All Optical Multi-Sensor Well Monitoring System to Survey and Monitor Gas Storage Operations

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Abstract— Paulsson, Inc. (PI) has partnered with Pacific Gas & Electric (PG&E) and California Energy Commission (CEC) funded by the CEC grant PIR-19-001, to develop and apply cost-effective, all-optical Underground Gas Storage (UGS) reservoir surveying and monitoring technologies. This project was to determine the capabilities that fiber optic sensor technology may have in monitoring a natural gas wellbore and reservoir. The project goals and objectives include designing, prototyping, third party laboratory testing, building and installing a borehole all optical multi-sensor array into a well drilled at UGS facility. The optical sensor system has recorded a number of nearby small earthquakes which have provided the seismic sources that will be used for site characterization. The optical sensor array has also recorded large earthquakes in Japan, Peru and Fiji. The array will be used to characterize and monitor the gas injection and withdrawal operations for a number of months. The preliminary results of this project are discussed describing some potential applications for use.

Index Terms—Gas storage, integrity management, fiber-optic monitoring, borehole seismic, reservoir monitoring, well monitoring, flow assurance, and well integrity.

I. Research

This document discusses the installation and monitoring of fiber optic sensory equipment to observe and monitor the downhole operating environment of a natural gas storage well.

In July of 2021, PG&E partnered with Paulsson, Inc. (PI) to install a fiber optic monitoring system funded by CEC. The installed all optical multi-sensor array includes Enhanced Distributed Acoustic Sensors (EDAS), and Distributed Temperature Sensors (DTS). The multi-sensor array was deployed in a well to a measured depth of 5,400 ft at the McDonald Island Underground Gas Storage (UGS) facility near Stockton, CA. The McDonald Island facility is the one of the largest UGS facilities in the USA and provides a major supply of natural gas to northern California. A multi-sensor array was deployed on the 4.5” production tubing string that was installed and centralized inside the 8 5/8” casing. The tubing was landed into a production packer to ensure a dual barrier construction. The large-aperture optical sensor array was used to record thermal and acoustical data.
After the installation in July 2021, the optical sensor system has been continuously operated and monitored. While the data is being recorded, the data is field processed in real time using remote access to the field data acquisition system. The all-optical array was monitored continuously for a period of at least 6 months. The installed fiber optic sensor system was used to monitor the subsurface of the storage field immediately surrounding the well bore during injection and withdrawal operations of the stored natural gas.

A. Background of Storage Field

McDonald Island natural gas storage field was first discovered in 1936. PG&E acquired the field from union oil company in the early 1960’s. Through the early 1970’s, PG&E began storage operations and developed the field through the drilling of directional wells from two large gas processing platforms. The natural gas storage industry is very focused on the monitoring of wells to provide reservoir integrity as well as analyzing the flow performance of, and the forces acting on wells during the injection and withdrawal of stored natural gas. For many years static noise and temperature surveys have been an industry best practice for the monitoring of natural gas storage wells, so much so that this monitoring is even required by state regulators to be performed once per year. A leaking casing collar or casing body has been shown in practice to manifest both a localized cooling as well as provide audible indications of gas movement. In a similar way the fiber optic monitoring systems can be used to monitor the thermal and auditory environment of a wellbore to deliver similar data, but continuously and in real-time. Currently these noise and temperature surveys are only performed in a shut-in state. This provides relatively little information regarding the change in temperature observed when the well begins flowing or when its withdrawal rate or injection rate is changed. Furthermore, there has not been a way to observe the in-situ strain or thermal forces acting on a flowing storage well.

B. Discussion of Technology

Two distributed fiber sensing technologies were deployed in this project: Distributed Acoustic Sensing (DAS) and Distributed temperature Sensing (DTS). Both technologies measure the backscatter of light in a fiber optic cable, however they differ in which part of the backscatter that is measured. DAS, typically, is an interrogation technique for fiber optic cables that uses the inherent Rayleigh Scattering from a pulse of light to map the relative radian length changes in a fiber optic cable. Since the first patent in acquired in 1993, this technology has evolved to become a popular fiber optic sensing option in the current marketplace (H. Taylor). DTS is similar in principle, except that Raman Scattering of the propagating pulse of light is measured to measure the temperature of the environment of the fiber. Rayleigh Scattering is the strongest scattering phenomenon in the fiber, and thus perturbations can be measured at much higher sampling rates when compared to Raman Scattering DTS measurements. Typical DAS units have a sampling rate that is limited by the sensing length of the fiber, which usually falls in the range of 1-10 kHz. The lower amplitude Raman Scattering phenomenon requires several tens of seconds to hundreds of seconds to make a temperature measurement. Essentially, DTS must be averaged to improve the accuracy of the temperature measurement, and therefore, can take several minutes to make an accurate temperature measurement along the fiber.

This project used a Fotech Helios Theta DAS interrogator to monitor a specially engineered fiber optic cable that has a 10 dB enhancement over that of a standard telecommunications grade fiber. The raw data capture of the DAS unit results in spatial sampling of 0.68 meters. The gauge length and averaging window have been modified throughout the project; however, the gauge is typically set between 4.0 and 5.3 meters and the averaging window is set to 5, resulting in a window of about 3.4 meters. Enabling an averaging window allows for suppression of noise and other non-advantageous optical effects at the cost of some 'smearing' of the optical signal. The resulting system produces a vibration sensor every 2 meters (6.56 ft) along the fiber in the wellbore for a total of 823 vibration, or acoustic, sensors.

A LIOS Optical Frequency Domain Reflectometry (OFDR) interrogator based on Raman Scattering was used in this project to monitor a pure silica core fiber, which is engineered to inhibit hydrogen darkening, especially for Oil & Gas applications. The unit was setup to average the response for 260 seconds (4 min, 20 seconds), resulting in the best accuracy possible, and taken every 1 meter (3.28 feet) for a total of 1,646 sensors.

An temperature and vibration insulated instrument room was deployed onsite to house instruments and a direct burial cable was trenched from the instrument room to the wellhead, where a splice from Draka Bendbright XS fiber to the downhole fibers was performed. The splice enclosure was rated for explosive environments in accordance with PG&E requirements.

C. Data Acquisition and Processing

The optical sensing data are continuously acquired by an interrogator through a field computer. Software with graphic user interfaces eases the operation of data acquisition. The field computer can be logged in to remotely operate the interrogator and monitor the data being acquired. Real-time recorded data are displayed on a screen with a low resolution. When portions of low-resolution data appear of interest, these data can be acquired by downloading the originally recorded data. The downloaded data with much higher resolution can then be used for further analysis.

The DAS data was acquired with a 3,000 Hz sampling rate, from 2,616 channels at a 0.68 m spaced interval. For continuous data acquisition, approximately 2TB of data are generated each day. Five large, 18 TB external hard drives were used for onsite data storage, and each drive can store one week of DAS data.

When the hard drives with recorded DAS data are retrieved and brought to the processing center, an auto-search of the data is performed to screen for possible events. This auto processing can process five days of DAS data in one day, so it is also possible to run this auto-search on site. The result of the auto-search is a coherent noise index for the data in each DAS data file. After this, the DAS data is checked according to the coherent noise index from high to low to try in further identify changes to the monitored measurements.

D. Fiber Optic System Installation

The fiber optic sensor system provided by Paulsson was installed in the well at the PG&E McDonald Island Underground Gas Storage (UGS) facility near Stockton California. Two Google Maps and a ground level photo from this facility are shown in Figure 1. A typical Gas Storage Well at the PG&E McDonald Facility is shown in Figure 2. The well, used for the fiber optic sensors, is a deviated well with a drilled depth of about 6,000 ft. This well design is common for wells at UGS facilities. The sensor fibers are encapsulated in a robust high-pressure ¼" stainless steel tubing. The fiber sensors are used for Distributed Acoustic Sensing (DAS) and Distributed Temperature Sensing (DTS) for this project. Other optical sensors are also available but were not deployed for this project. The ¼" stainless steel tubing is field deployed using a large diameter spool inside a regular sea container. As the 4.5" OD 40 ft long production tubing string is lowered into the well the ¼" tubing is attached to the production tubular using a custom centralizer seen in Figure 6. This centralizer is placed on each 4.5" production tubular to protect the fiber tube by centralizing the 4.5" tubing. Across the coupling of the 4.5" tubing the ¼" fiber tube is protected by a cross coupling protector. The installation steps were as follows:

1. Spot the containers with the spool holding the ¼" tube with optical fibers.
2. Hang the large sheave wheels, seen in Figure 5, guiding the ¼" tube from the spool to the well head.
3. Thread the ¼" tube with fibers from the spool over the sheave wheel to the well head.

4. Secure the ¼" tube with fibers to the first section of the 4.5" production tubing.
5. Match the feed-speed of the ¼" tubing to the deployment speed of the 4.5" production tubing.
6. Deploy a centralizer, Figure 6, to each 4.5" production tubing to protect the ¼" tubing.
7. Deploy a cross coupling protectalizer over each 4.5" production tubing coupling.

Figure 1. The PG&E Underground Gas Storage (UGS) facility at the McDonald Island, Central California.

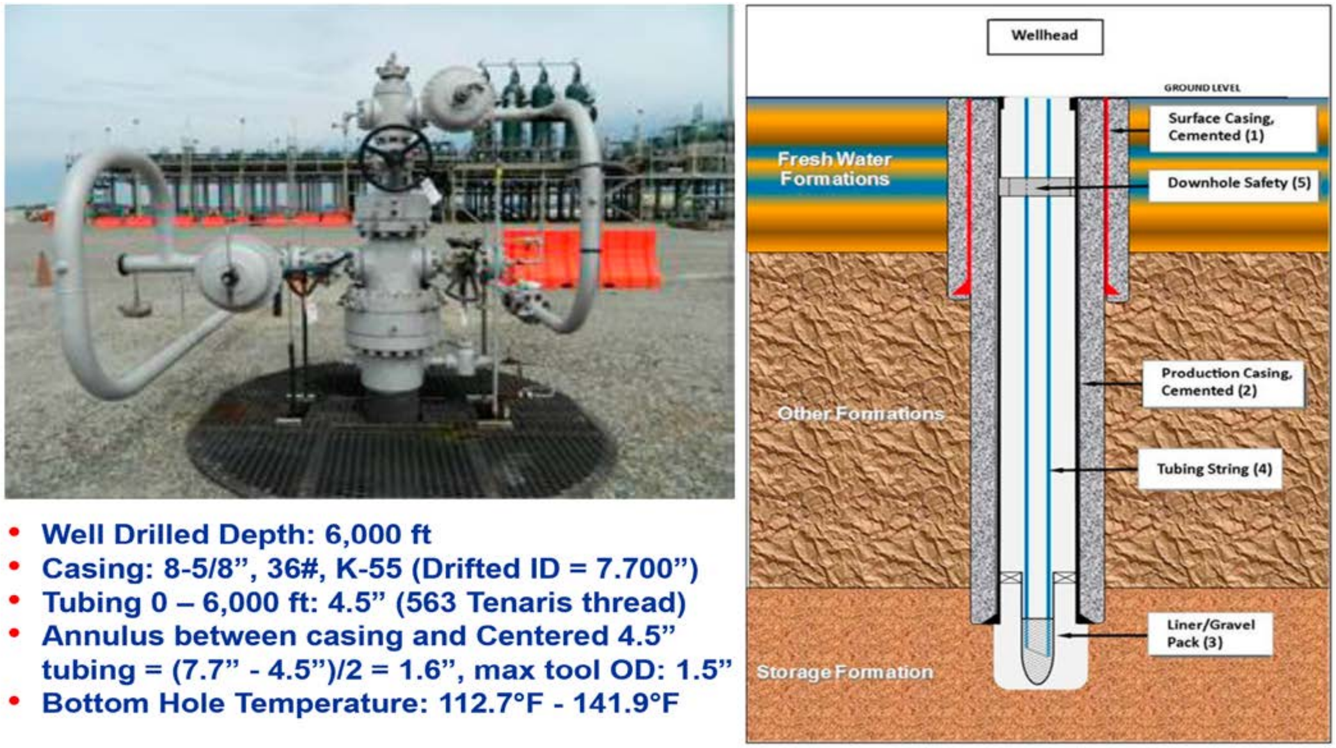

Figure 2. Typical Gas Storage Well at the PG&E McDonald Island Facility.

Figure 3. Showing Internal Porting in the wellhead that that allows fiber optic cable to enter the well.

Figure 4. Showing fiber optic cable spliced connection boxes at surface immediately following installation.

Figure 5. The drilling rig at the McDonald Island UGS in the process to deploy the 4.5" OD production tubulars into the well. The Paulsson fiber optic sensors are enclosed in the ¼" stainless tubing shown on the right hand of the figure. This ¼" tube with fiber is mounted to the 4.5" production tubing.

Figure 6. This figure shows the 4.5” OD production tubular that serves as a carrier of the optical fiber encapsulated in the ¼” stainless steel tubing. The ¼” tubing is secured to the 4.5” production tubular using a specialized centralizer that secures and protects the ¼” tubes containing the fiber.

E. Field Measurements

1) Comparison to Gradient Survey

a) DTS (Distributed Temperature) Measurements

A wireline survey which included temperature logging was performed and the temperature results were compared to the fiber optic DTS measurements. This presented a great opportunity to calibrate the optical data. On March 28, 2022, the well was surveyed through the tubing with a suite of downhole wireline tools at an average speed of 8 ft/min. A calibrated thermometer was included in the well survey suite. The wireline survey results were compared to the DTS measurements (Figure 7) shows the comparison of the DTS data with the logged temperature data. They match very well. The DTS measurements were within the error tolerance of the thermometer and fiber optic systems, except at the bottom of the well. The slight divergence in measurements at the bottom of the wellbore can be attributed to the difference between static steady-state measurements (DTS) and the dynamic measurement environment created by running tools into the well and disturbing the gas column.

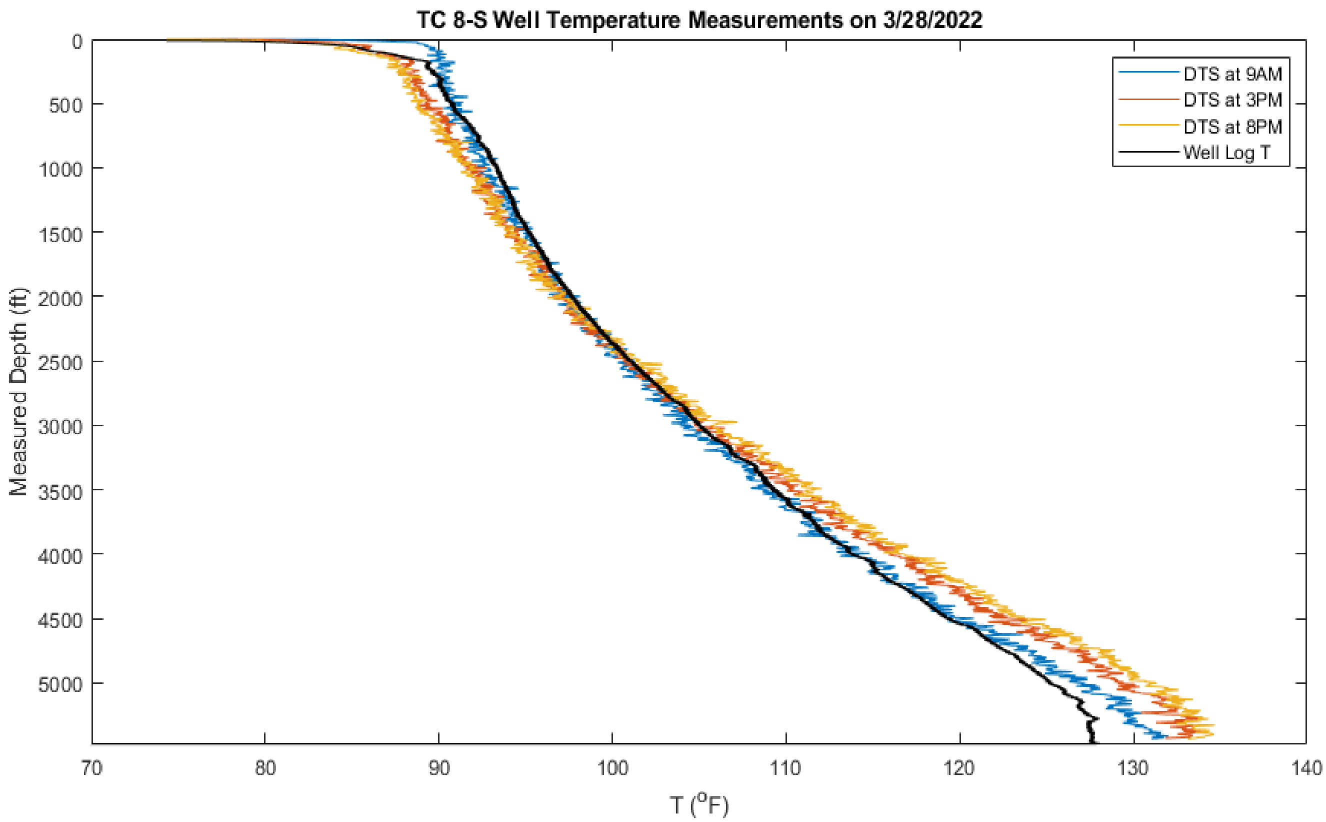

Figure 7. The comparison of wireline logging temperature data (black curve) and the optical DTS data. The DST data was updated about every 10 minutes. In here we only show 3 check points when the wireline tool was at the bottom of the well (9 AM), in the middle of the well (3 PM), and near the surface (8 PM). From it we see the temperature curves match quite well. Difference among curves related to the range of precision of the wireline tool temperature measurements. The wireline probe temperature was artificially lowered by the mixing of the borehole fluid during the trip-in of the tool and the repeat tool run as seen in Figure 8.

b) DTS (Distributed Temperature) Measurements

An analysis was also performed on the sound recorded in the borehole during the wireline logging operation. Figure 8 shows the DAS data energy distribution in depth and in time. The wireline tool position was clearly identified by the DAS reading during the course of the survey. From this, we can see the wireline tool was quickly lowered down to the bottom of the well within 1 hour, pulled up about 200 ft, and lowered back to the bottom, then gradually pulled up to the surface in about 10 hours for the wireline survey. From it we clearly see how the wireline tool was lowered down to the bottom of the well and gradually pulled up.

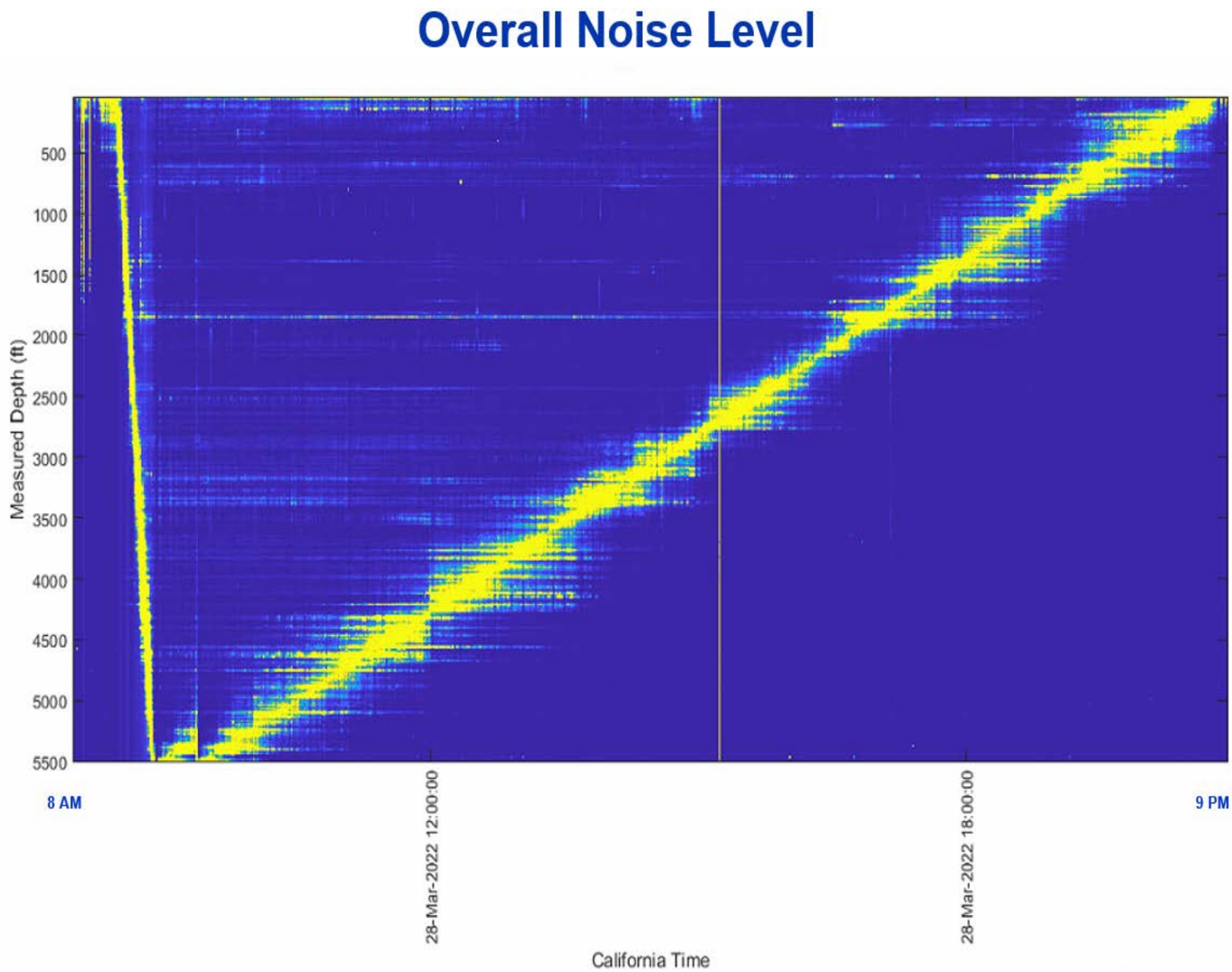

Figure 8. The DAS data energy (summation of amplitude squares in 30 seconds) distribution along the borehole in 13 hours from 8 AM to 9 PM on 3/28/2022 during a wireline survey. The data shows first the fast lowering of the logging probe followed by a short 200 ft up-run followed by lowering the tool following by a slow logging run from 5,500 ft to the surface. The DAS system shows the exact position of the logging probe at all times.

2) Flow Description

An extended flow event was recorded after the completion of the well rework and fiber optic installation. The well cleanup process from December 9, 2021, to January 11, 2022, was the first flow period after reworking the well. This flow period consisted of 33 days of continuous gas withdrawal at sequentially increasing flow rates from 5 to 10 MMSCF/D with the objectives of removing any residual workover fluids from the wellbore and near-wellbore region of the reservoir and restoring the flow performance of the well.

a) DTS (Distributed Temperature) Measurements

The DTS data is shown in Figure 9 over six weeks, including the withdrawal period. As illustrated in the figure, the DTS data showed strong correlation to the flow rates recorded at the flow meter during the withdrawal period. The DTS data showed a temperature increase in the shallow and mid-depths of the wellbore while the temperature near the production zone decreased. Overall, during the gas withdrawal period, the entire borehole experienced an increase in temperature of approximately five degrees Fahrenheit.

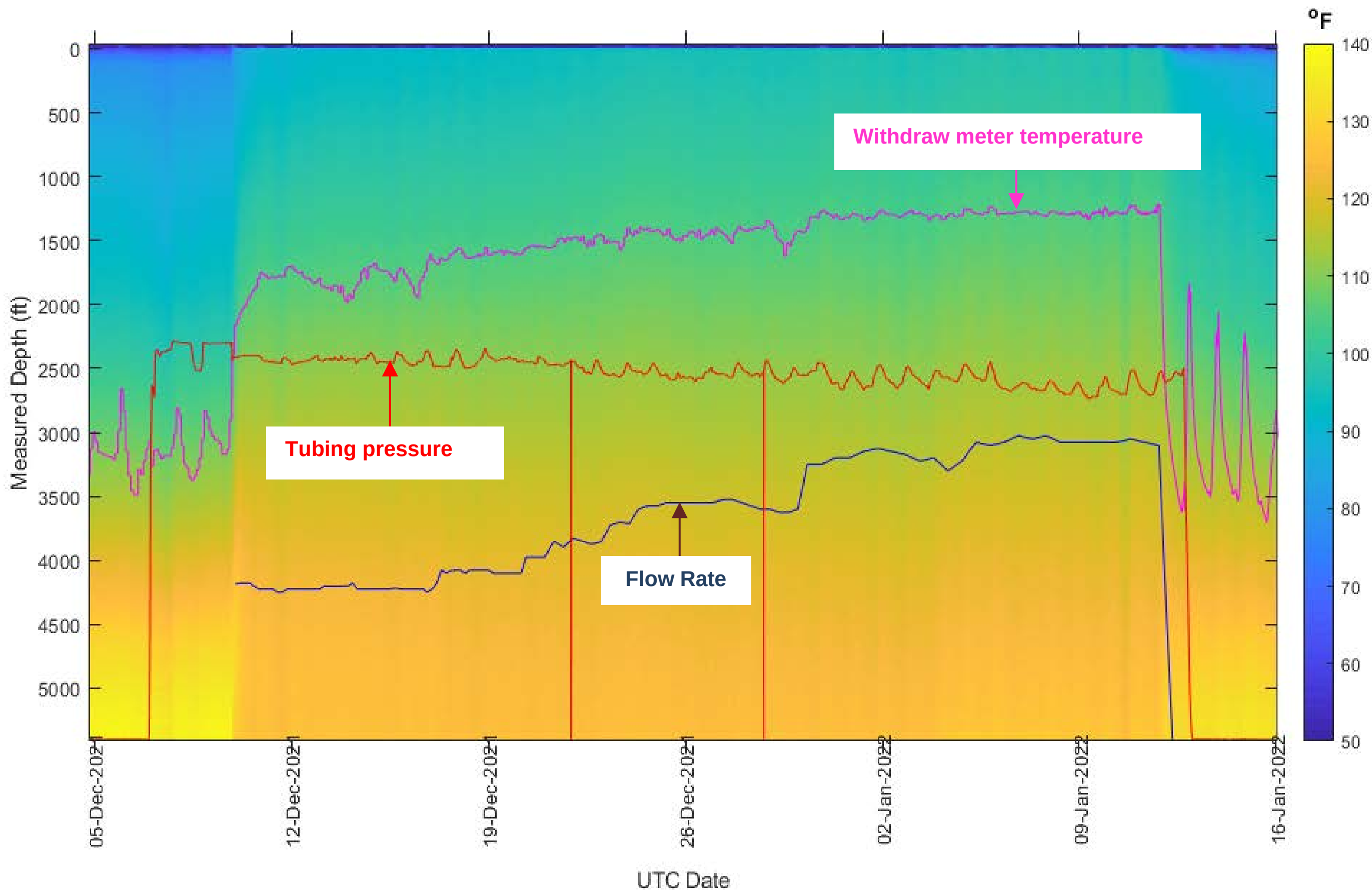

Figure 9. The DTS data over 6 weeks including the continuous gas withdrawal period from 12/9/2021 to 1/11/2022.

b) DAS (Distributed Acoustic) Measurements

The DAS data was analyzed to represent acoustic events using the ‘coherent noise index’. The coherent noise index is an inverse measurement of randomness of the DAS data. These events increased significantly above the baseline with the start of the withdrawal period. Each increase in flow rate resulted in a corresponding increase to the event count in the DAS data (Figure 10).

Figure 10 shows the DAS data coherent noise index event auto-search results. During the gas producing period, many small coherent or ambient noises are also generated. Some of the strong coherent events are associated with routine surface work performed during the monitoring period and some large earthquakes, such as the San Ramon, California magnitude 3.9 on November 17, 2021, and the Eureka, California magnitude 6.2 earthquake on December 20,2022. Beside these singular events, we see overall coherent noise index increase during the gas withdrawal period.

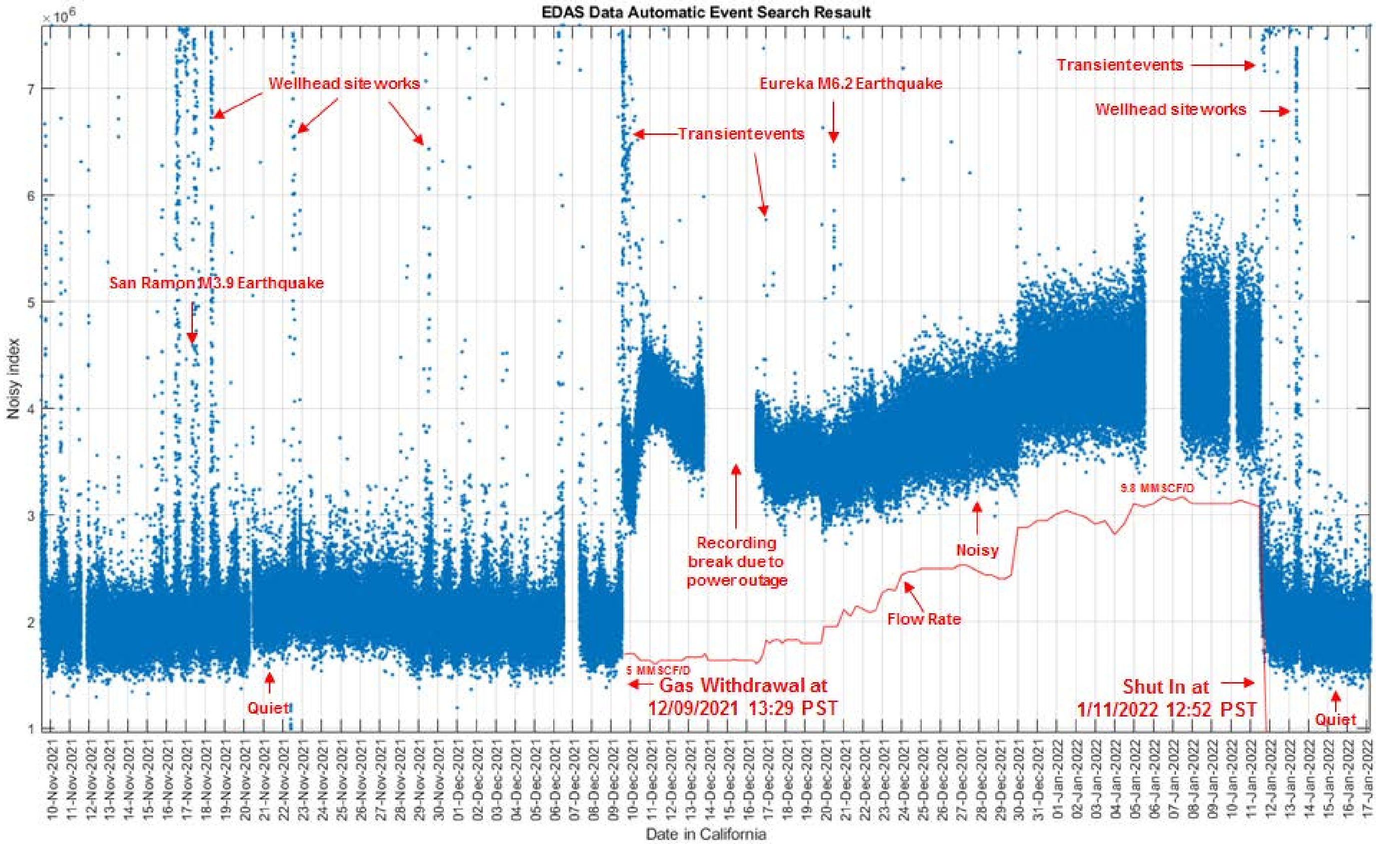

Figure 10. The coherent noise index over 68 days, including a withdrawal period (from withdrawal to shut in).

3) Seismic Related Measurements

Earthquake data can also serve as another good calibration source for the recorded DAS data. The USGS website has real-time earthquake information. When there is an earthquake occurring, the seismic wave arrival time can be determined at a station near McDonald Island. Using this time information, we can easily locate the DAS record of the earthquake. So far, the fiber optic monitoring system DAS has recorded almost all the earthquakes that can be reasonably recorded,

Generally referring to:

Magnitude 1 earthquakes within about 10 miles,
Magnitude 2 earthquakes within about 30 miles,
Magnitude 3 earthquakes within about 90 miles,
Magnitude 4 earthquakes within about 200 miles,
Magnitude 5 earthquakes within about 500 miles,
Magnitude 6 earthquakes within about 2000 miles,
Magnitude 7 earthquakes within about 6000 miles,
Above M7, almost everywhere on the earth.

Figure 11. Shows the locations of the epicenter of Fukushima M7.3 earthquake on 3/16/2022 and Macdonald Island where the fiber optical arrays are installed. The distance between them is about 5000 miles.

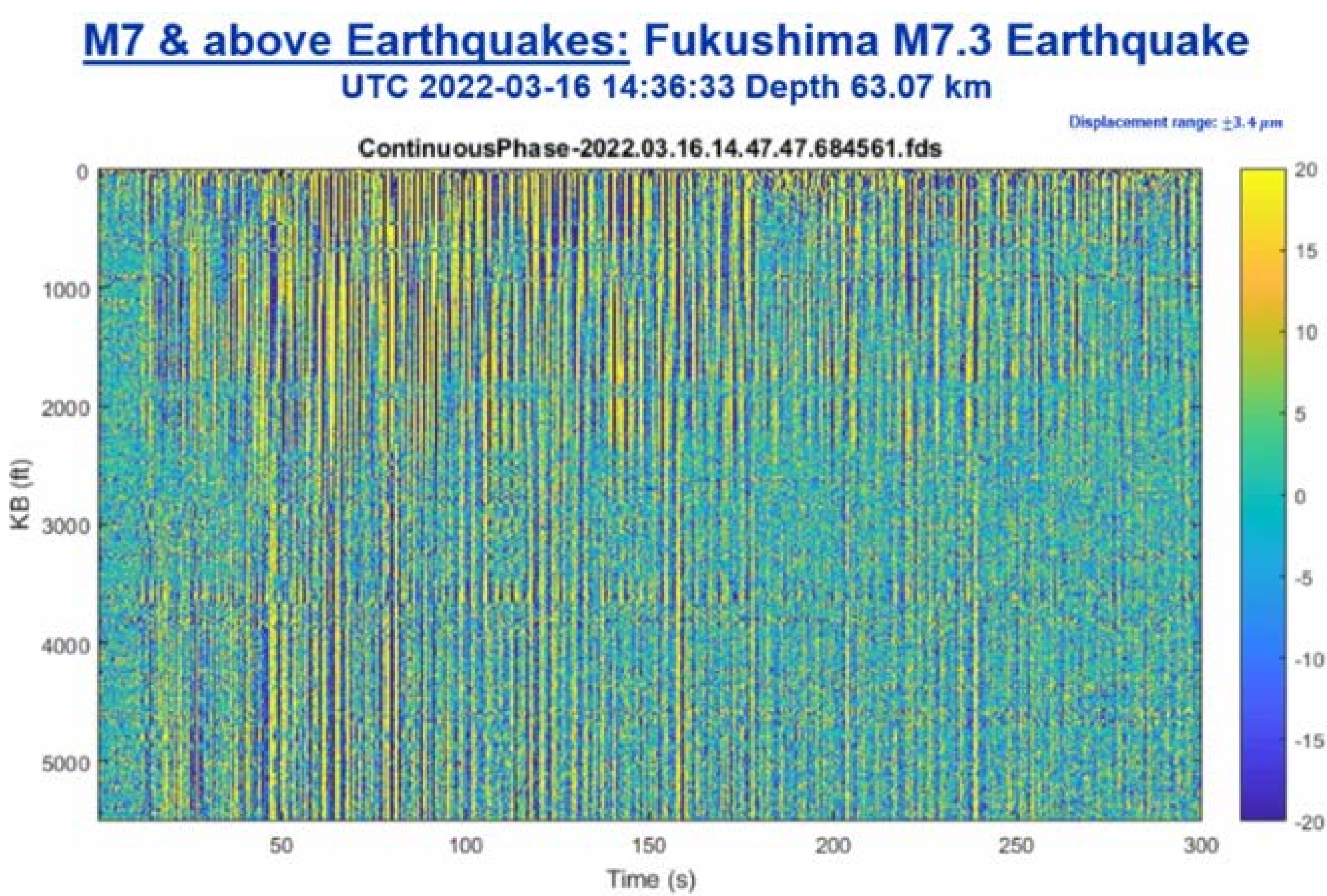

Figure 12. Shows the Fukushima M 7.3 earthquake clearly recorded by DAS with strong amplitudes and long duration (more than 5 minutes).

Figure 13. Shows the map of another much smaller earthquake (M1.9), but very close to the borehole (5 miles).

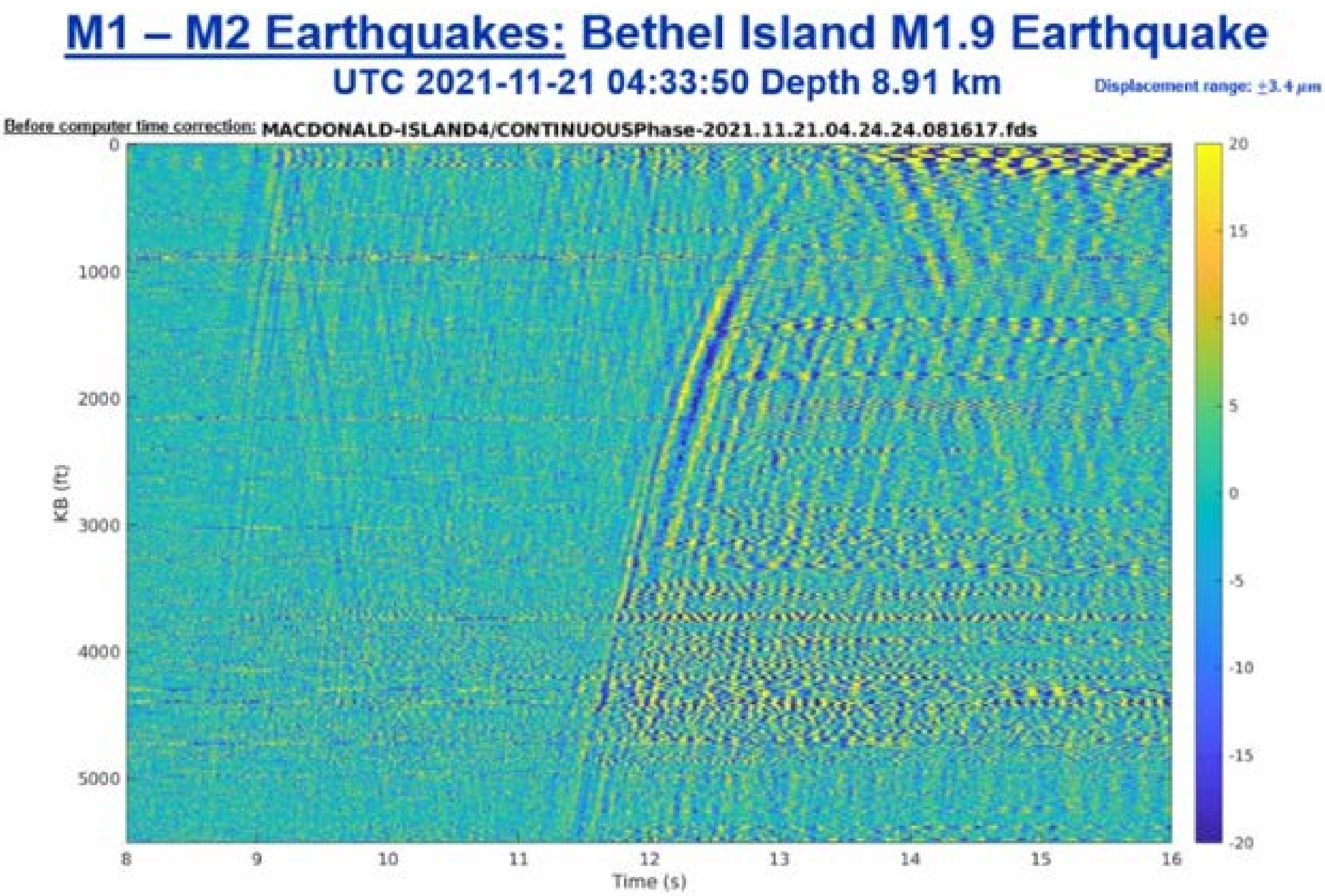

Figure 14. Shows the smaller earthquake M 1.9 clearly recorded by the DAS system with clear P and S waves, along with their reflections from the surface. The high frequency events might correlate with geology.

F. Conclusions and Application

Gas storage integrity management programs can find significant value in deploying fiber-optic survey and monitoring systems for several applications. As was shown above the monitoring system was able to detect and map different flowing conditions of the well during flow periods. This data can also be used to show how the thermal conditions of the well change as the well acclimates to the temperature of the flowing gas. These systems can be used to monitor earthquakes and other seismic events occurring regionally proximal to fiber optic monitoring systems. Additional research is being performed to identify the well and reservoir integrity related aspects of the fiber optic monitoring system as well as any observations related to lithology. Additional research should pay particular attention to the changes in wellbore and reservoir related information describing the wells operating condition during different phases of operation. This technology is very useful; however, the commercialization of such equipment could present challenges relating to the need for a field-based power source, the immense volume of data being recorded and stored, and the cost that these systems currently incur for installation and on-going monitoring. It is likely that many of these challenges will be overcome as the systems are scaled up from one well to an entire field application. The desire to increase monitoring capabilities continues to increase and this technology could offer the capability to acquire monitoring data more frequently with a much lower execution risk than wireline or rig-deployed surveys.

II. Authors

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Allan is the Manager of Reservoir Engineer at PG&E. His research interests include novel and applied integrity management techniques, risk assessment, financial analysis, and reserves estimation. He has been engaged in the oil and gas industry since 2005. He holds a B.S. in Petroleum and Natural Gas Engineering from West Virginia University and is a licensed professional engineer in the State of California. Allan is actively involved in the American Gas Association, Society of Petroleum Evaluation Engineers, and Society of Petroleum Engineers having served on the local board in 2009.

B. Chris Barclay

Chris is a Senior Reservoir Engineer at PG&E. He holds a B.S. in Petroleum Engineering from the University of Oklahoma and has worked in the underground gas storage industry since 2013. He has worked on drilling, workover, and completions projects as well as integrity management, reservoir, and production engineering and operations.

C. David Xu, Ph.D.

David has 20 years of experience in Silicon Valley High Tech industries and joined Pacific Gas and Electric Company's Gas Operation R&D and Innovation group in 2016. He is responsible for R&D project portfolio management covering corrosion, design, materials, construction, inspection, monitoring, and integrity management. Currently he also serves as vice chair on difficult-to-inspection at PRCI Inspection & Integrity Technical Committee. He is educated in material/mechanical engineering and welding with a doctoral degree from UC Berkeley.

D. Björn Paulsson, Ph.D.

Björn is the CEO and President of Paulsson, Inc. He received a Ph.D. from UC Berkeley in Seismology and Rock Mechanics in 1983. He currently holds nine patents, with one patent pending, and has published over 50 papers. He led large research projects while at Chevron and started and managed high technology seismic companies. During his career, he has developed new borehole seismic source and receiver technologies. Dr. Paulsson has managed many large projects developing borehole seismic instrumentation in the past 40 years, starting in 1977. This includes a $12 million, seven-year, successful project to develop a downhole seismic hydraulic based vibrator. Dr. Paulsson also proposed and managed a two-year $3.5 million successful project to develop an 80 – 400 level 4.5" OD downhole receiver array using production tubulars as the deployment mechanism operational to a temperature of 105°C (221°F). This system was successfully used in 55 3D VSP around the world recording all the largest 3D borehole seismic VSP surveys between 2003 and 2008. Dr. Paulsson has designed and developed the most sensitive and broadest bandwidth optical seismic vector sensor technology, funded by DOE, starting in 2010 until present.

E. Michael T. V. Wylie, Ph.D.

Michael is the principal systems engineer for Paulsson, Inc. He holds a Ph.D. in Electrical Engineering, specializing in fiber optic sensor development from the University of New Brunswick, Canada. Michael has 14 years of experience working with fiber optic sensors in both Academia and Commercial applications. At Paulsson, Inc. Michael is responsible for internal fiber optic interrogator and sensor development and selection of third-party sensing technologies such as those used for this project with PG&E.

F. Ruiqing He, Ph.D.

Ruiqing is VP of Geophysics at Paulsson, Inc. Dr. He received a Bachelor of Science in geology and geophysics from Nanjing University in China in 1992, and a Master of Software Engineering from Kansas State University in 2002, and a Ph.D. in Geophysics from University of Utah in 2006. Now a US citizen, he has 25 years of experience processing seismic data, including cross-well tomography, seismic multiple reflections' prediction, removal and imaging, 3D borehole and surface seismic data imaging, time-lapse seismic data processing, etc. He worked as an intern with Chevron in 2004 and with BP in 2005 before joining Paulsson Geophysical Services Inc as an algorithm and software developer in 2006. Since 2010, he has been the Vice President of Geophysics with Paulsson, Inc. He has 12 years of fiber optical seismic data processing experience.

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