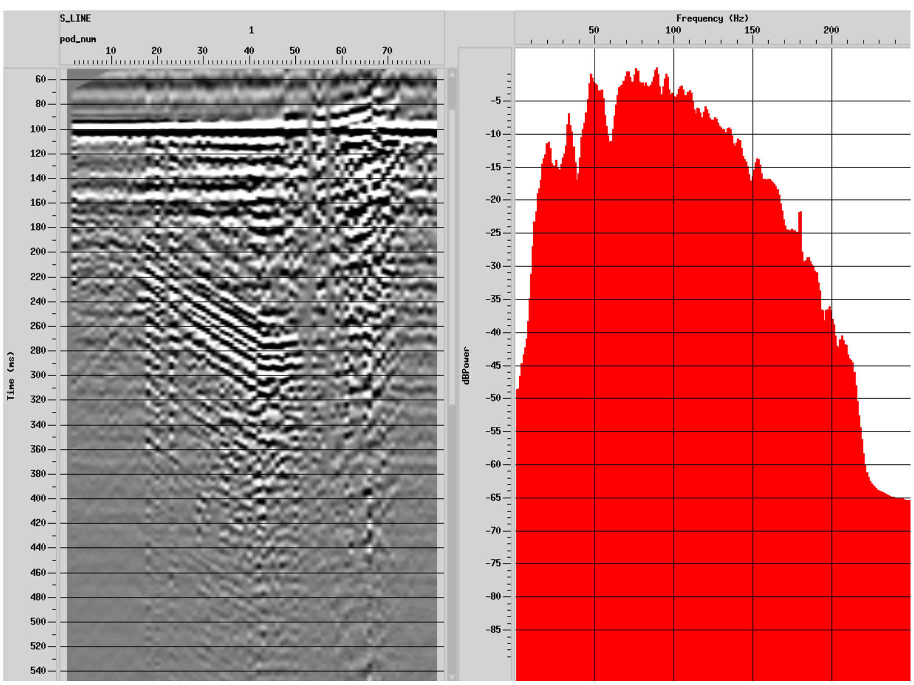
Predictive deconvolution at zero offset



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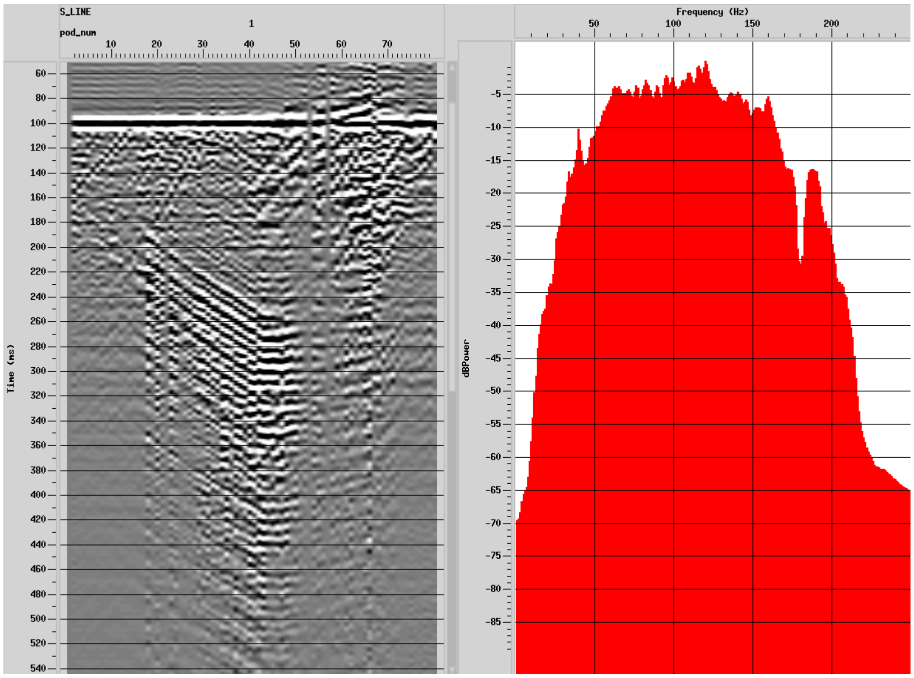
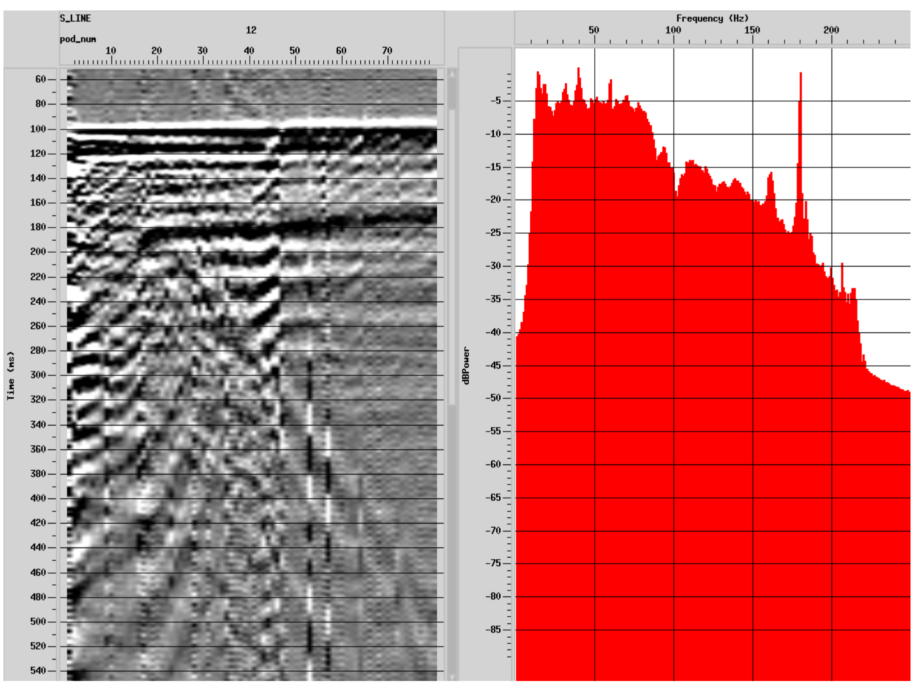
Wavelet inversion at zero offset



This presentation contains P/GSI processing information

Slide 5 of 11

Raw wavefield at 1500 ft offset (Ring 12)



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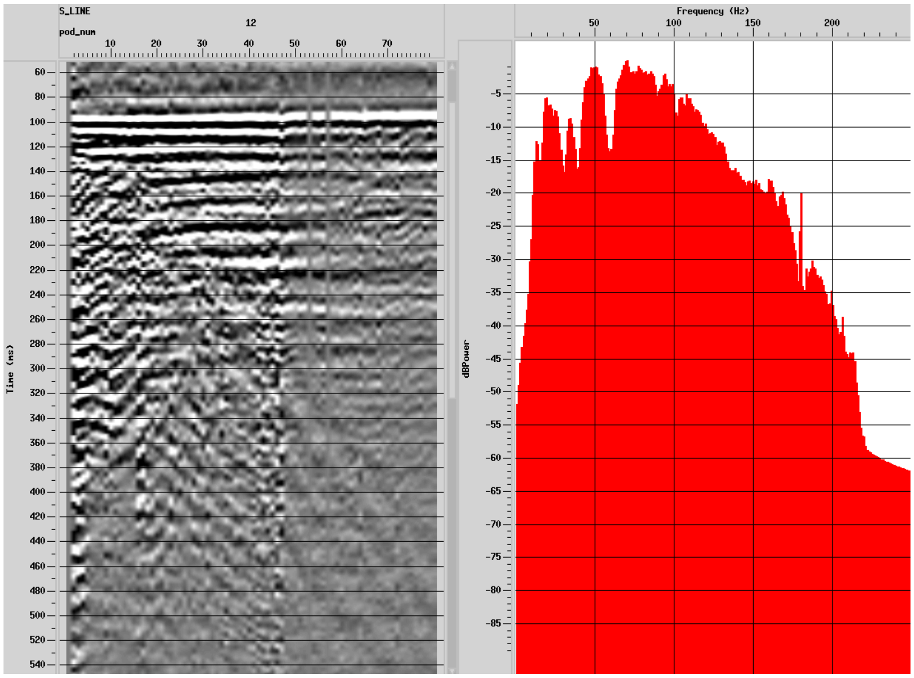
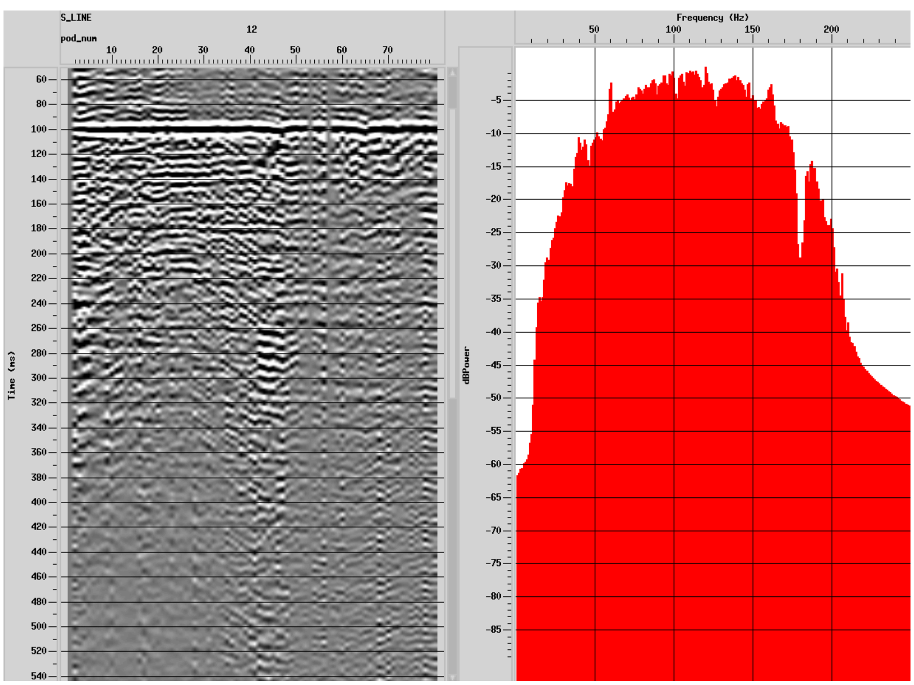
Predictive Deconvolution at 1500 ft offset



This presentation contains P/GSI processing information

Slide 7 of 11

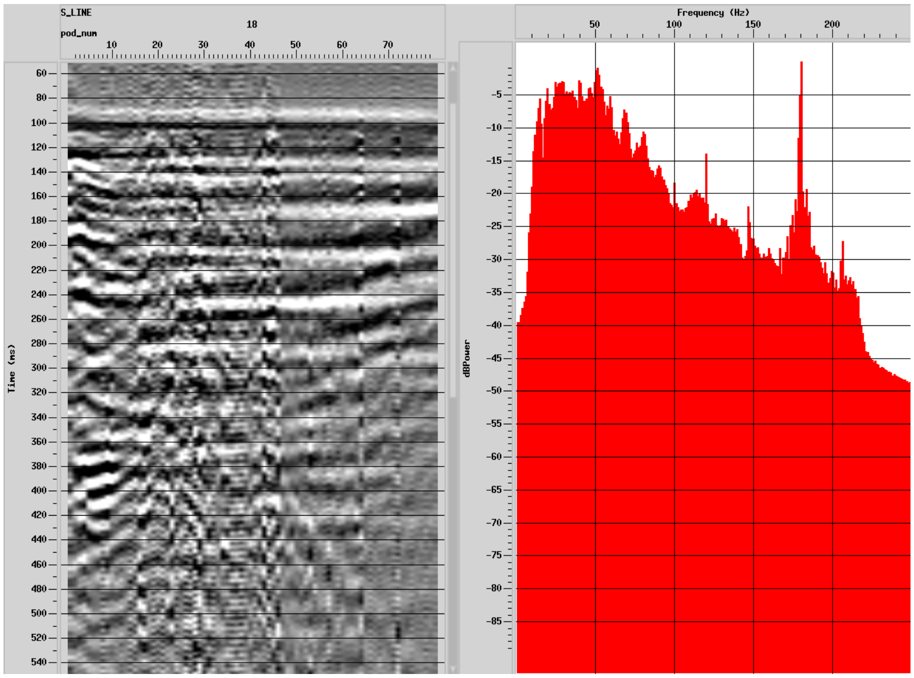
Wavelet inversion at 1500 ft offset



This presentation contains P/GSI processing information

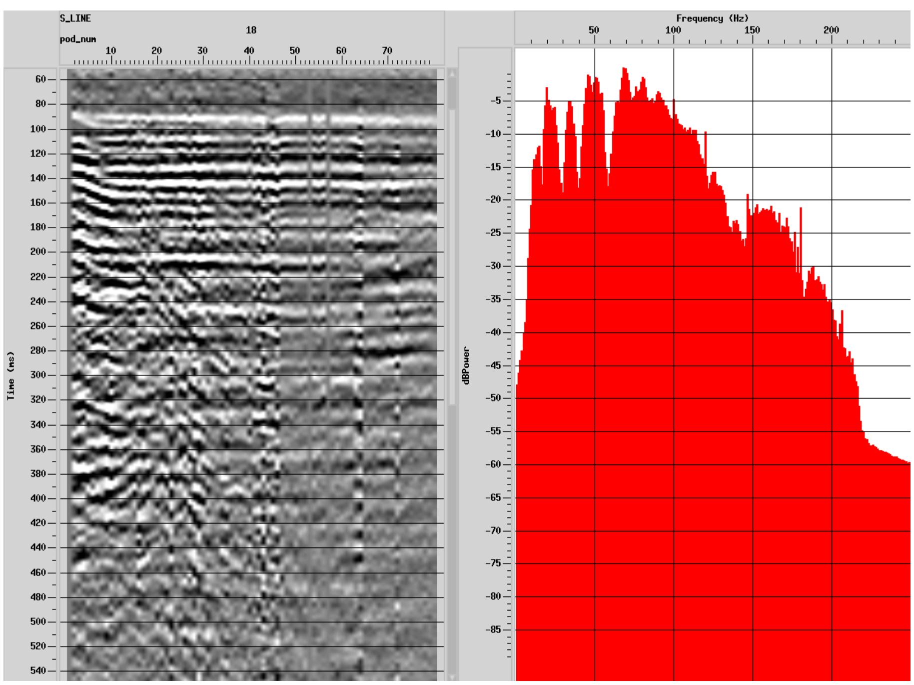
Slide 8 of 11

Raw wavefield at 2400 ft offset (Ring 18)



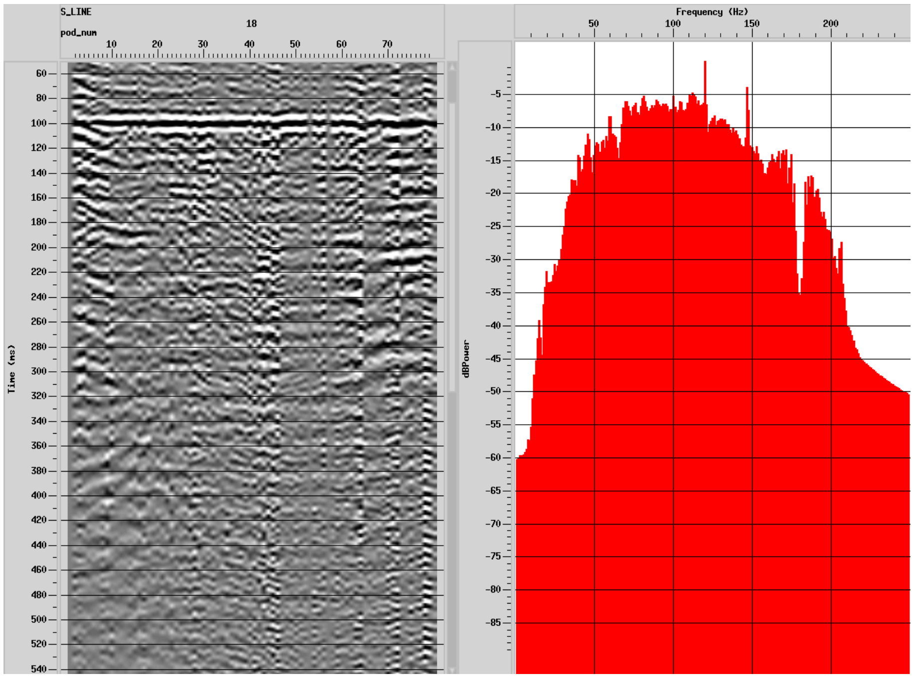
This presentation contains P/GSI processing information **Slide 9 of 11**

Predictive Deconvolution at 2400 ft offset



This presentation contains P/GSI processing information **Slide 10 of 11**

Wavelet inversion at 2400 ft offset



This presentation contains P/GSI processing information

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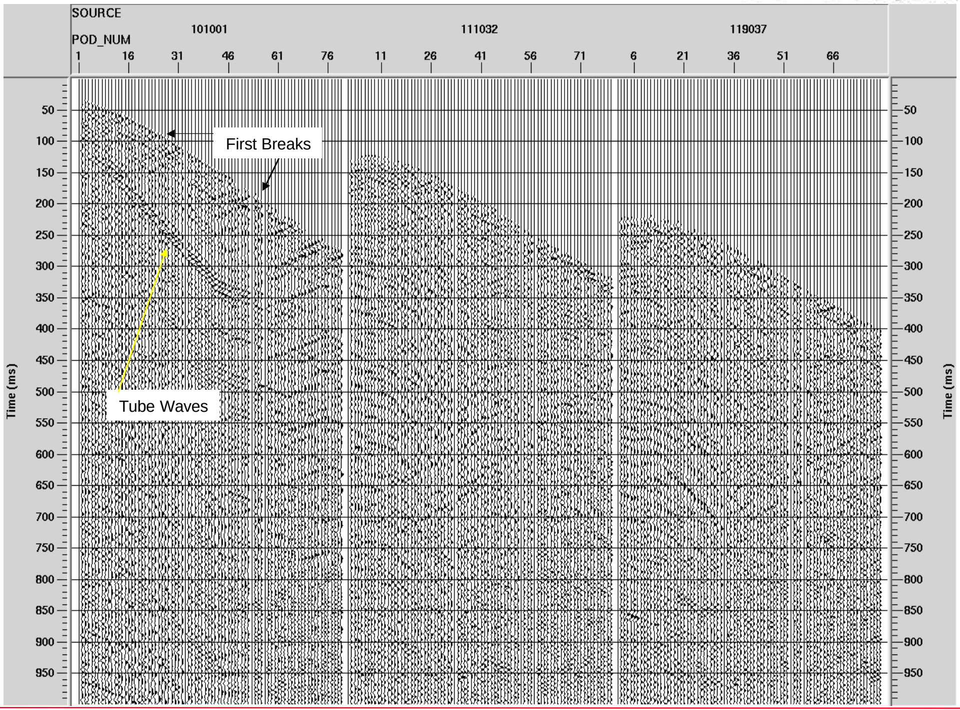
Appendix J

Amplitude Recovery

Amplitude recovery tests

- Displays of near, mid and far offset panels with different amplitude recovery functions applied
  - Trace balancing based on first break + 100 ms AGC
  - Trace balancing based on first break + 250 ms AGC
  - Trace balancing based on first break + $T^{1.2}$ gain
  - Trace balancing based on first break + 16 dB / sec time-variant gain
  - Trace balancing based on first break + offset - time-variant gain
  - 1/distance - spherical divergence correction (1D model based)
  - 1/distance - spherical divergence correction + $T^{1.2}$ gain
  - 1/distance - spherical divergence correction + 8 dB/sec time-variant gain

FB balancing + 100 ms AGC



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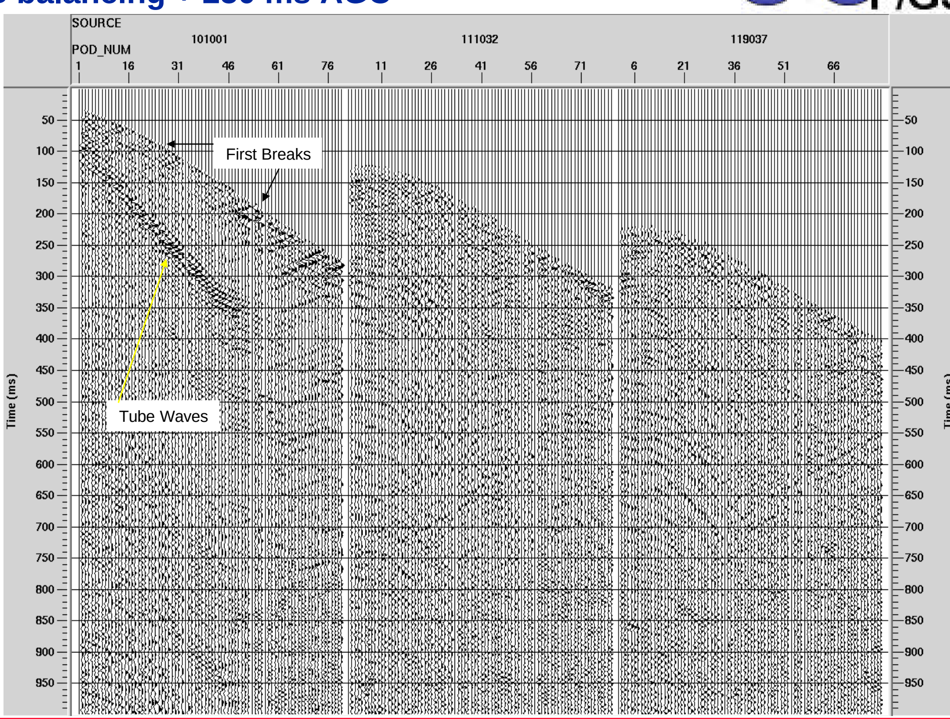
Slide 3 of 10

FB balancing + 250 ms AGC



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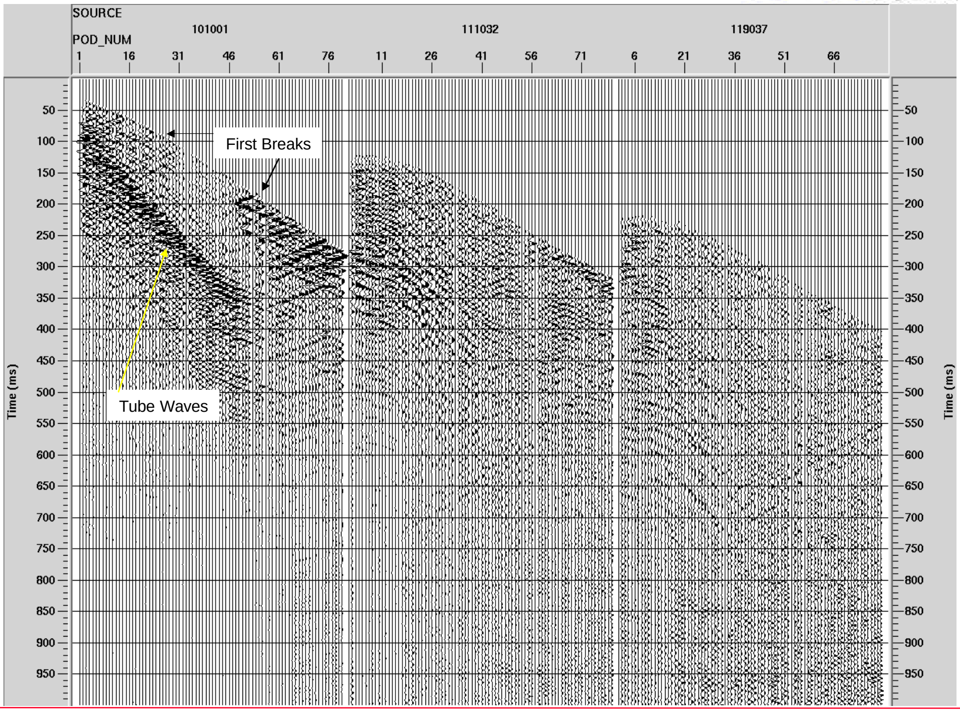
Slide 4 of 10

FB balancing + $T^{1.2}$ time-variant gain



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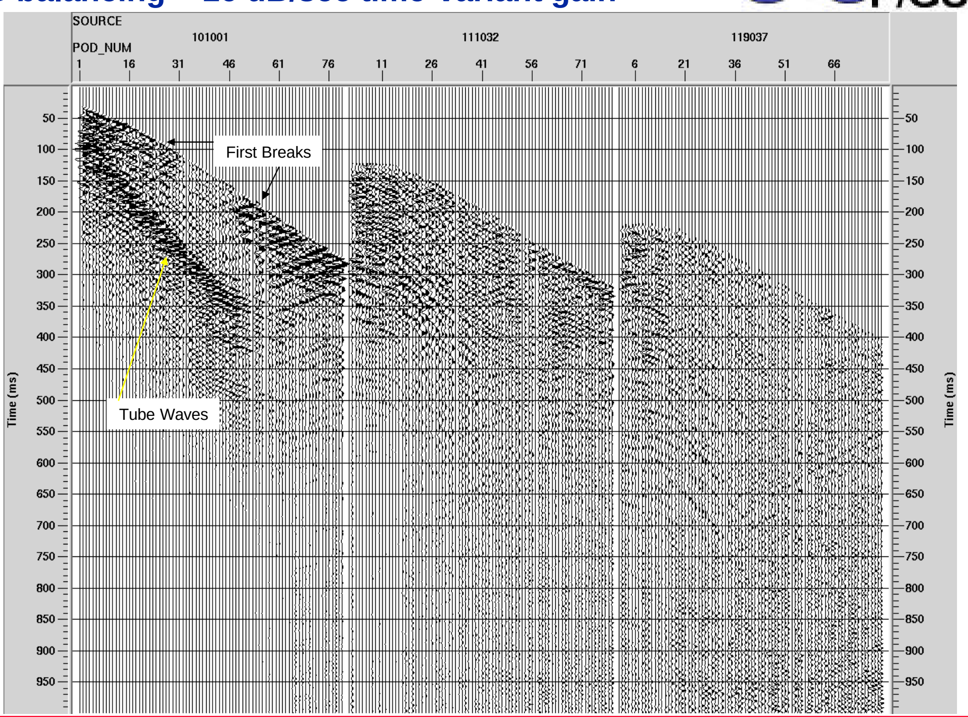
FB balancing + 16 dB/sec time-variant gain



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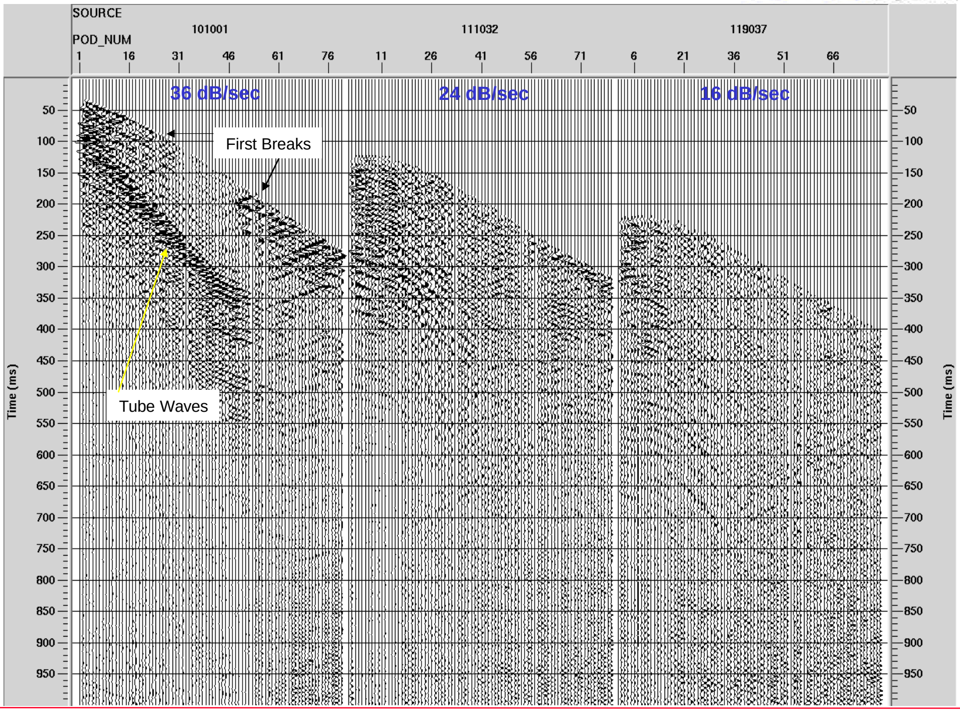
FB balancing + offset-time-variant gain



This presentation contains P/GSI processing information

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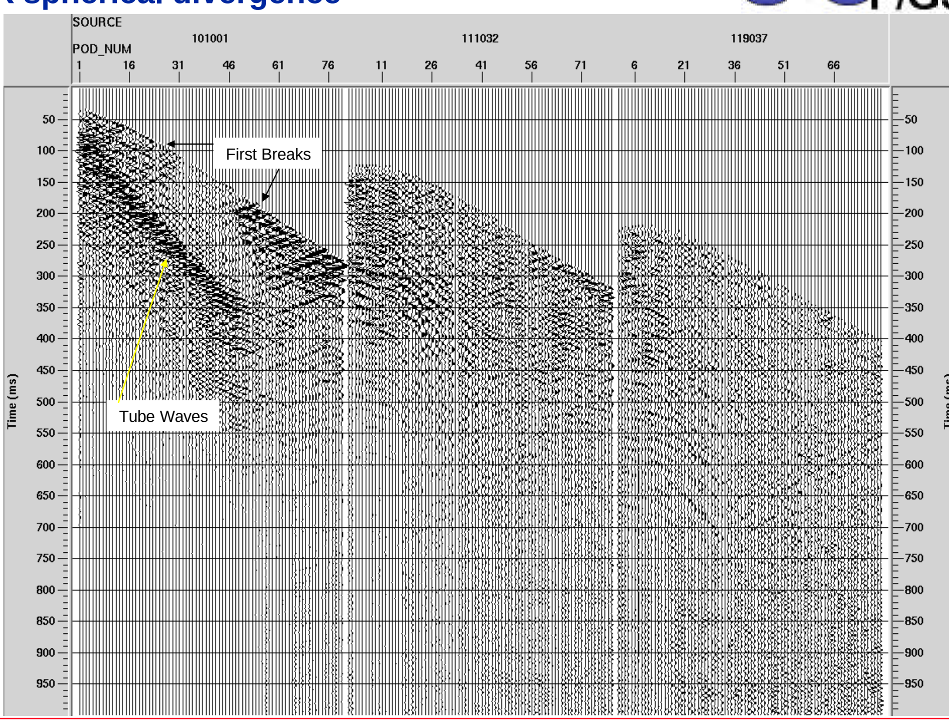
1/R spherical divergence



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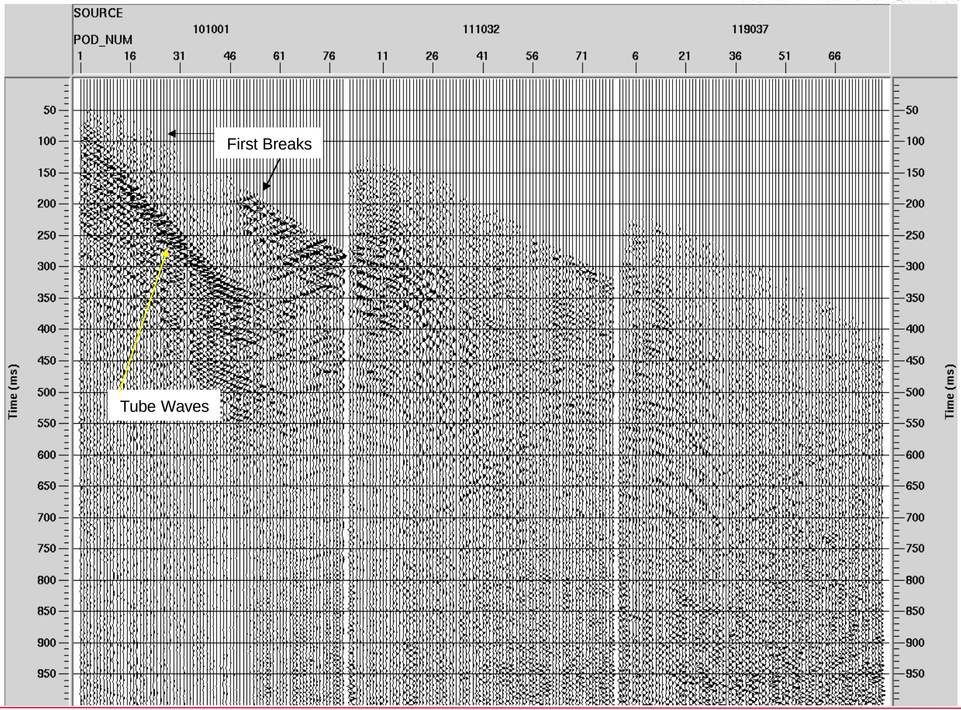
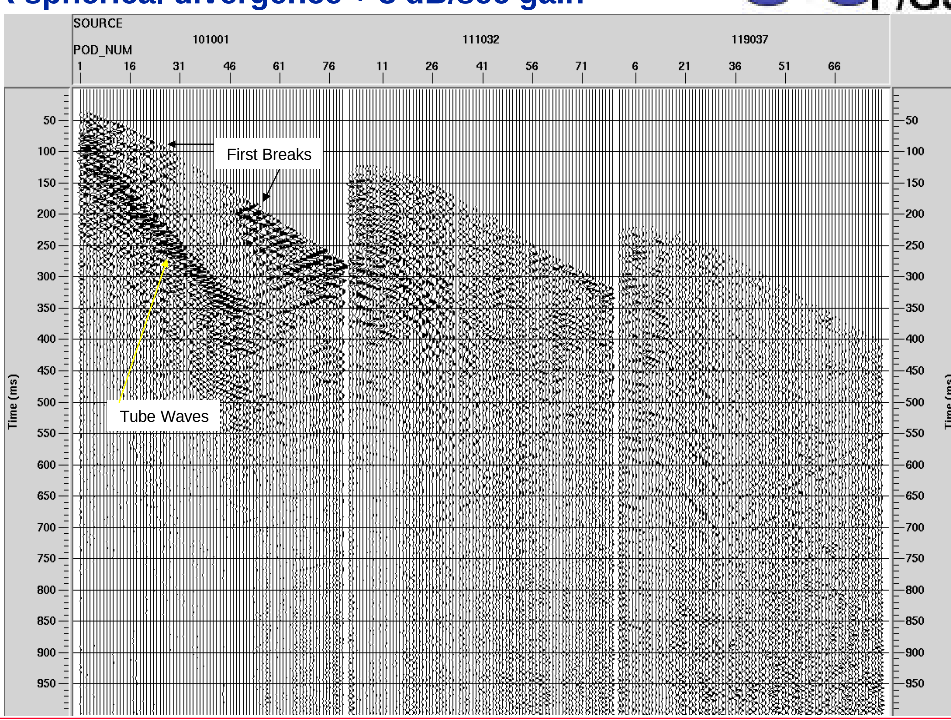
1/R spherical divergence + $T^{1.2}$ gain



This presentation contains P/GSI processing information **Slide 9 of 10**

1/R spherical divergence + 8 dB/sec gain



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Appendix K

3D Velocities

This presentation contains P/GSI processing information

Slide 1 of 12

Prestack Depth Migration

- Zero-Offset single velocity function migration with planar approximations of reflectors
- Cube of planar approximations to constrain velocity distributions
- 3D velocity model
- Images of 3D migrated data
- Common incidence angle (CIA) gathers

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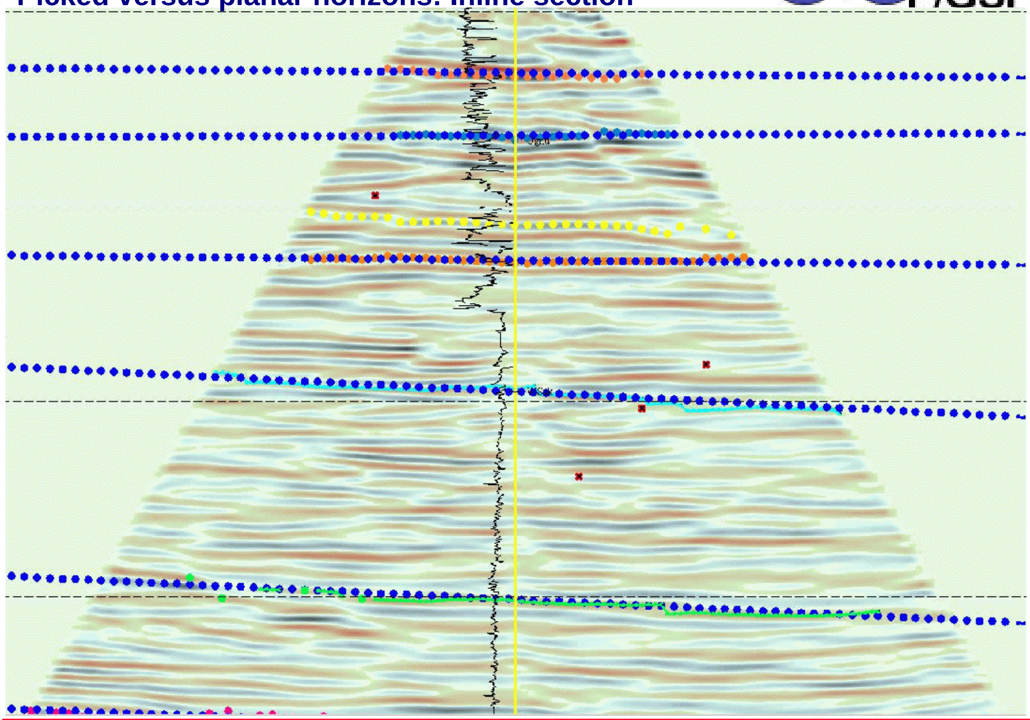
Slide 2 of 12

Picked versus planar horizons: Inline section



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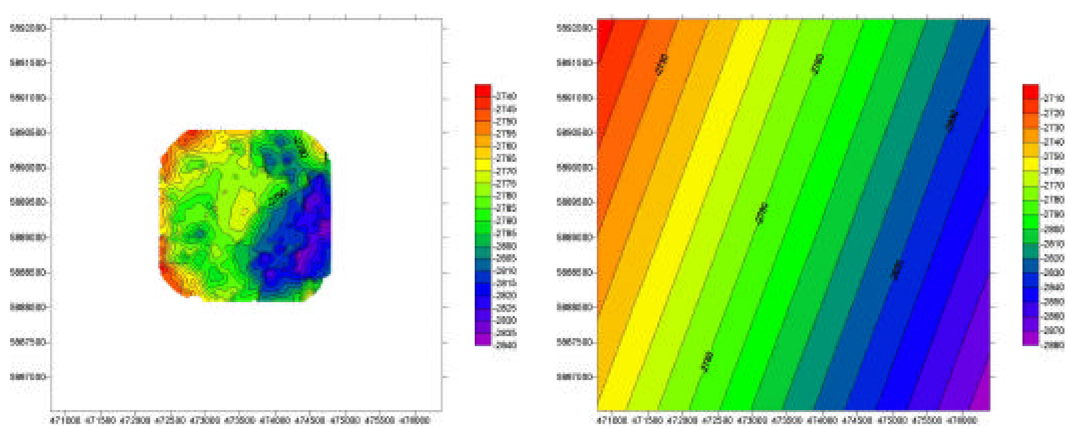

Horizon picked at 2800 ft depth

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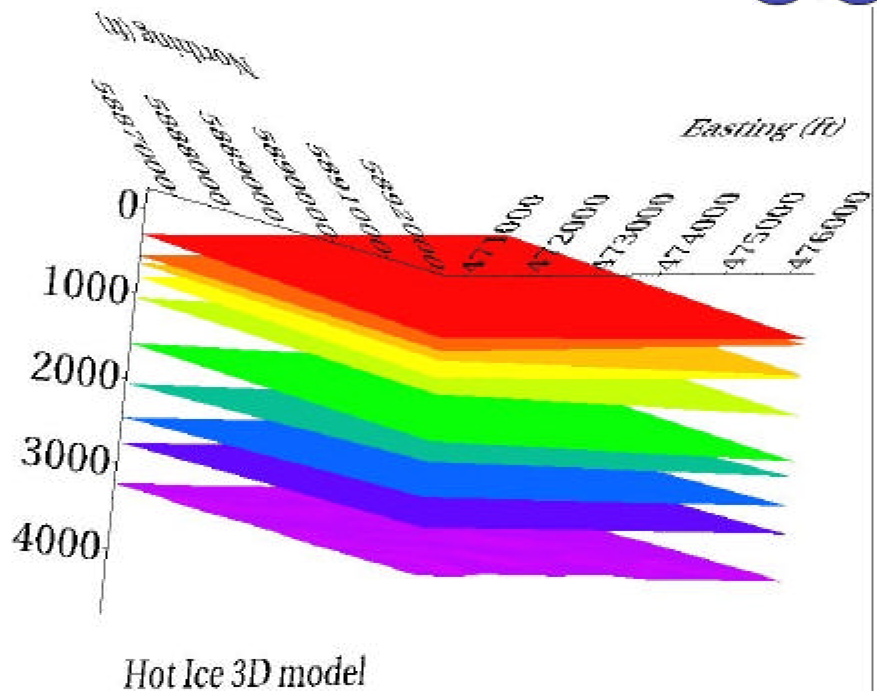

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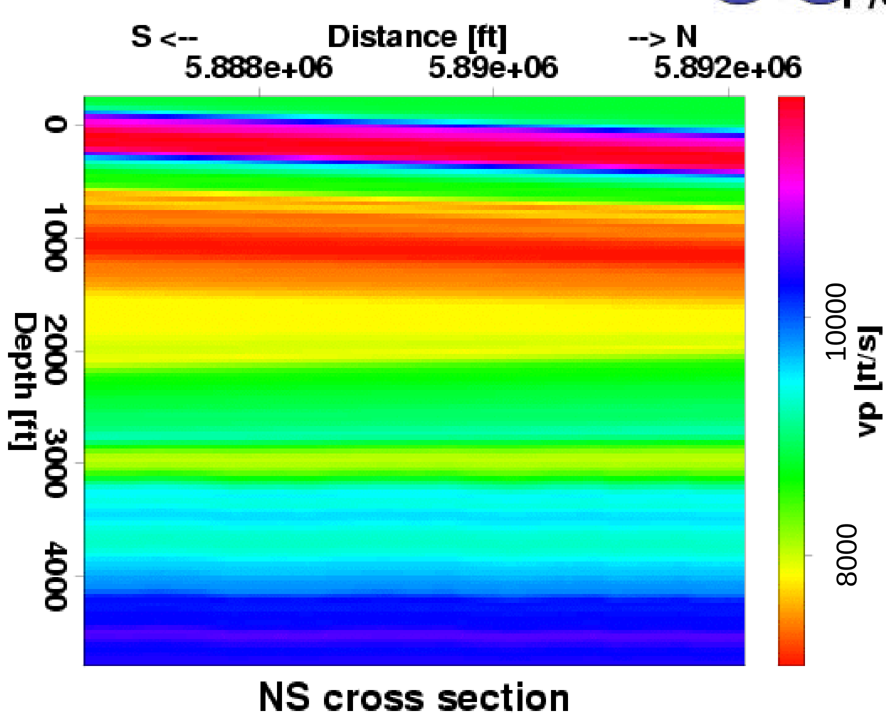
Slide 5 of 12



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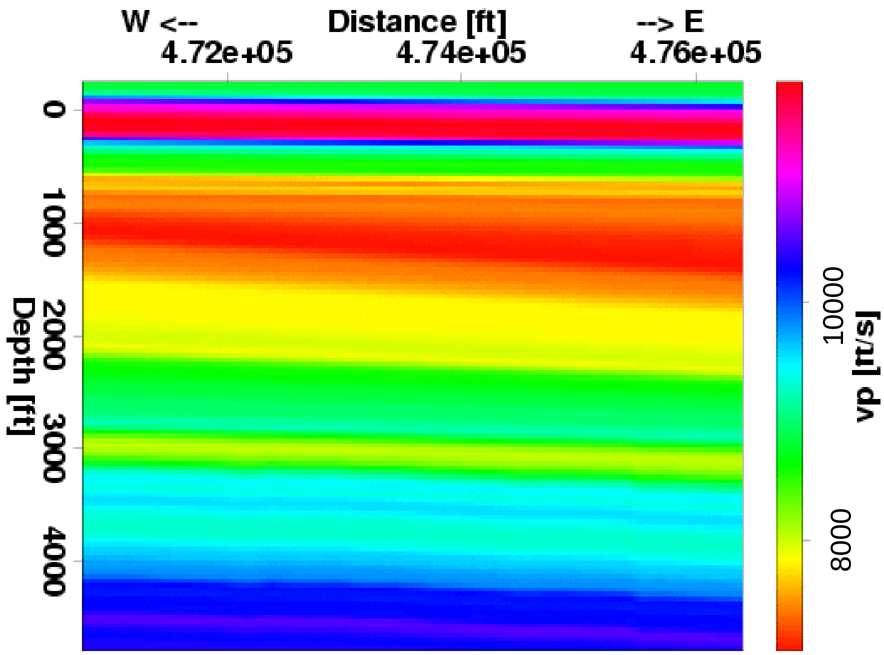

EW cross section

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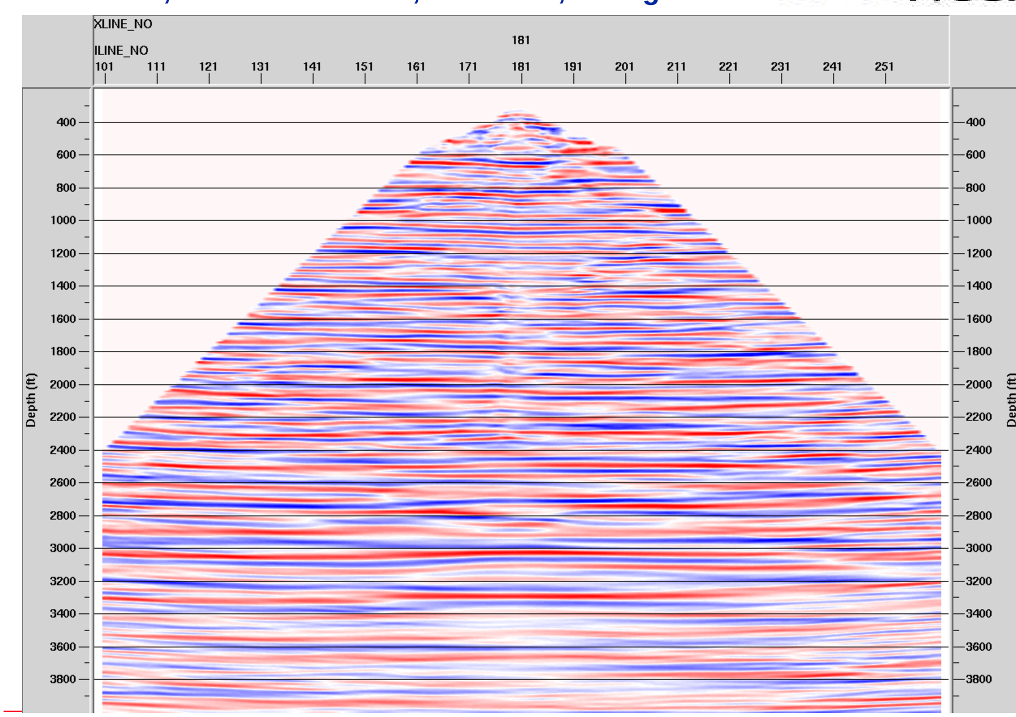
Slide 7 of 12

N–S slice, normalized stack, 3D model, Env. gain



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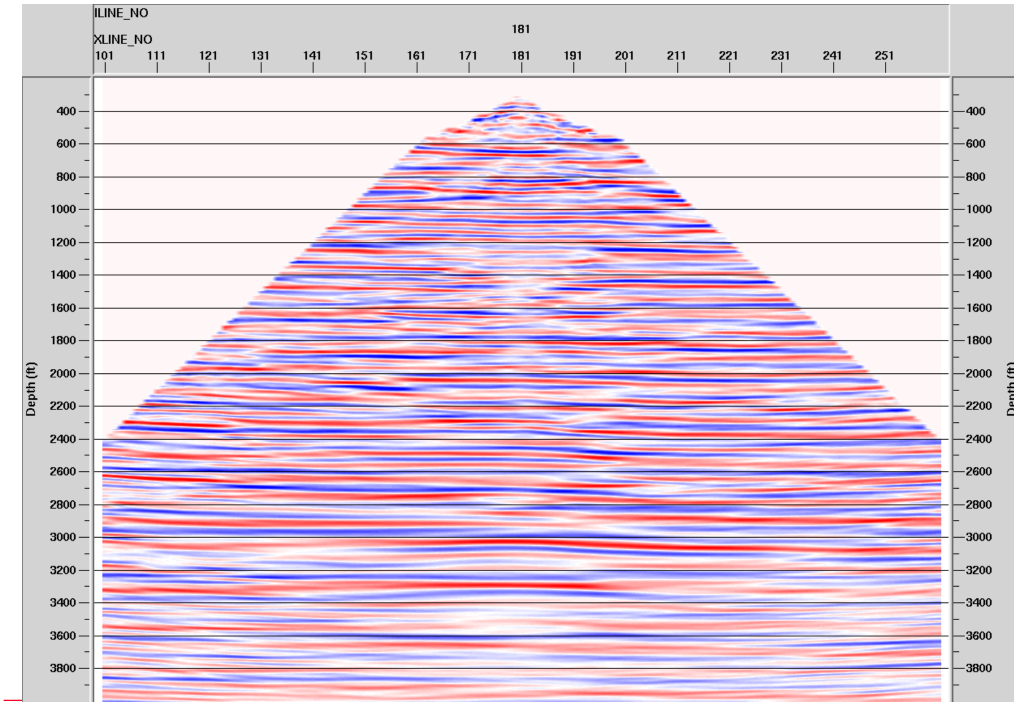
W - E slice, normalized stack, 3D model, env. Gain



This presentation contains P/GSI processing information

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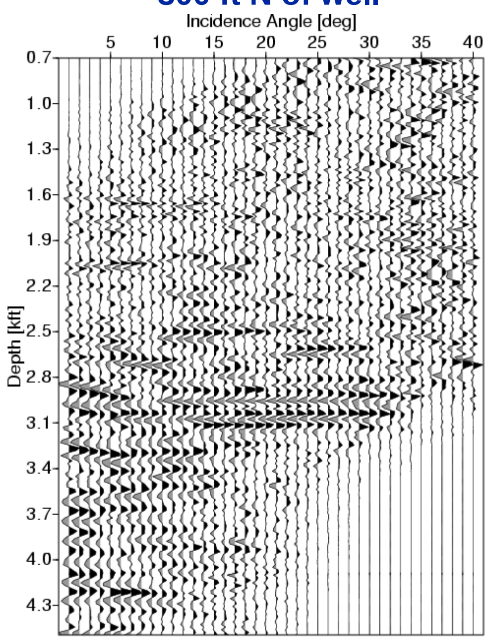
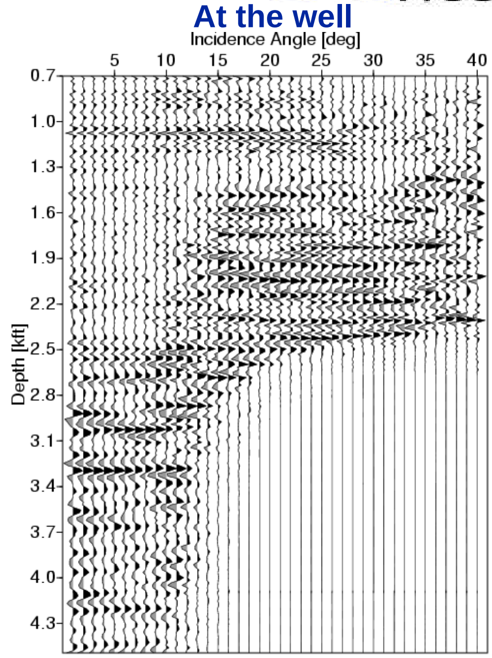
300 ft N of well



3D model

At the well



3D model

This presentation contains P/GSI processing information

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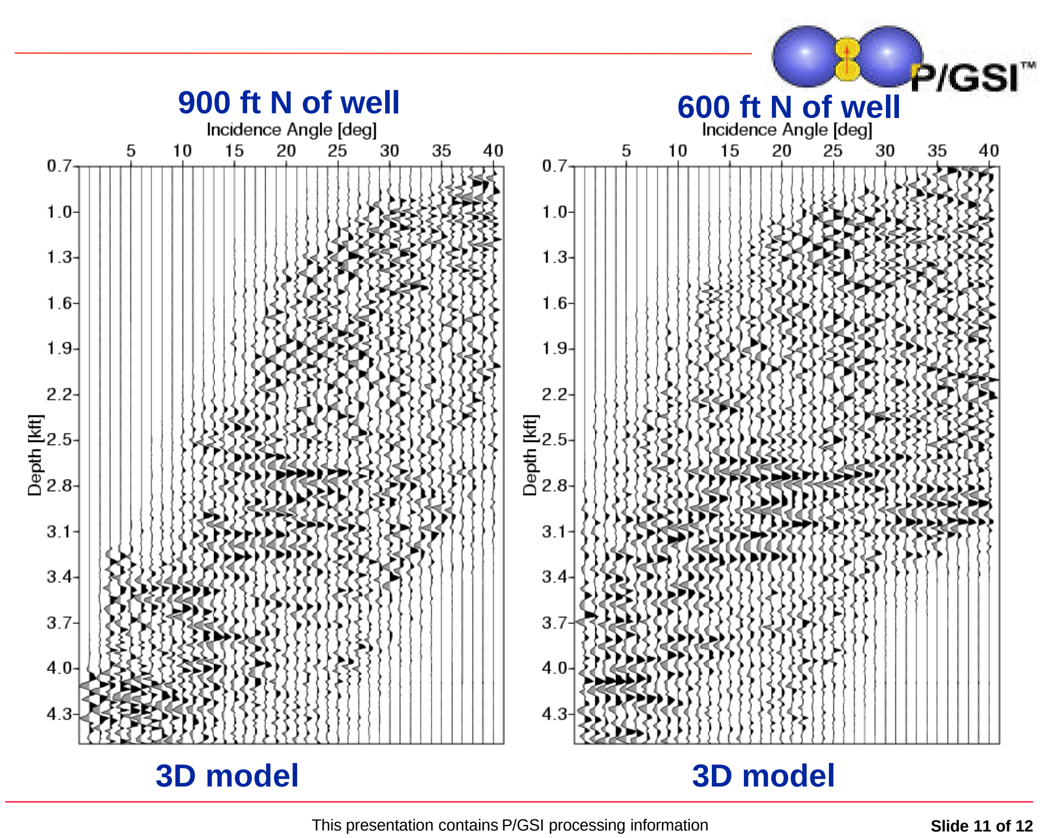
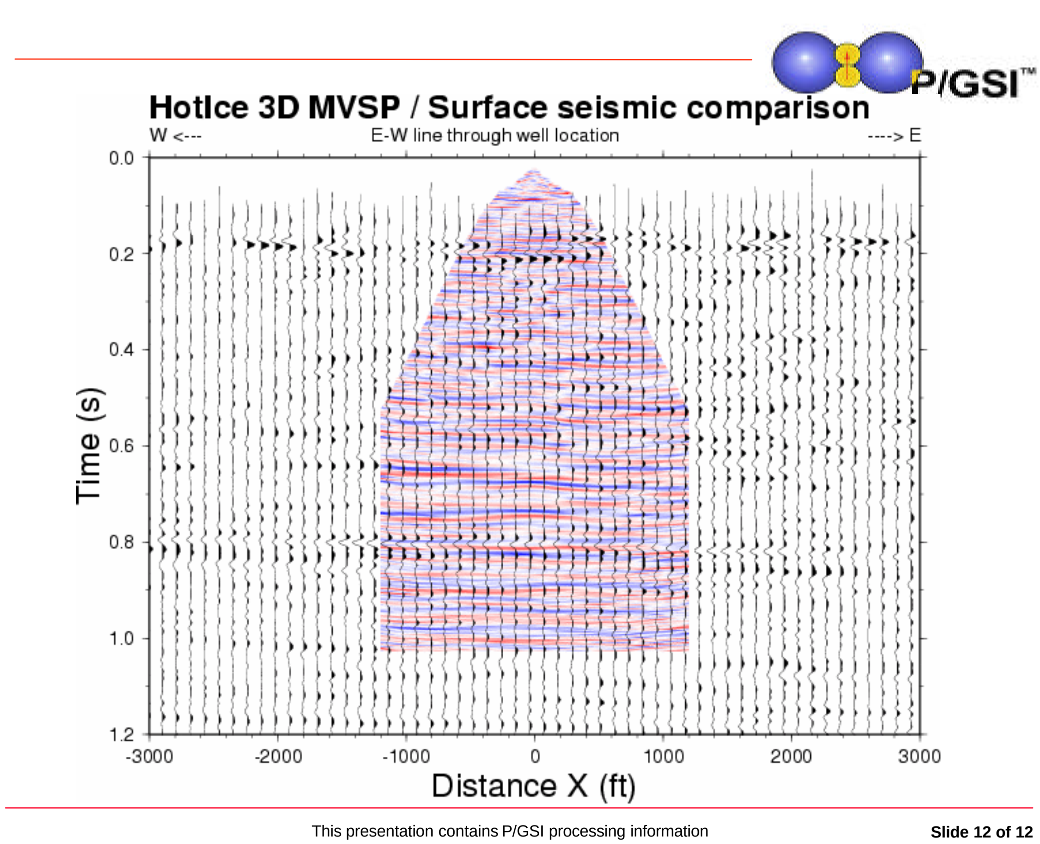

P/GSI™
900 ft N of well
Incidence Angle [deg]
5 10 15 20 25 30 35 40
0.7 1.0 1.3 1.6 1.9 2.2 2.5 2.8 3.1 3.4 3.7 4.0 4.3
Depth [kft]
3D model
600 ft N of well
Incidence Angle [deg]
5 10 15 20 25 30 35 40
0.7 1.0 1.3 1.6 1.9 2.2 2.5 2.8 3.1 3.4 3.7 4.0 4.3
Depth [kft]
3D model
This presentation contains P/GSI processing information
Slide 11 of 12


P/GSI™
HotIce 3D MVSP / Surface seismic comparison
W <---
E-W line through well location
---> E
0.0 0.2 0.4 0.6 0.8 1.0 1.2
Time (s)
-3000 -2000 -1000 0 1000 2000 3000
Distance X (ft)
This presentation contains P/GSI processing information
Slide 12 of 12

Appendix L – "L-Plot"

showing correlation between VSP and log data

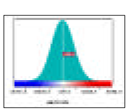
Hot Ice 1 Hydrate Well

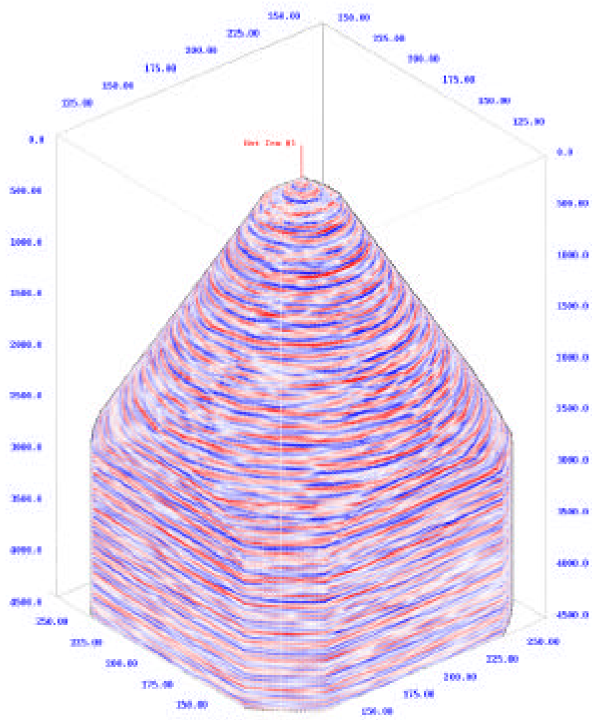
Appendix M

VSP Interpretation

Slide 1 of 13

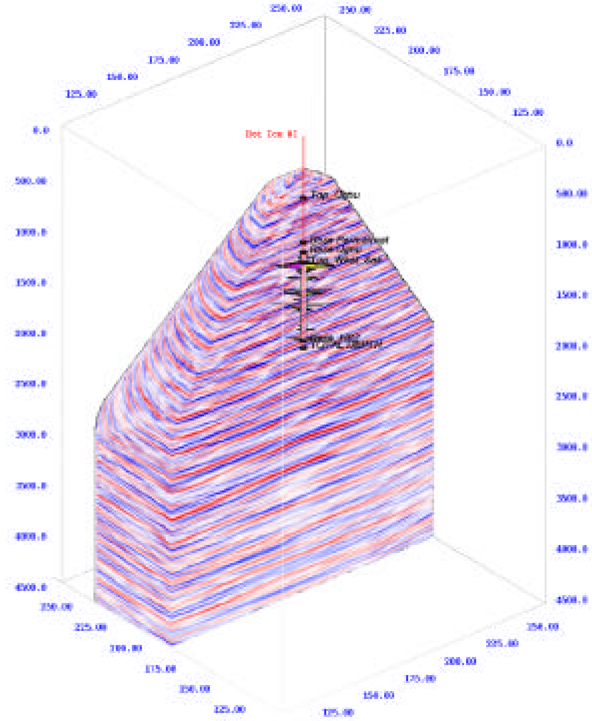
3D VSP Seismic Volume

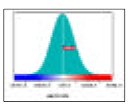




Slide 2 of 13

3D VSP Seismic Volume with Well Logs

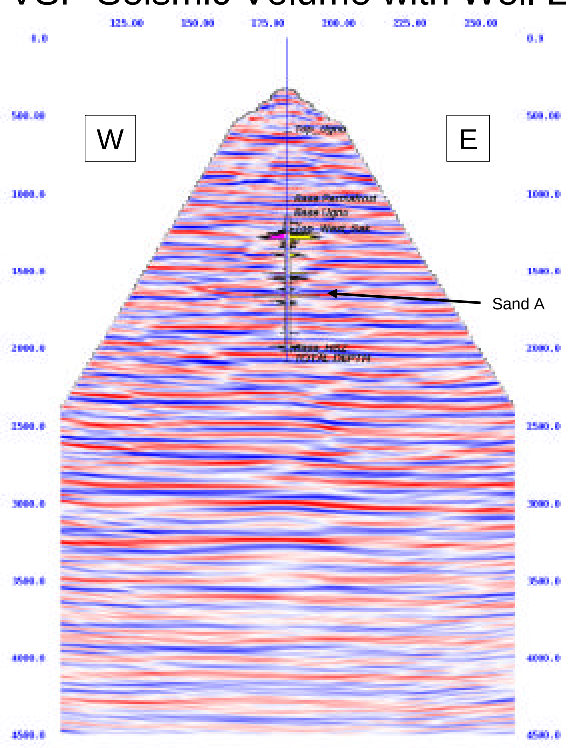


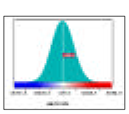


Well log colorfill:
Left: Vshale < 50%
Right: Porosity > 15%

Slide 3 of 13

3D VSP Seismic Volume with Well Logs

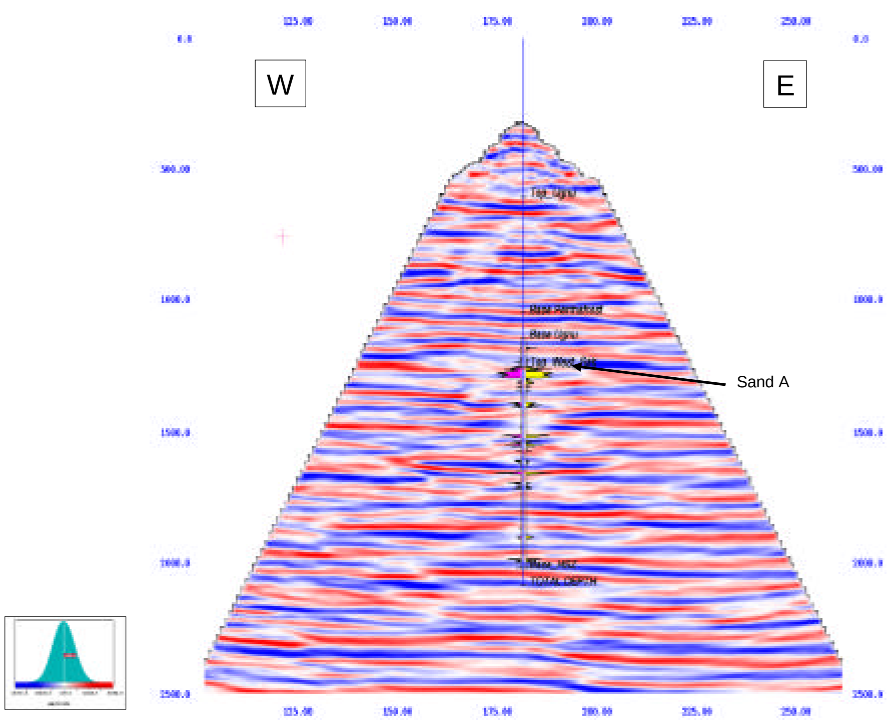




Well log colorfill:
Left: Vshale < 50%
Right: Porosity > 15%

Slide 4 of 13

3D VSP Seismic Volume with Well Logs



Well log colorfill:
Left: Vshale < 50%
Right: Porosity > 15%

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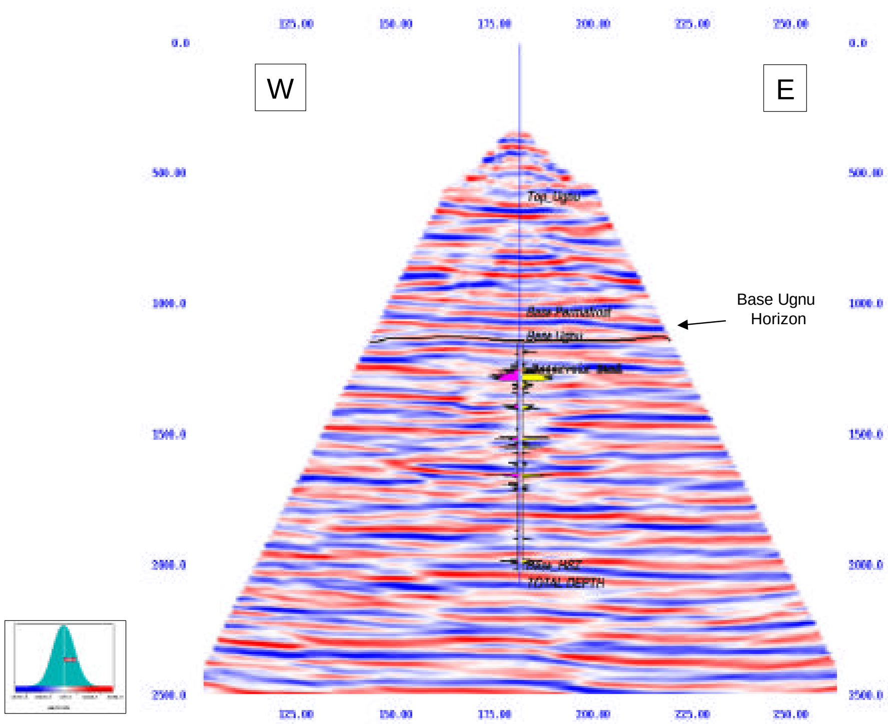
E-W Profile with Ugnu Horizon



Well log colorfill:
Left: Vshale < 50%
Right: Porosity > 15%

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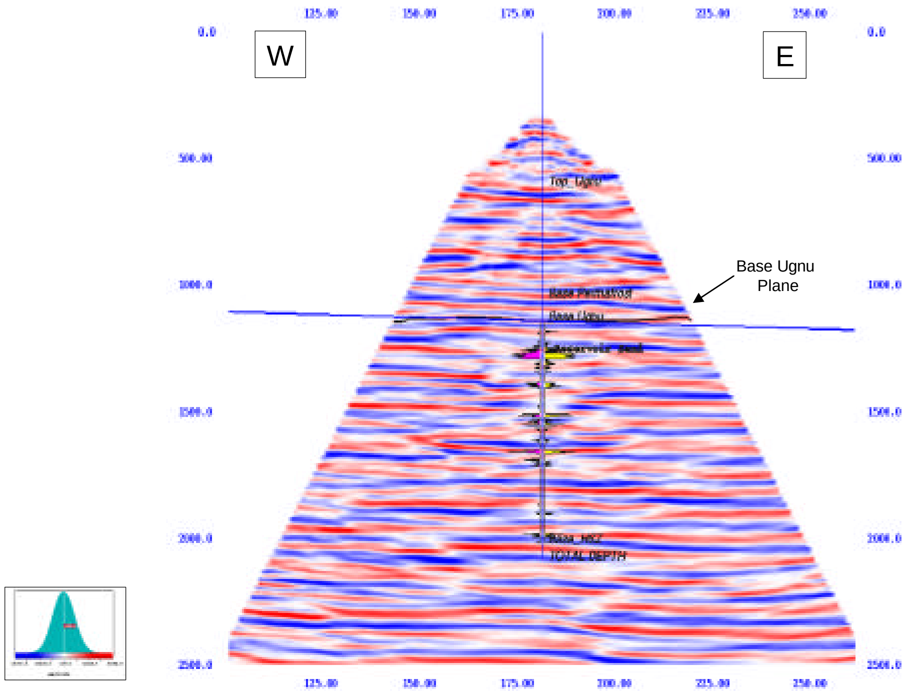
E-W Profile with Ugnu Plane



Well log colorfill:
Left: Vshale < 50%
Right: Porosity > 15%

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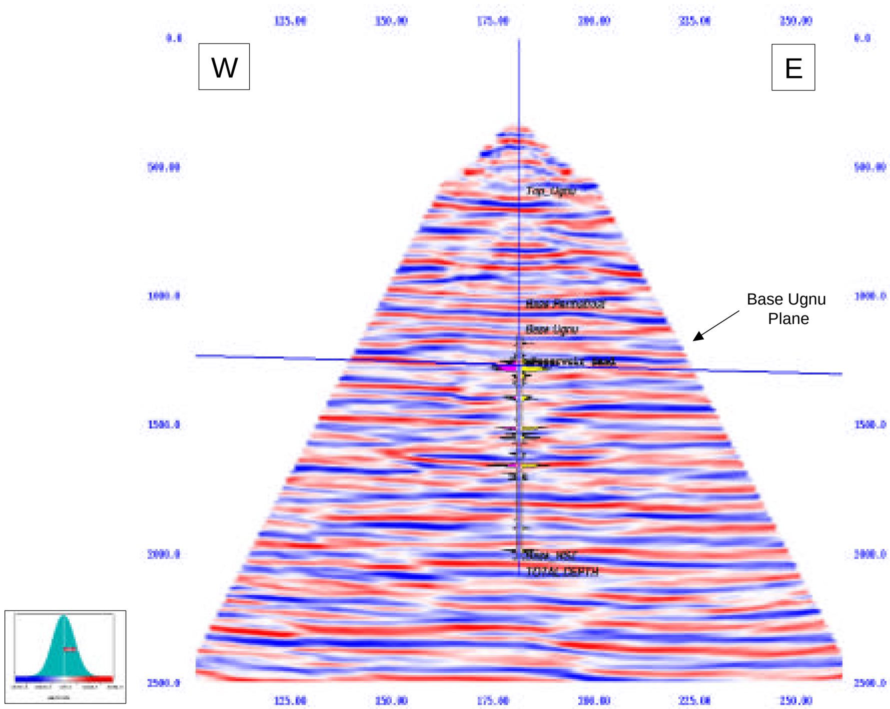
E-W Profile with Ugnu Plane at Top of Sand A



Well log colorfill:
Left: Vshale < 50%
Right: Porosity > 15%

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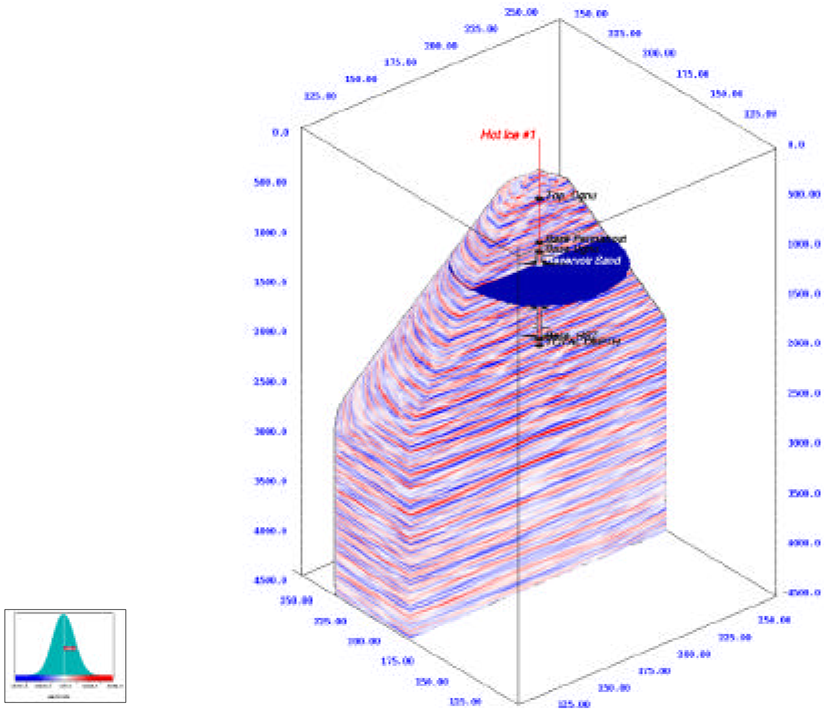
3D VSP Seismic Volume with Geologic Marker



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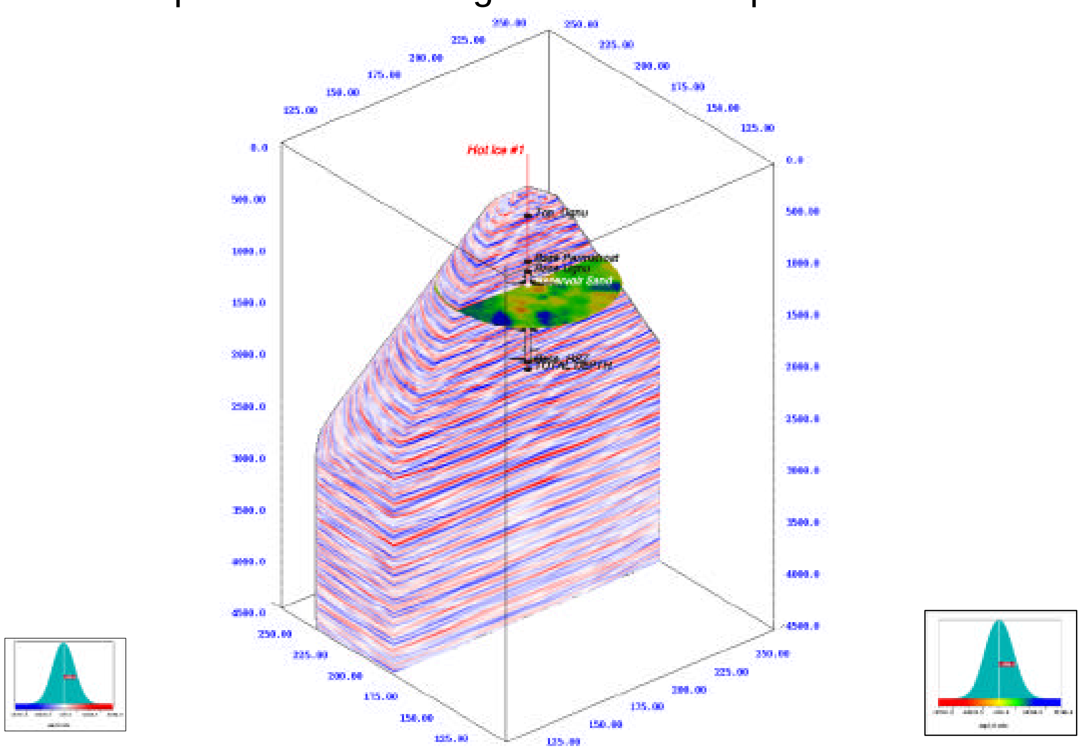
Amplitudes on Geologic Marker at Top of Sand A



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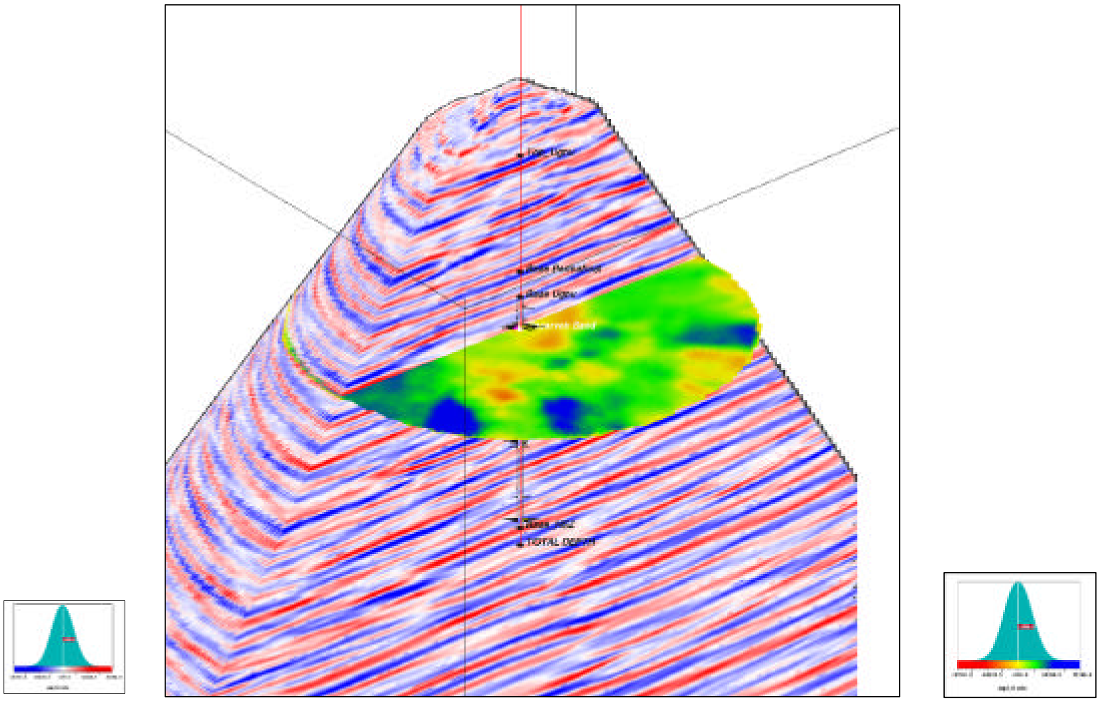
Amplitudes on Geologic Marker at Top of Sand A



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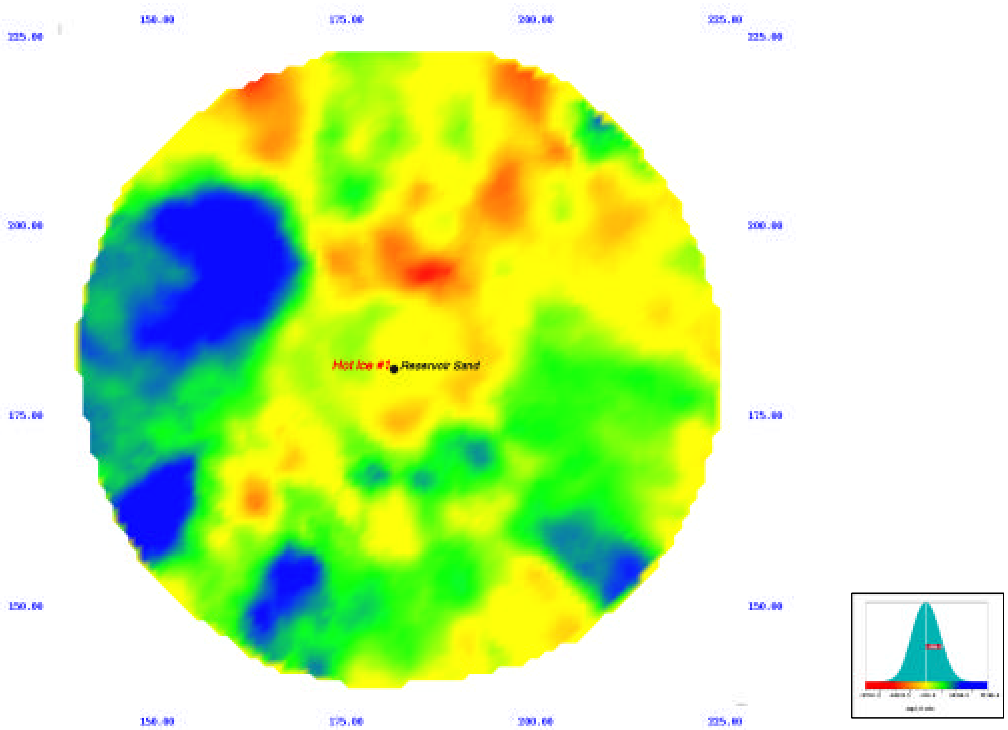
Amplitudes on Geologic Marker at Top of Sand A



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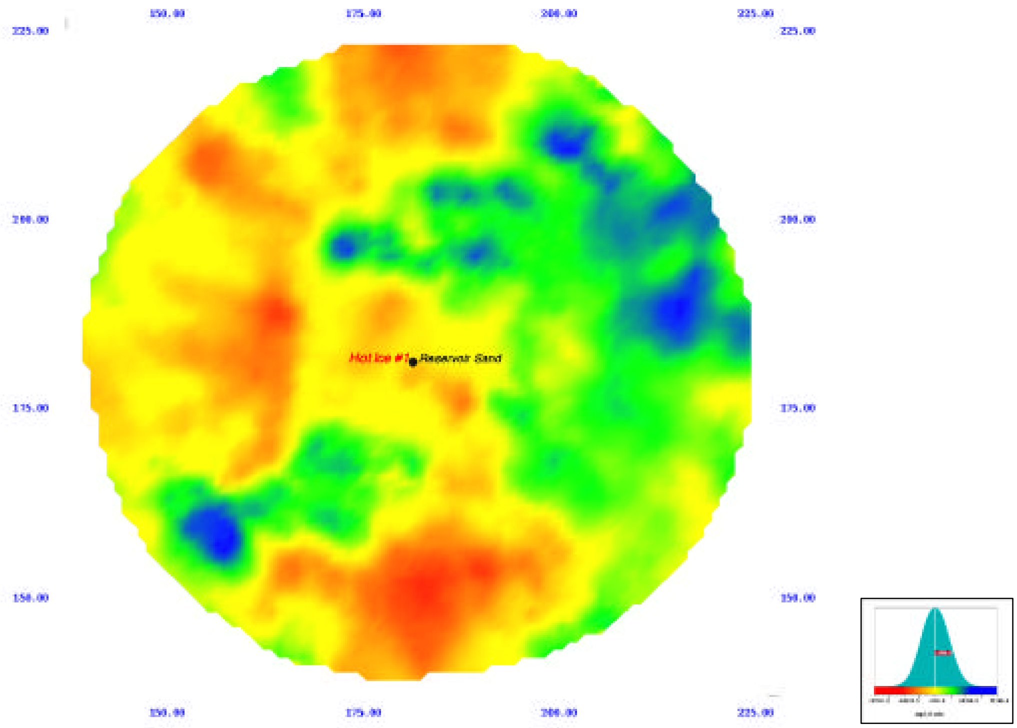
Amplitudes on Geologic Marker at Base of Sand A



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