HISTORY AND ANALYSIS OF DISTRIBUTED ACOUSTIC SENSING (DAS) FOR

OILFIELD APPLICATIONS

A Thesis

by

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ABSTRACT

The inherent nature of distributed acoustic sensing technology is a direct result of two key components: optical fiber and the speed of light. Because the speed of light is constant and optical fiber is an isolated medium, combining the two creates a mechanism insulated from environmental interference that effectively "moves" at the speed of light. This process is most visible in the telecommunications industry where the technology transports large amounts of data over significant distances at very high speeds.

The same factors that make optical fiber excellent for transporting data (high speed and low environmental interference) also make the technology very applicable for precise measuring applications. Because optical fiber is insulated, a change to the fiber will have a pronounced (measurable) effect. These measurable effects manifest themselves as changes in the amount of light that is reflected within the optical fiber. This change in reflected light can be measured and quantified to indicate both the specific location along the fiber where the change in reflection occurred and the magnitude of the change in reflection. Knowing both the location of the affected area and the extent to which the reflection changed allows for precise measuring and subsequently, educated inferences about what caused the changes initially.

The ability of optical fiber to detect changes at myriad intervals over long distances has particular appeal for functions involving remote and hard to get to environments. Both of these conditions are inherent to the petroleum industry and provide substantial incentive for investigating DAS for oilfield applications.

DEDICATION

To my family and my mom in particular, I love you all and am truly grateful for all of your strength and encouragement.

ACKNOWLEDGEMENTS

I would like to thank my advisors Dr. A. Daniel Hill and Dr. Ding Zhu who guided me throughout the course of this master's degree with extraordinary understanding and kindness.

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1. INTRODUCTION

1.1   History of Distributed Sensing

Optical fiber sensing, as a broadly recognized technology, was initially patented in 1967 by Curtis D. Kissinger (Kissinger, 1967). This first optical sensing device was known as a Fotonic sensor and involved a bifurcated fiber bundle where half of the bundle illuminated a surface and the other half of the bundle received the reflection off the surface. Single mode optical fibers were developed roughly a decade later and significantly changed optical sensing due to the fact that these single mode fibers could be built into interferometers (instruments that use interference patterns to make accurate measurements of waves) (Culshaw and Kersey, 2008).

Since its initial development optical fiber sensing has continued to develop and is now classified into two distinct families: extrinsic sensors (such as the Fotonic sensor described above) and intrinsic sensors such as distributed sensing. For extrinsic sensors the fiber acts primarily as a conduit providing a path for light to travel between two external mediums where the light is affected (modulated). In contrast, intrinsic sensors keep the light within the fiber at all times resulting in only external forces modulating the light as it moves along the fiber. This distinct difference led to the progression from the early work in fiber sensing that concentrated on measuring the physical world at a particular point, to the development of methods for measuring parameter fields as a function of position along the fiber. This distributed measurement feature is a unique

capability and has emerged as an extremely important differentiator of fiber sensor

technology (Culshaw and Kersey, 2008).

Both intrinsic and extrinsic sensors have proven to be commercially viable

technologies and have been coopted by a wide range of industries for a myriad of uses.

These uses rang from leak detection in dielectric fluid filled, high-voltage electrical

distribution lines to estimating locations of Acorn woodpeckers using their vocalizations

(Kurmer et al., 1992; Wang et al., 2005).

1.2   Distributed Sensing Fundamentals

At its core, distributed sensing employs the principle known as of time-of-flight.

The technology itself is comparable to that utilized by RADAR or in any modern

rangefinder. There is no specialized sensing point required, thus making it a very simple

and effective system for measuring over large distances. Where distributed sensing

differs from these other technologies is that the system is fully self-contained, meaning

that the light source is never exposed to anything other than the medium being measured.

Specifically, in fiber optic distributed sensing a laser light is fully encapsulated by a fiber

optic cable, eliminating dispersion of the light source as a function of the environment.

Consequently, fiber optic distributed sensing takes advantage of the fact that the

reflection characteristics of laser light travelling down an optical fiber, vary only with

factors that affect the optical fiber itself, such as temperature, strain or sound (Tanimola

and Hill, 2009).

Distributed sensing, in its most base form, can be thought of as an isolated, self-contained system consisting of thousands of tiny mirrors joined end-to-end. In this arrangement, each individual mirror can be temporally altered on a fundamentally structural level; resulting in measurable changes to the mirror's reflective characteristics. When a mirror is exposed to a temperature, strain or sound (pressure waves – also known as a vibro-acoustic disturbance) the physical structure of the mirror is temporally changed and consequently, the mirror's reflective characteristics. Should the same mirror be exposed to a different temperature, strain, or sound, the physical structure of the mirror as well as the mirror's reflective characteristics will be altered to indicate the change. Distributed sensing works by accurately measuring this change in reflective characteristics which is, as noted above, a direct result of the physical effects the mirror is experiencing.

To measure the changes in reflective characteristics, distributed sensing utilizes three types of measuring systems known as Rayleigh, Raman and Brillouin based systems. This nomenclature is derived, from the frequency of signal that is analyzed and the discrete peaks within the electromagnetic spectrum (**Fig. 1.1**) (Tanimola and Hill, 2009). More specifically, the light scattering in a fiber optic cable contains three spectral parts: (1) Rayleigh scattering which is directly correlated with the wavelength of the laser source used, (2) Stokes line components which are from photons shifted to longer wavelengths (lower frequency) than the Rayleigh and (3) anti-Stokes line components which are from photons shifted to shorter wavelengths (higher frequency) than the Rayleigh (Molenaar et al., 2012).
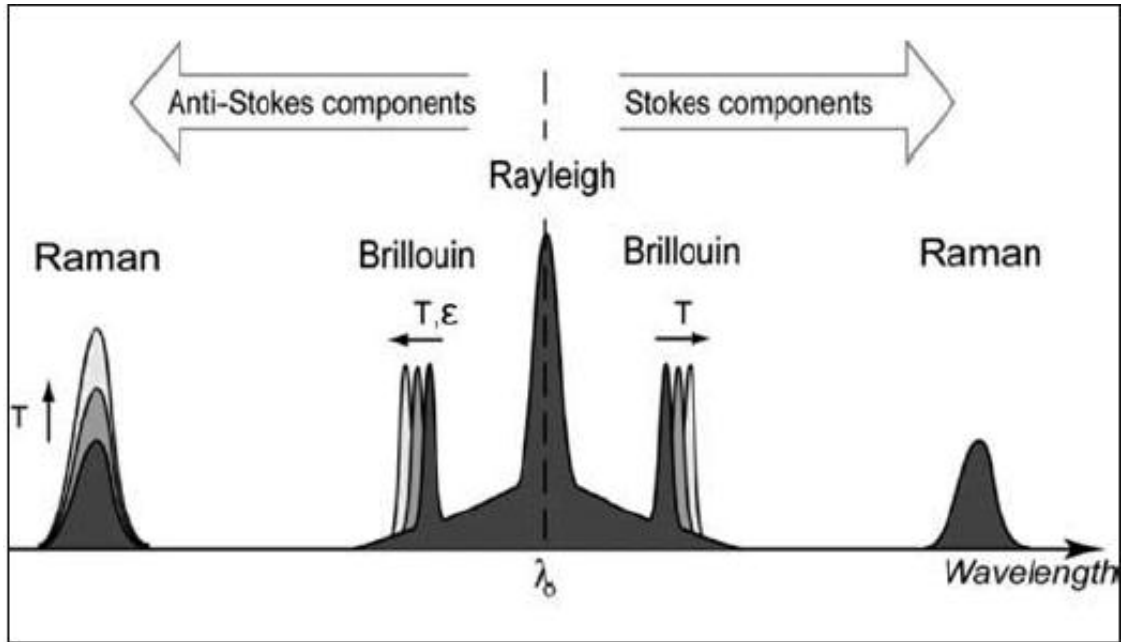
Fig. 1.1—Schematic of Rayleigh, Raman and Brillouin peaks in the electromagnetic spectrum (Frings and Walk, 2011).

By exploiting the unique characteristics of the discrete peaks as well as differences in frequencies, fiber optic distributed sensing is capable of measuring the unique properties of temperature, strain and sound. For Distributed Temperature Sensing (DTS) a Raman based system is employed. In this system the intensity of the Raman component in the anti-Stokes band is temperature-dependent, while the Raman component in the Stokes band is practically independent of temperature. The temperature at any point along the fiber can therefore be determined by computing the ratio of the anti-Stokes to the Stokes reflected light intensities.

In a similar way, Distributed Strain Sensing (DSS) uses a Brillouin system which is strain-dependent in the anti-Stokes band and independent of strain in the Stokes band.

Raman systems (DTS) can provide very accurate temperature measurements with resolution of better than 0.01 °C, without any sensitivity to strain. Brillouin systems (for distributed strain sensing) can measure temperature but are extremely sensitive to strain, hence providing distributed strain measurements (Molenaar et al., 2012; Tanimola and Hill, 2009).

In Distributed Acoustic Sensing (DAS), a Rayleigh system is used to measure sound (pressure waves). A Rayleigh system operates by detecting minute strains induced in the fiber by external vibrations (direct mechanical movement caused by a pressure wave hitting the fiber). The acoustic capability comes from the fact that the Rayleigh signal is continually sampled at high frequency which is limited only by the time of flight for an optical pulse to make the round trip to the end of the fiber and back (roughly the speed of light). Because of the speed with which the samples are attained, an entire pressure wave associated with a "noise" can be detected. Effectively meaning that DAS is "listening" to what is happening to the fiber. By "listening" to what is happening to the fiber, DAS allows for reasonable inferences regarding what caused the "noise" (pressure wave) initially (Molenaar et al., 2012).

The specific components of distributed sensing consists of a length of standard telecommunications optical fiber which is encased in a protective cable and a measuring instrument that uses a laser to fire pulses of light into the sensing fiber. A detector then measures the reflections (backscatter) of a particular measuring system (Rayleigh, Raman or Brillouin) from the fiber as the pulse of light travels down its length. Measuring the change of the discrete peaks as well as differences in frequencies of these

reflections against time allows the instrument to calculate temperature, strain or sound effects on the fiber cable at all positions along the fiber (Tanimola and Hill, 2009).

1.3   Objective of Research Work

Optical fiber pressure and temperature sensors as a way of measuring downhole conditions have been under investigation since the early nineties (Lequime and Lecot, 1991). As such, the present research seeks to present an account of the technology itself. Specifically, to describe how the technology itself came into existence and the basics of how the current "distributed" technology has evolved. The intent, with regard to this analysis, is to show the historical progression of the technology and provide a context for understanding why DAS is being investigated as a tool for monitoring the production of oil and gas reserves. The further objective is to provide a thorough understanding of the technology without getting so "bogged down" in technical details as to diminish the overall understandability of the paper.

Once the above is established, the next step will be to analyze DAS from a more strictly downhole standpoint. This will involve describing in detail the DAS equipment and how the system is employed in actuality. The analysis will illustrate the current status of DAS as an oilfield diagnostic tool; focusing primarily on the fact that DAS is substantially "supported" by other technologies. This will naturally lead to a discussion regarding the availability and amount of specialist level expertise as well as the relatively young nature of downhole DAS technology.

Recent advances both within optical technology itself as well as in petroleum production techniques have brought DAS into the forefront of current research endeavors. As a result, "real world" trials of DAS have been conducted, providing the opportunity to categorically evaluate the technology. This research will examine the tangible capabilities of DAS as detailed by case studies of actual field testing. This will reveal whether DAS can support real-time data acquisition and if it is capable, as some current research suggests, of accurately measure downhole conditions on a sub-meter basis. Also assessed will be the areas where DAS needs additional improvement and research as well as a range of "unknowns" relating to DAS technology. This will provide a substantial platform from which to postulate where DAS technology is moving and where further research efforts should be focused.

2. DOWNHOLE DISTRIBUTED ACOUSTIC SENSING

2.1   System Components

To fully understand how DAS works downhole, one must first recognize the components that make up a DAS system. As noted by Molenaar et al. (2011) there are two main system components required for the downhole deployment of DAS; the working principles of the interrogator system at the surface and the downhole deployment configuration of the fiber.

The surface portion of a DAS system consists of three main components: an interrogator unit, a processor unit and the control unit. The control unit is similar in size and power requirements to an industrial PC and, as its name implies, operates the interrogator and processor units (Tanimola and Hill, 2009). The interrogator unit is the "muscle" behind the DAS technology while the processing unit is the "intelligence". The interrogator unit operates by pulsing a laser into a single mode fiber which then travels down the length of the fiber and backscatters light to the interrogator unit. The backscattered light is processed by the interrogator unit to extract the acoustic (pressure wave) signals from each position along the fiber. This data is then sent to the processing unit. At the processing unit the acoustic signals are analyzed and sent to a display. Typically the data is shown in a waterfall format with the x-axis being depth, the y-axis being time and the color intensity representing the acoustic intensity (Molenaar et al., 2012). The Sound Field Display (SFD) shows scrolling images of all live acoustic

(pressure wave) data (**Fig. 2.1**). The data is generated continuously and allows for observations made over a desired depth interval to be displayed in a scrolling two minute window. This scrolling window is viewed in real time and is also recorded as a movie for future viewing. At the top of certain displays (above the SFD) the instantaneous peak acoustic amplitude is also displayed. A tool in this display allows users to "draw" a line on the screen over any observed features to calculate the velocity of a moving event (Warren et al., 2012).
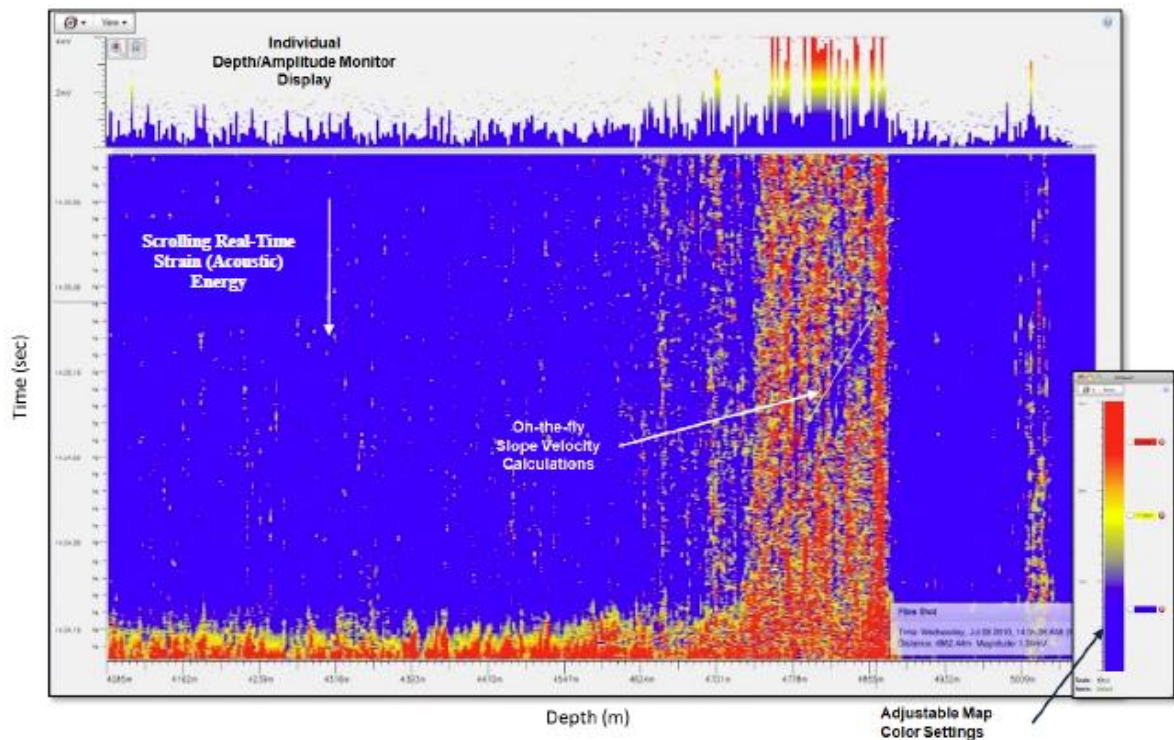
Fig. 2.1—Sound field display showing scrolling images of live acoustic data (Warren et al., 2012).

The interrogator processing and control units are usually located in a control room environment (**Fig. 2.2**). (Tanimola and Hill, 2009)

**Fig. 2.2—Example of interrogator, processor and control units in control room (Rassenfoss, 2012).**

For instances in which a stationary control room is not feasible, the interrogator, processor and control units can be mounted on a mobile platform (**Fig. 2.3**).

Fig. 2.3—Example of interrogator, processor and control unit in data van (Warren et al., 2012).

The second major system component in the deployment of DAS is the downhole deployment configuration of the fiber. The fiber that is deployed for DAS is "standard telecom" (single-mode) fiber and is usually deployed several kilometers over the full length of the wellbore (Molenaar et al., 2011). Single-mode fiber is optical fiber that is designed to carry only a single mode (ray) of light. A mode defines the way a wave travels through space. In the case of single mode fiber, this means that regardless of the frequency of the light traveling in the fiber, each wave will travel through the fiber in the same manner, resulting in a single ray of light. In contrast, multi-mode fiber is optical fiber that is designed to carry multiple modes (rays) of light (**Fig. 2.4**) (Hoss and Lacy, 1993).

Fiber Cross-Section and Ray Paths
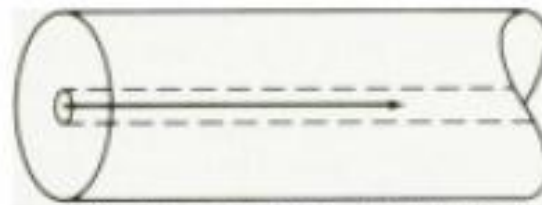
Singlemode step-index fiber
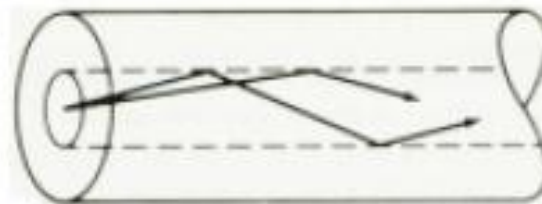
Multimode Step-index fiber
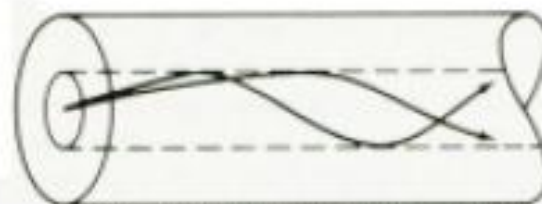
Multimode Graded-index fiber

Fig. 2.4—Example of single-mode and multi-mode optical fiber (Keiser, 1999).

Because single-mode fibers propagate light in one clearly defined path, the light wave is less affected by dispersion as a function of fiber length. This results in the fiber being able to operate at longer distances and larger bandwidths than a multimode fiber (Hoss and Lacy, 1993). Single-mode optical is extremely fine (typically between 8 and 12 μm in diameter) and is almost always surrounded by several protective layers (**Fig. 2.5**) (Keiser, 1999). When deployed in a downhole environment, optical fiber is usually placed outside of casing (**Figs. 2.6-2.7**) (Rassenfoss, 2012).

Fig. 2.5—Example of optical fiber core and protective surrounding layers (Rassenfoss, 2012).

Fig. 2.6—Example of optical fiber instillation at wellhead (Rassenfoss, 2012).

Fig. 2.7—Example of alternate optical fiber instillation at wellhead (Warren et al., 2012).

2.2   Oilfield Applications

The first uses of downhole fiber optic sensing in the petroleum industry occurred

in the early nineties and primarily focused around single-point pressure and temperature

sensors (Molenaar et al., 2011). However, as optical sensing technology continued to

move forward, a new method of "distributed" sensing was developed (**Fig. 2.8**). By the

middle of the decade, distributed temperature sensing was adapted for downhole use

and the technology grew from an initial commercial oil well installation in 1995 to more

than 100 instrumented wells by 2002 (Brown & Hartog, 2002). DAS by comparison has

seen a much more recent adoption.
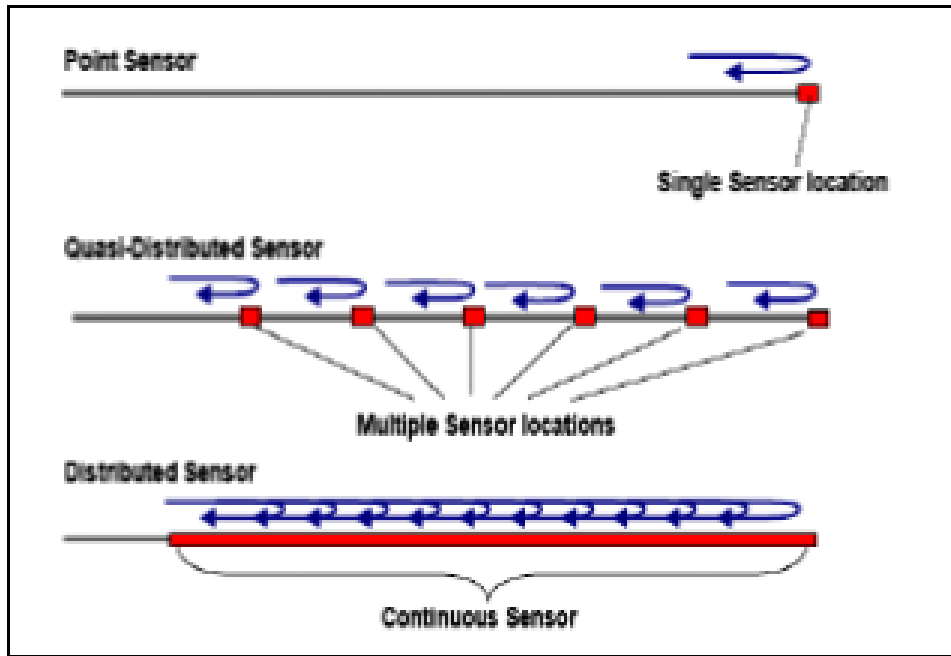
Fig. 2.8—Schematic of single-point and distributed sensors (Molenaar et al., 2012).

DAS is employed by taking a "standard telecom" (single-mode) fiber that has been deployed over the entire well path (usually a length of several kilometers) and turning it into a permanent array of microphones. This is accomplished by detecting direct mechanical movement or any vibro-acoustic disturbances along the length of the optical fiber. Specifically, a DAS system employs a technique known as Coherent Optical Time Domain Reflectometry (C-OTDR) which transmits short, successive pulses of highly coherent light down the length of an optical fiber and observes the very small levels of backscatter in the signal that results from heterogeneities in the glass core (Molenaar et al., 2011).

As noted by Tanimola and Hill (2009) in distributed acoustic sensing the component of the backscatter signal used is the Rayleigh backscatter. Due to random

inhomogeneities in the optical fiber a very small amount of light from a pulse injected into the fiber will be reflected back from every location along the fiber length. As with other distributed fiber optic sensing methods, if a disturbance occurs along the fiber it changes the backscatter light at that point. This change can be detected at the receiver (interrogation unit) and from it the original source signal can be reconstructed. This technique is implemented using a Coherent Optical Domain Reflectometer approach which has the advantage of providing very low noise levels, high dynamic range and excellent discrimination between adjacent measuring points. The acoustic capability comes from the fact that the backscatter signal is repeatedly sampled at high frequency which is limited by the time of flight for an optical pulse to make the round trip to the end of the fiber and back (**Fig. 2.9**).
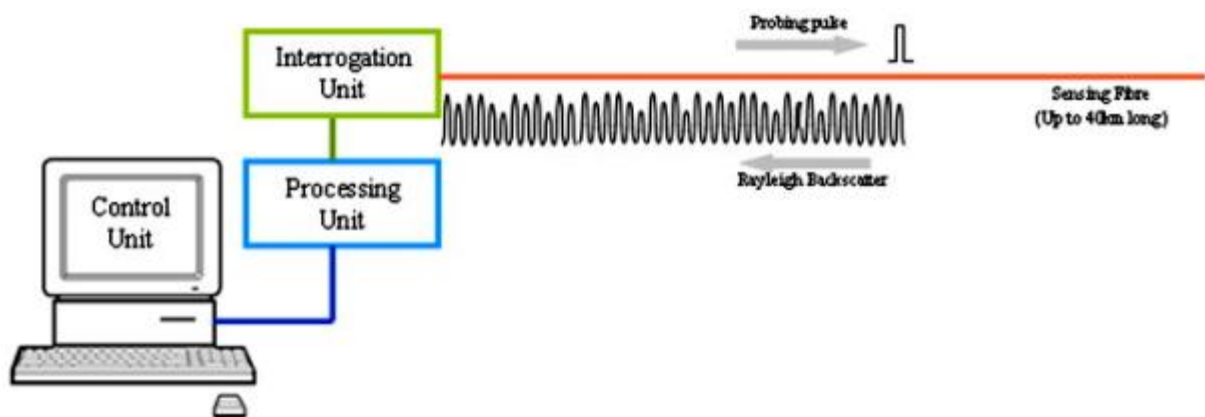
Fig. 2.9—Schematic of laser pulse and Rayleigh backscatter signal (Tanimola and Hill, 2009).

Molenaar et al. (2011) also noted that any vibro-acoustic or direct mechanical disturbances that reach the optical fiber cable will alter, on a microscopic level, scattering sites within the glass of the fiber and affect the back-reflected laser light. This causes a characteristically measurable change or "signature" in the Rayleigh backscattered light signal. These measurable changes in the backscattered light signal are interpreted by an interrogator unit which generates a series of independent, simultaneously sampled signals along the fiber (**Fig. 2.10**).
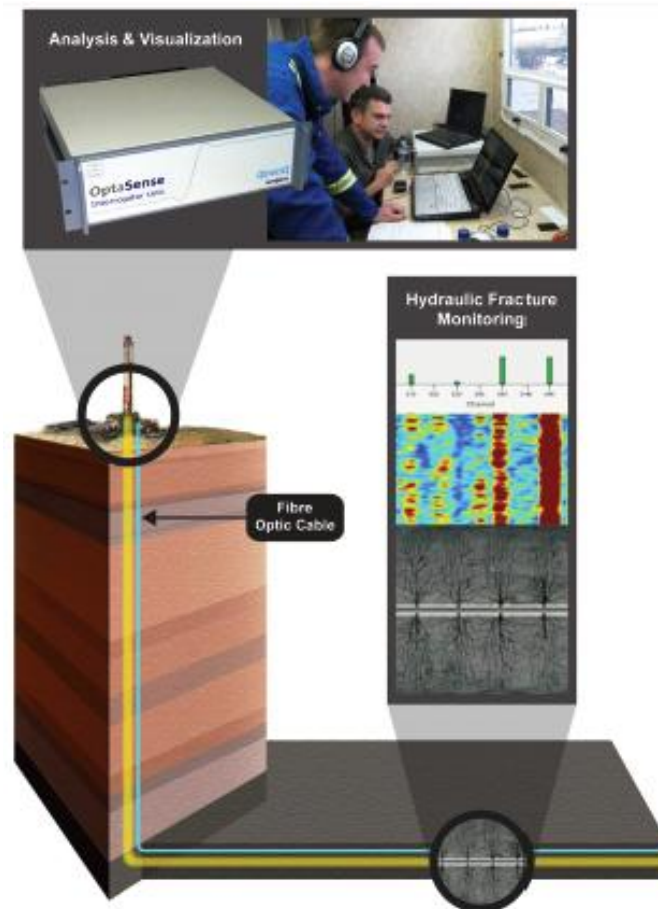
Fig. 2.10—Schematic of DAS system components and deployed optical fiber (Molenaar et al., 2011).

The acoustic signals generated by the interrogator unit each correspond to a 1-10 meter long segment or "channel" in the fiber. Each channel or segment length directly corresponds to a spatial resolution and as such, a 5000 meter long fiber deployment having a 5 meter resolution will have 1000 channels. If the fiber deployment was sampled at a rate of 10 kHz (10,000 samples per second) then each time sample at 10 kHz will contain a snapshot of the acoustic field averaged over the 5 meter section of cable at that particular sample section. The interrogator unit directly controls and optimizes parameters such as the sample rate, spatial resolution and number of channels. After this "raw" acoustic data has been acquired by the interrogator unit it is then passed off to the processing unit where it is interpreted and converted to visual representations (Molenaar et al., 2011).

3. EVALUATION OF DISTRIBUTED ACOUSTIC SENSING TECHNOLOGY

3.1   Analysis of Distributed Acoustic Sensing

Due to recent research efforts, case studies of DAS for oilfield applications exist and provide the opportunity to better quantify the actual sensing capabilities of the technology. Examining these case studies provides a way to evaluate some of the expectations associated with DAS technology; particularly, if the technology can support real-time data acquisition and accurately measure tangible downhole conditions. The first true E&P downhole field trial of DAS was conducted by Shell Canada in 2009 (Molenaar et al., 2011). Since 2009 further testing has been conducted, most recently by Warren et al. This field trial was the first use of DAS in a multi-fractured horizontal well and the study sought to investigate the application of DAS in hydraulic fracturing applications (Warren et al., 2012).

In one case study conducted by Molenaar et al. DAS was used to monitor the acoustic noise generated by a wireline tool for setting a bridge plug in the wellbore. In this particular field trial, the fiber optic cables were permanently deployed in several vertical and horizontal wells. Three optical fibers were run clamped to the outside of the production casing to the toe of the well. The measured data showed, in real time, the location of where the plug was set as well as the ignition of the charges (**Fig. 3.1**). They were also able to follow the tube waves induced by the explosives all the way to the wellhead. From this test Molenaar et al. concluded that DAS could be used to confirm

the proper placement of downhole tools such as packers or perforation guns. In theory,

any tool with an acoustic signature could be monitored by DAS to detect and monitor its

wellbore activities. (Molenaar et al., 2011)
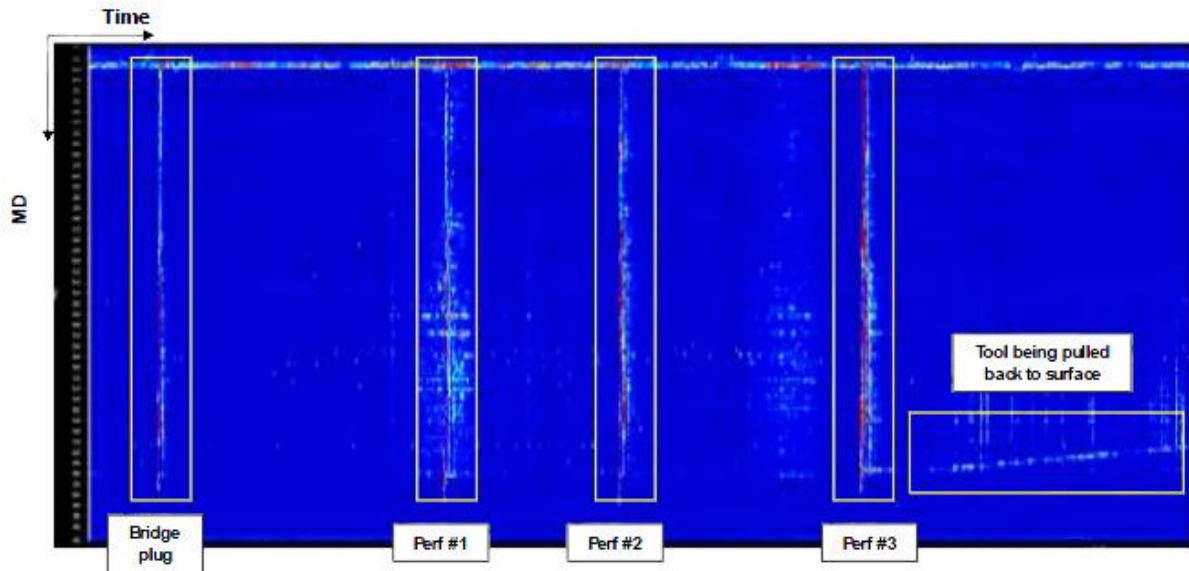
Fig. 3.1—DAS recording of bridge plug being set followed by 3 perforating shots and tool removal (Molenaar et al., 2012).

Another important test conducted by Molenaar et al., was in hydraulic fracture

monitoring. The results from their tests indicate that DAS measurements can capture the

dynamic changes throughout the hydraulic fracturing activity. The broad frequency

content enabled discrimination of which perforations were active during the acid

injection as well as which perforations were taking most of the fluid and proppant

throughout the job (**Fig. 3.2**). They noted that this capability could prove to be

extremely important because well completion costs are often the largest factor in

determining if a well is economical. Consequently, if DAS could improve optimization of the volume placement design and improve future treatments, significant production cost reductions could be realized. (Molenaar et al., 2011)
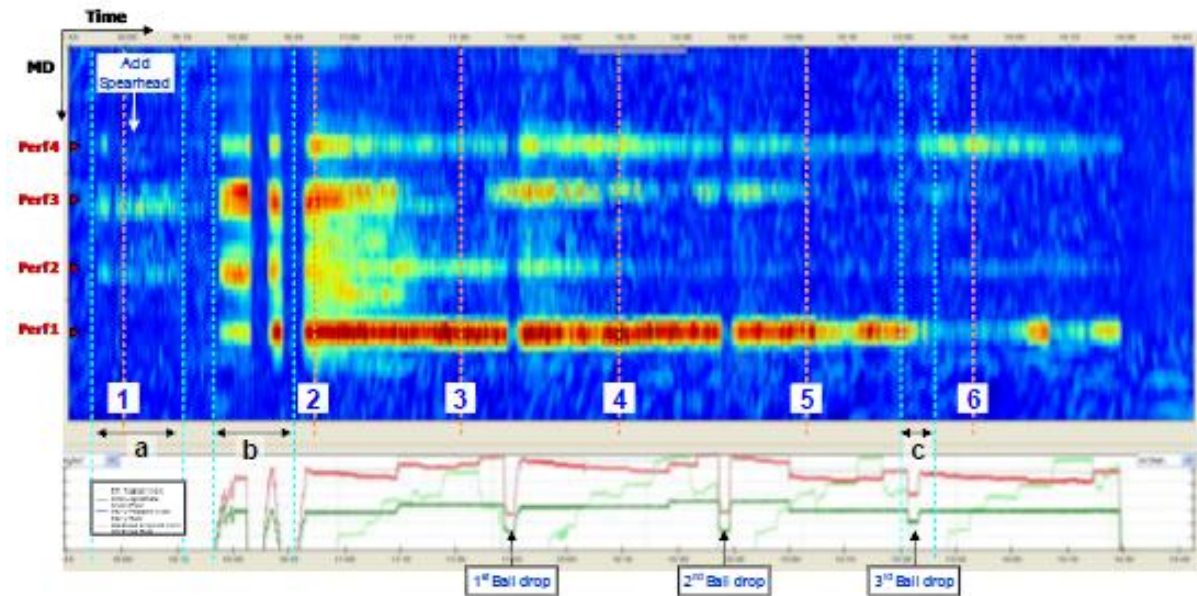
Fig. 3.2—DAS recording showing acid injection and which perforations took most of the fluid and proppant (Molenaar et al., 2012).

After completion of the field trial, Molenaar et al. noted several conclusions about DAS. First, it has the potential to be applied in a wide variety of applications including distributed flow measurement, sand detection, gas breakthrough, artificial lift optimization, smart-well completion monitoring, near-wellbore monitoring, real-time hydraulic fracture optimization and geophysical monitoring. They also postulated that permanently installed fiber-optic cables could potentially offer low-cost, on-demand geophysical monitoring where once the system was installed, minimal if any further well

interventions would be required. This could prove particularly useful for continuing

operations such as monitoring more permanent downhole equipment such as electrical

submersible pumps. Other interesting DAS applications noted were in the areas of

inflow and injection profiling and gas lift monitoring. (Molenaar et al., 2011)

The conclusions arrived at by Molenaar et al., were supported and expanded

upon by the field testing done by Warren et al. In their study, Warren et al. took DAS

testing a step further and applied it to a multi-fractured horizontal well. The subject well

had a total measured depth of 4186 meters from the Kelly bushing while the completion

consisted of a ball actuated frac valve of 10 stages, openhole swell packers and casing

external optical fiber set as a permanent downhole gauge (**Fig. 3.3**).
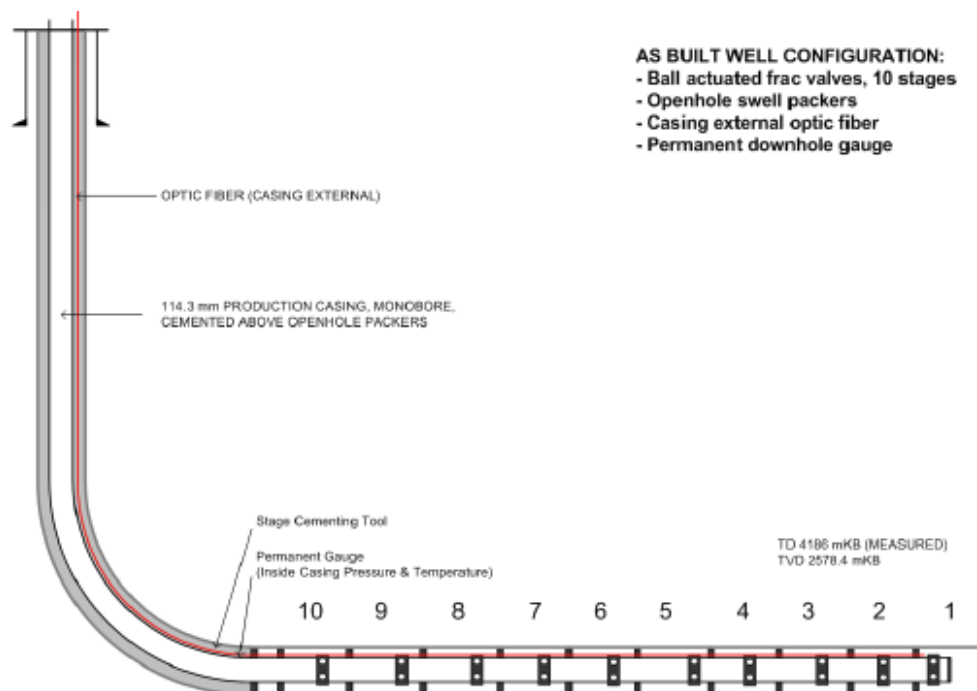
Fig. 3.3—Wellbore diagram of 10 stage completion tested by Warren et al. (Warren et al., 2012).

Warren et al. (2012) noted that various component modifications were required to enable deployment of the optical fiber outside of the casing over its full length, from the wellhead to below the bottom packer. One such modification was adapting the frac valve with a channel for the optical fiber line (**Fig. 3.4**). The modifications enabled fiber penetration of the wellhead, stage cementing tool, swell packers, and frac valves. It was also noted that cross coupling clamps were used to protect the fiber across all casing connections.
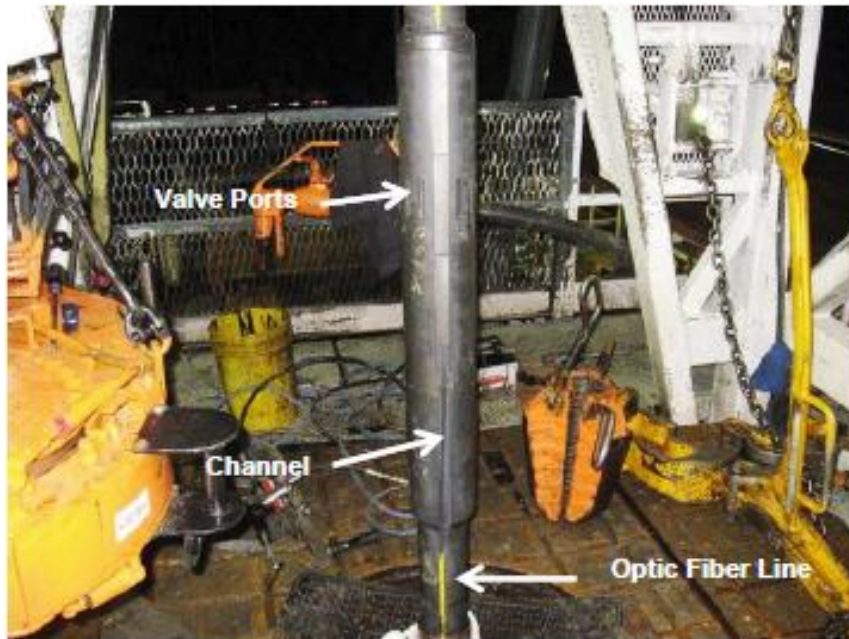
Fig. 3.4—Modified frac valve with channel for optical fiber line (Warren et al., 2012).

As part of their study Warren et al. (2012) incorporated DAS as a part of a fully instrumented setup. This provided the unique opportunity to compare and complement

DAS with other well diagnostic instruments including DTS, microseismic, fracture treatment record and radioactive tracer. These additional instruments allowed the DAS data to be visually compared with different types of correlating observations (**Fig. 3.5**).
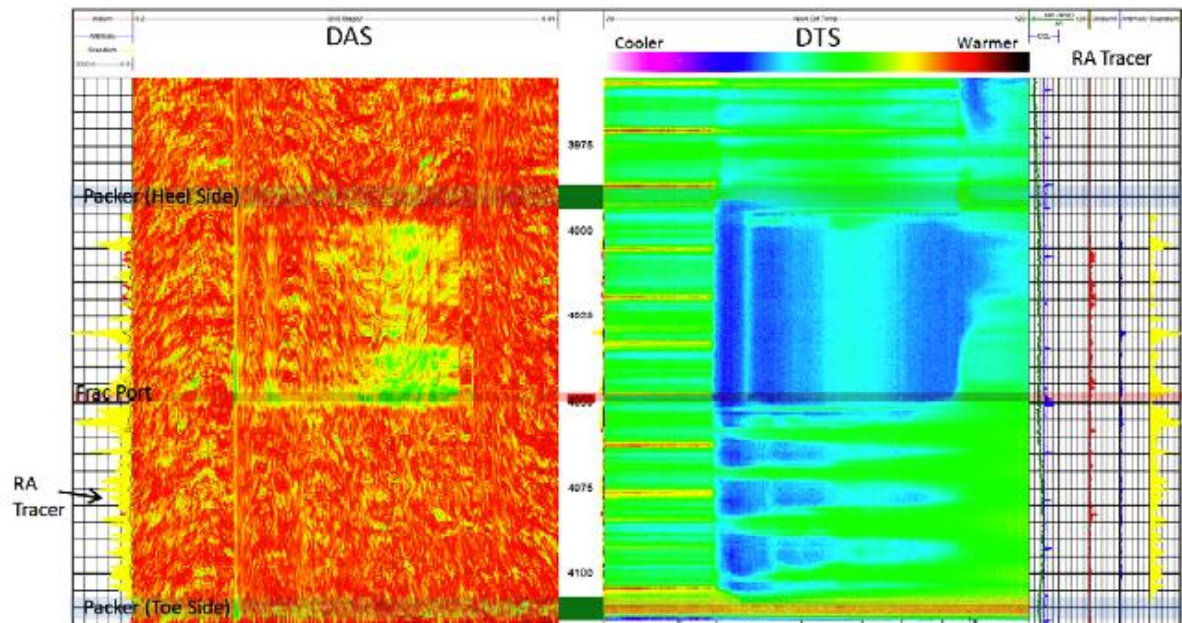
Fig. 3.5—Visual comparison of DAS, DTS and radioactive tracer data (Warren et al., 2012).

The study also noted that the incremental cost of deploying DAS in conjunction with DTS is marginal and that no additional modifications over and above those needed for DTS alone were required.

Other important examinations conducted by Warren et al. involved determining if DAS technology was capable of accurately measuring frac valve ball seating as well as monitoring fracture propagation and containment over time. During the field trial, Warren et al. (2012) observed the event of a ball arriving and seating in the frac valve

followed by approximately 70 seconds of delay where the casing pressure increased enough to open the valve (**Fig. 3.6**).
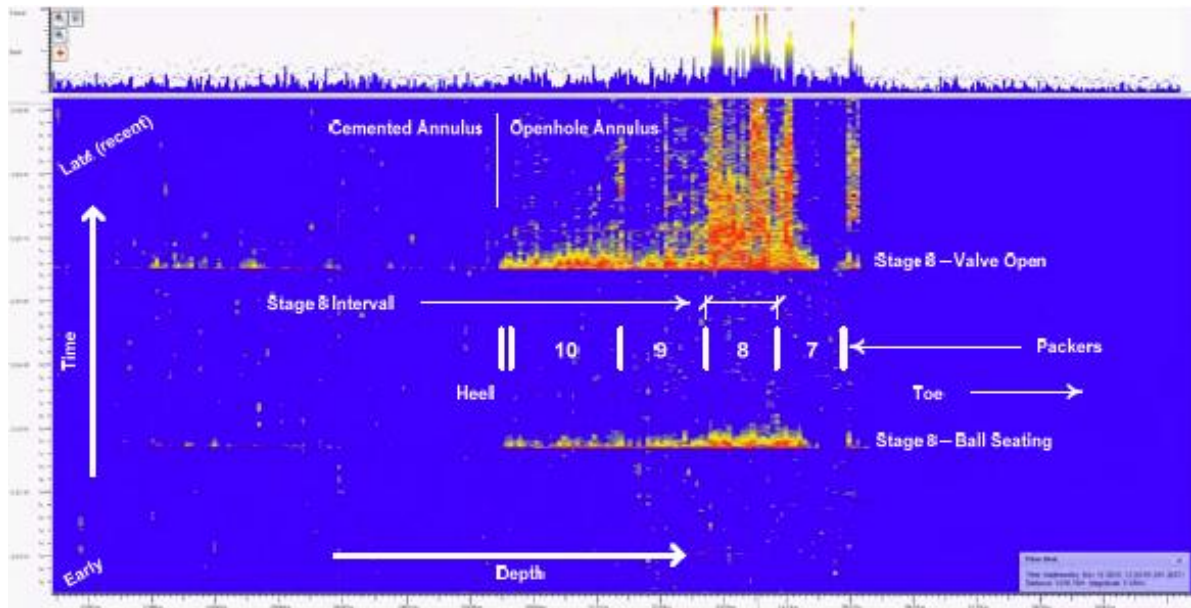
Fig. 3.6—Ball seating in frac valve and resulting valve opening (Warren et al., 2012).

Warren et al., (2012) noted that the valve was set using shear pins to open with a load of 30,000 pounds. As a result, the valve opening was a high energy event and can be seen in the impulse load related energy that occurs up to 10 seconds after the valve opens. After approximately 43 minutes the transition from pad to the first proppant stage occurred. The resulting observations showed that the proppant propagated through but was contained by the 60 meter frac stage interval (**Fig. 3.7**).
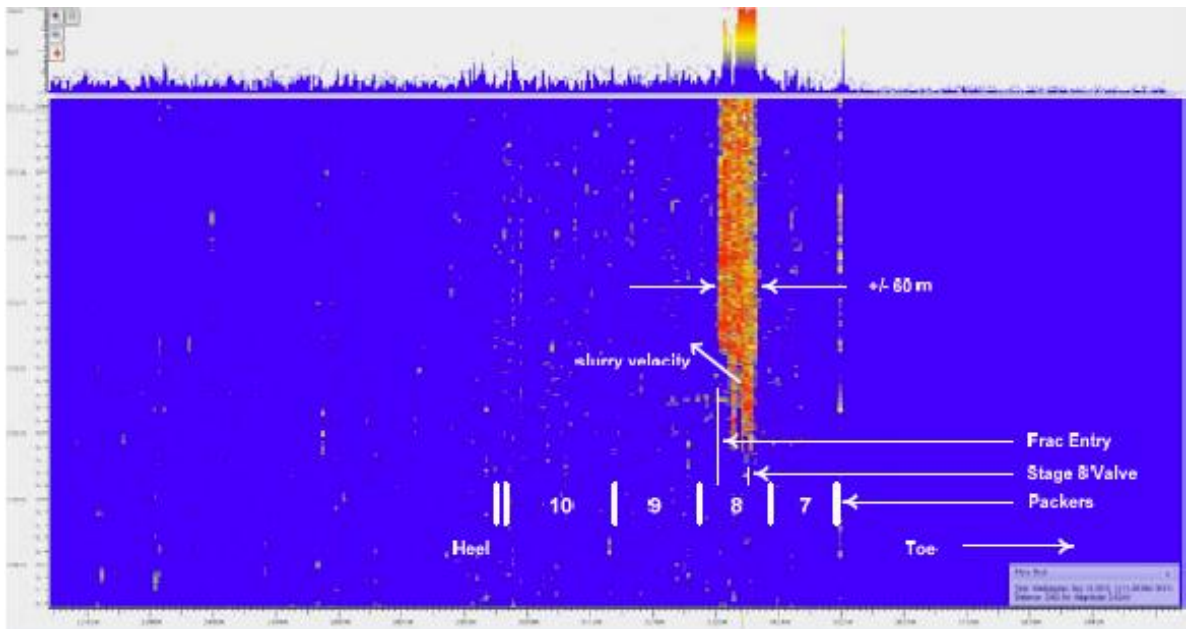
**Fig. 3.7—Energy concentration at transition from pad to first proppant stage
(Warren et al., 2012).**

After completion of the field trial, Warren et al. noted several conclusions about

DAS. First, the most obvious value of obtaining a real time image of downhole events

during the hydraulic fracturing process lay in the opportunity it provided to change the

frac program "on the fly," with good confidence that the change would have positive

impacts on the outcome. Examples of this include increasing or decreasing proppant

pump rates as well as optimal placement of frac stages. While there is great value in "on

the fly" optimizations, a potentially even greater value lies in the opportunity for more

in-depth understanding of fracture behavior downhole. Processing of numerous DAS

dataset could open the door to significantly more complete and cost effective frac design

optimizations (Warren et al., 2012).

3.2   Physical Limitations of Distributed Acoustic Sensing

The physical limitations of DAS are directly correlated to the integrity of the optical fiber in the downhole environment. Because of the continuous nature of optical fiber, any break in the internal glass core will fundamentally alter the way light scatters within the fiber. The resulting situation is a loss of signal from all of the fiber beyond the point of the break. The downhole environment is an extreme service environment that requires special design considerations when working with optical fiber. Adequate protection of the optical fiber is essential for its survival during installation and during well stimulation events. This is particularly true during the proppant pumping stages as abrasive cutting of the optical fiber can easily occur. However, if the optical fiber survives these initial stages of the well's life, the survivability drastically increases (Warren et al., 2012).

Once optical fiber has been installed and well stimulation events completed, the greatest threat to fiber integrity is clouding of the glass that makes up the fiber core. The ability of DAS to accurately monitor downhole conditions depends on the optical fiber being extremely good at conducting a beam of light. As a result, optical fibers are clear. However, when deployed in a downhole environment, where hydrogen is plentiful and high-temperature speeds damage, optical fibers can cloud and turn dark. If the clouding is severe enough, the optical fiber will be effectively killed rendering it unusable for distributed sensing applications (Rassenfoss, 2012).

3.3 Technological Limitations of Distributed Acoustic Sensing

The largest current technological limitation of DAS is the inability to turn large volumes of data into useful information in a form that does not require an expert to interpret it. One of the key attributes of a distributed acoustic sensing system is the very large quantities of acoustic data produced. Rassenfoss (2012) noted that a temperature sensor can send a reading every 4 seconds for each meter along the fiber cable. In contrast, acoustic fiber can send 10,000 times as much data every second. With up to 400coustic channels, a single standalone system is able to process, in real-time, up to 720Mbytes/sec of data, which is comparable to recording an entire set of the Encyclopedia Britannica every two seconds (Warren et al., 2012). Data volumes of this size present challenges from both a storage and manipulation standpoint. Quickly storing such large data volumes is often limited by the speed of the underlying physical storage medium. Manipulating data volumes of this size are a function of the compression algorithm used which can drastically affect the resolution of the data (Warren et al., 2012).

Another major limitation of DAS is the lack of a standard by which to compare the acoustic quality of in-well sensors. This is particularly important as there is currently no way to compare a device's ability to detect sound or its signal-to-noise ratio, which is like measuring the sound of a radio broadcast versus the level of static in the background. This results in the vast majority of what is heard in an oil well being left open to listener interpretation (Rassenfoss, 2012).

DAS is also limited by the fact that the technology is substantially "supported" by other diagnostic tools and has a very limited usefulness as a standalone diagnostic instrument. This is due in part to the lack of specialist level expertise as well as the relatively young nature of downhole DAS technology. Warren et al. (2012) noted in their field test that associating the DAS data with other measurement tool data (DTS, microseismic, fracture treatment record, etc.) allowed for a side-by-side comparison of the DAS data and given the lack of a processing platform, provided one of the few methods for accurately interpreting DAS records. However, work is just beginning to create programs integrating different kinds of fiber measurements (Rassenfoss, 2012).

4. RECOMMENDATIONS FOR FUTURE WORK

4.1   Collective Focus Areas

There exist substantial areas for further DAS improvement and investigation. One of the most pressing areas relates to the huge amounts of data captured. As noted in the Warren et al. (2012) study, in one week of testing, over 80 terabytes of continuous data was capture by the 10kHz DAS sample rate. This enormous amount of data is particularly problematic when coupled with the fact that there are very limited processing platforms and virtually no existing commercial software available specifically for DAS data processing. Further development of hardware expressly tailored for acoustic data storage as well as processing software dedicated explicitly to DAS are the critical next steps in the technology.

The lack of available processing platforms leads to another issue: absence of specialist level expertise. A very particular skillset is needed to meaningfully utilize DAS. This skillset encompasses aspects of geophysical knowledge for data processing, hydraulic fracturing and log analysis knowledge for data interpretation and computer programming knowledge to manipulate the massive amount of captured data (Warren et al., 2012). Future work will need to develop a way to integrate these knowledge bases in a form that does not require an expert to interpret it.

Other areas of future work should focus on "unknown" factors associated with DAS in a downhole environment. In particular, our understanding of the nature of a

wellbore and hydraulic fracturing is limited. Consequently, the unprecedented data acquisition and resolution levels of DAS lead to a situation where you simply "don't know what you don't know" in the wellbore. Because there has been very limited DAS field testing, the nature of the observational environment is poorly understood. This results in a significant amount of ambiguity when determining how to best employ DAS downhole. For example, the optimal location of optical fiber placement is not known (outside of the casing, inside of the fracture chamber, etc.). Fiber location could have significant impacts on the captured DAS data because different locations are likely to have significantly different soundfields (pressure wave characteristics representing "noisy" or "quiet" environments) (Warren et al., 2012). Understanding and quantifying the unknowns of DAS will be the most challenging aspect of future work but is a necessity if the technology is to continue to move forward.

4.2 Discrete Research Topics

Although collective investigation will be needed to solve some of the larger questions surrounding DAS, there are several key topics where impacts can be made on a more discrete level. Two of the most important potential uses for DAS are inflow profiling and gas lift monitoring. As such, these areas should be the focus of future research efforts. With inflow profiling DAS offers the opportunity to combine inflow profiles with locations along the wellbore. This ability to know what is being produced and in which zones/stages of the wellbore the production is occurring has the potential to revolutionize production/completion engineering and drastically improve Expected

Ultimate Recoveries (EURs). This is particularly true in dry shale gas formations where water loading is often one of the most important factors affecting the lifetime of a well. Knowing not only that a well is loading but where along the wellbore the water is coming from could drastically alter the engineering decision making process. Because DAS can accurately identify inflow on the individual perforation level, isolating the water inflow zones/stages by setting packers becomes a reasonable course of action that could be undertaken with a high degree of confidence. Potentially resulting in significantly improved recovery rates and extending the time the well can be flowed without installing tubing. Furthermore, this process is not limited to water loading; other downhole activities such as packing off, salting up and well treatment effectiveness could also be monitored. Going forward research capital should be expended to specifically identify gas and liquid inflow acoustic energy levels. This could be accomplished through laboratory experimentation. Specifically, reservoir representative fluids could be flowed through perforated casing at varying concentrations and flow rates under downhole conditions. The associated acoustic energy levels could then be recorded and this information conglomerated into an acoustic "library".

Developing an acoustic (pressure wave) "library" is in itself a potential area for significant individual contribution. An acoustic library is extremely valuable because it could be implemented across the entire DAS technology spectrum. To develop a library, a statistically significantly sample size of similar DAS data would need to be evaluated. Downhole activities such as a ball landing in a seat to open a sleeve, or fluids leaking around a packer can be identified with non-DAS technologies. However, because these

downhole activities also make noises (clunk of the ball landing in the seat and fluid rushing around the packer), it is possible to use the technologies concurrently and associate a downhole activity with a particular acoustic signature (pressure wave). Consequently, it might be possible to develop parts of the library from data collected in actual DAS field trials. However, laboratory established acoustic energy levels would be easier to obtain and possibly more valuable because of their potential to provide insight into downhole acoustic signatures that are not fully understood. Conglomerating and generalizing a statistically significant number of these acoustic signatures would allow for the creation of a library of known downhole sounds. A library of known sounds would be extremely valuable to industry as an integral first step to any viable commercial software package for DAS interpretation. Moreover, the ability to associate an acoustic signature with a downhole activity is absolutely critical if DAS is to be used as a standalone technology with any reasonable degree of confidence.

Gas lift monitoring should also be a significant research focus area. A wealth of flow information can be seen in an acoustic energy plot, including DAS capabilities for gas lift monitoring (**Fig. 4.1**).
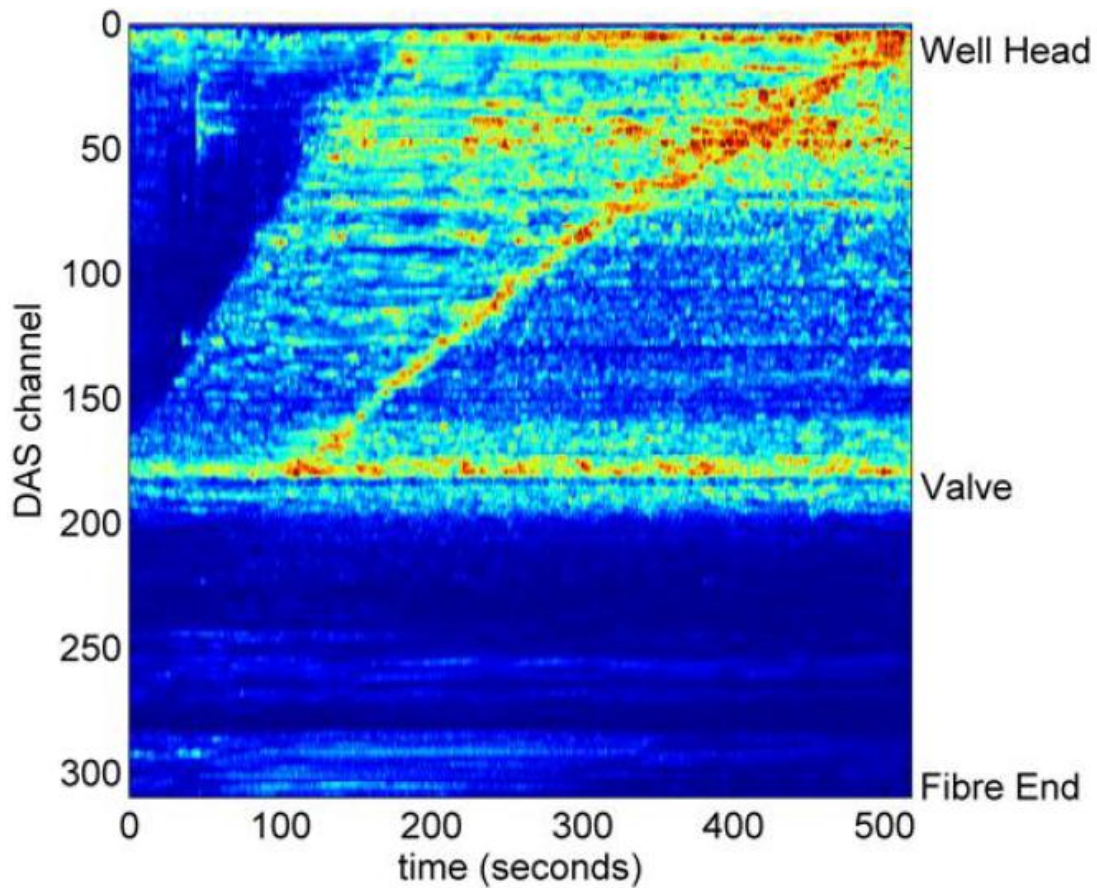
Fig. 4.1—Acoustic energy plot of gas lift valve; red: high, blue: low (Koelman et al., 2012).

As noted by Koelman et al. (2012) a pronounced feature in this particular visualization is the development of multiphase flow starting at the gas lift valve and subsequently reaching shallower levels. This can be seen in the rising gas bubbles marked by the noise wedge starting at the gaslift valve (time 0) and reaching the well head approximately three minutes later (time 180 seconds). A strong localized turbulence can also be seen. This turbulence is most likely associated with a slug of gas that starts at the gas lift valve with a delay of 100 seconds, and propagates upwards at

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about half the speed of the bubble front. Below the gas lift valve there are lower gas-liquid ratios (blue areas associated with weaker acoustic energy levels). Combining this observed data with knowledge of the well/completion geometries, the flow rates over these single phase flow intervals could be quantified using interpretive methods traditionally applied to noise logging data. Further interpretation and processing of DAS in combination with other technologies could add significant robustness to flow interpretations, particularly as they relate to multiphase flow.

Acoustic energy data like the plot shown above have the potential to drastically alter our understanding of flow in the wellbore. Likewise, a DAS acoustic library would provide a reliable way to identify key downhole activities. However, in order to develop an accurate energy plot, acoustic library, or any other meaningful evaluation mechanism, actual DAS data must be incorporated. Consequently, future DAS research at the university must include the considerable task of obtaining actual DAS data. To combat the significant costs associated with physically acquiring the data, a partnership with industry should be pursued.   As noted in Section 3, test wells exist that have yielded substantial amounts of DAS data. The going forward plan of action should include liaising with one or more of the noted companies to determine if they would make any of their DAS data available and if so, addressing the proprietary nature of the data.

It is also important to note that further research to delineate the capabilities of DAS will require, at the very least, a cursory level knowledge of Digital Signal Processing (DSP). This naturally leads to the need to involve persons with knowledge of this particular subset of engineering. Moreover, some form of overlap will occur with

electrical/computer engineering and a prudent course of action going forward is to seek out appropriate research partners who can provide expert level understanding in this specific field. In particular, because DAS uses C-OTDR, it will be most beneficial to connect with a research partner whose expertise is in DSP time domain (as compared to spatial domain, frequency domain or wavelet domains). Having expertise in DSP time domain will allow for selection of the correct digital filtering methods necessary to turn acoustic data into a form that will be valuable from a production and completion engineering research standpoint (**Fig. 4.2**).
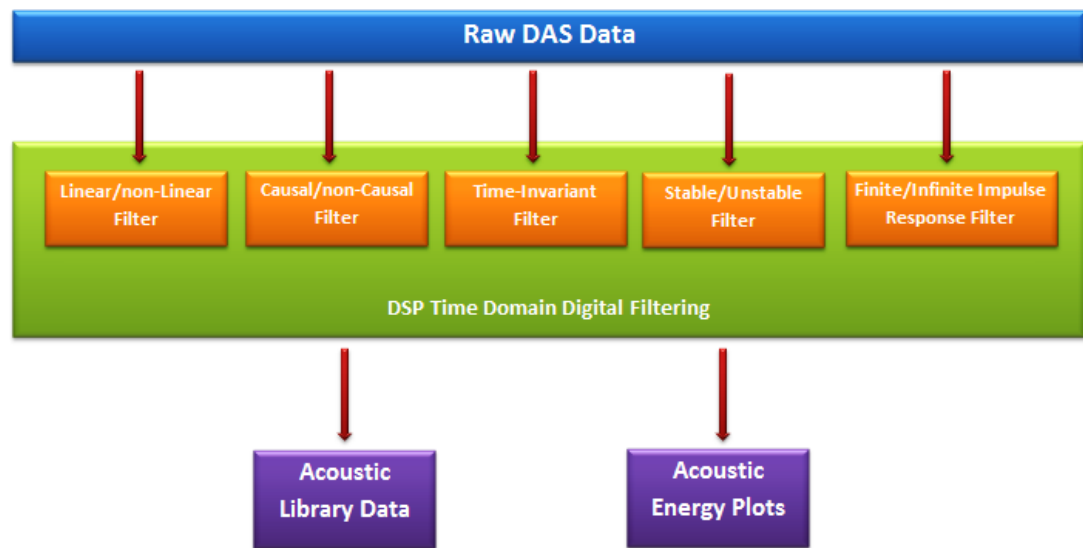
Fig. 4.2—DAS digital filtering progression from raw DAS data to a form useful to researchers.

Collecting and processing acoustic data through time domain knowledge of DSP provides an opportunity to develop a cross-disciplinary collaborative research platform from which many further significant individual contributions can be launched.

5. CONCLUSIONS

5.1   Conclusions

The current state of acoustic fiber monitoring is like the early days of personal computers. There is a lot of excitement about its potential, but it lacks what is known in the electronics business as "killer apps"—widely used applications that would make monitoring pressure waves and vibration in the well a standard business tool (Rassenfoss, 2012). Despite the immature nature of DAS technology, there exists high potential for DAS to aid in the interpretation of wellbore events, particularly those associated with hydraulic fracturing. Many questions still remain regarding the hydraulic fracturing process, especially in the area of multi-fractured horizontal wells. Field trials of DAS suggest that the technology may be useful in finding answers to these questions or in validating the applicability of hydraulic fracturing engineering theories within a particular play (Warren et al., 2012).

DAS has overcome some limitations of other diagnostic tools, notably by the increased confidence of its interpretation and the real time nature of its cursory level observations (Warren et al., 2012). DAS has the potential to fill a much needed gap in the industry's toolkit for hydraulic fracture diagnostics. Quantitatively comparing the more common tools used to image hydraulic fractures in a multi-fractured horizontal well provides a clear understanding of both the capabilities and limitations of DAS technology (**Fig. 5.1**).

Diagnostic Tool	Feedback Time	Field of Investigation	Limitations
MSM	Semi real time	Far field	• Location uncertainty of frac induced microseismic events • Not indicative of proppant placement
DTS	Real time	NWB	• Fiber survival under harsh conditions • Data resolution was limited to a sample period of about 20 seconds for this well; this is a common limitation of DTS
DAS	Real time	NWB	• Fiber survival under harsh conditions • Currently available DAS processing methods do not provide the focused discrete resolution of all regions of the soundfield that are expected to yield knowledge about the fracturing process, though processing capabilities are rapidly improving
RA Tracer	Post completion	NWB	• Presence of tracer not necessarily indicative of treatment in zone or location of the hydraulic fracture

Fig. 5.1—Quantitative comparison of common tools used to image hydraulic fractures (Warren et al., 2012).

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