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INTEGRATED APPROACH TOWARDS THE APPLICATION
OF HORIZONTAL WELLS TO IMPROVE
WATERFLOODING PERFORMANCE

1995 Annual Report

By
Mohan Kelkar
Chris Liner
Dennis Kerr

June 1996

Performed Under Contract No. DE-FC22-93BC14951

The University of Tulsa
Tulsa, Oklahoma

FOSSIL
FUEL
ENERGY

Bartlesville Project Office
U. S. DEPARTMENT OF ENERGY
Bartlesville, Oklahoma

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Work Performed Under Contract No. DE-FC22-93BC14951

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Acknowledgment

The research effort described in this report was supported by the U.S. Department of Energy under Contract DE-FC22-93BC14951. Additional support is provided by Amoco Production Company and Uplands Resources, Inc. The computer facilities were provided by The University of Tulsa.

We would like to thank Dan Richmond from Uplands Resources, Inc. for his valuable contribution and insight to our work. We also would like to acknowledge the guidance provided by Rich Chambers, Henry Tan, John Eager and Chandra Rai from Amoco Production Co. Lastly, our special thanks go to Rhonda Lindsey, representative of the contracting officer of the project, for her enthusiasm and valuable suggestions.

Mohan Kelkar

January 1996

Abstract

This annual report describes the progress during the third year of the project on Integrated Approach Towards the Application of Horizontal Wells to Improve Waterflooding Performance. This project is funded under the Department of Energy's Class I program which is targeted towards improving the reservoir performance of mature oil fields located in fluvially dominated deltaic geological environments. The project involves using an integrated approach to characterize the reservoir followed by proposing an appropriate reservoir management strategy to improve the field performance. In the first stage of the project, the type of data we integrated include cross borehole seismic surveys, geological interpretation based on the logs and the cores, and the engineering information. In contrast, during the second stage of the project, we intend to use only conventional data to construct the reservoir description.

This report covers the results of the implementation from the first stage of the project. It also discusses the work accomplished so far for the second stage of the project. The preliminary results look promising from the field implementation. The production from the Self Unit (location of Stage I) has increased by 35 bbls/day with additional increase anticipated with further implementation. Based on our understanding of the first stage, we hope to examine a greater area of the Glenn Pool field for additional increase in production. We have collected available core and log data and have finished the initial geological description. Although not a direct part of this project, we also have initiated a 3-D seismic survey of the area which should help us in improving the reservoir description.

Executive Summary

This annual report discusses the progress made so far in a DOE Class I Project which is designed to improve the performance of Glenn Pool oil field using better reservoir management strategies. The first part of the report summarizes the preliminary results of the first stage of the project. It also explains what we have learned from the project. The next two parts discuss the geological and geophysical descriptions of the field under Stage II of the project. The final part explains the technology transfer activities conducted under this project to disseminate the technology to various interested parties.

During the first stage, this project used an integrated approach to improve the water flooding performance of a mature oil field producing over a 90 year period. We used geological, geophysical and engineering data to develop a detailed reservoir description. Based on flow simulation studies, we observed that the best strategy to improve the recovery from this unit is to selectively perforate part of the interval and increase the water injection rate.

We have started implementing the reservoir management plan in the field. Seven wells are selectively perforated and completed. The oil production from these seven wells has increased by about 35 bbls/day. We expect that after completion of the implementation, the production will go up by a total of 65 to 95 bbls/day. The economic evaluation indicates that the finding cost of oil is in the range of \$4.50 to \$6 per barrel.

The technologies used in our project are cross borehole tomography, formation micro-resistivity borehole imaging, geological description based on genetic units, geostatistics, and field flow simulation. We believe that with the exception of cross borehole tomography, all the other techniques were very helpful in improving the reservoir description.

1. Introduction

The overall goal of the project is to develop and apply cost effective technologies to improve the waterflooding performance of mature oil fields. To achieve this goal, we applied various technologies to improve the production performance of a ninety year old Glenn Pool field. The technologies employed include cross borehole tomography, detailed facies biased geological analysis, micro-resistivity imaging, geostatistics, flow simulation and multi-disciplinary effort. With the exception of cross borehole technology, all the other technologies contributed to the improvement of the field production. This report summarizes the findings of our efforts, as well as the planned future work in the other parts of the field.

The report is divided into five chapters, including this chapter. In the second chapter, results from the first stage of the project are presented. These include field observations, as well as the assessment of technologies which were proven to be effective. In the third chapter, the preliminary geological description of the Berryhill Glenn Unit is discussed. The second stage will concentrate on that Unit for further optimization of the performance. In the fourth chapter, discussion focuses on the steps being taken for collecting and processing seismic data as well as the further analysis of the cross borehole seismic data. In the last chapter, the technology transfer activities related to this project are explained.

2. Review of Stage I of the Project (by Mohan Kelkar and Dan Richmond)

2.1 Historical Information

The Glenn Pool field is located in portions of Tulsa and Creek Counties of Oklahoma (see **Figure 1**). The field was discovered in 1905, and has produced approximately 330 million barrels of oil from Middle Pennsylvanian age Bartlesville Sandstone (also called Glenn Sand). The field encompasses 27,440 acres. Initial production from the wells ranged from 75 BOPD to 4,000 BOPD. Currently the field produces about 1,000 bbls of oil per day with a very high water cut.

The Self Unit is located in south-east portion of Glenn Pool field (See **Figure 1**). The first well on the Unit was drilled in November, 1906. Since then a total of 82 wells have been drilled on the Unit. Currently, 28 wells are active in the field (See **Figure 2**). Out of these wells, well 82 was drilled as part of this project. The original oil in place(OOIP) is estimated to be 13.1 MMBO. Primary recovery was 1.8 MMBO or 13% OOIP. The response to the secondary oil recovery has been less than satisfactory. To date, 1.0 MMB of additional oil has been recovered because of gas and water injection. As can be seen from **Figure 3**, the production history of the field indicates that the Unit has responded well to changes in the reservoir management strategies. In 1950, 1966, and 1982, the production increased to 30,000 bbls per year after a new reservoir management plan was implemented. Based on this response as well as poor secondary recovery, we believed that the reservoir is highly heterogeneous, and significant oil may be recovered by a better reservoir management plan.

2.2 Technologies Used and their Effectiveness

In this project, we used several modern technologies. In this section, we briefly describe the technologies and their value to the project.

2.2.1 Integrated Approach

We made a concerted effort to integrate information from various sources to better understand the reservoir. Geophysical, geological, and engineering data were used to better describe the reservoir properties. In addition to interdisciplinary nature of the project, this project also involved active participation from government, the university, a small oil company and a major oil company. The biggest benefit of working together among such a diverse group of people is understanding and appreciating each other's language and perspective on the issues at hand. Communication between

Figure 1: Geographic location of Glenn Pool and location of Self Unit.

Figure 2: Present well location.

Figure 3: Production data - historical performance.

different disciplines helped us better understand what each discipline considers to be an important part of the reservoir description. We tried to create a good balance between the form of the reservoir (architecture) and the function of the reservoir (production performance). Interaction among various entities during the project made us aware of each other's priorities and each other's objectives. Although the objectives of each organization did not always coincide, we learned to appreciate and respect each other's objectives. This helped us in proceeding in the project in an optimal way.

2.2.2 Cross Borehole Tomography¹

Cross borehole tomography is a method by which an inter well image of reservoir characteristics is constructed by using an acoustic source in one well and receivers in another well. We conducted three such surveys with the help of Amoco Production Company and Conoco. The surveys were conducted between well pairs 82-63, 82-64 and 82-81 (See **Figure 2**). The collected data were processed by Amoco, using a public domain software and by Memorial University in Newfoundland, Canada. In addition, data were also provided to a group of scientists from Imperial College. Depending on the assumptions involved in the software, the results obtained from the three methods were significantly different. The results are in the form of sonic velocity distribution across the well pair. We used this information by relating the velocity to the porosity and the facies at the well location. The use of these data slightly improved our reservoir description. Because of the high cost of acquisition and significant uncertainty in the interpretation, the use of cross borehole data were limited.

2.2.3 Formation Micro-Resistivity Borehole Imaging²

We used this tool in the newly drilled well 82. Along with the resistivity imaging, we also cored the desired interval. Formation Micro-resistivity Imaging tool produces a high resolution resistivity of the wellbore. Analysis of the image provides spatial orientation of architectural elements in the vicinity of the wellbore. By combining the information from the core data and the imaging tool, we were able to describe the geological heterogeneties at higher resolution level than otherwise possible with conventional well logs. Unfortunately, we were not able to use this detailed information in an effective way in flow simulations due to computer memory limitations. For a mature, shallow, oil field with marginal oil production, the detailed knowledge of geological structure may be important in predicting unswept reservoir and preferential flow paths. The cost benefit analysis of using micro resistivity log versus taking an oriented core needs to be evaluated further before reaching the final conclusion on the utility of these type of logs.

2.2.4 Discrete Genetic Interval (DGI) Evaluation²

Using the data collected from all the wells, we were able to construct a detailed description of geologically distinct units deposited during a limited time interval. This information was extremely valuable in understanding the vertical as well as areal heterogeneities. Previously, Glenn Sand was divided into three basic units - upper, middle, and lower. With the help of DGI approach, we were able to divide the sand in six geological units. **Figure 4** shows an example of Unit A. This detailed geological description helped us in flow simulation as well as in our overall reservoir management planning.

2.2.5 Geostatistics

Geostatistics is a procedure by which inter well properties are described using all the available information. Geostatistics assumes that the reservoir properties are spatially correlated, and this correlation can be quantified by a method called variogram analysis. Geostatistics further allows us to quantify uncertainties in describing these properties. Using geostatistics as a tool, we were able to describe the spatial relationships for geological facies as well as the petrophysical properties. By using the relationship between the seismic velocity and the porosity, we were able to use the cross borehole data to improve the spatial relationship for porosity at inter well distances. Using a geostatistical technique called conditional simulation, we generated geological facies image. The comparison between the simulated image and the geologist's view of the reservoir indicated good results (See **Figure 4**). This provided us the confidence that the architecture of the reservoir is preserved. Using the geological description as a starting point, alternate images of the petrophysical properties (permeability and porosity) are constructed by further integrating engineering and geophysical information. **Figure 5** shows the comparison between the simulated and observed porosity at well 82 which was not used as part of the data in simulation. Overall, geostatistics was a valuable tool in constructing realistic reservoir descriptions.

2.2.6 Flow Simulation

Once the reservoir description was constructed, we used the ECLIPSE commercial simulator to simulate the reservoir performance. We used both the deterministic (conventional, "layer-cake") as well as geostatistical reservoir descriptions for simulation purposes. Typically, the number of grid

Simulation

Geologist

Figure 4: Sand A comparison - simulated map vs. geologist view.

Figure 5: Well 82 - comparison of simulated vs. observed porosity.

blocks in the simulator is less than the number of grid blocks in geostatistical simulation. As a result, appropriate up scaling procedure³ is used to scale the petrophysical properties suitable for simulation purposes. Since the performance data from individual wells were not available, we could only match overall Unit performance. After matching the historical oil production performance (see **Figure 6.a**), we projected the future oil production performance under various scenarios to understand the benefits and the drawbacks of various alternatives.^{3,4}

With increasing speed of computers, flow simulation technology is becoming increasingly viable for small operators. Field simulations can be conducted on personal computers without much difficulty. We believe that flow simulation will be an integral part of future reservoir evaluation procedures.

2.3 Recommendations

Our evaluation of the reservoir and production data indicated that the DGI's A and B probably contain immovable oil, DGI F (lower unit) has already been flooded, and DGI's C, D and E have the most potential in terms of additional recovery. DGI C is already open in most of the existing wells. This left us with two possible units for further exploitation, DGI's D and E. We also noticed that an increase in the injection rate has resulted in an increase in the oil rate in the past. Based on the well configuration, the injection wells are capable of taking a lot more water without any modifications.

Based on our understanding of the reservoir, we considered several strategies to improve the performance of the Unit. These included: i) re-perforating selected intervals and stimulating them; ii) increasing the injection rate; iii) drilling a horizontal injection well; and iv) drilling additional vertical wells. We also considered combinations of these alternatives. Assuming an oil price of \$17/bbl over the life of the project, we determined that the best alternative is to re-perforate some of the intervals and double the injection rate. Drilling of a horizontal injection well may have resulted in higher production rates, however, the cost of the horizontal well did not justify the additional production. Drilling of additional vertical wells did not result in any significant increase in production. For recompletion, increase in injection rate scenario, our future predictions of the possible oil rates, along with the uncertainties in the rates, are shown in **Figure 6.b**.

Figure 6: Future performance prediction for recompletion/double injection scenario.

2.4 Field Implementation - Problems and Solutions

Upon identification of the additional intervals to be perforated in each of the 28 wells on the Self Unit, a prognosis was developed for up-sizing the water injection station, and re-completing each of the wells. Several concerns were considered with regard to recompletions. These included the current integrity of casing, condition of the injection well packers and tubing, and the actual increase of fluid volumes that would come from the producing wells after completion. Five producers and two injectors were selected for initial recompletion so that the operator can test the recompletion methodology and obtain actual production data to evaluate the economic viability of the project in stages. This also ensured that the lease continued to produce without undue loss of production.

The steps involved in recompletion are: i) pull all the equipment out of casing; ii) run the bit and scraper to clean casing; iii) re-perforate the desired intervals as indicated by the simulation results; iv) acidize both new and old perforations; and v) test wells. No substantial problems were encountered through the perforation process. However, acidization took longer than expected. The breakdown took longer; because the formation needed to be pre-soaked with acid before acidizing. The pre-soaking helped reduce the time required for acidizing. Through a learning experience, the costs of recompletion for the last two wells were less than the AFE. The up-sizing of the water plant was done without significant deviation from the construction plan.

All wells were initially swabbed back to recover the spent acid and flush, and the producers were swab tested. It became apparent that the fluid volumes being produced were substantially greater than expected. To measure the maximum possible rates, variable speed submersible pump was used. Both the volume and the oil cuts were monitored for three weeks for each well. The initial production from the wells was essentially all water. However, as the time progressed, the oil cut from the well increased gradually. At present, the oil cut varies between 1 to 1.5%. This is an improvement over previous observations. With the stabilization of the well production and an increase in the injection rate, we expect the oil cut will increase even further.

2.5 Preliminary Results

Based on the partial implementation of the reservoir management plan, we have observed an increase in the oil production. The total oil production from the Unit has increased by approximately 35 bbls/day. An individual increase from the five wells re-completed ranges between 5 bbls per day to 10 bbls per day. There is a slight improvement in oil cut. We expect

that after complete implementation of the reservoir management plan, the overall oil production should increase by 55 to 75 bbls/day along with some improvement in the oil cut.

2.6 Economic Evaluation

One of the important goals of this project was to investigate the economic feasibility of the implemented strategies. For an effective transfer of technology, it is critical that the technology be cost effective.

By assuming that the production will decline at 6% per year, we estimated the range of additional oil that can be recovered from the Unit in the next 15 years. This amount ranged between 200,000 barrels to 250,000 barrels. The anticipated cost of this project is approximately \$1.2 million. This translates into finding cost per barrel of \$4.80 to \$6. This number may be unattractive. However, we can also calculate the finding cost based on the knowledge gained in this project. Some technologies in this project were either proven to be ineffective or marginal. If we assume the same field costs and further assume that the methodology proposed in this project can be applied by a typical consultant in the oil patch, the overall cost of the project will be in the range of \$500,000 to \$600,000. This translates into finding cost of \$2 to \$3 per barrel. This is significantly less than the present acquisition cost used in the market. This reduction in the cost, although dramatic, is not unrealistic. For example, the cost associated with cross borehole seismic data acquisition and analysis was \$250,000. The cost of drilling a new well and acquiring the modern suite of logs was \$120,000. Additional costs associated with the administration of the project as well as technology transfer costs can be paired down substantially as well.

It is also worth remembering that the Glenn Pool field is one of the oldest fields in the United States. Most of the fields are much younger than this field. If we can apply better reservoir management techniques to improve the performance of this field in an economically viable manner, we sure will be able to do the same for fields which are much younger.

Overall, the implemented plan appears to be economically viable. We hope to complete the implementation by the end of the summer of 1996, and will continue to monitor the performance of the Unit over an extended period.

3. Geologic Description (by Dennis Kerr and Liangmiao Ye)

During the second stage of the project, we intend to concentrate on Tract 7 and surrounding areas. Tract 7, another 160-acre unit in southern Glenn Pool field, is located about 1 mile north of the Self Unit. The emphasis of Project Phase II is to use conventional technology and knowledge gained from advanced technology of Phase I (FMI, cross-well tomography etc.) in developing an effective reservoir management plan.

Study of Tract 7 and adjacent area involve data compilation, well log correlation of DGIs, and facies architecture reconstruction. For a better and more complete description of Tract 7, its adjacent areas including Tract 6, Tract 10, Tract 12, Tract 13, Tract 11, part of Tract 3, Tract 4, Tract 33, and Corbray unit are included into the mapping area (**Figure 7**), with total area about 1.6 square miles.

3.1 Data Compilation

Data compilation includes collecting all logs and core data available in the office of Uplands Resources Corporation and Oklahoma Well Log Library and constructing the well location map (**Figure 8**).

Tract 7 includes 36 wells which have some sort of data available to use: 14 wells were logged (8 open-hole logs and 6 cased-hole logs) but not cored; 9 wells were both cored and logged (8 cased-hole logs and 1 open-hole log); and 13 wells were cored but not logged.

In areas adjacent to Tract 7, information from 80 wells were collected and used for the study. Of these 80 wells, 9 wells were both logged and cored (in some intervals), 18 wells were cored but not logged, and the remaining 53 wells have log data only. In total, core and/or log data from 116 wells were collected and used for the mapping area. Unfortunately, the 23 wells with logs in Tract 7 are not uniformly distributed across the unit but mainly concentrated along the edge of the unit (**Figure 8**), cores of this unit are from the lowest part (DGI F & G) of the Glenn Sand only. In addition, all cores within Tract 7 have been physically missing and are likely not to be found.

To deal with this data configuration (i.e. lack of logs in the central part of Tract 7), cased-hole log acquisition program has been proposed. **Table 1** provides a list of wells proposed for cased-hole logging and ranked in priority, was submitted to Uplands Resource Corporation. These additional logs, if available, will certainly assist in the reservoir evaluation.

Figure 7: Index map showing the locations of the six cross sections constructed.

Figure 8: Data availability within the mapping area.

priority	well name	tract	TD (ft.)	suggested logging interval (ft.)*	alternative well
1	7-94	7	≥1570	1340-TD	7-63
2	7-99	7	≥1565	1300-TD	7-47
3	7-107	7	≥1570	1300-TD	7-57
4	7-97	7	≥1570	1330-TD	7-78
5	H-13	7	1569	1340-TD	7-66
6	7-93	7	?	1350-TD	7-44
7	7-91	7	?	1350-TD	7-76
8	16-30	16	?	1330-TD	16-21
9	7-100	7	≥1547	1330-TD	7-69
10	E-11	7	?	1320-TD	7-51
11	7-90	7	?	1320-TD	7-59
12	7-92	7	?	1340-TD	7-65
13	7-103	7	≥1570	1350-TD	7-81
14	11-82	11	≥1580	1340-TD	11-65
15	16-28	16	?	1350-TD	16-27
16	16-20	16	?	1340-TD	16-32
17	11-80	11	≥1585	1340-TD	11-66
18	11-83	11	≥1577	1340-TD	11-64
19	11-79	11	≥1565	1340-TD	11-57
20	F-13	7	?	1340-TD	7-10
*: the suggested logging interval is intended to cover from Inola marker bed to TD. If the Pink Lime					
is to be included, additional 220 ft or so must be logged above the suggested interval.					

Table 1: Proposed wells for cased-hole GR logging (ranked in priority).

3.2 Well Log Correlation

Well log correlation aims at investigating the stratal relationship between Self Unit and Tract 7. Detailed correlation at a level of individual DGIs were performed and six cross sections were constructed, three of them are in N-S direction connecting the Self Unit and Tract 7 (**Figure 7**). Correlation results show that the Glenn Sand interval thickens from Self Unit to Tract 7 (160 ft to about 200 ft). In Self Unit, six DGIs (DGI A to F) are recognized, but seven DGIs (DGI A to G) in Tract 11 and eight DGIs (DGI A to H) in north-central part of Tract 7 are recognized. DGI G and H are equivalent to the lower Glenn Sand of Kuykendall and Matson.⁵ Thus, the lower Glenn Sand (DGI G and H) is absent in Self Unit, and DGI H is absent in Tract 11. **Figure 9** shows schematically the stratal relationship from Self Unit to Tract 7.

Based on the correlation results, tables of sandstone depth intervals for each DGI at each well used were developed, which will serve as an important database for further mapping and reservoir simulation.

3.3 Facies Architecture Reconstruction

Based on log facies interpretation, net sand isopach and facies map for each DGI was tentatively developed. As in Self Unit, DGI A through E are interpreted as fluvial channel-fill and splay deposits. DGI F is still interpreted as channel mouth bar deposits. Facies interpretation for DGI G and H needs more work, it can not be done based on the observations thus far because of fewer wells have encountered or/and penetrated these two intervals.

Preliminary analysis of log responses indicates that DGI A and B at Tract 7 have a better reservoir quality than at Self Unit. Generally good vertical separation between DGIs can be expected. Facies maps, developed based on current data availability, show that the channel-fill facies in Tract 7 and adjacent area are much wider than that in Self Unit. This leads to three possible explanations: (i) some channel boundaries are not recognized because of lower data density, especially the lack of logs in the central part of Tract 7; (ii) Glenn Sand at Tract 7 is of a higher sinuosity of meanderbelt; (iii) Glenn Sand at Tract 7 is in higher-order distributary system than that at Self Unit. The resolution of this issue is critical for the accurate determination of pore volumes and connectivity within a DGI. The acquisition of suggested additional cased-hole logging will assist on resolving these issues.

Figure 9: A sketch map showing the general stratal relationship from Self Unit to Tract 7. (figure not drawn to scale; thickness variation of each DGI is not shown; see Figure 7 for position of lease tracts.)

3.4 Field Scale Evaluation

As the project progresses, it is perceived that a field scale evaluation of Glenn Sand is critical to understanding the observations and results obtained from the 160-acre tracts of Self Unit and Tract 7. Thus, in parallel to the study of Tract 7, field scale evaluation of the Glenn Sand is also under way. This evaluation will focus on the stratal relationship (i.e. sequence stratigraphic architecture), facies architecture, and reservoir heterogeneity patterns among different parts of the field.

For this purpose, logs and core data of about 150 wells from different parts of the field have been compiled. Field scale well log correlation has begun.

3.5 Near-Term Goals

Tract 7 study

- Modify the facies map once additional logs are acquired.
- Construct the shale map to see the vertical separation between DGIs.
- Analyze cores (if available) taken from the area adjacent to Tract 7, particularly for facies interpretation of DGI F to H.
- Evaluate the petrophysical properties of each DGI based on the core data in Tract 7 and adjacent area.

Field Scale Evaluation

- Continue data collection and compilation.
- Field scale correlation and sequence stratigraphic architecture reconstruction.

The geological interpretation is expected to be completed within the next four to six months.

4. Geophysical Description (by Gokay Bozkurt and Chris Liner)

The first part of this section will discuss the work done on the cross borehole tomography. The second part will provide some of the details regarding the 3-D seismic shoot to be conducted on the Glenn Pool field.

4.1 Crosswell Seismic + Anisotropy

Although the project is in the evaluation stage for the recompletion plan, work continues on the crosswell seismic data acquired in 1994. As outlined in the 1994 Annual Report, velocity anisotropy is an important issue at the project site. Unfortunately, no academic or government tomography code was available which can incorporate anisotropy effects. However, a new faculty member in the Geosciences Department at The University of Tulsa (D. Epili) has a general purpose seismic imaging code which can be modified to include anisotropy. This modification will be done by the geophysical Ph.D. student (G. Bozkurt) supported on the project. It is still our opinion that crosswell travel time tomography is of insufficient resolution to constrain the geological interpretation, but by including anisotropy effects we hope to deliver the best tomography result consistent with the data. The following sections briefly describe the approach taken to include the anisotropic effects in the computer program.

4.1.1 Anisotropy

Anisotropy is defined as variation of a physical property depending on the direction in which it is measured (Sheriff⁶). Anisotropy is a directional quantity where properties at a single point vary depending on the direction of measurement.

Anisotropy is commonly understood as *velocity anisotropy* when the term is used in seismology. The general definition of anisotropy is adopted to seismic nomenclature as variation of seismic velocities in different directions (i.e., horizontally, vertically). Velocity anisotropy can be expressed in different ways. It is the fractional difference between vertical and horizontal P-wave velocities $[(V_h - V_v)/V_v]$, and sometimes, it is simply the minimum to maximum velocity ratio $[V_{min}/V_{max}]$ for a given wave surface. Despite this common anisotropy understanding, Crampin⁷ suggests that different wave velocities in different directions are not the only way to characterize anisotropy. Shear-wave splitting also helps describe anisotropy with its relationship to 3-D particle displacements. Crampin⁷ stresses that anisotropy is a 3-dimensional (3D) phenomenon and

parameterizing the 3D vector variation by only velocity anisotropy is a rough measure of expressing anisotropy.

The directional variation of elastic properties of a uniform material due to its internal structure (cracks, pore space distribution, etc.) is described as elastic anisotropy. Winterstein⁸ explains it as the systematic directional variability in a way the solid matter is composed. There are several (but limited) ways a solid can be created to result in anisotropy. The variations can be explained with symmetric systems. Of the 32 possible symmetry classes, eight of them are common and physically sound representation of the subsurface strata. These symmetry classes are: isotropic, triclinic, monoclinic, orthorhombic, tetragonal, trigonal, hexagonal, and cubic. Further details on the symmetry classes can be found in Winterstein.⁸

In order to develop the understanding of anisotropy parameters and different symmetry systems *stiffness tensors* are useful. Stiffness tensors basically express elastic properties of a medium. The stiffness tensor (a 6×6 symmetric matrix) explains the basic stress-strain relationship, known as Hooke's Law. In matrix notation Hooke's Law is,

$$\sigma = C \varepsilon$$

where,

σ = stress tensor

C = stiffness tensor

ε = strain tensor

An alternative vector/matrix representation of the above equation can be found in Appendix A.1.

The reason for introducing symmetry systems and the stiffness matrix will be obvious in the following part of the report. It turns out that anisotropy has a close relationship with the stiffness (elastic) coefficients. Different solids with different symmetry systems are compared through the C matrix. The wave equation can be expressed through the elastic coefficients which allow for wave equation modeling.

The matrix configuration for each of the eight symmetry systems are different and will not be discussed individually. However, *hexagonal symmetry* which is commonly known as *Transverse Isotropy* (TI) will be further investigated. This is the type of anisotropy we are interested in modeling at Glenn Pool. Appendix A.2 shows the stiffness matrix in anisotropic (TI) media.

Now the question is “Why TI ?” The precise physical causes of anisotropy in Glenn Pool are not known. We suspect that repeated sequences of finely layered sediments (sand/shale alternation), and/or grain alignments in shales are the primary causes for anisotropy. This layer-induced anisotropy is classified as TI (Helbig,¹¹ Crampin,⁷ and Byun and Corrigan¹⁰). TI is also a general form of anisotropy with a wide range of geophysical applicability (Thomsen¹²) with an axis of symmetry normal to the layering (e.g., Symmetry axis is vertical if the beds are horizontal).

The **C** matrix can be used in the equation of motion from which a quasi-compressional (qP), and two quasi-shear (qSV and SH) velocities are derived for three orthogonal directions of wave propagation. The derivation can be found in Daley and Hron¹³ and Crampin.¹⁴ Thomsen¹² suggests a compact definition of the exact *phase velocity* relationships (Appendix A.3) which include the stiffness (elastic) coefficients, C_{ij} . This approach is useful in forward modeling since wave equations can also be expressed through these coefficients.

However, the notation introduces ambiguity when assessing the effects of anisotropy on seismic measurements. It is not clear what these coefficients (C_{ij} ’s) really represent in terms of anisotropy. Certain combinations of the elastic coefficients are sought to eliminate the obscured effect of anisotropy from the phase velocity equations. This was done by defining three dimensionless (ϵ, δ, γ) parameters (Thomsen¹²) which would simplify the velocity relationships given in Appendix A.3. Together with vertical P and S velocities ($V_p^\perp$ and $V_s^\perp$, respectively), the dimensionless parameters (ϵ, δ, γ) would be appropriate to describe anisotropy. These five parameters ($V_p^\perp$, $V_s^\perp$, ϵ, δ, γ) are described in terms of the five independent elastic coefficients (C_{11} , C_{33} , C_{44} , C_{66} , C_{13}) and the density (ρ). These relationships are included in Appendix A.4.

The advantages of using these suggested parameters are demonstrated and discussed in Tsvankin¹⁵ to a great extent, as well as Thomsen’s¹² original paper.

For the sake of algebraic simplicity in the equations the phase velocities are derived using a “weak anisotropy” approximation. Thomsen¹² justifies this assumption by compiling a list of published anisotropy measurement data in sedimentary rocks. It is shown that most of them fall into the weak-to-moderate anisotropy range, which is less than 20% deviation from isotropy.

The three approximate phase velocity relationships expressed in terms of the five parameters ($V_p^\perp$, $V_s^\perp$, ϵ, δ, γ) are given in Appendix A.5.

Again note that these equations are in simplified form by making the weak anisotropic assumption.

An important point is that the wavefront (phase) angle and ray (group) angle are different in a TI medium. **Figure 10** illustrates the difference in a wavefront snapshot in an isotropic versus anisotropic medium. Clearly, for the isotropic example the normal to the tangent at the ray-wavefront intersection goes through the point source location. Phase angle and ray angle are identical. However, in the anisotropic case one can define a phase angle (θ) and a ray angle (Φ), which do not coincide. Our objective is to trace rays in an anisotropic medium. Therefore, we need to determine the relationship between phase angle and ray angle (also the relationship between phase velocity and ray velocity). This would enable us to express ray velocities as a function of ray angle along which the energy propagates. Note once again that above equations are used to calculate *phase velocities* for different wave types (P, SV, SH) given the anisotropic coefficients (ϵ, δ, γ) and the *phase angle* (θ).

A detailed explanation relating phase angles to ray angles is found in various publications (Berryman,¹⁶ Byun,¹⁷ and Thomsen¹²). Here, a linearized relationship discussed in Thomsen¹² is given. The derivation can be found in Berryman¹⁶ and Thomsen.¹² We restrict the discussion to P-waves only, since this is the type of wave under attention in the Glenn Pool project.

P-wave group angle is expressed by the following linear approximation,

$$\tan \Phi_p = \left[1 + 2\delta + 4(\epsilon - \delta) \sin^2 \theta_p \right] \tan \Phi_p$$

where,

Φ is the ray (group) angle

θ is the wave front (phase) angle

The idea is to find the phase angle (θ) for a given ray angle (Φ) with the above equation, and make use of the linear approximation between phase and ray velocities to calculate the ray velocity, $V_p(\Phi)$,

$$V_p(\theta) = V_p^\perp \left(1 + \delta \sin^2 \theta \cos^2 \theta + \epsilon \sin^4 \theta \right) V_p(\Phi)$$

The group velocity calculation will be an important component of estimating travel times along the ray trajectory for this study.

ISOTROPY

ANISOTROPY

Figure 10: Wavefronts in isotropic (top) and anisotropic (bottom) media. Note the difference in wave and ray angles for the bottom picture.

4.1.2 Causes and Recognition of Anisotropy

In sedimentary rocks the primary cause of seismic anisotropy is the “layer-induced” anisotropy mentioned earlier in this report. Seismic waves propagating through an alternation of thin layers (much less than a wavelength) average the individual properties of these layers. Therefore, the waves behave as if propagating through a single transversely isotropic composite solid. A recent paper by Brittan et al.¹⁸ investigates the equivalent effect of combination of isotropic materials resulting in anisotropy.

A uniform material with internal structure (cracks, pore space alignment, accretion surfaces, ripple bedding, cross stratification) considerably smaller than the seismic wavelength will also cause anisotropy. These sedimentological features are in the order of a few centimeters (even millimeters) which is orders of magnitude smaller than the typical wavelengths (several tens of meters).

A core description from the Glenn Pool field provides a good physical evidence of small scale features. These include very thin (1-2 mm) horizontal lamination, interbedded silt (1 mm - 1 cm), etc. However, this is just half of the picture. Do these small scale features really cause anisotropy in the Glenn Pool field? Commonly, anisotropy is inferred from discrepancies. An example is a mismatch in depths calculated from stacking velocities and well logs, or, the disagreement of interval velocities from stacking velocities versus those from well logs. In this respect the Glenn Pool surface seismic data is an important information source for deducing anisotropy.

The clues for anisotropy can be sought through (a) Field/Laboratory observations, (b) Qualitative assessment.

(a) Field/Laboratory Observations of Anisotropy

Anisotropy can be recognized in various ways in seismic measurements. Here are a couple methods of detecting anisotropy:

- Compare Log data (V_v) with a common level gather from a crosswell survey (V_h). Due to the nature of sonic logging technique, vertical slowness values (in μ s/ft) are recorded. A sonic log from the 1220-1580 ft depth interval is shown in **Figure 11**.

A constant level (zero vertical offset) gather can be pulled out from a crosswell data by extracting the travel times for a source-receiver pair at the same depth. Subsequently

Figure 11: Sonic Log for the 1220-1580 ft. from Self #82. This depth interval corresponds to the crosswell image plane depths. Note the three distinct zones labeled as A, B, and C.

dividing the time (μ s) into offset (ft) (well spacing) will provide a comparable scale to that of a sonic log. **Figure 12** is a common level gather between two wells (82-64) in the Glenn Pool Field. Figure 11 and 12 compare well for intervals marked as B and C on both figures. However, for interval A (1220-1360 ft) there is a considerable mismatch. Log values indicate slowness values of around $90 \mu \text{ s/ft}$ ($= 11000 \text{ ft/s} = V_v$), whereas the pseudo-sonic values are around $70 \mu \text{ s/ft}$ ($14300 \text{ ft/s} = V_h$) for the same interval. This is to demonstrate that velocity comparisons are possible when crosswell and log data are available.

- Compare V_v with V_h from core measurements.

Figure 13 is a plot of vertical and horizontal P-wave velocities of 40 dry core plug measurements from the 1424-1573 ft depth interval of the Self #82 core. A 45° line is drawn to indicate where $V_v = V_h$ pairs would fall. The values on top of the data points indicate the depth in feet from which the velocity measurement is taken. **Figure 14** presents the data in a different perspective more conformable with the anisotropy concept. Here, the epsilon value, calculated from vertical and horizontal velocities, indicating the velocity anisotropy of the medium is on the y-axis and it is plotted against depth. An isotropic measurement would fall on the zero-line. Any deviation away from this line indicates presence of velocity anisotropy.

(b) *Qualitative Assessment*

This type of anisotropy detection does not yield a value for the degree of anisotropy present. However, it may be useful for realizing the problem and correcting for it.

A typical observation of anisotropy on a tomogram is the diagonal velocity anomalies which are not part of a real subsurface feature. A round velocity artifact often appears in the middle of the tomogram as well (see **Figure 15**).

Usually these velocity artifacts appear when isotropic tomography method is used for an anisotropic medium (Carrion et al.,¹⁹ and Bozkurt and Liner²⁰). Anisotropic treatment is essential to remove these anomalies which introduce error to the constructed image.

Figure 12: Common Level Gather (zero vertical offset gather) for an image plane between wells 82 and 64. The first arrival times are scaled to a unit comparable to a sonic log. Zones B and C are in relative agreement with Figure 11; Zone A is not.

Figure 13: Comparison of vertical and horizontal P-wave core measurements. Numbers posted on data points indicate depth.

Figure 14: Epsilon ($(V_h - V_v)/V$) as a function of depth. Samples with identical vertical and horizontal velocities should fall on the zero-line.

Figure 15: Straight ray, isotropic velocity tomogram between wells 63 and 82. Note the poor image quality. Ball-shaped velocity anomaly at 1400 ft. and diagonally extending linear features are artifacts. Isotropic tomography applied to an anisotropic medium typically causes these unreal velocity structures.

4.1.3 Measuring Anisotropy

Recall that for the linearized group angle and velocity relationship, δ and ε are the two anisotropy parameters that have to be quantified.

The parameter, ε , is shown to be the fractional velocity difference between vertical (V_v) and horizontal (V_h) velocities (Thomsen¹²). It is expressed as,

$$\varepsilon = \frac{V_h - V_v}{V_v}; \text{ } V \text{'s are P-wave velocities.}$$

This parameter can easily be determined locally from the core measurements. However, one requirement we need to keep in mind is that for a 3-D ray tracing algorithm, the anisotropic parameters need to be assigned over a gridded volume, in 3 dimensions. This problem is not addressed in this paper. However, it is the next step we should proceed with. We can calibrate a seismic attribute to the anisotropic parameter at the well location and map the anisotropic parameter within the 3-D volume coverage.

The parameter δ can be found with a combination of log and seismic data. For a horizontal reflector, the normal-moveout (NMO) velocity can be defined as (Thomsen¹²),

$$V_{nmo}(dip = 0) = V_p^1 \sqrt{1 + 2\delta}$$

Solving for δ gives,

$$\delta = \frac{1}{2} \left(\frac{V_{p_{nmo}}^2}{(V_p^1)^2} - 1 \right)$$

where,

P-wave NMO velocity, $V_{p_{nmo}}$, can be obtained from seismic data.

Vertical P-wave velocity, V_p^1 , can be obtained from sonic log.

4.1.4 Travel Time Calculation Methods

Having completed an investigation of anisotropy, anisotropic parameters and necessary velocity relationships, We will briefly compare/contrast the major travel time calculation methods, developing the utilization of anisotropy for the fixed point travel time method.

The three major travel time calculation methods are: finite difference eikonal method, shooting method, and fixed point method.

(a) *Finite Difference (F.D.) Eikonal Method*

The eikonal method always calculates the first arrival times which are required for travel time tomography applications. Travel times are calculated at all grid points by constantly making use of previous calculations. This method can be computationally slow compared to other methods if few receivers are used.

(b) *Shooting Method*

In the shooting method rays are launched from the source point into the medium at certain angles and azimuths. Rays honor Snell's Law at each velocity discontinuity. The "hope" is that ray makes it to the designated receiver. A ray is not guaranteed to reach a receiver.

Unlike the eikonal finite difference method, in the shooting method, shadow zones can be created. Also a ray may not always correspond to the first arrival ray. On the other hand, shooting methods are relatively inexpensive.

(c) *Fixed Point Ray Method*

The fixed point ray bending method traces a ray from source to a designated receiver location. This avoids the problem of "zone of no illumination" associated with shooting methods.

This method starts with an initial raypath connecting the source to the receiver. In a forward problem the raypath is perturbed until the least travel time is reached when simulating first arrivals. In an inverse problem the waves are bent, and velocity field is updated until the difference between the observed and calculated travel times is minimized.

4.1.5 Integration of Anisotropy

This section discusses how anisotropy can be incorporated into a fixed point ray bending method.

- Derive ϵ , δ parameters from seismic, log data for a gridded 3-D volume (explained previously)
- For each ray perturbation, for each cell that the ray goes through, calculate ray angle and ray path length within the cell.

- For each calculated ray angle, calculate a phase angle.
- For each phase angle calculate the phase velocity. Using the Thomsen¹² approximation, derive the ray velocity.
- Using the ray velocity and the raypath length, calculate the travel time.
- Minimize the time difference for the cumulative travel time along the ray trajectory and the observed travel times by updating the velocity field (ray velocity) in each cell.

4.2 3-D Seismic Data Acquisition

A 3-Dimensional surface seismic survey is planned for acquisition on part of the Glenn Pool Field, including the W. B. Self Unit. The survey was organized by C. Liner of The University of Tulsa on the basis of in-kind contributions by Uplands Resources, The University of Tulsa (TU), Mercury International Technologies (MIT), and Nemaha Resources.

The total area of the survey will be approximately 10 square miles. Although related to the ongoing DOE research project involving Uplands Resources and The University of Tulsa, this seismic survey is to be acquired, processed, and interpreted through in-kind contributions and without use of DOE funds. The market value of the survey is approximately \$300,000.

The objective is to acquire (Nemaha), process (MIT), and interpret (TU) a 3-D seismic survey over an area including and extending beyond the Self Unit.

Specific interpretation objectives include: (i) analysis of the Glenn Sand interval for evidence of channels and/or reservoir quality indicators, (ii) structural interpretation of the Wilcox formation, and (iii) structural interpretation of the Arbuckle formation.

With the growing trend toward the use of 3-D seismic in all phases of exploration and production, we feel this project will serve as an example and a stimulus to 3-D work in the shallow oil province of Northeastern Oklahoma. It is our intention to hold the data confidential for a period of one year commencing at the time acquisition is complete. However, in this period certain portions of the data may be shown by the partners for purposes of advertising and/or technical presentation. Beyond the one year confidentiality period, the data may be released in whole or in part at the discretion of each partner individually.

This is an important project that should benefit all parties involved, and enhance the existing DOE Glenn Pool project.

5. Technology Transfer Activities

In this section, we briefly discuss the technology transfer activities conducted as part of the project. Briefly, we have published several papers and made several presentations in various meetings to promote the success of the project. In addition, we have also participated in the Class I Traveling Workshop Series organized by BDM-Oklahoma, Inc. to promote the project.

5.1 Publications and Presentations

- Two abstracts were accepted for the March 5-8 AAPG(American Association of Petroleum Geologists) 1995 Annual Meeting in Houston. Approximately 45 slides and 20 poster figures were prepared.

The poster presentation titled "Interdisciplinary Analysis of Fluvial Dominated Deltaic Reservoirs: Glenn Pool field, Creek County, Oklahoma" was presented at the student session. It was awarded Second Place in the Student Paper competition. The oral presentation "Characterization of Fluvial-Dominated Deltaic Reservoirs in a Mature Oil Field: Glenn Pool Field, Northeastern Oklahoma" was given in the Field Compartmentalization Technical Session. The results were of interest to independent operators and other researchers as judged by several meaningful discussions that followed the presentation.

- Two oral presentations and short papers were prepared for the October 8-10, 1995 AAPG Midcontinent Section Meeting in Tulsa, Oklahoma. The papers are titled: "Application of Microresistivity Image Logs in Detailed Reservoir Architecture Reconstruction of Glenn Sandstone, Glenn Pool Field, Northeastern Oklahoma" and "Integrated Reservoir Description and Flow Performance Evaluation: Glenn Pool Field-Self Unit Study." The first paper and oral presentation centered on how to use this advanced technology to better constrain the lithologic heterogeneity found in the Glenn Sandstone (Ye, L., and Kerr, D. R.²¹). In addition, it includes an example of finding the apparently unswept oil (at perhaps original saturation) in the splay complexes of DGI D interval in the vicinity of the Uplands Self No. 82, a project well (**Figure 16**). The second paper described the application of integrated approach in developing a reservoir management plan for the Self Unit. This meeting was largely attended by independent operators, so it was an ideal forum for presenting these successful results.

Figure 16: Microresistivity image and tadpole plot for DGI D in the Self No. 82 well. Note that the DGI D is made up of 4 splay units each having a different average paleocurrent direction. The darker image color of sandstone in the D2 unit is the result of relatively higher water saturation. It appears that of the 22-ft thick DIG D only some 4-ft have ever been contacted by injected flood waters in the vicinity of Self No. 82; the other sandstones may very well contain original oil saturations. This point is not obvious in the conventional wireline log.

In addition, another poster presentation, titled "A Multi-Disciplinary Approach for Reservoir Characterization in the Glenn Pool Field, Oklahoma" was also presented in the same meeting. As other papers, this poster also attracted the attention of various operators and small independents.

- A poster paper titled "Integrated Reservoir Description and Flow Performance Evaluation: Glenn Pool Field - Self Unit Study" was presented at the Annual SPE Meeting in Dallas, Texas. This poster attracted a lot of attention. Over 100 people visited the poster and asked very detailed questions regarding the success of the project. Visitors included employees from both the major oil companies and the small operators.
- A paper titled "Implementation of Reservoir Management Plan - Self Unit, Glenn Pool Field" will be presented in the independents forum in the IOR Meeting that will be held in Tulsa, Oklahoma in April, 1996. We expect several small operators to attend the session.

5.2 Workshop

As part of the technology transfer program, Mohan Kelkar and Dan Richmond participated in a traveling workshop series organized by BDM-Oklahoma, Inc. The purpose of the workshop series is to make small operators aware of the technologies used in the Class I projects. The workshop included four Class I projects including this project. A total of six workshops were held at the following locations: Bartlesville, Oklahoma; Wichita, Kansas; Denver, Colorado; Billings, Montana; Oklahoma City, Oklahoma; and Grayville, Illinois.

The University of Tulsa intends to conduct several one day workshops addressing the specific technologies developed in this project over the summer of 1996. Currently, preparations are under way for these workshops.

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Appendix A

A.1 Hooke's Law And The Stiffness Matrix

In matrix notation Hooke's Law is,

$$\sigma = C\varepsilon$$

where,

σ = stress tensor

C = stiffness tensor

ε = strain tensor

Hooke's Law can be alternatively expressed in terms of vector/matrix notation as,

$$\begin{bmatrix} \sigma_{xx} \\ \sigma_{yy} \\ \sigma_{zz} \\ \sigma_{xy} \\ \sigma_{yz} \\ \sigma_{zx} \end{bmatrix} = \begin{bmatrix} C_{11} & C_{12} & C_{13} & C_{14} & C_{15} & C_{16} \\ & C_{22} & C_{23} & C_{24} & C_{25} & C_{26} \\ & & C_{33} & C_{34} & C_{35} & C_{36} \\ & & & C_{44} & C_{45} & C_{46} \\ & & & & C_{55} & C_{56} \\ & & & & & C_{66} \end{bmatrix} \begin{bmatrix} \varepsilon_{xx} \\ \varepsilon_{yy} \\ \varepsilon_{zz} \\ \varepsilon_{xy} \\ \varepsilon_{yz} \\ \varepsilon_{zx} \end{bmatrix}$$

$(C_{ij} = C_{ji})$

where stiffness matrix C is,

$$\begin{bmatrix} C_{11} & C_{12} & C_{13} & C_{14} & C_{15} & C_{16} \\ & C_{22} & C_{23} & C_{24} & C_{25} & C_{26} \\ & & C_{33} & C_{34} & C_{35} & C_{36} \\ & & & C_{44} & C_{45} & C_{46} \\ & & & & C_{55} & C_{56} \\ & & & & & C_{66} \end{bmatrix}$$

$(C_{ij} = C_{ji})$

Note that in some publications (e.g., Love⁹ and Byun and Corrigan¹⁰), C matrix is expressed with letters,

$$\begin{vmatrix} A & H & G & P & Q & R \\ & B & F & S & T & U \\ & & C & V & W & X \\ & & & L & K & J \\ & \text{symmetric} & & & M & I \\ & & & & & N \end{vmatrix}$$

However, the notation is not convenient, especially in implementing algorithms, and its use is discouraged (Crampin⁷).

A.2 The Stiffness Matrix In An Anisotropic Medium

The stiffness matrix, C , of a TI medium is,

$$\begin{vmatrix} C_{11} & C_{12} & C_{13} & 0 & 0 & 0 \\ & C_{22} & C_{23} & 0 & 0 & 0 \\ & & C_{33} & 0 & 0 & 0 \\ & & & C_{44} & 0 & 0 \\ & \text{symmetric} & & & C_{55} & 0 \\ & & & & & C_{66} \end{vmatrix}$$

In fact, the stiffness matrix of a TI medium has only five independent components (C_{11} , C_{13} , C_{66} , C_{33} , and C_{44}). The rest (C_{12} , C_{22} , C_{23} , C_{55}) can be expressed in terms of the five independent components,

$$C_{12} = C_{11} - 2C_{66}$$

$$C_{22} = C_{11}$$

$$C_{23} = C_{13}$$

$$C_{55} = C_{44}$$

The stiffness matrix, C , can then be re-written using the five independent components as,

$$\begin{vmatrix} C_{11} & C_{11} - 2C_{66} & C_{13} & 0 & 0 & 0 \\ & C_{11} & C_{13} & 0 & 0 & 0 \\ & & C_{33} & 0 & 0 & 0 \\ & & & C_{44} & 0 & 0 \\ & \text{symmetric} & & & C_{44} & 0 \\ & & & & & C_{66} \end{vmatrix}$$

A.3 Phase Velocities

A compact definition of the exact *phase velocity* relationships for P-, SV, and SH waves as suggested by Thompson are,

$$\rho V_p^2(\theta) = \frac{1}{2} [C_{33} + C_{44} + (C_{11} - C_{33}) \sin^2 \theta + D(\theta)],$$

$$\rho V_{sv}^2(\theta) = \frac{1}{2} [C_{33} + C_{44} + (C_{11} - C_{33}) \sin^2 \theta - D(\theta)],$$

and,

$$\rho V_{sh}^2(\theta) = C_{66} \sin^2 \theta + C_{44} \cos^2 \theta$$

where,

$$\begin{aligned} D(\theta) \equiv & \left\{ (C_{33} - C_{44})^2 \right. \\ & + 2 \left[2(C_{13} + C_{44})^2 - (C_{33} - C_{44})(C_{11} + C_{33} - 2C_{44}) \right] \sin^2 \theta \\ & \left. + \left[(C_{11} + C_{33} - 2C_{44})^2 - 4(C_{13} + C_{44})^2 \right] \sin^4 \theta \right\}^{1/2} \end{aligned}$$

ρ = density

C_{ij} = stiffness coefficients

θ = phase angle from vertical

Note the qualifier “quasi-” is dropped from the notation for simplicity

A.4 Anisotropy Parameters

Anisotropy in a medium can be described with the help of the following relationships,

$$V_p^\perp = \sqrt{\frac{C_{33}}{\rho}}$$

$$V_s^\perp = \sqrt{\frac{C_{44}}{\rho}}$$

$$\varepsilon = \frac{C_{11} - C_{33}}{2C_{33}}$$

$$\delta = \frac{(C_{13} + C_{44})^2 - (C_{33} - C_{44})^2}{2C_{33}(C_{33} - C_{44})} \quad (\text{weak anisotropy})$$

$$\gamma = \frac{C_{66} - C_{44}}{2C_{44}}$$

where $\varepsilon, \delta, \gamma$ are the dimensionless anisotropy parameters and $V_p^\perp, V_s^\perp$ are the vertical P- and S-velocities, respectively.

A.5 Approximate Phase Velocities

The exact phase velocities (Appendix A.3) can be approximated using the weak anisotropy assumption and using Appendix A.4 as,

$$V_p(\theta) = V_p^\perp (1 + \delta \sin^2 \theta \cos^2 \theta + \varepsilon \sin^4 \theta),$$

$$V_{sv}(\theta) = V_s^\perp \left[1 + \frac{(V_p^\perp)^2}{(V_s^\perp)^2} (\varepsilon - \delta) \sin^2 \theta \cos^2 \theta \right],$$

and,

$$V_{sh}(\theta) = V_s^\perp (1 + \gamma \sin^2 \theta)$$