Integrated Reservoir Modeling Results on FRAM

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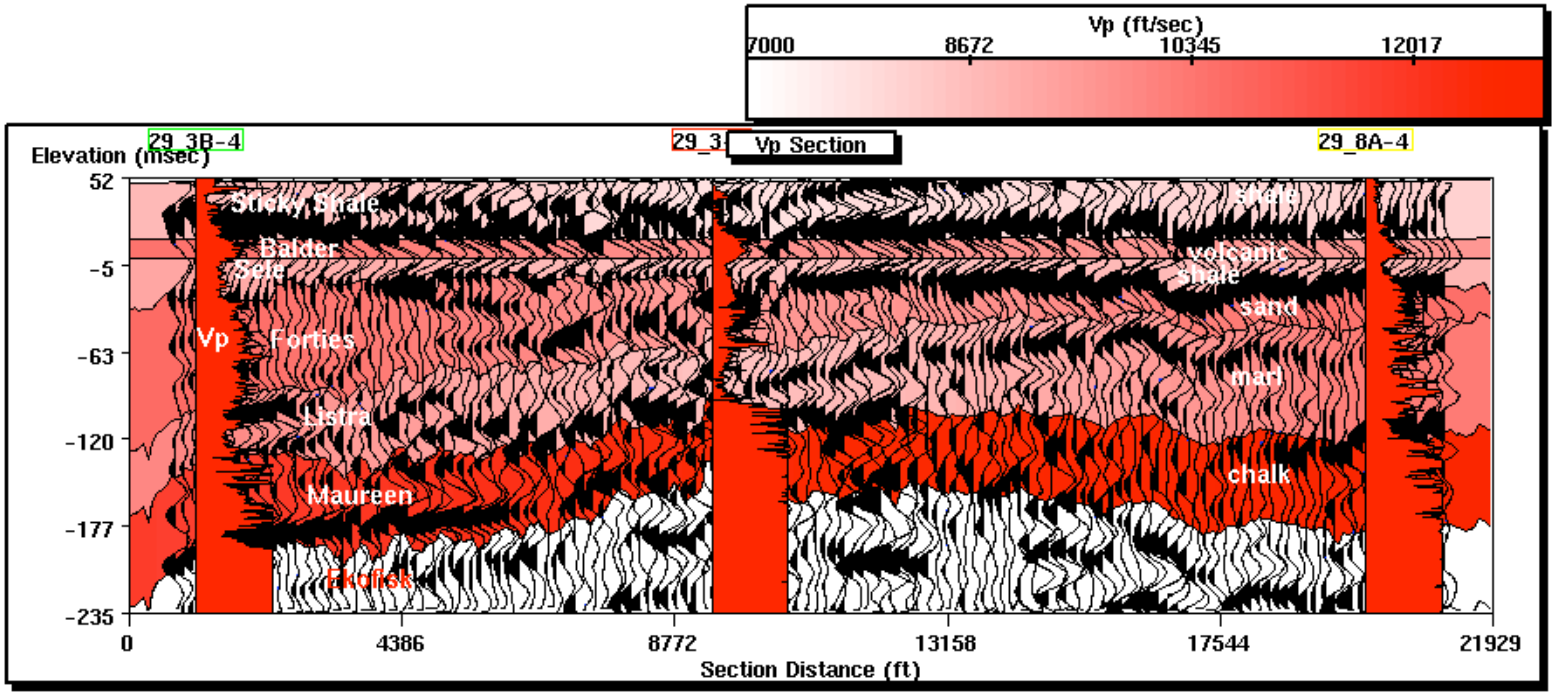
What was done

- **DepSim reservoir model constructed from:**
  - interpreted Sele, Top Forties, and Bottom Forties events
  - well log formation markers and average interval properties
  - petrophysics from well log trend analysis and swell curves
- **FLINT, deterministic seismic inversion, done on PSI stack**
- **PROMISE, probabilistic seismic inversion, done on PSI stack**

Outcome of the work

- P12, P50 and P88 net sand maps generated
- seismic inversion refined estimate of net sand near salt dome
- seismic inversion refined estimate of gross thickness of Forties
- seismic inversion did not refine estimate of net to gross from the krieged well values
- quality of inversion limited by quality of Forties picked events, they sometimes track a reflector within the Forties
- there is evidence of an unconformity not included in the model leading to “loop skipping” in the inversion

Section through wells shows seven layer model before seismic inversion



Well information and swell trends are used to specify petrophysics

sand (gas):

vp(in ft/s) = 0.75 * D(in ft) + 4875 +- 400

vs(in ft/s) = 0.79 * vp - 2375 +- 150 (from swell)

porosity = -3.3e-5 * vp +0.63 +- 0.015 (from swell)

mudrock:

vp = 0.67 * D + 2670 +- 400

vs = 0.84 * vp - 3900 +- 200 (from swell)

density(in gm/cc) = 0.12 * vp ^ 0.33 +- 0.04 (from swell)

laminated sands:

net/gross +- 0.12

Balder (volcanic):

vp = 0.8 * D + 2000 +- 400

vs = 0.56 * vp +- 300 (from DeMartini)

density = 0.027 * vp ^ 0.49 +- 0.04

More petrophysical trends

Listra (marl):

vp = 1.1 * D - 1000 +- 500
vs = 0.50 * vp + 500 +- 300 (limestone swell)
density = 0.044 * vp ^ 0.44 +- 0.04

Maureen (marl):

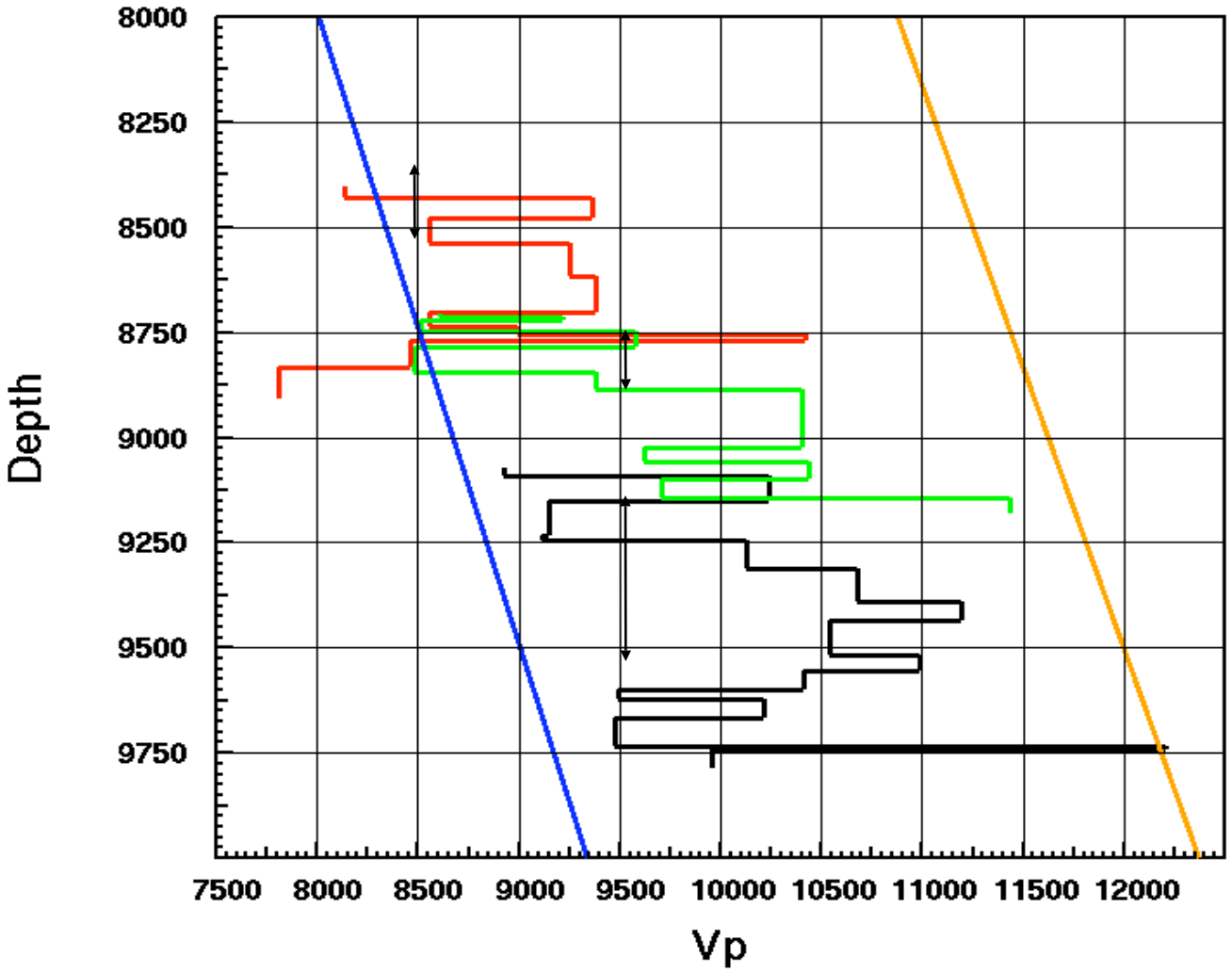
vp = 13000 +- 500
vs = 0.5 * vp + 500 +- 200 (limestone swell)
density = 2.48 +- 0.04

Ekofisk (chalk):

vp = 0.85 * D + 5750 +- 400
vs = 0.5 * vp + 500 +- 300 (limestone swell)
density = 0.24 * vp ^ 0.25 +- 0.04

(unless otherwise noted, all trends are from well information)

29/3-1, 29/8A-4, 29/3B-1 with PROMISE Sand and Shale Trends



Structural constraints and fluids in the inversion

Horizon time constraints (std dev):

- top Sele (8 ms)
- top Forties (8 ms)
- bottom Forties (8 ms)
- top Ekofisk (10 ms)

Layer thickness constraints (std dev):

- Balder (20 ft)
- Sele (35 ft)
- Forties (40 ft)
- Listra (60 ft)
- Maureen (60 ft)

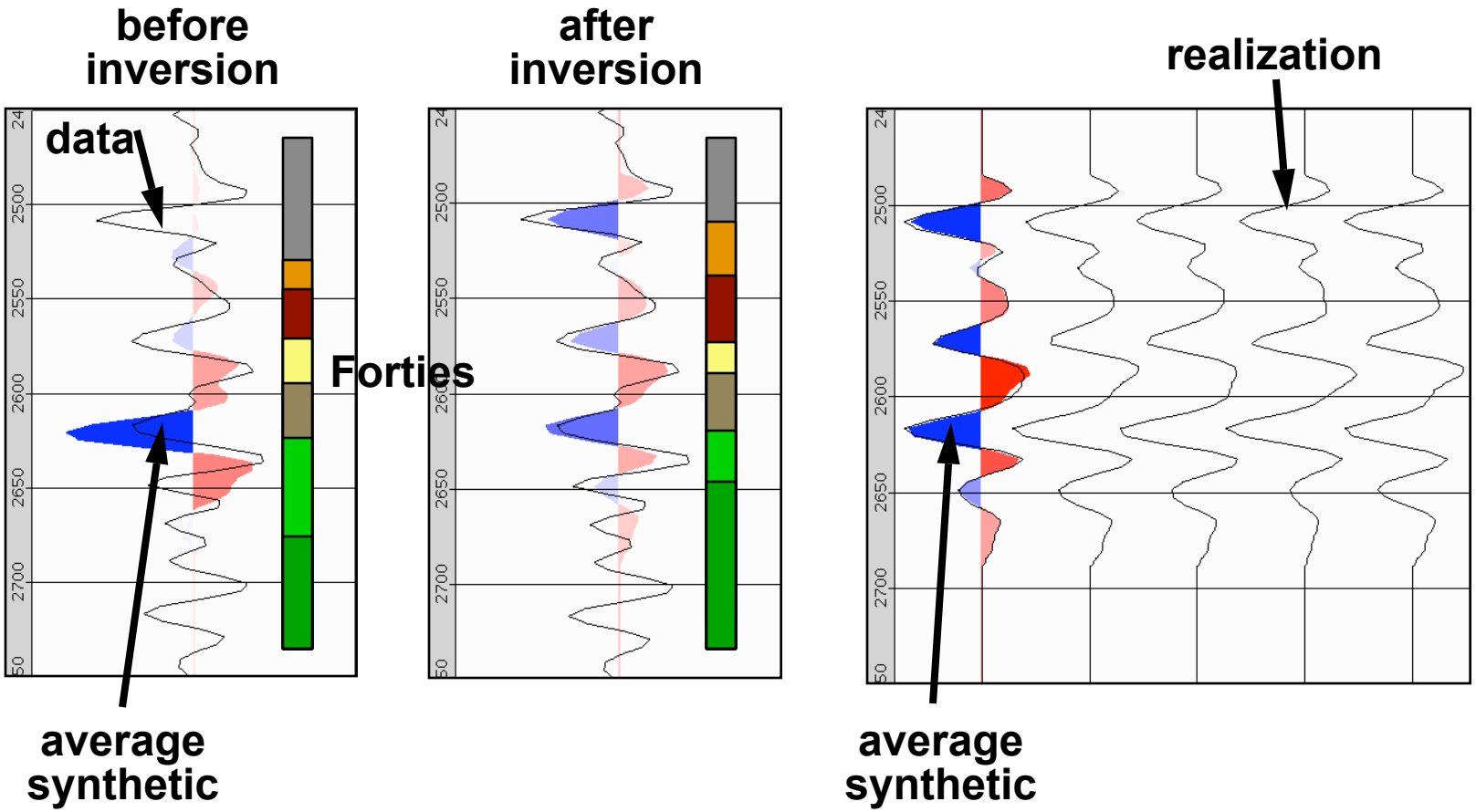
gas:

- prior probability = 0.5
- vp = 3000 ft/s
- density = 0.3 gm/cc
- saturation = 85%

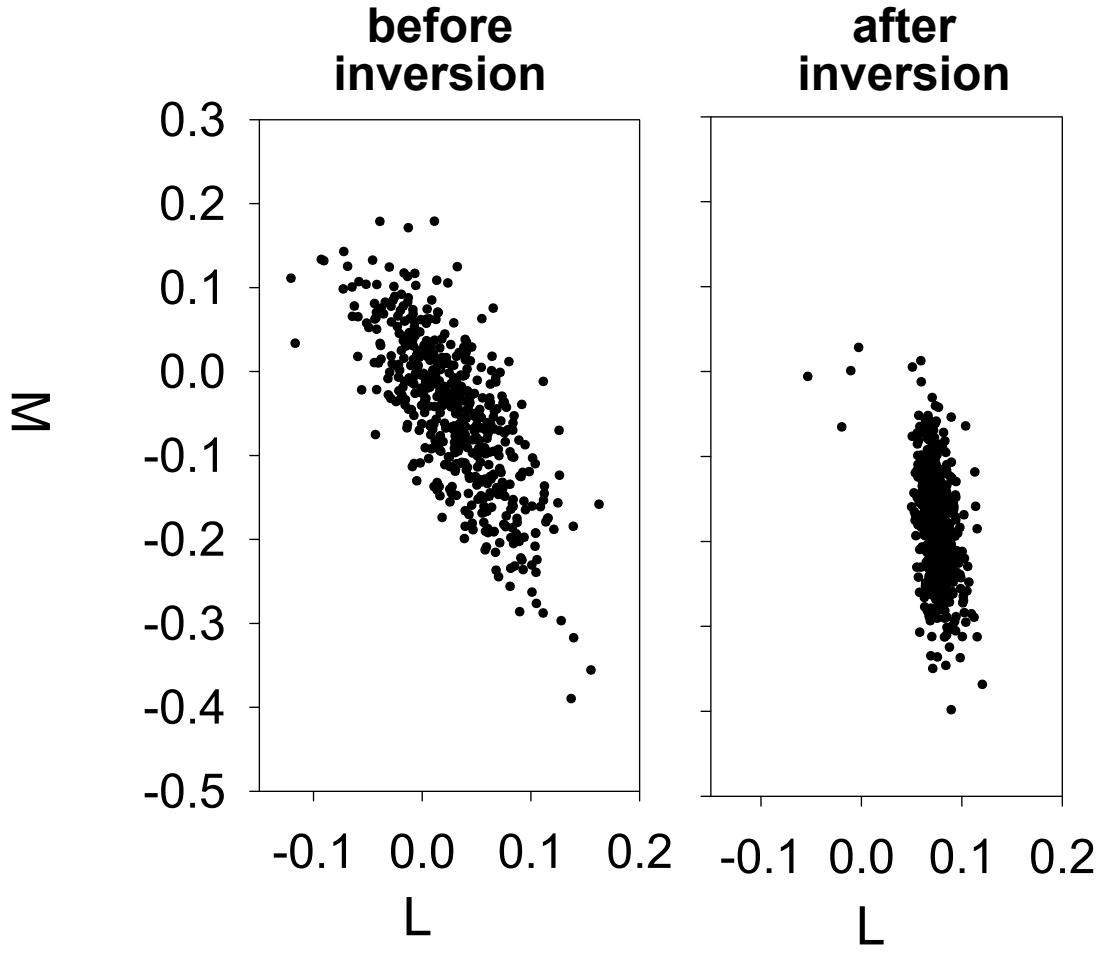
brine:

- prior probability = 0.5
- vp = 5000 ft/s
- density = 0.95 gm/cc

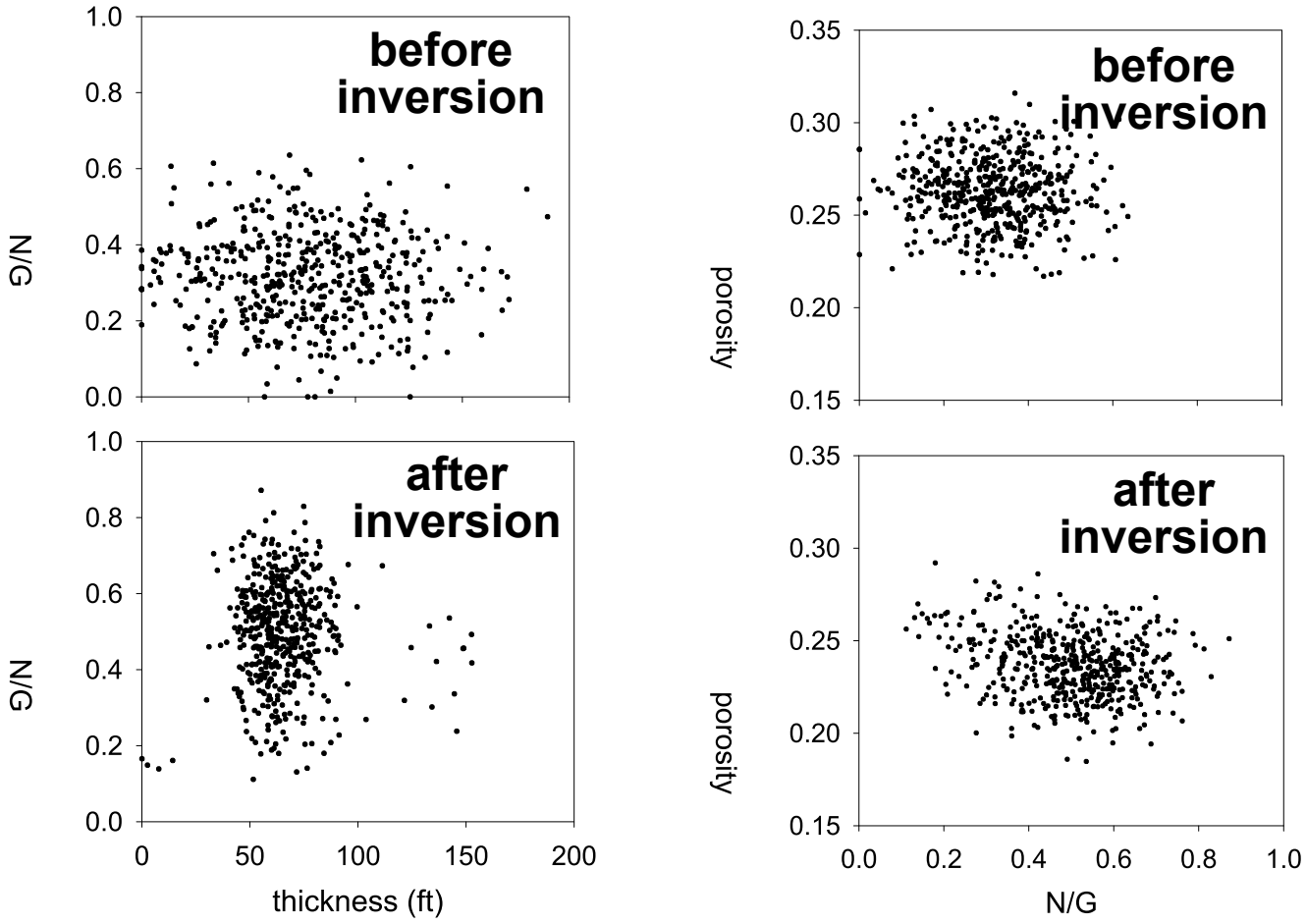
Seismic inversion improved match with well at well 29/3-1



Top of Forties is localized in LM space by inversion at well 29/3-1

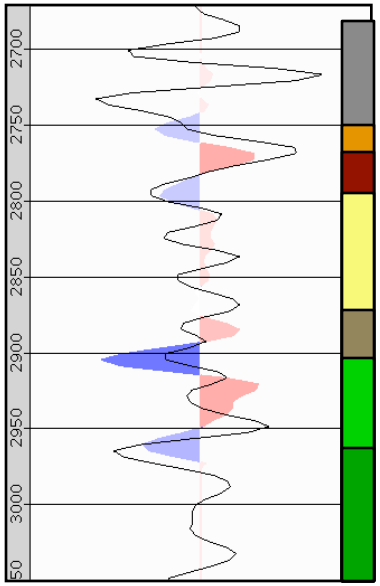


Gross thickness is refined by inversion but N/G and porosity are correlated (29/3-1, Forties)

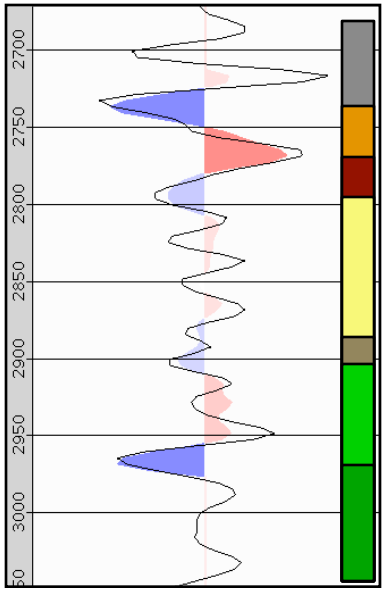


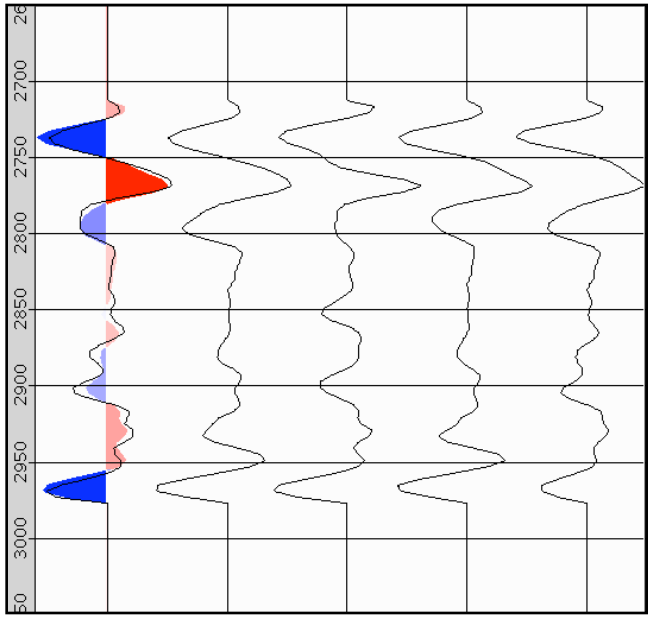
Lack of structure in Forties causes difficulty in well match at 29/3B-4

before inversion

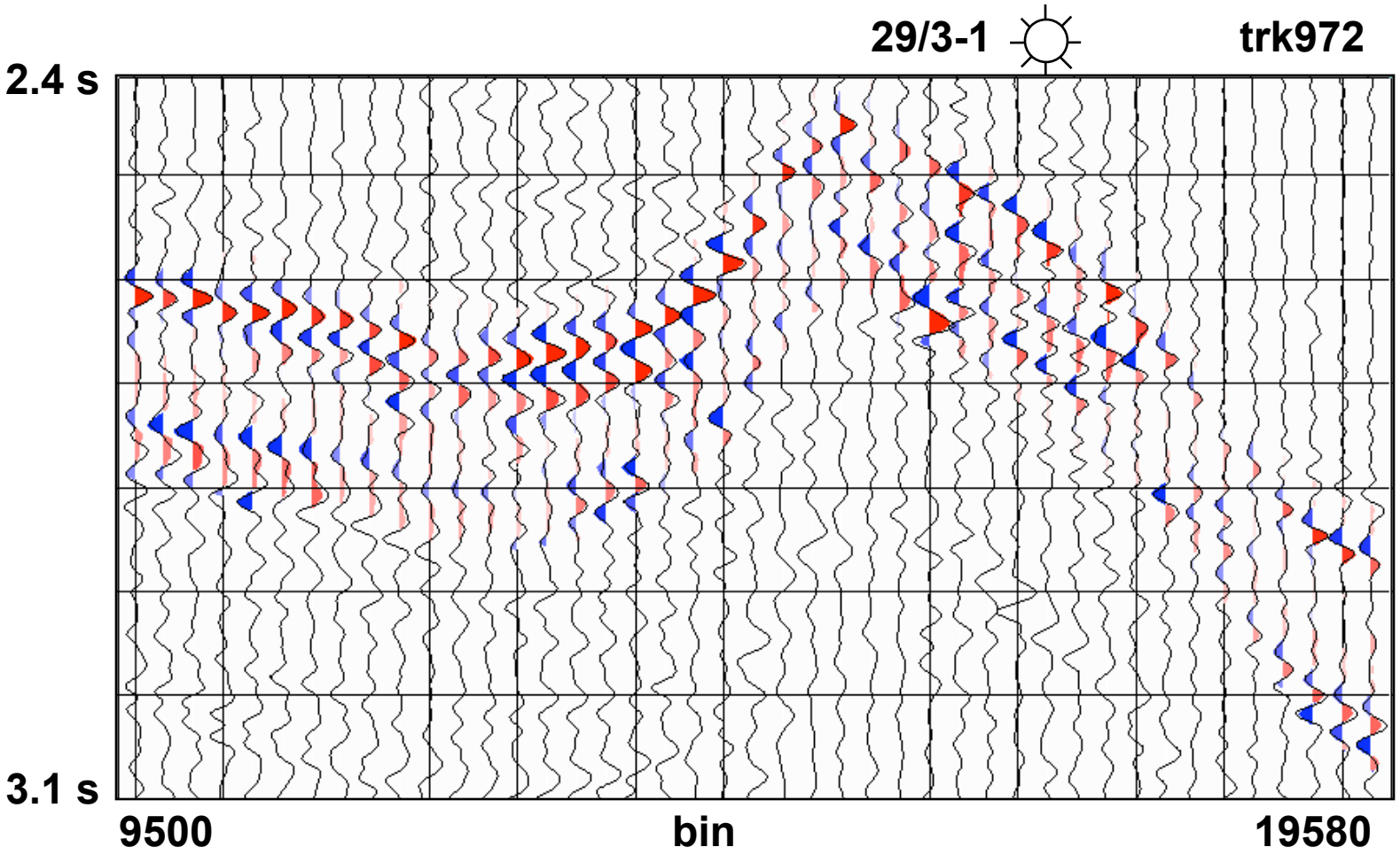


after inversion



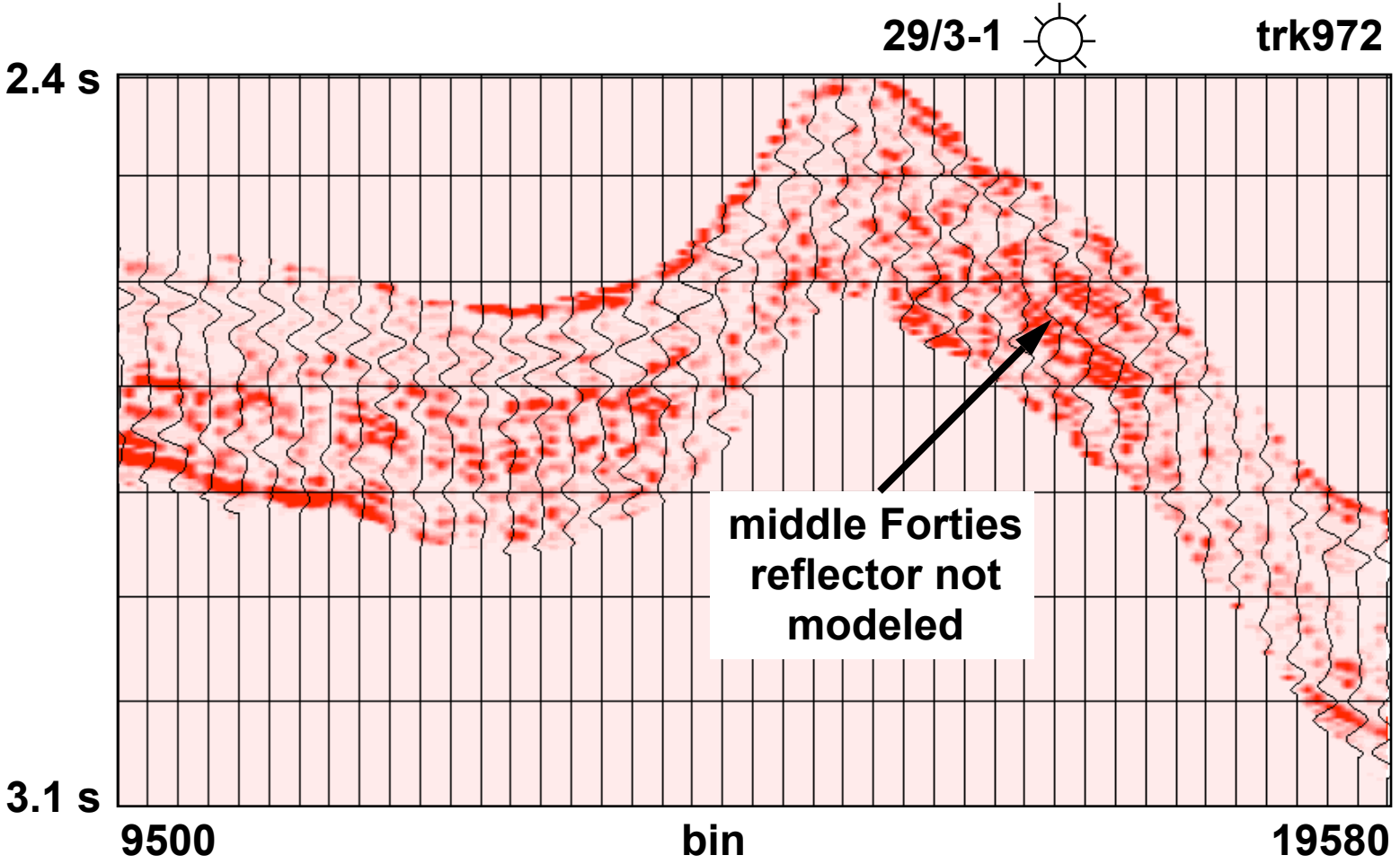


Synthetic seismic after inversion compared to data



Data = black wiggle, synthetic = blue & red

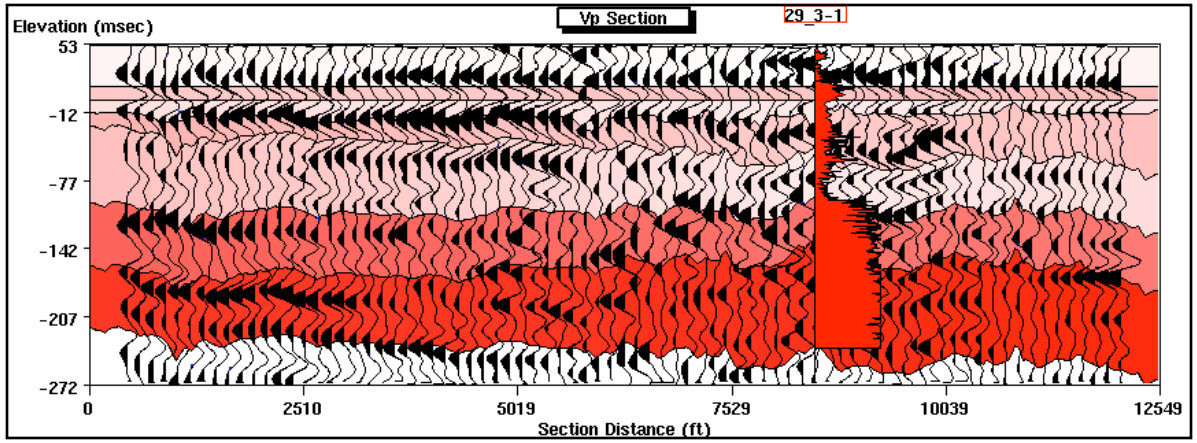
Error in seismic match indicates additional structure in Forties not in model



chi-squared = 0 to 10 (white to red)

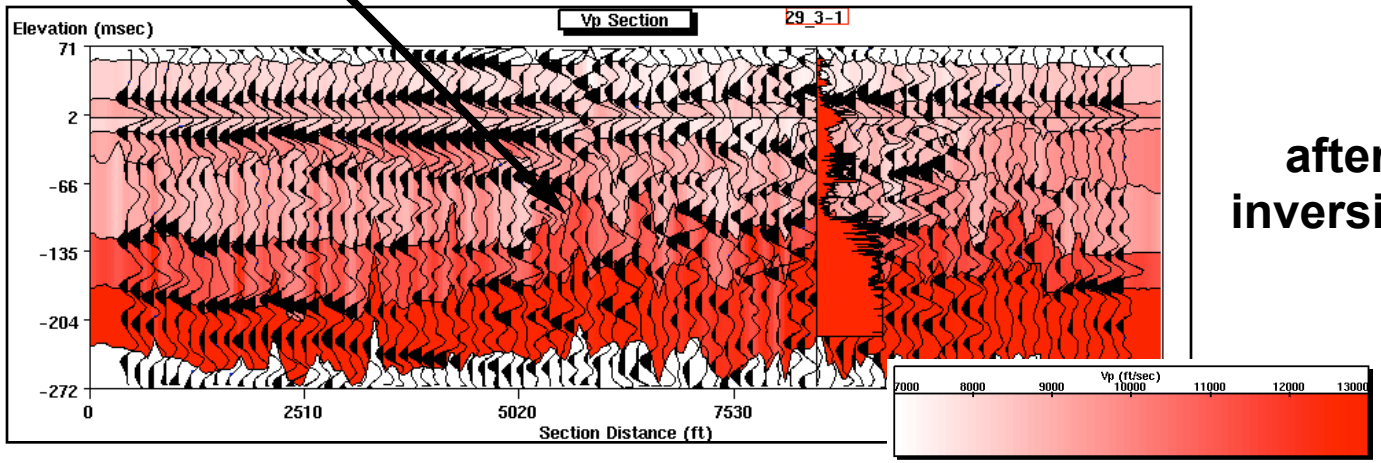
Inverted velocity section shows “loop skipping” near suspected unconformity

trk972



before inversion

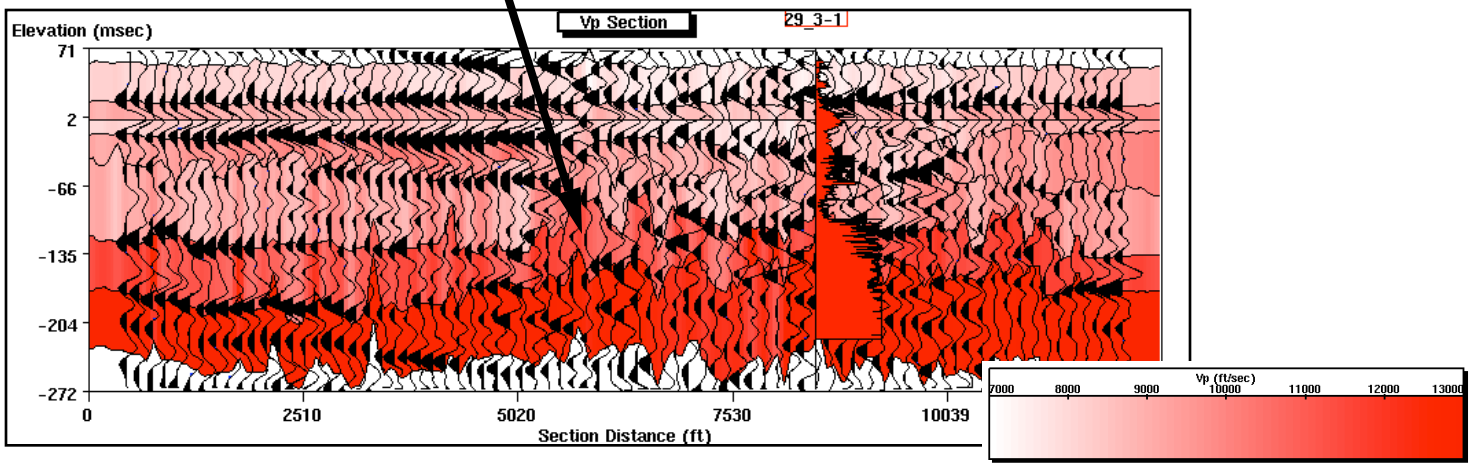
unconformity



after inversion

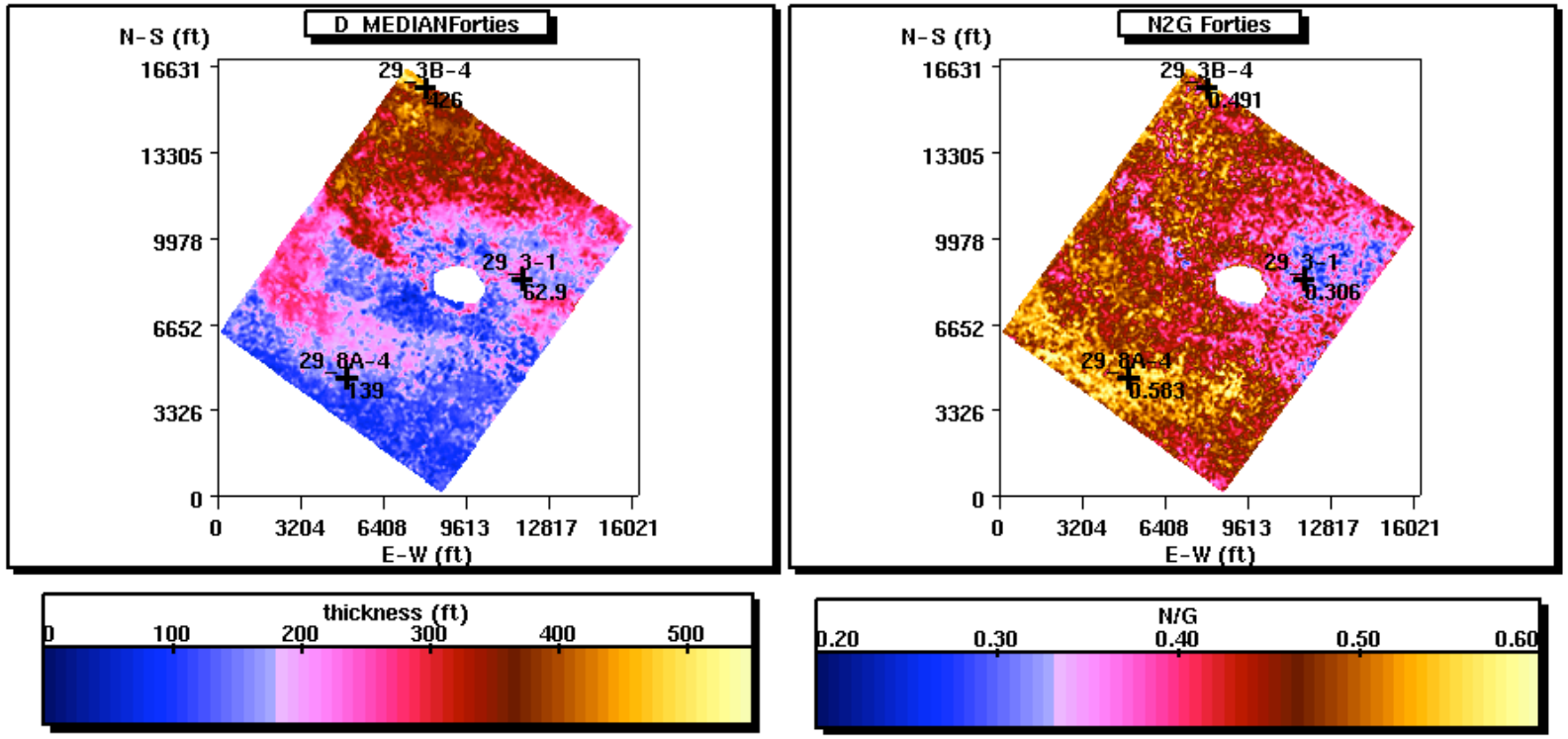
“loop skipping” could be slumps in marl

slumps in marl due to slope near salt dome



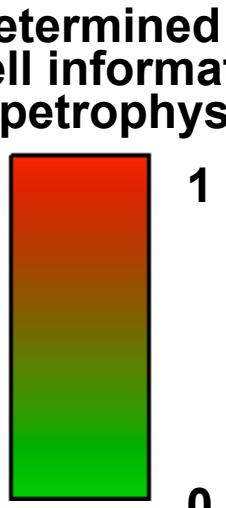
marl beneath Aren sandstone (Tremp basin) slumping due to uplift

P50 maps of Forties N/G and thickness

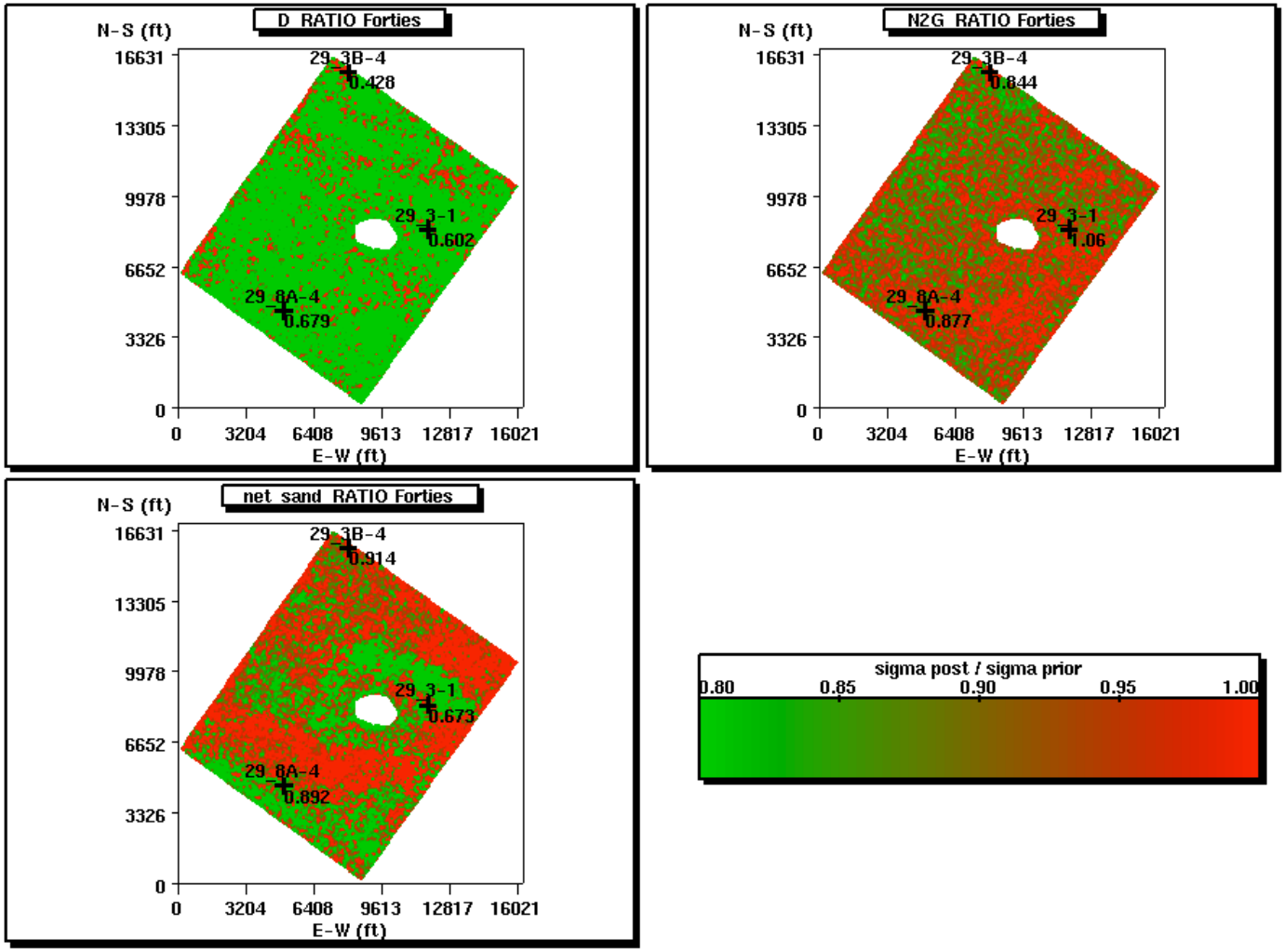


Measure of contribution of seismic data to inversion results

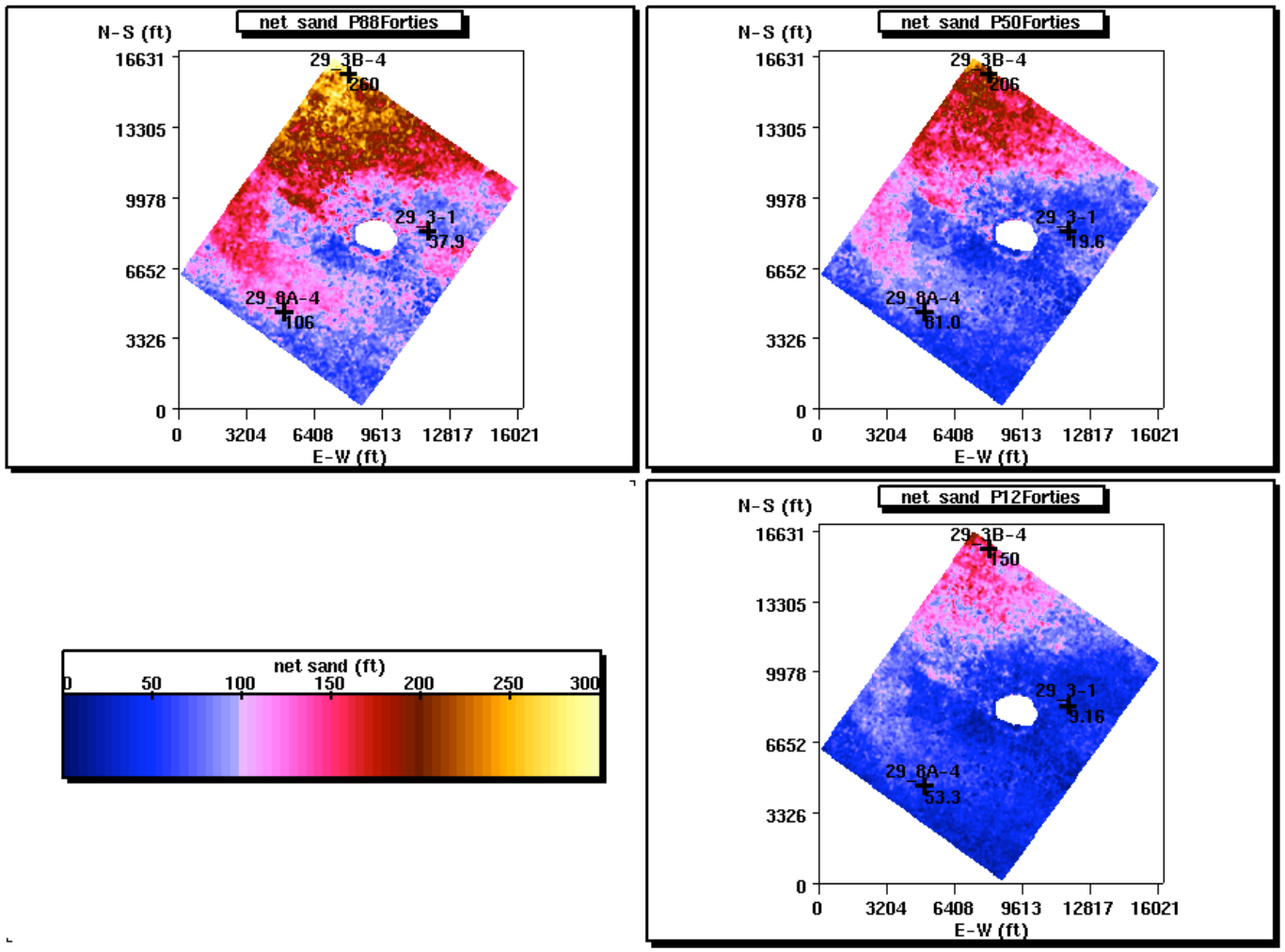
$$\frac{\text{standard deviation after inversion}}{\text{standard deviation before inversion}} =$$



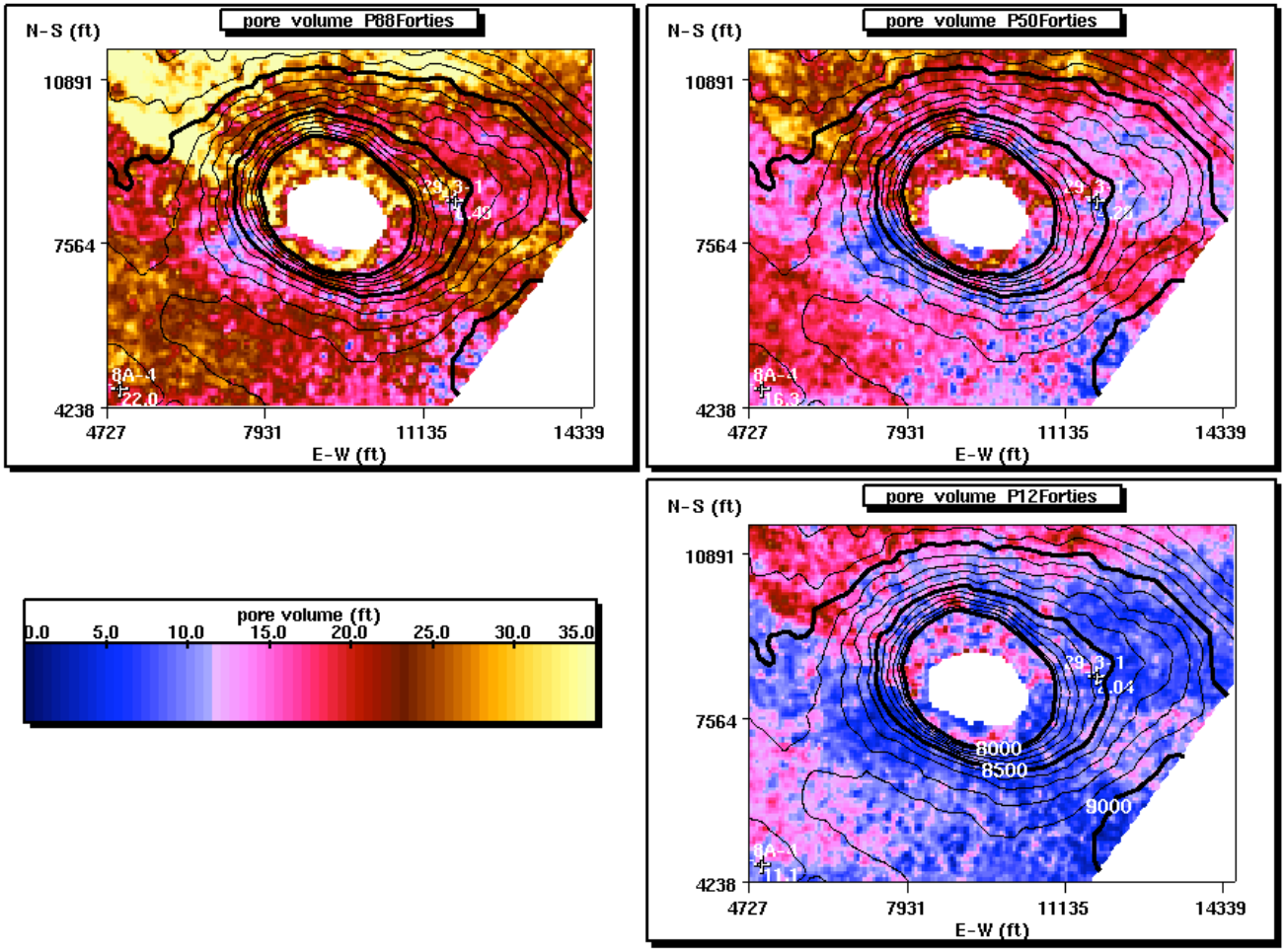
Which quantities are determined by inversion



Uncertainty in the net sand estimation



Pore volume is shown versus structure



Pore volume is integrated to give reserve estimates

GWC (ft)	saturation	P12 (bcf)	P50 (bcf)	P88 (bcf)
8550	40%	147	231	336
8550	55%	202	317	462
8550	70%	257	404	588
8850	40%	300	477	688
8850	55%	412	655	946
8850	70%	525	834	1204

gas expansion factor = 235

Summary

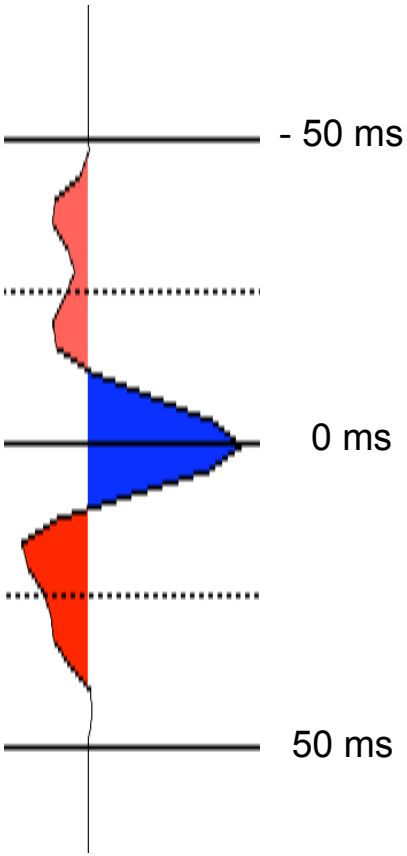
- DepSim model built, petrophysics analyzed, and inversions (FLINT & PROMISE) done in 8 calendar days
- inversion improved estimates of volumetric distributions
- inversion limited by variation in lithologies bounding the sand, and ambiguity in porosity and N/G changes

APPENDIX

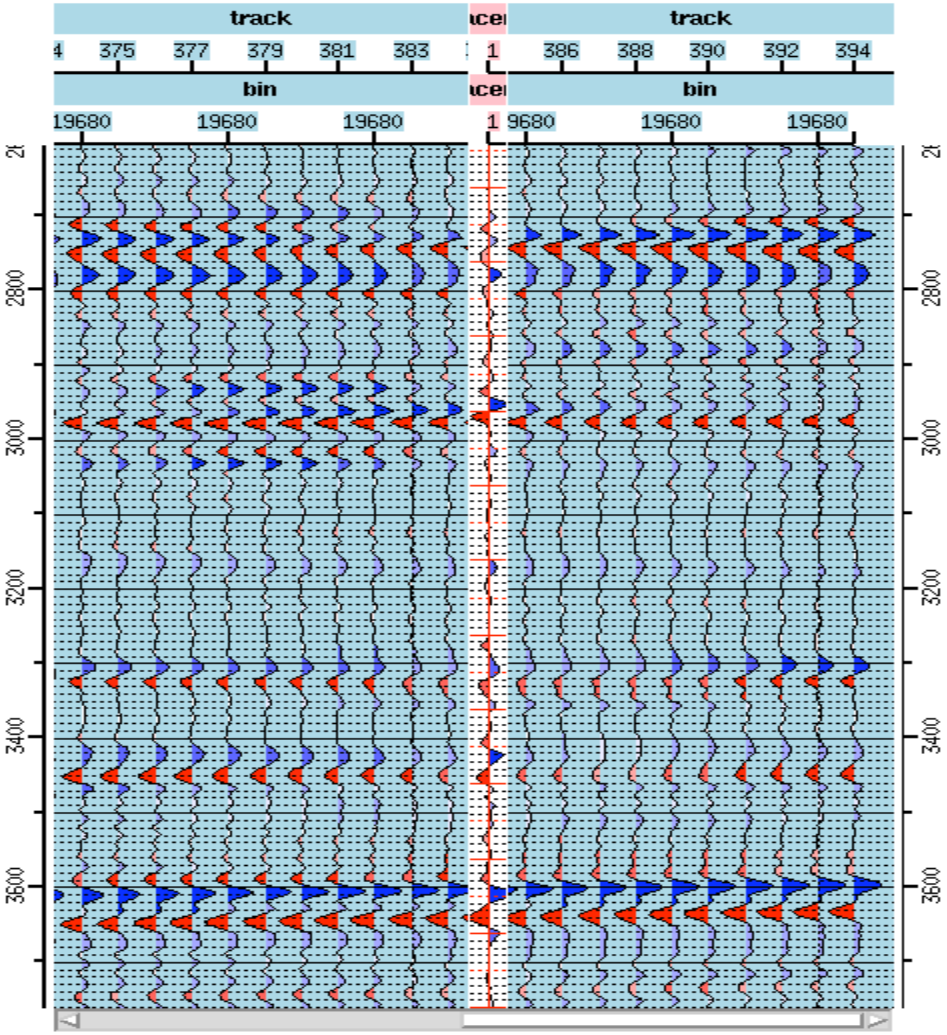
- **Wavelet Extraction**
- **Well Ties**

Wavelet Extraction

Normal incidence reflection coefficient traces were created from acoustic and density logs from the three wells in the area of interest (29/3B-4, 29/3-1, and 29/8A-4). Program XTRACT was then used to derive a single wavelet from the averaged correlations from the three wells and the seismic (PSI full stack). The resulting wavelet, shown at the right, was then convolved with the three reflection coefficient traces to generate the well-tie displays shown in the following three figures. The wavelet was, of course, also used for the seismic inversion results described in the main text.

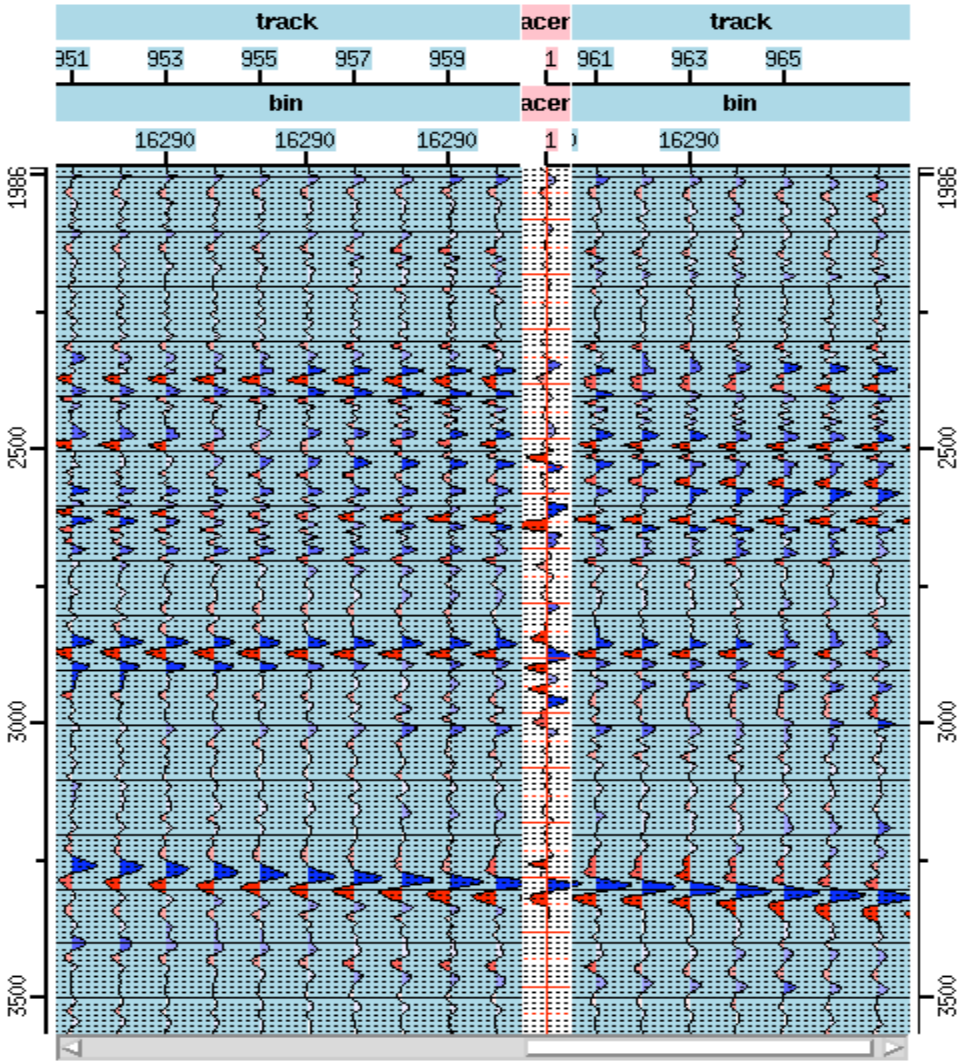


29/3B-4 Well Tie



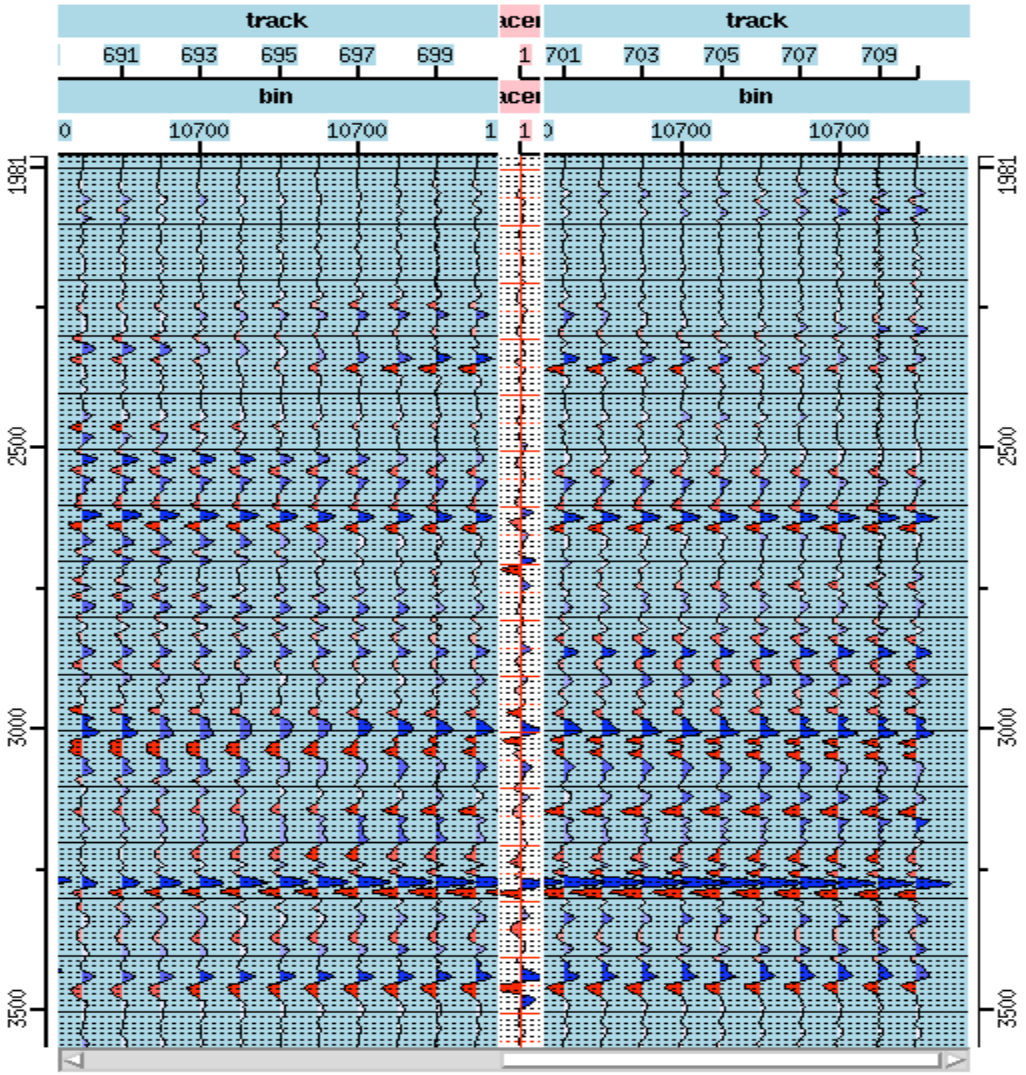
This figure shows the result of convolving the reflection coefficient trace for well 29/3B-4 with the wavelet described earlier and inserting the resulting trace into the east/west line 19680 at the nominal well location.

29/3-1 Well Tie



This figure shows the result of convolving the reflection coefficient trace for well 29/3-1 with the wavelet described earlier and inserting the resulting trace into the east/west line 16290 at the nominal well location.

29/8A-4 Well Tie



This figure shows the result of convolving the reflection coefficient trace for well 29/8A-4 with the wavelet described earlier and inserting the resulting trace into the east/west line 10700 at the nominal well location.