INTRODUCTION

The workhorse of the seismic exploration business has been 2D and 3D single component seismic data for many years now, with multicomponent seismic data perceived to hold a niche interest, largely in research projects. Within that niche, 3C/4C data has proven to be a valuable tool for structural imaging below gas and much of the development work is narrowly focused to support that objective. Early attempts to extend beyond structural interpretation were often met with disappointment because the fundamental data quality and processing technology simply weren’t up to the higher standards required. Acquiring high quality 3C/4C data is considerably more difficult than 1C data, especially offshore, with issues such as orientation and ground coupling having a great deal of impact. Processing 3C/4C data isn’t just an extension of processing 1C data, but instead requires dedicated algorithms, tools, and procedures. The result of these early disappointments is that the 3C/4C business has been slow to develop and realize the full benefit of the multicomponent measurement. However, recent advances in both acquisition and processing technology are beginning to generate renewed interest in multicomponent seismic data, and recent successful field cases are paving the way toward a better understanding of reservoir characteristics. Given the ability of 3C/4C data to discriminate between sand and shale, it is reasonable to suggest that multicomponent seismic surveys could become a powerful reservoir appraisal tool.

MULTICOMPONENT SEISMIC PRINCIPLES

In the petroleum industry, the term ‘seismic’ refers to the measurement of elastic or acoustic signals at receiver locations as the result of energy released at source locations. The source generates elastic waves that propagate through the earth where it is reflected, refracted, polarized and absorbed according to wellknown physical principles. In this way the seismic signals reflect the properties of the subsurface at and between wells. The primary interest in petroleum geophysics is the reflection at interfaces (such as a sand/shale boundary), although other mechanisms are increasingly important as well. Conventional surface seismic uses compressional waves (P-waves) to explore the subsurface, and the resulting images reveal the P-wave properties of the subsurface, comprising both the rock matrix and the fluid contained within the pore space. In multicomponent seismic, we seek to also utilize shear waves (S-waves) to explore the subsurface. Shear waves travel primarily through the rock matrix and are relatively unaffected by the pore fluid. This means that the fluid type, saturation, and pressure do not impact the propagation of shear waves, whereas they do affect compressional waves. This is important when the P-wave image is obscured as a result of gas filled pores since the S-wave image will not be obscured.

Just as the P-wave image reveals the compressional wave properties of the subsurface, the S-wave image reveals the shear wave properties of the subsurface. Since the two measurements are independent measures of the same subsurface, the combination of the two can be used to get better and more reliable reservoir property estimates.

At an interface, compressional waves reflect compressional waves, as expected, but also convert some energy to shear waves. Experience has shown that most of the shear wave energy recorded at the surface was converted and reflected from points in the subsurface, as opposed to near-surface conversions associated with transmission and refractions. This observation allows several simplifying assumptions that expedite processing, but also produces common terminology referring to recorded P-wave energy as PP (P-wave down, P-wave up), and recorded S-wave energy as PS (P-wave down, S-wave up). These converted waves are
the most common source of shear waves in multicomponent seismic surveys since shear wave sources are expensive in land applications, and rare in marine applications. The velocity of shear waves is lower than for compressional waves in the same medium. This leads to increased resolution on converted waves observed downhole on a VSP survey. However, the attenuation of the high frequency shear waves is higher than the corresponding P-waves traveling back to the surface. Therefore, the increased resolution observed downhole on a VSP survey is not observed on the surface seismic measurement. In general, converted wave data in the shallow part of a section is often observed to have higher resolution than the P-waves, but the opposite effect is observed in the deeper parts of a section. That said, good converted wave data has been recorded from very deep reflectors.

MULTICOMPONENT SEISMIC MEASUREMENT

Multicomponent seismic data must be measured using receivers (geophones) that are in good contact with the ground. In land applications, this is similar to the standard acquisition configurations, but with a three component (3C) sensor package instead of a single component package (1C). The 3C configuration requires three times the recording channels and data volume, in addition to tighter operational specs for orientation and deployment.

In marine applications, however, there are considerable differences because the receivers must sit on the sea floor (also known as OBC for ‘ocean bottom cable’), or be trenched into the sea floor for permanent installations. Handling a seabed cable is quite different from handling a towed streamer, and a lot of effort has gone into operating the cable at increased water depth, including positioning, and safe deployment and retrieval.

The seismic source, however, is still a towed marine seismic source generating compressional waves in the water layer, giving recorded shear waves from conversion in the subsurface. The need for a seabed cable leads to different cable fabrication and operational requirements that make multicomponent seismic acquisition in marine environments considerably more expensive than marine streamer acquisition. This increase in cost is often justified by the uniqueness of the additional measured components that provide solutions to more geologic and geophysical problems, as will be discussed in the next section. As in land applications, the OBC sensor package measures and records three components instead of one. In addition, the OBC sensor package contains a hydrophone to measure pressure waves in the water, making it a 4C package instead of 3C. The combination of hydrophone and vertical geophone component enables processors to suppress most of the multiple energy reflected from the sea surface. As this multiple is commonly very strong, this combination can be crucial for the results of the P-wave processing.

Multicomponent sensor packages, whether 3C or 4C, measure motion in three orthogonal vector directions. The sensors used are either omni directional, which means they will operate correctly at any orientation, or specifically horizontal or vertical, which means that they will only operate at that orientation. On land, correct orientation is obtained through careful deployment, often called ‘planting’. On the seabed, orientation can be obtained through using gimbaled geophones. When the sensor is ‘gimbaled’, it means it is free to rotate to ‘find vertical or horizontal’ for any given cable deployment. For omni directional sensors, the direction either has to be measured separately or derived from the data.

The vertical sensor yields a measurement similar to the single component measurement of conventional seismic data. Most of the energy on this vertical sensor will be P-wave energy because the shear velocity is very low in the near surface. Conversely, the two horizontal sensors will measure most of the S-wave energy.

APPLICATIONS OF MULTICOMPONENT SEISMIC

Table 1 presents a list of geologic and geophysical problems that could potentially be addressed by shear wave data, along with an assessment of the likelihood that the shear wave data will solve that problem. This assessment is a couple years old now, and is the result of polling the participants in a 2001 SEG summer workshop focused on the topic of multicomponent seismic. (Gaiser et.al., 2001) As such, it cannot be considered technical proof of multicomponent applications, but instead is expert guidance based on experience using multicomponent technology available up to that time. The table lists the highest ranked ‘proven’ applications as 1) imaging below gas clouds, 2) imaging targets of poor PP reflectivity, 3) lithology delineation of clastics, and 4) increased shallow resolution (<1000m depth). Indeed, several publications have illustrated the use of multicomponent data in imaging below gas clouds (Nahm and Duhon, 2003; Li et.al., 2001), and the Alba Field in the North Sea is a good example of imaging targets of poor PP reflectivity (MacLeod et.al., 1999; Hanson et.al., 2003). The list comprising ‘proven’ and ‘probable’ is much longer, and addresses problems that are more widespread and more applicable to the task of characterizing reservoirs. Note that for most of these applications, there was no dissent, in that even if participants didn’t think the application had been proven, they still thought it was possible. Such an opinion-based poll does not establish technical feasibility, but with new technologies on the horizon, it is likely that more of these applications will become ‘proven’.

Most of the problems in the list, and indeed most of the published papers, are directly related to imaging interfaces,
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but some are related to layer properties. In the following discussion, these characterization-related applications are grouped to focus on activities common to reservoir characterization needs.

Fault and fracture characterization

Listed in Table 1 as Fracture characterization (orientation and density) and Imaging faults. Faults and fractures are very different features, but both have a significant impact on reservoir volume, flow, and recovery factor. Fracture characterization has been a target for multicomponent research for many years, so the theory of shear-wave splitting is well developed (Michelena et.al., 2001; Ata and Michelena, 1995).

Table 1: Results of the shear-wave poll from the 2000 SEG/EAGE Summer Research Workshop.

<table>
<thead>
<tr>
<th>Geologic/geophysical problem</th>
<th>Proven</th>
<th>Possible</th>
<th>Improbable</th>
<th>Abstain</th>
</tr>
</thead>
<tbody>
<tr>
<td>Imaging below gas clouds</td>
<td>100</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Imaging targets of poor PP reflectivity</td>
<td>86</td>
<td>14</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lithology delineation : clastics</td>
<td>56</td>
<td>44</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Increase shallow resolution (&lt;100 m depth)</td>
<td>56</td>
<td>40</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>Fracture characterization (orientation and density)</td>
<td>46</td>
<td>54</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fluid discrimination</td>
<td>33</td>
<td>67</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Detection of shallow gas</td>
<td>17</td>
<td>83</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Imaging faults</td>
<td>15</td>
<td>85</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Imaging below salt</td>
<td>14</td>
<td>85</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Density estimation</td>
<td>12</td>
<td>88</td>
<td></td>
<td></td>
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<tr>
<td>Pore pressure prediction</td>
<td>8</td>
<td>92</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stress characterization</td>
<td>8</td>
<td>91</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Reservoir monitoring</td>
<td>4</td>
<td>96</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Detection of shallow water flows</td>
<td>100</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Lithology delineation carbonates, evaporites</td>
<td>100</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Imaging below basalt</td>
<td>97</td>
<td>3</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Imaging below chalk</td>
<td>97</td>
<td>3</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Increase deep resolution (&gt;100m depth)</td>
<td>90</td>
<td>10</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Imaging with multiples</td>
<td>13</td>
<td>65</td>
<td>22</td>
<td></td>
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<tr>
<td>Gas hydrates</td>
<td>89</td>
<td>11</td>
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<td></td>
</tr>
<tr>
<td>Imaging complex structures (overthrust)</td>
<td>80</td>
<td>20</td>
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<td></td>
</tr>
<tr>
<td>Formation strength (drilling hazard)</td>
<td>64</td>
<td>4</td>
<td>32</td>
<td></td>
</tr>
<tr>
<td>Permeability estimation</td>
<td>55</td>
<td>20</td>
<td>25</td>
<td></td>
</tr>
<tr>
<td>Coal-bed methane</td>
<td>4</td>
<td>48</td>
<td>48</td>
<td></td>
</tr>
</tbody>
</table>

* The numbers indicates the percentage of workshop attendees that selected each category. Detailed definitions of proven, possables and abstain are given in the text.

Simply put, shear wave splitting theory states that S-wave energy polarizes, or ‘splits’, into vector directions aligned with the fracture direction (fast path) and perpendicular with the fracture direction (slow path). Mathematically rotating the acquired shear components identifies these fast and slow directions to suggest fracture orientation, and the velocity difference between the fast and slow components suggests the fracture density. While fracture orientation and density can be obtained from a carefully designed single component survey, utilizing measured shear components is more reliable. Figure 1 illustrates fracture orientation and density resulting from azimuthal anisotropy analysis. Rapid changes in fracture properties suggest key reservoir features that could control fluid movement within the reservoir, and that would be difficult, if not impossible, to anticipate from well data alone.

Fault imaging can be improved using multicomponent data when either 1) the P-wave data is obscured by a gas cloud, or 2) the OBC-derived P-wave data quality is better than the streamer-derived P-wave data. These imaging and interpretation issues have been well covered in the published literature (Nahm and Duhon, 2003; MacLeod et.al., 1999).

Drilling hazard identification

Listed in Table 1 as Pore pressure prediction, Detection of shallow-water flows, Stress characterization, and Formation strength (drilling hazard). Drilling is one of the largest costs, and certainly the greatest source of risk and uncertainty, in developing a petroleum reservoir. As such, much work has gone into using seismic data to predict hazards that will likely be encountered by the drill bit, allowing the driller to plan mitigating measures (Sayers et.al., 2001; Huffman and Castagna, 2001).

P-wave seismic data is currently used for this purpose, but S-wave seismic data could improve the accuracy and confidence in the result. Many techniques require estimates of density, Poisson’s ratio, and lithology from the seismic data to make the pressure and rock strength predictions, but P-wave seismic data alone cannot distinguish the
influences of fluid, lithology, and pressure. Adding the S-wave seismic data reduces some of this ambiguity, allowing better estimates of reservoir properties and the subsequent improvement of pressure and rock effective stress predictions (Huffman and Castagna, 2001).

**Reservoir property prediction**

Listed in Table 1 as Reservoir monitoring and Permeability estimation. The holy grail of reservoir engineering is to have a noninvasive measurement that will accurately provide reservoir properties throughout the reservoir. As with most things in this industry, multicomponent seismic doesn’t provide the ultimate answer, but does provide unique information that helps estimate some of the properties needed (Fontaine et al., 1998; Jack, 2001). Since lithology and fluid will be discussed in the following sections, here we focus on permeability and the changes in saturation and pressure over time.

While there is some theory that reservoir permeability is related directly to seismic measurements, there was little support for this shown in Table 1. There is, however, a clear relationship between reservoir permeability and time-lapse seismic in that observation of fluid movement over time can be tied to reservoir flow properties. Until permanent reservoir monitoring systems are installed and utilized frequently, it is unlikely that time-lapse seismic will yield a very sensitive, or highly resolved, measure of permeability.

For reservoir management purposes, however, it is most important to characterize permeability extremes, and time-lapse seismic has proven effective in providing this information (Jack, 2001; Koster et al., 2000; Kloosterman et al., 2003). The clearest indication comes in observing sealing faults that either compartmentalize or control fluid movement. The other extreme, high permeability streaks or layers, can be more difficult because this often implies smaller features (thin thief zones, for example) that would generate less acoustic signal than if the same change occurred over the entire (and thicker) reservoir interval. However, recent developments in history matching systems that add time-lapse seismic constraints, in addition to production data constraints, provide a means to adjust reservoir properties such as permeability to achieve a match (Waggoner et al., 2003).

The role of multicomponent data in this application is two-fold. Firstly, for areas not imaged well by P-wave data, S-wave data may be the only choice for reservoir imaging, and thus time-lapse information. Secondly, the use of both P-wave and S-wave data allows the effects of pressure and saturation changes to be distinguished.

**Discrimination of lithology (sand/shale) and fluid (water, gas, fizzy water)**

Listed in Table 1 as Lithology delineation: clastics, Lithology delineation: carbonates, evaporites, Fluid discrimination, and Density estimation. In terms of understanding reservoir characteristics, lithology and fluid discrimination is perhaps the most significant use of multicomponent data (MacLeod et al., 1999; Hanson et al., 2003; Micheletta et al., 2001; Engelmark, 2001; van Dok and Gaiser, 2001; Margrave et al., 2001). P-wave data propagation is affected by both the rock and fluid, so without knowledge of either, it is impossible to distinguish their effects. Adding the PS data provides the discrimination needed since S-wave is affected only by the rock.

Figure 2 shows a top reservoir amplitude map from the Alba field in the North Sea (MacLeod et al., 1999; Hanson et al., 2003). The sand/shale interface forming the top reservoir is only a weak P-wave reflector, resulting in the poor reservoir image on the PP section on the left. However, that same interface converts P-wave energy to S-wave energy and produces the PS section on the right. The reservoir sands can now be distinguished from the encasing shales, allowing the well to be located just below the top reservoir horizon to reduce the influence of water influx and unproducible attic oil. The PS image also revealed ‘wings’ of sand that changed the understanding of reservoir structure.

Figures 3 illustrates the use of multicomponent data to distinguish between gas and water filled sands. ‘Bright spots’ are high amplitudes that stand out from the surrounding, hopefully caused by the presence of gas (Nahm and Duhon, 2003). Drilling based on bright spot analysis has discovered commercial gas reservoirs, but it has also resulted in dry holes. Misleading P-wave amplitudes come from the fact that high amplitudes can be caused by both fluid and lithological variations in the subsurface. In Fig. 3, a bright spot on PP also looks like a bright spot on PS. Therefore, it is possible to conclude that there must be a change in the lithology at that point. A well was drilled into the target and proved to be dry.

Accurate bright spot analysis must be accompanied by a modeling study to understand the relation between P-wave and S-wave responses. Once a PP/PS pattern is identified through modeling, the seismic cubes can be interrogated to locate desired conditions (Nahm and Duhon, 2003).

**BENEFITS OF MULTICOMPONENT DATA**

Some of the applications described above can be addressed with single component P-wave data, but there are distinct benefits in acquiring the additional shear components.

**Measured, not estimated, Vs**

Measurement of Vs is more accurate and reliable than estimating Vs. In processes requiring Vp/Vs ratio, say to identify shallow water flow drilling hazards, knowing both Vp and Vs removes uncertainty and simplifies the calculation (Huffman...
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and Castagna, 2001). In fluid discrimination, knowing $V_p$ and $V_s$ means the inversion can focus on estimating bulk density, resulting in better identification and quantification of fizzy water or commercial gas deposits.

**Improved $V_p$**

The P-wave signal obtained from OBC acquisition systems is often better than the P-wave signal obtained from marine streamer acquisition (Jack, 2001). On land, there should be no difference between 1C and 3C acquisition, but the acoustically quieter environment on the seafloor can significantly improve the signal to noise ratio compared with the wave and streamer noise environment near the sea surface.

**Shear components**

The shear wave components measure different subsurface properties compared with the P-wave component. The 3C/4C result is more than a higher quality measurement, because comparing the P-wave and S-wave derived properties yields additional information content.

**Acquisition geometry**

In marine seismic, OBC acquisition allows many more options for survey design than does streamer acquisition. In essence, OBC is like land acquisition at sea since receiver lines and source lines are decoupled. Marine streamer systems are constrained to narrow swath geometries with fixed offset and very limited azimuth ranges. Adding a second source boat can add a few options, but will never be comparable to the flexibility of land and OBC geometries. This can be particularly important when anisotropy is significant since wide azimuth surveys are required to properly illuminate and characterize complex subsurface structures.

**RECENT ADVANCES IN MULTICOMPONENT TECHNOLOGY**

Improvements in sensor, cable, and seismic processing technology are producing advances in multicomponent seismic technology that promise to alleviate current limitations and enhance applications.

**Sensor technology**

The miniaturization of electronic components allows more functional and lower cost sensor packages than ever before. Small, yet highly sensitive and robust, sensors replace bulkier geophones as the primary receiver element. These analog signals are digitized at the sensor to minimize subsequent transmission losses. An extensive use of low power consumption electronics allow more sensors on a cable, enabling longer cables and/or shorter receiver intervals. These

Figure 2: PP and PS horizons illustrating the visibility of the top sand reflector in PS but not in PP. The reservoir sand show up so clearly that it is possible to also see, with confidence, additional reservoir sand, called ‘wings’, outside the main channel.

Figure 3: PP and PS sections again illustrating the coordinated use of PP and PS data in bright spot interpretation. In this case, both the PP and PS sections show a bright spot, indicating that the amplitude anomaly is probably the result of a lithology change. A well was drilled into this target, but proved to be nonproductive.
advances improve the density and vector fidelity of OBC data which are known limitations of current systems.

**Cable technology**

Cable technology, including packaging technology, is moving from modified streamer cables toward fit-for-purpose OBC cables. These improvements increase the strength and durability of the system, allowing use at greater water depths. Current systems operate down to the 200 – 500 m range, but newer systems can reach 800 – 1000 m, and above. Given the increased activity in producing deepwater reservoirs around the world, these cable depth improvements are significant. Another advance in cable technology is the use of a high speed network backbone on the seafloor to permit the high channel count required for dense spacing of multicomponent sensor packages.

**Processing multicomponent data**

Just as multicomponent data consists of P-wave and S-wave elements, multi-component processing consists of P-wave and S-wave steps. Firstly, the P-wave component is processed much the same as conventional processing. Most of the advances in processing conventional surface seismic data are applicable to processing the P-waves in the multicomponent datasets. In particular, advanced prestack migration methods have produced good improvement in seismic images. In 4C data, where hydrophones and vertical geophones are used to suppress water layer related multiples, new methods have been introduced to suppress these multiples.

After this, the S-waves are processed, but are more challenging to process than P-waves. The increased difficulty is largely due to the asymmetric raypath that makes it difficult to correctly bin the data, and polar anisotropy affects the S-wave velocities more than P-wave velocities. A number of published converted wave projects, some of them good success stories, have been processed with fairly rudimentary processing without taking any of the effects above into account. Processing technology has progressed very rapidly, particularly within the last year, and we are now able to correctly handle these effects in processing.

The technique now used to correctly bin the data and compensate for dip and polar anisotropy is a curved ray anisotropic Kirchhoff prestack time migration. The effect of correct binning and traveltime calculation is illustrated by a simple synthetic example, shown in Fig. 4, wherein the full anisotropic curved ray calculation is compared with two isotropic approximations. By getting useful prestack data to higher offset ranges, the final anisotropic Kirchhoff prestack time migration of the converted wave data are yielding significant improvement over more conventional techniques, particularly in complex settings and otherwise difficult seismic areas. However, this kind of advanced processing has so far only been performed on a very small number of surveys.

Shear-wave splitting may provide important information about the subsurface, but if it is not properly accounted for in processing, the final resolution will be limited. Methods are available for analyzing and accounting for shear-wave splitting, and recent examples show how the azimuthally anisotropic processed images give clear improvements over the isotropically processed images. For optimal imaging of converted waves, both azimuthally anisotropic analysis and processing, and anisotropic prestack migration need to be included in the processing sequence. Most older multicomponent survey would undoubtedly benefit from being reprocessed with these new techniques, and likely turn previous failures into good successes.

**Interpreting multicomponent data**

In order to utilize the information contained in the combined PP and PS image for reservoir characterization, the two datasets need to be interpreted together, and corresponding events identified. The PS dataset might look unfamiliar to the inexperienced interpreter, but once correctly interpreted, the PS data can be ‘destretched’ to PP time to verify the interpretation with the PP data, as illustrated in Fig. 5. As with conventional seismic interpretation, the success of multicomponent seismic interpretation also relies on experienced interpreters, including all available borehole and geological information in the process. Interpretation benefits from being part of the processing phase, rather than being left as a separate and sequential task at the end. Part of the interpretation process is to establish the big picture with a small number of corresponding key horizons that are strong in both PP and PS, but not necessarily geological markers that might be strong only in the PP section. For a typical North Sea case, again using Fig. 5, there are a small number of events common to the PP and PS sections, making it possible to establish a reliable overall interpretation as the foundation for more detailed interpretation to follow.

In the Gulf of Mexico (GOM), the typically extensive sand shale sequences in the subsurface makes it difficult to establish a reliable interpretation. One technique that has become increasingly popular within the last year is known as ‘fault registration’. By interpreting the same non-vertical fault on PP and PS sections, the PS section can be ‘destretched’ knowing that the same temporal and lateral position of the fault in the PP and PS sections must correspond, as illustrated in Fig. 6.

**CONCLUSION**

Multicomponent seismic data has seen a relatively slow growth as a niche solution. However, recent advances in the technology and greater understanding of the characteristics and benefits of the measurement, should
broaden its base of applicability and acceptance in the years to come. By understanding the unique information content, the reservoir engineering community will be able to direct the development of multicomponent technology and be in a better position to reap the benefits to reservoir management.

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Figure 6: Multicomponent data from GOM where fault registration is utilized to interpret the data.