Wireless Communication in Oil and Gas Wells

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Lead-In: This paper reviews the techniques of below ground wireless communication in the oil and gas industry. A historical and theoretical analysis of pressure wave and electromagnetic communication is presented. Case studies for both technologies and their current applications are evaluated for the purpose of identifying each method's limitations and opportunities for innovation. Finally, the possibilities of smart well technology are discussed with focus on wirelessly powered sensors for continuous monitoring of shale oil/gas reservoirs using electromagnetic methods. We conclude that the critical challenges are associated with powering the devices, which must perform for a period of months to years and which must be capable of generating sufficiently powerful signals so as to overcome the large signal attenuation associated with electromagnetic wave propagation through geological media.

1. Introduction

The demand for oil and gas in the United States has increased rapidly over the past two decades [1]. Advancements in horizontal well drilling and hydraulic fracturing have helped to meet this demand, most recently through development of shale gas and oil reservoirs [2]. Additional attempts to increase the efficiency of petroleum recovery through the use of "smart wells" have been developed during the past two decades [3]. These smart wells use permanently deployed sensors and control systems to allow operators to remotely monitor and shutdown poorly performing zones without the need for a well intervention. A well intervention is a data collection and/or maintenance on the well. Because the well production must be shut down during the intervention, they can be costly and are avoided whenever possible. Through sensor information and valve management, the efficiency of the well can be increased to meet demand without the need for the well to be shut down and without the need for additional surface facilities [4].

The most common smart well systems currently utilize fiber optic cables and hydraulically operated in-well valves to retrieve measurements and optimize the production from the well [5]. While the deployment of these smart wells has grown in the past decade, the installation difficulty of the fiber optic cable has limited the industry wide adoption of such technologies. Additional challenges arise from the high temperature, high pressure environment encountered in deep wells. Recent advances have been made in high temperature transistor design that are allowing embedded controllers to operate upwards of 175º C [6]. While these advances are still not sufficient for high pressure and temperature deep wells, they have begun to pave the way for permanently installed electronic sensors in relatively shallow shale gas wells where the temperature and pressures are low enough to enable extended operation of sensors.

Although advancement of fiber optic sensor/communication as well as high temperature and pressure electronic devices lead the way for the adoption of smart well sensors, a reliable and wireless telemetry method has yet to be developed that can be permanently implemented throughout the lifetime of the well. This would be a critical step to widespread uptake of installed downhole sensing because it would eliminate the operational challenges associated with permanent fiber optic or communication wire installation as the well is being constructed.

This review paper is targeted primarily at summarizing the relevant technology and identifying barriers to extend downhole sensing that would persist through stimulation and into the production phase of the well. However, as the majority of downhole sensing occurs during the drilling process, the focus of the literature review will necessarily be limited to the measurement while drilling process and the associated telemetry link. Here we review the state of the art in wireless downhole communication, focusing on two wireless communication methods that have been developed and tested in industry over the past few decades and what can be learned from these technologies going forward.

The first is pressure wave telemetry, which employs pressure pulses that propagate through the production fluid or drilling fluid to the surface. Pressure wave telemetry systems have been widely used throughout industry during the drilling process but the technology has never been implemented for long-term downwell monitoring. The second is electromagnetic (EM) telemetry, which utilizes the drill string or well casing as a transmission line over which electromagnetic radiation can propagate to the surface. Electromagnetic telemetry has not shared broad acceptance in industry, although recently EM telemetry has been growing. The technology can be used during the drilling process as well as during well production to increase the efficiency of wells, making the technology extremely promising.

In both of these wireless communication protocols, high attenuation, low data rates and low reliability of the telemetry channel have provided a significant barrier to extension of the technology for longer-term installations associated with the adoption of smart wells. Nonetheless, as previously alluded to, these technologies are presented as a review of wireless communication in oil and gas wells. Following this review, we conclude by summarizing the challenges and recommending

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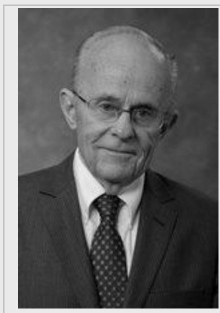

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directions of research and development aimed at making wireless downhole communication robust, inexpensive, and free of the operational challenges that currently prevent it's widespread deployment, especially in on-shore shale gas/oil wells where limiting costs is paramount.

2. Pressure Wave Methods

2.1. Practicalities

The propagation and communication through the drilling mud have been developed and implemented in industry using two methods: Mud Pulse Telemetry and Continuous Wave Telemetry. Both implementations exist only during the drilling process and use the drilling fluid as the propagation medium. The pressure waves are generated through water hammer, which are pressure waves produced when a fluid is forced to stop or change direction suddenly. The data are encoded into the pressure waves through a variety of analog and digital modulation techniques. Pressure wave transducers on the casing head convert the pressure waves to voltages that are interpreted by embedded processors and used by operators during the directional drilling process. The topic of pressure wave propagation has been extensively commercialized since the 1970s [7].

2.2. Theory

While both technologies are used extensively throughout the industry, the theoretical analysis of a propagating pressure wave is the same for both mud pulse and continuous wave telemetry. During propagation in a hollow fluid filled cylinder, three types of waves exist: longitudinal waves, torsional waves and flexural waves. Since the bulk modulus of steel typically used for the drill string is 160 GPa and the bulk modulus of water is 2.2 GPa, the well casing will undergo minimal deformation due to the pressure pulse and can be considered to be infinitely stiff. The attenuation of the torsional waves and flexural waves will be reduced significantly within a relatively short distance from the drill string telemetry casing.

Due to the stiffness of the well casing and the propagation through the drilling mud, the analysis can be simplified. The pressure wave propagation will depend on the frequency of the pressure wave, and the properties of the drilling mud and drill string. Assuming uniform flow, these propagating pressure waves (p) are described by the wave equation:

$$\nabla^2 p = \frac{\rho_o}{B}\frac{\partial^2 p}{\partial t^2} \tag{1}$$

where p is the pressure of the wave, ρ is the density of the drilling mud, B is the bulk modulus of the drilling mud. Equation 1 relates the time and spatial relationship of the pressure wave to the density of the drilling mud. Equation 2 provides the solution to the Helmholtz wave equation with a point source at the center of the drill string casing in the cylindrical coordinate system:

$$p(r,\theta,z)=(c_1\cos(n\theta)+c_2\sin(n\theta))*J_n(k_a r)*e^{-ik_z z} \tag{2}$$

where J_n is a Bessel function of n^{th} degree, and c1 and c2 are constants. Due to the complexity of the frequency domain solution to Equation 2, the derivation has not been included but has been solved by Kondis [8] and Drumheller [9]. From the Fourier transform of Equation 2, it can be shown that distinct modes exist inside of the acoustic waveguide, in which propagation can occur. With mud pulse telemetry, these modes do not effect propagation of the pulses due to the low frequency content but acoustic dispersion, the frequency dependency of the group velocity, will cause a spreading of the pulse over time, distort the transmitted data and limit the maximum possible data rate.

Additionally, density changes in the drilling mud are dependent on the temperature, pressure and depth. As such, an empirical model has been developed that relates the density, pressure and temperature.

$$\rho = \rho_{sf} e^{\Gamma(p_o, T)} \tag{3}$$

where ρ_{sf} is the static density of the drilling mud at the surface, T is the temperature, and $\Gamma(\rho_o,T)$ is an empirical function determined by the temperature and pressure differentials. Because pressure and temperature increase with increasing depth, two opposing effects are experienced. The increase in pressure will increase density due to the compressibility of the drilling mud. The increase in temperature will decrease the density due to thermal expansion. While changes in the density of the drilling mud will affect the attenuation of the pressure wave, the moment of inertia and stiffness of the tool joints as well as radiative losses will further attenuate the wave [10]. Accurate modeling of wave propagation has been extensively researched and verified through simulation and experimental data [11].

2.3. Implementation

Two separate classifications of mud pulse telemetry exist: positive pulser and negative pulser. A positive pulser produces an increase in the standing pressure of the drilling fluid and through use of a poppet-type valve that is oriented parallel to the flow of the drilling fluid. When the valve is instantaneously opened and closed, a pressure pulse is generated that propagates through the fluid to the surface. Figure 1 shows the pressure waveform and a model of a positive pulser configuration.

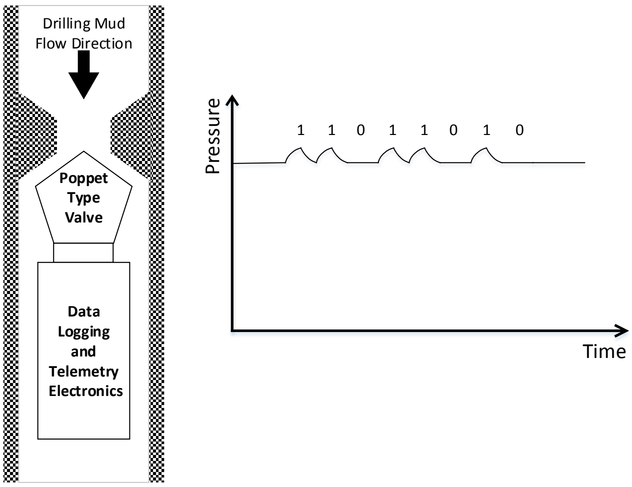

Figure 1: Positive Pulse Pressure Wave Generator and Corresponding Pressure Waveform with Encoded Digital Data

A negative pulser produces a decrease in standing pressure of the drilling fluid through the rapid opening and closing of a poppet-type valve that diverts drilling fluid through perforations in the drill collar into the annulus, shown in Figure 2.

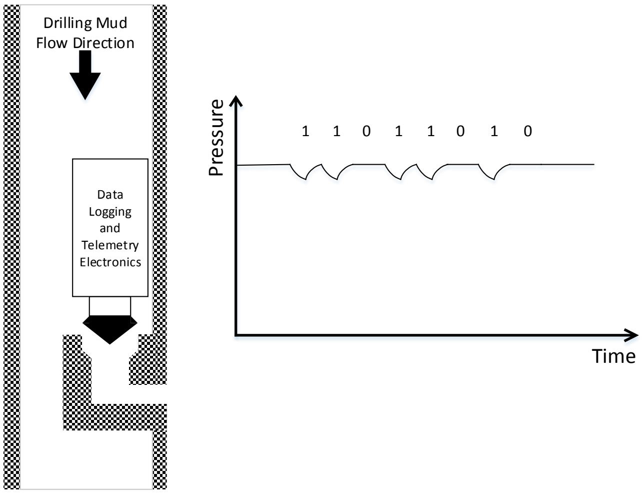

Figure 2: Negative Pulse Pressure Wave Generator and Corresponding Pressure Waveform with Encoded Digital Data

A net decrease in standing pressure is generated until the valve is closed. Data are encoded into the pressure pulses typically using a binary modulation scheme. The negative pulser has not been widely implemented due to fractures that can occur in the earth due to the continued injection of drilling fluid into the annulus. Additionally, the magnitude of the pressure pulses generated in negative pulser systems are typically smaller than in positive pulser systems due to the limitation of the injection rate into the annulus.

In both positive and negative pulsers, the high pressures inside of the drill string require the poppet-type valves to be able to withstand high levels of mechanical stress and erosion that can significantly affect performance of the telemetry system [12]. The effect of dispersion can cause significant problems in the transmission of pressure pulses through the drilling mud. This limits the ability to successfully recover the pressure wave pulse at the surface as sufficient time must be allowed in between successive data transfers to ensure smearing of the data does not occur. Because of this, the data rates have been typically limited to 10 bits/sec.

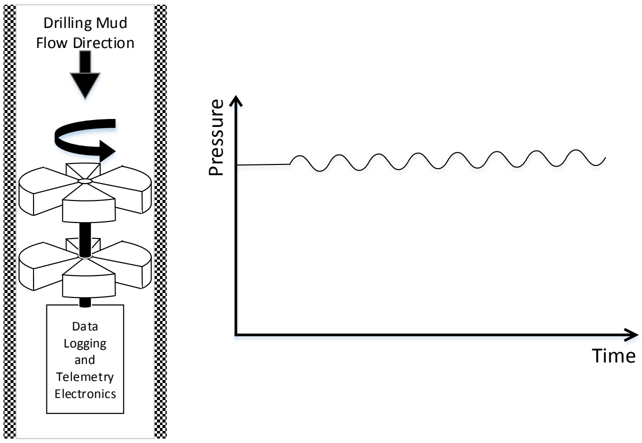

Figure 3: Continuous Wave Pressure Generator and Corresponding Standing Pressure Waveform

In continuous wave telemetry, shown in Figure 3, the rotation of a rotary valve relative to a stator creates a continuous sinusoidal pressure wave, which allows for the data to be encoded by modulating this sinusoidal carrier wave. The sinusoidal pressure pulses operate at a various frequencies that will depend on the depth of the well, drilling fluid and diameter of the well casing. The data are encoded into the pressure wave using various analog and digital modulation techniques to increase the data rate with negligible effect on the attenuation.

The continuous wave pulser has been developed over the past decade and is capable of generating pressure waves in the range of 100Hz to 2000Hz [13]. The method that has been developed treats the drill string as a filter with multiple passbands and stop-bands. Data are transmitted on each passband using multiple acoustic wave pulsers in the drill string [14]. While this method provides significant increase in data rate, it requires extensive modeling to accurately determine the passband locations for a given well casing configuration [15]. Case studies have shown that the continuous wave telemetry is comparable with mud pulse telemetry in depth and data rate [16].

Mud pulse technology was initially implemented in the mid-1960s by *Arps et al.* [17] who presented details of the first implementation as well as a commendable review of the state of the art in wellbore logging. One of the early practical challenges was associated with powering the pulser. Because battery powered systems generating large mechanical forces were unsustainable for long drilling periods, the original telemetry systems were powered via a custom designed turbine that used the flow of drilling mud to power the telemetry electronics and sensor equipment. With advances in battery technology, the effects of a downhole environment on the battery lifetime are no longer a concern during the design of the system. Due to the controlled attenuations and stable power supply, mud pulse telemetry has become the industry standard for the communications supporting measurement while drilling [18], although developments in continuous wave telemetry have started to be used in industry [19].

2.4. Advantages and Limitations

The major advantage of the mud pulse telemetry system is the controlled transmission medium relative to electromagnetic methods and the low attenuation relative to continuous pressure wave methods. Because the density and bulk modulus of the drilling mud can be measured in advance, the attenuations in the pressure wave can be estimated over long distances resulting in an efficient and reliable communication channel. Because the attenuations are known, the modulation scheme of the pressure wave telemetry systems can be optimized with sustained data rates as high as 48 bits/sec [20]. While accurate modeling of acoustic wave telemetry systems is required, the increase in frequency allows for higher sustained data rates and multi-band communication to further the data throughput.

The major limitation is that mud pulse technology relies on the pressure waves generated during fluid hammer. Hence, for it to work, continuous flow of the drilling mud must exist. During the drilling process, partial and total loss of circulation often occur, which will decrease the rate-of-penetration and increase the cost of drilling [21]. Additionally, the vibration due to drilling can also create turbulent flow in the drilling fluid effecting the pressure wave propagation and increasing noise in the system [22]. Furthermore, the choice of drilling fluid has a significant effect on the dispersion of the propagating wave, and as a result complexities such as the presence of high density solids or multi-phase fluids in the wellbore during drilling can be detrimental to successful data transfer [23].

The pressure waves will, of course, attenuate, with a level of attenuation based on the drilling mud that is used during drilling. By using higher static pressures, the generated fluid hammer pressure waves will increase in magnitude and magnitude of the received waves can be increased above the noise floor. This high static pressure places additional stress on the well casing seals, the formation and the drilling hardware that limit the lifetime of the pressure wave telemetry system and the well casing. Furthermore, mud pulse technology is essentially non-applicable in so-called underbalanced drilling applications (e.g. [24]). Underbalanced drilling refers to drilling when the pressure at the wellbore is kept lower than the fluid pressure in the formation. During under-balanced drilling, the drilling mud pressure is not sufficient for pressure wave telemetry to operate.

3. Electromagnetic Wave Methods

3.1. Practicalities

Electromagnetic telemetry methods in oil and gas wells involve the use of the drill string for the propagation of electromagnetic (EM) waves that can be measured on the surface of the earth [25]. The field of electromagnetic propagation through geological media has been extensively researched for nearly half a century [26]. In the model illustrated in Figure 4, the horizontal antenna at the end of the drill string can be seen to generate the electric field radiation pattern in black, which extends from the source antenna along the drill string to the surface. The horizontal and vertical portions of the drill string provide one of the differential measurement for the receiver electronics. Additionally, the electric field interaction between the drill string and the transmitting antenna in white.

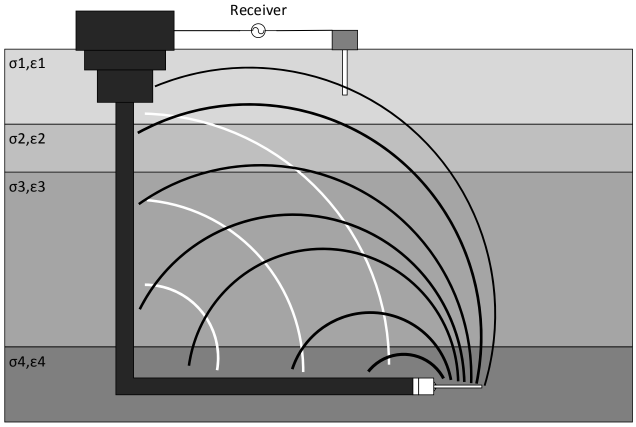

Figure 4: Electric Field Lines from downhole transmitter and receiver using the drill string and the earth as a propagation medium

In Figure 4, the field lines extend through multiple layers of geological media that will cause attenuations in the electric field due to the conductivity *(σ)* and the permittivity *(ε)*. These layers can affect the impedance matching of the antennas and because the radiating element is small in comparison to the electrical wavelength in the geological media, there will be difficulties in power delivery and recovery of the electromagnetic signal.

3.2. Theory

The propagation of the electromagnetic waves through conductive media can be derived from Maxwell's equations, relating the time and spatial variations of the electric and magnetic fields. Because the wavelength of the electric field is multiple orders of magnitude larger than the dimensions of the well casing, the system can be said to operate in the near field and a circuit approximation can be made during propagation through the geological media. Using Ampere's law from Maxwell's equations, the spatial relationship between the magnetic field (**H**), the time varying relationship between the electric flux density (**D**), and the conduction current (**J**):

$$\nabla \times \boldsymbol{H} = \frac{\partial}{\partial t}\boldsymbol{D} + \boldsymbol{J} \tag{4}$$

The time derivative of the electric flux density (**D**) is related to the electric field (**E**) and the permittivity *(ε)* of the material, and corresponds to the electric field transportation through the medium. The conduction current (**J**) is proportional to the conductivity *(σ)* of the medium and the electric field (**E**), which corresponds to the propagation of electric current through a medium. The corresponding magnetic field (**H**) will propagate perpendicular to the electric field lines.

A majority of bulk geological mediums can be decomposed into three separate categories: a low-loss medium $(\sigma << 1)$, a lossy medium $(\sigma \sim 1)$, and a good conductor $(\sigma >> 1)$. If the geological media is a good conductor, the conduction current (**J**) will dominate Equation 4. The electric field will attenuate heavily as current flows through the medium, which is similar to that of a metal wire in the circuit model. If the geological media is a low-loss media, the electric flux density term will dominate Equation 4. The electric field will propagate through the medium with no conduction current flowing that is similar to that of a capacitor in the circuit model. If the geological media is lossy, both electric field and conduction current will propagate through the media, which is analogous to a resistor in the circuit model. Thus, the geological media will determine the method of propagation and the optimal configuration of the antennas must be chosen accordingly to inject current into the formation or radiate electric field. In either case, the attenuation of the propagating electric fields is exponentially proportional to the attenuation constant, and is given by:

$$E(z) \approx E_0 e^{-z\sqrt{\frac{\omega\mu\sigma}{2}}} \tag{5}$$

where E(z) is the magnitude of the electric field along the drill string, E_o is the initial electric field strength at the transmitter, and ω is the angular frequency of the EM wave. Further examination of Equation 5 shows that in addition to an increase in conductivity, an increase in frequency and distance will correspond to greater attenuations of the electric field caused by the spreading of the electromagnetic wave in space.

The combination of Equation 4 and well logs help to provide an estimate of the dominant method of propagation through the geological media. In order to develop a solution to the electric field distribution surround the well casing and associated attenuations, an integral representation has been developed in Equation 6. The electric field integral equation allows for a convenient method for the numerical calculation of the electric field (**E**) due to the electric current distribution (**J**), the wave number (k) and the Green's function (**G**):

$$\mathbf{E}(\boldsymbol{r}) = i\omega\mu \int_V d\boldsymbol{r}'\mathbf{J}(\boldsymbol{r}') \cdot \frac{1}{4\pi}\left[\mathbf{I} + \frac{\nabla\nabla}{k^2}\right]\mathbf{G}(\boldsymbol{r},\boldsymbol{r}') \tag{6}$$

where **I** is the identity matrix, ω is the angular frequency, **r** is an arbitrary point along the drill string, and **r'** is an observation point at a far distance. In Equation 6, the Green's function represents the potentials generated due to a point source electric dipole and, by the integration along the drill string, the charge distribution can be calculated. Through Equation 6 and the circuit model developed using Equation 4, the solution can be simplified to represent the voltage and current distribution along the drill string, using the method of moments, which discretizes the drill string into a finite number of segments, allowing for a matrix relationship to be developed between the electric field and the current that is dependent on the impedance along the drill string, shown in Equation 7.

$$\sum_{m=1}^{N-1}\left[\mathbf{V}_m = \sum_{n=1}^{N-1}(\mathbf{Z}_{m,n} + \mathbf{Z}_i)\mathbf{I}_m\right] \tag{7}$$

where $\mathbf{V}_m$ is the voltage drop across a discretized step, $\boldsymbol{Z}_{m,n}$ is the impedance due to the conductive media surrounding the well casing segment, $\boldsymbol{Z}_i$ is the impedance of the drill string, and $\mathbf{I}_m$ is the current from along the drill string. The solution to Equation 6 has been researched extensively over the past 50 years and is dependent on the orientation, conductivity, and mud surrounding the drill string as well as conductivity of the stratified geological media and the mathematical integration of Green's function [27]. Additional research has been performed that models the drill string as a transmission line model consisting of a network of resistive, capacitive and inductive components to simplify the numerical calculations and provide a quick determination of the attenuations in the channel [28].

A new approach has been proposed for communication that uses magnetic induction to power sensors and communicate downwell [29]. This technique utilizes large coils of wire as the antennas along the drill string and the magnetic field to produce a weakly coupled inductive link between the down well transmitter and the surface antenna. The major advantages are the lower attenuation of the magnetic field in the geological media due to electrical properties and a possible increase in the impedance of the antenna system allowing for higher efficiency in the electronics and longer corresponding lifetimes. This allows for the greatest possible power delivery and higher throughput telemetry links. While this system has not been widely tested in industry, the analysis of the telemetry link is promising.

3.3. Implementation

An EM wireless telemetry system that is implemented in the well is not significantly different than a standard wireless electromagnetic transceiver. Figure 5 provides a simplified layout of the configuration for transmitting from downwell to the surface. The reverse telemetry link is a simple reversal of the blocks that are designed with both sets of electronics.

The embedded processor inside the well casing collects data from an array of sensors, which aide in the generation of well logs. The data are compressed using a variety of custom algorithms to minimize the quantity of data, enable the highest possible throughput to the surface, and extend the battery life. A modulator converts the digital data to an analog signal using a specific modulation scheme at a given frequency. A power amplifier boosts the signal to allow for transmission over long distances through the geological media. An impedance matching network connects the power amplifier to the antenna and ensures that the maximum amount of power is delivered to the antenna.

A conducting stake driven into the ground acts as the receiving antenna converts the electromagnetic signals to voltages that are amplified by the low noise amplifier to a useable range. The data are then demodulated, decompressed and received by the embedded processor at the surface. At this point, the data are available for processing and interpretation to aide in the drilling process.

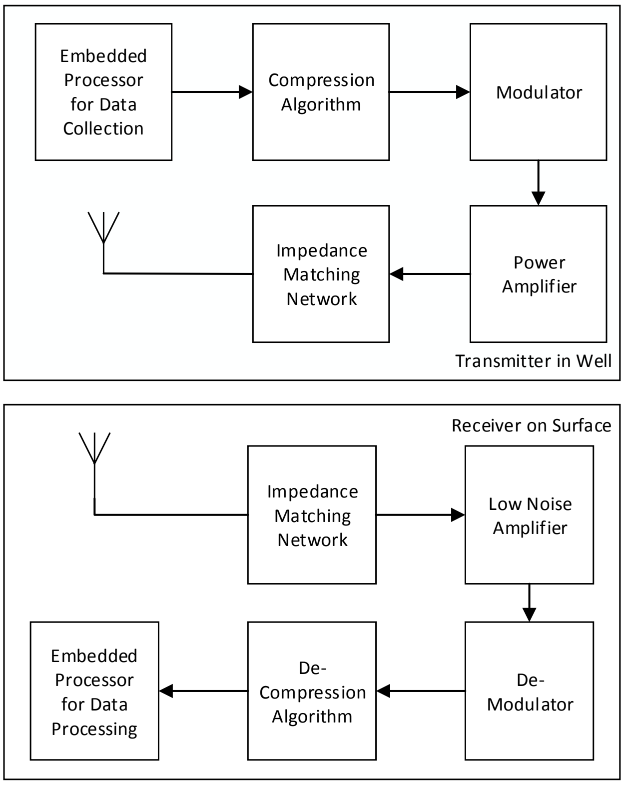

Figure 5: Block Diagram of transmitting electronics inside of the well casing and the receiver electronics on the surface

One critical and consistent result from past analysis of EM telemetry in the Earth's subsurface is that the attenuation of the electric field is considerable but at lower frequencies, the attenuation due to a change in frequency does not vary significantly. This is seen from the simulation results that show the attenuation of an electromagnetic field through conductive stratified geological media [30]. These simulation and field test results have provided a basis for electromagnetic telemetry systems in oil and gas drilling that exploit the lower attenuation of EM waves at frequencies below 10Hz and the attenuation differences between oil and water based drilling muds [31].

While modeling of the electromagnetic propagation along the drill string provides a theoretical analysis, limited access to field testing facilities has, until recently, limited the comparison between the theoretical models and experimental well measurements. Due to the relatively high attenuation in geological media, EM telemetry systems in the past have been implemented in onshore, shallow-depth (<10,000 ft.) wells. However, motivated by the challenges associated with carrying out mud pulse technology in conditions with loss of fluid circulation and/or in underbalanced drilling operations, there is an extensive patent literature associated with downhole EM telemetry (e.g. [32]), and several oilfield services companies have developed commercial EM telemetry for measurement while drilling applications. The early field trials were carried out in 2003 and by 2010 EM telemetry for measurement while drilling had been used on more than 700 wells [23].

The robustness of EM telemetry relative to mud pulse methods has been examined in a 2010 case study in the Fayetteville Shale in North America [23]. A total of 66 wells were drilled in various locations through the shale play with 25 wells drilled using pressure wave telemetry and 41 wells drilled using EM telemetry. Depths ranges from 1,200-8,000 ft. and lateral lengths averaged 4,000 ft. A 36% increase in the average rate of penetration and a 13% reduction in the drilling time was achieved in comparison to traditional pressure wave telemetry systems. EM telemetry data rates as high as <12 bits/sec were seen during drilling which was comparable to the pressure wave telemetry throughput. However, the EM monitoring was not affected by the presence of high density solids and/or multi-phase fluids and the wellbore, and it was able to continue transmitting data during periods where mud loss to the formation limited circulation. In this regard it was more robust and hence able to provide data that was needed for drilling optimization during critical periods, and this is what appears to have accounted for its success in this trial. Similar success related to the ability to transmit data even during periods of total mud loss in a geothermal drilling application are reported by [33].

EM telemetry has also been the subject of reported successes for measurement while drilling (MWD) for underbalanced drilling operations for which mud pulse telemetry cannot be used [34]. In the last of these case studies [34c], EM MWD was used during underbalanced nitrogen foam drilling in several ~500 m (1640 ft.) deep wells that were completed in the Agua Nueva formation, Mexico. A signal frequency of 4 Hz was used to transfer an average of over 300 EM pulses (understood from their discussion to be the equivalent of 1 bit of information) per hour for between 31 and 90 hours in each of 4 drilling runs. The average power consumption for the battery-operated pulser was 15,000 Joules/hour.

EM MWD has also been successfully demonstrated by Hussain et al. [35] for a 2200 m (7217 ft.) deep well completed in a limestone gas reservoir in Pakistan. Besides being considerably deeper than the case study of [34c], these authors report that high conductivity of one of the limestone layers caused high signal attenuation. The issue of attenuation was overcome by placement of 4 downhole antennas, that is, signal repeaters that boosted the signal every ~500 m.

In 2012, a case study was performed that compared EM telemetry and pressure wave telemetry in 4 wells during a casing-while-drilling operation [36]. Both the pressure wave and EM telemetry were performed on each well during drilling to provide a direct comparison between the technologies. A high communication packet success rate of 90% was seen during EM telemetry compared to the significantly lower 40% packet success rate of pressure wave telemetry. Additionally, the EM telemetry provided high data rates upwards of 12 bits/sec when compared to the 4 bits/sec that the pressure wave telemetry was able to provide. The authors estimated that the use of EM

Table 1: Review of Wireless Telemetry Methods in Oil and Gas Wells

	EM Telemetry	Mud Pulse Telemetry	Continuous Wave Telemetry
Advantages	Bi-directional Communication, Unaffected by Partial or Total Loss of Circulation, No Mechanical Parts, No Requirement on Drilling Fluid	Reliable and Controlled Telemetry Channel, Extensively Implemented throughout industry with years of results.	
Disadvantages	High Attenuation of Signal and Limited Data rate during High Attenuation Periods	Communication Effected by Partial or Total Loss of Circulation, Attenuation Dependent on Drilling Fluid	
Depths and Data Rates	Up to 12 bits/sec during 8,000 ft. of drilling [23] Up to 14,800 ft. offshore measured depth [34b]	Up to 4 bits/sec from 29,123 ft. [12] Up to 3.5 bits/sec from 34,570 ft. [12] Up to 3 bits/sec from 36,075 ft. [12]	Up to 20 bits/sec from 3,595 ft. [13c], Up to 30 bits/sec from 9,865 ft. [12], Up to 27 bits/sec from 11,394 ft. [12], Up to 20 bits/sec from 20,991 ft. [12], Up to 9 bits/sec from 23,215 ft. [12]
Applications	Shallow On-shore wells, Underbalanced Drilling, Wells prone to loss of drilling fluid circulation	On-shore and Off-shore Wells. High Pressure and Circulation Wells. Wells with known properties of the drilling fluid	

telemetry would reduce the drilling time by as much as 3.9 days contributing to a reduction in drilling costs as high as 26%.

In 2013 and 2014, a new EM telemetry system was developed and tested in the Texas and Wyoming that drills and deploys a separate EM anchor antenna on the outside of the drill string allowing EM propagation to occur between the well casing and the anchor antenna [37]. The anchor antenna system was found to extend the depth range of the EM telemetry system and allows for the drilling of multiple wells from a single anchor well.

In summary, the case study literature demonstrates that EM telemetry can be successfully deployed in relatively shallow wells. Success in deeper wells depends on sufficiently low formation resistivity, although the use of downhole signal repeater antennas has been successful at overcoming issues of high attenuation in high resistivity wells.

4. Summary and Outlook

Nearly all of the research performed to date on telemetry channels in oil and gas wells is aimed at measurements while drilling application with little research on sensor placement downhole [38]. From the experience that has been gained, advantages, disadvantages, data rates, and applications for the wireless telemetry methods have emerged and are summarized in Table 1. However, little has been researched on the possibility of placing wireless sensor and communication systems downhole for the continuous measurements inside of the well and along the well casing. But there are potentially significant economic benefits of well management that makes use of continuous downhole measurements and control systems [39], especially with the widespread deployment that would be likely with systems that do not entail the operational difficulties of those that require cables to be run in along with the casing. Hence, we will now focus the discussion on barriers from medium properties to long term - that is, a few months to a few years, respectively - wireless downhole monitoring for onshore shale gas/oil wells.

While both pressure wave telemetry and EM telemetry suffer from signal attenuation that is inherent to the communication channel, pressure wave telemetry has clear advantages over electromagnetic telemetry in the application of measurement-while-drilling as the drilling mud provides a stable communication channel allowing for greater reliability when compared to electromagnetic telemetry. This ability to accurately model the attenuation losses regardless of the type or location of well provided the initial incentive for commercialization. However, for the purpose of medium to long term monitoring when there is no drilling fluid circulation, the EM methods are a clear choice.

Because the properties of the geological medium cannot be chosen, there are essentially three ways to reduce the negative effects of attenuation. The first is to better optimize operating frequencies and propagation method to the surrounding medium, where we note that this optimization is performed as a part of the current state of the art (e.g. [23]). The optimization typically involves a reduction in the operating frequency. However, models that are able to more accurately identify optimum operating frequencies in light of characterization data that is collected for the complex surrounding environment could lead to substantial improvements.

A second approach to overcoming attenuation is to increase the power output. However, it is important to recall (Eq.4) that the power requirements increase exponentially with depth. Although little has been published in the open literature, the data from the 500 m deep wells reported by Kolaric et al. [34c] suggest they transmitted each pulse with an average power of 35W and an estimated throughput of 43 pulses/sec where a pulse contains 5 ½ cycles of a 4 Hz to 19 Hz electromagnetic wave. A 20 kHz carrier wave is modulated onto this low frequency signal. With the large battery used by Kolaric et. al., the high transmit powers, and assuming a requirement for communicating one 10-bit sensor value per day, the lifetime of the downhole sensor is less than a few months. Furthermore, the power requirements for shale gas/oil reservoirs is expected to be even larger because typical depths of shale gas/oil wells is in the range of 1,000-14,000 ft. and is typically between 5,000-10,000 ft. [40]. Although EM methods have been demonstrated across this entire depth range [23], the power required for continuous monitoring will be onerous and in most cases prohibitive.

A third approach to overcoming attenuation is the deployment of an array of downhole repeater systems so that the required transmission distances are a fraction of the total depth of the well. These repeaters reduce the transmission power required by each of the sensors and can drastically extend the lifetime of the system. The effectiveness of this approach has been demonstrated by Hussain et al. [35], who deploy 4 repeaters in a 2200 m deep well. In the future, smaller electronic devices could be placed on each casing section and, as a result, repeater arrays at 45 ft. spacing is plausible. In this way the issue of transmission power would be reduced to communication between repeater units at this spacing and the entire system would be fully scalable to deep or shallow wells.

Hence we see that the latter two solutions to the attenuation problem - repeater arrays and increasing signal power - both shed light on the main barrier to medium to long term wireless downhole telemetry: The need to power the devices is a major concern. Still, there may be some emerging solutions with their origins in other telemetry application. For example, the application of RFID technologies and sensor design has advanced significantly over the past decades due to developments in integrated circuit manufacturing and biomedical research in the field of wirelessly powered implantable sensors [41]. As the field of sensor design has become a focus of interest in the biomedical field, the sensor applications mirror the requirements for the oil and gas industry. While the environments and transmission distances vary by many orders of magnitude, the frequency of the EM waves are on a similar order of magnitude. Thus, the analogy between the wireless propagation and communication inside of the body and along a well casing is not difficult to develop. The field of biomedical sensor design parallels the development of smart wells as the measurement of temperature, pressure and pH can provide valuable information for the production capabilities of the well. The use of microelectromechanical (MEMS) devices and RF energy harvesting devices can provide valuable information concerning the production of the well and the integrity of the well casing and is currently being investigated by Halliburton [42]. Because these sensors consume extremely small quantities of power, less than 1mW, the development of an efficient wireless telemetry system must exist for sustained continuous communication.

5. Conclusion

Since the early days of oil and gas well drilling, the ability to monitor the status of a reservoir in real-time has been a major objective. Advances in measurement-while-drilling (MWD) technology have driven two wireless downhole technologies: pressure wave telemetry and electromagnetic (EM) telemetry. While pressure wave telemetry provides the most robust and reliable communication, the application has been limited to measurement-while-drilling applications dues to the long term reliability of the hardware. On the other hand, electromagnetic telemetry suffers high attenuation of the signal due to unknown geological formation properties. While the well depths associated with most shale gas/oil reservoirs are within the range for which successful EM-MWD has been demonstrated, collecting megabytes of data over a period of months to years will require a combination of scalable, low power repeater arrays that are integrated in the casing string along with high capacity, compact batteries and passive methods for continuous or period recharging of the powering for the devices. While these are significant challenges that remain, the recent advances in EM-MWD combined with advances in passively powered devices in biomedical applications have placed the industry within reach of the long-pursued goal of continuous, wireless downhole monitoring.

Acknowledgements

The authors would like to thank the Center for Energy at the University of Pittsburgh and the Richard King Mellon Foundation for their support and guidance in the writing of this paper.

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