



Universidade Federal do Rio Grande do Norte
Centro de Ciências Exatas e da Terra
Programa de Pós-Graduação em Geodinâmica e Geofísica

DISSERTAÇÃO DE MESTRADO

CARACTERIZAÇÃO DE RUÍDO SÍSMICO AMBIENTE EM UM CAMPO DE PETRÓLEO

Autor:

David Wendell Tomaz da Silva

Orientador:

Prof. Dr. Aderson Farias do Nascimento (DGef/PPGG/UFRN)

Dissertação n.º 237/PPGG.

Natal, RN, 13 de Outubro de 2019



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Comissão Examinadora:

Prof. Dr. Aderson Farias do Nascimento¹²³ - Orientador
Prof. Dr. Walter Eugênio de Medeiros¹²³ - Examinador interno
Prof. Dr. Marcelo Peres Rocha⁴ - Examinador externo

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¹Universidade Federal do Rio Grande do Norte - UFRN

²Programa de Pós-Graduação em Geofísica e Geodinâmica - PPGG

³Departamento de Geofísica - DGef

⁴Universidade de Brasília - UnB

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Resumo

Utilizamos um experimento de 5 horas de duração com 182 sensores verticais de 2 Hz implantados na superfície para caracterizar o ruído antes e durante um monitoramento de fraturamento hidráulico na Bacia Potiguar, Brasil. Observamos que o ruído sísmico é principalmente de induções eletromagnéticas e de vibração de máquinas perto da cabeça do poço, e de fontes localizadas a 2 km do centro da rede sísmica como as bombas de vareta de sucção, tubulações, estradas e instalações industriais. Também relatamos uma ressonância composta por ondas de corpo provenientes da área tratada, que só está presente quando a injeção ocorre. Interpretamos essa ressonância resultante de fraturas cheias de fluido na subsuperfície, mantendo ondas que reverberam nas fraturas. Diferentes estratégias foram empregadas para correlacionar e empilhar os dados para a Interferometria Sísmica de Ruído Ambiente: correlação cruzada normalizada geométrica (CCGN), correlação cruzada de fase (PCC), empilhamento linear e empilhamento ponderado de fase (PWS). PCC e PWS são baseados na coerência instantânea de fase dos sinais analíticos. Por causa da distribuição inadequada da fonte de ruído e da geometria da aquisição, artefatos surgem nos correlogramas. Nós propusemos uma metodologia simples para atenuar esses efeitos indesejados, que consiste em aplicar a correção estática (*Linear Moveout* - *LMO*), empilhar os dados no domínio do tiro e filtro f-k. As curvas de dispersão após esse processamento são aprimoradas e os resultados da análise de velocidade de fase são consistentes com os dados da literatura.

Palavras-chave: Ruído sísmico, ondas de superfície, interferometria sísmica, fontes de ruído e correlação cruzada.

Abstract

We use a 5-h long experiment with 182 vertical 2 Hz sensors deployed on the surface to characterize noise before and during a hydraulic fracking monitoring in the Potiguar Basin, NE Brazil. We observe that the seismic noise is mainly from electromagnetic inductions and from machinery vibration near the wellhead, and within 2 km from the array center from pumpjacks, pipelines, roads, and industrial facilities. We also report a resonance composed of body wave coming from the treated area which is only present when the injection takes place. We interpret this resonance resulting from fluid filled fractures in the subsurface maintaining waves that reverberate in the fractures. Different strategies were employed to cross-correlate and stack the data to Ambient Noise Seismic Interferometry: classical geometrical normalized cross-correlation (CCGN), phase cross-correlation (PCC), linear stacking and phase weighted stacking (PWS). PCC and PWS are based on the instantaneous phase coherence of analytic signals. Because of the unsuitable distribution of the noise source and geometry of acquisition, spurious arrivals arise in the correlograms. We proposed a simple methodology to attenuate these unwanted effects which consists of applying Linear Moveout (LMO) correction, stack the data in the shot domains and f-k filtering. The dispersion curves after this processing are improved and the results from the phase velocity analysis are consistent with those data from the literature.

keywords: Seismic noise , surface waves , seismic interferometry , noise sources and cross-correlation.

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Sumário

Resumo

Abstract

Agradecimentos

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Capítulo 1

Introdução

O ruído é um termo designado para definir um sinal indesejado presente em um dado. Em geral, na geofísica de exploração, os ruídos indesejados podem mascarar os sinais que são de interesse. Por isso, há uma necessidade de conhecermos os ruídos presentes em nosso campo de estudo e a entendermos a sua influência no dado, para que possamos atenuá-lo ou removê-lo.

A definição do que é ruído em um dado, depende exclusivamente do tipo de sinal que deseja-se recuperar. Por exemplo, no levantamento de dados sísmicos os sinais que surgem no dado oriundo do próprio campo de estudo, são considerados com ruídos sísmicos de ambiente (RSA). Esses sinais muitas vezes são de origem desconhecidas e não são controlados, diferentemente das fontes que são utilizadas no levantamento sísmico (carga explosiva, caminhão vibrante, canhão de ar (*airgun* e etc), que são fontes controladas e conhecidas.

No entanto, o RSA pode ser utilizado como fonte para investigar uma zona de interesse. Essa técnica é denominada como interferometria sísmica de ruído ambiente (ISRA), onde é possível recuperar a partir da correlação cruzada de uma série temporal de um par de sensores localizados em uma zona de interesse a resposta ao impulso do meio, conhecida como função de Green (FG) (Campillo and Paul, 2003).

A ISRA é uma técnica alternativa de baixo custo, mobilidade favorável e baixo impacto ao meio-ambiente em relação ao levantamento de sísmica convencional. Devido aos diversos benefícios dessa técnica, é possível encontrar inúmeros trabalhos na literatura com aplicação na indústria de petróleo (Dantas et al., 2018, Miyazawa et al., 2008, Mordret et al., 2013) e produção de energia geotérmica (Lehujeur et al., 2015, Obermann et al., 2015).

A qualidade dos resultados da ISRA dependem de alguns fatores. Dentre eles, destacam-se: i - a distribuição de fontes de ruídos e a sua iluminação (Halliday and Curtis, 2008, Harmon et al., 2010, Snieder, 2004, Wapenaar and Fokkema, 2006), ii - a existência de numerosas camadas de refletoras no meio geológico (Snieder et al., 2006), iii - a presença de múltiplos *scatterer* (Curtis and Halliday, 2010) e iv - ruídos com espectros de frequências monocromáticas proveniente de equipamentos mecânicos ou elétricos utilizados próximo a região de exploração (Harris et al., 2017).

Wapenaar and Fokkema (2006) afirmam que nem todas as fontes de ruídos sísmicos presentes nos locais de estudos são igualmente importantes. Pois, segundo os mesmos, as principais contribuições para a reconstrução da FG provêm de pontos estacionários na superfície circundante. Draganov et al. (2013), ratifica que o sucesso para a recuperação da FG a partir da correlação cruzada do RSA, está vinculado às características e distribuição das fontes dos ruídos.

Desta forma, podemos constatar que há uma necessidade de ampliarmos o conhecimento sobre o RSA, antes da realização de qualquer estudo na área de interesse através da ISRA. A

identificação da origem do ruído sísmico e seu conteúdo espectral podem conter informações relevantes para compreensão dos resultados da ISRA. Essas informações, podem ser obtidas respectivamente através de um arranjo sísmico e de uma análise do dado no domínio tempo-frequência.

Um outro aspecto importante sobre o uso de RSA, é a sua utilização para o monitoramento e imageamento dos processos referentes ao fraturamento hidráulico aplicado tanto na indústria de petróleo como na produção de energia geotérmica. O fraturamento é técnica que tem como finalidade o aumento da permeabilidade no reservatório (Gaucher et al., 2015, Rezaee, 2015). Esta técnica consiste na injeção de um fluido fraturante a uma alta pressão (Kaden and Rose, 2015).

Com o monitoramento adequando durante o processo do fraturamento hidráulico, é possível obter informações geométricas da fratura, estimar o volume do reservatório, verificar a variabilidade do campo de tensão e localizar os micro terremotos gerados pelas fraturas (Kushnir et al., 2014, Maxwell, 2011).

Durante o processo de fraturar a rocha, é comum que ocorram milhares de eventos sísmicos, cujas magnitudes são tipicamente $< 0,0$ M e, portanto, a detecção destes eventos é dificultada pela presença de ruídos externos (Cipolla et al., 2012, Davies et al., 2013, Maxwell et al., 2008, Warpinski et al., 1998).

Deste modo, a caracterização do RSA, pode fornecer informações significativas para remover ou atenuar sinais indesejados presentes tanto no monitoramento do fraturamento hidráulico como na ISRA. Com o conhecimento adequando das características de cada ruído, é possível reduzir o viés provocado pelo mesmo.

1.1 Objetivos

1.1.1 Objetivo Geral

O objetivo deste trabalho é caracterizar o RSA no âmbito do de fraturamento hidráulico situado em um campo de petróleo, na Bacia Potiguar, NE do Brasil.

1.1.2 Objetivo Específico

Os objetivos específicos consistem:

- Identificar e localizar as fontes dos ruídos presentes nos dados de 5 horas de gravação para 182 sensores;
- Avaliar a influência dos ruídos no monitoramento do fraturamento hidráulico e ISRA.

1.2 Metodologia

Para alcançar os objetivos destacados na seção 1.1, dividimos este trabalho em duas etapas: I - Caracterizamos o RSA e analisamos a influência dos ruídos presentes para o monitoramento do fraturamento hidráulico e II - Aplicamos a correlação cruzada e avaliamos a influência dos ruídos para as correlações.

Para primeira parte do trabalho, temos as seguintes etapas:

- Análise tempo-frequência no dado;
- Identificação das possíveis fontes de ruídos mediante análise do decaimento do *root mean square* (RMS) em função do afastamento (*offset*);
- Aplicação do *beamforming FK* para identificação da velocidade e direção de propagação das fontes de ruídos presentes nos dados.

Para a segunda parte do trabalho, temos as seguintes etapas:

- Preparação do dado (filtragem, normalizações e parametrizações das correlações);
- Empregar duas técnicas de correlação cruzadas, a (*Cross-correlation geometrically normalized* (CCGN) e o *phase cross-correlation* (PCC) desenvolvido por Schimmel (1999));
- Empregar duas técnicas de empilhamento, o empilhamento linear e o empilhamento não linear (tf-PWS - *time-frequency domain phase-weighted stack*) desenvolvido por Schimmel and Gallart (2007) para os resultados dos correlogramas obtidos pelo CCGN e PCC;
- Aplicação de correção estática para os correlogramas obtidos, *Linear moveout* (LMO) ;
- Empilhamento linear após a correção estática;
- Aplicação do filtro FK;
- Curva de dispersão.

No capítulo subsequente, será apresentada a fundamentação teórica das principais técnicas adotadas neste trabalho. Em seguida, exibimos o manuscrito submetido para a revista referente a este trabalho em forma de capítulo, o qual, realizamos todas as discussões pertinentes ao trabalho seguindo das conclusões obtidas deste trabalho.

Capítulo 2

Fundamentação Teórica

2.1 Análise tempo-frequência

A caracterização de um ruído presente no dado, pode ser realizado de diversas formas. Em casos mais simples, muitas vezes é possível identificar-lo no domínio do tempo, outras vezes é possível identificar-lo no domínio da frequência. No entanto, para casos mais complexos como o que está sendo estudo neste trabalho, a tarefa de caracterizar do ruído torna-se algo mais complexo.

Comumente, na interpretação de dados sísmicos, são utilizados a análise do dado no domínio da frequência por meio do espectro de potência (Marfurt and Kirilin, 2001, Partyka et al., 1999). Todavia, este tipo de análise não me fornece o conteúdo do espectro de potência e frequência em função do tempo.

Uma solução para este problema foi proposto em 1946 por Dennis Gabor, em que o sinal é fracionado em pequenos segmentos e calcula-se o espectro de potência através da Transformada Discreta de Fourier (*Discrete Fourier Transform* - DFT) para cada segmento. Este método é conhecido como Transformada de Fourier de curto Tempo (*Short Time Fourier Transform* - STFT) e pode ser representada como :

$$STFT(t, \omega) = \int_{-\infty}^{\infty} [x(\tau).g(\tau - t)].e^{-i\omega t} d\tau, \quad (2.1)$$

em que, g é a janela deslizando no tempo. Logo, $STFT(t, \omega)$ é uma representação no tempo-frequência de uma dada função.

2.2 RMS

O RMS ou valor eficaz é dado pela seguinte equação:

$$RMS = \sqrt{\frac{1}{N} \sum_{i=1}^N x_i^2} \quad (2.2)$$

O valor do RMS tem um relação direta com energia do ruído. Sendo assim, todos os ruídos identificados mediante a análise tempo-frequência, foram selecionados para analisarmos o decaimento do RMS em função do posicionamento de cada sensor, ou seja, quanto maior for a distância (*offset*) entre o sensor e a fonte menor será o valor do RMS devido a atenuação sofrida para frente de onda.

Deste modo, como o arranjo sísmico tem uma posição fixa no levantamento, é possível localizar a fonte do ruído pelo decaimento do seu RMS. Para isso, é necessário determinar o tempo de duração do ruído e a faixa de frequência que ele surge.

2.3 Beamforming

A técnica do *beamforming* utiliza os diferentes tempos de percursos da frente de onda plana correspondente a um dado *backazimuth* e uma dada vagarosidade que são obtidos num arranjo sísmico. Os tempos de atrasos de um evento identificado nos sismogramas das diferentes estações da *array* sísmica, fornecem uma estimativa direta do *backazimuth* e vagarosidade (Rost and Thomas, 2002).

Podemos calcular o tempo de atraso pela seguinte expressão:

$$\varsigma_i = \frac{\xi_i}{c_f}, \quad (2.3)$$

em que ς_i representa a diferença de tempo da frente de onda entre um sensor i e o sensor de referência (centro da rede de sismogramas), c_f é a velocidade de fase (com frequência única) e ξ_i é a distancia entre um par de sensor.

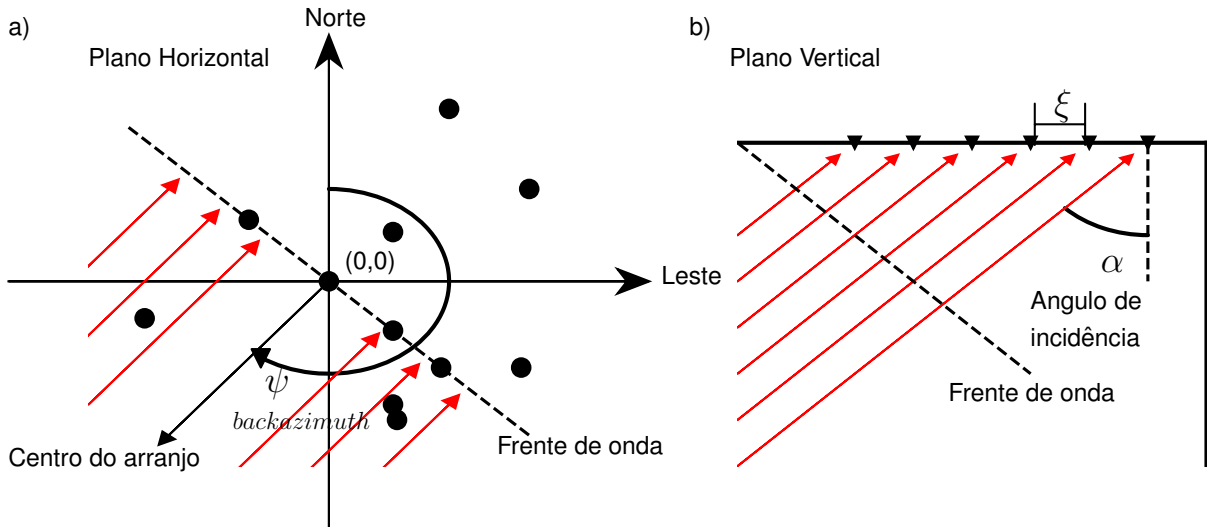


Figura 2.1: Ilustração de um arranjo sísmico para utilização da técnica do beamforming a) arranjo sísmico no plano horizontal com a propagação da frente de onda plana b) arranjo sísmico no plano vertical com a propagação da frente de onda plana.

Em geral, pressupõe que a chegada da frente de onda no arranjo sísmico é plana. Na figura 2.1 ilustramos a chegada da onda plana. Figura 2.1-b a frente de onda chega no arranjo com um ângulo de incidência (α), na realidade, não utilizamos o ângulo de incidência e sim o inverso da velocidade aparente, este termo é denominado como vagarosidade.

$$s = \frac{1}{c_{ap}} = \frac{\sin \alpha}{c_0} \quad (2.4)$$

em que, c_0 é a velocidade média abaixo do arranjo. Na figura 2.1-a determinamos o *backazimuth*.

Calculando o tempo de atraso em função das coordenadas dos sensores e lembrando que o vetor de vagarosidade denomina-se como $\vec{s} = \frac{1}{c_{ap}}$, têm-se a expressão em notação vetorial

$$\varsigma_i = \vec{r}_i \cdot \vec{s} \quad (2.5)$$

Um sismograma com sinal $f(t)$ e ruído $n_i(t)$ com variância σ^2 registrado no centro da rede sísmica pode ser expresso como: $\chi_{centro}(t) = f(t) + n_i(t)$. No entanto, devido às diferentes posições de cada sensor dentro da rede sísmica, a frente de onda possui diferentes tempos de percursos, em que este tempo de percurso ou tempo de atraso depende da vagarosidade e da posição do sensor ($\chi_i = f(t - \vec{r}_i \cdot \vec{s}_1) + n_i(t)$), em que $\vec{s}_1$ representa a vagarosidade aparente no plano da superfície (horizontal). Reescrevendo a equação temos que ($\chi_i = f(t - \varsigma_i) + n_i(t)$).

No caso, em que removemos o tempo de atraso do sismograma, pode-se calcular seguinte forma:

$$\tilde{\chi}_i(t) = \chi_i(t + \varsigma_i) = f(t) + n_i(t + \varsigma_i) \quad (2.6)$$

O atraso e a soma, correspondem ao registro do sinal em relação ao sensor do centro de rede sísmica. O *beamforming* é definido como:

$$B(t) = \frac{1}{M} \sum_{i=1}^M \tilde{\chi}_i(t) = f(t) + \frac{1}{M} \sum_{i=1}^M n_i(t + \varsigma_i) \quad (2.7)$$

Em que, M representa a quantidade de sensores da rede sísmica. $B(t)$ é uma superposição de todos os sinais da rede sísmica, na qual o sinal é amplificado devido a interferência construtiva das fases por causa da vagarosidade apropriada, enquanto os ruídos são suprimidos devido a interferência destrutiva das fases incoerentes.

2.3.1 Beamforming FK

O *beamforming* descrito na secção 2.3 utiliza os diferentes tempos de percursos da frente de onda plana correspondente a um dado *backazimuth* e vagarosidade apropriadas que são obtidos através de uma rede sísmica. Os tempos de atrasos de um evento identificado nos sismogramas dos diferentes sensores da rede sísmica fornecem uma estimativa direta do *backazimuth* e vagarosidade (Rost and Thomas, 2002).

Quando estes eventos sísmicos são obliterados por outros eventos indesejados, as determinações do *backazimuth* e vagarosidade são dificultadas, pois não é possível identificar com clareza, o tempo de chegada da fase sísmica de interesse. Deste modo, em contraposição a este método baseado na visualização do tempo de chegada da onda sísmica a análise FK ou *beamforming* FK é capaz de estimar o simultaneamente o *backazimuth* e a vagarosidade.

O método de análise FK é amplamente utilizado em estudos com redes sísmica para inferir o *backazimuth* e vagarosidade de fontes sísmicas. Visto que, em qualquer ponto espacial do campo de onda, é possível calcular a *cross-power spectral density*, que compreende aos valores das médias quadráticas das amplitudes das ondas sísmicas. A *cross-power spectral density* é dada pela equação

$$E = \sum_{m=-\infty}^{\infty} B^2(t) \quad (2.8)$$

Utilizando o teorema de Parseval na equação 2.8 obtêm-se a seguinte expressão:

$$BF(w, \vec{k}) = \frac{1}{2\pi} \int_{-\infty}^{\infty} |F(\omega)|^2 \left| \frac{1}{M} \sum_{m=1}^M e^{2\pi i \vec{k} \cdot \vec{r}_i} \right|^2 d\omega, \quad (2.9)$$

em que, $F(\omega)$ é a transformada de Fourier de $f(t)$, e $\vec{k}$ é o vetor número de onda ($k = \sqrt{k_x^2 + k_y^2}$). O *backazimuth* Ψ pode ser calculado por

$$\Psi = \tan^{-1}\left(\frac{k_x}{k_y}\right). \quad (2.10)$$

Supondo que a densidade espectral de potência $F(\omega)$ seja normalizada

$$\frac{1}{2\pi} \int_{-\infty}^{\infty} |F(\omega)|^2 d\omega = 1. \quad (2.11)$$

Logo, podemos reescrever a equação 2.9 da seguinte forma

$$BF(w, \vec{k}) = \left| \frac{1}{M} \sum_{m=1}^M e^{2\pi i \vec{k} \cdot \vec{r}_i} \right|^2, \quad (2.12)$$

2.4 Correlação Cruzada

Na literatura atual, as principais formas da recuperação da FG é por meio da correlação cruzada (Wapenaar et al., 2010), a *cross-coherence* (Nakata et al., 2011), o PCC (Schimmel, 1999) e a deconvolução Nakata et al. (2013).

Neste trabalho, utilizaremos a correlação cruzada clássica e o PCC para recuperar a FG. Nas subseções subsequentes, apresentaremos as duas técnicas utilizadas.

2.4.1 CCGN

O CCGN pode ser obtido pela seguinte expressão:

$$C_{CCGN}(t) = \frac{\sum_{\tau=\tau_0}^{\tau_0+T} u_1(t+\tau)u_2(\tau)}{\sqrt{\sum_{\tau=\tau_0}^{\tau_0+T} u_1(t+\tau)^2 \sum_{\tau=\tau_0}^{\tau_0+T} u_2(t+\tau)^2}} \quad (2.13)$$

em que u_1 e u_2 são as duas séries temporais, t e T são o intervalo de tempo e o comprimento da janela de correlação, respectivamente. τ_0 é o tempo de início da janela de correlação. O intervalo de tempo t é aplicado a u_1 . O denominador é a média geométrica da energia dentro da janela de tempo T .

2.4.2 PCC

O PCC é baseado na teoria do sinal analítico. O sinal analítico $s(t)$ de uma série temporal real $u(t)$ é definida unicamente como $s(t) = u(t) + iH[u(t)]$, no qual, $H[u(t)]$ é a Transformada

de Hilbert da série temporal $u(t)$. Esta transformação é do domínio real para o complexo. Assim, se consideramos a forma exponencial $s(t) = a(t)\exp(i\phi(t))$ obtém-se o envelope $a(t)$ e a fase instantânea $\phi(t)$. Esta fase deve ser a mesma para todos os sinais coerentes em cada momento no dado, a Transformada de Hilbert pode ser expressa como uma operação de janela móvel fortemente localizada (Schimmel et al., 2011).

Este método foi apresentando por (Schimmel, 1999) e é definido pela seguinte expressão:

$$C_{PCC}(t) = \frac{1}{2T} \sum_{\tau_0+T}^{\tau=\tau_0} \{|e^{i\phi(t+\tau)} + e^{i\psi(\tau)}|^v - |e^{i\phi(t+\tau)} - e^{i\psi(\tau)}|^v\} \quad (2.14)$$

em que, C_{pcc} é uma função de coerência que mede a semelhança de duas séries temporais u_1 e u_2 como função do *lag time* t análogo ao CCGN. $\phi(\tau)$ e $\psi(\tau)$ são as fases instantâneas de u_1 e u_2 que tornam $C_{pcc}(t)$ uma correlação que não depende da amplitude. C_{pcc} baseia-se no número de amostras coerentes de fase em vez da soma dos produtos das amplitudes como é o caso para a correlação cruzada convencional.

2.5 Empilhamento

O termo empilhamento é denominado ao somatório de todos os traços, com a finalidade de obter um único traço melhorando a razão sinal/ruído.

Os resultados obtidos pelo CCGN e PCC serão empilhados por meio do empilhamento linear (*Linear Stack* LS) e o tf-PWS. A finalidade de utilizar duas formas de empilhamento é para comparar qual técnica apresenta ser mais adequada para ser utilizada no ambiente de estudo.

2.5.1 Time-frequency domain phase-weighted stack

O tf-PWS é uma extensão do *phase-weighted stack* (PWS) apresentado por Schimmel and Paulssen (1997). Esta forma de empilhamento, reduz os limites para detecção de eventos fracos, todavia coerentes. No tf-PWS, os sinais fracos detectados são destacados, desta forma, faz com que os ruído incoerente de grande amplitude tenha pouca influência no sinal diferentemente do processo no LS.

O PWS é um empilhamento não linear onde cada amostra de um empilhamento linear é ponderado por uma medida de coerência explicitamente independente da amplitude. Este empilhamento pode ser expresso da seguinte forma:

$$c_{ps}(t) = \frac{1}{N} \left| \sum_{j=1}^N e^{i\Phi_j(t)} \right|^v, \quad (2.15)$$

em que, $c_{ps}(t)$ representa o empilhamento de fase, N indica o número de traços usados, j é um índice que enumera os traços usados, $\Phi(t)$ é a fase instantânea, e v representa um parâmetro que ajusta a transição entre a soma de um sinal coerente e menos coerente. A finalidade do PWS é reprimir os sinais empilhados que não são coerente.

As amplitudes do empilhamento de fase variam entre 0 e 1 em função do tempo. Se as fases instantâneas dos sinais a um certo tempo são coerentes, então, a amplitude do empilhamento de fase é igual a um. As amplitudes zero significam que os sinais são somados destrutivamente. O empilhamento de fase é uma medida de coerência em função do tempo,

que é a eficácia do empilhamento sobre a qual a base da fase instantânea é descrita. As amplitudes dos traços sísmicos são somente envolvidas na computação de fases instantâneas

Ao realizar a multiplicação entre os termos do LS com PWS, obtemos o empilhamento de fase ponderada

$$p_{pws}(t) = \frac{1}{N} \sum_{k=1}^N S_j(t) \mid \sum_{j=1}^N e^{i\Phi_j(t)} \mid^v, \quad (2.16)$$

em que, $p_{pws}(t)$ representa o empilhamento de fase ponderada e $s(t)$ representa o traço. Segundo Schimmel and Paulssen (1997) toda amostra do LS será ponderada pela coerência de suas fase instantâneas.

Como dito anteriormente, o tf-PWS é uma extensão do PWS e é apresentado da seguinte forma:

$$\begin{aligned} S_{pws}(\tau, f) &= S_{1s}(\tau, f) c_{ps}(\tau, f) \\ &= S_{1s}(\tau, f) \mid \sum_{j=1}^N \frac{S_{j(\tau, f)} e^{i2\pi f \tau}}{|S_j(\tau, f)|} \mid^v, \end{aligned} \quad (2.17)$$

em que, $S_j(\tau, f)$ representa a transformada S da j - ésima série temporal e $S_{1s}(\tau, f)$ é a transformada S do LS de todas as N séries temporais. A coerência de fase é utilizada para ponderar as porções incoerentes do LS no domínio tempo-frequência Schimmel et al. (2011).

2.6 LMO

A técnica de *linear moveout*, corresponde a uma correção estática. Na qual, aplica-se um deslocamento equitativamente na variável do tempo em todos os traço com base na identificação de evento linear no sismograma, que representa a velocidade de propagação da onda. A constante de deslocamento do tempo é obtido através seguinte expressão:

$$t_{lmo} = \frac{d}{v} \quad (2.18)$$

em que, t_{lmo} é o tempo de correção estática, d representa o *offset* do traço e v é a velocidade do evento do qual deseja-se aplicar a correção.

Desta forma, a aplicação de t_{lmo} preserva todas as características do traço, suas amplitudes, número de amostras e o *offset*. Pois, só há deslocamento em tempo.

Neste trabalho, o LMO será aplicada juntamente com a técnica do empilhamento linear para obter o valor da velocidade absoluta da onda e melhorar a razão sinal-ruído.

Na figura 2.2, dispomos de uma representação dos passos adotados para aplicação do LMO juntamente com o empilhamento.

A figura 2.2-a) indica o sismograma sintético de um tiro virtual para um arranjo de sensores em dispostos em linha em uma superfície. Este tiro representa o primeiro tiro virtual para todos os canais da linha de aquisição. Figura 2.2-b) representa o N-ésimo tiro para todos os canais. Deste modo, obtemos a velocidade da onda destacada pela linha vermelha tracejada (figura 2.2-a) para todos os tiros. Assim, utilizando a equação 2.18 obtemos o valor de t_{lmo} para cada traço.

Para a realização do calculo da t_{lmo} , reorganizamos o sismograma, como podemos observar na figura 2.2-c), em que, o sismograma está disposto de todos os tiros para o mesmo canal,

que neste exemplo é o primeiro canal. Posterior ao calculo do t_{lmo} aplica-se a correção deslocando o traço em tempo (figura 2.2-d). Em seguida, realiza-se o empilhamento de todos os traço referente ao mesmo canal, desta maneira, obtém-se um único traço para o primeiro canal (figura 2.2-e), isto é realizado para todos os canais. Por fim, o sismograma é organizado em função do tiro para todos os canais que foram empilhado (figura 2.2-f), apresentando uma melhora na relação sinal/ruído e com a velocidade absoluta da onda.

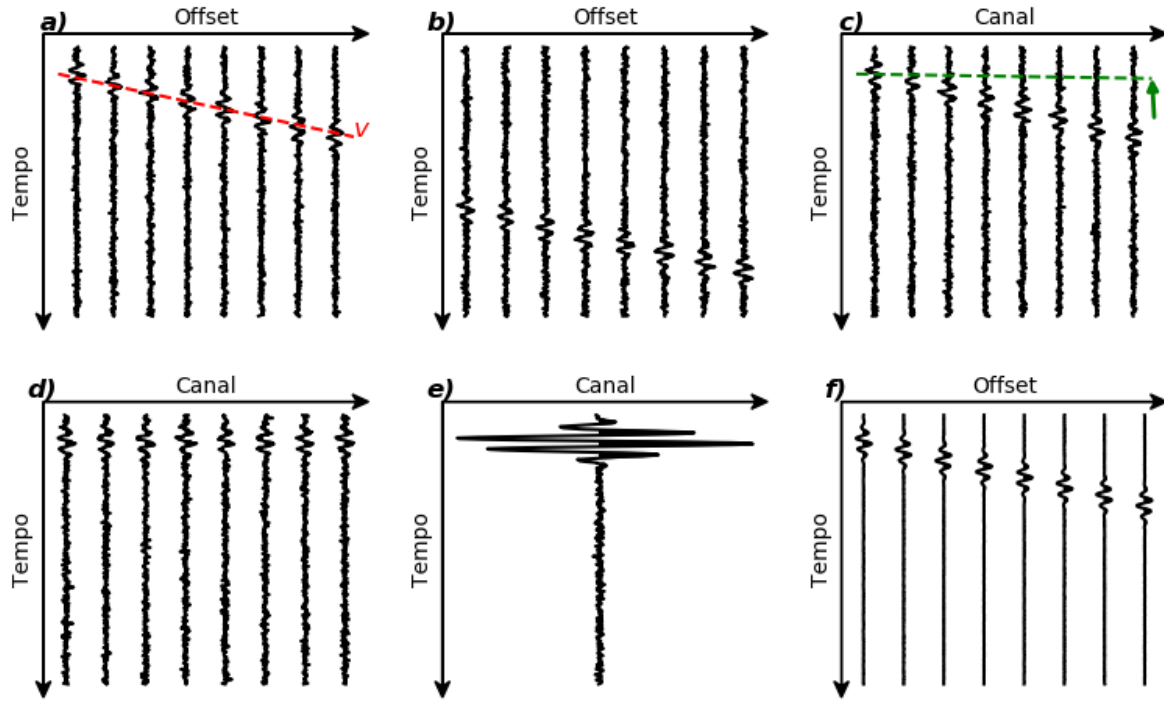


Figura 2.2: Sequência do método do LMO aplicado a um sismograma sintético. a) sismogramas do primeiro tiro em função do offset, a linha traceja em vermelho indica a velocidade da onda, b) sismogramas do tiro N em função do offset, c) sismogramas no domínio do canal, a linha verde tracejada indica a projeção da do deslocamento do tempo (t_{lmo}), d) sismogramas no domínio do canal com a correção do tempo do tempo t_{lmo} aplicado, e) traço resultando após o empilhamento e f) os sismogramas com a correção de LMO mais o empilhamento.

2.7 Filtro FK

O sismograma na sís mica ativa, é representado no domínio t - x , em que t representa o tempo no eixo das ordenadas e x representa o *offset* no eixo das abscissas.

Para a realização da filtragem FK, faz-se necessário a mudança do domínio que o sismograma está representando. Esta mudança ocorre por meio da transformada 2D direta de Fourier, passando do domínio t - x para o domínio f - k . No qual, f representa da frequência e k o número de onda. Existe uma relação fundamental entre f e k , que está descrito abaixo:

$$f = \frac{v}{\lambda} \quad (2.19)$$

e

$$k = \frac{2\pi}{\lambda} \quad (2.20)$$

Logo, temos a seguinte relação:

$$\frac{f}{k} = \frac{v}{2\pi} \quad (2.21)$$

A transformada 2D direta de Fourier responsável pela transformação do sismograma do domínio t-x para o f-k está expressa da seguinte forma:

$$F(w, k_x) = \int_{-\infty}^{+\infty} \int_{-\infty}^{+\infty} f(t, x) e^{ik_x - iw} dt dx \quad (2.22)$$

Capítulo 3

Manuscrito Submetido:

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Characterization of seismic noise in an oil field using passive seismic data from a hydraulic fracking operation

David Wendell Tomaz da Silva · Aderson
Farias do Nascimento · Flavio Lemos de
Santana

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Abstract We use a 5-h long experiment with 182 vertical 2 Hz sensors deployed on the surface to characterize noise before and during a hydraulic fracking monitoring in the Potiguar Basin, NE Brazil. We observe that the seismic noise is mainly from electromagnetic inductions and from machinery vibration near the wellhead, and within 2 km from the array center from pupjacks, pipelines, roads, and industrial facilities. We also report a resonance composed of body wave coming from the treated area which is only present when the injection takes place. We interpret this resonance resulting from fluid filled fractures in the subsurface maintaining waves that reverberate in the fractures. Different strategies were employed to cross-correlate and stack the data to Ambient Noise Seismic Interferometry: classical geometrical normalized cross-correlation (CCGN), phase cross-correlation (PCC), linear stacking and phase weighted stacking (PWS). PCC and PWS are based on the instantaneous phase coherence of analytic signals. Because of the unsuitable distribution of the noise source and geometry of acquisition, spurious arrivals arise in the cor-

David Wendell Tomaz da Silva
Postgraduate Programme in Geodynamics and Geophysics, Federal University of Rio Grande do Norte, Natal, Brazil
E-mail: davidwendell@ufrn.edu.br

Aderson Farias do Nascimento
Postgraduate Programme in Geodynamics and Geophysics, Federal University of Rio Grande do Norte, Natal, Brazil
Department of Geophysics, Federal University of Rio Grande do Norte, Natal, Brazil
INCT-GP/CNPq - Instituto Nacional de Ciências e Tecnologia em Geofísica do Petróleo.
Tel.: +55-084-3342-2237, r. 558
E-mail: aderson@geofisica.ufrn.br

Flavio Lemos de Santana
Postgraduate Programme in Geodynamics and Geophysics, Federal University of Rio Grande do Norte, Natal, Brazil
Department of Geophysics, Federal University of Rio Grande do Norte, Natal, Brazil
INCT-GP/CNPq - Instituto Nacional de Ciências e Tecnologia em Geofísica do Petróleo.
E-mail: flavio.geofisica@yahoo.com.br

relograms. We proposed a simple methodology to attenuate these unwanted effects which consists of applying Linear Moveout (LMO) correction, stack the data in the shot domains and f-k filtering. The dispersion curves after this processing are improved and the results from the phase velocity analysis are consistent with those data from the literature.

Keywords seismic noise · surface waves · seismic interferometry · noise sources · cross-correlation

1 Introduction

In the oil industry and geothermal energy production, it is often necessary to artificially enhance the reservoir permeability, and hydraulic fracturing is a common technique for this purpose (Rezaee 2015; Gaucher et al. 2015). Hydraulic fracturing consists of injection fluids and propellant under high pressure (typically greater than a few thousand psi) into the target formation (Kaden and Rose 2015). The idea is that the fracking fluid pressure is greater than the rock strength and natural fractures will enhance their permeability and new fractures will be created. The propeller that goes into the formation with the fluid is responsible for ensuring that the generated fractures are maintained after the pressure is reduced. Thus after the fracking treatment, the formation suffers a permeability increment of the rock since preferential pathways are kept available.

The monitoring of hydraulic fracturing may occur via the recording of (small, $< 3.0ML$) earthquakes which are generated during the induced fracture growth. The sensors can be deployed in boreholes and/or on the surface (Anglin and Buchbinder 1985; Chen et al. 2018; Meng et al. 2018). With adequate monitoring, it is possible to obtain geometrical information of the fracture, to estimate the reservoir stimulated volume, to verify the stress field variability, and to locate the generated microearthquakes which may be used as proxies for the fracture growth (Maxwell 2011; Kushnir et al. 2014).

However, the record of the induced microearthquakes using sensors on the surface are obliterated due to the large amount of noise that is generated on the surface during the hydraulic fracturing process and other antropogenic noises generated in the oil field. In a typical fracking monitoring operation, it is usual that thousands of seismic events may occur. As these events have magnitudes are typically less than $0.0 ML$, their detection and location are quite challenging (Cipolla et al. 2012; Warpinski et al. 1998; Davies et al. 2013; Maxwell et al. 2008)

The characterization of ambient seismic noise (ASN) will provide subsidies for a better design of filters to attenuate undesirable noise such as those observed in hydrofracking monitoring fusing surface sensors. Thus, noise characterization is an important step in any study that makes use of noise. With adequate knowledge of the characteristics of the noise, it is possible to reduce bias provoked by the undesirable components of the recorded data. Additionally, ASN interferometry has become widely popular in the last 15 years for

imaging purposes (Huang et al. 2010; Sabra et al. 2005; Shapiro and Campillo 2004). However, the quality of the image depends on the quality of the retrieved correlograms which in turn are dependent on the seismic noise source distribution. Several authors that show that the results obtained ASN interferometry showed a significant bias due mainly to: i - the distribution of noise sources and their illumination (Halliday and Curtis 2008; Harmon et al. 2010; Wapenaar and Fokkema 2006; Snieder 2004), ii - the existence of numerous layers of reflectors in the geological environment (Snieder et al. 2006), iii - the presence of multiple scatterers (Curtis and Halliday 2010) and iv - noise with monochromatic frequency spectra from mechanical or electrical equipment used near the exploration region (Harris et al. 2017).

In our work, we use data from a 182 vertical 2 Hz sensor array deployed on the surface during 5h to monitor a fracking treatment in the Potiguar Basin, NE Brazil. We characterize the seismic noise recorded using time-frequency analysis, beamforming, noise amplitude spatial analysis, and locate the main noise sources which obliterate the microearthquakes from the the fracking operation. Then we obtain the correlograms using two cross-correlation methodologies, Cross-correlation geometrically normalized (CCGN) and the phase cross-correlation (PCC) developed by Schimmel (1999) associated to two different techniques of linear stacking and time-frequency domain phase-weighted stack (tf-PWS) presented by Schimmel and Paulssen (1997). After, we propose a straightforward methodology to improve the correlograms and the phase velocity dispersion analysis, consisting of Linear Movout (LMO) correction, stacking in the shot domain, and finally f-k filtering.

2 Site and noise characterization

In Figure 1 we show a map of where our passive seismic survey was made in the Potiguar Basin, NE Brazil. Very few published studies have systematically investigated seismic noise in this basin (de Vasconcelos Lopes and Nunes 2010; Dantas et al. 2018). The data is from a passive onshore experiment to monitor a hydraulic fracturing in a target at 453 m depth, and part of the data used in this work was processed by (Dantas et al. 2018) to retrieve body waves.

The sedimentary filling of the Potiguar Basin comprises three principal depositional sequences: rift, transitional, and postrift (Bezerra et al. 2019). The first two sequences are the Açú and Jandaíra Formations and they record the first phase of the opening of the South Atlantic, during the Late Cretaceous. The Açú Formation is the oil bearing formation and contains siliciclastic alluvial deposit deposited from the Albian (110 Ma) to the Cenomanian (94 Ma). The Jandaíra Formation documents carbonates that formed in tidal to shallow shelf environments from the Turonian (93 Ma) to the Campanian (80 Ma) (Pessoa Neto et al. 2007).

Figure 2 shows an E-W profile with the directional well trajectory, gamma ray (GR) and bulk density ρ_b logs, well head, array centre and fracking point. The GR and ρ_b logs clearly indicate the contact between the Jandaíra and

Açu Formations at 412 m. The Açu Fm. has some (thin) clay layers that are evident from the GR log. The Barreiras Formation covers the Late Cretaceous units and encompasses a few siliciclastic lithologies accumulated in different marine-associated transitional environments (Rossetti et al. 2013). The Barreiras Formation age is established on its stratigraphic relationships with other Oligo-Miocene sedimentary units present in the western part of the Brazilian equatorial margin (Rossetti 2004). The average thickness of the Barreiras Fm. is 20 m (Braga Júnior 2016). There is paucity of published data on body-wave velocity for these formations from seismic data and/or well logs. Nonetheless, Carvalho and Amorim (1989); Rodrigues (2013); Lopes et al. (2018) report average values for P-wave propagation in the Barreiras, Jandaíra and Açu Formations of 2,000, 4,300 and 2,700 m/s, respectively. This oil field has been in operation since the 1980's and to improve its recovery factor, hydraulic fracturing operations are performed to enhance the permeability artificially. In this experiment, we used 182 vertical velocity sensors with natural frequency of 2 Hz sampling at 5 ms of continuous data for 5 h prior and following hydrofracks treatments in one horizontal wells on August 29, 2012, using the RefTek 125-A (Texan) acquisition system. The acquisition was made according to the parameters shown in Table 1.

Table 1 Acquisition parameters of our passive experiment shown in Figure 1

Line	number of sensors	sensor spacing
1	33	15
2	59	10
3	66	10
4	24	10

2.1 Noise description using spectrogram

Figure 1 illustrates a simplified map of the oil field with the location of the sensors used in this acquisition and the location of the directional well. The area has many sources of artificial noise such as pumpjacks, frack van, and pumps used during the fracturing process (Dantas et al. 2018). Figure 1 also shows that within 2.0 km of the acquisition area, there is a produced fluids distribution centre, industrial plant facility, salt field, pipelines and roads.

Figure 3a shows the recorded data obtained for the 5-h hour period for the easternmost sensor in line 3. Figure 3b shows the spectrogram obtained from the data in Figure 3a using a 1024 samples window with 50% overlap. The mini-frack and fracturing intervals are indicated by vertical dashed lines. The mini-frack and fracturing operations lasted for 12 and 45 minutes, respectively. Acquisition stopped due to memory limitations in the acquisition system, after 30 minutes the fracturing operation initiated. Therefore, we do not have data for the last part of the fracturing and after it. Figure 3c shows the amplitude spectra

for the entire period. The data presents strong narrow peaks in the power spectra with some of them are well correlated with the injection operations. The characteristics of this noise prior and during and pumping operations are analysed.

We inspect the spectrogram of the data to identify the noise, selecting the resonant frequencies or frequency bands to be analyzed. From Figure 3 we are able to visually identify several resonant noise sources which dominate the power spectrum. These noise sources are identified and are presented in Table 2.

Table 2 Main noise sources identified from the spectrogram in Figure 3

Frequency (Hz)	Noise source (group)
16, 19 and 30	01
42, 46, 54, 64	02
66	03
74-78	04
52, 70, 83.3	05

Noise source 01 are characterized by low (≤ 30 Hz) frequency noise and we associated these with noise coming from pumpjacks, rotatory machines, generators, frackvan, additional human-made and natural noise (Dantas et al. 2018). We should expect that microseismicity signals are also present in this frequency band (Eisner et al. 2013) for a surface array. Noise source 02 is characterized by a series of monochromatic sources which we believe are harmonics from the heavy pumping machinery associated with the fracking at 70 and 83 Hz. Noise 03 at 66 Hz is present in the entire 5-h record and is associated with electromagnetic induction from power generators. Noise 04 is noise which are in the 74-78 Hz range, and they appear in some periods of the data only. Noise 05 is quite well correlated with the injection operation (mini-frack and fracking). We observe that the 70 Hz noise is pervasive in the record but is absent during the injection intervals when we observe a resonance of 83.3 Hz. This is because during the injection the machinery runs at a higher rotation. Basically, during the injection, the machinery shifts from a 70 Hz rotation regime (4,200 rpm) to a 83.3 Hz rotation (5,000 rpm). When the injection finishes, the rotation reduces to 70 Hz and later to 52 Hz (corresponding to approximately 3,100 rpm).

2.2 Identification and source location

Noise characterization is important to acquisition design and denoising techniques (Forghani-Arani et al. 2014; Harris et al. 2017). In this section we use two strategies to identify and characterize the noise sources. One is base on the decay of the noise with distance and the second one is based on beamforming. Next, we locate the noise sources so that we know if the noise we identify is associated with the fracture growth or some process of interest to the fracture

characterization, or is noise that obliterates the amplitude of microseismic events used to image the fracturing process occurring at depth.

2.2.1 RMS analysis

In this approach, used for frequencies > 30 Hz, we assume the noise source is from heavy machinery, frack vans, pumps from near the well head. To confirm that the noise is produced in the well head and adjacencies, we calculate the RMS value of the amplitude recorded in each sensor as a function of the offset from the well head to the sensor. If the noise is produced near the well head and on the surface, we would expect it to decay with the inverse of the offset. We evaluate the RMS as the squared root of squared mean for 5 minutes for each frequency (band) of interest. Figure 4a shows the simplified situation map with the RMS evaluation for noise 04 (64-78 Hz band) of Table 2, assuming the source at the wellhead (red star). The radii of the colored circles on the map are proportional to the logarithm of the RMS amplitude in each sensor. From a visual inspection of Figure 4a, the size of the colored circles reduces as the offset from the well head increases. Figure 1b illustrates the RMS vs. offset plot. As a matter of fact, we observe that the RMS decay is consistent with $\text{RMS} \propto 1/(\text{offset})$, shown as a black trend line. We observed that all monochromatic noise sources, except for noise 03, are consistent with their source near the well head and are qualitatively similar to Figure 4b. Because of the position of line 2 related to the well head, we do not observe a consistent decay in RMS for this line, as the maximum offset between the sensors is not greater than 140 m. In lines 2 and 3, we observe that the RMS in some sensors is nearly $10\times$ smaller than at neighbours sensors.

2.2.2 Beamforming Analysis

For frequencies less than 30 Hz, we used beamforming to identify the incoming direction and apparent velocity of the noise during the mini-fracking and fracking operations. We have already identified that noises with frequency greater than 30 Hz are mostly associated with machinery near the wellhead. For frequency less than 30 Hz, the noise spectrum includes fracture growth processes, wind, noise source 01 from Table 2, and additional sources we are able to identify. Beamforming is widely used in studies with seismic arrays to infer the slowness and backazimuth of sources of seismic noise (Bonnetoy-Claudet et al. 2006; Lehujeur et al. 2015). We apply a classical beamforming technique (e.g. Rost and Thomas (2002)) to a array composed of sensors located in lines 1, 2 and 3 to estimate the spatial origin of the seismic noise for frequencies ≤ 30 Hz using 5-minute time windows before and after both the mini-fracking and fracking operations as shown in Figure 5. Table 3 summarizes these results. The efficiency of an array depends on the number of stations, geometry and wavefield characteristics. The number of array elements dictates the signal-to-noise ratio gain attained by the array and the geometry controls the wavenumber resolvability (Rost and Thomas 2002; Wathelet

et al. 2008; Karamzadeh et al. 2019). Theoretically, the longest wavelength (λ) that can analysed by an array is roughly the array aperture: $\lambda_{max} \simeq a$. Also, a wave overpassing the array should be sampled by at least two elements. Hence, the smallest detected wavelegth is $\lambda_{min} = 2d_{min}$, where d_{min} is the minimum interstation distance (Bormann 2002). For our array, λ_{max} , and λ_{min} are, respectively 700 and 20 m.

Table 3 Noise source direction according to frequencies from 2 to 16 Hz before and during mini-frack and fracking operations

Operation	Period	Frequency Hz	Wave type	Direction of source
Minifrack / Frack	Before	2-3	Surface Wave	WNW-ENE
		4-8		NNE-SSE
		9-15		ENE-SSE / ENE-S
		≥ 16	Surface Wave	SE-SSE / SE-S
			Body Wave	All Directions
	During	2	Surface Wave	ENE-S / ENE-SSE
		3		NNE-E / NNE-SSE
		4-8		NNE-SSE
		9-15		ENE-SSE / ENE-S
		12	Surface Wave	ENE / ENE-S
			Body Wave	NE, E
			Surface Wave	ENE-S / SE-S
		≥ 16	Body Wave	all directions

In the 2-15 Hz frequency range, most of the surface-wave noise have slowness ≥ 0.6 s/km, and comes from the North and East quadrants, and is related to discrete surface sources related to the industrial facilities and nearby pumpjacks to the North and East of the array centre. Body-wave energy coming directly from bellow travelling across the Jandaíra and Açú Formations with incident angle $\leq 20^\circ$ relative to the array center (which would include the treatment point) the slowness should be ≤ 0.3 s/km.

Figure 6 illustrates the beamforming analysis at 7 Hz for the minifraccking (Figures 6a and 6b) and fracking (Figures 6c and 6d) operations. In the 2-15 Hz range, the noise distributions is practically the same before and during both operations.

Figure 7 shows that for frequency ≥ 16 Hz, the surface-wave noise is still dominating the records, but now the beamforming analysis reveals strong presence of body waves coming from various directions with slowness typically ≤ 0.3 s/km during both operations.

In Figure 8 we noted a 12 Hz ressonance that is present only during the operations and with slowness values ≤ 0.3 s/km, which would imply this is body wave energy from bellow the array center and from the NNE direction (Figure 8a). The occurrence of this 12 Hz resonance is correlated with the pressure and flow rate as shown in Figure 8b. In Figures 8c and 8d we show the azimuth and slowness for the interval shown in Figure 8b. The red squares

are slowness values ≤ 0.3 s/km and are coincident with fluid injection periods into the Açu Formation.

3 Ambient Noise Seismic Interferometry—ANSI

In the second part of our work, we calculated noise correlation functions (NCF) using line 4 as virtual source for sensors in lines 1,2 and 3. This (virtual) source-to-receiver setup yields offsets between 535 and 1424 m, and assures that the minimum interstation distance to retrieve useful cross-correlations is ≥ 3 wavelength (Kimman et al. 2012; Cheng et al. 2015). Before processing we remove the mean and linear trend of the data. Firstly, we split the 5 h long data into 60 s long segments. The choice of this segment length is reduce the effect of cross-terms of the cross-correlations (Medeiros et al. 2015). Then, we filter the data in the frequency range of 2-40 Hz, and do the one-bit normalization and spectral whitening (Bensen et al. 2007).

We use two approaches to calculate the cross-correlations. The first one is the classical cross-correlation (CCGN), defined by

$$C_{CCGN}(t) = \frac{\sum_{\tau=\tau_0}^{\tau_0+T} u_1(t+\tau)u_2(\tau)}{\sqrt{\sum_{\tau=\tau_0}^{\tau_0+T} u_1(t+\tau)^2 \sum_{\tau=\tau_0}^{\tau_0+T} u_2(t+\tau)^2}} \quad (1)$$

where u_1 and u_2 are the two time series, t and T are the time interval and the correlation window length, respectively. τ_0 is the start time of the correlation window. The time interval t is applied to u_1 . The denominator is the geometric mean of the energy within the time window T .

The second form of cross-correlation is based on Phase-Cross Correlation (PCC), after Schimmel (1999) and is defined by:

$$C_{PCC}(t) = \frac{1}{2T} \sum_{\tau_0+T}^{\tau=\tau_0} \{|e^{i\phi(t+\tau)} + e^{i\psi(\tau)}|^v - |e^{i\phi(t+\tau)} - e^{i\psi(\tau)}|^v\} \quad (2)$$

where C_{pcc} is a coherence function that measures the similarity of two time series u_1 and u_2 as a function of lag time t analogous to CCGN. $\phi(\tau)$ and $\psi(\tau)$ are the instantaneous phases of u_1 and u_2 that make $C_{pcc}(\tau)$ a correlation that does not depend on the amplitude. C_{pcc} is based on the number of coherent phase samples instead of the sum of the amplitude products as is the case for conventional cross correlation.

To stack the correlograms, obtained by the two forms of cross-correlations (CCGN and PCC), we also use two different approaches. The first one is the linear stacking (LS), and the second one is via the time-frequency domain phase-weighted stack (tf-PWS), which is an extension of the phase-weighted stack (PWS) presented by Schimmel and Paulssen (1997).

The time-frequency domain phase-weighted stack is defined by

$$\begin{aligned} S_{pws}(\tau, f) &= S_{1s}(\tau, f) c_{ps}(\tau, f) \\ &= S_{1s}(\tau, f) \left| \sum_{j=1}^N \frac{S_j(\tau, f) e^{i2\pi f \tau}}{|S_j(\tau, f)|} \right|^v, \end{aligned} \quad (3)$$

where $S_j(\tau, f)$ represents the S-transform of the j -th time series and $S_{1s}(\tau, f)$ is the S-transform of the LS of all N time series. Phase coherence is used to weight the inconsistent LS portions in the time-frequency domain (Schimmel et al. 2011).

Figure 9 illustrates the virtual shot gather in line 3 using sensor 1 of line 4 as virtual source for the two different cross-correlations approaches (CCGN and PCC) using two different stacking methodologies (linear and time-frequency domain phase-weighted stack). We see also from Figures 9a-d, that as the noise sources are not isotropically distributed, the causal and acausal correlations are not the same since the majority of the energy is concentrated in the causal part. Thus, we decided to work only with the causal part of the correlograms. In Figure 9 we plot the linear moveout for a velocity of 1,300 m/s and is an indication for surface waves. We note that the use of CCGN and tf-PWS (Figure 9a) provides an easier identification of the retrieved Rayleigh wave. We also observe a surface waves trains with higher amplitude (but with approximately the same velocity) are also present in the causal part of this correlogram, which are not associated with a wave a zero offset in the virtual shot. We also obtained virtual shot gathers for lines 1 and 2 but their offset spread is much smaller and for clarity of the text, we show them as Supplementary Figures 13 and 14. Because PCC is amplitude unbiased, it is able to enhance even these minor surface waves with are not associated with zero offset in the virtual shot but are coherent. In our work for the sake of condensation we decided also to concentrate the display of the results using CCGN and tf-PWS. In any case, processed the data using the other three options (CCGN and linear, PCC and tf-PWS, and PCC and linear stack) and show the results also as Supplementary Figures.

Next, we present in Figure 10 we the linear moveout (LMO) correction we applied using an absolute velocity is 1,300 m/s. In Figure 10a we show the virtual shot gather using CCGN and tf-PWS of sensor 24 in line 4 in the shot domain. This is actually is the maximum offset for line 3. We note that the surface wave arriving at 1.1 s (arrival 2) in channel 1 is actually weaker than another wave train that is arriving at approximately 0.8 s (arrival 1) and is not related to the zero offset. In Figure 10b, we change from shot to channel domain, and channel 01 in Figure 10a is used. In other words, we are taking the first channel in Figure 10a and showing how the different virtual shots are recorded in this channel in line 3. Now, in Figure 10c, we show the data after we apply a static correction in all the channel 01 domain data. After we obtain this correction, we stack the data. We repeat this procedure to all channels in line 3 to retrieve the LMO corrected data illustrated in Figure 10d. It is

evident that the LMO corrected virtual shot gather attenuates arrival 2 and enhances arrival 1.

We further enhance the arrival 1 by f-k filtering the data. Figures 11a and 11b show the virtual shot gather presented in Figure 10d, and the f-k spectrum. In Figures 11c and 11d we show the F-k filtered data and its respective f-k spectrum and attest that arrival 1 is much clearer after f-k filtering. We used the following (f, k) polygon: (25.7, -0.596), (26.3, -0.164), (1.5, 0.179), and (0.9, -0.198).

In Figure 12 we show the dispersion images using the Multichannel analysis of surface waves—MASW (Park et al. 1999; Olafsdottir et al. 2018), and the MATLAB script from Olafsdottir et al. (2017). We observe that the dispersion analysis is facilitated with the use of the LMO correction and f-k filtering. We can easier identify the phase velocities for frequencies until 15 Hz. We also observe that the higher modes are not very affected by our LMO and f-k filtering. For frequencies greater than 15 Hz, the dispersion analysis is hampered by an overlap between the fundamental and the higher modes and attenuation (Ivanov et al. 2008).

4 Discussions

4.1 Noise characterization

Our experiment lasts for 5 h and the instruments have a corner frequency of 2 Hz. Thus, the noise analysis is limited to frequencies which are higher than commonly reported for noise characterization in the literature (Lehuteur et al. 2015). The spectrogram analysis reveals a set of discrete noise sources (Table 2) which can readily be identified as coming from the operation machinery near the well head. For frequencies up to 30 Hz the noise source are mostly associated to pumpjacks, road traffic and industrial facilities in the vicinity of the are (see Figure 1, and noise source 01 in Table 2). For frequencies greater than 30 Hz, the noise sources are locally produced near the well head, are monochromatic, and are either from electromagnetic induction (local power generators for the operation), or operational noise near the well head. These are noise sources 02, 03, 04, and 05 from Table 2. Noise sources 05, for instance, correlated with injections periods when the machinery increases its rotation to produce the fractures into the target formation. These local noise sources dominates the power spectrum (Figure 3b and 3c) and will our mask out the microseismic activity generated by the reservoir stimulation. Additionally, there are harmonics associated with this noise which further complicate the signal. So, a filter to be used to remove the effect from this local has to be designed to deal with such challenge. We believe that adaptive filtering alone or in combination with other methods like adaptive beamforming, or using a maximum likelihood approach is suitable to deal with such situation (Harris et al. 1991; Kushnir et al. 2014; Harris et al. 2017). The RMS analysis confirms the local and strongly correlated nature of noise for frequencies greater than 30

Hz. Figure 4b illustrates the RMS decay vs. offset assuming the noise source is on the well head and is composed of surface waves. We verify that the observed decay agrees quite well with the theoretical $1/(\text{offset})$ curve for surface waves, and we attribute the deviations from the theoretical prediction to attenuation, sensor gain, coupling to the ground, or very local noise variability.

The beamforming analysis was made for the lower bound of our spectrum (i.e. ≤ 16 Hz), before and during the fracking and mini-fracking operations. For all the frequency bands we investigated, before and during the injection operations, the surface wave noise characteristics are similar, and come from the WNW and East quadrant with slownesses between 0.7 and 0.8 s/km relative to the array center.

Before fracking and mini-fracking, in the 2-3 Hz band, we identify noise associate with pumpjacks in WNW and NNE directions from the array center (see Figure 1). The WNW source is no longer present for frequencies ≥ 4 Hz. The noise source in NNE direction remains present in the beamforming for frequencies until 8 Hz. This noise distribution influences the retrieval of the surface waves in the correlogram. Actually, it is evident from Figure 9 that the acausal part of the correlogram is practically absent. Body-wave is preferentially present for frequencies ≥ 16 Hz and they come from all directions. These body waves are precisely those used to retrieve reflections in the area (Dantas et al. 2018) and they contaminate the dispersion curve as seen in Figure 12.

During the injection operations we observe a stronger influence of noise sources coming from the ENE direction relative to the array centre for frequencies between 6 and 10 Hz. We interpret these as being from the wellhead and related to the greater activity from the machinery to inject the fluid. In this frequency band the noise comes the East quadrant and could be from the pumpjacks. In the 2-5 Hz band, the noise distribution is very similar before injection. We also observe body-waves for frequencies greater than 16 Hz coming from all directions. However, we observe the emergence of a resonance at 12 Hz consistent with body wave coming from the fracking point at depth, with slowness ≤ 0.3 s/km as shown in Figure 8a. This resonance is well correlated with the pressure and flow rate, as depicted in in Figures 8b and 8c where the slowness values ≤ 0.3 s/km are represented as red circles. The distance between the array center to the projection of the fracking point at surface is 100 m, and the treatment occurs at 453 m depth. Therefore, if the resonance is associated with the treatment, we would expect these body waves to have incident angles of $\approx 87^\circ$, i.e., close to a vertical incidence. If we consider that the average P-wave velocity from the injection point until surface is between 4,000 and 4,500 km/s, the estimated slownesse would vary between 0.22 and 0.25 s/km, which is consistent with those found in Figures 8b and 8c. Most of the body wave energy in Figures 8 have incoming directions in the NE and E directions and we interpret this result as associated with the fracture growth. The literature (Tary et al. 2014a,b; Liang et al. 2017; Sicking and Vermilye 2019) reports that fluid filled fractures in the subsurface maintains waves that reverberate in the fractures and resonate for long time periods. The presumably source for this mechanism of resonating signals in fractures is attributed

to the Kraukalis waves (Tary et al. 2014a,b) in which the frequency of the resonance increases with fracture width and decreases with fracture length:

$$l = \left\{ \frac{h\mu\pi}{4\rho_f f^2} \left[1 - \left(\frac{v_s}{v_p} \right)^2 \right] \right\}^{\frac{1}{3}} \quad (4)$$

where f is the resonance frequency, ρ_f is the fluid density, V_S and V_P are the S and P wave velocities, $\mu = V_s^2 \rho_m$ is the shear modulus of the surrounding solid, ρ_m in the surrounding rock density, and h is the crack thickness. In our experiment, $f = 12$ Hz, V_S and V_P are 2,427 and 4,200 m/s, $\rho_m = 2,500$ kg/m³, and $\rho_f = 1,050$ kg/m³, yields $l = 8$ m for a crack thickness of 0.01 m. Crack radii equivalent to the magnitude range normally observed during fracking treatments are commonly between -4 and -1, are a few centimeters to a couple of meters (Brune 1970), which are smaller than the results from Equation 4. Therefore, a network of only a few interconnected fractures is required to explain the observations, as postulated by Tary et al. (2014a).

4.2 Ambient Noise Interferometry

The literature has a profusion of noise interferometry studies, but no general agreement on the best processing flow has come up (Fichtner and Tsai 2018). This is indicative the the ‘best’ processing is flow is rather subjective and very particular to a data set and on what one chooses as the ‘signal’ to be modeled. In our case, we used two different cross-correlations approaches (CCGN and PCC) using two different stacking methodologies (linear and time-frequency domain phase-weighted stack). Although we decided to take CCGN and tf-pws as the ‘best’ option to provide with clear surface wave arrivals (Figure 9a), other different cross-correlation and processing schemes may be considered. PCC (Figures 9c and d) is amplitude unbiased and therefore enhances minor although coherent arrivals. For the retrieval of body-waves, the same combination was found to present the ‘best’ results (Dantas et al. 2018).

As demonstrated in our case, most of the energy comes from the East quadrant and this has a strong effect in the retrieved correlations in Figure 9 where most of the energy is in the causal part.

According to Halliday and Curtis (2008) when only orthogonal source geometries are accessible spurious events are brought into the correlograms and it is due to the cross-correlation of different higher mode surface waves. In our work, we use the correlation-type seismic interferometry to obtain the empirical Green’s Function. It has been reported in the literature that this type of seismic interferometry leads to time- and offset- susceptible amplitude errors and intense spurious arrivals (Halliday and Curtis 2009). These spurious arrivals are precisely related to the non-cancellation of contributions from stationary points that would cancel if there were no energy losses. In Figure 16, we a virtual shot gather of sensor 24 of line 4 for different cross-correlations and stacking schemes to obtain the correlograms. Figures 16a, c, e, and f illustrated

unprocessed data. Figures 16b, d, f, and h are the results after processing in which we applied LMO correction and f-k filter. In this virtual source-receiver deployment, the receiver are orthogonal to the virtual sources. As a matter of fact we still are able to notice a quite symmetrical split-spread point close to sensor 33 of line 2. However, we observe the emergence of spurious events earlier than 0.8 s and we interpret these as being due to the source geometry bringing in higher mode surface waves cross-correlation, and scattered surface waves. The LMO correction and the f-k filter attenuates some of these spurious events, but they still remain after processing.

The virtual shot gathers using the sensors from lines 1,2 and 3 are severely affected by the monochromatic and reverberating noise from the wellhead and all the results present in Dantas et al. (2018) are achieved by removing from the analysis the periods in which the mini-fracking and fracking operations are occurring. In the present work, since we are using virtual sources in line 4 (see Figure 1), the wellhead noise has no contribution to the retrieval of the correlograms.

4.3 Dispersion Analysis

The results from Figure 9 show that we are able to retrieve a surface wave phase velocities. The dispersion analysis show that this surface wave train is dispersive and its phase velocity reaches 1,570 m/s at 2 Hz and 1,250 m/s for frequencies around 14 Hz. These results are quite consistent with the Barreiras Fm. in the shallowest depths of the site (10's of meters) and with the Jandaíra Fm.. The fundamental mode Rayleigh wave dispersion is insufficiently sensitive to material variation properties greater than 1/3 to 1/2 of the maximum wavelength retrieved (Foti et al. 2014) which in our case is 632 m. So, our maximum investigation depth is between 210 and 316 m, and we are unable to detect the Jandaíra and Açu Formation contacts which occurs at 412 m depth as shown by the well logs in Figure 2.

5 Conclusions

A 5-h experiment provided data to analyse the high (≥ 2 Hz) frequency characteristics of the noise recorded by a surface array designed to monitor hydraulic fracturing in a mature field in the Potiguar Basin, NE Brazil. Spectrogram computations, beamforming and noise amplitude vs. offset analysis are used to infer noise characteristics before and during treatments. Up to 30 Hz the noise source are mostly associated to pumpjacks, road traffic and industrial facilities within 2 km from the array center. For frequencies greater than 30 Hz, the noise sources are locally produced near the well head, are monochromatic, and are either from electromagnetic induction or caused operational noise near the well head. If the data recorded is to be used to locate microseismic events, we anticipate that due to these noise conditions adaptive filtering would perform well to remove this surface noise. We report a 12 Hz resonance composed

of body waves which are correlated with the injection. We interpret this resonance as from fluid filled fractures in the subsurface that support waves that reverberate in a interconnected network of a few fractures and resonate.

As most of the energy comes from the East quadrant, the retrieved empirical Green's Functions have most of the energy is in the causal part. Additionally, because of this noise source distribution and the geometry of the array, we observe some spurious arrivals in the correlograms. We improve the emergence of the surface waves by performing a LMO corrections, stacking and f-k filtering. The dispersion analysis exhibit phase velocities which are consistent with data published in the literature.

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Conflict of interest

The authors declare that they have no conflict of interest.

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Fig. 1. Situation map of the passive survey area in the Potiguar Basin, Brazil.

Fig. 2. E-W projection of the experiment. The gray and red stars indicate the array center, and well head, and injection point (at 453 m depth) projection on the E-W profile on the surface, respectively. The black start indicates the injection point. We also show the gamma-ray (GR) and bulk density (ρ_b) logs. The horizontal line at 412 m depth is interpreted as the contact between the Jandaíra (upper) and the Açu (lower) Formations.

Fig. 3. (a) velocity-proportional sensor record after mean and trend removals. (b) Spectrogram computed using a 1024 samples window with 50% overlap with data from the easternmost seismometer line 3 of Figure 1. The black vertical dashed lines indicate the intervals of the mini-frack and fracking. (c) Amplitude spectrum of the entire record shown in (a).

Fig. 4. (a) Simplified version of Figure 1 highlighting the RMS variation in all the lines of the survey. The size of the colored circles are proportional to the logarithm of the RMS amplitude calculated over 5 minutes for the 64-78 Hz band (noise 04 of Table 2. (b) RMS vs. offset graph assuming that the noise source is positioned in the well head. The color code for the lines is the same as in (a). The black line represents the relation $\text{RMS} \propto 1/(\text{offset})$.

Fig. 5. (a) Pressure and flow rate records for the mini-fracking. (b) Pressure and flow rate records for the fracking. The shaded rectangles represent the 5-minute interval used for beamforming.

Fig. 6. Beamforming analysis, for 7 Hz. a) and b): before and during minifracking, respectively. c) and d) before and during fracking, respectively. The intervals used for the beamforming are shown in Figure 5.

Fig. 7 . Beamforming analysis, for 16 Hz. a) and b): before and during minifracking, respectively. c) and d) before and during fracking, respectively. The intervals used for the beamforming are shown in Figure 5.

Fig. 8. Beamforming analysis, for 12 Hz. a) and b): before and during fracking, respectively. c) and d) before and during fracking, respectively. The intervals used for the beamforming are shown in Figure 5. The red circles indicate slowness values ≤ 0.3 s/km and are associated with body wave energy.

Fig. 9. The cross-correlograms were computed and stacked using a) CCGN and tf-PWS, b) CCGN and linear, c) PCC and tf-PWS and d) PCC and linear stack. The red lines corresponds to a linear moveouts for a velocity of 1,300 m/s.

Fig. 10. Linear moveout (LMO) correction. (a) Virtual gather in the shot domain for line 3 with CCGN and tf-pws using sensor 24 of line 4 as virtual source. (b) Same as (a) in the channel domain. (c) Time shifted data according to a phase velocity of 1,300 m/s. After we obtain this correction, we stack the data. (d) Final result in the shot domain after using all the shots in line 4.

Fig. 11. F-k correction. (a) Same as Figure 10d. (b) Data in the F-k domain of (a). (c) Data after F-k filtering. (d) Data in the F-k domain after filtering.

Fig. 12. Dispersion analysis. (a): Virtual gather in the shot domain for line 3 with CCGN and tf-pws using sensor 24 of line 4 as virtual source. (b) Dispersion analysis of (a). (c): Same as (a) with LMO and stack. (d) Dispersion analysis of (c). (e) Same as (a) with LMO, stack and f-k filtering. (f) Dispersion analysis of (e).

Supplementary Figures

Fig. 13. Virtual shot gather for line 1 using sensor 1 of line 4 as virtual source. a)CCGN tf-pws b)CCGN tl c)PCC tf-pws d)PCC tl.

Fig. 14. Virtual shot gather for line 2 using sensor 1 of line 4 as virtual source. a)CCGN tf-pws b)CCGN tl c)PCC tf-pws d)PCC tl.

Fig. 15. Virtual shot gather for line 1 using sensor 1 of line 4 as virtual source with CCGN and tf-pws. b) Data from a) after LMO, stacking, and f-k filtering. c) Same as a) with CCGN and tl. d) Data from c) after LMO, stacking, and f-k filtering. e) Same as a) with PCC tf-pws. f) Data from e) after LMO, stacking, and f-k filtering. g) Same as a) with PCC and tl. h) Data from g) after LMO, stacking, and f-k filtering.

Fig. 16. Virtual shot gather for line 2 using sensor 1 of line 4 as virtual source with CCGN and tf-pws. b) Data from a) after LMO, stacking, and f-k filtering. c) Same as a) with CCGN and tl. d) Data from c) after LMO, stacking, and f-k filtering. e) Same as a) with PCC tf-pws. f) Data from e) after LMO, stacking, and f-k filtering. g) Same as a) with PCC and tl. h) Data from g) after LMO, stacking, and f-k filtering.

Fig. 17. Virtual shot gather for line 3 using sensor 1 of line 4 as virtual source with CCGN and tf-pws. b) Data from a) after LMO, stacking, and f-k filtering. c) Same as a) with CCGN and tl. d) Data from c) after LMO, stacking, and f-k filtering. e) Same as a) with PCC tf-pws. f) Data from e) after LMO, stacking, and f-k filtering. g) Same as a) with PCC and tl. h) Data from g) after LMO, stacking, and f-k filtering.

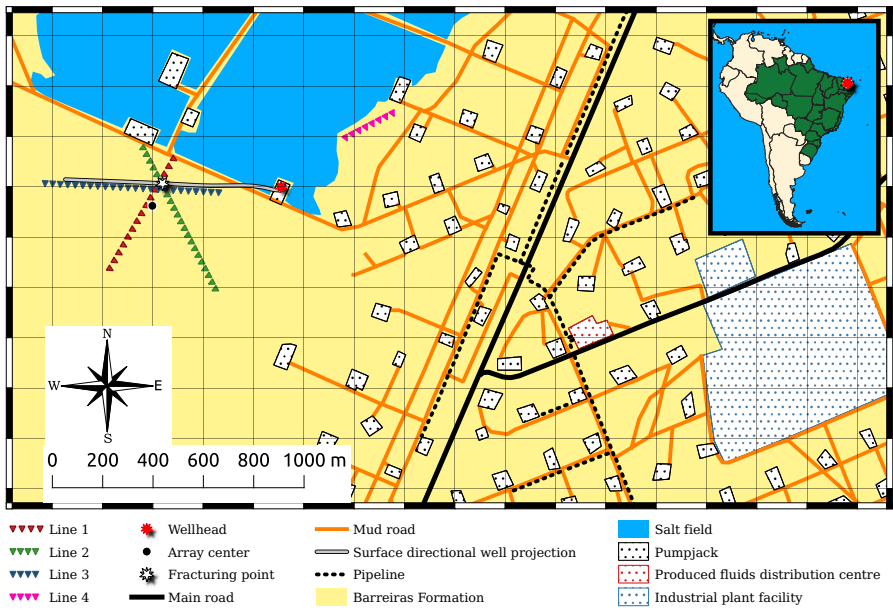


Fig. 1

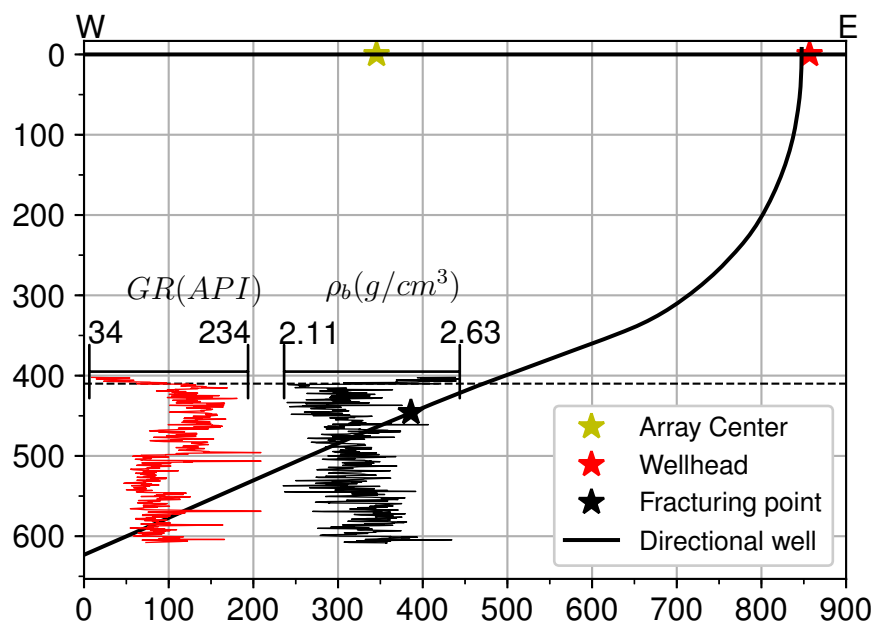


Fig. 2

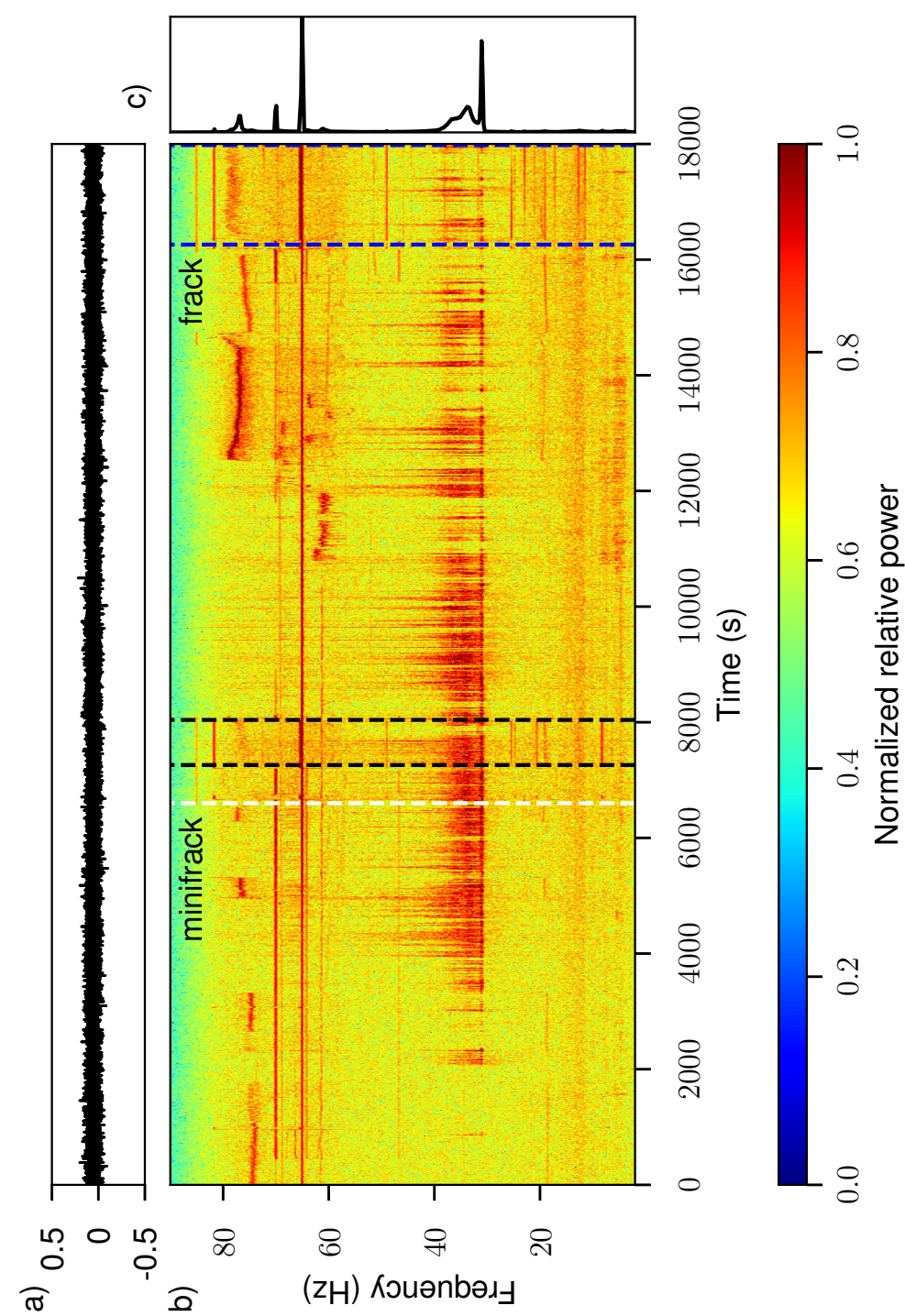


Fig. 3

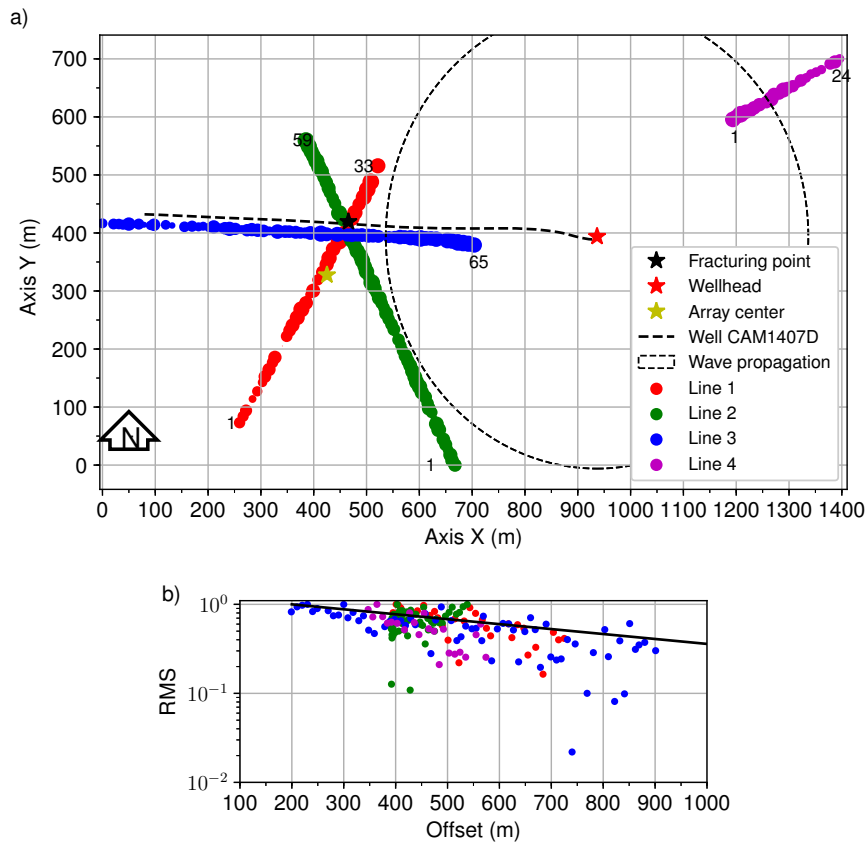


Fig. 4

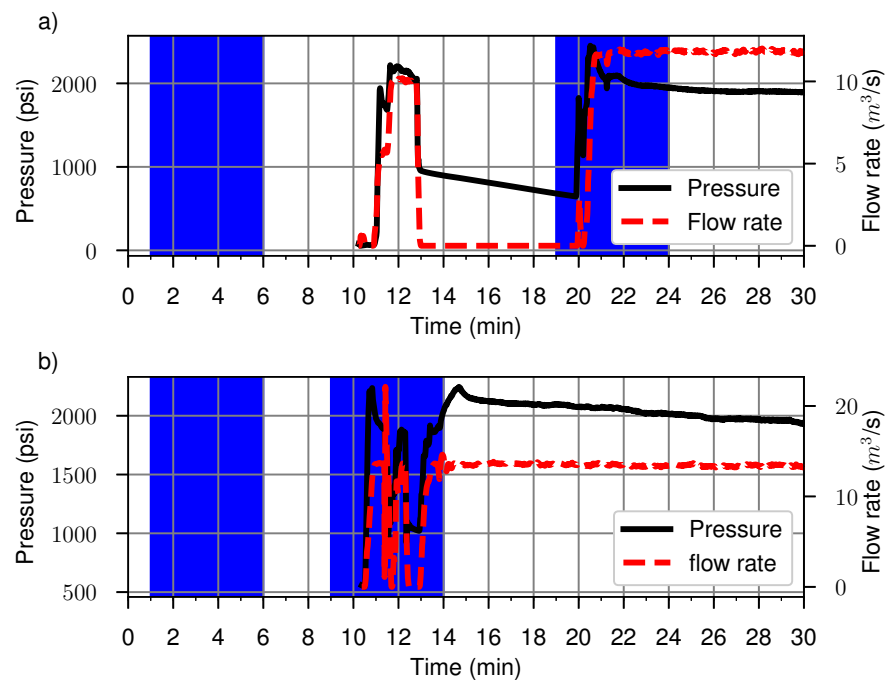
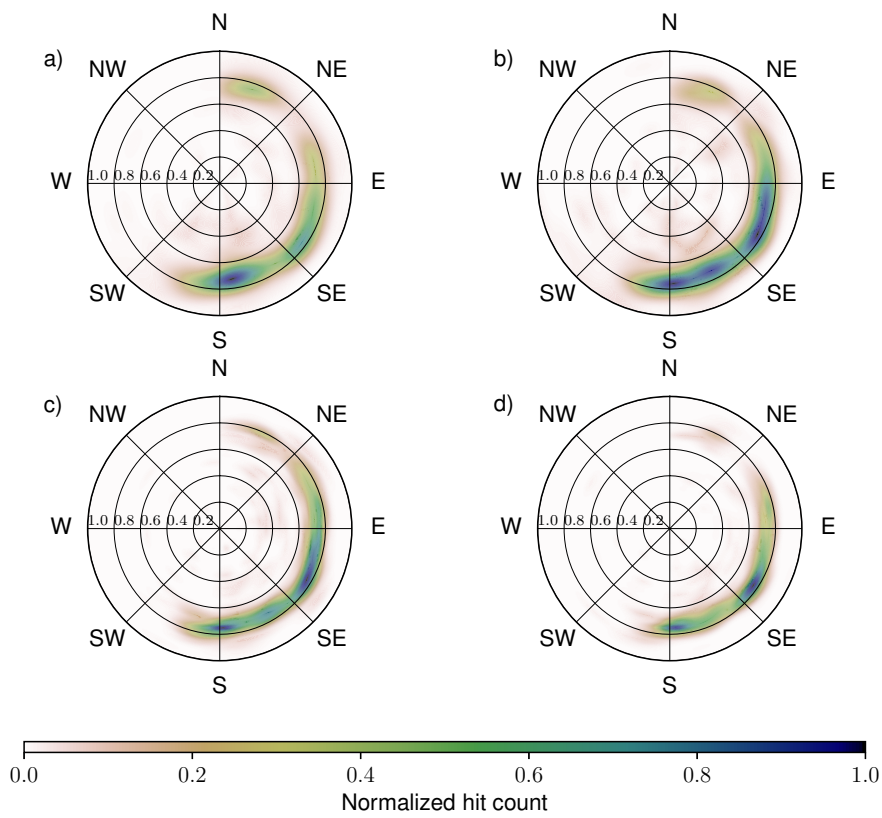
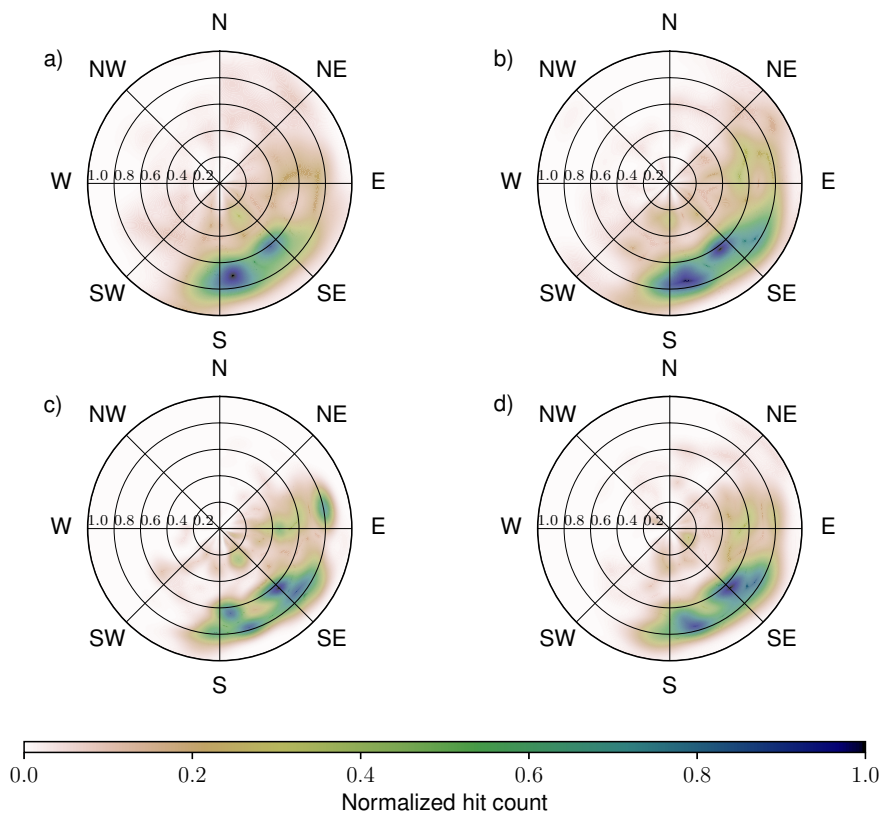


Fig. 5

**Fig. 6**

**Fig. 7**

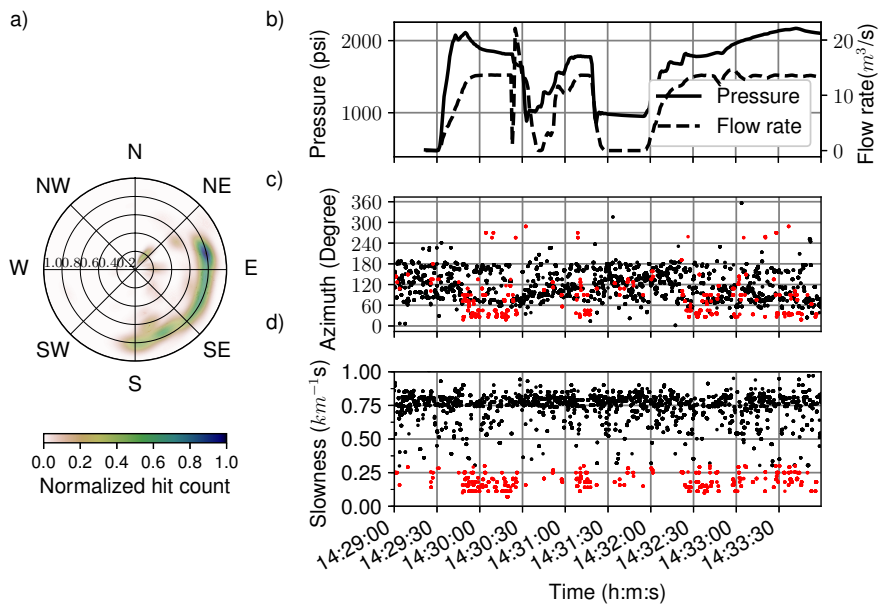
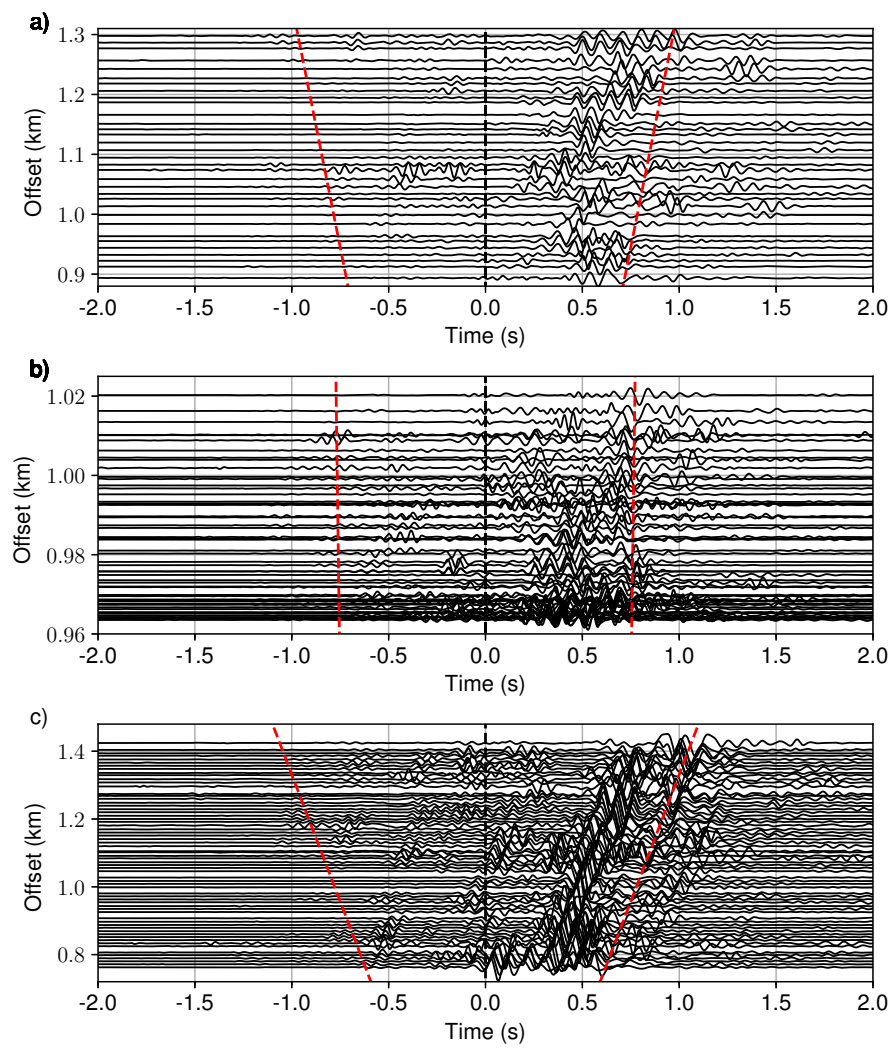


Fig. 8

**Fig. 9**

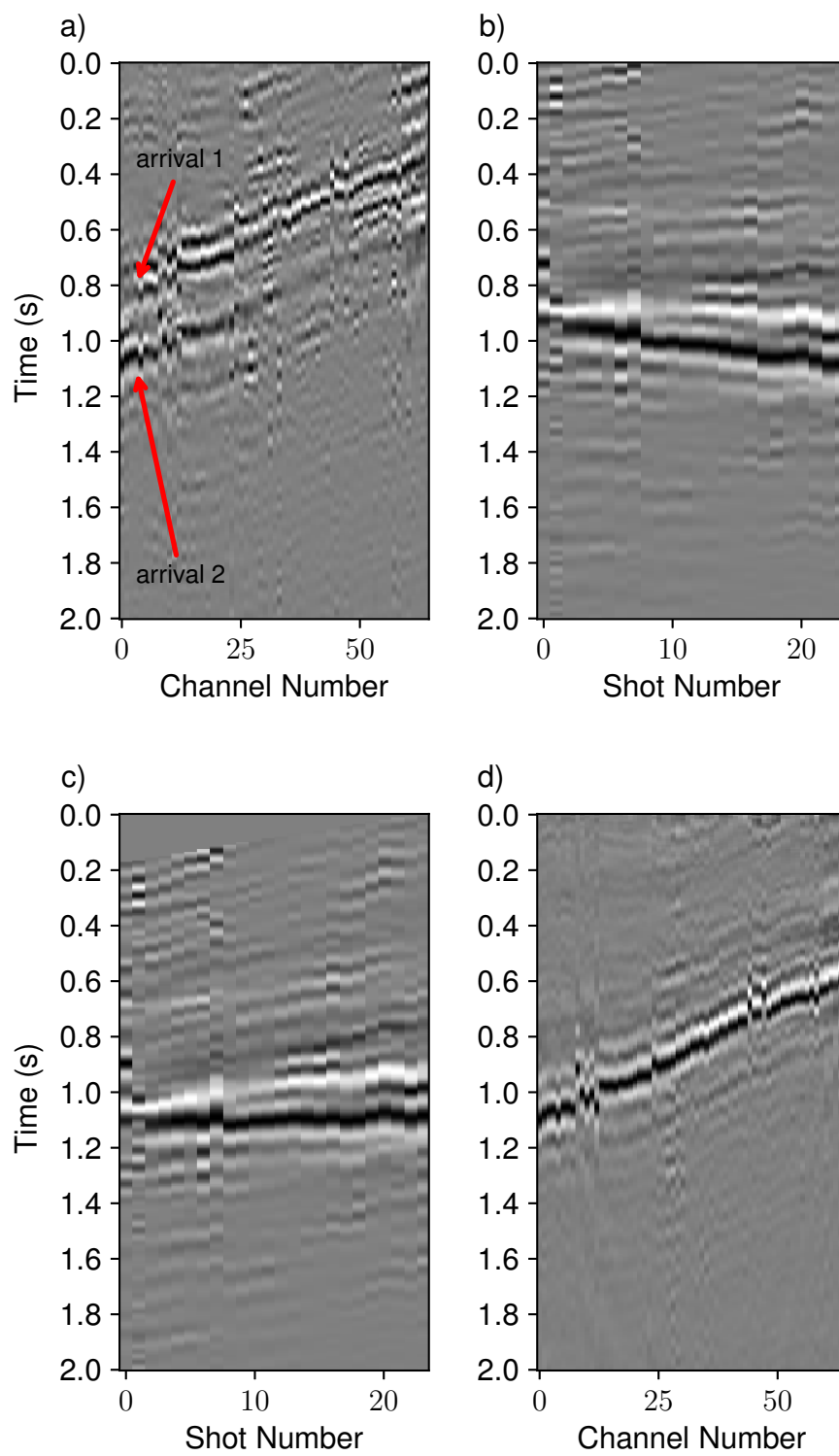


Fig. 10

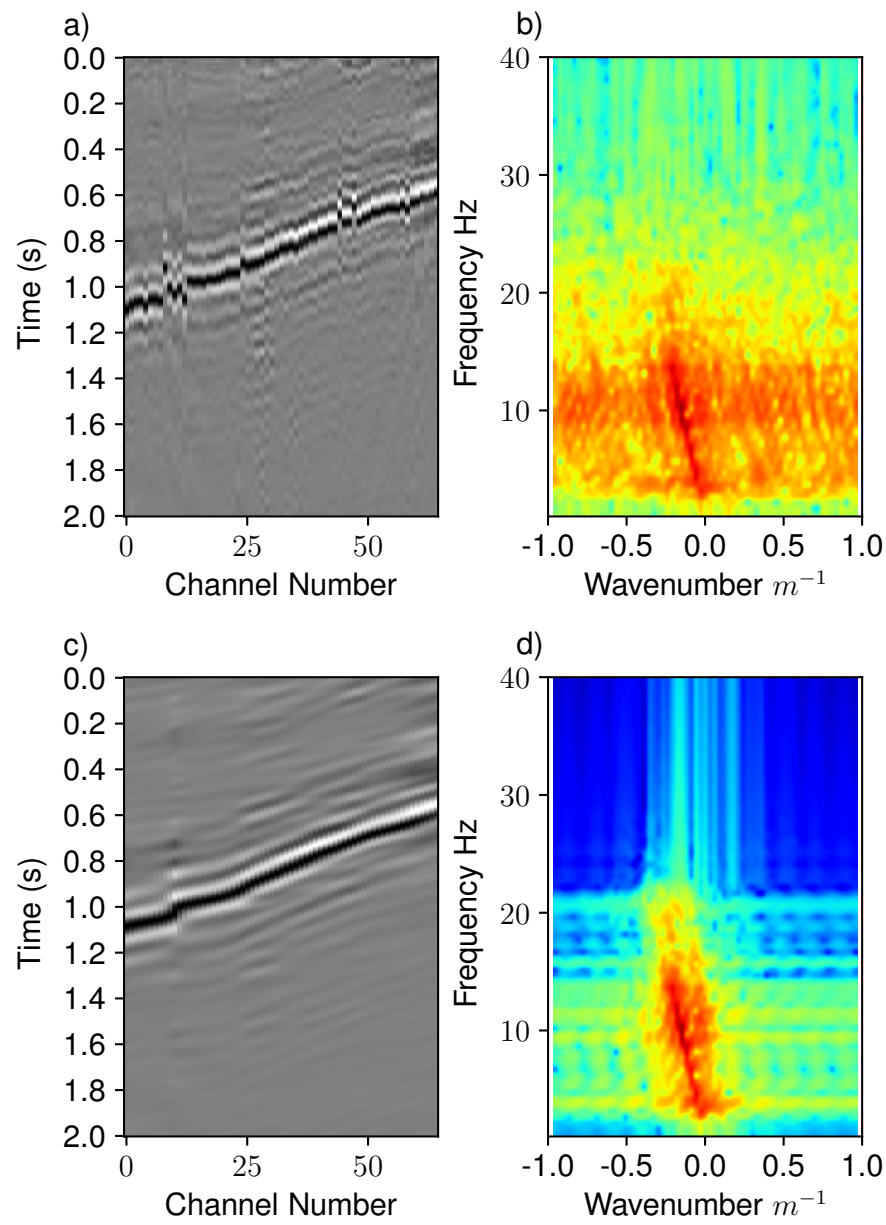


Fig. 11

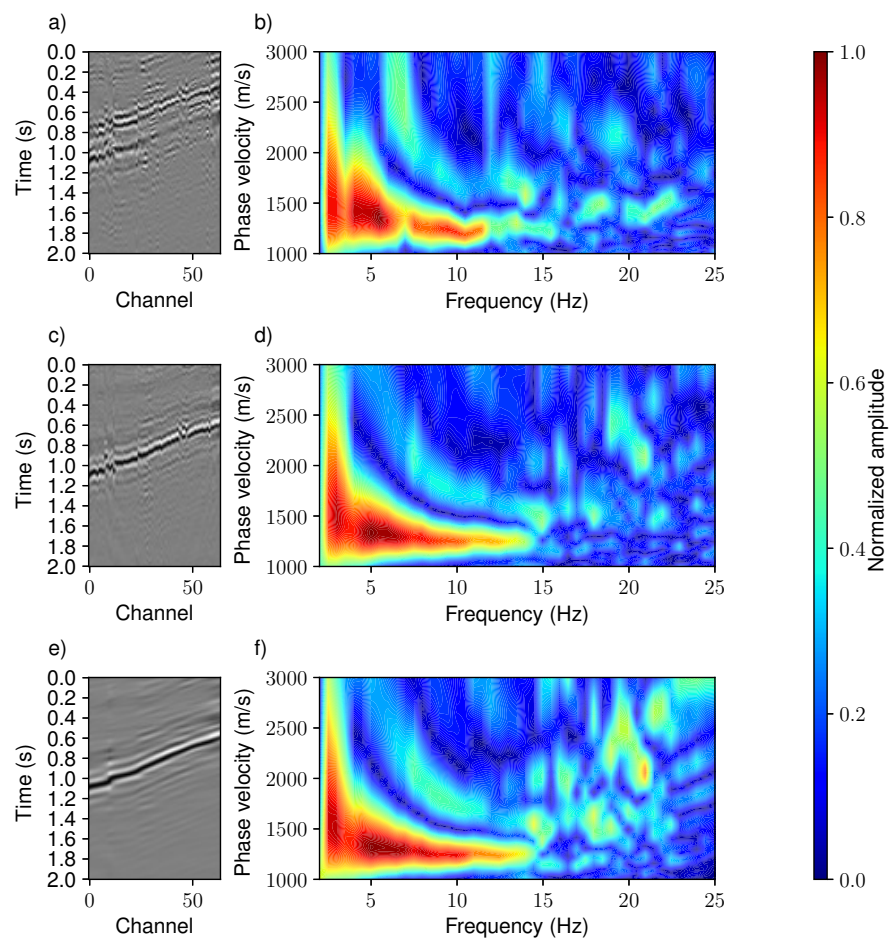
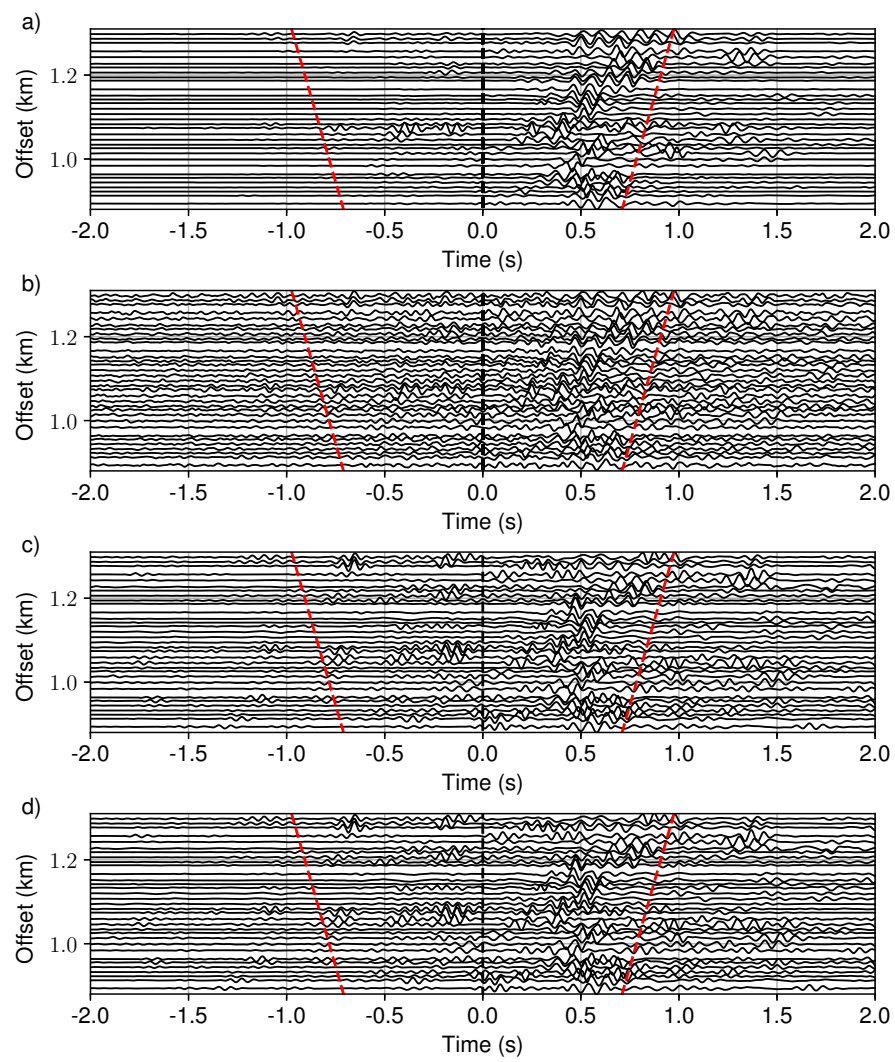
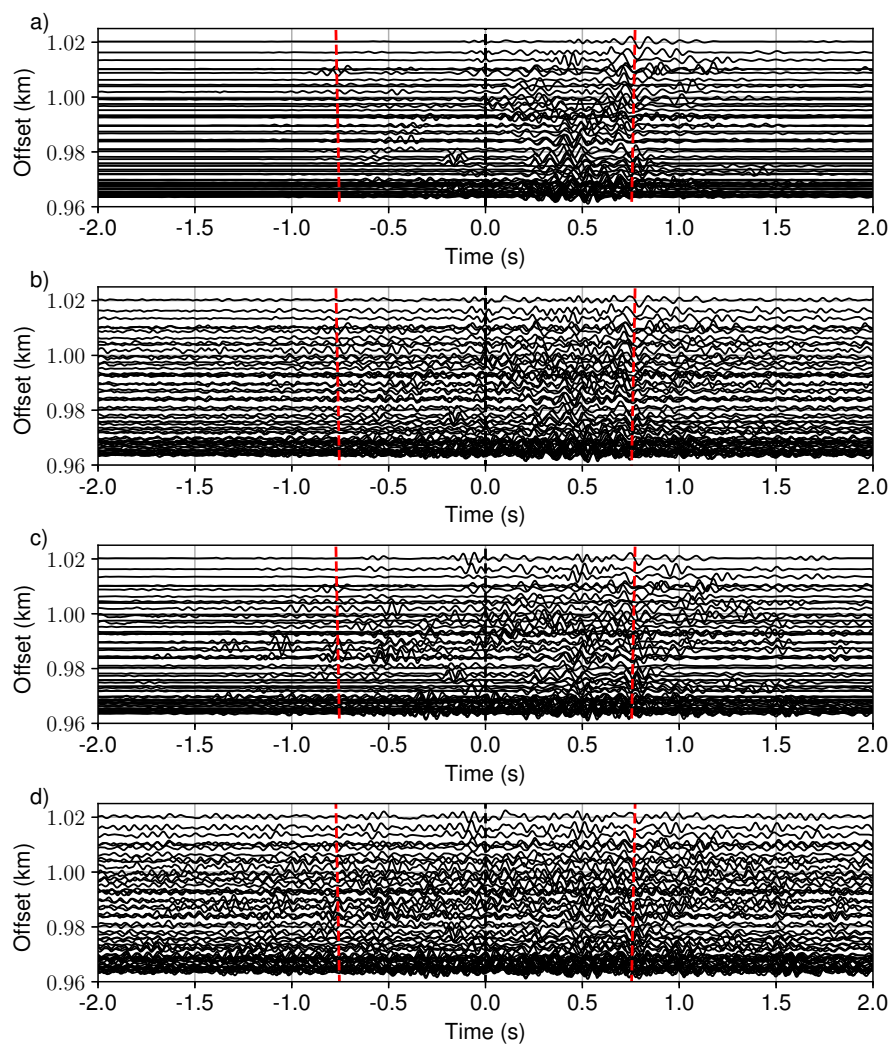


Fig. 12

**Fig. 13**

**Fig. 14**

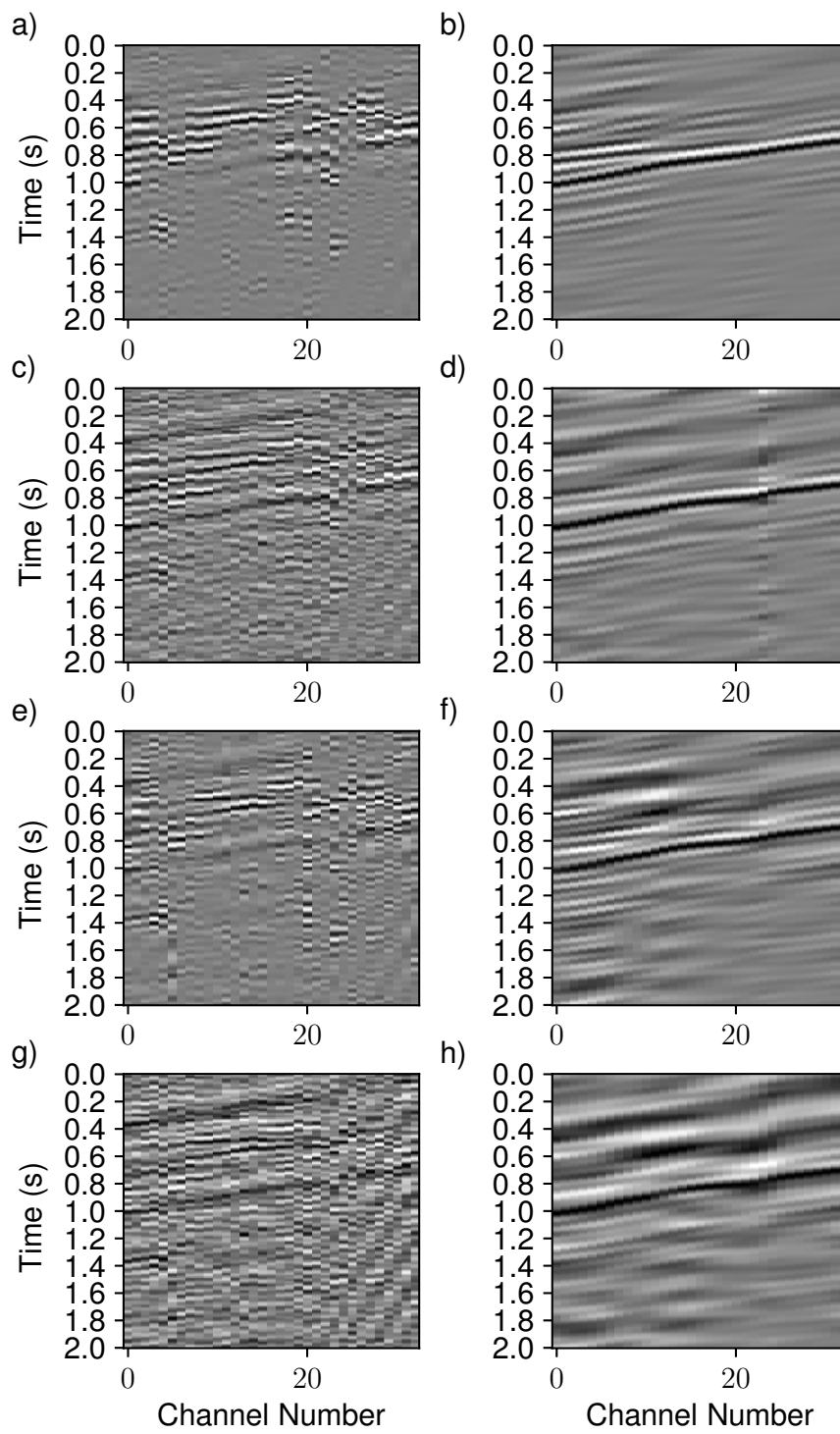


Fig. 15

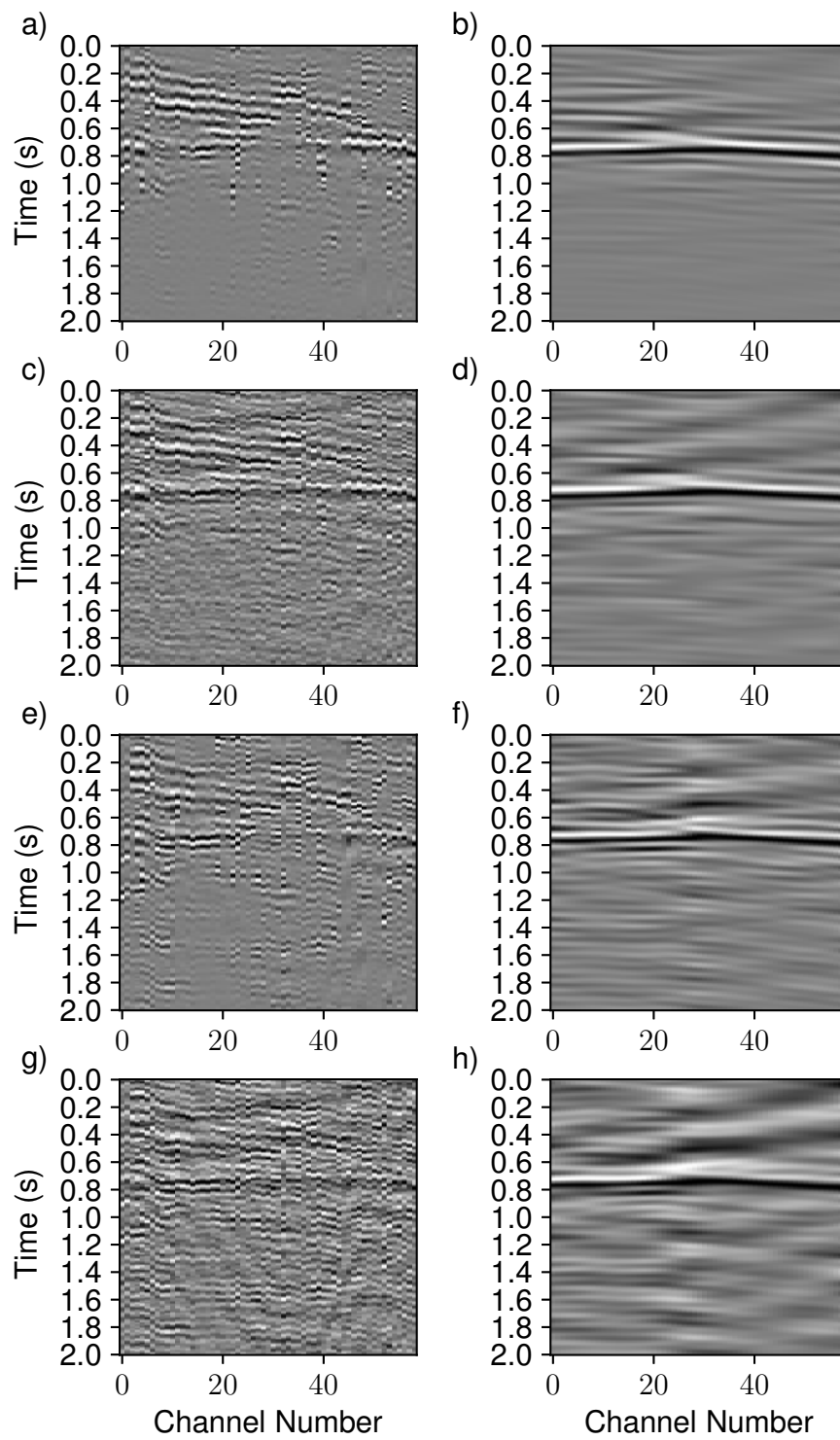


Fig. 16

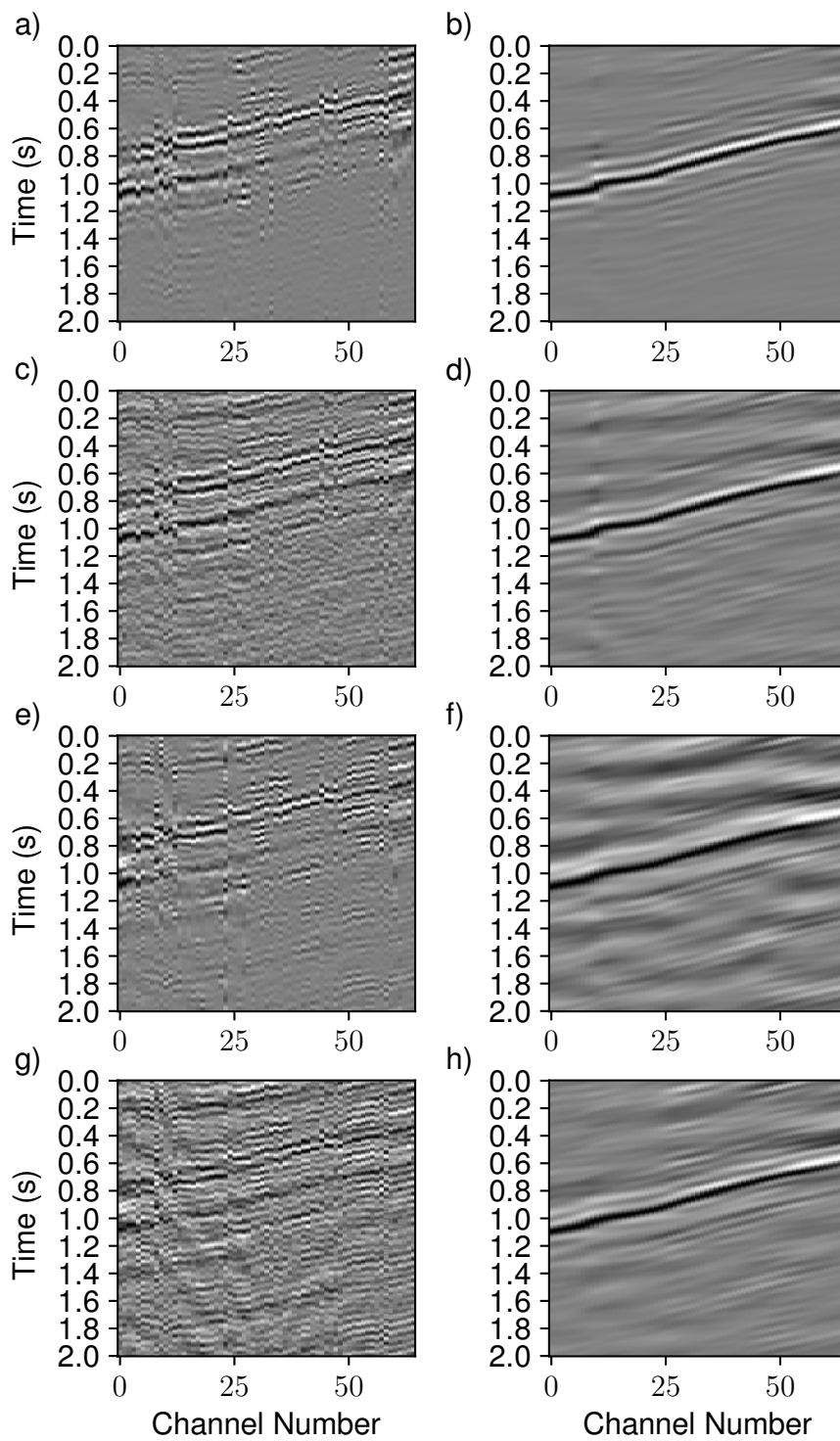


Fig. 17

Capítulo 4

Considerações Finais

A partir da análise de 5 horas de dados no domínio tempo-frequência, cálculos do decaimento do RMS em função do *offset* e *beamforming fk*, caracterizamos os principais ruídos do dado.

Os ruídos de 2-30 Hz estão associados a fontes com mais de 2 km de distancia do centro do arranjo sísmico (bombas, tráfego rodoviário e instalações industriais). Para os ruídos com frequências maiores que 30 Hz, as fontes são produzidas localmente, são ruídos monocromáticos e densidades espectrais fortes que são oriundos de indução eletromagnética ou de procedimentos operacionais ocorridos na cabeça do poço.

Constatamos a forte influência causada pelos ruídos de ondas de superfície presente no dado (*geq* 2 Hz) que obliteram os sinais de ondas de corpo que são originados pelo fraturamento hidráulico. Caso, os dados forem usados para localização de eventos microssísmicos, sugerimos a utilização da filtragem adaptativa para remover esse ruído de superfície.

Observamos uma ressonância de 12 Hz composta por ondas de corpo que correlacionadas ao momento de injeção do fluido. Nós interpretamos que essa ressonância é consequência da abertura de diversas fraturas que surgem e são preenchidas com fluido reverberando em uma frequência predominante.

Em relação a recuperação das funções empíricas de Green, os resultados emergiram apenas na parte causal, isto é devido a maior parte de fontes estar presente no quadrante leste do arranjo de aquisição. Devido a esse tipo de distribuição de fontes e geometria do arranjo, verificamos a presença de eventos espúrios nos correlogramas.

Melhoramos os correlogramas por meio da correção estática (LMO) juntamente com o empilhamento e a filtragem f-k. Com isso, a análise de dispersão exibe velocidades de fase que são consistentes com os dados publicados na literatura.

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