Reservoir Characterization and Integrated Analysis of Attributes for Interpretation of 3D Seismic Data of F3 Block, Netherlands

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By

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CANDIDATE'S DECLARATION

I hereby declare that the work which has been presented in this dissertation entitled, "**Reservoir Characterization and Integrated Analysis of Attributes for Interpretation of 3D Seismic Data of F3 block, Netherlands.**" in partial fulfilment of the requirements for the award of the degree of **INTEGRATED MASTER OF TECHNOLOGY** in **GEOPHYSICAL TECHNOLOGY,** submitted in the Department of Earth Sciences, Indian Institute of Technology, Roorkee, is an authentic record of my own work carried out under the guidance of **Prof. Sagarika Mukhopadhyay,** Department of Earth Sciences, IIT Roorkee during the period of 2018-19.

The matter embodied in this dissertation has not been submitted by me for the award of any other degree or diploma of this institute or any other university/institute.

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CERTIFICATE

This is to certify that the work presented in this thesis entitled "**Reservoir Characterization and Integrated Analysis of Attributes for Interpretation of 3D Seismic Data of F3 block, Netherlands**" submitted by Mr. Ashish Mittal to Indian Institute of Technology, Roorkee, India, in partial fulfilment of the requirements for the award of the degree of **INTEGRATED MASTER OF TECHNOLOGY in GEOPHYSICAL TECHNOLOGY** is a record of bona fide original work carried out by him under our supervision during the academic year 2018-2019.

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ABSTRACT

Reservoir characterization is a broad process which means that the reservoir is studied in terms of the fluids in the reservoir and thus reservoir modelling and reservoir simulation are both under reservoir characterization. The search for hydrocarbon comes under the category of reservoir characterization as it includes both modelling and simulation. In this thesis I have studied the reservoir modelling part. Reservoir modelling is generating a model of a reservoir using the available geophysical and geological information about the area and thus studying the model is seismic interpretation.

In the field of reservoir characterization seismic attributes are used by interpreters to better characterize a reservoir. The main objective in exploration of hydrocarbon is to correctly image the structure in time and depth and to characterize the amplitudes of the reflections. Using these amplitudes, the additional features which are derived are called attributes. Thus, a quantity which is derived from the traditional seismic data and which contain information about the better geological and geophysical interpretation of the original seismic section. The project characterizes the area F3 Block located in offshore of Netherlands and by using texture attributes along with other physical attributes and geometrical attributes on a given three-dimensional Post Stack Time Migrated seismic data (PSTM) the area is studied for potential hydrocarbon bearing zones.

F3 Block is a block in offshore of Netherlands and is in the Dutch area of the North Sea. The block consists of acquired 3D seismic data which was used in the exploration and production of oil and gas in the area. The top 1200ms of the study area consist of reflections from different geological times such as Miocene and Pliocene. The area shows a geological feature such as sigmoidal bedding, downlap, onlap, and toplap with some truncative structures. The area also consists of bright spots which are studied in this dissertation thesis.

The 3D Seismic data was conditioned to remove the noise and enhance the signal to noise ratio with the use of dip steered median filter. The removal of noise is important as it extracts the information about fault and fractures in the area and the faults are more visible after conditioning of the data.

The attributes used to study the zone of interest are geometrical and physical attributes. The Geometrical attributes are the attributes which help the interpreter to study the geometrical

characteristics of the area for example the faults, the dip and the similarity between the traces. The physical attributes are attributes which help the interpreter to study the physical properties using the amplitude of the seismic reflections and extracting details for the interpretation of seismic data such as energy and coherency attributes. Texture based attributes were also used such as Energy, Entropy, Contrast, Homogeneity and Dissimilarity attributes were calculated on the marked horizons and the results were studied using joint analysis of all the attributes.

The data consist of four Well logs in the entire 3D seismic region. However, the wells F02_1 and F03_2 only had density logs and the other two wells were not having those logs so a neural network was used to determine densities at other two wells F03_4 and F06_1. However, this is already done originally and I used the pretrained logs for interpretation. The logs also were used to calculate the porosity ⌀=2.65-rho/ (2.65-1.05) at all the wells, however my work does not require this to be done and I used the pre converted logs from the TerraNubis open data website for both the Seismic and the Well log data. The Well logging data gave the behaviour of different density and velocity logs in the area and acoustic impedance log was calculated from them that was helpful in inversion studies.

Seismic inversion was done at the last to convert our volume to acoustic impedance volume. Model based deterministic inversion was used. The trend in the data were generated with the help of the low frequency information of the data and also a relative impedance result was added to the low frequency which created a model with both the low and high frequency. This is called deterministic inversion which was used in the thesis. The inversion is an important step which can define the rock property in the last to avoid any type of confusion regarding the lithology of the area.

The integrated attribute and inversion study resulted in delineating a bright spot in one of the horizons. The bright spot is due to the sand deposits in the area with the presence of hydrocarbon. Also, the possibilities of presence of coal and the presence of carbonates in the area was removed using the study.

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Seismic Reflections is an interface property and this happens when the wave reflects from an interface where the acoustic property of the rock changes, for example the density and the velocity of the next layer is different from the initial layer. The acoustic impedance of the layer is the product of density and velocity and thus this change in the impedance leads to the reflectivity of the layer which gives the reflection and transmission coefficients. In general trend the lithology of the area is related with the acoustic impedance of the layers and thus they follow each other.

The Hydrocarbon (HC) reservoir is typically a sand encased in the shale units and this leads to the change in the impedance at the boundaries which generate a reflection both at the boundaries of the sand unit (Fig. 1.1) and thus these reflections are a major source for study of the reservoir. This is possible as shale and sands have different impedance values because of different velocity and densities. The sands as having a larger grain and the pore space is more the velocity in sand is less than shale and so is the density, so the impedance in sand is less than shale typically (Fig. 1.1) but this can change if the sands are of older age and due to compaction the impedance may change (Fig. 1.1). The reflection in the sand top and bottom will be different as the contrast depends on from where the reflection is going and thus will be in opposite sense. The impedance contrast polarity is not important as it can be according to the SEG standard or any opposite standard the main thing to consider is the reverse polarity of the reflections. The geological and the seismic data can be compared with each other if the information about the velocity of the region is known.

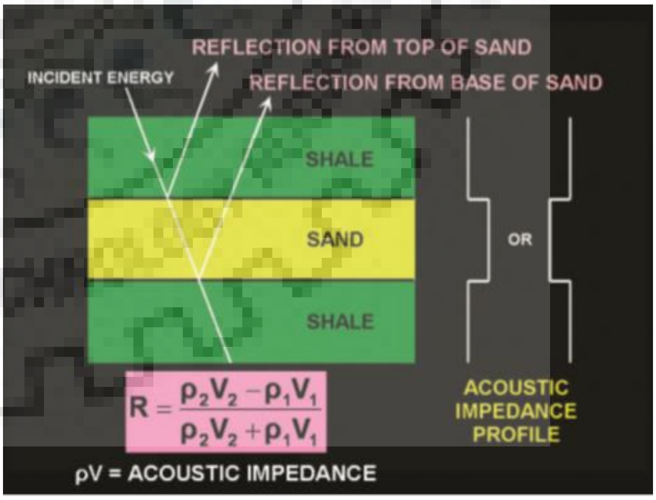


Figure 1.1: Reflection Characteristics due to Sand and Shale (Ref: Brown, 2012)

The resolution of the Seismic data is of great importance as both vertical and horizontal resolution will dictate the amount of information shown in the seismic data. The resolution is affected by mainly the method of collection and processing however the resolving power is determined by the wavelength. The vertical resolution is determined by the one-fourth of wavelength as below that mark the waves interfere destructively and the resolution decreases. The increase in the seismic velocity with depth is observed because of the presence of the compaction in the older rocks and this changes the seismic velocity. The frequencies decrease with depth as earth is a high cut low pass filter this means that earth allows the low frequencies to pass and block the high frequencies. Thus, as the frequency decreases the wavelength increases with the depth. The thickness of bed at that wavelength is equal to the tuning thickness which is equal to bed thickness. The limit of separability is defined which is equal to that wavelength (one-fourth of wavelength), as the wavelength is decreased, the top and the bottom reflections are visible but their amplitude will decrease to great extent and this is reduced till the limit of visibility of the two events occur and signal is converted to a noise (Brown, 2012). The Horizontal Resolution is determined by the Fresnel zone sampling which can be thought of as a ball which if placed on the surface will take some space at the bottom and thus anything which is within that surface cannot be resolved.

Reservoir characterization is a field in which a model of a reservoir is made using all the available information about the area through geological, geophysical and petrophysical information of the area. The result of reservoir characterization is the creation of the shared-earth model which is useful to study the subsurface. Petrophysical measurements is an important step in characterizing a reservoir as the logs are a necessary tool for velocity model generation and inversion studies. Seismic interpretation and attribute analysis play a leading role in understanding the characteristics of the formation which does not lie on the well bore and needed to be studied and interpreted to define the geology of the structures.

Most of the basic techniques like direct detection of hydrocarbons and the presence of flat spots and bright spots no longer are directly seen in the seismic section and thus it is generally not possible to extract the complete information from the seismic section using basic interpretation, if however these are seen in the seismic data the credibility of the features are at risk and thus seismic attribute analysis is a great method to study these features effectively (Brown, 2012).

1.1 History of Seismic Methods

As the Earth is 3D but the seismic surveys were first done in 2D which imposed a lot of limitation on the quality of the interpretation which could be made. However, the old 2D methods were starting to fade when the computation power increased drastically and 3D data recording and processing began. The first 3D survey was done by a company called Esso in 1960 which published the work in 1972. That time the migration was not very good in processing the data so the quality was still not very good. Large-scale survey was done by

Geophysical Services incorporated which conducted the survey with the help of many other oil companies in the state of Mexico around 1973-74. The technology was quickly circulated around the world and 3D seismic survey became the new trend in the industry. 3D survey was very expensive in the starting but with time it became affordable to the industry and it became the main type of surveying. The under sampled version of the 3D survey was also used to promote the survey but that was not found to be very useful and nowadays full 3D surveys are conducted on land and in the marine environment. In 1992 and after that the main source of petroleum areas are all covered with 3D surveys and the different improvements in technology is applied to the previous fields to recover hydrocarbons as the efficiency of the seismic methods improved. If the technology keeps on improving, use of neural networks and artificial intelligence can replace the use of exploration wells in the future and drilling shall only be useful for the development and production wells.

1.2 Seismic Attribute

Any information which is derived from the traditional seismic data which enhances the amount of information from the traditional seismic data and is useful in extracting more information from the seismic data that cannot be directly seen in a normal seismic image is called seismic attribute. This leads to a better interpretation of the data. Attributes are divided into physical and geometrical and can be applied to both pre stack and post stack time migrated data. Geometrical attributes are directly related to the geometry of the reflectors and the physical attributes defines the physical properties such as lithology (Brown et.al, 1999)

The study in this project is based on the attribute analysis out of which the principle attribute is Texture attribute. In Texture attributes the cubic Texel is chosen which can be called a pixel, from the seismic data and this is used to compute the second order derivatives which measure the characteristics of the lithology. The seismic signature generally depends on the geological environment in which it is deposited which can be studied with stratigraphic patterns, however the patterns are not standard and can change as per the signal to noise ratio, thus this was not very useful. So, a new method called GLCM (Gray Level Co-Occurrence Matrix) was used which is a method for analysing the texture with the help of gray level co-occurrence matrix (Chopra et.al, 2006). The GLCM can be used to compute the different properties of the seismic data such as Energy, Entropy and other like contrast, homogeneity.

1.3 GLCM

A computed GLCM has a square matrix of n dimension. The dynamic range of the data can be studied with the help of these gray levels and thus can be studied. There are 14 different measures of textural features which can be derived from GLCMs, each of which represent image properties like coarseness, contrast, textural complexity however 4 were identified as the major features:

- **Energy:** It is a measure of uniformity in an image that is if the elements are same, they will have low energy and vice versa, thus it is useful for highlighting geometry and continuity of the data.
- **Entropy:** It is opposite of energy and is a measure of Disorderness in the image, High for non-uniform images.
- **Contrast:** It measures contrasting pixels, high for contrasting pixels and denotes discriminating formation.
- **Homogeneity:** It measures Similarity of different pixels in the image and is used for quantifying seismic continuity.

According to Chopra (2006), the continuous reflections having high amplitudes have a Low value of texture energy and entropy with high contrast which are generally shale deposits. The discontinuous reflections with low amplitude are associative of high values of energy and homogeneity with the low value of contrast. The reflections which have less frequencies and high amplitude which are generally indicative of the HC deposits have high energy and the other contrast and the entropy are low when compared with non-hydrocarbon deposits. Thus, properties of the GLCM based texture attributes are used to identify different type of lithologies and distinguish between hydrocarbon and non-hydrocarbon bearing formation.

The Seismic inversion which was performed creates an impedance model which converts our assumed reflection amplitude interpretation to the rock property which can be interpreted for different lithology and fluid content of the rock. This proves that the inverted dataset is an ideal study for the interpretation of the seismic data without any ambiguity. The integrated analysis of all the attributes and the acoustic impedance studies after inverting the section gives a better guess of the geology of the area and help to delineate the reservoir in an efficient manner.

1.4 Location of the Study Area

The study area is the Dutch Offshore F3 block, in the Dutch sector of the North Sea (Fig. 1.2). It is located on the top of the Dutch central Graben as one of the main constituents of the

Kimmerian Rift Basins at Dutch Northern offshore and as a part of the structural element of the Mesozoic Southern North Sea Rift system (de Jager, 2007). It covers a total area of approximately 386.929 km^2. The study area lies on latitude N45^{0}52’ and longitude E4^{0}48’ in the Northern North Sea.

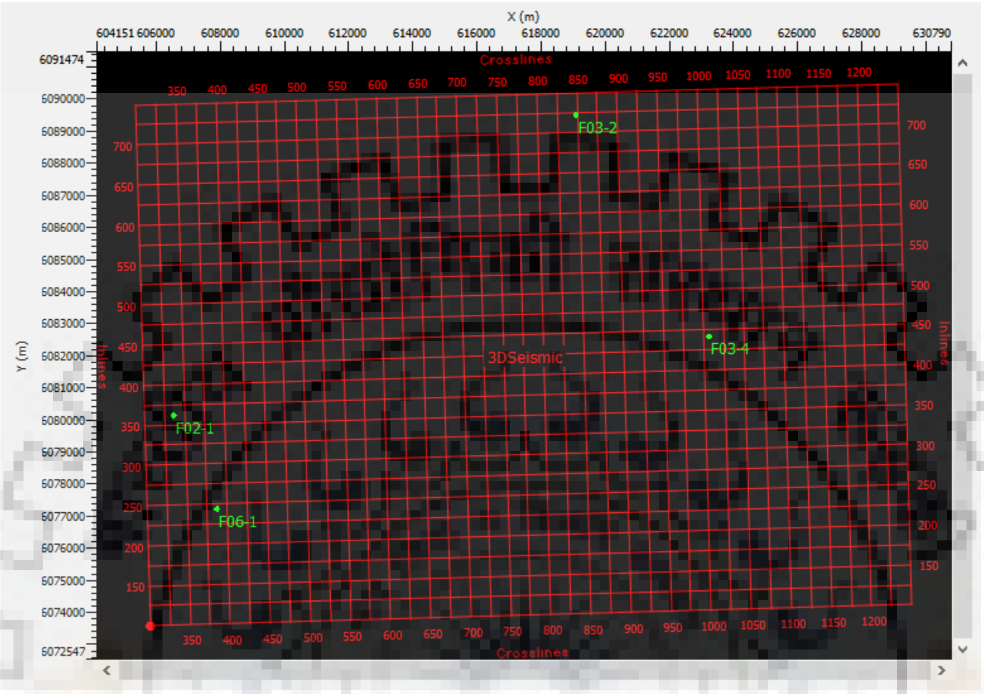


Figure 1.2: Basemap showing the 3D Seismic and 4 Wells in the area.

1.5 Data

The 3D seismic data which was taken from the TerraNubis Website is OpendTect data provided by the SEG OpendTect repository and which is also a dataset available for use in OpendTect. The data is of F3 block which is an offshore block in the Netherlands in the North Sea. It consists of an area of twenty-four by sixteen (24X16) km^2.It consist of around 650 inlines and 950 crosslines. The spacing between the inlines and the crosslines are 25m which is the bin size of the data. The sampling rate of the data is 4ms. The seismic data volume was loaded into OpendTect software for interpretation. The dataset also consists of four wells (F02_1 which will be called well 1, F03_2 which will be called well 2 and F03-4 which will be called well3 and F06_1 will be called well 4). Wells F02-1 and F03-4 were drilled in 1976 at X: 606554, Y: 6080126 and X: 623256, Y: 6082586 (UTM31), respectively. Well F06-1 was drilled in 1981 at X: 607903, Y: 6077213, Well F03_2 is at X: 619101 and Y: 6089491). The logs available for study are GR and Caliper which are lithology logs, the density, sonic and the porosity are three porosity logs, the resistivity log is missing in the data so cannot be used. The complete data is open source. The 3D Seismic survey of F3 block was done by NAM, a Dutch Oil and Gas company in 1989.

1.6 SOFTWARE USED

<u>OpendTect</u>

OpendTect is an open source seismic interpretation software (Fig. 1.3) which is made and maintained by the company called dGB Earth Sciences. Its free version includes all the basic interpretation tools for processing the initial seismic and some attributes for interpretation however for complete study the pro version is available which adds a commercial layer to the software and allows it to complete a lot of functionalities which are useful for the professions in the field. Also, for the inversion of the seismic data in OpendTect it needs a licence file for the pro mode. In this study OpendTect pro was used as a lot of processes done here could not be completed with free version. We used 6.0 and 6.2 for the interpretation.

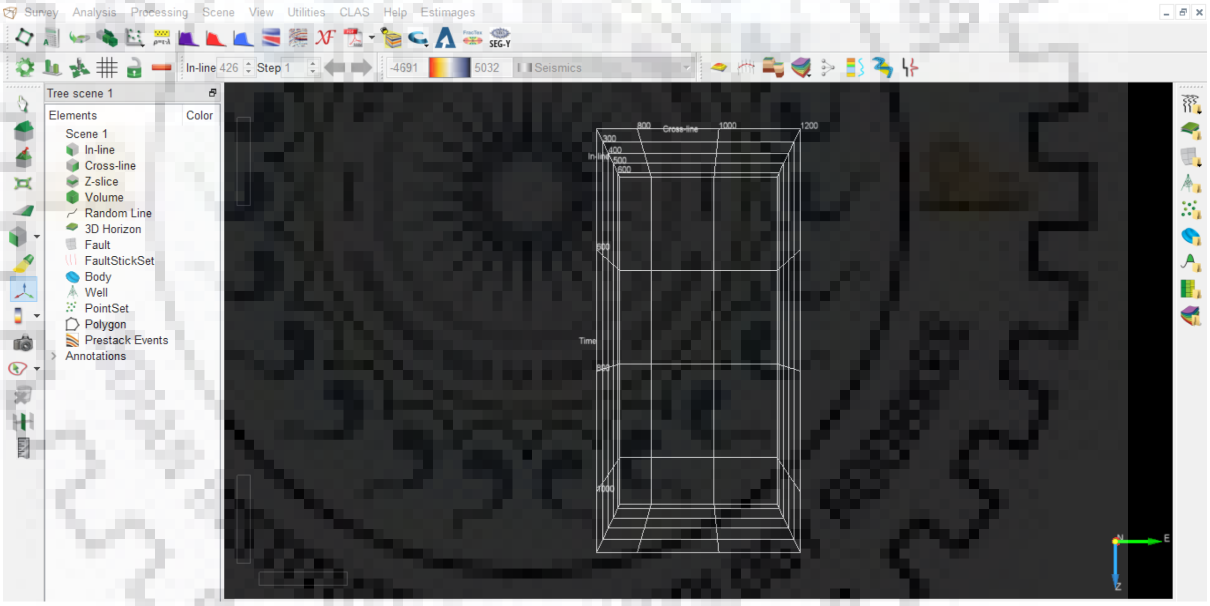


Figure 1.3: A Typical OpendTect window

<u>Hampson Russell Suite</u>

The HRS (Hampson Russell suite) is the most advanced and easy tool for computation of seismic reservoir characterization from 3D seismic data and also is the best tool for beginners as it is very easy to operate and can also be used by non-professionals in the field. The inversion and the seismic well tie were done in HRS in the project as it provides a better analysis of those processes. The version used is 10.4 in this project.

2.1 Geological Setting

F3 Block is situated on the top of the Dutch Central Graben in North Sea shelf (Fig. 2.1). The North Sea geology is divided in 3 rift episodes (Gautier, 2005). which are: The pre, syn and the post rift episodes. The episodes which occur before the rifting are called as pre-rift, when the rifting is happening are called as syn-rift and the processes after the rifting has stopped are called as post rifting processes. The processes after the K-T boundary are post rift processes.

The basin of the South North Sea is dominated by post rifting in the cretaceous period as the rifting stopped in the cretaceous time (Ziegler, 1990) with various tectonics activities associated with it and the formation of the Atlantic Ocean. The basins accumulated very deep layers of sediments in the post rifting phase which is the main cause of sediments in the area. The extension due to aulacogen formation resulted in the main structural features which were the main areas of trapping of oil and gas.

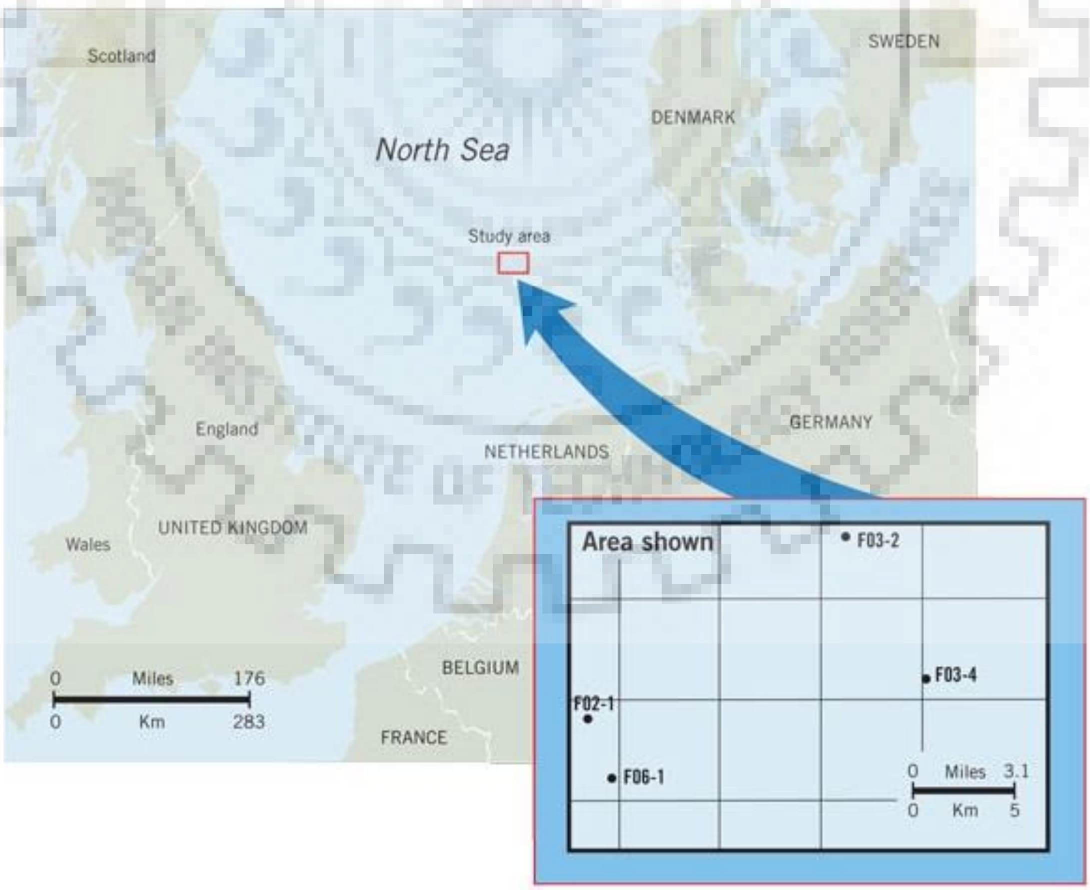


Figure 2.1: Study Area in the North Sea (Ref: Qayyum et al., 2013)

The geothermal gradients near the extensional tectonic environment reduced to a large extent and a gradual cooling was observed near the axis of the aulacogen which is a failed rift that means that rifting started but the two sides did not drift apart and a failed rift is formed. The sediments which were accumulated near the axis of the aulacogen were also then subsided and thus a pattern occurred near the area.

F3 block has a great horizontal and vertical variability. According to Michalowicz (2016), three generational faults system is notable in the F3 block. The first are known to be reversing, oblique-slip, sinistral faults with orientation SSW-NNE. The second are normal, oblique-slip, dextral faults with orientation W-E, and the third are faults disturbed by Permian Halokinesis which are genetically linked with faults from first and second generation. The Permian diapirs were probably formed from pre-existing faults, which together with the movement of salt were transformed and expanded. Furthermore, the petroleum system of the study area is built by different proven hydrocarbon plays, including Paleogene, Neogene and Quaternary play (de Jager and Geluk, 2007).

The rock present in abundant quantity in the sedimentary basin which serves as a purpose of source rock for petroleum generation are the Westphalian coalbeds which generally are the source rocks for gas and some Posidonia flakes are present which are source rocks for oil. The mid-Miocene unity is the presence of the tectonic activity which was recently observed in the basin and it is at a depth of around thousand to fifteen-hundred meters.

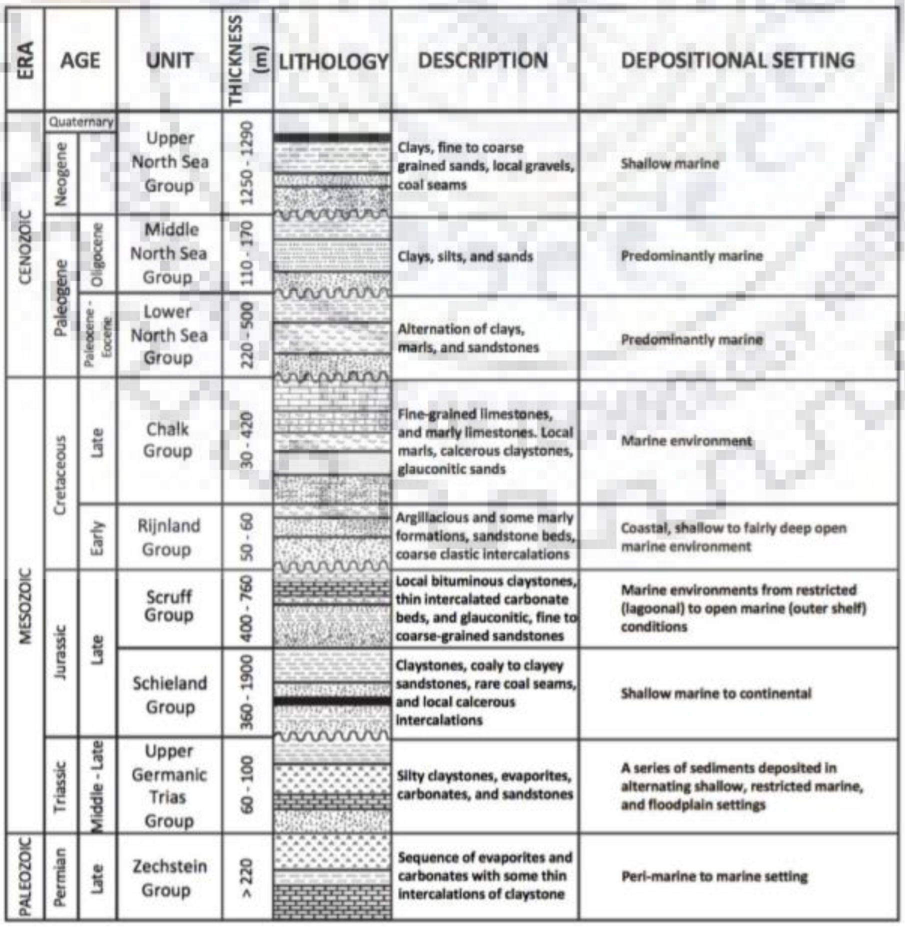
The features which are generally available in geology are mostly present in this area such as the stratigraphic features such as down, top and on laps. The region also includes truncations in the area and some sigmoidal bedding. These types of structures are formed in sequence stratigraphy when there is transgression or regression that is the sea level fluctuates that is the sea moves towards land or land moves towards the sea.

In the south of the North Sea where our study area is the main source of the clastic matter is the presence of the material from the Europe side and very less or rare part from the United Kingdom side. The coast of the North Sea is present in the north part of the Netherlands and this kept on changing in the geological past due to changes in the coastal transgression. The area consist of channel type of deposits and the presence of uninterrupted deposits are very less. The part of the Dutch sector which was affected due to transgression is the north and it was found that the sand sheets were visible in the area. The sand and clay together form the sediments in the marine environment deposit.

2.2 Stratigraphy

It is divided in 3 eras which are Palaeozoic Era, Mesozoic Era and Cenozoic Era. The main group of the North Sea came together in the Tertiary period and around Quaternary period. It can be split into the Lower, Middle and the Upper North Sea (Fig. 2.2).

The lower group consists of alternations of clays, marls and sandstones which are the main lithologies found in the North Sea. These were formed due to the sedimentation cycles in the marine environment. The top boundary of it consist of the middle group and the bottom boundary is a drastic change in the lithology which is chalk. The marine setting is responsible for the presence of such limestones in the areas. The middle group consist of some clay, silt and sands which are mostly due to marine environment and the sand is the main part in that time zone having deposited in the southern area. The upper group is a thin sequence of clay, fine to course grained sand and local gravels with some coal seams. It is shallow marine in environment so the presence of coal is justified. The course to fine trend is towards the north and the west. The boundary above the upper North Sea is mostly the sea surface and the fluvial and lacustrine is dominant. The top part of this succession may also contain glaciers due to the temperature changes in the sea and the environment.



ERA	AGE		UNIT	THICKNESS (m)	LITHOLOGY	DESCRIPTION	DEPOSITIONAL SETTING
CENOZOIC	Quaternary / Neogene		Upper North Sea Group	1250 - 1290		Clays, fine to coarse grained sands, local gravels, coal seams	Shallow marine
CENOZOIC	Paleogene	Oligocene	Middle North Sea Group	110 - 170		Clays, silts, and sands	Predominantly marine
CENOZOIC	Paleogene	Paleocene - Eocene	Lower North Sea Group	220 - 500		Alternation of clays, marls, and sandstones	Predominantly marine
MESOZOIC	Cretaceous	Late	Chalk Group	30 - 420		Fine-grained limestones, and marly limestones. Local marls, calcerous claystones, glauconitic sands	Marine environment
MESOZOIC	Cretaceous	Early	Rijnland Group	50 - 60		Argillacious and some marly formations, sandstone beds, coarse clastic intercalations	Coastal, shallow to fairly deep open marine environment
MESOZOIC	Jurassic	Late	Scruff Group	400 - 760		Local bituminous claystones, thin intercalated carbonate beds, and glauconitic, fine to coarse-grained sandstones	Marine environments from restricted (lagoonal) to open marine (outer shelf) conditions
MESOZOIC	Jurassic	Late	Schieland Group	360 - 1900		Claystones, coaly to clayey sandstones, rare coal seams, and local calcerous intercalations	Shallow marine to continental
MESOZOIC	Triassic	Middle - Late	Upper Germanic Trias Group	60 - 100		Silty claystones, evaporites, carbonates, and sandstones	A series of sediments deposited in alternating shallow, restricted marine, and floodplain settings
PALEOZOIC	Permian	Late	Zechstein Group	> 220		Sequence of evaporites and carbonates with some thin intercalations of claystone	Peri-marine to marine setting

Figure 2.2: Stratigraphy of the North Sea Basin (Ref: www.nlog.nl)

3 METHODOLOGY AND RESULTS

3.1 WORKFLOW

The workflow is explained in detail in the following sections, viz.:

Data loading and QC

Data conditioning: Seismic and Log

Log analysis with the help of markers

Well to Seismic tie

Tracking of key horizons on conditioned 3-D seismic data.

Structural mapping

Attribute analysis: Geometric and Physical

Texture attributes

Integrated analysis of attributes with log data.

Impedance inversion Studies

3.2 Data Loading

3.2.1 Data Format

The obtained data is 3-D PSTM seismic data which are generally converted to and stored in SEG Y format for further processing and interpretation. The SEG has various formats, e.g. SEG D, SEG X, SEG Y. The SEG D is the format when the data is stored in demultiplexed format and in multiplexing the SEG Y is the second iteration of SEG X format. The components of the format are:

1. Text File header is of 3200 bytes.
2. Binary file header is also available to store binary information of 400 bytes.
3. The individual trace headers are available to store information about each trace which is of 240 bytes.

SEGY Text Header

It contains the storage to store a text description of the survey which can be around 40 lines and it can be read by human and thus contain some general description of the survey parameters. It is of 3200 bytes (Fig. 3.1).

SEGY Binary Header

It is the main header file for the complete SEGY as it contains all the necessary information about the processing of the SEGY file and the parameters which was used during the survey of the seismic section. It is of 400 bytes and records the values in binary values that is 0’s and 1’s. The interpreter and the processor take the information about the sampling interval and the binning strategy from this header (Fig. 3.1).

The SEG-Y Trace Header

The last header is the trace header which contains all the information about the seismic trace and it is of 240 bytes but this storage is available for each trace so this storage comes out to be very large due to the presence of large amount of traces in the seismic section. The information about the traces are the information that is needed to identify the trace. The information to process the trace is also available in this header (Fig. 3.1).

After the headers are completed the trace data is available which contains the actual data about the amplitudes of the trace at each time location (Fig. 3.1).

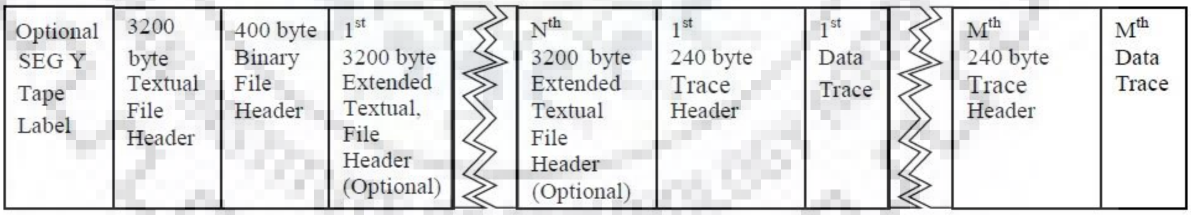


Figure 3.1: The Format stored in tapes in graphical format. (Ref: Faichney, 2002)

3.2.2 Survey Setup and Seismic Data loading

The design of the Survey was done keeping in mind the sampling theorem which states that a signal is only preserved if the sampling rate is minimum two times the maximum recoverable frequency needed in the survey. A 4ms sampling is adequate for sampling frequencies upto 125 Hz but keeping the other practical problems the frequencies upto 80 Hz will be preserved effectively. Thus, the survey must be designed to avoid any type of aliasing which is the effect of under sampling the information. The design of the survey is not the job of a seismic interpreter however these factors affect the quality of interpretation thus these things are needed to be taken care of while performing the survey. The results of the fringe zone are unreliable so these measures are taken to a good seismic acquisition.

For a 3D seismic volume it can be seen as inlines, crosslines and time slices in respectively three directions as x,y and z. The inline direction is the direction in which the boat moves that is the cable is laid in the direction of inlines and vertical to that is crosslines. The horizon slice or a time slice are different as horizon is the picking out the same reflection which is due to the picking of same reflection in the complete inline and crossline simultaneously while time slice is the window having the same time along the complete seismic.

The new survey has to be created before loading a project in OpendTect, the survey setup window is shown (Fig. 3.2) which inputs the SEGY file from which the coordinates and the other information about the survey is extracted from the headers and thus after creating the survey the SEGY file has to be imported which contains the data. SEG-Y Examiner contains all the information about the file header, binary header, trace header and trace information and it also shows the byte location in which the above information is stored (Fig. 3.3). The byte location of the inline, crossline and the CMP should be inserted which extracts the data from the file.

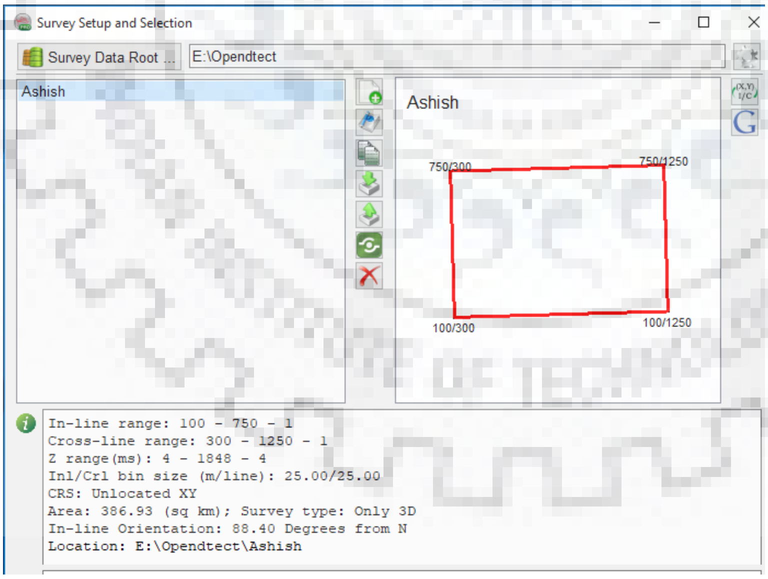


Figure 3.2: Survey Setup and Selection Window

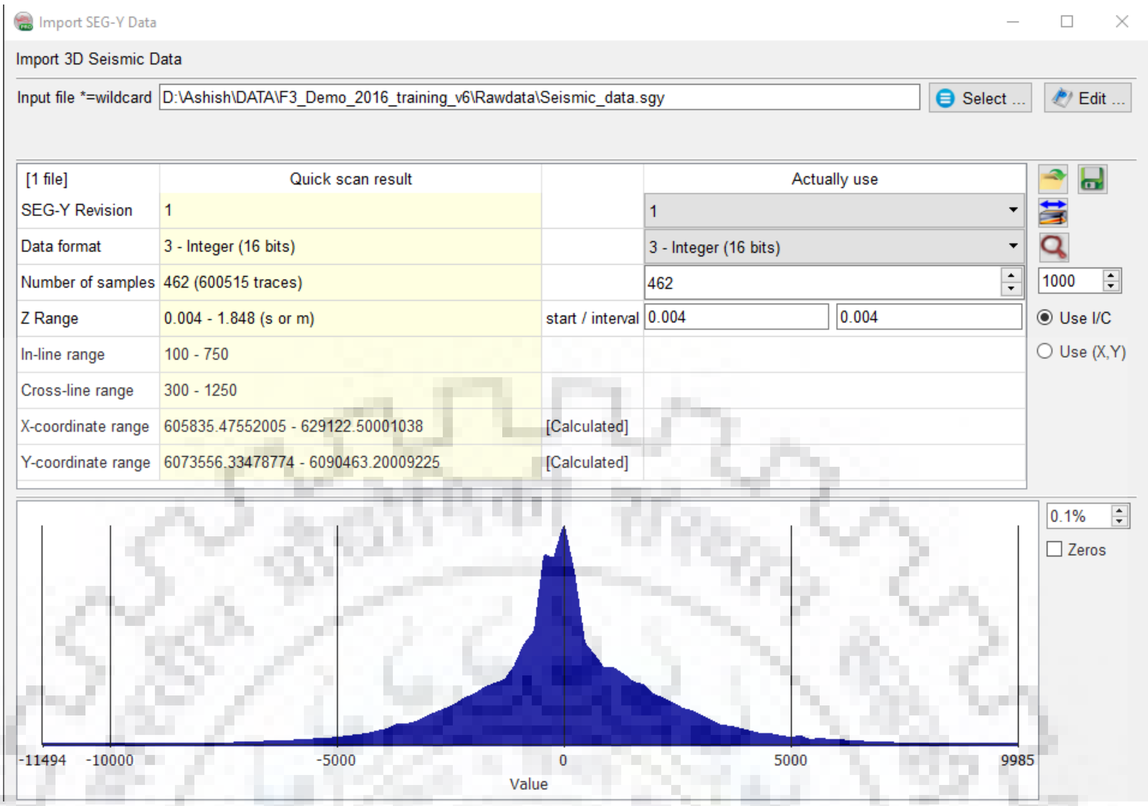


Figure 3.3: SEG-Y Import in OpendTect

The second window is the SEG-Y scan window (Fig. 3.3) which require information about the inline, cross-line, X-coordinate and Y-coordinate byte. After providing the necessary information with the help of file header information obtained from the SEG-Y Examiner and then proceed. Then a survey setup window will pop-up showing all the info of the data created for the survey. It should be cross-checked with the input SEG-Y file. After checking all the fields in the survey setup window is now complete.

3.2.3 Well Log importing

First, before importing the well log, the wells must be imported or written in sheet (Fig. 3.4) so that the coordinates of the wells are defined, after defining the coordinates, the logs in these wells are imported.

Import Simple Wells

	Well name	[X(m)]	[Y(m)]	[KB(m)]	[TD(m)]	[GL(m)]	[UWI]
1	F02_1	606554.0000	6080126.0000	30.0000	1500.0000	0.0000	
2	F03_2	619101.0000	6089491.0000	30.0000	2140.0000	0.0000	
3	F03_4	623256.0000	6082586.0000	30.0000	1900.0000	0.0000	
4	F06_1	607903.0000	6077213.0000	28.6400	1700.0000	0.0000	

Figure 3.4: Creating Wells at the defined location in OpendTect with parameters such as X(m), Y(m), KB(m), TD(m), GL(m).

Next process is to import the logs in the Wells made in the excel sheet with the coordinates and importing the logs to the defined wells respectively as shown in Fig 3.5.

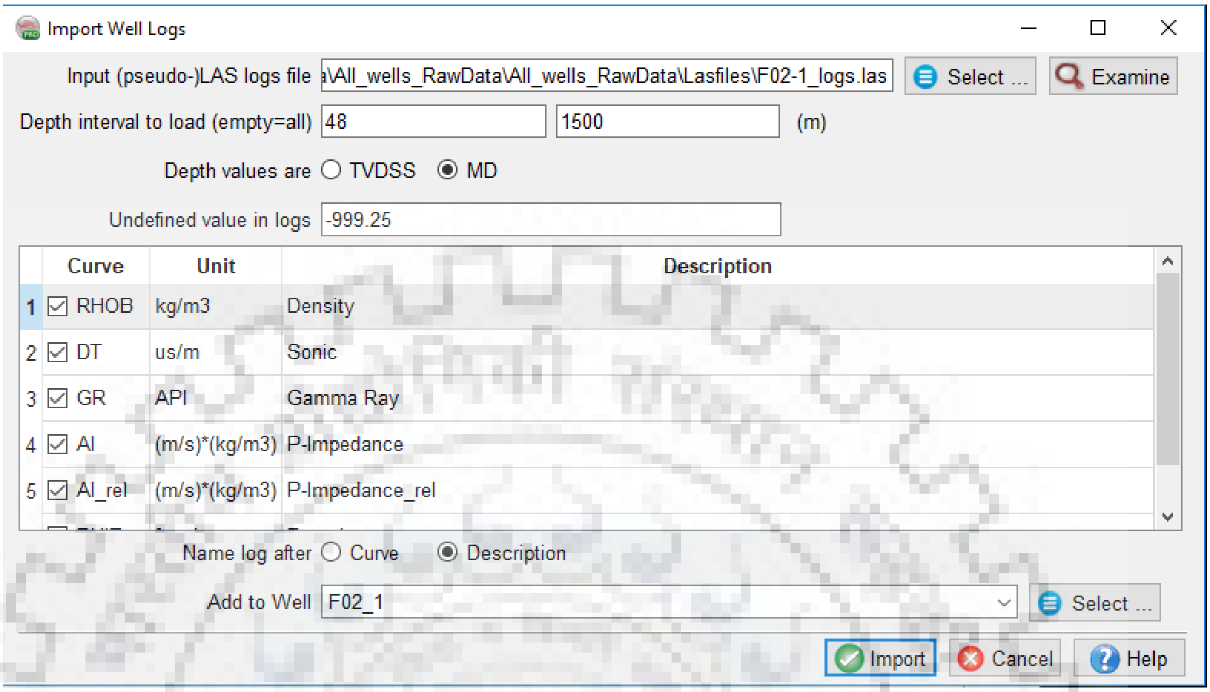


Figure 3.5: Importing Well logs to the earlier created Well F02_1. Similarly done for other wells F03_2, F03_4 and F06_1.

3.3 Data Conditioning

3.3.1 3D Seismic Conditioning

The obtained data is Post-Stack Time Migrated (PSTM) seismic data which is of good quality, but still it contains some random and coherent noise which will affect the geological interpretation of the data as noises can alter the image and can make the interpretation of minor faults and fractures difficult. The data should be filtered to increase the signal to noise ratio and to increase the quality of the data prior to interpretation. The Data Conditioning is carried by applying Dip steering median filter which uses steering cube extracted from the raw data.

Dip Steering

Dip steering is a process which actually stores the seismic dip and azimuth values at every trace location (Fig. 3.6).

There are two kinds of steering cubes:

1) For 2 D seismic – which will compute and store dip along inline direction
2) For 3D seismic – which will compute and store dip along the inline and cross-line directions

The dip steering algorithm gives two types of steering options to create a steering cube they are:

- **Central Steering:** The elevation point is taken and from that point dip and azimuth is followed to the next trace however the dip is not bent and represents a straight line.
- **Full steering:** It does not represent a straight line however the dip amount and direction is calculated and changed at each trace location to get a more detailed steering.

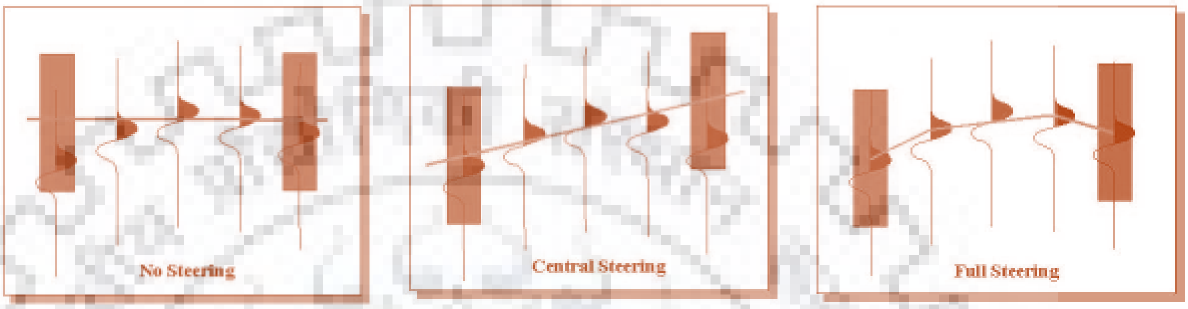


Figure 3.6: The figure showing difference between different steering algorithms. (Ref: dGB Earth Sciences)

There are two types of steering cubes provided by OpendTect software they are:

- **Detailed Steering:** In detailed steering mild smoothing takes place. In this type noise is removed and contains details such as dip, faults, stratigraphic features and flexures. It is typically used when details such as similarity should be preserved in the data.
- **Background Steering:** In background steering noises and the details are removed and it contains only information about the structural dip and primarily background structure. It is primarily used for calculating multi trace attributes and filtering.

The seismic dip is calculated along the line direction generally in mm/m or µs/m.

$$Seismic\ dip = \frac{-\Delta t}{\Delta x}$$

The algorithms for the calculation of Dip steering in OpendTect are:

- **Principal Component analysis (PCA)**: It is basically fitting the data points in such a manner that an n dimensional ellipsoid is fitted. Both the axes of the ellipse will represent the principal components. The principal component is calculated as the direction which shows the maximum representation of a trend and for that the data is first shifted to the origin system and then using eigen value analysis the axis is fitted to the data and the variance of each data point can be calculated by dividing the eigenvalues with the sum of the eigenvalues. The direction of the trend is given by the eigenvectors corresponding to the axes of the ellipsoid.

- **Fast Fourier Transform algorithm** popularly known as FFT is standard algorithm used for steering and it is precise but the time needed to compute this is large. FFT algorithm also can be used on poor quality data sets and obtain good results. The FFT algorithm calculates dip from the maximum amplitude in the Fourier domain.

PCA algorithm was used at filter size 1 and the maximum dip specified was 800um/s and a median filter was applied simultaneously at 3 stepouts (Fig. 3.7).

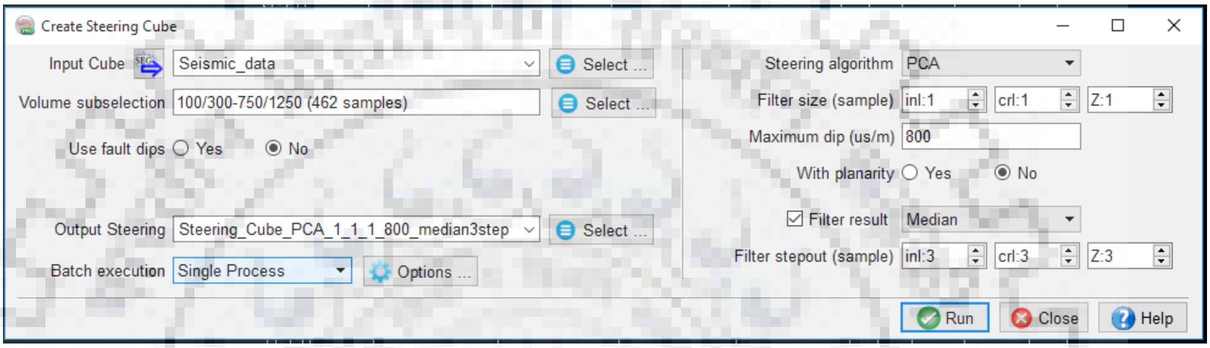


Figure 3.7: Creating a Steering Cube with parameters such as Steering algorithm, filter size, maximum dip and Filter result with Filter stepouts.

Dip Steering Median Filter

DSMF is a tool which will reduce the noise and yield a cleaned up seismic data. The tool works by enhancing similar events and by decreasing randomly disturbed noise. This filter helps in increasing the overall interpretability and it also helps in improving the efficiency in horizon tracking. The filter uses amplitudes from user defined area and then replaces the central amplitude with the median value of amplitudes.

The common filter with steering cube works as defined below:

1. A user defines the search radius for the algorithm.
2. Generally, from the center of the defined radius acts as a starting point (Red dot in Fig 3.8) and the extraction of amplitude begins.
3. The dip amount and the direction are extracted at the location and the same is followed to the next trace to calculate the steering.
4. The amplitude value is interpolated at each point and these interpolations and tracking of local dip and azimuth is repeated for all the traces defined in the search radius.
5. Then median values are calculated from all the amplitudes within the search radius and the central amplitude is replaced by this median value.

6. These processes continue for whole cube and all central amplitude values are substituted by the median values.

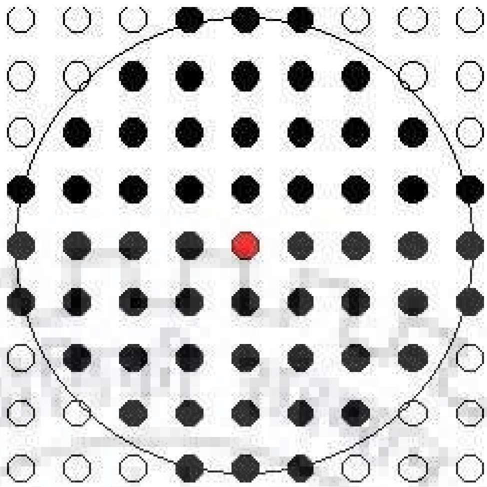


Figure 3.8: Working model of Dip Steered Median Filter. (Ref: dGB Earth Sciences)

Fig 3.9 shows the Raw Seismic data which is applied with different stepouts of DSMF filter and the results are compared for the best stepouts for study.The parameters which needed to be kept in mind while creating DSMF is the stepouts value. If we use less stepouts value the data still consists of noise and using high stepouts values smoothens the faults and difficult to identify the minor faults and fractures. Thus, the stepouts value at different stepouts were checked as shown in the fig 3.10.

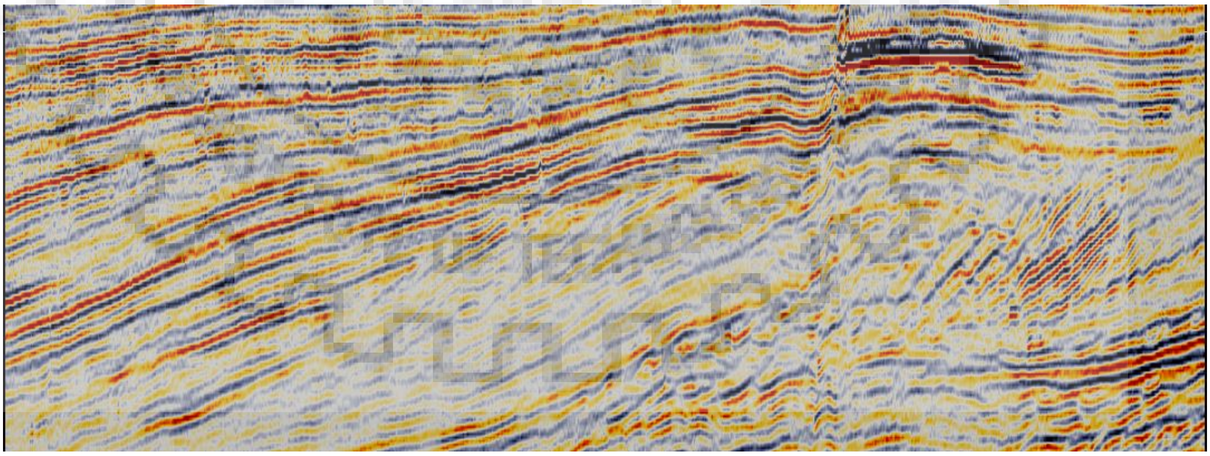


Figure 3.9: Raw Seismic Section at an inline 248.

Figs. 3.10 and 3.11 shows results after applying DSMF at different stepouts and at full Steering.

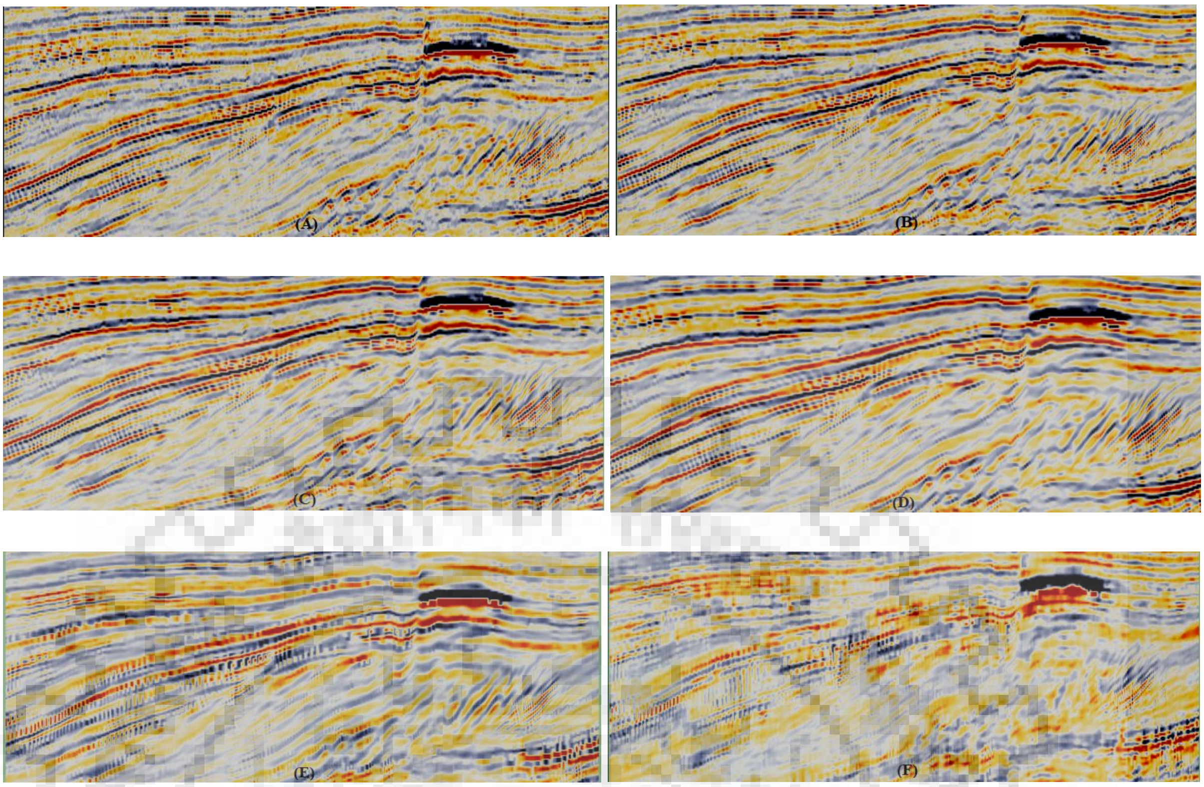


Figure 3.10: Median Filter at inline 248 at different stepouts. A) 1 inline, crossline and time B) 2 inline, crossline and time C) 3 inline, crossline and time D) 4 inline, crossline and time E) 6 inline, crossline and time F) 14 inline, crossline and 3 time. All are obtained using Full Steering Cube.

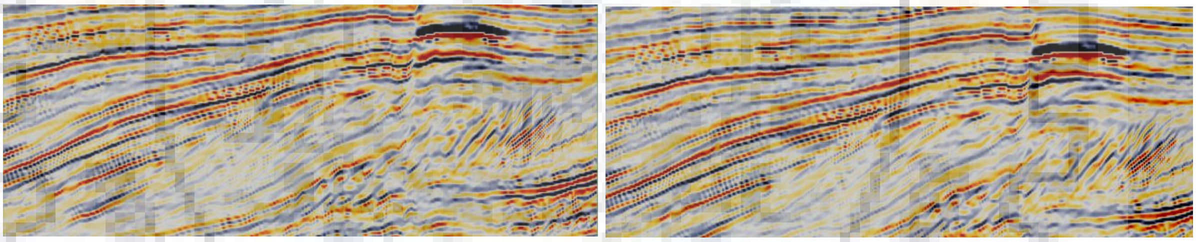


Figure 3.11: Median filter at inline 248 at 3 stepouts of inline, crossline and time. Full steering (LEFT) and Central Steering (RIGHT)

Analysing the outputs at different stepouts we can come to the conclusion that 3 stepouts gives the best in terms of removing the noise and preserving the events, thus 3 stepouts was used to create the DSMF (Figs. 3.10 and 3.11).

If the same filter is calculated at central steering the amount of time reduces from 24 hr which would take in case of full steering to 1hr and the accuracy is within the acceptable amount and the extra time needed to compute with full steering is not worth the extra computation so we have to make a trade-off for the time and accuracy and thus central steering was chosen. Hence, the median filter with 3 stepouts and central steering was used to create the DSMF. The complete volume of the 3D seismic with the filter was created with 3 stepouts and Central Steering (Fig. 3.11).

3.3.2 Well Data Conditioning

After importing the log data, they need to be conditioned as the logs can contain random noise and spikes which needed to be removed so that the interpretation can be done in a better way and no anomalous spike in the data is interpreted as a significant change in lithology or rock property. The Well Editing window can be directly accessed from the Manage wells window and the logs can be edited for suppression of noise (Fig. 3.12).

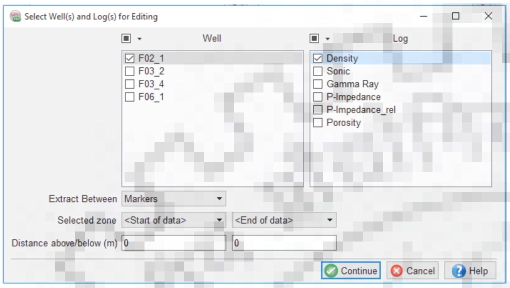


Figure 3.12: Well editing window

Despiking filter are first applied to the logs at the window size (that is the number of samples) of 300 and threshold of 3 as shown in Fig. 3.13. The increase in the window size leads to increase in the number of samples and thus the filter will be less effective in removing the spikes as it will not be able to detect spikes due to increase in the number of samples. Reduction in the number of samples will lead of decreasing the frequency of the signal and the data is lost. Thus 300 filter length is chosen which is effective in removing the spikes as well keeping the data intact. After applying the despiking filter the log is smoothened with window size of 15 which removes the random noise in the logs and improves the signal to noise ratio. The Red curve is the new data after editing and the blue is the original data before editing (Fig. 3.13). Figs. 3.13 to 3.16 show the editing in practice for GR, Density, Porosity and Sonic logs respectively.

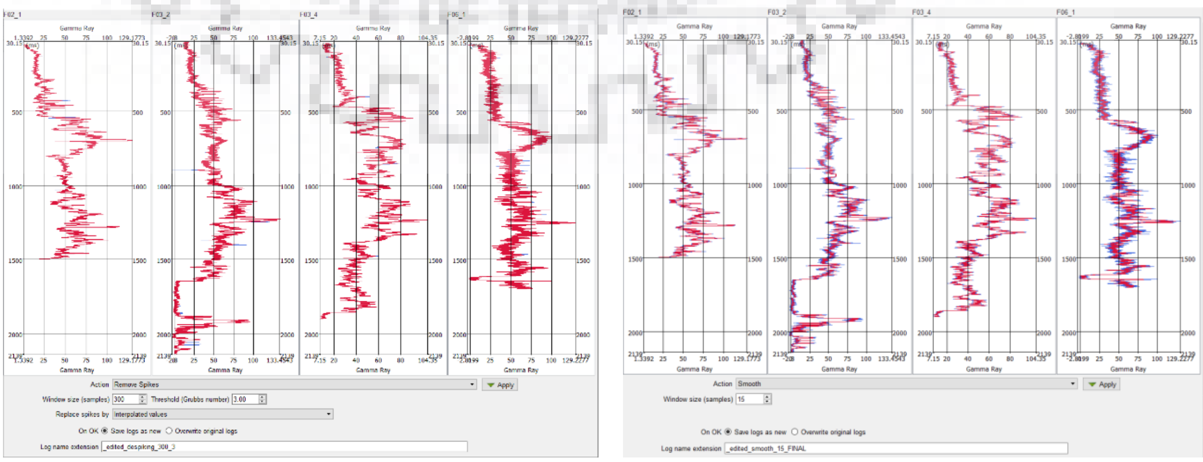


Figure 3.13: Editing GR log. Removal of Spikes (LEFT) and Smoothing (RIGHT).

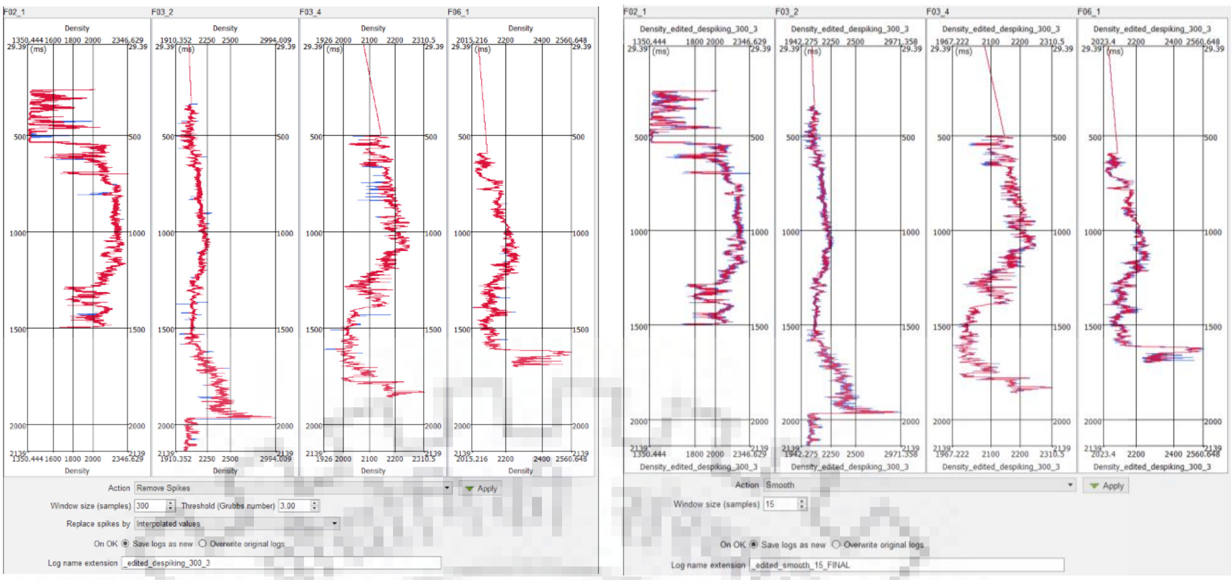


Figure 3.14: Editing Density log. Removal of Spikes (LEFT) and Smoothing (RIGHT).

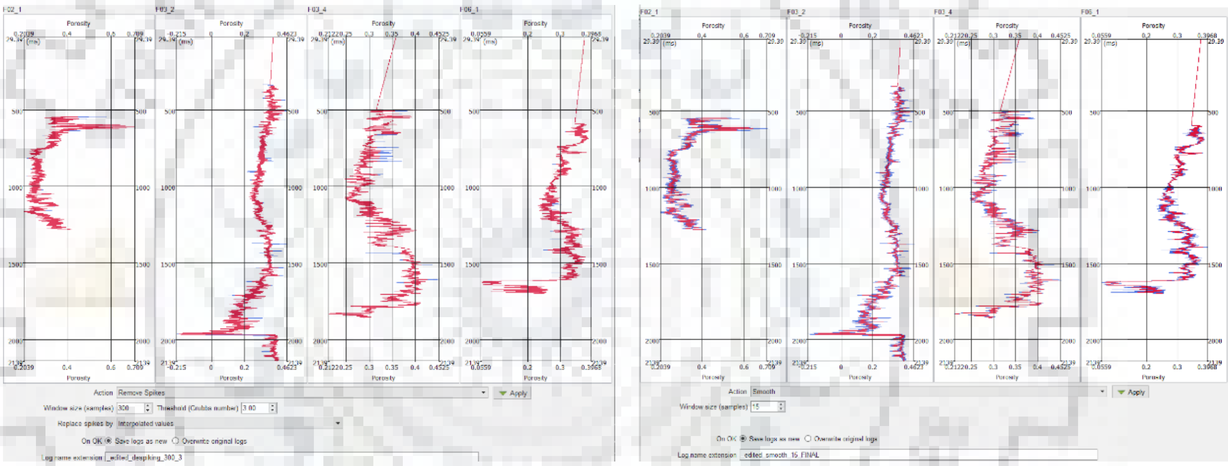


Figure 3.15: Editing Porosity log. Removal of Spikes (LEFT) and then Smoothing (RIGHT).

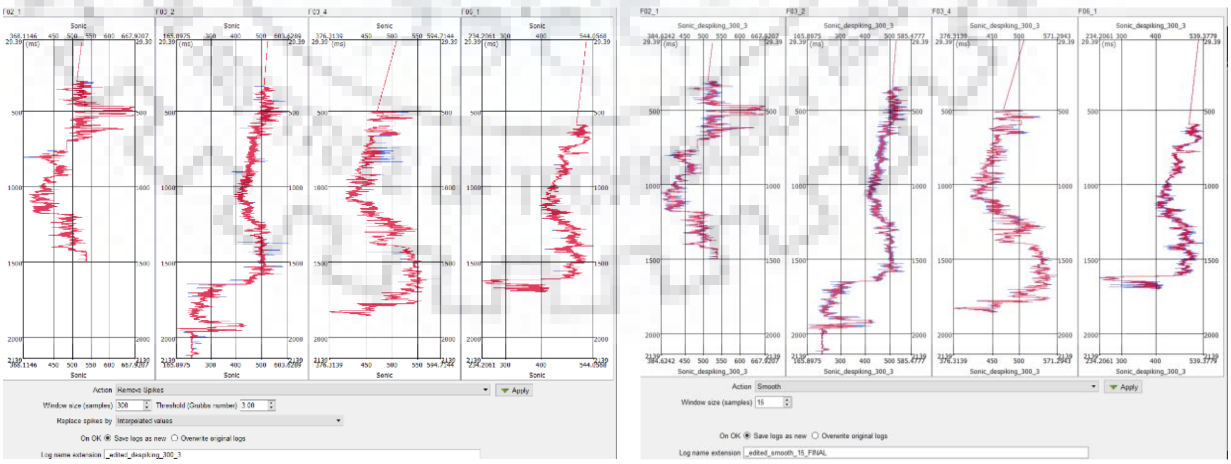


Figure 3.16: Editing Sonic log. Removal of Spikes (LEFT) and Smoothing (RIGHT).

3.4 Well Logs Interpretation

Well logging is the process of obtaining electric, physical, chemical or other properties with depth. Generally, these well logs are obtained from the existing bore hole or by drilling a new bore hole at the required location. Logging data are used to measure the thickness and depth of a pay zone, to recognize the productive zones, to differentiate between water and hydrocarbon in the reservoir. Fig. 3.17 gives an idea what we can actually infer from the well log data.

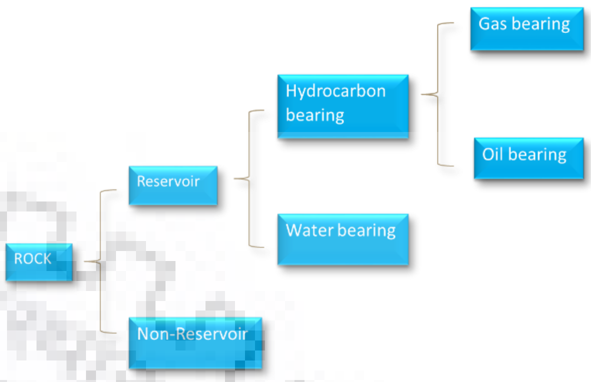


Figure 3.17: Flowchart for Interpretation

There are many types of well logs of which the prominent or the commonly used logs are:

1) Lithological logs
    a. Gamma Ray log
    b. Spontaneous Potential log
2) Resistivity logs
    a. LLS – Lateral log shallow resistivity
    b. LLD – Lateral log deep resistivity
    c. MSFL – Micro spherically focused log
3) Porosity Logs
    a. Density log
    b. Neutron Porosity log
    c. Sonic log

Gamma Ray Log

Gamma Ray log measures the natural radioactivity of the formation. Naturally occurring radioactive materials (NORM) comprises elements such as Potassium, Radon, Radium, Thorium, Uranium, etc. These generally contribute to the radioactivity of the formation. Gamma Ray log is a simple log which contains only the detector to measure the natural radioactivity in the API units. This is the first nuclear well log used and was introduced in 1930. The main feature of this log is: it can be used in both open hole and cased well. The depth of investigation of this log is generally low, so it measures the gamma ray intensity of the flushed zone.

The radioactivity of these logs is used to identify the lithology. These logs are commonly helpful because sandstone and shale contain different gamma ray signatures that can be useful to identify the lithologies and to correlate different wells. Shales and clays contain much of the radioactivity as they contain NORM, so they show high gamma readings and sandstone beds generally reflect low gamma readings.

SP Log

It measures the difference in potential which is generated in the formation due to the change in the salinity of the fluid in the mud and the formation. The log measures the electrical potential between a reference electrode which is kept on the surface to be kept at zero potential and an electrode which is moving in the borehole. This log measures resistivity in millivolts. This log helps to differentiate between the porous and permeable membranes. This log also helps to calculate the formation water salinity and the clay content in the formation.

Resistivity Log

Resistivity log measures the subsurface resistance to flow the current through it. This log measures the resistance and then calculates the resistance per unit cube of the formation (Ohm-m). Resistivity logs are often displayed in the log scales due to the large variation in measured resistivity values. As hydrocarbon and water contains a great difference of resistivity values. These logs are used to identify whether a reservoir rock contains water or hydrocarbon. Water formation represents a low reading of resistivity values whereas the hydrocarbon reads a high value of resistivity.

Neutron Log

Neutron log measures the hydrogen index. Generally, neutron log contains a source which emits neutrons and the receiver measures the back scattered neutrons from the formation. When neutrons collide with the hydrogen atoms, they became slow and neutrons lose their energy so the receiver reads low back scattered neutrons which represents high porosity. Water and hydrocarbon contain more hydrogen atoms than gas so the log reads more hydrogen index in the gas formations indicating less porosity relative to the formation containing water and hydrocarbon.

Density Log

Density log measures the back scattered electron density from the formation. This log works on the mechanism of gamma ray absorption by Compton scattering. This log measures the density in grams per centimeter cube (g/cc). The density log emits gamma rays from the radioactive source fixed to the log. The gamma rays pass through the formation where some of the rays are absorbed. But some gamma rays reach the receiver which is located at 20 to 25 inch above the source. The quantity of the gamma rays which are received at the detector are inversely proportional to the number of electrons in the formation and which is directly related to the bulk density of the formation.

Sonic Log

Sonic log measures the speed of sound in the formation measured in micro seconds per foot (μs/ft) or microseconds per meter (μs/m). Normal sonic logs contain the source which emits sound waves and two receivers at different distances from the source. The first arrival of the sound is detected by the two receivers which are actually located away from each other and the time elapsed between the two receivers is the required travel time. This log is used for porosity determination, and as a gas indicator. The sonic travel time is inversely proportional to velocity and density as sound travels slower in less dense materials.

In OpendTect the lithological logs (GR, SP and Caliper) are generally presented in track 1, Track 2 generally consists of depth scale. Resistivity logs are presented in track3. Density, porosity (RHOB, NPHI) and sonic logs (DT) are presented in track 4.

The common scale ranges for all the logs are as follows (Table 1):

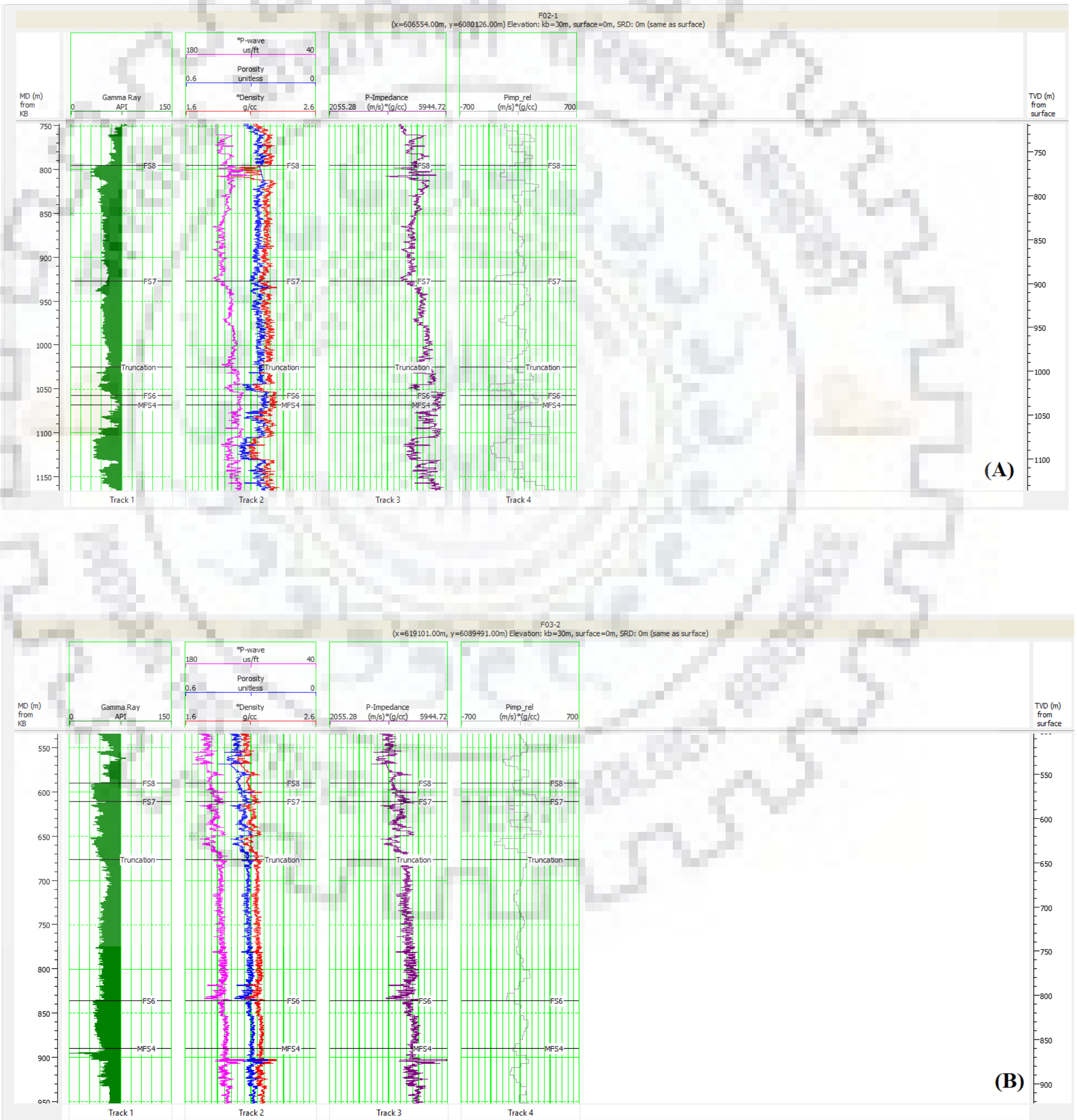
Log Name	Minimum Value	Maximum Value
Gamma Ray log	0 API	150 API
Caliper	0 m	20 m
Spontaneous Potential	-100 mV	100 mV
LLD (log scale)	0.1 ohm-m	100 ohm-m
NPHI	0 Frac	0.6 Frac
RHOB	1650 kg/m^3	2650 Kg/m^3
Sonic Time	131.12 us/m	590.55 us/m

Table 1: Log types and their scales with minimum to maximum values.

These are the standard value which are considered for evaluation of the well logs and the markers are used to mark the horizon of interest. The Wells used in the study does not contain LLD or any resistivity log.

3.4.1 Well Log window

Figure 3.18 shows the GR, Density, Porosity, Sonic and P-impedance logs for all the wells vs the depth from KB and from surface.



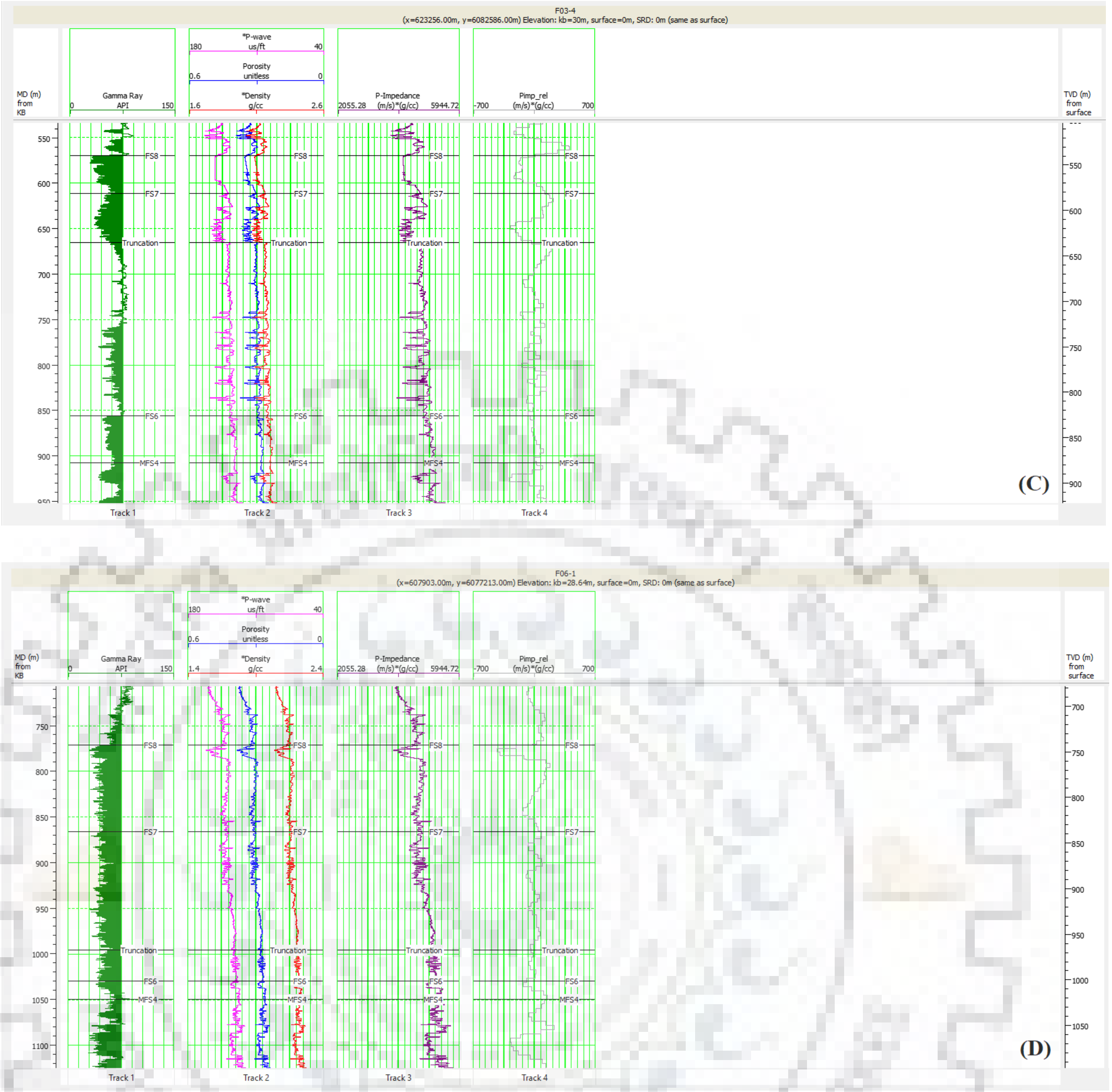


Figure 3.18: A) Well display of F02_1 B) Well display of F03_2 C) Well display of F03_4 D) Well display of F06_1 showing GR, RHOB, NPHI, SONIC and PIMP logs.

3.4.2 Lateral Correlation of Wells

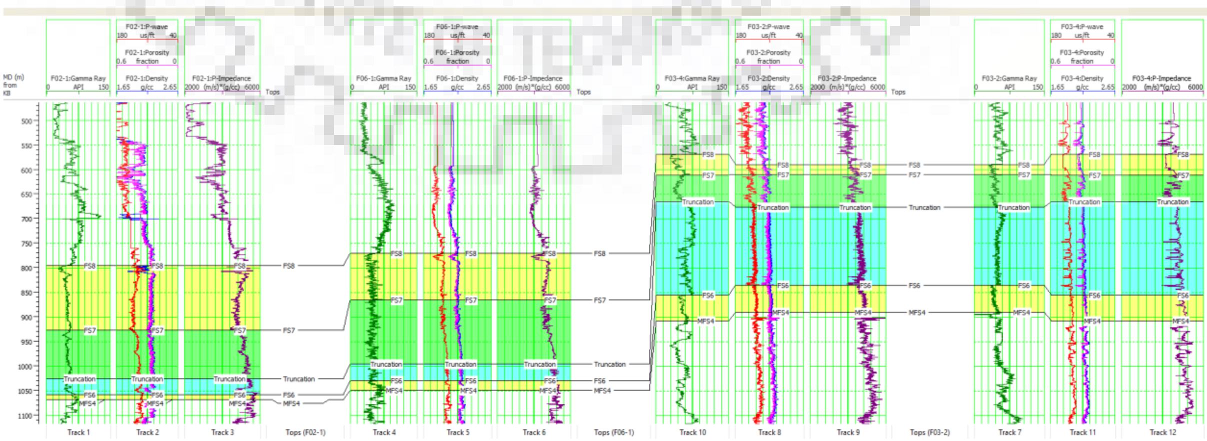


Figure 3.19: Lateral correlation of all the wells.

Fig. 3.19 shows the 4 Wells in lateral correlation and using the markers provided in the data. I have studied the different zones of study in the data and according to them after doing the seismic to well tie, the horizons will be made in the seismic data. The wells show the exact pattern of highs and lows which can be seen through the seismic data. Out of all the markers available from the data only 5 markers were used to study the area as these were close to my area of interest.

3.5 Seismic Well Tie

The main motivation for performing the seismic to well tie is as the well is in depth but the seismic is in time so this creates a need for the creation of velocity model at the well locations to convert these two interactively and also interpolate the velocity model to get the velocity at different zones in the seismic section. This is done by creating a wavelet which is convolved with the product of the two logs, the density and the sonic log which will create an impedance log which can be compared with the seismics and matched for different changes in the velocity log and the one with the best corrleation velocity log is converted to create a depth-time model.

This process is called the forward modelling as the creation of the synthetic and its analysis with the original is a forward model. The difficulties while performing the seismic to well tie is that the first the quality of logs cannot be taken as the best needed to convert and even after editing the logs are of high frequency and since seismic is in low frequecy this creates a problem for the correlation. Another problem arises with the use of a wavelet and the wavelet is very crucial for the tie as if the wavelet does not model the source signature at the well location the correlation will suffer.

The seismic well tie thus creates a method to relate the tops in the well logs with the horizons in the seismic section and the interpretation of the seismic data is aided. Thus it acts as a viaduct to form wiggles that seismic section have to the wiggles which are formed due to rock property in the seismic section as seismic well tie is a crucial step in the seismic inversion which is used to create the impedance value which relates with the rock property. Thus Seismic well tie is a crucial step in interpretation of the seimic data.

3.5.1 Well to Seismic tie Procedure

1. Editing and calibrating the sonic and density log is a must in the seismic well tie procedure and if required the low pass filter can also be applied to the logs.
2. Synthetic seismogram is constructed by:

a) The product of density and velocity logs will give the impedance and hence the reflection coeficients series.
b) The reflection series is convolved with a wavelet which converts it into a synthetic seismogram.

3. The peaks and troughs of the synthetic seismogram is matched with the original seismic at near to the crosslines at the well inline location.

The shifting and stretching of the synthetic seismogram to correlate it with the seisimic generates a new sonic velocity curve which also generates a depth time curve which gives us the two way travel time (TWTT) with depth. This is the velocity model which is generated which can be used to convert the seismic time to the well log depth.

The most important element to be taken in consideration is the wavelet, which is used to convolve the density and sonic log to convert into synthetic seismogram.

3.5.2 Extraction of Wavelet

I have used well logs to extract a wavelet, which can then be used for such processes as inversion or wavelet deconvolution. The algorithm uses both the available wells and the seismic data near those wells. The Statistical from Seismic method does not have a resolution due to a lack of well data. The wavelet is extracted as the basic process in signal processing is that the auocorrelation of the seismic source shall be equal to the wavelet chosen so the autocorrelation is calculated which is aided with the phase information from the data. The wavelet is extracted from the seismic section near the wells and by using the well logs (Fig. 3.20). The well density and velocity logs are used for the same.

Often, the statistically-extracted wavelet is first created to correlate wells in preparation for this type of extraction. To extract this wavelet we have to select extract wavelet using wells and then input volume has to be selected and the time window has to be given which will decide the window in which the data will be used to extract the wavelet. The well logs to be used has to be chosen which will be later used in the inversion. The wavelet is in milliseconds (Fig. 3.20).

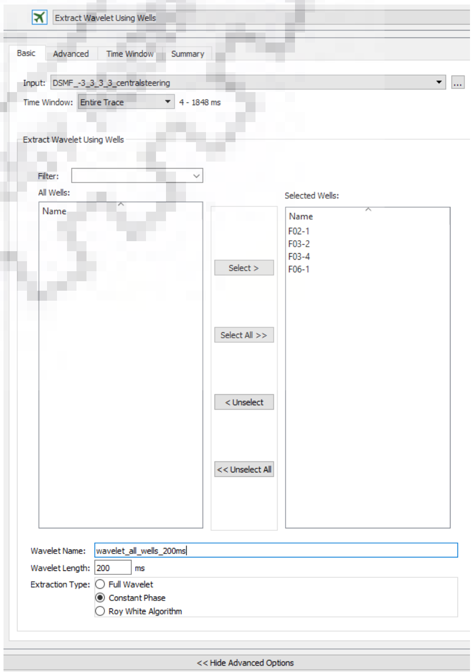


Figure 3.20: Wavelet extraction using well window.

The Extraction type provided are :

a) **Full Wavelet**: It uses the well logs to determine the phase and amplitude of the wavelet which shapes the reflectivity of the well logs to match with the seismic composite trace. We use this if we have several good events for correlation and the well ties are good but this type of wavelet is not recommended when inversion is also done in the project.

b) **Constant Phase**: The autocorrelation of the seismic traces are used to calculate the amplitude spectrum and the phase spectrum is approximated to be a linear spectrum with constant values which can be changed to see what matches with best correlation. This method is more robust than the Full Wavelet method, and should be used when the logs do not tie well with the seismic.

c) **Roy White Algorithm**: Uses a technique developed by White to extract the wavelet amplitude and phase. We use this only if we have several good events for correlation and the well ties are good.

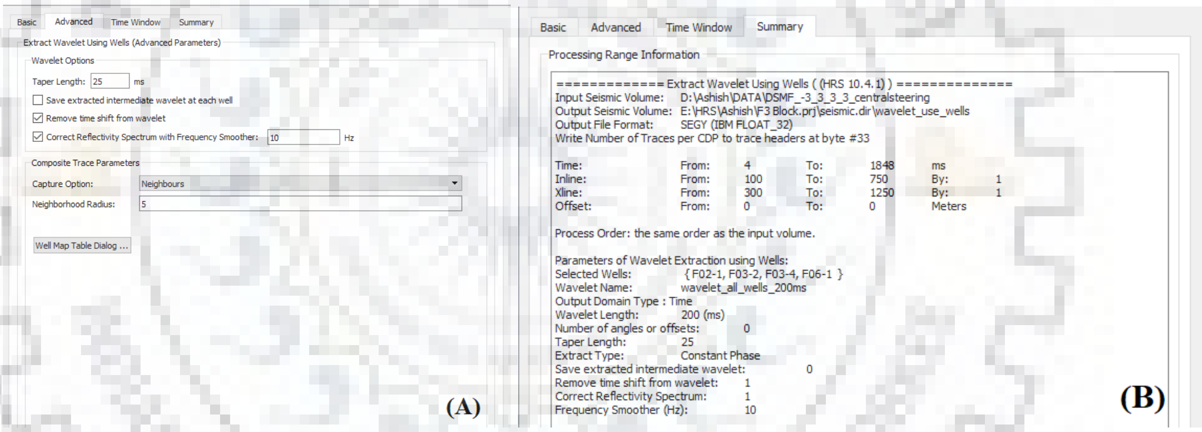


Figure 3.21: A) Wavelet Options taken during creation of wavelet that is Taper length, 10 Hz frequency smoother correction, capture neighbour's radius as 5. B) Summary of the extracted wavelet containing information about the wavelet.

We have chosed constant phase (Fig. 3.21) as the constant phase wavelet is best to tie seismic and well and further suitable for seismic inversion and also the inversion result produced with this wavelet is least sensitive to the quality of Seismic well tie and thus produces least error. The Taper Length sets the length (in milliseconds) of the taper that will be applied to the extracted wavelet. The taper is a cosine taper with this specified length applied at both the start and end of the wavelet.The Taper Length should be 10-20% of the wavelet length. Too much taper will cut too much off the wavelet. We can use a "0" taper length to check the wavelet length. If the resulting wavelet is too small for the window, reduce the wavelet length, and if the wavelet cannot fit into the window, increase the length. Then readjust the taper length. The chosen taper length was 25ms (millisecond).

Ideal wavelet for the inversion analysis

- The wavelet generated should be close to constant phase (with a linear phase spectrum).
- If the window shows that the amplitude spectra bears little resemblance to the zero-phase spectra, then the well used to extract the wavelet may be incorrectly tied or the correlation is relying too much on one event. If the extraction is poor, then retry with zero-phase or constant phase wavelets.
- We can compare the wavetes saved latter on and they should have a phase difference no greater than 30degrees to 40degrees between them.

Generating a wavelet from a single well will improve the resulting synthetic for that well, but that would be because the extraction was set up to match the two. We need to check the synthetics made by that wavelet for other locations and also by using multiple wells within a survey and using the Multi-well Analysis function.

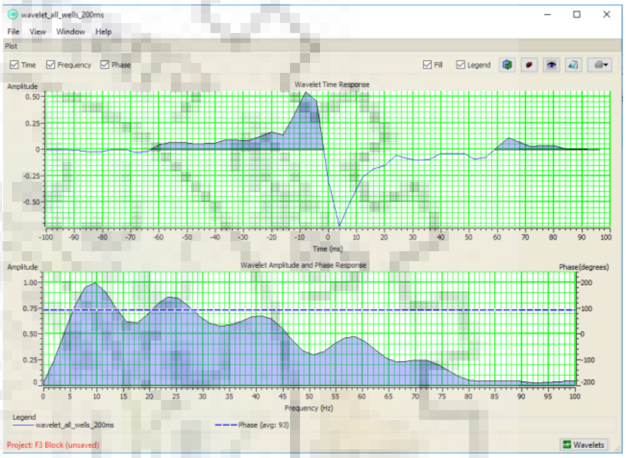


Figure 3.22: Wavelet time response and amplitude spectrum of the wavelet generated using wells.

Thus the wavelet shown in the Fig. 3.22 was used to Tie seismic to well and further in inversion analysis. The wavelet was derived using multi well extraction approach and the phase of the wavelet is constant and is 93^0. Thus this proves the presence of an airgun as the area under study is onshore and an airgun was used as a source for the seismic survey.

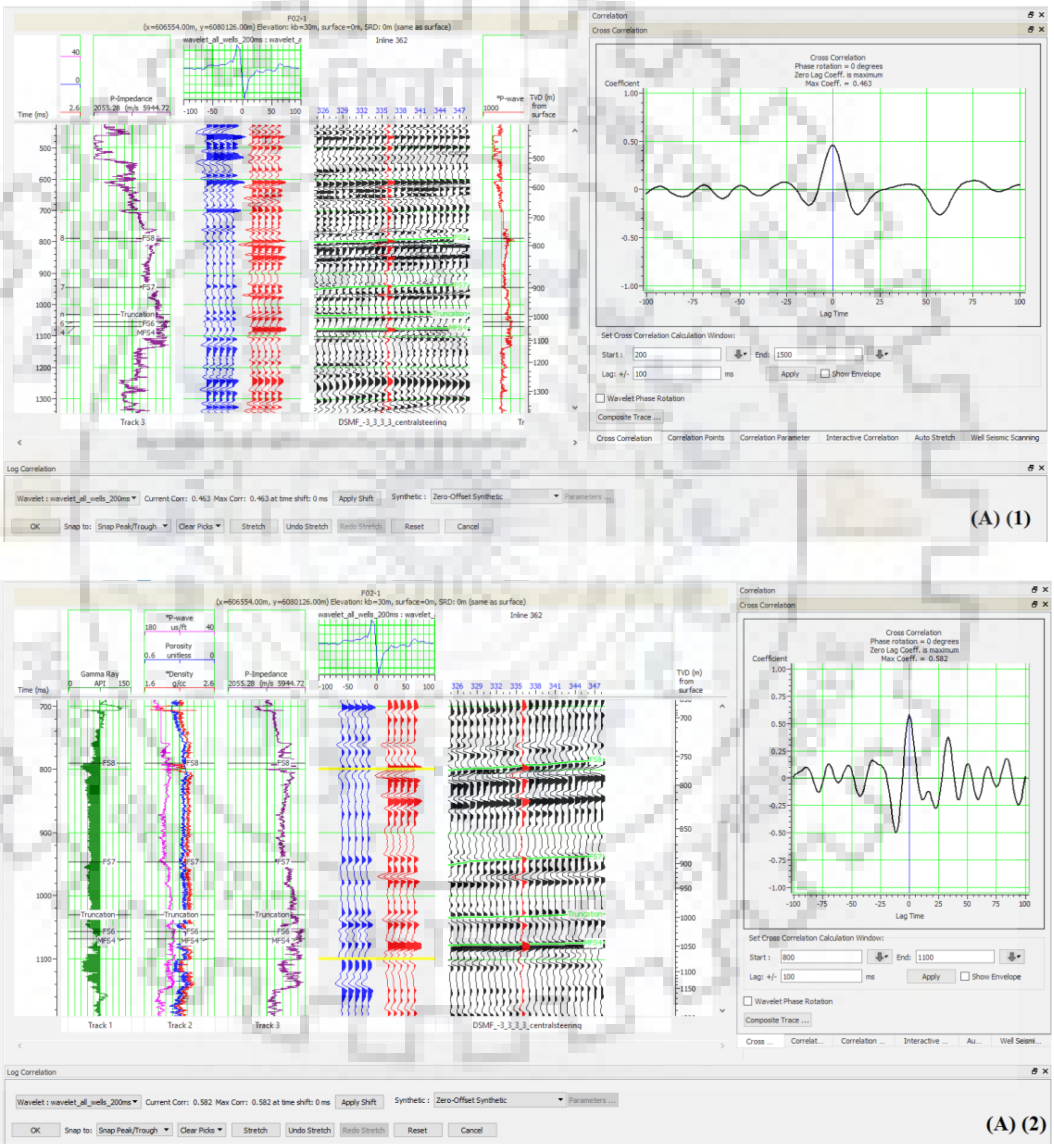
3.5.3 Well Seismic Tie in practice

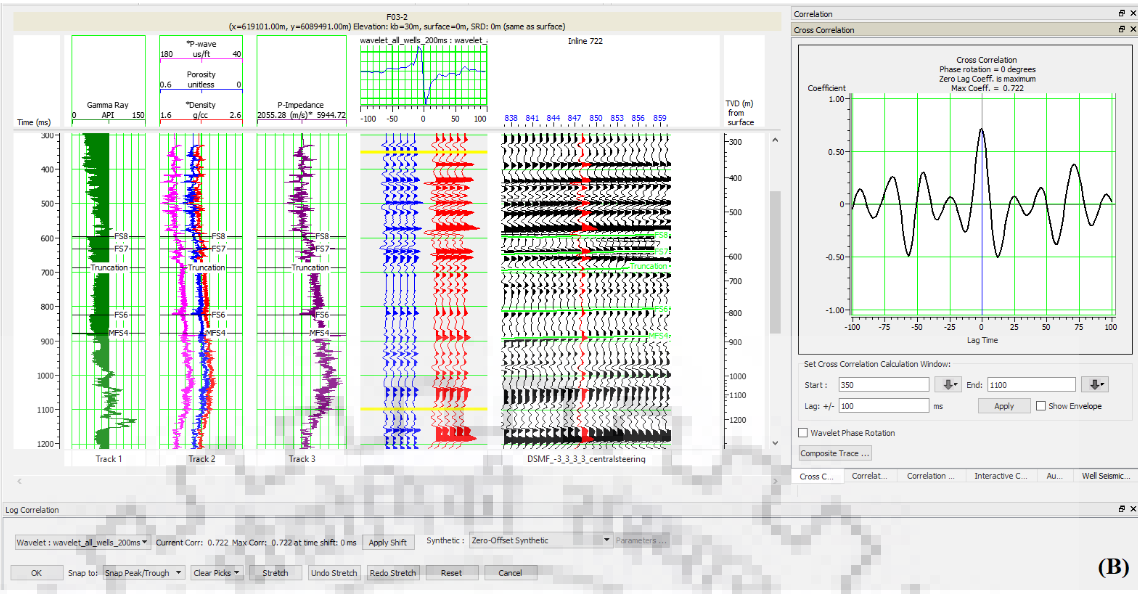
The Wells were tied with the seismic using the extracted wavelet and the coorelation as shown in the Table 2.

Figure	Well	Depth	Coorelation
A	F02-1(WELL 1)	1) 200-1500 2) 800-1100	0.463 0.582
B	F03-2(WELL 2)	350-1100	0.722
C	F03-4(WELL 3)	1) 0-1800 2) 450-1200	0.565 0.615
D	F06-1(WELL 4)	0-1800	0.704

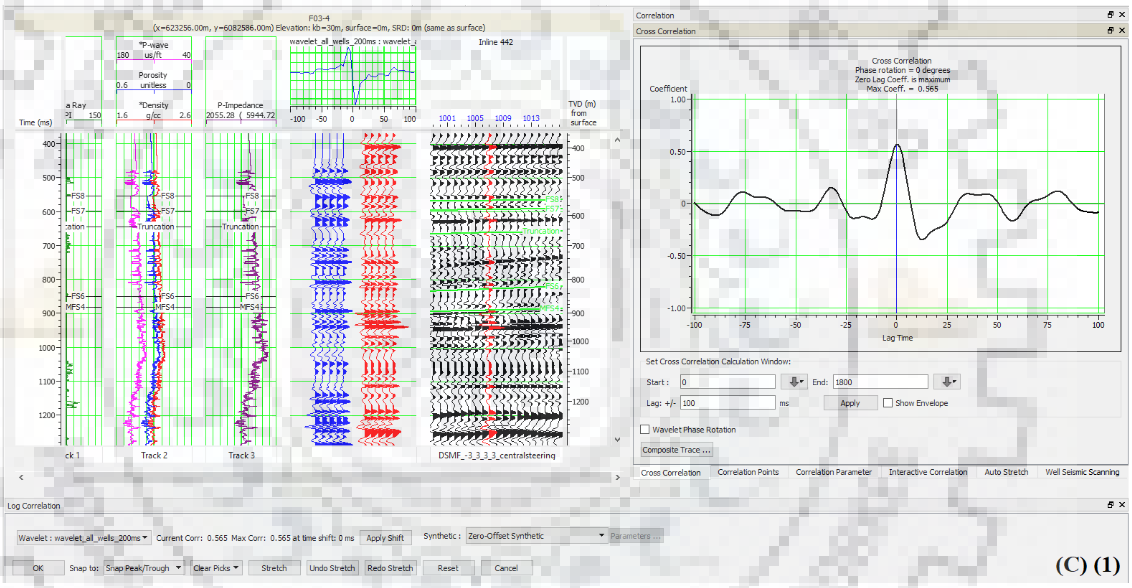
Table 2: Well log Coorelation with different depths

The correlation of 50 percent is enough for the complete well as the prevention of stretching and squeezing is more important as they create some serious very low or very high velocity layers. The area of study is at depth around 1000ms so the correlation in that region should be high which was tried to achieve in the seismic well tie. The well F02_1 contains very large amount of error so even after editing the correlation could not reach very high level. All the other logs had good correlation to perform that is around 70 percent to get a good velocity model of the area (Fig. 3.23).

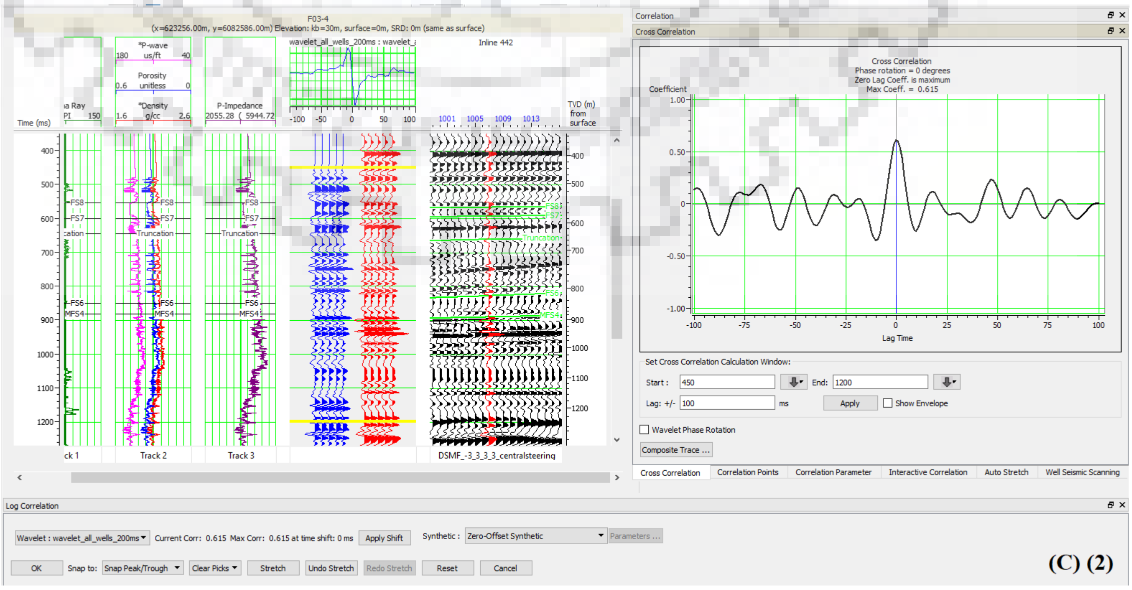



F03-2
Cross Correlation
Phase rotation = 0 degrees
Zero Lag Coeff. is maximum
Max Coeff. = 0.722
Lag Time
Log Correlation

(B)


F03-4
Cross Correlation
Phase rotation = 0 degrees
Zero Lag Coeff. is maximum
Max Coeff. = 0.565
Lag Time
Log Correlation

(C) (1)


F03-4
Cross Correlation
Phase rotation = 0 degrees
Zero Lag Coeff. is maximum
Max Coeff. = 0.615
Lag Time
Log Correlation

(C) (2)

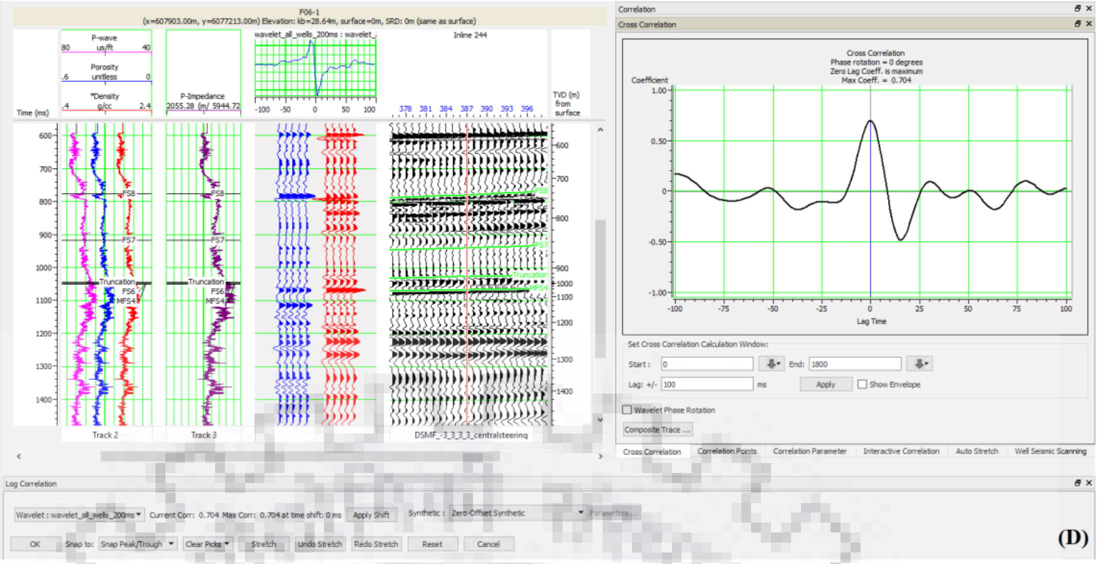


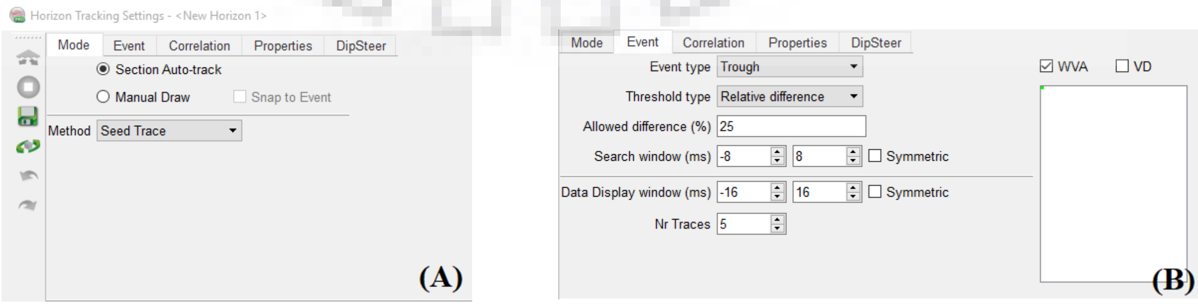
Figure 3.23: Well correlation window with the A, B, C, D for all the four wells where A) Well 1 B) Well 2 C) Well 3 D) Well 4 for different depths with reference to Table 2.

The seismic well tie enabled us to see the reflections in the seismic data corresponding to the markers in the wells and thus the horizon picking was the next step after Seismic well tie by picking the reflection corresponding to the markers.

3.6 Horizon Tracking

The conditioning of the data enabled us to better identify the prominent reflections. We can select a reflection which needed to be picked, after seismic and well tie the markers on wells are picked for reflections on seismic and thus horizons corresponding to them are marked. The parameters which are to be selected to pick a horizon are (Fig. 3.24):

i) Mode – tracking in volume
ii) Event – input data, event type (if horizon colour is red –min, if black- max) etc.
iii) Similarity – use similarity (yes), define compare window(ms)
iv) Properties – horizon colour, seed shape, seed size, seed colour
v) Dip steer – it may be yes or no



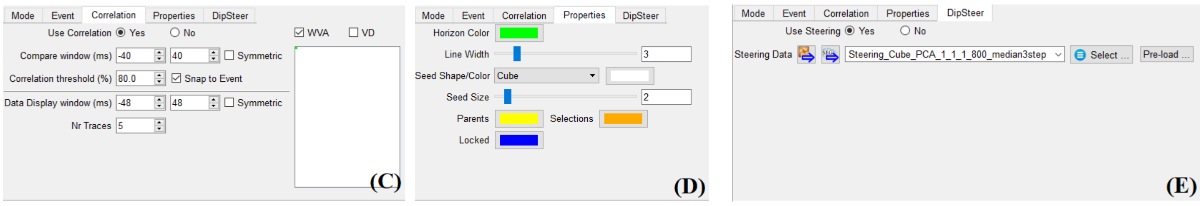


Figure 3.24: A) Horizon Tracking Mode Window and selecting auto track or manual marking window using Seed trace method. B) Parameters window selecting Event type, threshold, percent difference allowed and search window. C) Settings to use Correlation with selecting window, threshold and display window. D) Horizon colour, width and seed size window. E) Using dip Steering to track horizon using pre made steering cube.

The horizons are tracked at an inline of 10 each and then auto track in volume should be selected so that the horizon is made by collecting all the seeds. The seeds are then interpolated and thus a 3D horizon is made. The seeds are connected to make a line in an inline and the same is repeated at different inlines and thus a web is made which is later connected to form a horizon. The places which are left after making the horizon are filled by interpolating in between the seeds to fill the horizon (Fig. 3.25).

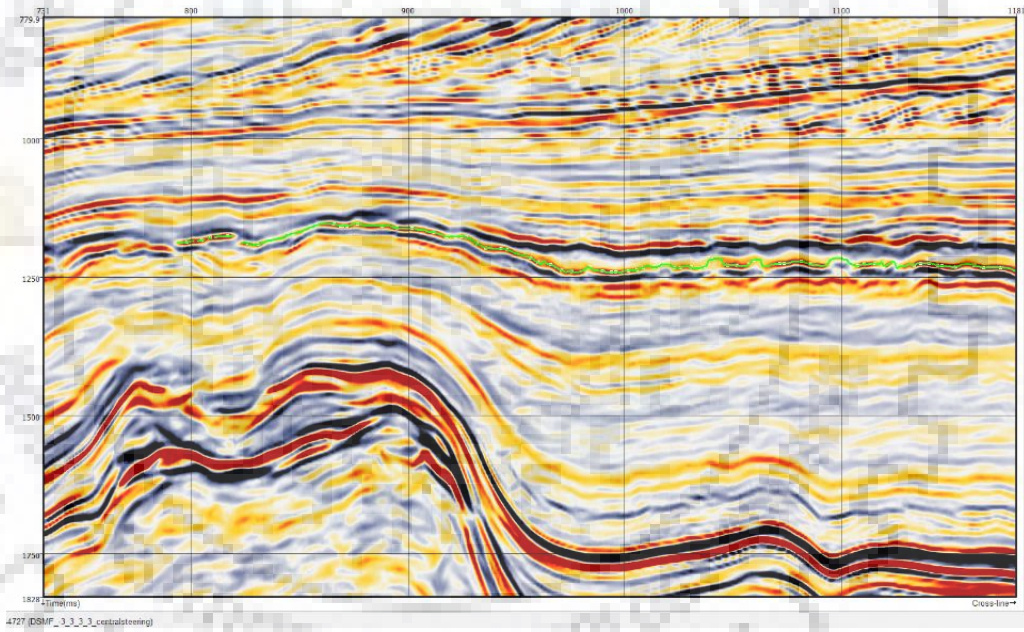
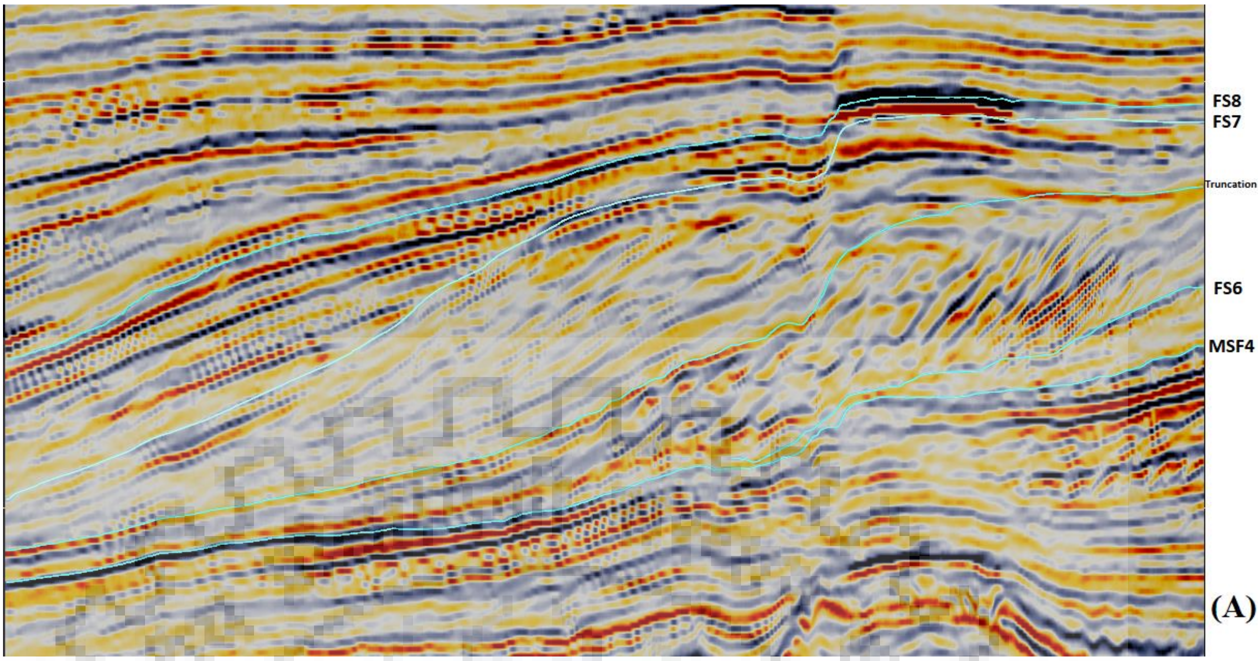


Figure 3.25: Marking of horizon on inline using seeds and then the same steps are repeated on different inline which will make a grid in crosslines and inlines which can be interpolated to form horizon.

The Horizons named FS6, FS7, FS8, MSF4, and Truncation were picked which was analogous to the markers in the well log. The median filter was applied on all the horizons at a stepouts of (-3,3) to smoothen the horizons as there may be some error in choosing reflection which may lead to kinks in the data and thus horizon is seen as faulty.

The Horizons in inline no. 248 are shown in the Fig. 3.26A). These horizons are made to study the time structural map of these horizons however as the area of interest lies on horizon FS8 all the attribute analysis shall be done on horizon FS8 to study the anomalous zone in the 3D seismic data.



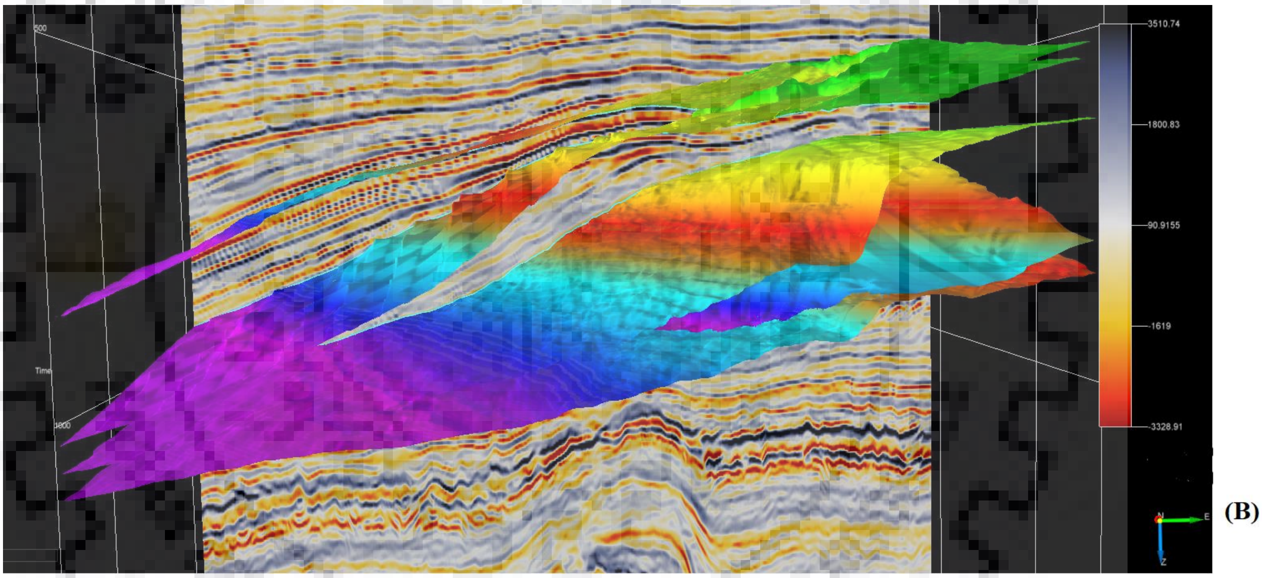


Figure 3.26: A) Horizons FS8, FS7, Truncation, FS6, MSF4 on an inline showing only on the line. B) Horizons showing as 3D on an inline.

3.7 Time Structural Maps

Time structural map is a type of subsurface map whose contours represent the elevation of a formation or a reservoir. They are valuable because they display folds, faults and other geological structures like highs and lows in the map. These maps are similar to topographic map except their subsurface nature.

The time structural maps for the 5 horizons which are picked are shown in the Fig. 3.27. The accuracy of the horizon can be directly seen in the time structural map. As seen in FS7 horizon the contour lines are very staggered and thus this is a possible indication that the horizon is not perfectly made. All the horizons are studied in brief and after analyzing them horizon FS8 showed an interesting feature that is the presence of very dark reflections which were also prominent in the traditional seismic section. Thus, the area of study was chosen to be the spot on which all the attributes were applied to further study that spot.

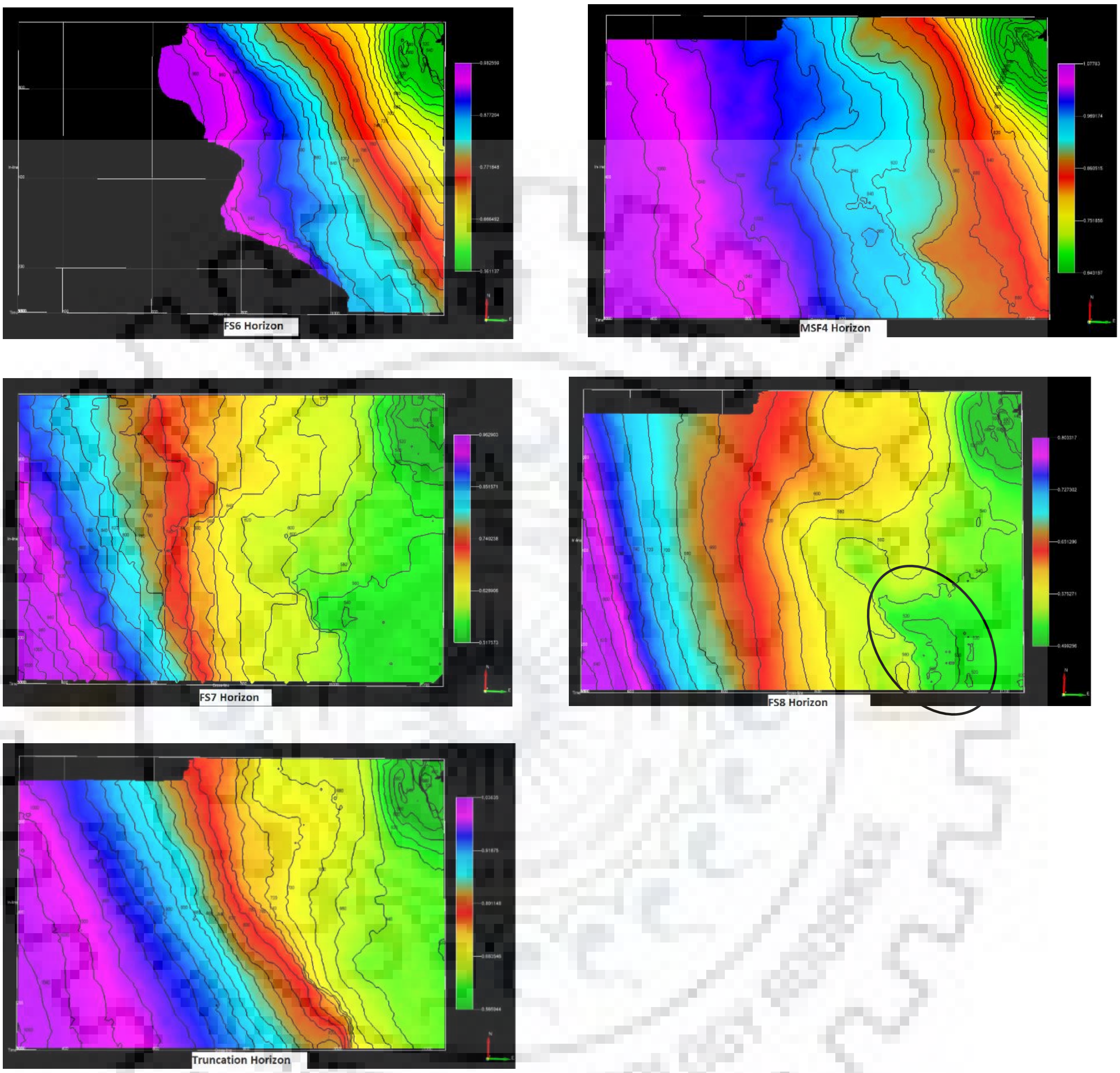


Figure 3.27: The figure shows 5-time structural maps of FS6, MSF4, FS7, FS8, Truncation horizons. The contour interval in each is of 20 units.

The interpretation of Time structural maps is such that it shows the contour lines on the section through which the highs and lows can be identified and the colour is the z value that is the time in the section (Fig. 3.27). The area having more z value i.e. more time value is such that the TWTT is more so the area is a low-lying area and this can also be concluded with the contour maps that the low-lying area has more value on the contour. Thus, this can be concluded that this is a SW dipping reflection.

The horizons have a SW dipping trend which can be seen through the time structural maps as the pink colour denotes the high two-way travel time which can be achieved when the structure is low lying (Fig. 3.27). Thus, through the use of time structural maps the topography of the area at the time when the horizons were deposited denotes the presence of these highs and lows which will be useful in interpretation of the area in terms of hydrocarbons presence and movement.

3.8 Area of Interest/ Horizon of Interest

The horizons are studies and the area of interest was found to be horizon named FS8 as shown in Fig 3.27, it shows a high reflection characteristic, so attributes analysis was done on that horizon to study the characteristics of the reflection and the causes of it. The horizon having FS8 have these 2 very high amplitude reflections along two different inlines however the inline which was originally studied is 248. The other inline (Fig. 3.28) which also show the same type of reflection characteristics is studied simultaneously with the inline number 248 as the reflections and its characteristics are visible on the horizon and attribute analysis can be done to study both at once.

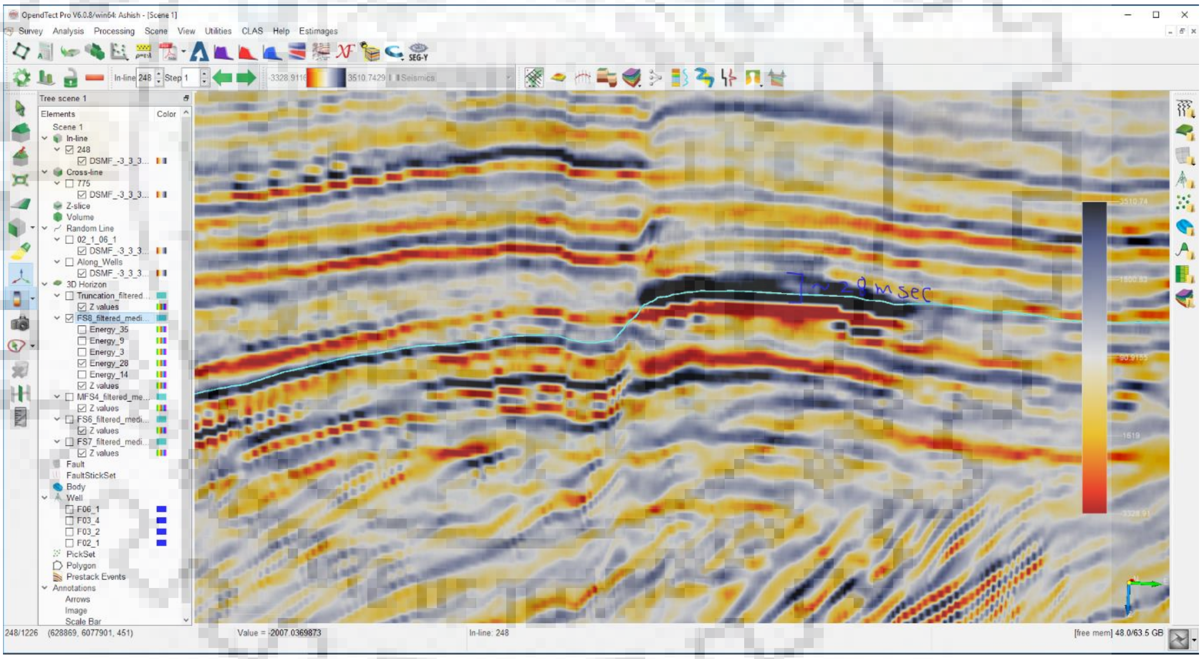


Figure 3.28: The bright patch of high amplitude which is our area of interest as seen in inlines from 246 to 250. The patch is of approximately 28ms in time.

The time window is approximately 28ms of the reflection so the attributes are calculated at time window (-14, 14) to get a good understanding of the reflection. Thus, all the attributes until specified otherwise will use the time window (-14, 14) to do any type of generation of attributes from the seismic data. The inline crossline stepouts will be 3 until specified otherwise.

3.9 SEISMIC ATTRIBUTES

An attribute is something which defines the particular item that is having some qualities which are able to identify that item. The same is the case with Seismic attributes where attributes are the quantities which are created using the traditional seismic data and these are analyzed for the particular seismic data to understand the geology of the area. The attribute analysis is a major arm of the seismic interpretation where the information about the lithology and the fluid content can be inferred with the help of attributes. The geometrical features such as the dip and the curvatures of the horizon can be studied along with identifying the faults in the area. There are basically two types of attributes (Fig. 3.29):

1. **Physical attributes**: These define the physical properties of the rock such as lithology and parameters relating to the wave propagation. The information about the amplitude and phase and all derived from them are also available through it.
2. **Geometrical attributes** These define the geometrical characteristics of the data. The faults and fractures along with the presence of dip and curvatures on the horizons can be studied.

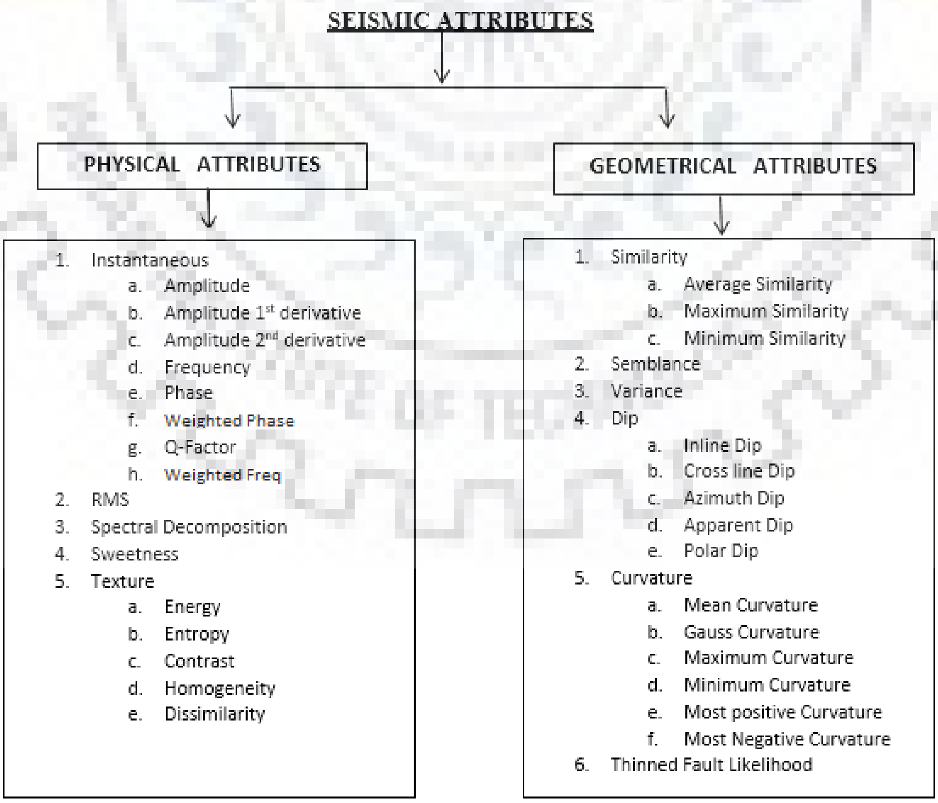


Figure 3.29: List of Geometrical and Physical attributes studied in the project.

3.9.1 Geometrical Attributes

Similarity

Similarity attribute explains the coherency that expresses how similar the two traces are and thus the similarity between two traces is calculated. It contains values ranging between 0 and 1. If the trace segments are completely similar in both amplitudes and waveforms then the similarity of 1 is achieved and a similarity of zero is achieved if both trace segments are quite dissimilar. The similarity is calculated between adjacent traces by using the dip.

It can be used to relate the lateral continuity in the geology and the dissimilarities like faults, fractures can be easily identified by this similarity attribute. The similarity attribute first calculates the most similar points around a central trace and picks the most similar seismic amplitude as the similar event with in the range of search.

$$Similarity = 1 - \frac{\sqrt{\sum_{i=1}^{N}(X_i - Y_i)^2}}{\sqrt{\sum_{i=1}^{N} {X_i}^2} + \sqrt{\sum_{i=1}^{N} {Y_i}^2}}$$

Here N is total traces and X_i and Y_i are trace vectors.

The positions of different traces are defined relative to the other traces as shown in the Fig 3.30. The time gate is in ms and the inline and crossline make a cube in which the similarity is studied. The 2D seismic however uses stepouts instead of inline or crossline.

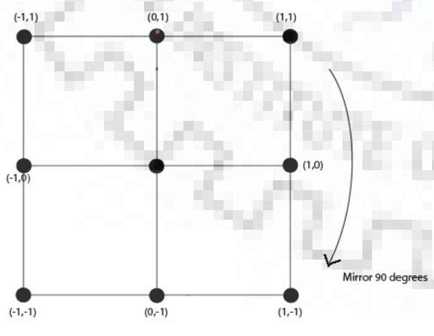


Figure 3.30: Trace position reference relative to the origin (0,0).

The similarity is calculated at various parameters:

- **None:** Here only the traces at the trace positions are calculated.
- **Full block:** All the traces in the block are computed which are used for the calculation of the attribute, the downside is it is not computationally efficient and takes too much time.

- **All Direction:** This type of calculation involves taking in all the possible traces in the star shaped bounded units. For example, in the Fig. 3.30 taking the traces at all the vertices. It is similar in accuracy to the full block but takes very less time in computation.
- **Cross:** Here the traces in the cross fashion are used for computation of attribute. The cross fashion is the '+' column boundary.

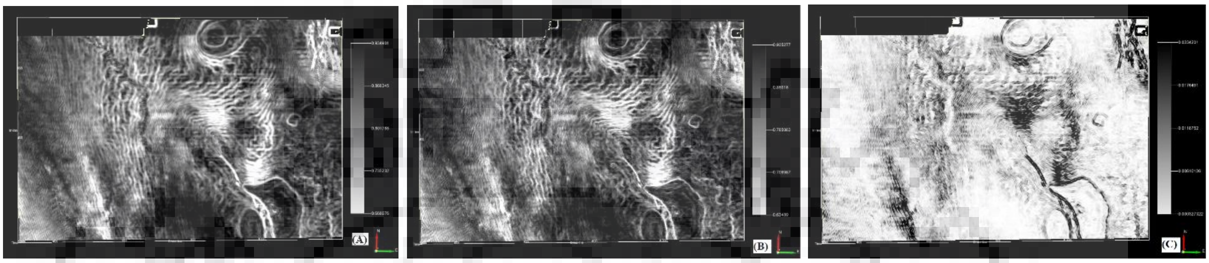


Figure 3.31: A) Average Similarity B) Minimum Similarity C) Maximum Similarity using a stepouts of (-14,14) time window and (3,3) inline and crossline using central steering.

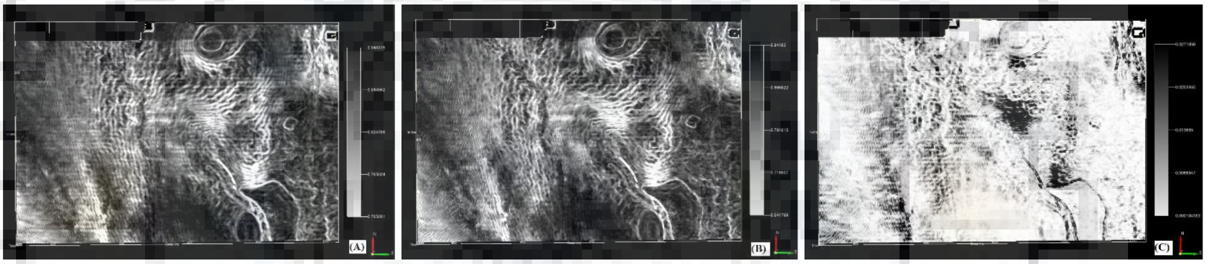


Figure 3.32: A) Average Similarity B) Minimum Similarity C) Maximum Similarity using a stepouts of (-14,14) time window and (3,3) inline and crossline using central steering.

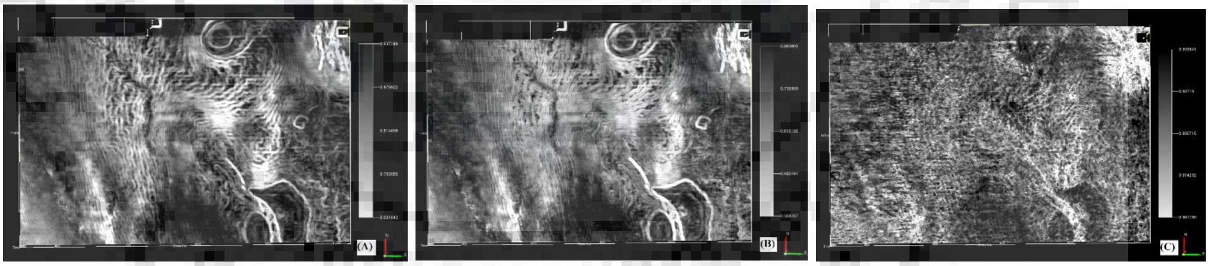


Figure 3.33: A) Average Similarity B) Minimum Similarity C) Maximum Similarity using a stepouts of (-14,14) time window and (3,3) inline and crossline using central steering.

The results of one such study is shown in Fig. 3.31 for all directions, in Fig. 3.32 for crossline and in Fig. 3.33 for full block. The Similarity attribute thus basically helps to identify the faults and fracture in all the configurations and it can be seen that the area of interest has faults along the sides and there is a difference in similarity which is best visible in average similarity in Full block configuration.

Semblance

This attribute helps in returning the coherency of the traces. It is just that how similar are the traces which are studied with the other traces in the defined search window.

It is different to similarity as in it the semblance coefficient is calculated from the data and thus it is different as in it the trace is compared with the other group of traces but in similarity only two traces at a time are studied. Zero denotes completely different traces and semblance comes out to be zero and if semblance is 1 then the traces are identical.

It is however similar to similarity in the analysis and also shows faults and fractures and full block shows better dip azimuths along the area of interest. The attribute is calculated as the square of the energies of the traces are added and it is divided by the sum of energies. If the traces are identical then the value comes out to be high and less if the values are different.

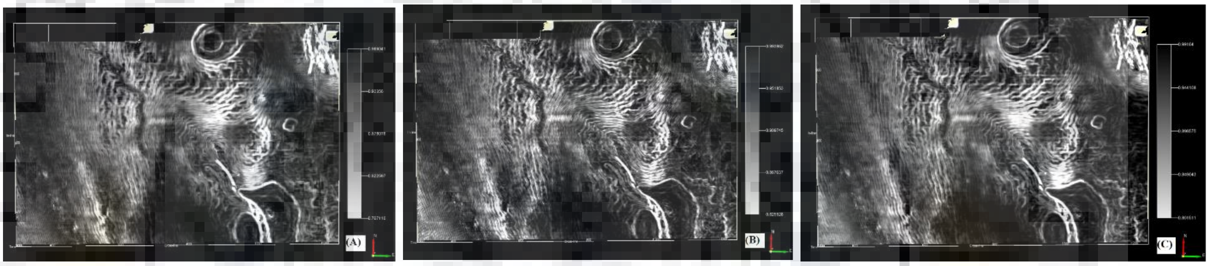


Figure 3.34: A) All Direction B) Cross C) Full Block

The best results in the semblance attribute are seen in the all direction (Fig. 3.34) and computationally also it is efficient. Thus, the faults and fractures which were identified with the similarity attribute are however confirmed with another attribute of same type but the difference is comparing one on one or in a group.

Variance

Variance is a volume statistics attribute that returns the statistical properties of the seismic data. The variance is opposite of semblance and coherency. It defines the variability of the traces from each other in a defined interval and that is due to the change in the AI of the horizon laterally. The traces which are same will produce very less variance and standard deviation will also be less but the traces having high variance shows discontinuities. Generally, faults and fractures show a high amount of discontinuity which is seen in the volume. The sands in the area generally are discontinuous with comparison to shale, so the variance attribute of the sands will be higher than shales. So, our region of study always will be having high variance.

RMS Amplitude shows vertical variations while the variance shows lateral variations and if both the variations are high then the area is some zone of anomalous body which needed to be studied. The Variance is expressed as the square root of the standard deviation. The horizon FS8 which have these 2 patches of high amplitude are shown in Fig. 3.35 which was talked about in the area of interest. The below patch is at inline around 248 and the upper patch is along late inlines around 600. The most of the interest is along the lower patch which is studied using attribute analysis. The bright region of discontinuity may be due to some factors which will be analysed with the help of other attributes.

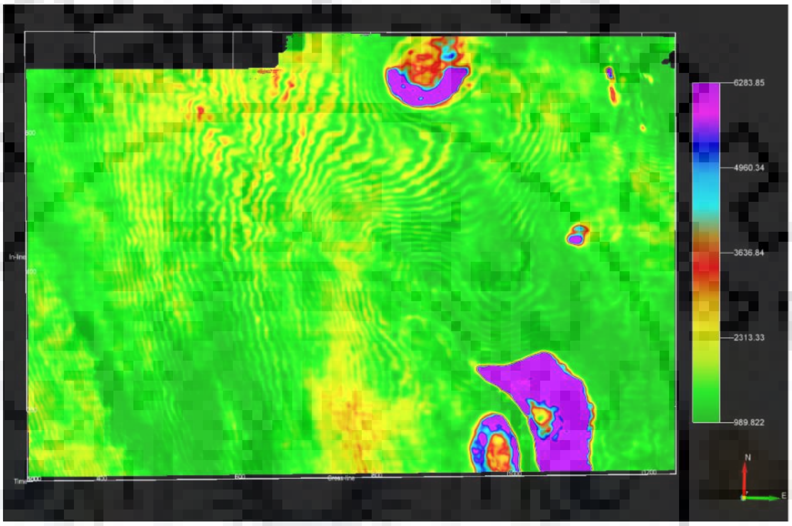


Figure 3.35: Variance attribute at a stepouts of (-14, 14) time window and (3, 3) inline and crossline using central steering.

Dip

The dip attribute is an attribute which calculates the dip of the plane or curve in both 3D and 2D. It fits a best fit plane in the curve and thus the neighbouring traces are studied on a horizon and the dip attribute at each trace are calculated which gives the amount of the dip on that plane. The magnitude is in degrees. The dip is an important property of the plain as it makes the seismic events more visible in terms of the faults and fracture analysis of the area. The dip attribute seen in the direction of inline is inline dip and seen in the direction of crossline is crossline dip. The true dip can be calculated with the Pythagorean triplet of inline and crossline dip. Steering cube which was calculated earlier that gave the central, full steering information is used in the calculation of the dip attribute. The steering cube which was calculated contains the apparent dips along all the angles at 30-degree difference from 0 to 180 and thus it is used to calculate other dips in the dip attributes.

Inline Dip: Inline dip is the dip of the surface in the inline direction. The more the dip is in inline direction the more the surface strike is in crossline direction. It is measured in microsecond per meter or millimeter per meter depending on the time or depth scale used.

Crossline Dip: Dip computed in the crossline direction using crossline dip. The steering cube is used to compute the dip as in inline. Dip is computed in the crossline direction.

Polar Dip: This attribute uses the mathematical Pythagoras theorem as the inline and the crossline dips are the components of dip which is broken into two mutually perpendicular dips and then the Pythagorean triplet of both can be used to create the polar dip which is the true dip of the surface. As it is square root of a number it is always positive. The units are same that is microsecond per meter or millimeter per meter depending on the time or depth scale used. It is only used in 3D as in 2D there is no concept of inline or crossline dip there will be just a dip in the direction of survey.

$$\boldsymbol{Polar\ Dip} = \sqrt{(\boldsymbol{Inline\ Dip})^2 + (\boldsymbol{Crossline\ Dip})^2}$$

Azimuth: The azimuth of the dip is the direction of the dip in degrees from -180 to 180. If the azimuth is zero then the dip is dipping in the direction of crosslines and if the dip is in inline direction then the azimuth will be 90. Positive azimuth is defined from the inline direction to the crossline direction. This attribute is not available in 2D.

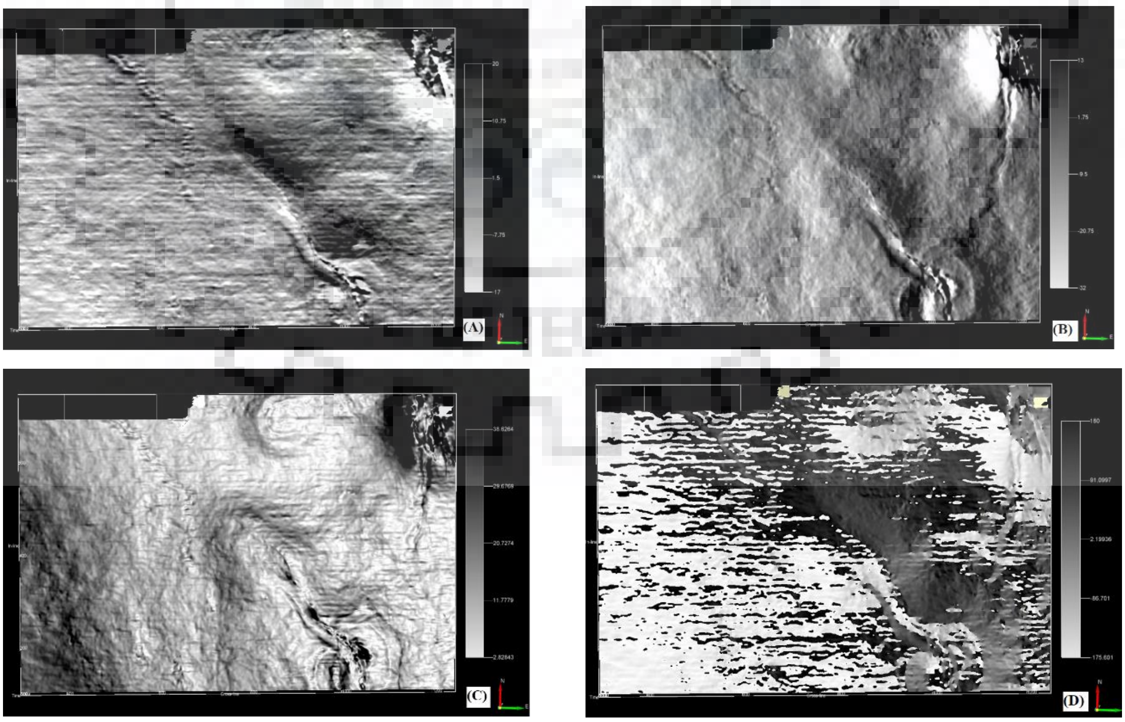


Figure 3.36: A) Inline B) Crossline C) Polar and D) Azimuth Dip

Fig. 3.36 shows the dip in the inline, crossline and the calculated true dip using polar dip attribute. The scale is the dip direction along that direction. The dip amount along an inline and crossline show the tilt along these directions however polar dip returns the net dip of the area in true geological direction. The polar dip thus gives the best results in terms of fault and fracture analysis of the area.

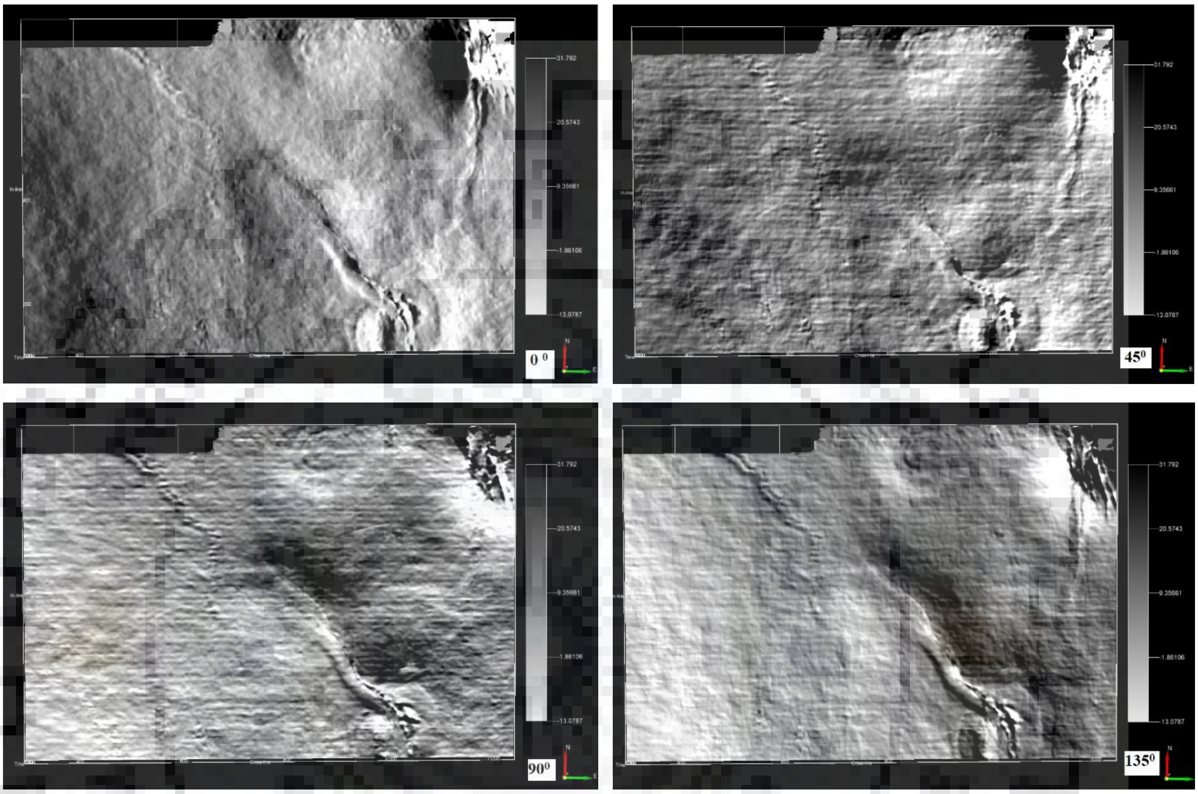


Figure 3.37: Apparent Dip at 0^0, 45^0, 90^0, 135^0.

The apparent dip is the dip along the direction that is measured in the vertical plane but not perpendicular to the strike but at a different direction to the strike. Fig 3.37 shows the dip amount in vertical scale along the directions to the strike thus 0^0 apparent dip is dip along the strike in the 3D and 90^0 apparent dip will give the true dip.

Curvature

The curvature attribute measures the curvature of a particular horizon (Fig. 3.38). It is used to calculate the values of the curvatures at the horizons which include the magnitude of the curvature and its direction. The attributes such as maximum and minimum curvatures measure the magnitude and direction of these curvatures and thus the magnitude of the curvature along the horizons dip direction and along strike direction is a representation of the azimuth and curvature of contours. The curvature attributes are also a second derivative attribute which is also used to delineate the faults and fractures and other structural information of the seismic section.

Basically, in laymen terms the curvature attribute gives the information about how much bent is present on a surface at a location. The curvature is more if the bending is more and less if the bending is less. The positive curvature is when the curvature forms an anticlinal type structure and the negative curvature is when the curvature forms the synclinal structure, but if the structure is planar then the curvature is zero. There can be many curvatures at a surface that is the curvature at any point is infinite that is the plane along with the curvature is studied can be at any angle to the surface which will create the curvature along that plane but the important curvature is the one which is a plane perpendicular to the surface and is called normal curvature (Fig. 3.38).

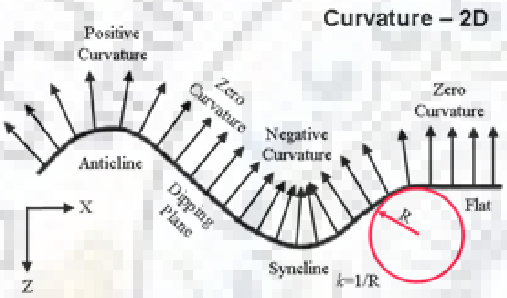


Figure 3.38: Positive and Negative Curvature

Types of curvatures:

Maximum: The largest curvature is the maximum curvature. The absolute value is considered in taking the maximum curvatures. The planes of the maximum and the minimum curvatures are mutually perpendicular to each other.

Minimum: The least curvature is the minimum curvature, that is the surface is least bent at that place. This is not very useful in analysis as the fault and fracture analysis which is our main objective have a large curvatures and not minimum curvatures.

Mean: The mean is the average of the two curvatures and not very useful in identifying the faults.

$$Mean\ Curvature = \ ((Maximum\ Curvature + Minimum\ Curvature))\ /\ 2$$

Most positive and most negative curvatures: This calculates the curvature which has the most positive value and most negative value among the all normal curvatures which can be seen on the surface. It highlights the anticlines and synclines.

Gaussian Curvature: This is a mathematical derivation from the maximum and the minimum curvatures. The product of them calculates the distortion of the surface.

$$\textit{Gaussian Curvature} = \textit{Maximum curvature} * \textit{Minimum curvature}$$

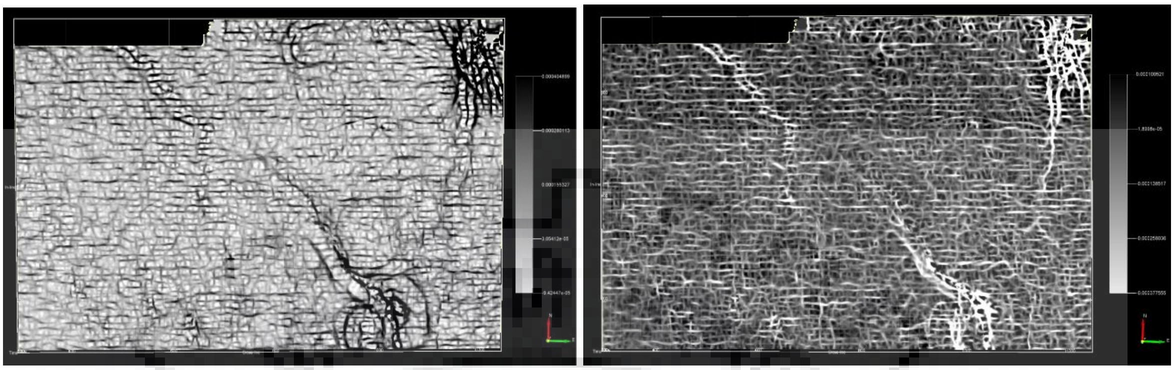


Figure 3.39: Most Positive (LEFT) and most negative (RIGHT) curvature at stepouts of 3 each.

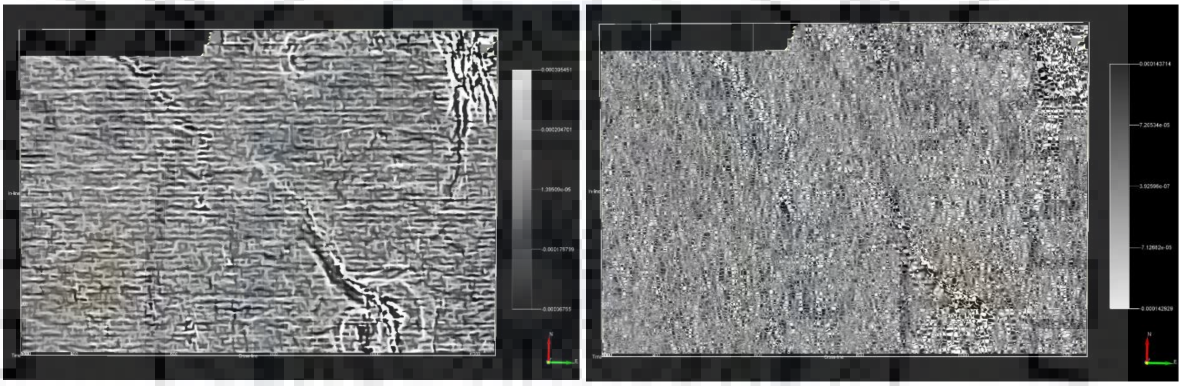


Figure 3.40: Maximum (LEFT) and Minimum (RIGHT) curvature at stepouts of 3 each.

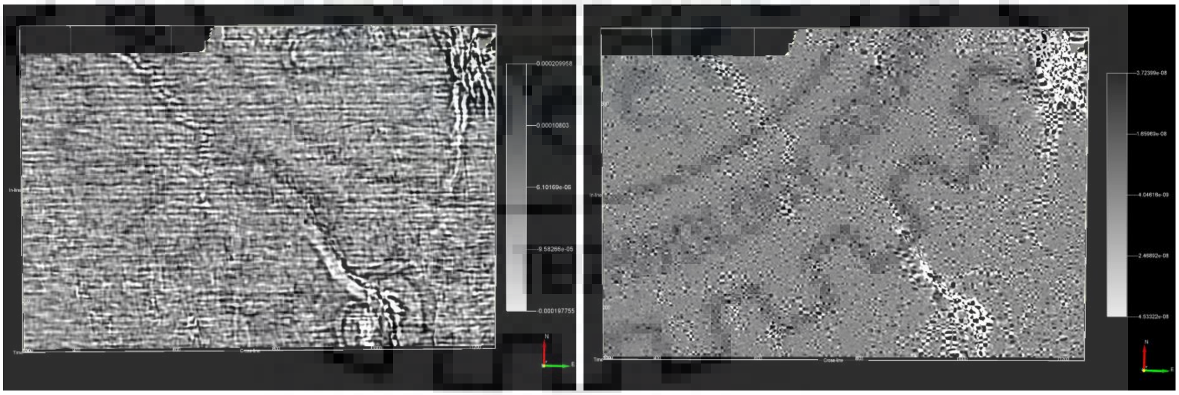


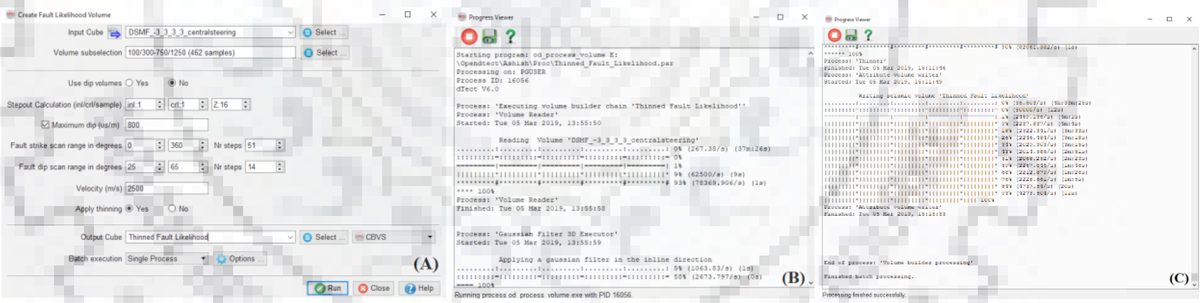
Figure 3.41: Mean (LEFT) and Gaussian (RIGHT) curvature at stepouts of 3 each.

Curvature is a second derivative measure thus it leads to noise in the attribute and hence should be taken with care when analysing. The Most positive and the most negative curvatures shows the best analysis of the dips and faults along with anticlinal and synclinal features (Fig. 3.39). However, the Maximum curvature also provides acceptable result (Fig. 3.40) but that does not give the plane of maximum curvature can also be explained as local maximum rather than global maximum. All other curvature attributes could not delineate the faults and found to be of no use in the analysis as they are susceptible to noises (Fig. 3.41).

Thinned Fault Likelihood (TFL)

It is an OpendTect exclusive attribute that produces very clear faults as if they are drawn on paper. It is the last attribute which is applied in the geometrical attributes category as this is the best attribute to delineate the faults in the horizon. However, this attribute cannot be run in the starting as this produces a complete cube of the 3D seismic and not just the horizon or inline specific. Thus, the calculation on the complete horizon takes time and thus it is not advisable to use it in early phases of interpretation. It also uses the coherency function to find the value of the semblance from zero to one. Thus as the name suggest it captures the places having maximum and minimum likelihoods which create the fault map of the zone.

Lastly to get the most information from the data thinned fault likelihood was run on the complete volume and a cube was made for the entire data. Then the cube was applied as an attribute on the horizon. The algorithm in thin fault likelihood calculates the faults at every 30 degree in the 360degree data and then combines the complete analysis in the volume showing all the faults (Fig. 3.42).



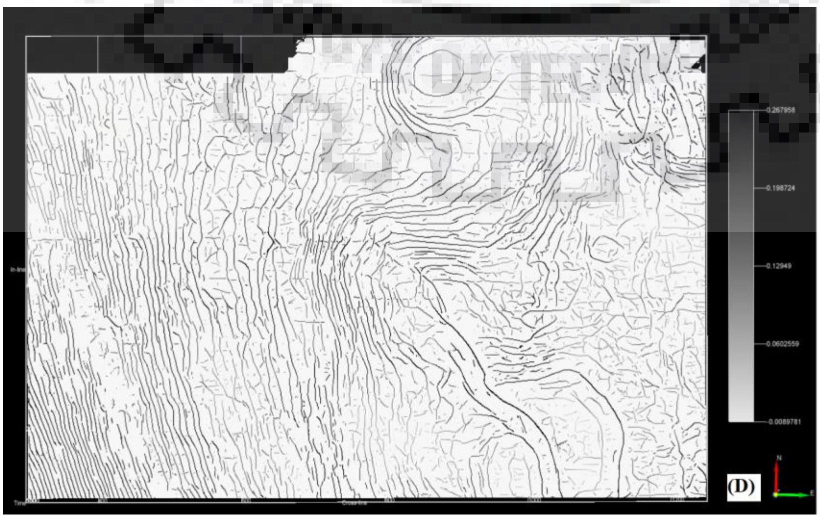


Figure 3.42: A) Creating thin fault likelihood volume with stepouts of 1,1,16 in inline, crossline and Z and specifying the maximum dip to be 800us/m. B) Progress window in starting. C) Progress window after completion of attribute generation. D) Thin fault likelihood attribute on the horizon FS8.

The thin fault likelihood is one of the recent attributes which give the best indication of fault and fractures in the Seismic Horizon and this attribute is calculated in the end of the geometrical attribute study to show all the remaining faults which could not be seen in similarity, dip and curvature attributes. It clearly shows the faults in the horizon (Fig. 3.42).

3.9.2 Physical Attributes:

The physical attributes as the name suggest are the attributes showing the physical characteristics of the lithology, the propagation of waves and the other rock properties and not about the amplitude of the seismic waves. These attributes are the main ones for the characterization of the reservoir and for classification of the lithology of the area.

Instantaneous Attributes

These attributes are different from other attributes as they calculate the value at the specified location and not by creating a cube and then doing math on the values within that. The instantaneous attributes are considered as the combination of both the real and imaginary traces which is a complex trace attribute.

The real and complex trace can be analyzed as the energy being converted to kinetic and potential when moving. The Real trace is the kinetic energy when the particles move from their natural position and potential energy is when they store energy and the energy moves forward to another particle (Fig. 3.43). Thus, the oscillation between kinetic and potential energy is observed. The complex trace is defined as:

$$C(t) = T(t) + iH(t)$$

Where, **C (t)** is the complex trace which is studied in these attributes.

T (t) = It is the real part of the seismic trace which is actually recorded from seismic data.

H(t) = It is the imaginary part of the trace and this is not recorded but is computed by Hilbert transforming the real part and as it is complex so it is at an angle of 90^0 from the real part.

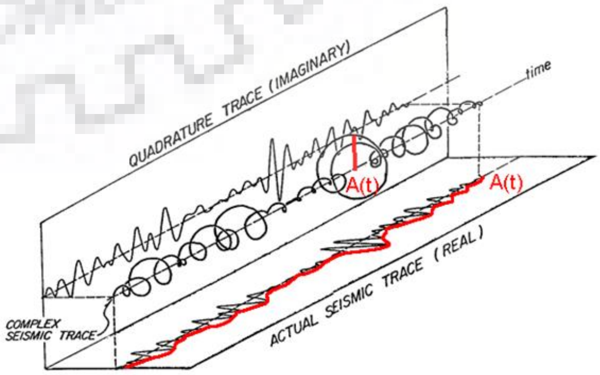


Figure 3.43: Complex Seismic Trace Attributes (Ref: Tanner, 1977)

Instantaneous Amplitude A (t)

$$A(t) = \sqrt{[T^2(t) + H^2(t)}$$

The instantaneous amplitude is the amplitude of the complex trace attribute at any point. It is computed using the formula given above which gives the total amplitude of the reflection at that point. The amplitude signifies the energy at that point in time and place. The energy is directly related to the presence of some high reflections in the area which may be due to some factors such as bright spots and carbonates deposits. The envelope of the instantaneous amplitude is an important attribute as it lacks the phase information and thus helps in understanding lithology and changes in deposition without considering the changes in phase due to those depositions.

The main uses of Instantaneous amplitudes are:

- It represents AI contrast and therefore reflectivity can be obtained.
- Bright spots are visible which can be probably due to gas accumulation.
- Thin-bed tuning effects can be studied using Inst. Amp as amp will be distorted if tuning takes place.
- Major changes in depositional environments can be studied using amplitude analysis.

As the instantaneous amplitude is the amplitude at the location of the trace rather than a cube as in that of RMS, the results of instantaneous amplitude are similar to that of RMS in Fig. 3.44 and hence this states that the amplitude is due to some anomaly and not due to other factors. Also, this states that the bright reflection which is the study area is not only on the horizon FS8 which we are studying but is a thick patch above and below this horizon whose thickness will be studied using spectral decomposition attribute. The study zone has a bright reflection and thus that high amplitude is shown in the instantaneous amplitude attribute as a high reflection.

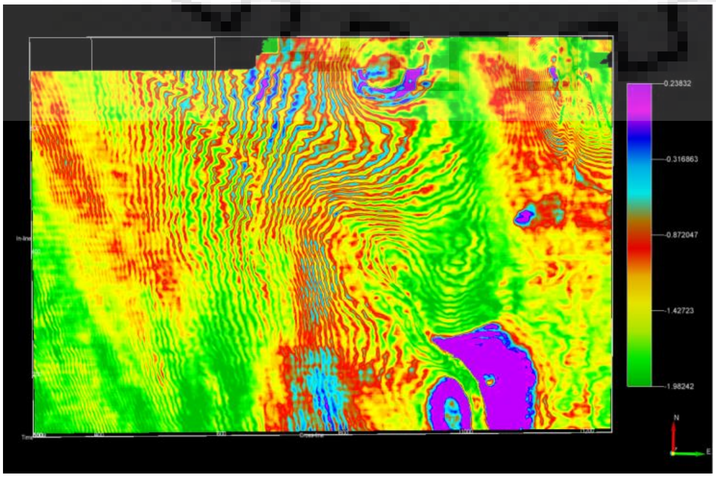


Figure 3.44: Instantaneous Amplitude attribute on Horizon FS8.

Amplitude 1st derivative ***RE (t)*** and 2nd derivative ***R^2E (t):***

$$RE(t) = dE(t)/dt \qquad\qquad R^2E(t) = d^2E(t)/dt^2$$

The amplitude 1st derivative is the rate of change of amplitude with time and thus it shows the change in the energy of the reflected event with time (Fig. 3.45). The events which will have a increase in the 1st derivative shows that the lithology there is having less absorption characteristics and thus is used in studying the lithology using the absorption characteristics of the rocks.

This gives information about:

- The change in reflectivity as rate of change of amplitude or energy and is also related to the absorption of energy that is if the rate of change of energy is more and energy is reducing thus it shows that the rocks nearby have more absorption characteristics.
- Sharp interfaces can be studied as they will be rate of change of energy.
- Discontinuities can also be studied if there is high rate of change of energy.

The 2nd Derivative gives the change in the sharpness of the amplitudes which are studied (Fig. 3.45). The derivative of the 1st derivative is the 2nd derivative so if the energy is increasing at a faster rate than the second derivative will be high and vice versa.

The first derivative of the instantaneous amplitude clearly denotes the discontinuity in the area as it shows high amplitude so the rate of change of amplitude along the study area is high which means that the energy is changing that is increasing so the rocks in the study area show a less absorption characteristics and the low instantaneous second derivative show that the rate of increase in the energy is less.

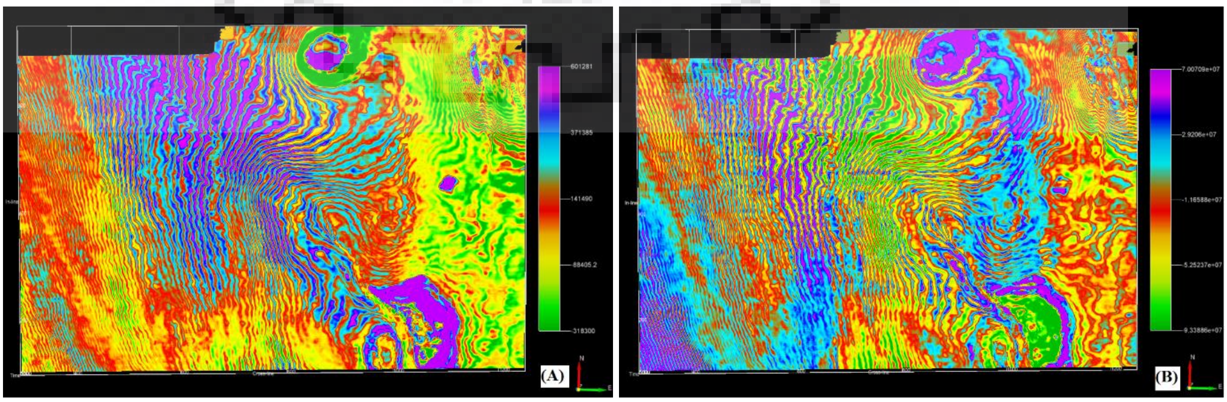


Figure 3.45: A) Instantaneous Amplitude 1st Derivative B) Instantaneous Amplitude 2nd Derivative

Instantaneous Phase Φ (t):

The instantaneous phase attribute is the tan inverse of the complex to the real components of the seismic trace (Fig. 3.46A). It outputs the phase of the data at the sample point and thus as phase remains same for a formation with same depositional characteristics, it acts as an attribute to study the depositional information about the data. It can also be used as a lateral continuity indicator as phase changes when the continuity breaks.

$$\Phi(\mathrm{t}) = tan^{-1}\left|\frac{H(t)}{T(t)}\right|$$

The Seismic Trace can be obtained from the amplitude spectrum that is the instantaneous amplitude and the phase information as shown in the equations:

$$T(t) = A(t) * cos\Phi(\mathrm{t})$$

$$H(t) = A(t) * sin\Phi(\mathrm{t})$$

The main advantage to use the instantaneous phase attribute is that it lacks the amplitude information of the reflections and this leads to visibility of all the reflections irrespective of the less amplitude or high amplitude reflections. The applications of instantaneous phase are:

- If low frequency anomaly then it can be due to hydrocarbon.
- As it shows the lateral continuity of reflections so it can be used as an indicator of fractures and thus called as fracture zone indicator.
- The phase component of the wave propagation is related with it.

Envelope weighted phase: This is the envelope of the instantaneous phase (Fig. 3.45B) and is the attribute formed by choosing the peaks and troughs of the waves to form new attribute.

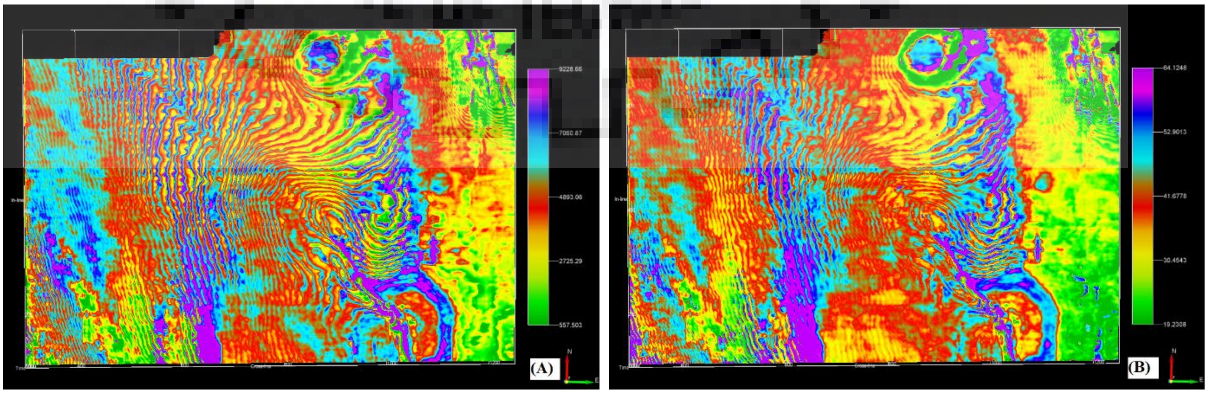


Figure 3.46: A) Instantaneous phase B) Instantaneous envelope weighted phase

The instantaneous phase is constant in the area of study that is it is showing to be red colour and pink continuous in the outer side and it states that the events in the region are continuous as it represents the continuity of reflections. The continuous phase represents that the deposition is a single deposition not due to some foreign material in the zone and thus the bright reflections is due to some geological factors and not due to movement of some foreign material and residing in the area. The envelope of the phase is taking the max or minimum of the curves and not the curve in general thus the frequency of the curve reduces and it gives a general trend.

Instantaneous Frequency

Instantaneous frequency attribute is related to the power spectrum of the seismic wavelet as the frequency is rate of change of phase (Fig. 3.47A).

The attribute can be used as a direct hydrocarbon indicator as if there is a hydrocarbon present it will show less frequency with relative to the surrounding and this effect is generally seen in unconsolidated sands where there is the presence of oil or gas in the pore spaces of the sand grains.

It also acts as an indicator of thin beds in the area as according to tuning thickness the h thickness body can be delineated with a wavelength which is at least one fourth of the wavelength used in the survey. If the frequency decreases after that destructive interference occur and bed is not visible. Thus, low frequencies can map massive bodies but high frequencies are needed to map thin bedding.

Envelope weighted frequency: This is the envelope of the instantaneous frequency and is the attribute formed by choosing the peaks and troughs of the waves to form new attribute (Fig. 3.47B).

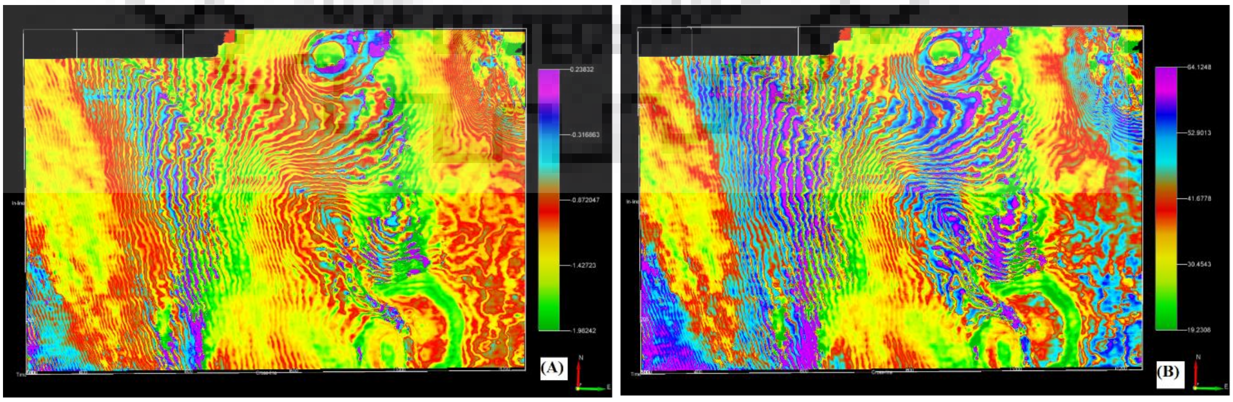


Figure 3.47: A) Instantaneous frequency B) Instantaneous envelope weighted frequency

The area of study shows a less frequency value in the zone (Fig. 3.47). The outer zone is having a very less frequency however the internal zone also has a low relative frequency and thus it is an indicator of some hydrocarbon in the zone which may be producing a bright spot but it cannot be confirmed without other attributes and this attribute must be used with amplitude attribute which will confirm our predictions which will be done in the further analysis. The envelope attribute is the same as in phase and gives a more generalized trend.

Q-Factor (Q):

It is an attribute derived from the instantaneous frequency that is the ratio between the instantaneous frequency and bandwidth with a factor of 2 in the denominator.

$$Q(t) = {}^{-F(t)}\big/_{2 * B(t)}$$

Where, F(t) is the instantaneous frequency

B(t) is bandwidth given by which is given by: $B(t) = \frac{\frac{dE(t)}{dt}}{2\pi E(t)}$

From above formulas, the Q factor is the:

$$Q(t) = \frac{-\pi F(t)E(t)}{\frac{dE(t)}{dt}}$$

Figure 3.48: Q-factor attribute

This attribute is useful as it can be used to study the absorption characteristics of beds (Fig. 3.48). Here Q factor is negative as the formula suggest so we will have to compare the relative values of Q factor and not the absolute value. As Q factor is inversely proportional to the attenuation characteristics of the beds thus the high q factor will give the less attenuation and thus less absorption characteristics. As in the Fig. 3.48 the study area shows relatively large qfactor thus the study area shows low absorption characteristics. It was also shown in Fig. 3.45 what the study area is having low absorption characteristics as the energy was increasing in the 1st derivative of instantaneous amplitude and this Q factor attribute proves the result of that attribute. Sands have a high q factor compared to shale and thus can be used to indirectly study the lithology of the area.

Spectral Decomposition

Spectral decomposition is a new seismic attribute which aims to convert the time section of seismic into its frequency components. As discussed earlier the frequency which will be able to delineate some beds depend on the thickness of the beds. Here 1D seismic traces are converted into the 2D time and frequency representation of traces. Thus, this technique is used to study the seismic data at a resolution which is not possible in the traditional seismic section and also it can be used to study the effect produces by hydrocarbons which causes the attenuation of the waves. This method produces a time-frequency spectrum of a seismic trace as shown in Fig. 3.49.

Thus, Spectral decomposition is used to estimate the thickness of the layer qualitatively. And by taking a horizon surface and studying the spectral decomposition on it using different frequencies we can study the thickening and thinning directions in the surface. It can also be used as a direct HC indicator as low frequency shadows appear under hydrocarbon reservoirs. The transformation can be done either by using either FFT which is used to delineate the structural or stratigraphic information or by using Continuous Wavelet Transformation which is used to delineate the thickness changes.

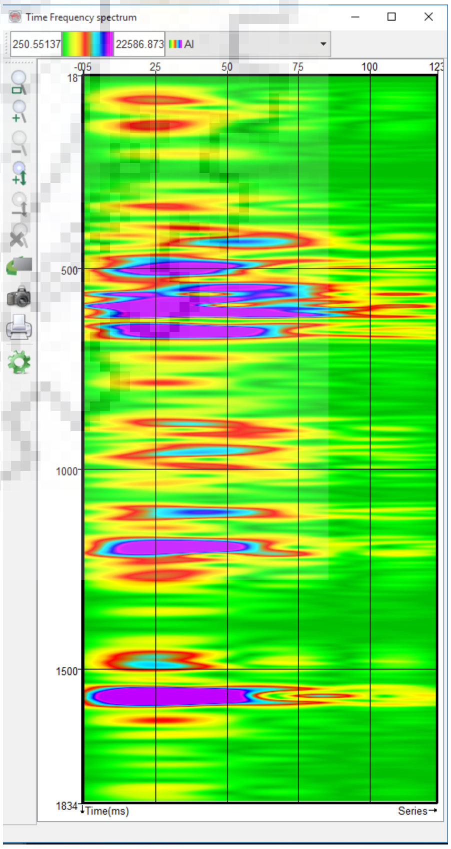
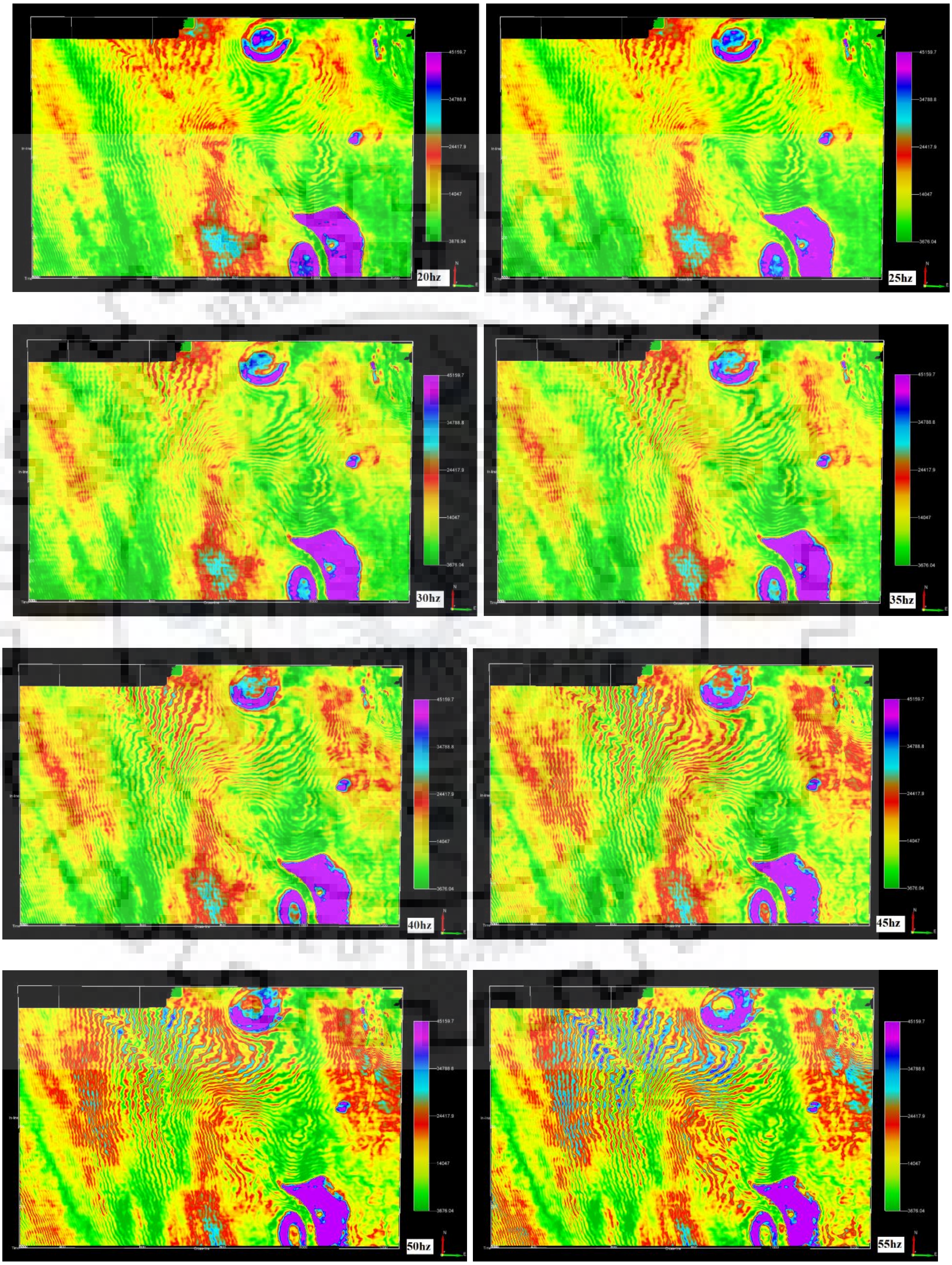


Figure 3.49: Time frequency panel generated before spectral decomposition to study the dominant frequencies at different time in the data.

Fig. 3.49 shows the frequency which are mostly available at different times, as most of the pink patch which states the presence of particular frequency is around 20 to 75 so the spectral decomposition is done in this range for the horizon FS8.



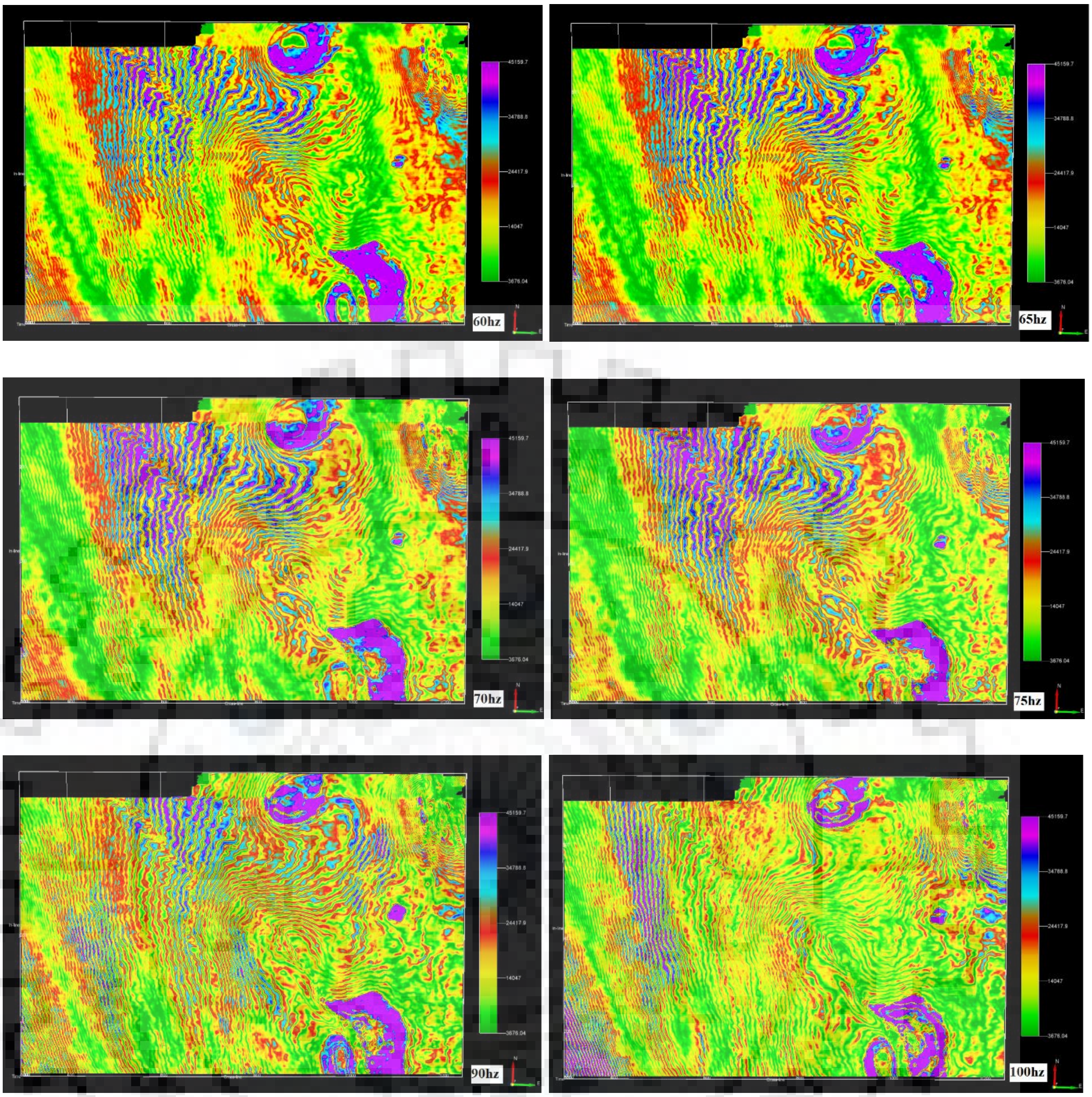


Figure 3.50: Spectral Decomposition attribute from 20 Hz to 75 Hz at a step of 5 Hz and at 90 Hz and 100 Hz. FFT Algorithm was used with a stepouts of (-14, 14).

The Spectral decomposition is (Fig. 3.50) directly related to the bed thickness and thus the bed which less thickness needs to be delineated with high frequency thus when the frequency is increased the beds with less thickness are also visible so to compare the thickness of the beds we can analyse the decreasing frequencies and when the bed disappears on the frequency that will be the optimum frequency of the bed and using that thickness can be generated. In this thesis we are not going to quantitatively evaluate the thickness however the qualitative interpretation is done. The horizon FS8 is located at around 800 to 1000ms so the analysis of the Fig. 3.49 that is time frequency panel shows that the maximum amplitude at around 40 Hz-45 Hz for the horizon and thus the area of analysis is best visible at that frequency.

As **v=f*λ**, Taking the velocity to be around 2500m/s. This was taken from the well log correlation table which gave the time-depth curve and thus velocity model was generated. Thus λ=v/f=2500/42.5=58.8m. As tuning thickness is the thickness for the layer and tuning thickness is h= λ\4. Thus h= 14.7m. Thus, the thickness of the patch is approximately 15m on the horizon.

RMS (Root Mean Square) Amplitude

RMS amplitude as the name suggest is taking root mean square of the amplitudes in a sample chosen which creates the window and within that window the RMS is calculated and replaced with the central point which will give the information about the amplitude information in the vicinity of the point and is different from instantaneous where only the amplitude at the point is considered. As it is the Root mean square so with the data the noises will also be squared and thus it is susceptible to noise.

$$RMS = \sqrt{\sum_{i=0}^{n} \frac{{A_i}^2}{n}}$$

Here the amplitude is A and the "i" is the sample and 'n' represent the total number of samples in the specified time gate.

It is directly related to the amplitude of the reflection and thus reflectivity so as the region of the study shows high amplitude so the RMS amplitude will be also high and as the time gate is -14 to 14 so the high amplitude is not just on the horizon as seen in instantaneous but also above and below it (Fig. 3.51). This is just a direct indication of energy in the region and used to compare with instantaneous attributes like instantaneous amplitude.

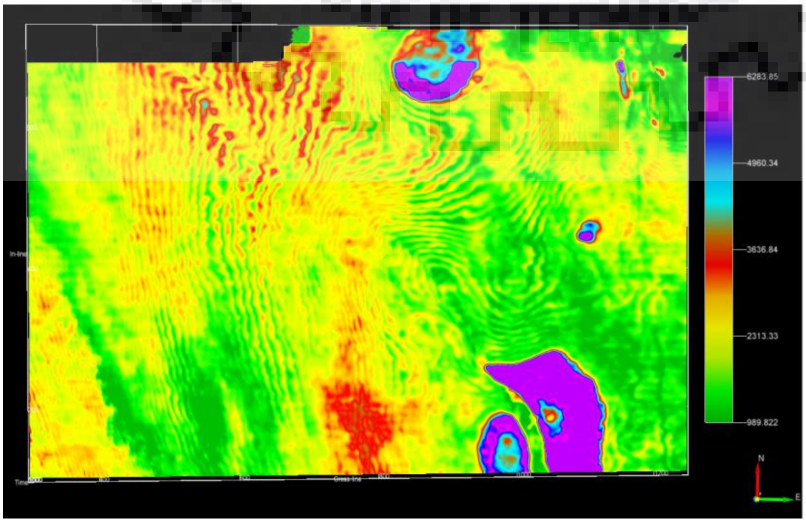


Figure 3.51: RMS amplitude attribute at horizon FS8 using central steering at a stepouts of (-14, 14) in time and (3, 3) in inline, crossline.

Sweetness

This is a new attribute created to be used as a DHI (Direct Hydrocarbon indicator). It is used as a simple tool to highlight thick clean reservoir, and hydrocarbons (HC) filled reservoir (Fig. 3.52). It is being calculated by dividing the amplitude attribute value with a frequency attribute value. The only drawback of this attribute is that in the areas of coal it misleads the interpreter and needs to be supported by other attributes.

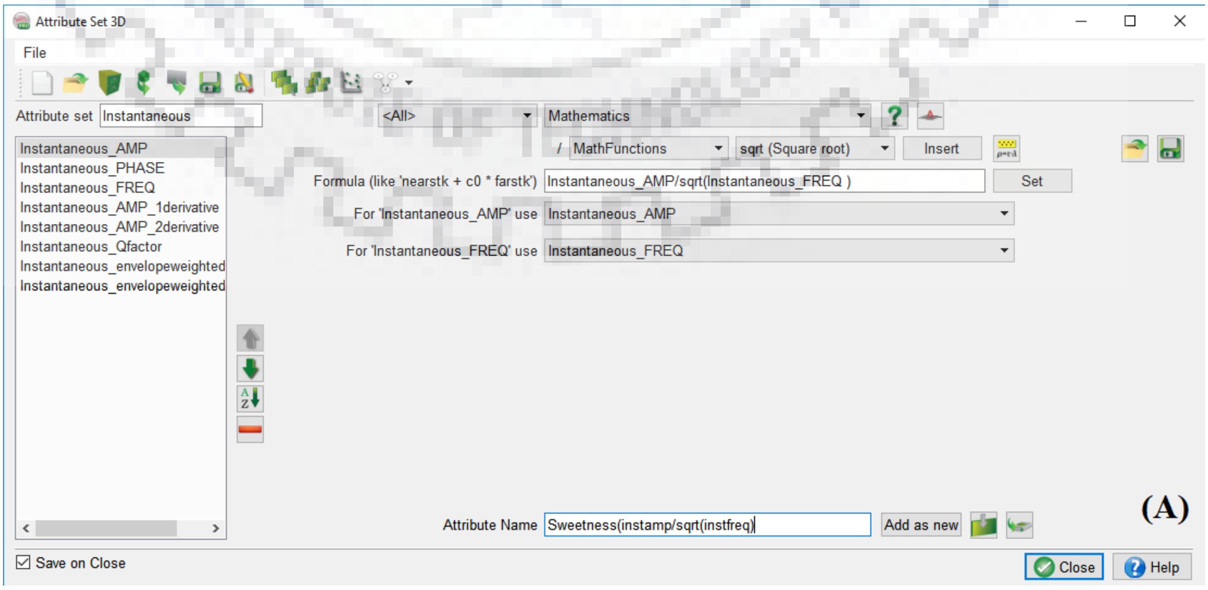
- For reservoir (low AI sand embedded in shale): Amp: High and Freq: Normal
- For HC presence, the effects are when HC gets introduced, Amp: Higher and Freq: Lower so the combined effect is that the sweetness is high in this case.

Mathematically, Sweetness is given by the ratio of amplitude and root of frequency of the instantaneous attributes.

$$Sweetness = \frac{instantaneous\ amplitude}{\sqrt{instantaneous\ frequency}}$$

The reflections from the shale lithology is characterized by the low amplitude reflection (small AI contrasts) and closed reflections that is discerned by high frequencies. However, the sand reflections are high amplitude corresponding to channel deposits and also show a broad low frequency component if the fluid is hydrocarbon.

The nature of the reflection that is the movement from sand to shale or shale to sand is not important as the instantaneous amplitude is always positive and only the phase will change in these circumstances which does not affect the formula of sweetness.



(A)

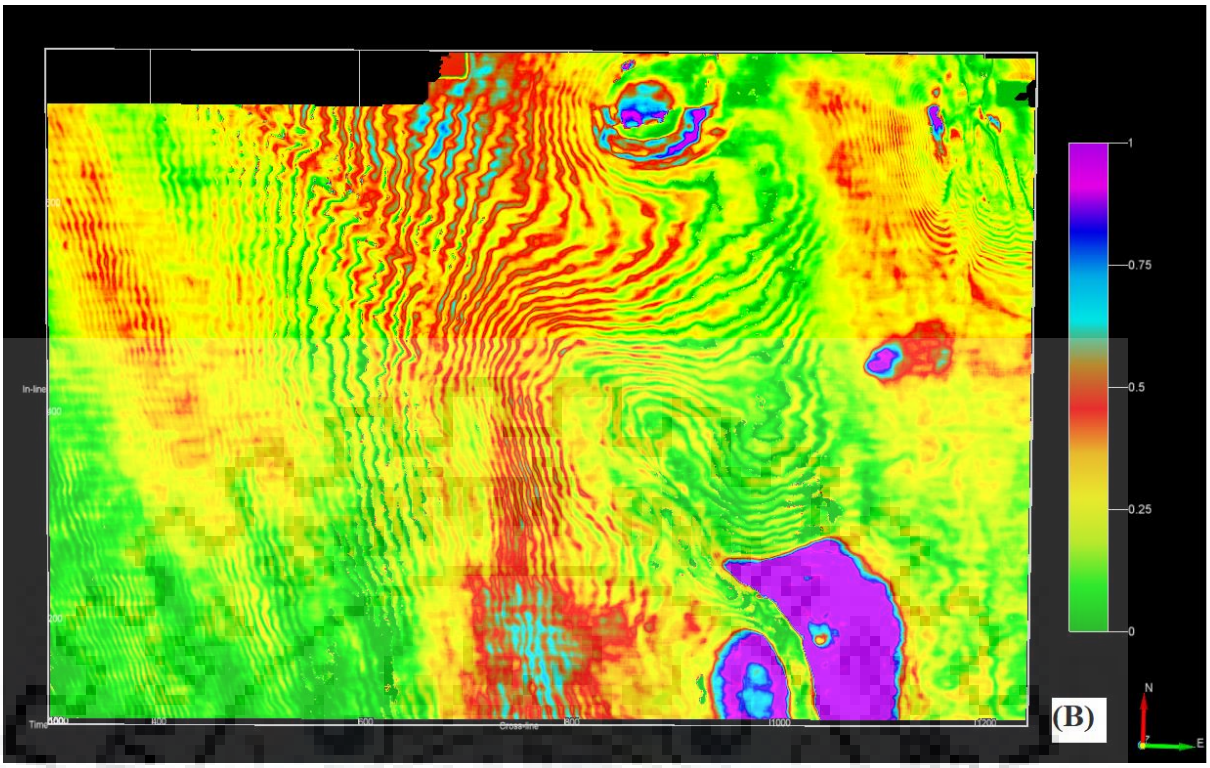


Figure 3.52: A) Creation of the Sweetness attribute which is using the math function. B) The sweetness attribute applied on the horizon FS8.

The Fig. 3.52 shows the creation of the sweetness attribute using the match function in the OpendTect and then applying the attribute on the horizon FS8. The area of study shows the high value of Sweetness which is a direct indicator of the gas in the zone. However, the texture attributes will be applied on the horizon to confirm the same and thus the texture attributes can directly establish the lithology and the fluid in the lithology using the integrated analysis of different texture attributes (Fig. 3.53).

Textural Attributes

These attributes are first used (Fig. 3.53) as the comparison of the texel or the pixel value of the image which is the seismic section. The approach however was not very useful as the seismic reflections could not be accustomed to a particular geology and thus the next approach of using the GLCM was found to be useful in the texture attributes. The properties of the images are captured with GLCM such that the uniformity and the smoothness of the image.

The GLCM is a n dimensional matrix which contain the dynamic range of data upto n dimensions. For example, if the dynamic range are set from 1 to n then when cruising through the image, when it is divided into texel the individual texel is studied with its pair which is the neighbour to the that texel and the amplitude corresponding to every texel is studied and a probability matrix is formed which tells the probability to find the neighbouring amplitudes in the area. The matrix is normalised by dividing the total matrix with the total number of occurrences of the data.

Texture attributes are the main attributes with definite results in facies analysis that is the study of the lithology along with the environment. The GLCM matrix size is given by the GLCM size and generally 32 x 32 give better result but the speed reduces and the computation time reduces. The data can be studied in both 4 bit which contain 16 values from 0 to 15 or 5 bits which contain 32 values from 0 to 31. Thus, these two are GLCM 16 and GLCM 32 respectively.

For the equations used afterwards (i,j) is the column and row whereas P is the probability matrix. N is the size of the matrix.

Energy

Texture Energy is the measure of uniformness in the image (Fig. 3.54). If the elements in the image are similar the texture energy of the image will be low but if the elements are different then the energy of the image will be high. For example, in shales all the particles are similar and sorting is more and grain size is almost same so the texture energy in shales is low, however in sands there is a large amount of difference in grain sizes and thus energy is high. It helps to delineate the geometry of reflections and the continuity of reflections.

Entropy

$$Entropy = \sum_{i,j=0}^{N-1} P_{i,j}(-lnP_{i,j})$$

It is the reverse of energy and is a measure of disorderness in the seismic data (Fig. 3.55). As entropy in chemistry is the energy which is lost and cannot be recovered to do some work. It represents the disorderness in the system and the same applies to the texture attributes. The formula to calculate the entropy from the probability matrix is shown in the above equation.

Contrast

$$\boldsymbol{Contrast = \sum_{i,j=0}^{N} P_{i,j}(i-j)^2}$$

When i=j, the cell is on the diagonal and thus (i-j) =0. Thus, it signifies the value is entirely similar to the neighbor and then a weight of zero is assigned to the contrast.

If (i-j) =1, then w= 1 and when (i-j) = 2, w is 4, where w is the weight of the probability matrix value at the (i,j) point. The contrast keeps on increasing if the difference between adjacent cells increases (Fig. 3.56).

Dissimilarity

$$Dissimilarity = \sum_{i,j=0}^{N-1} P_{i,j}|i-j|$$

Here it is similar to contrast just the difference is that the weights are increasing linearly and not quadratically (Fig. 3.58).

Homogeneity

$$Homogeneity = \sum_{i,j=0}^{N-1} \frac{P_{i.j}}{1+(i-j)^2}$$

Dissimilarity and Contrast are around the same but the factor which is changing the value changes. When the (i-j) decrease away from the diagonal the attribute will result in little contrast. Homogeneity is opposite of contrast and need not to be defined individually and is the value opposite of contrast (Fig. 3.57).

Texture attributes were tried with different GLCM size that is 16 and 32 and on time window (-14,14) with a stepouts of 3 in inline and crossline direction and the GLCM size 32 best delineated our area of interest with the expense of more computation time.

Integrated analysis of Texture Energy, Entropy, Contrast and homogeneity was used to delineate the sands and shales on the horizon FS8.

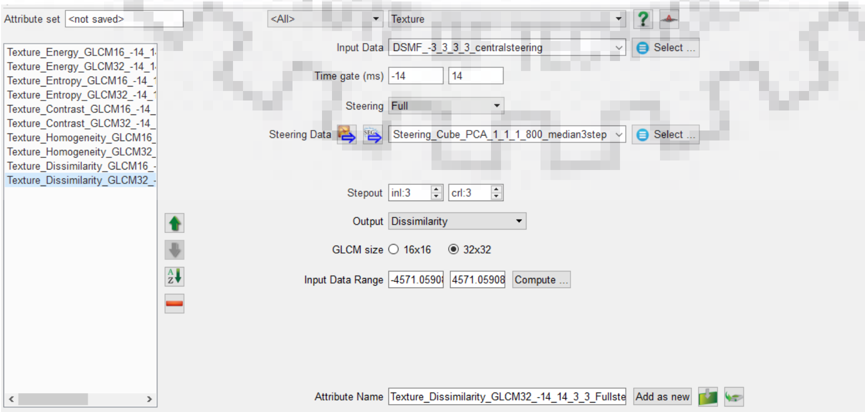


Figure 3.53: Creation of Texture attributes at time gate of (-14, 14) ms and stepouts of (3, 3) in inline and crossline at GLCM 16 and 32.

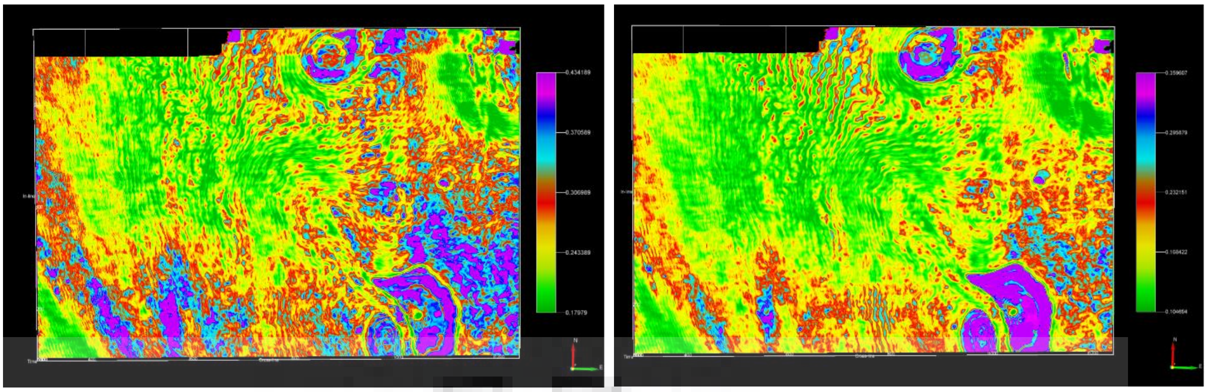


Figure 3.54: Texture Energy at GLCM 16(LEFT) and GLCM 32(RIGHT).

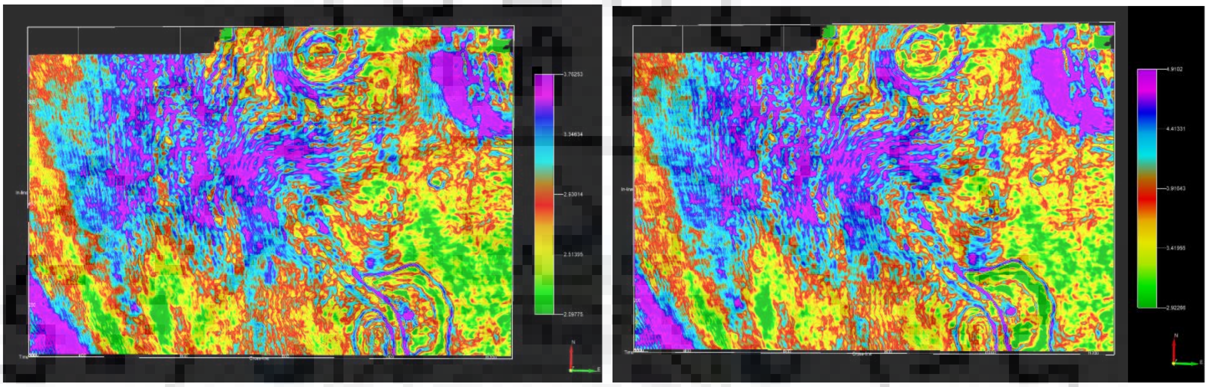


Figure 3.55: Texture Entropy at GLCM 16(LEFT) and GLCM 32(RIGHT)

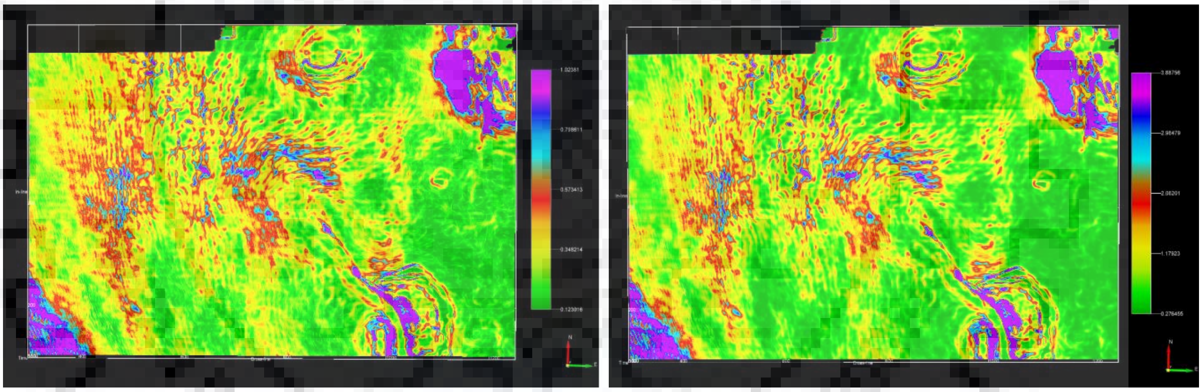


Figure 3.56: Texture Contrast at GLCM 16(LEFT) and GLCM 32(RIGHT)

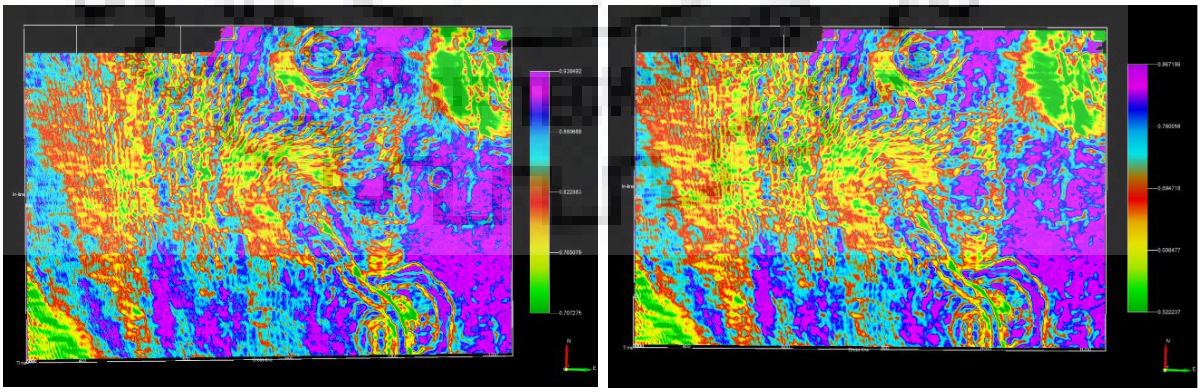


Figure 3.57: Texture Homogeneity at GLCM 16(LEFT) and GLCM 32(RIGHT)

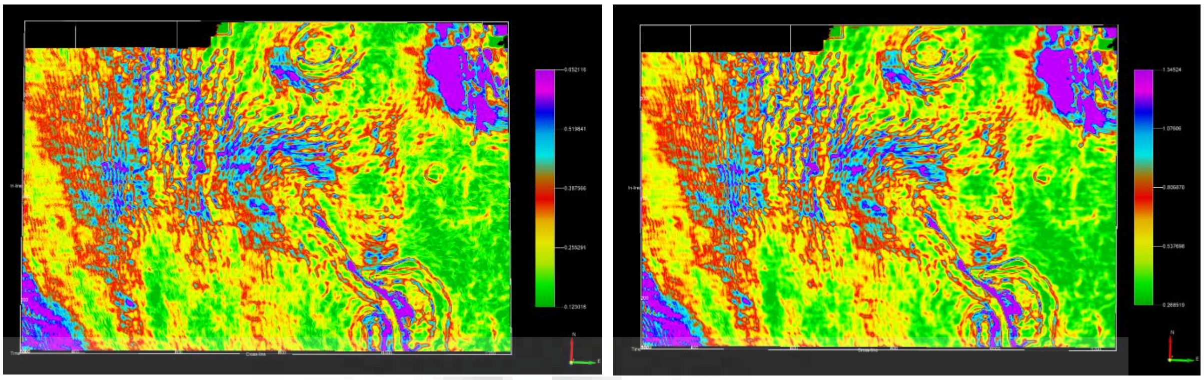


Figure 3.58: Texture Dissimilarity at GLCM 16(LEFT) and GLCM 32(RIGHT)

In the previous attribute analysis that is sweetness we identified our region to be hydrocarbon bearing and to confirm we used another set of attributes that is texture and thus with the reference to paper by Chopra (2006) on Texture attributes we can come to the conclusion that hydrocarbon accumulations having low frequency and high amplitude which was proved till now show Energy to be high and entropy and energy low for HC deposits. Fig. 3.54 shows the texture energy to be high in the region of interest along with Fig. 3.55 shows that the entropy is low in the region with Fig. 3.56 showing low contrast in some and high in some in the study area so the low contrast area is definitely containing hydrocarbon and this shall be proved will the help of impedance inversion that will be the final study about the hydrocarbon properties in the area.

3.10 SEISMIC INVERSION

Seismic inversion is the process of transforming reflection seismic data which is the main amplitude information in traditional seismic section to a petrophysical information of reservoir. The seismic inversion is both pre and post but here since we are dealing with post stack data, we will undergo post stack seismic inversion. There are different types of post stack inversion that is deterministic, random and geo-statistical, these differ from each other in the process of model choosing and iterations to be performed along with inversion algorithm. Seismic data is interpreted with the help of inversion, as it provides a detailed section of subsurface and not just the amplitude information.

Inversion advantages are:

- It increases the resolution of the seismic data and make it more reliable for interpretation.
- Other rock properties can be derived after inversion which helps the interpreter.

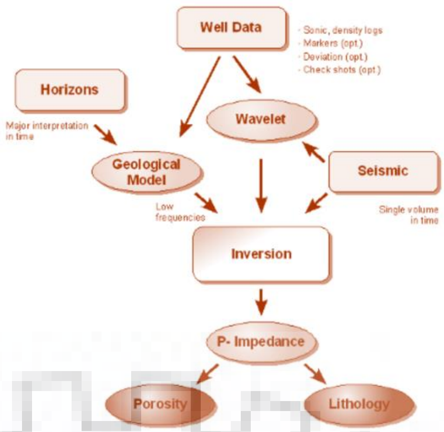


Figure 3.59: Flowchart of Seismic Inversion.

A typical workflow for post-stack inversion consists of the following steps (Figs. 3.59, 3.60):

1. Starting Geoview which is the main window in HRS.
2. Loading wells and seismic in geoview.
3. Loading the key horizons which will be used for inversion model creation and analysis.
4. Correlating each well with the seismic volume to optimize the depth-to-time conversion. The seismic to well tie should be done for all wells using the same wavelet which is generated using all the wells in the wavelet extraction window.
5. Now building an initial model for inversion which shall be low frequency.
6. Runing inversion analysis to determine inversion parameters and changing them as per need of the inversion.
7. Running the inversion over the entire volume and then applying on the horizon of interest and then the area of interest.

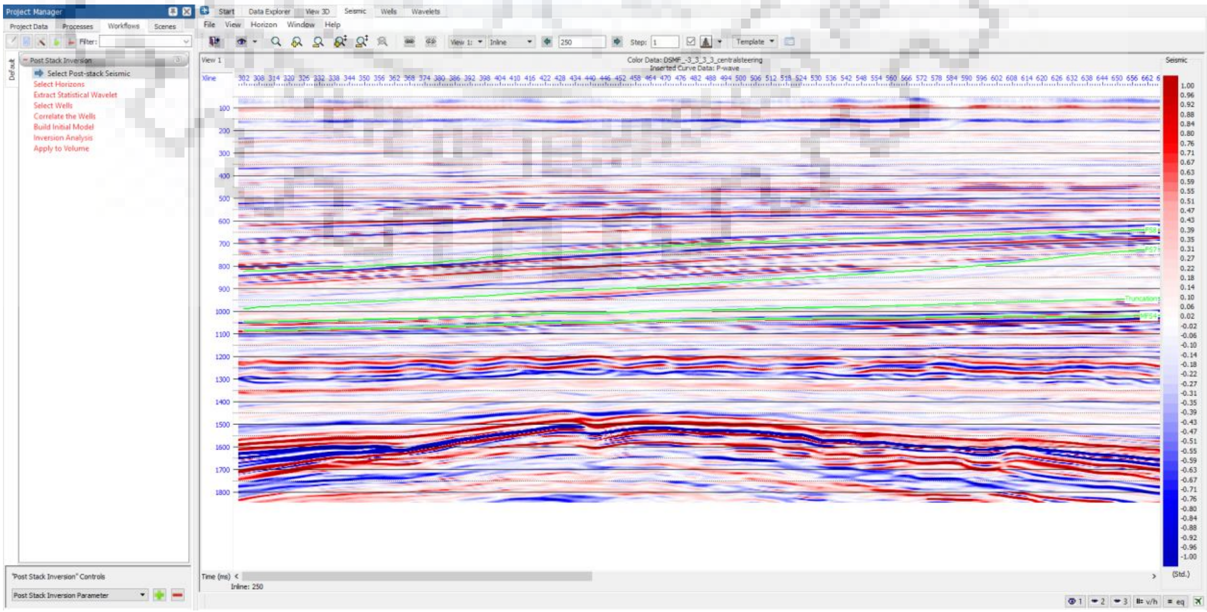


Figure 3.60: Seismic 3D with horizons loaded in HRS and Workflow for post stack inversion.

In seismic inversion the well data is used to create the model of the impedance values at the wells and it is guided by the seismic and the horizons which create the model in the complete 3D seismic section. The editing of the logs is an important step before impedance inversion studies as if the well logs are not conditioned then the model will not be good and as in inversion the convergence of the problem is solely dependent on the initial model chosen. If the initial model is very fare from the real result it is highly likely that the algorithm can stuck in local minima and not reach the global minima which is the impedance we are searching for. Seismic is a limited band data which contains frequency from around 30 to 100 hz however the well is in kHz. The high frequency component of the inversion is obtained from wells and low frequency from seismic and also if very low frequencies which are not present in the seismic data is obtained by inserting the interval velocity model in the software and thus all the frequency range is covered.

3.10.1 Post-stack seismic inversion

The Post Stack Seismic inversion results in creation of an acoustic impedance (AI) of the seismic data, which is the density multiplied by P-wave velocity at well location.

Post-stack inversion methods include Deterministic and probabilistic inversions. The model-based inversion done here and others such as coloured and recursive inversions are all grouped as deterministic methods as they do not involve probabilistic measures. The other types of methods are stochastic methods which use probabilistic approach in choosing the model before the inversion and the model is an important factor in determining the quality of inversion. The inversion in this project was model based deterministic inversion (Fig. 3.61).

Model-based inversion

A model is initially generated which represent the acoustic impedance of the section before the inversion and which is iterated to create the final impedance model. The model is changed at each iteration and the error is reduced till the error cannot be reduced further and reach a threshold value. The main advantage of this type of inversion is that it gives very good results even if the data contains noise and well data is not conditioned very effectively. The method to calculate the error at each iteration is least square method.

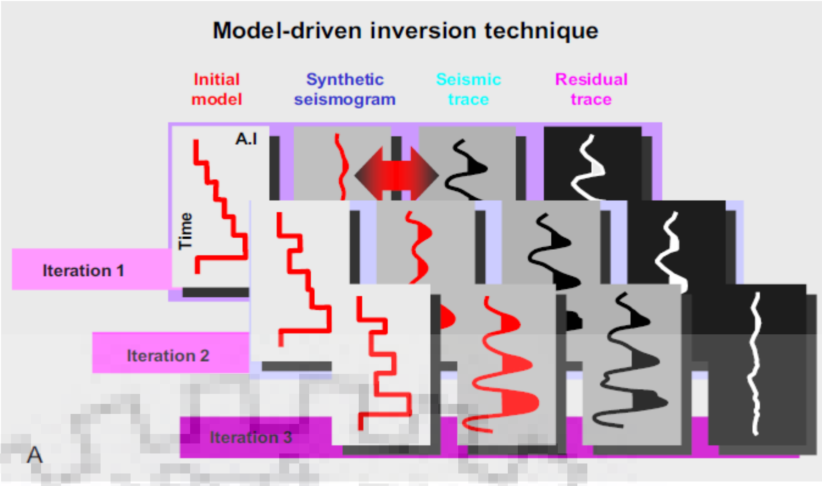


Figure 3.61: Modelling technique for Seismic inversion (Ref: SEG Wiki)

Generation of Initial Model

1. In the HRS the post stack seismic inversion section guides in creation of the initial model.
2. Seismic data will act as a reference grid for the guidance for the model and has to be selected. The well logs and the horizons are also given as the interpolation in the inversion is aided by the horizons. The interpolation between the wells and using horizons create a basic model of some impedance value at different layers. The inverse square distance method was used which is the basic technique for interpolation.
3. The wells which are correlated originally are chosen and the density and the sonic logs are supplied to the program which converts them to the acoustic impedance curves.
4. The time window has to be selected for which the model will be made. We have generated model for the complete seismic that is from 0 to 1800ms at a sampling rate of 4ms. The resampling values were chosen as standard which creates new amplitudes by interpolating between values or averaging them.
5. The no filter was chosen at the end in modelled trace filtering options as it will just interpolate the control points which will create a better low frequency model.

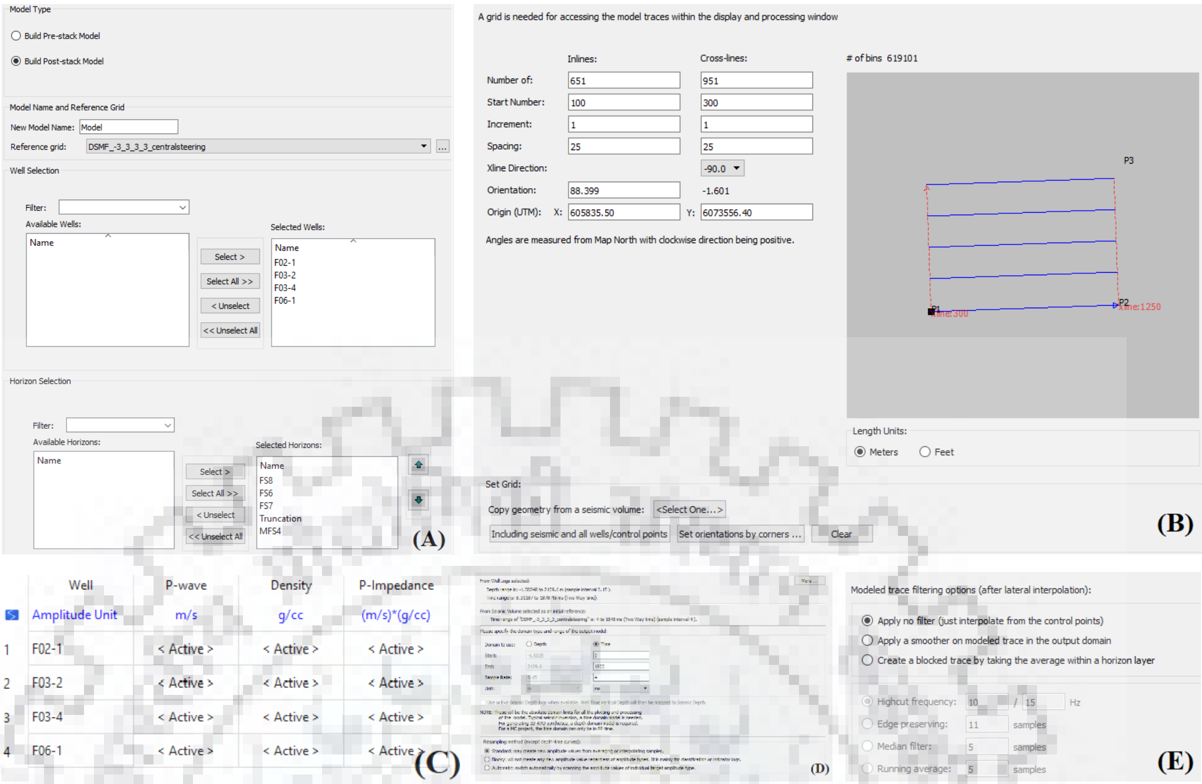


Figure 3.62: A) Model Generation window and selecting wells and horizons to be used to make model. B) Importing the 3D Seismic to be used in model generation. C) Choosing the P-wave, Density and P-impedance logs for wells to be used to create synthetic model. D) Time window for which model has to be made. E) Filtering of model options.

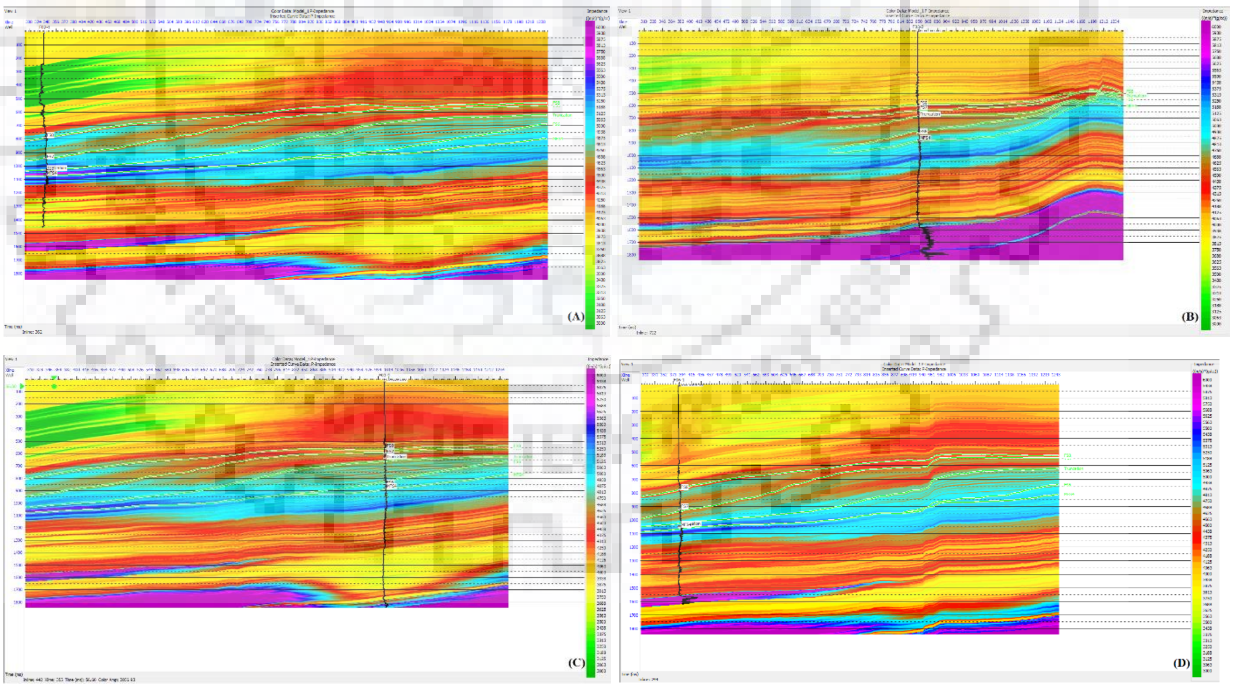


Figure 3.63: A) Model at Well F02_1. B) Model at Well F03_2. C) Model at Well F03_4. D) Model at Well F06_1 with respective impedance value applied at wells so that quality check can be done.

The model is generated (Fig. 3.62) which was complete volume and thus the model was tested about the effectiveness of the initial model by analysing the model at the well location and seeing the quality of the model. The model at the well locations 1,2,3,4 is shown in Fig. 3.63.

3.10.2 Inversion Analysis

The model generated in the previous step was used in the inversion. The inversion analysis window (Fig. 3.65) inputs the Seismic data and the model which was created in the previous step. The wells were selected which were used for inversion. The wavelet which was used for seismic well tie was also provided in the inversion window and we need to make sure same wavelet should be supplied as the Seismic to well tie is wavelet dependent so if we change the wavelet the correlation will change and will affect the inversion result.

The inversion window was chosen to be the FS8 – 200ms to MFS4 + 200ms. The area of study is on horizon FS8, however as the seismic well tie was done between the first and the last horizon so the inversion was also done between the horizons. The impedance value outside the defined window was set to 0. We have used hard constraints at 100% lower and 100% upper maximum impedance change. Average block size was set to 2ms and pre-whitening at 1%.

Iteration test was run (Fig. 3.64) and as there is a tradeoff between computational power and error, so a best number of iterations was 25 which was shown in the plot of power and error and hence 25 was chosen to be the number of iterations.

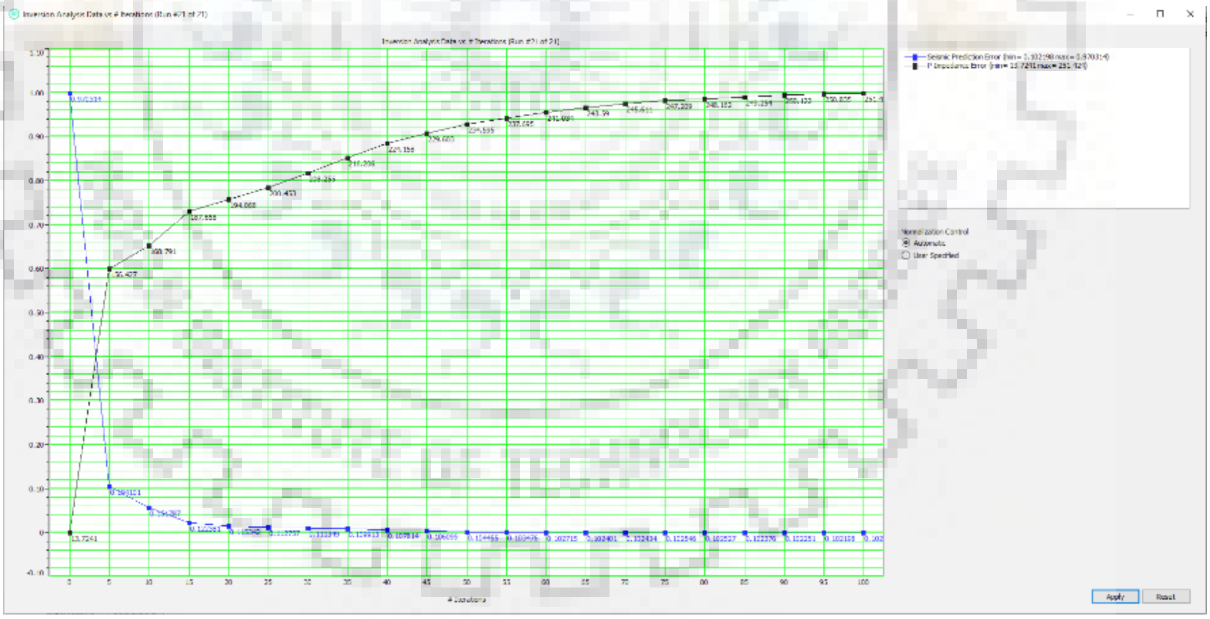


Figure 3.64: Iteration test of inversion showing Seismic prediction error and P-impedance error.

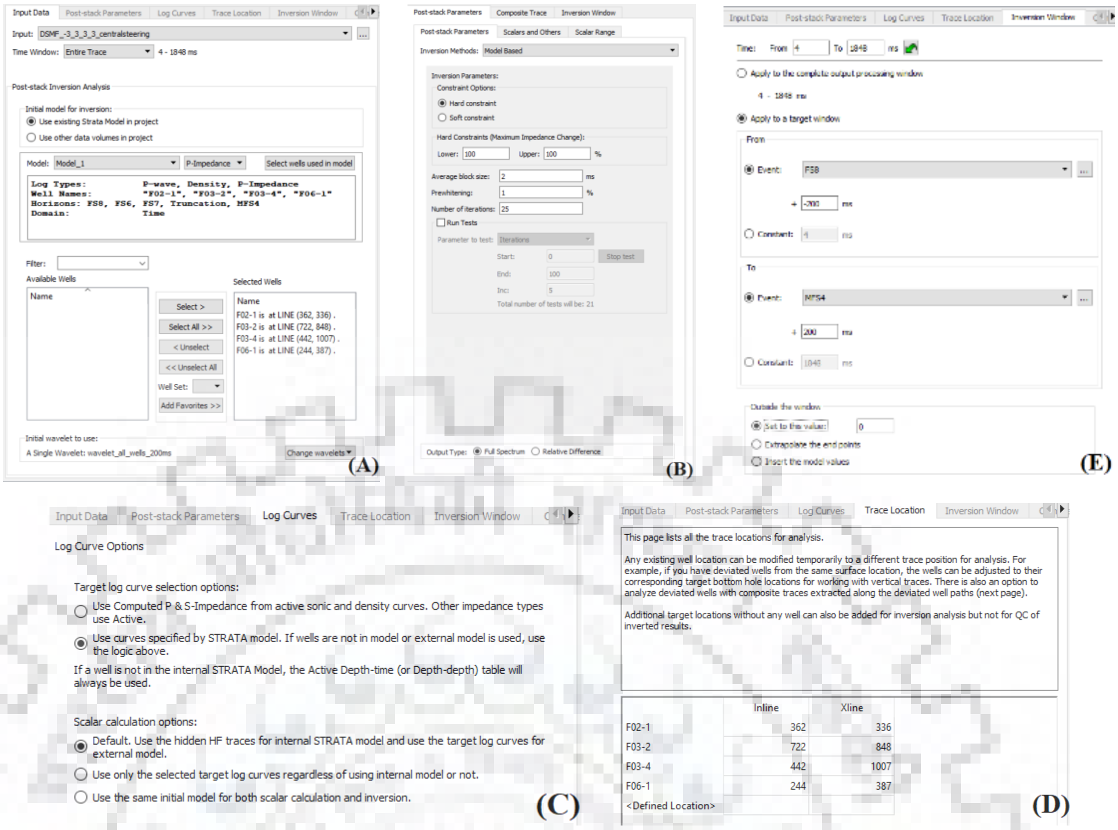


Figure 3.65: A) Input 3D Seismic Data and created model with the available wells in the database. B) The Post stack parameters used for the inversion and identifying the number of iterations by running test on the data. C) Selecting the Log Curve options. D) Trace Locations of different input wells. E) The time window in which the inversion has to be done and the value being given to the data outside that time window.

3.10.3 Inversion analysis window

Fig. 3.66 show the inversion analysis window at all the wells which shows the AI in between the defined zone of inversion and also shows the AI value from the wells, thus this helps us compare the quality of inversion. If the error between the impedance value from the Well log and the inverted value has less error and high correlation (Table 3), the inversion is accepted when the correlation comes out to be high in all the wells and thus the inversion parameters must be changed until the correlation is not improved.

Well	Correlation	Error
F02-1	0.988986	0.148762
F03-2	0.995841	0.0931056
F03-4	0.99498	0.10074
F06-1	0.990767	0.142015

Table 3: The table shows the error and the correlation of inversion at all the Wells.

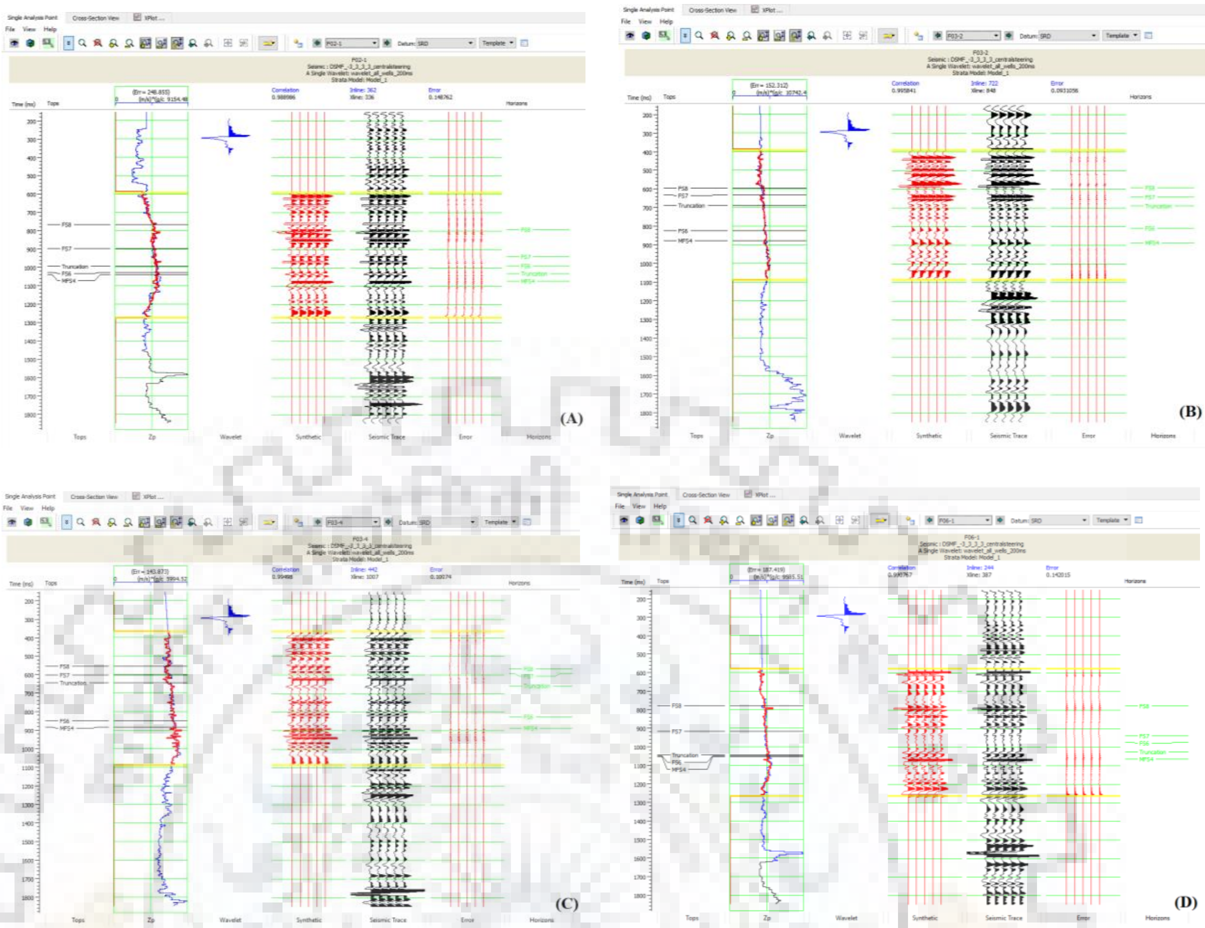


Figure 3.66: Inversion analysis window for all the Wells 1(F02_1), 2(F03_2), 3(F03_4), 4(F06_1).

The analysis of inversion (Table 3) shows that the inversion is within permissible error range and the inversion can be applied using the parameters successfully. The cross plot between the p impedance of the original log and the computed log (Fig. 3.67) is a best fit line between the points and hence again proves our inversion to be successful.

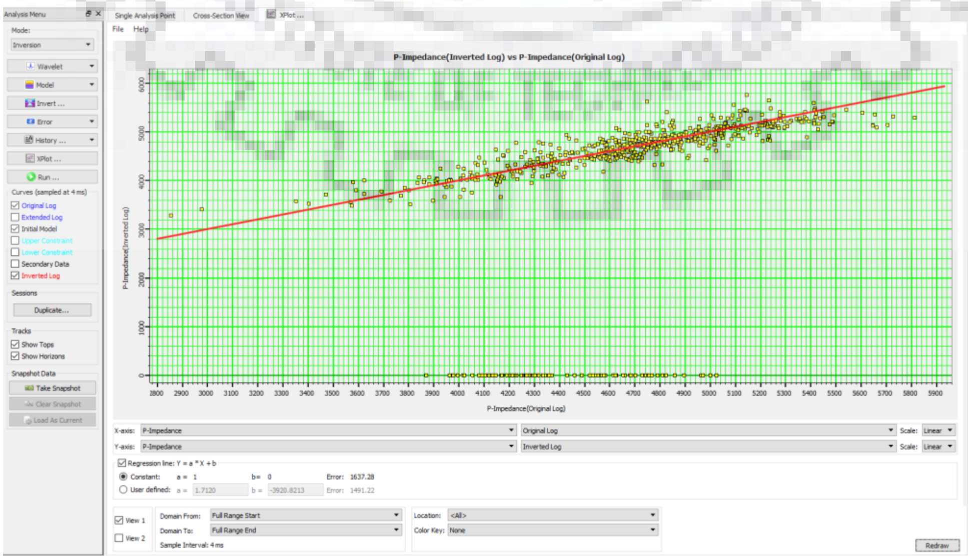


Figure 3.67: Cross plot between P-impedance of the inverted log and the original log. This is a Quality check Step which states the inversion to be correct if the points form a straight line.

3.10.4 Inversion Result

The inversion results at the inlines of the well location were checked and the complete volume for the inversion was made (Fig. 3.68).

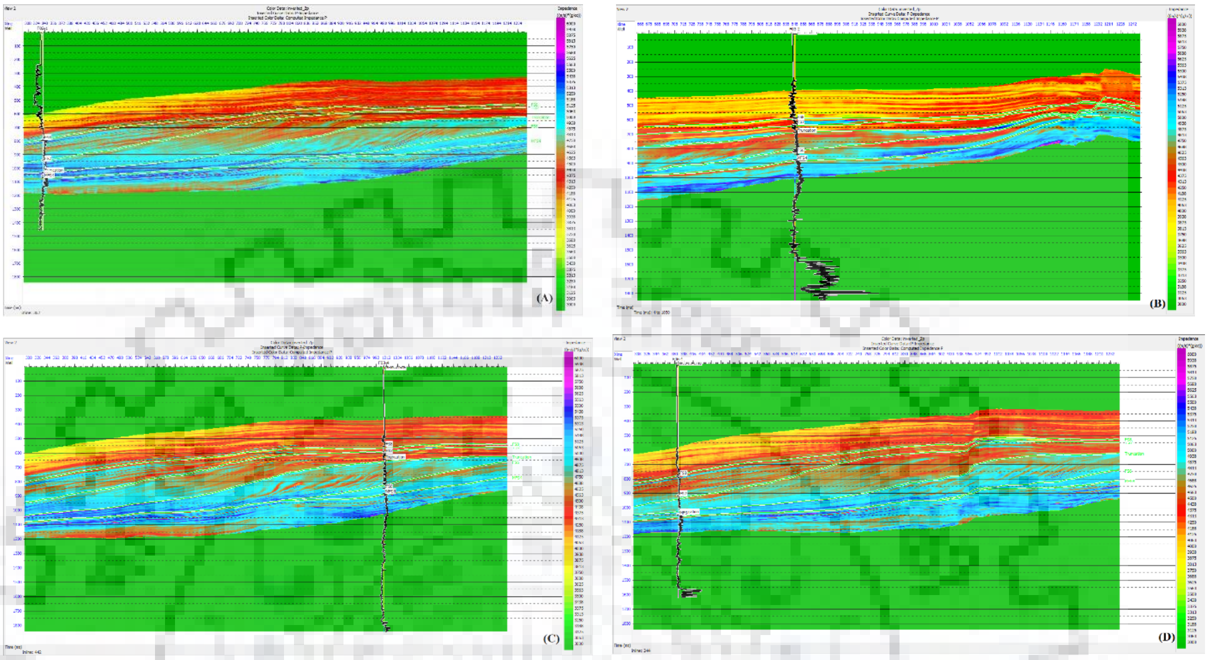


Figure 3.68: Inversion Result at all Well locations.

The well shown Fig. 3.68 shows the impedance log on it and thus the impedance value can be seen at the well locations on the curve and at the seismic through the color. The analysis of them shows that the impedance value at the seismic matches with the well log impedance, hence our inversion result is good and now the complete volume of the inversion can be made.

The complete volume of the inversion now is imported in OpendTect and applied at the horizon of study to see the impedance value of the anomaly which was studied using attribute analysis.

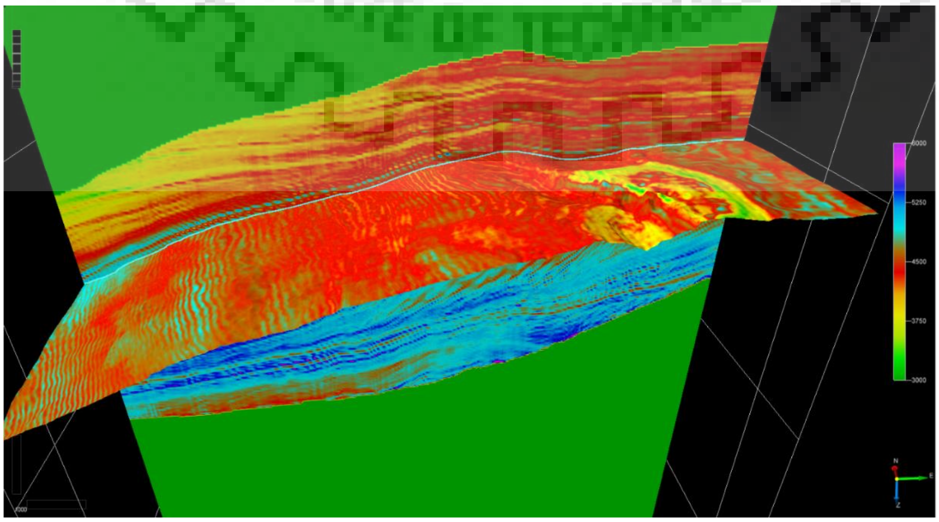


Figure 3.69: The inversion applied on horizon FS8 with the inline also imported from the inverted cube from HRS to OpendTect. This plot is called as Chair plot where an inline and a horizon are shown simultaneously.

Fig. 3.69 shows the chair plot of the horizon and the inline applied is the inverted volume which was imported in the OpendTect. The scale of the inverted volume chosen is 3000 to 6000 (m/s*g/cc). Fig. 3.70 shows the impedance value at the area of interest which is found to be around 3750 m/s*g/cc.

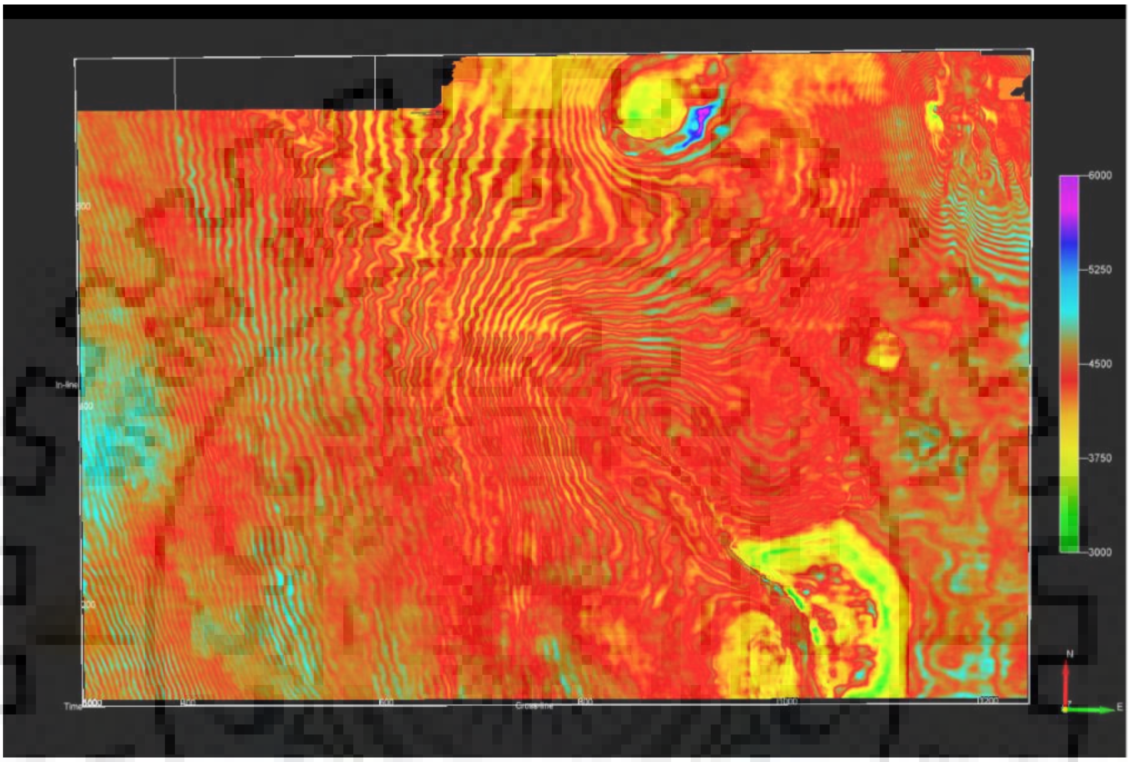


Figure 3.70: The FS8 Horizon with P-impedance after flattening the horizon.

The Acoustic impedance values of different materials in the earth are such that pure water has an impedance of 1500 m/s*g/cc with water having 1460 m/s*g/cc (Helgerud et al., 2009). The clay gave an impedance value which is high in the range of 8000-9000 m/s*g/cc. Sands have a relatively less impedance value and as the velocity of the seismic waves is less in sand then it can be analysed that they will have less impedance value and also if the sand is gas saturated the velocity will further decrease and so is the acoustic impedance. The ambiguity which we had in the starting that the bright spot could also be due to the presence of carbonate in the area is clarified that since the carbonates does not have impedance in these ranges which are shown in the figure thus we can strike out the possibility of the carbonate presence and bright spot is mostly due to the presence of hydrocarbon bearing sands which is creating these amplitude signatures.

4 Discussion and Conclusion

In the given study of the 3D seismic data, the interpretation of seismic data was done which was post stack data of the F3 block, Netherlands. In the inline number 248 a thick black patch was visible which was analysed with the integrated analysis of attributes and post stack seismic inversion to understand the properties of the patch and infer the conclusion about the possible lithology and fluid of the patch. The following conclusions were made on the basis of the techniques discussed in the thesis:

1. The conditioning of the seismic data and the well data enabled us to better visualize the faults and fractures in the data and as the data was noisy, the conditioning of the data prevented us from interpreting the anomalous noises as some useful anomaly in the data and interpreting wrong results and noisy horizons. The well data conditioning enables us to accurately select the markers for which the horizons will be made and studied from a list of markers supplied with the data.
2. The seismic well tie enables us to get a velocity model of the region which could help us to mark the horizons which will be in time to the markers which are in depth. The wavelet used for the seismic well tie of all the wells are created as a single wavelet from seismic data near the wells. The source wavelet used in the survey is not known, thus the synthetic wavelet was created which closely represents the source used in marine survey such as an airgun.
3. The time structural maps for all the horizons show the area is dipping in the SW direction and the closed anomaly which have some closed contour lines which indicate an object in the horizon and this was seen in FS8 in lower right corner which was studied in the project.
4. The geometrical attributes such as similarity and semblance concluded the presence of faults and fractures in the area of study which proves the presence of some anomalous structures and object which was seen in the time structural maps.
5. The variance attribute was chosen as the next for seeing the variability of the amplitudes in the zone and it was found to be that the zone shows very different amplitudes in the zone then the rest of the horizon and the contrast in the variability at the edges proves the presence of faults which was earlier studied with similarity and semblance.
6. The dip and the curvature attributes were used next which are better attributes to see the faults in the area and study the structures dip in different azimuth directions which

provide a certain presence of faults and polar dip provided with the dip in the area of study clarifying the amount of dips which was high in the study area. The curvature attribute also showed a max positive curvature around the study area which completed our fault and fracture analysis of the zone and motivated us to move forward to further attribute analysis of the zone.

7. Thin fault likelihood was finally used in the geometrical attributes to have a precise fault structures and in this attribute our area was visible having faults along all the sides.
8. Instantaneous attribute concluded the presence of some hydrocarbon as the amplitude was high which is in sand and on top of that the first derivative of amplitude was high and second derivative low which proved the study area has less absorption characteristics which are an indicative of hydrocarbon deposits. Phase and frequency attribute concluded the continuity within reflection and less frequency concluded the presence of hydrocarbon.
9. Spectral decomposition concluded the thickness of the patch which was studied and it was found to be sufficiently thick to possess hydrocarbon and the thickness was found to be approximately 15m.
10. The sweetness attribute which is a direct hydrocarbon indicator was used to confirm the presence of hydrocarbon as high sweetness is directly related to hydrocarbon. The sweetness attribute however can give wrong result in presence of coals as coals also show high sweetness so for that texture attributes were used which can clarify the lithology to be sand bearing.
11. The integrated analysis of texture showed the presence of high energy, low entropy and low contrast which is an indicator of hydrocarbon deposits in sands which was concluded with texture attributes. The presence of carbonate still can give us wrong result so for that the seismic inversion was done.
12. The impedance value was found to be around 3750m/s*g/cc which is a direct indicator of presence of sand in the region and strikes out the presence of patch due to carbonate.

Thus, this concludes our project with the integrated analysis of all the geometrical and physical attributes the all the possibilities were mitigated which could give us wrong results and the study area was found to be a bright spot which is due to hydrocarbon in the sand deposit and which could be if not already be a prospect for future research and development.

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